INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Reducing Regulatory Barriers to Demand Management

AVIODED DISTRIBUTION COSTS AND CONGESTION PRICING FOR DISTRIBUTION NETWORKS IN NSW

- Draft Report
- July 2003

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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 and congestion pricing initiatives into the regulatory framework for NSW electricity distributors, and to study the feasibility and develop a framework for congestion pricing for distribution networks.

SKM is seeking feedback and comments on this draft report from stakeholders and interested parties. Comments should be received no later than 1 August 2003, and sent to Ben Kearney at Email: bkearney@skm.com.au (please also Cc: michael_seery@ipart.nsw.gov.au)

This report has been commissioned in response to calls from DNSPs and others for the introduction of congestion pricing and greater uptake of demand management options, and to address disincentives and regulatory barriers to the uptake of demand management by DNSPs.

Based on analysis of the disincentives to demand management that currently exist in the raw weighted average price cap, two models have been proposed:

- ***An incentive regulation mechanism*** that allocates both the costs and benefits of demand management to DNSPs, allowing them to keep any net value created. This gives a strong incentive to DNSPs to implement efficient demand management and congestion pricing.
- ***A cost recover mechanism*** where DNSPs recover the costs of demand management from end-users, and also pass the benefits through as cost savings. This transfers the risk and benefit of demand management to end-users, insulting DNSPs.

The second part of the report finds that congestion pricing is feasible, but will represent a significant change to the pricing of distribution services in NSW. The introduction of congestion pricing needs to be carefully considered, backed up by limited trials before a full rollout.

SKM has proposed a framework for congestion pricing, using congestion prices overlaid as a location specific premium on the existing “base” tariffs currently used by DNSPs. Other key features are:

- A threshold test so that congestion prices are only applied to significant capital expenditures.
- Caps on the size and movements in congestion prices, separate to the existing side constraints.
- Congestion prices should be available as payments to embedded generators.
- Congestion prices can include positive and negative cost components.
- Targeted time-of-use or interval meter roll-outs be considered to support congestion pricing.

Contents

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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.

As part of this review IPART has commissioned Sinclair Knight Merz, in conjunction with M-Co, to conduct a study of the feasibility of congestion pricing for distribution networks, calculating avoided distribution costs, and integrating congestion pricing and demand management into the regulatory framework for distributors in NSW.

Distribution costs make up around 37% of a typical energy user's bill[1], yet have not been substantially reformed since the introduction of the National Electricity Market in line with the other sectors of the electricity supply chain. Generation and transmission costs collectively account for around 54% of a typical bill[2], and have undergone substantial reforms since the mid 1990s. Generation costs are determined through a real-time market, which signals costs and constraints in time, and to a lesser extent, location[3]. Transmission charges are also calculated on a locational basis. The efficiency of current distribution charges has been raised as an issue, and whether improved outcomes could be achieved through the introduction of more cost reflective pricing and greater uptake of non-network alternatives. One key area identified is the application of congestion pricing to better signal to end-users and embedded generators the cost of distribution network constraints.

The National Electricity Code 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." Upstream and downstream implies efficient levels of investment in generation and demand management, both of which should

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[1] *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004*, IPART Nov 2002. Cost breakdown for a typical domestic customer, p6.

[2] *Ibid.*

[3] Locational signals are reasonably weak at present, with a single "pool" for each state effectively, and the calculation of actual transmission losses. Constraints are only signalled at a state level, with an additional locational signal superimposed relating to losses. Proposals to move to "regional" pools for the NEM have been put forward, and would provide additional locational signals if implemented.

be addressed by congestion pricing frameworks. Where this report refers to demand management, it should be taken to include distributed generation options unless specifically excluded.

This report examines some of the issues surrounding the introduction of congestion pricing. In particular, it seeks to develop a framework for congestion pricing that is both practical and effective. It then identifies issues with the regulation of distribution networks that may constitute barriers to congestion pricing and demand management, and proposes alternatives.

1.2 Comments sought on draft report

Work on this study commenced in mid May 2003, with a final report due in mid August 2003. Further analysis, consultation, and consideration of stakeholder comments on this draft report will be included in the final report. Note that the analysis of marginal costs and other aspects of the study are preliminary at present and include estimates of some data. Figures in this draft report should be considered as indicative only, and should not be quoted or used as the basis for decision making. Further analysis will be included in the final report, with the findings applied to case studies in NSW, once additional information from DNSPs has been received and analysed.

The purpose of this draft report is to set out preliminary findings and issues that have not been resolved, and seek stakeholder feedback. The proposed approaches represent SKM's current thinking on complex subjects, and in this regard should be regarded as a starting point to stimulate discussion, rather than an entrenched position.

Text in blue italics identifies issues on which SKM are specifically seeking feedback from stakeholders. Comments are also welcomed on other areas of the report or relevant issues stakeholders believe have not been covered.

Comments (preferred format is by email / MS Word or PDF) should be sent to Ben Kearney at Sinclair Knight Merz by no later than 1 August 2003 at:

- Email: bkearney@skm.com.au (please also Cc: michael_seery@ipart.nsw.gov.au)
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SECTION 1 – INTEGRATING DEMAND MANAGEMENT AND CONGESTION PRICING WITHIN THE REGULATORY FRAMEWORK FOR NSW DNSPS

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 or introduction of congestion pricing by DNSPs, and means of overcoming these barriers. Commonly cited regulatory barriers include uncertainty regarding the treatment of demand management costs, the issue of lost revenue for DNSPs undertaking demand management, and the lack of a clear efficiency incentive or share of benefits for DNSPs.

The Tribunal's 2002 inquiry into the Role of Demand Management[4] recognised these barriers, and proposed 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.

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, often seeking to mimic the outcomes that competition would achieve. This is an important issue for this study, as it examines how costs, efficiency improvements and risks are allocated. In an competitive market, efficiency improvements will appear at first as improved profits, but will eventually be eroded as others match these improvements in order to remain competitive. Efficiency and profitability cannot be measured against a fixed point, but

[4] 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

against a background of continuous improvement and innovation. The introduction of off-peak hot water has resulted in substantial demand management savings, which are now effectively transferred to end-users as lower prices - there is no allowance for the additional capacity or revenue DNSPs might have if off-peak hot water was not used. Over time it is reasonable that this also occur with the adoption of other demand management initiatives and the benefits of congestion pricing.

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 demand management if they erode profitability. To the extent that DNSPs are able to create value through innovative use of demand management, they should be rewarded. This report seeks to find an appropriate balance that will align the incentives for DNSPs with the economically efficient adoption of demand management, whilst delivering a share of these benefits to end-users.

Lost revenue associated with demand management is another complex but important issue. A DNSP implementing demand management may defer a capital investment by a few years, whereas reduced energy consumption will continue to occur for many years in the future. If DNSPs are compensated for this lost revenue in perpetuity, the cost will usually exceed the value of the capital deferral. The answer to this problem lies partially in the fact that that lost revenues are a transfer payment, not an economic cost. To the extent that DNSPs are allowed to recover these "costs", end-users should have cost savings from reduced consumption that at least offset any allowance made to DNSPs. If the demand management was *economically* efficient, the overall costs of energy supply will be lower than they otherwise would have been. It is also important to remember that demand management initiatives have a limited life, and in many instances will bring forward efficiency improvements that would occurred eventually rather than inducing a permanent change. Real lost revenues are not perpetual, but will decay over time – and determining an appropriate "sunset" horizon is a critical issue in achieving an equitable outcome.

Broader application of demand management 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) demand management programs elsewhere have also played an important capacity building role, which has been a crucial factor in the success of demand management in competitive markets adopted around the world in the last decade. A period of learning and capacity building will be required before the full benefits of demand management are realised, and DNSPs should not bear this responsibility and risk entirely. The most appropriate regulatory treatment and incentives will change as we move from a learning phase to a mature or integrated approach to demand management.

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3. What are the regulatory barriers?

The financial impact on a DNSP undertaking demand management is a function of the regulatory framework it faces. The *demand* impacts of a demand management 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 short or long term effect (for example interruptions that are suspended when the constraint is resolved, versus energy efficiency improvements that will continue for the life of the installation).

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 is a short term lost revenue issue.

The objectives of integrating the treatment of demand management costs into the regulatory framework are to align the financial drivers for DNSPs to the uptake of economically efficient demand management. To do this we must provide certain and transparent outcomes to DNSPs, and overcome disincentives to demand management inherent in the regulatory framework.

The financia l implications of demand management for DNSPs is a complex subject, which includes consideration of:

- The direct cost of implementing demand management initiatives
- Overhead, system and administrative costs incurred by DNSPs
- The value of reduced or deferred capital and operating expenditure, and how this affects DNSPs under the regulatory framework
- How the practical impact of demand management initiatives can be determined, given the uncertainty in load forecasting. Many examples exist of capital investments that have been deferred for a number of years due to lower than expected load growth (without demand management). Separating these effects from demand management will be difficult and imprecise in practice.
- The length of regulatory determinations, and boundary issues that occur at each determination.
- How are the benefits of demand management shared between participants, DNSPs, and other end-users?
- Who bears the risk of demand management initiatives that are ultimately unsuccessful in actually deferring network investments? Is this equitable considering the sharing of benefits in the previous point.

- Is the framework neutral with respect to the different demand management options available, such as interruptable loads, energy efficiency initiatives and embedded generation.

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.

The tribunal has also foreshadowed the possibility of other correction and incentive mechanisms, including a passthrough of avoided distribution costs associated with demand management in line with the recommendations of its Inquiry into Demand Management.

Pricing regulation for DNSPs must also be consistent with a number of other documents, 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 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, demand and capacity charges.

A limited number of passthrough items is also included in the currently proposed form of regulation. This includes TUOS and avoided TUOS payments to embedded generators, and may also include an adjustment for avoided distribution costs. Further details of the WAPC and proposed passthrough arrangements can be found in Appendix B.

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.

3.1.1 High level incentives inherent in WAPC regulation

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

- Minimise capital expenditure (at least in the short term. In the longer term, there may be a driver to increase investment in the network, as this is the basis of future regulated returns)
- 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 (demand, capacity charge, etc). This may constitute a barrier to demand management and congestion pricing, where these reduce consumption and hence revenues.

The Tribunal has already identified the issue of perverse incentives inherent in WAPC [5].

> Under a weighted average price cap, DNSPs can increase their profits by increasing sales. This creates a relatively good incentive for them to set prices efficiently, as in theory, if they price too high above cost they are likely to sell less and so receive lower profits.
>
> 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.

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

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3.1.2 What are the impacts of demand management on DNSPs?

The formula for the WAPC is:

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

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

giving total DUOS revenue for year t of:

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

Some of the effective impacts on DNSPs' revenue and profits are not immediately apparent, or are affected by second order effects. These marginal impacts are illustrated in the following table, assuming no adjustments or allowances for demand management. Each impact has been isolated (that is as if it occurred on its own):

A key assumption is that the WAPC is fixed for each regulatory period, having been determined based on efficient costs that include an allowance for forecast capital expenditure, and using a consumption forecast. Both these forecasts are effectively fixed for the period of the determination, and will be reset at the next determination to reflect any impacts of demand management. In this regard, any incentive mechanisms must deal effectively with regulatory reset, otherwise the long-term perverse incentives may not be adequately corrected.

Direct impact of DM / CP	Circumstances	Effect on DNSP through WAPC
Deferred capital expenditure	Item was included in forecast capital budget* for current regulatory determination period. Forecast expenditure was towards beginning of period, and deferral is not beyond the end of the current period..	DNSP revenue** is fixed for the period of the determination and includes an allowance for the capital item from the originally planned installation date. DNSP keeps this additional revenue, even though it's costs do not increase until the capital expense actually occurs. Windfall gain equal to NPV of deferral.
	Item was included in forecast capital budget for current regulatory determination period. Forecast expenditure was towards end of period, or deferral is beyond the end of the current period.	DNSP will retain windfall (as described above) for remainder of current period. From the start of the next period, the new capital forecast will reflect the deferral. DNSP revenue in new determination period includes an allowance for the capital item from the deferred installation date. Revenue reflects costs and there is no windfall gain or loss.
	Item was not included in forecast capital budget for current regulatory determination period.	Capital forecast for the new period will reflect the deferral. DNSP revenue in new determination period includes an allowance for the capital item from the deferred installation date. Revenue reflects costs and there is no windfall gain or loss.
Consumption volumes are reduced as a result of demand management initiatives	In current determination period	WAPC is based on a volume forecast fixed for the period of the determination. To the extent that volume is reduced, DNSP will under-recover allowed revenue.
	In future determination periods	New volume forecast will include impact of demand management***. WAPC is based on new (lower) forecast, and DNSP will recover allowed revenue.
Payments to end users for demand management (or congestion pricing) and other demand management costs.	Included in WAPC	WAPC revenue is fixed, so negative revenues mean more can be recovered from other tariffs and charges under with WAPC. Has the effect of automatically recovering those payments from all end-users.
Premium revenues from congestion pricing	Included in WAPC	Additional revenue would over-recover WAPC if uncorrected. Other tariffs and charges must be reduced (by the same amount) to bring WAPC back into balance. Has the effect of automatically ensuring congestion pricing does not result in DNSPs "price gouging", as any congestion pricing income reduces other income.

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3.2 Neutralising lost revenue

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

Options for neutralising the lost revenue disincentive include:

- ***Correct volume if it strays above or below the forecast.*** If actual volumes fall below forecast volumes by a set amount, an adjustment[6] is made to compensate the DNSP for the lost revenue. If the same mechanism is applied symmetrically, it can also neutralise any incentive the DNSPs have to maximise sales in the short term. This would help ensure the WAPC form of regulation does not conflict with Government's other policy objectives in energy (such as reducing greenhouse gas emissions).

  Capping volume within a reasonably tight range introduces problems of its own. One of the benefits of price cap regulation is that it automatically adjusts revenues to reflect increased costs associated with volume growth[7]. Capping the volume within a tight range under a WAPC effectively introduces a de-facto revenue cap, with the consequent potential for windfall gains and losses if volumes are different from forecasts. Given that the Tribunal has deliberately moved away from a fixed revenue cap, this correction mechanism would seem unsuitable.

- ***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. DNSPs would not be compensated for lost revenues where these are more than offset by unexpected load growth.

- ***Estimating lost revenues directly.*** The Tribunal or DNSPs would analyse and quantify lost revenue. If congestion pricing and demand management are only applied in constrained network areas, there should be sufficient "control groups" to enable a reasonable comparison of what consumption would have been without the effects of congestion pricing. Likewise, the

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[6] The adjustment could be made in practice by having a passthrough item (outside the WAPC) calculated to be equal to the volume shortfall x WAPC (either in aggregate, or for each tariff and component).

[7] A key concern of DNSPs is that there was little scope under the current fixed revenue cap to adjust their allowed revenue and capital costs during the period of the determination from 2000 – 2004, even as it became apparent that load and peak demand growth had been underestimated. One of the perceived benefits of the WAPC form of regulation is that DNSP's revenues will automatically adjust for volume changes, though this introduces the potential for windfall profits or losses as well.

impact of specific demand management projects on volume can be determined by a suitably qualified person, with reference to the types of measures installed.

Once the volume impact of congestion price and demand management has been determined, the impact on DNSP profitability can be calculated, and included as a component of avoided distribution costs to be recovered across the customer base in the following year.

The last two options are preferred. The "correct below forecast" method is attractive in its low cost, transparency and simplicity. It will also not necessarily be accurate, and will not compensate for lost revenue at all if it is against a background of high growth.

The "estimate directly" method should be more accurate, but will be costly to administer, and the answer will be subjective and open to dispute.

Which mechanism is preferred to correct for lost revenues? Is there a better alternative mechanism?

3.2.1 Are lost revenues lost forever?

It is possible that lost revenues may be recovered, at least partially, at the next regulatory reset. The WAPC is effectively determined by taking the efficient costs for the DNSP over the period of the determination, and dividing by forecast consumption volumes. If demand management results in reduced consumption, the DNSP will under-recover its forecast revenues.

At the next determination, however, the volume forecast should take this into account, and the new WAPC will be calculated to recover the DNSPs efficient costs using this reduced consumption volume. In this way, unexpected under-recovery of revenues should be limited to one regulatory determination.

Is this reasoning regarding unexpected under-recovery (due to errors between actual and forecast consumption volumes) correct? Will this problem correct itself at the next regulatory reset?

Should there be a correction for the impact of reduced assets arising from demand management? Is this more a drag on the rate at which DNSPs can invest in the network business, rather than an actual cost to the business? Is the current rate of growth in part due to an effective monopoly subsidy to uneconomic load growth?

3.3 What are avoided distribution costs

Avoided distribution costs is a proposed adjustment or passthrough factor foreshadowed by the Tribunal. It includes avoided costs for a DNSP, such as reduced or deferred capital expenditure, as well as any associated expenses not otherwise recovered. It is, in effect, a mechanism to neutralise any perverse incentives in the WAPC formula, with regard to lost revenue, avoided capital costs, and any other "second order" or feedback effects. It can also be used to provide a share of efficiency improvements associated with demand management.

Avoided distribution costs are not a passthrough of DUOS to embedded generators. Where the installation of an embedded generator helps to support a constrained area of the network, the generator should be eligible for congestion price payments by the DNSP, or be able to negotiate specific demand management payments. Where this is not the case (that is, the generator is located in a part of the network that is not constrained), distribution costs have not been reduced, and no additional payments should be made to the embedded generator.

The calculation of avoided distribution costs depends on the regulatory mechanism adopted for demand management and congestion price, and is described in the following sections.

4. Case Study – Castle Hill demand management project

Integral Energy are 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 demand management 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 demand management, network augmentation costing $3.2m will take place in 2004 and 2005. The base case is 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[8], and assumes there is no regulatory recognition of demand management. 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).

Note that the "efficient costs" of the DNSP (determined using cost building blocks) are treated as income, as this will be principal determinant of the DNSPs regulated revenues.

[8] Cashflows and impacts are simplified and for illustrative purposes, using preliminary analysis by SKM 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: WACC = 7.5%. Operating costs 2% of capital. Depreciation 2% straight line. Does not include tax or inflation effects, nor regulatory determination boundary issues (it is considered the key issues are adequately illustrated with this simple analysis).

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Base case – No DM Initiatives

Year	2003	2004	2005	2006	2007	2008	2009	2010
Network determination period	Current		Next					Next+1
DNSP direct costs								
Capital expenditure	-	$2,000	$1,200	-	-	-	-	-
Operating costs (2% of capital cost)	-	$40	$64	$64	$64	$64	$64	$64
Total cost (pre-tax)	-	$2,040	$1,264	$64	$64	$64	$64	$64
DNSP efficient costs (using building block approach)								
Return of capital (depreciation)	-	$40	$63	$62	$61	$59	$58	$57
Return on capital	$-	$150	$237	$232	$228	$223	$219	$214
Operating costs	-	$40	$64	$64	$64	$64	$64	$64
Regulated efficient income	$-	$150	$236	$230	$224	$219	$213	$207

Now consider the case when demand management is used to defer the investment for three years. Note this analysis determines the efficient costs year-by-year, assumes WAPC regulation is already in place[9],and assumes the DNSP bears the cost of demand management implementation (that is there is no explicit pass through of demand management costs).

Demand management assumptions are as follows:

Year	2003	2004	2005	2006	2007	2008	2009	2010
MVA above rating	1.2	1.8	2.5	3.1	3.8	4.4	New capacity added	
Incremental DM capacity required (MVA)	1.2	0.65	0.65	0.65	0.65	0.65		
Reduction in MWh sales[10]	1,029	1,620	2,224	2,842	3,481	4,145	3, 523	2,995

The cost of demand management initiatives is assumed to be $175 / kVA[11]. SKM have assumed DM is required to be "proven" 1 years in advance, so is based on the forecast overload for the following year, and is why the first year costs are higher than other years.

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[9] 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.

[10] Reduction in sales volume assumes some DM capacity comes from interruptable / dispatchable measures (that can be stopped once the constraint has ended) while some comes from permanently installed energy efficiency or load control measures that will continue to operate. Effective lost sales reduce at 15% pa after DM initiatives end (when capacity is installed) to account for measures that were brought forward, refurbishment and performance creep. Lost revenue is calculated at a constant DUOS price of 4.3¢/kWh.

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DM case – DM used to defer capital expenditure by 3 years

Year	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
DNSP direct costs								
Capital expenditure	-	-	-	-	$2,000	$1,200	-	-
Operating costs	-	-	-	-	$40	$64	$64	$64
Total cost (pre-tax)	-	-	-	-	$2,040	$1,264	$64	$64
DM Costs								
Cost of DM measures	$201	$114	$114	$114	$114	$114	-	-
Lost revenue	$44	$70	$96	$122	$150	$178	$151	$129
DNSP efficient costs (using building block approach)								
Return of capital (depreciation)	-	-	-	-	$40	$63	$62	$61
Return on capital	-	-	-	-	$150	$237	$232	$228
Operating costs	-	-	-	-	$40	$64	$64	$64
Regulated efficient income	-	-	-	-	$150	$236	$230	$224

This has the following impacts on NPV cashflows for Integral, end-users, and in total (economic benefit). Net present value (NPV) is calculated over 20 years at 7.5% discount rate:

Net present value benefit (cost) to DNSPs and end-users.

	For DNSP			For end-users			Net economic benefit (cost) of DM
	No DM	DM	Marginal impact of DM	No DM	DM	Marginal impact of DM	
Capital expenditure	($3,269)	($2,592)	$677	$-	$-	$-	$677
Regulated revenue	$2,954	$2,205	($748)	($2,954)	($2,205)	$748	$-
Direct cost of DM program	$-	($615)	($615)	$-	$-	$-	($615)
Lost revenue	$-	($910)	($910)	$-	$910	$910	$-
Net NPV position	($315)	($1,912)	($1,597)	($2,954)	($1,296)	$1,658	$61

From this analysis it is clear the incentives of DNSPs do not align with benefits to end-users or the economic net benefit (the sum of DNSP and end-user costs and benefits).

[11] Incremental – that is demand savings purchased in one year will continue at no cost into future years. This is not the expected cost provided by Integral, but was chosen for simplicity, and to provide a small economic benefit from DM in order to demonstrate the likely outcomes and operation of incentive mechanisms.

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5. Integration options

There are two fundamental approaches to integrating the complex cashflows from demand management within the regulatory framework for DNSPs. The first is to use an incentive regulation approach, that builds high level or aggregate profit drivers into the regulated revenues of DNSPs. The second is to use a cost recovery approach, by looking at the individual cash flows associated with each demand management initiative, and make explicit adjustments to regulated revenues. Both approaches are described, and feedback is sought on the merits of each approach.

The incentive regulation approach requires three adjustments to the basic WAPC framework:

- The economic benefit of demand management or congestion price (deferred capital) is allocated to the DNSP. Associated costs are not passed through to end users, but funded by the DNSP from these savings. Any net benefit (savings less costs) is retained by the DNSP as an incentive to pursue demand management.
- Ensuring congestion price revenues do not lead to a windfall profit for DNSPs (that is, ensuring energy income is equal to effic ient costs).
- Lost revenue is corrected for any determination periods where demand management initiatives are implemented, in order to neutralise the short term disincentive.

The cost recovery approach also requires three adjustments to the basic WAPC framework:

- The economic benefit of demand management or congestion price (deferred capital) is passed through to end-users, along with associated costs. Any net benefit (savings less costs) goes to end-users.
- Ensuring congestion price revenues do not lead to a windfall profit for DNSPs (that is, ensuring energy income is equal to efficient costs).
- Lost revenue is corrected for any determination periods where demand management initiatives are implemented, in order to neutralise the short term disincentive.

These two approaches are explored in more detail in the following sections. The adjustments are either made at the time of the determination, through the WAPC, or using avoided distribution costs or other explicit passthroughs.

Which of the two methods is preferred? Is the a better alternative method? Will the most appropriate method change over time (starting with a cost recovery approach while there is little experience with demand management, and moving to an incentive approach over time)?

5.1 Incentive mechanism implementation

The incentive regulation seeks to align the high level profit drivers for DNSPs with the uptake of efficient demand management, by making three corrections to DNSP revenues:

1) Giving the "pool of value created by capital deferral" to the DNSP to administer, from which they must fund demand management costs. The DNSP is effectively left with the remaining (net) value created, and hence an incentive to seek out cost effective demand management opportunities, ignore uneconomic demand management, and to minimise the cost of implementing demand management. These are the appropriate incentives.

   Note this approach also allocates the risk of demand management to DNSPs, who will pay the cost of unsuccessful demand management initiatives. DNSPs must also fund demand management initiatives themselves in the short term, and will only achieve a return when capital expenditure is actually deferred.

2) Ensuring congestion pricing does not lead to an net increase in overall revenues for the DNSP, above its efficient costs.

3) Neutralising the lost revenue issue.

5.1.1 Regulatory reset calculations for incentive regulation

No allowance is made for demand management costs, as they are funded by the DNSP. In this regard, demand management costs should be excluded from efficient operating costs included in the building block revenues.

5.1.2 WAPC calculations for incentive regulation

Congestion prices premiums are included in the WAPC[12] to ensure the DNSP does not over recover by using congestion pricing. These can be incorporated into the WAPC in practice in the same way as existing prices, as they will appear in as an additional tariff component.

Any congestion price or demand management payments to end users are excluded from the WAPC in order to have these costs effectively funded by the DNSP from value created by capital deferrals.

[12] Recall section 3.1.2 found premium revenues included in the WAPC will reduce other allowed revenues, and thus prevent any over-recover of efficient revenues (except to the extent intended by the first adjustment).

Note this conflicts with earlier indications by the Tribunal (that these costs would be "recognised"), but for good reason and should deliver the correct answer.

5.1.3 Avoided distribution cost calculations for incentive regulation

Avoided distribution costs are the value of capital deferrals or savings achieved through demand management or congestion price, and should be passed through to DNSPs.

Avoided distribution costs are thus calculated as:

- *In the regulatory period when demand management commenced*: No adjustment is necessary, as any capital deferral benefit is automatically passed to the DNSP.
- *In subsequent regulators periods, until the capital expenditure takes place*: Avoided distribution costs is calculated as the efficient operating costs related to the item of capital deferred, for the period for which it is deferred.

  This can be calculated in practice by comparing the "business as usual" capital forecast with the capital forecast that includes the impact of demand management or congestion price deferrals. Return on capital, return of capital, and average operating costs (i.e. building block costs) are calculated on the difference, and passed through to the DNSP as an additional revenue allowance.

  This should only be done where the DNSP can make a reasonable case that the deferral has been achieved through the use of demand management. In practice, many network augmentations are deferred for several years due to factors other than demand management, and this should not be passed to the DNSP as a windfall gain.

  Once the capital expenditure has occurred, the avoided distribution cost adjustment for that item is discontinued. It may be appropriate to adopt a "sunset" period where capital investments are removed entirely.

An adjustment for lost revenue (which can be notionally included in the "avoided distribution cost" passthrough, or a dedicated lost revenue passthrough) is calculated by estimating the reduction in volume in the determination period when demand management commenced (in accordance with section 3.2). This adjustment is discontinued in subsequent regulatory periods, when reduced volumes should be included in the consumption forecast upon which the WAPC is based.

5.1.4 Benefit sharing under incentive regulation

While giving the net benefit of demand management may seem overly generous to DNSPs, the following points should be considered:

- The sharing mechanism is proposed for the next determination period, and is to be reviewed at the end of that period. By this time there will be more practical experience in the application of demand management, and some changes to this mechanism may be considered. Over time as the use of demand management becomes "business as usual", it is envisaged a greater share will be returned to end-users (mimicking the erosion over time in windfall profits from a one-off efficiency gain that would occur in a competitive market. For example, the efficiency dividends from off-peak hot water are now effectively allocated to end-users.
- Being an incentive mechanism, there is a symmetrical downside as well. If DNSPs invest in demand management initiatives that are ultimately unsuccessful in deferring investment, they will fund these costs from their profits. Given the risk and uncertainty regarding demand management that currently exists, it may be reasonable for the Tribunal to consider "underwriting" a capped amount of demand management expenditure for the upcoming determination period, in order to encourage DNSPs to "learn by doing".
- There will be other benefits that accrue to end-users, that are outside the boundaries of this analysis. These include reduced retail energy costs (from both avoided energy, and possibly lower prices due to improved demand profile and responsiveness), lower greenhouse gas emissions, and other environmental impacts associated with electricity supply.
- In most cases demand management solutions will be marginal, which means the net benefits will be quite small anyway.
- The costs and risks of demand management are high given the current lack of experience in applying demand management in NSW.

5.2 Cost recovery mechanism implementation

The cost recovery regulation approach seeks to compensate the DNSP for all costs, and remove all windfall gains, associated with demand management and congestion price. It effectively passes the costs and benefits through to end-users.

Because DNSPs are being allowed to recover costs directly from end-users, it may be appropriate to have separate oversight of these demand management costs. Alternatively, the recoverable costs could be capped for the next determination period, giving DNSPs a pool from which they can fund demand management trials, without exposing end-users to too much risk.

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The cost recovery mechanism is implemented, by making three corrections to DNSP revenues:

1) Passing the “pool of value created by capital deferral” to end-users.

2) Ensuring congestion pricing does not lead to an net increase in overall revenues for the DNSP, above its efficient costs.

3) Neutralising the lost revenue issue.

5.2.1 Regulatory reset calculations for incentive regulation

Demand management costs are allowed to be recovered, as they are being passed through to end-users. It is proposed that direct payments to end-users be included in the WAPC. Operating costs should include any other demand management costs, such as the cost of conducting feasibility investigations, running the expressions of interest process, systems development or communications.

5.2.2 WAPC calculations for incentive regulation

Congestion prices premiums are included in the WAPC to ensure the DNSP does not over recover by using congestion pricing. These can be incorporated into the WAPC in practice in the same way as existing prices, as they will appear in as an additional tariff component.

Any congestion price or demand management payments to end users are included in the WAPC in order to have these costs effectively passed through to end-users.

5.2.3 Avoided distribution cost calculations for incentive regulation

Avoided distribution costs are the value of capital deferrals or savings achieved through demand management or congestion price, and should be passed through end-users.

Avoided distribution costs are thus calculated as:

- *In the regulatory period when demand management commenced*: Any revenue allowance relating to the deferred capital item should be returned to end-users from the originally forecast implementation date.

  This is calculated in practice by comparing the “business as usual” capital forecast (upon which the building block revenues were determined) with actual capital expenditures. Return on capital, return of capital, and average operating costs (i.e. building block costs) are calculated on the difference, and returned to end-users as a reduced revenue allowance.

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- *In subsequent regulators periods, until the capital expenditure takes place*: Provided the capital forecast in the subsequent regulatory period includes the deferral, no additional adjustment is necessary.

  To the extent that any additional deferrals are achieved, or demand management is unsuccessful and the capital expenditure is brought forward again, an adjustment (+ or -) as per the first regulatory period should be made.

  Once the capital expenditure has occurred, the avoided distribution cost adjustment for that item is discontinued. It may be appropriate to adopt a "sunset" period where capital investments are removed entirely.

An adjustment for lost revenue (which can be notionally included in the "avoided distribution cost" passthrough, or a dedicated lost revenue passthrough) is calculated in the same way as the incentive mechanism, by estimating the reduction in volume in the determination period when demand management commenced (in accordance with section 3.2). This adjustment is discontinued in subsequent regulatory periods, when reduced volumes should be included in the consumption forecast upon which the WAPC is based.

5.2.4 Benefit sharing under incentive regulation

A share of the benefits created through demand management and congestion price can be explicitly returned to DNSPs, by calculating the total costs and benefits, and allocating a share of the net benefit.

This would provide DNSPs with an incentive to pursue demand management, even under the cost recover mechanism. It is expected the share of benefits would reflect the minimal demand management risks borne by the DNSP under this mechanism.

Do these two models correctly adjust for the costs of demand management to DNSPs, and eliminate or substantially reduce the barriers to implementing demand management?

Which method is preferred, and why? Is there a superior alternative?

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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.

The benefits congestion price will have are uncertain, and will depend on the willingness of end-users to adjust their consumption in response to congestion pricing signals. If end-users value convenience 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).

To the extent that end-users are willing to adjust demand, the benefits are potentially very large. Some 10% of the approximately $12billion invested in distribution networks in NSW is utilised for only 1% of the year – if a $1billion hospital was only 1% utilised there would be a public outcry! DNSPs are currently spending $200million each year to meet the demands of load growth, a cost borne by all end-users.

Some commentators have expressed concern at the impact congestion price may have on end-users. The introduction of congestion price may impose significant adjustment costs on some end-users, or unfairly impact those that are unable to alter their consumption. For this reason, it is recommended if congestion pricing does proceed, it should start with a limited trial, in order to better understand the impact on end-users. Caps or "side constraints" on the maximum congestion price and rate of change are also proposed, and the framework proposed (where congestion prices are incorporated in the WAPC) means there will be no increase in DNSPs' overall revenue – any premium revenues returned from end-users in congested areas will be returned to other end-users as lower tariffs in order to keep with WAPC balanced. Over time this should result in cost savings to all end-users, as network constraints will only have a limited duration..

There is also a cost to end-users of poor 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

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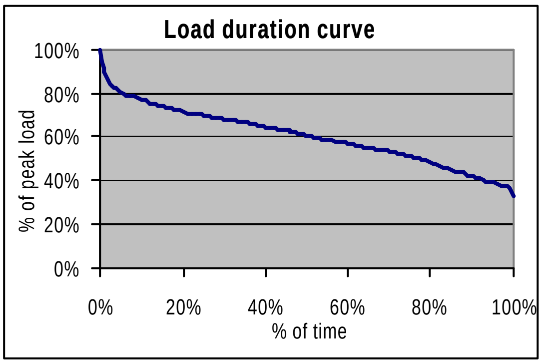
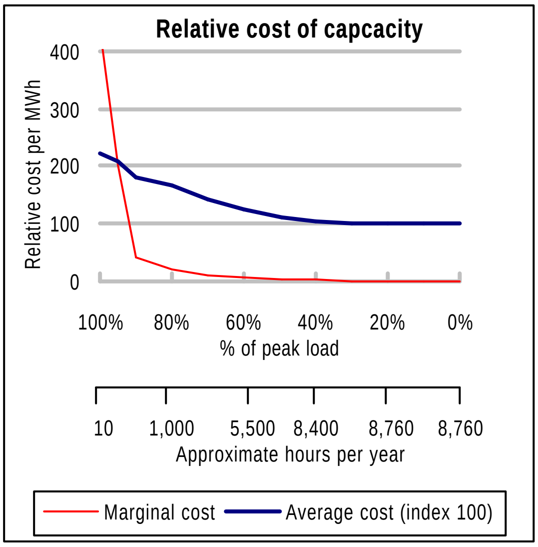
expensive than alternatives such as demand management or embedded generation. Just because these peak or congestion prices are not separately identified on users' bills, does not mean they aren't there. They already effectively pay congestion prices, they just can't see it.



The cost of providing capacity for peak loads can be up to 400 times the cost of base load (see charts 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 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.



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 Distribution Network Service Providers (DNSPs) in NSW to adopt congestion pricing as a means of controlling growing capital expenditure requirements.

The Inquiry found there was significant potential for demand management 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[13], which included recommendations relating to congestion pricing.

The inquiry concluded that Demand Management 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 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; 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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[13] 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

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

- **Environmentally driven**: reducing overall 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 retailers [risk] by encouraging end-users to reduce energy consumption in times of [high pool prices].

For example, off-peak hot water has been very successful in reducing peak demands in NSW, with around one third of the state peak demand available as controlled hot-water load. From an environmental perspective, however, off-peak hot water causes slightly higher greenhouse gas emissions than other electric water heating, and significantly more than gas or solar water heating[14].

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 demand management, it will primarily address network driven demand management, though demand management responses to congestion pricing may contribute to other outcomes as well.

The NSW Greenhouse Gas Abatement Scheme[15] 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 increases the cost of electricity, and provides financial incentives for actions to reduce emissions and/or consumption. It has, at least to a degree, internalised the cost of greenhouse gas emissions, which can no longer be considered as a pure externality. Those demand management 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.

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[14] Off-peak storage tanks are larger than continuous storage tanks, and hence have higher standing loses. Greenhouse emissions for gas and solar hot water are significantly lower than electricity. To the extent that off-peak tariffs makes electric hot water a financially attractive option, they may result in higher greenhouse emissions than would otherwise exist.

[15] 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.

6.2 Definition of congestion pricing

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 signal peak network loads to end-users.
- ***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 is economically efficient, but could impose significant 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 incentives, 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 total price signal can be made up of several elements, including tariffs, connection 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 an additional unit of consumption on a constrained network.
>
> The constraint targeted by congestion pricing can be by location, time, or preferably both. The constraint must be consistent and predictable, and defined (by location and/or time) to avoid targeting end-users or consumption not contributing to congestion to the extent that this is practical.
>
> Congestion prices can be voluntary or compulsory, with voluntary schemes preferable. It should not discriminate between end-users or customer classes, except to the extent that they contribute to network congestion.

Is this definition of congestion pricing correct and appropriate? Are inclining block tariffs or seasonal tariffs necessarily congestion pricing, or only if they are applied in constrained locations of the network?

The "ideal" congestion pricing scheme outlined below may not be practical in all respects, but does give an indication of a pure form of congestion pricing, or a "light on the hill" for the design of a practical scheme. A range of issues and equity concerns will constrain a practical congestion pricing scheme – these are outlined in the following section.

Congestion occurs when network loads exceed existing capacity limits. In this situation network operators should seek to reduce load or increase capacity. The cost of congestion, in these cases, is the lowest cost of the available options. At present, only one of these options is available, 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.

Congestion prices must be defined in time and location:

- ***Time***. Network congestion generally occurs for only a few minutes or hours of a day, and the days on which congestion occurs exhibit weekly and seasonal patterns. An ideal congestion pricing mechanism would charge higher prices only during periods when congestion occurs.
- ***Location***. Networks comprise multiple circuits, with congestion occurring on only a subset of them. An ideal congestion pricing mechanism would involve charging congestion prices only

on constrained elements, so that consumers see an incentive to locate on parts of the network that are not congested.

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.

An ideal congestion pricing mechanism should be voluntary so that consumers can limit their exposure to price volatility and select the options that suit them best. Advanced notice of emerging constraints make it less costly for consumers to respond to pricing signals, and greater certainty about future congestion prices often increases responsiveness to price signals.

6.3 Congestion and average cost pricing

DNSPs in NSW currently use an average cost pricing approach, where the charges for each tariff are 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).

Congestion pricing, on the other hand, is forward looking. It is not so much 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 spare capacity will have congestion prices of zero, while areas of the network that are approaching existing capacity will have high congestion prices.

This is not to say that average pricing is "bad" and congestion pricing is "good". Average cost pricing is good for recovering sunk costs, is equitable and provides stable cash flows. If there was no growth, congestion 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, and in the long term higher costs for all users.

The following example of two hypothetical networks illustrates this point Each network currently has a peak load of 1000MW, but with different capacity, utilisation and growth rates. The inherent price signals under average and congestion pricing are compared:

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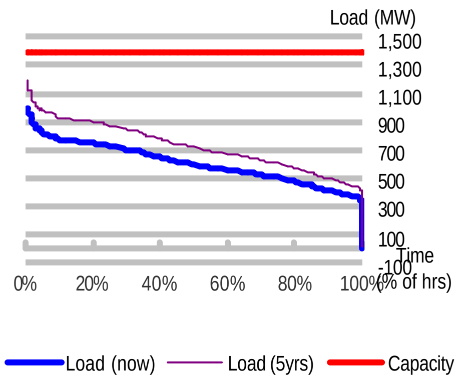
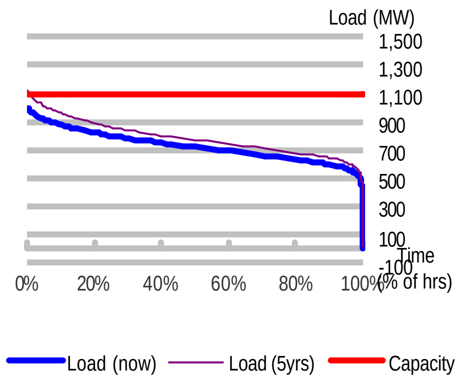
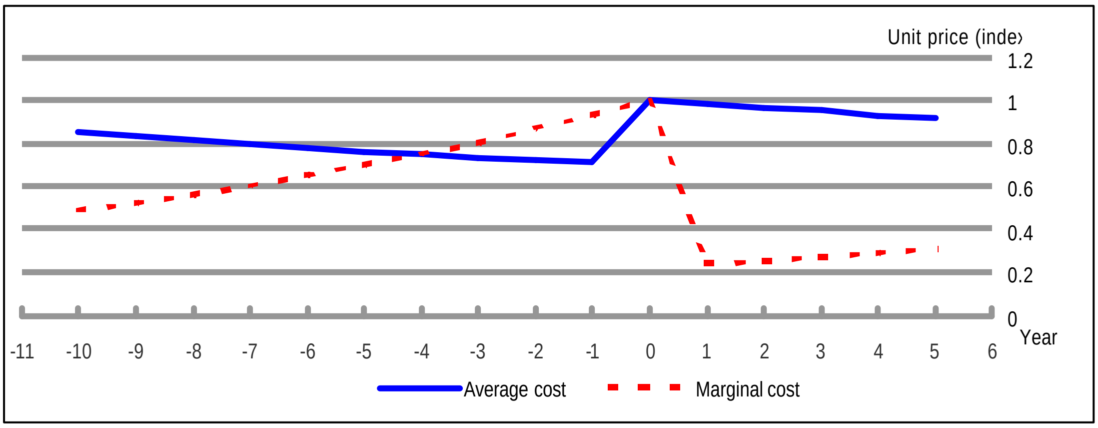
Network:	Network "A"	Network "B"
Loads	"Poor" load factor, moderate growth, but no imminent capacity constraint (see load duration curve** chart below). Peak load is currently 1,000MW, growing to 1,200 over the next 5 years. Existing capacity is 1,400MW, giving 10 or more years of capacity.	"Good" load factor, slow growth but approaching capacity (see load duration chart below). Peak load is currently 1,000MW, growing to 1,100 over the next 5 years. Existing capacity is 1,100 MW, indicating investment in additional capacity will be required within 5 years.
(Load duration curve chart)		
Price signals under average cost pricing	Lower utilisation (70%) and load factor (60%) leads to average unit price ~50% higher than Network "B". Sufficient capacity for 10+ years of growth, but higher prices discourage additional consumption.	High utilisation (90%+) 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 4 years, yet lower prices encourage additional consumption.
Price signals under congestion pricing	Looking forward, no augmentation is required for at least 10 years. Congestion price is zero.	Augmentation is required in approximately 4 years. Congestion price rises to signal emerging constraint, and should push price of Network "B" above that of Network "A" to signal the additional spare capacity in "A"

**Note: A "load duration curve" is a chart showing all the loads (for each hour or half hour of the year) in 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, explaining price variations, and analysing the types of demand management approaches that will be effective (for example a high peak for very short time may respond well to interruptible strategies, whereas peaks of longer duration are less likely to be prepared to interrupt for longer periods).

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 prices, as shown in the chart below of a hypothetical network augmentation in Year 0. If we consider the path the two prices will take over time, the benefits and shortcomings of the two approaches are apparent:



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 congestion pricing, the marginal price rises as the investment gets closer[16], and then drops away sharply (looking forward to the next investment in say 20 years) This sends the right consumption signals to end-users, but the volatility in marginal pricing has a number of implications:

- ***Price changes under congestion pricing are larger and faster.*** In the above example, the congestion price changes by 4.2:1, compared to 1.4:1 for average pricing..
- ***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. If DNSP revenues are linked to these more volatile consumption components, they will become more volatile.
- ***This is compounded by the 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.

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[16] 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.

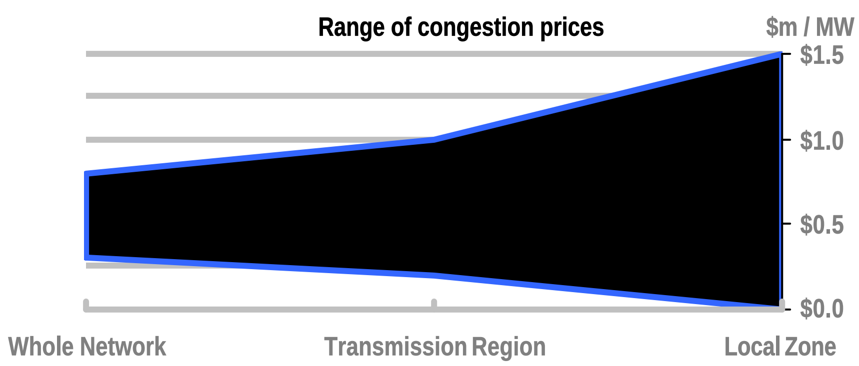
6.3.1 Likely range of congestion prices

Preliminary analysis by SKM shows congestion prices in NSW are likely to fall within the following ranges:

Location	Definition	Range of congestion prices ($m / MVA)	
		$ invested per MVA of peak demand growth	$NPV deferral value delivered by 1MVA
Whole network	Cost of peak demand growth across each DNSPs entire network	$0.7 - $1.6	$0.3 - $0.8
Regional	Cost of peak demand growth at a transmission bulk supply point	Awaiting additional information from DNSPs	
Zonal	Cost of peak demand growth at a zone substation	$0 - $5.0	$0 - $1.5

Source: Preliminary analysis of data from Total Cost Review – Draft Report June 2003, DNSP Annual Planning Statements, and questionnaires sent to DNSPs. Note these are the results of preliminary analysis, and further information and analysis will be undertaken for the final report. Discretion should be used in interpreting these results, which are subject to change.

This preliminary analysis supports the hypothesis that the size and range of congestion prices will increase as location becomes more tightly defined. This is illustrated in the following chart:



This initial analysis suggests that the range of congestion prices diverge at a local (zone substation) level, with the upper bound significantly above the system average. This supports the argument that congestion pricing should be applied at a local level, as averaging congestion prices across a DNSPs entire network has the effect of significantly watering down the congestion pricing signals in some zones, while overcharging in others. It is also worth noting that the upper level of these congestion prices, particularly at individual zone level, is within the cost range of some embedded generation and demand management options, making them viable in some situations.

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 that must be borne in mind when considering congestion pricing. 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 congestion 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. This raises a number of concerns:

- That DNSPs might not earn sufficient revenues to cover the cost of constructing and maintaining the network, or may over recover efficient costs.
- Even if forecast revenues were correct, congestion prices (and consumption components) are likely to be more volatile than current arrangements, and lead to an increase in the frequency and size of mismatches between forecast and actual revenues.
- Congestion pricing raises equity issues. As East Cape 17 noted:

> DNSPs are required to consider customer impacts and equity issues as well as economic efficiency… In designing the structure of network tariffs, a balance must be struck between providing prices which signal actual network costs… and meeting reasonable standards of fairness and equity… One approach to reconciling these objectives is to avoid sudden changes in prices by signalling well in advance areas of emerging congestion and phasing in price changes. Another approach would be to make greater use of optional tariffs. A further alternative is to use targeted rebates for reductions in energy use and maximum loads.

Possible solutions include

- Using "administered" congestion prices, calculated in order to return correct revenues, rather than the "pure" marginal cost.
- Recovering only a portion of revenues from congestion prices, with the remainder recovered from traditional historic average costs. This provides stability and continuity, while allowing congestion prices to be added to base tariffs in constrained areas.

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[17] *Efficient Network Pricing and Demand Management*, East Cape Pty Ltd for IPART Research Paper 18, February 2002. Available from www.ipart.nsw.gov.au under the Inquiry into demand management.

7.1.2 Price shocks to end-users

Congestion prices could rise significantly above the costs currently seen by end-users. Price shocks to end-users are undesirable for a number of reasons.

Section 6.3.1 identified congestion prices (on a deferral value basis) as high as $1.5m / MW, or $1,500 / kW. If we consider a constraint that lasts for 10 years, the congestion price would be $150 / kW pa (a very simplified example – in practice, setting congestion prices will be more complex).

Typical demand charges for end-users are significantly lower than this, in the range of $55 - $110 / kVA pa.[18]. In other words, congestion prices *at the top end of the likely range* could more than double the demand component, adding between 15% and 80% to a customers bill. Whether this level of price increase is acceptable within the congestion pricing framework is a matter for further consultation, bearing in mind this is the top end of the likely range of congestion prices.

Not only is the size of the congestion price signal important, but the rate of change of congestion price signals as well. Rapidly fluctuating congestion prices will confuse and frustrate end-users, and potentially diminish the price signal being conveyed through congestion pricing. It is likely the most effective price signals will be stable medium-long term prices.

Are side constraints or caps on congestion prices appropriate? What is a reasonable level that protects end-users from price shocks, while still delivering congestion prices that can be expected to deliver a demand response?

7.1.3 Effectiveness of congestion pricing

To be effective at reducing DNSP investment, end-users must respond to congestion pricing by reducing their 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 there must be a capability to service these needs (which may take several years to develop and mature), as well as a value proposition that is attractive (such as payments or savings above the value end-users place on convenience). The size and timing of response is unknown, and will only be determined through experience.

[18] Based on published prices from the 4 DNSPs in NSW, with analysis by SKM.

In order to ensure end-users are charged the correct amount, demand response must also be measurable (see box at right).

Congestion prices built into tariffs will affect all end-users, whereas those structured as side-payments or incentives will only affect end-users that participate in demand response programs. While the first option is likely to gain a larger response (all users will have an incentive to change their consumption), it will also affect a significant proportion that can not respond. There are arguments for and against this approach.

These measurement issues increase transaction costs, reducing the amount available to spend on useful demand responses. For these reasons, congestion prices built into tariffs is preferred to side payments or incentives. The exception is where the congestion price signal that can be conveyed through a tariff is limited (for example by a cap or side constraint) to below the actual marginal cost. In this situation, side-payments or incentives can be made at the full marginal cost without imposing price shocks on other end-users. This option should be available to DNSPs where they believe it can deliver improved outcomes.

Measuring demand response

Measuring demand response is notoriously difficult, because it is always with reference to "what would have happened in the absence of demand management". This is by definition impossible to determine with 100% accuracy. The two main issues are:

- What is the "without demand management" reference level? Is this a "baseline" of past consumption (that may not accurately reflect future consumption)?…How do we correct for changes in weather, production, outsourcing, new entrants, technology improvements etc?
- "Free riders" and "additionality" issues. Just because someone has reduced demand, does not mean it was in response to the demand management initiative. They may have done the same thing anyway.

"Rebate" style demand management programs that offer incentives to participants that can "reduce demand" will always encounter these issues, pushing up measurement and verification costs. These issues are currently being worked through with Demand Side Abatement projects under the NSW Greenhouse Benchmarks Scheme.

On the other hand, "cost reflective pricing" type programs do not suffer from these issues. Congestion price signals are built into tariffs, and users charged according to their actual consumption. End-users respond to the price signals as they see fit, and those that can reduce their demand during constrained periods will pay a correspondingly lower amount.

Another factor in the success of congestion pricing signals will be consistency, simplicity, and stability. End-users must be able to understand the price signals, and believe they will be in place for a sufficient time to justify changing their behaviour or investing capital to enable them to respond. End-users will expect capital investments to provide a commercial return of ten years or more. This will be an important factor in any trials of congestion pricing – trials must run for at least 2 or 3 years in order to gauge the full potential, and give minimum commitments to participating end-users.

7.1.4 There is no market price

Congestion pricing schemes for transmission networks (such as that in place at Transpower in New Zealand, and to an extent interconnectors between state pools in the Australian National Electricity Market) are able to use wholesale 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.

Market mechanisms are not available for distribution networks, and so the congestion price must be calculated explicitly. Section 0 demonstrated that the marginal cost of consumption drops sharply after a constraint is no longer present. While this is appropriate in the case where the DNSP has invested in additional capacity, it may not provide the correct signals where embedded generators or demand management alternatives have provided the solution. In this case, the generator or demand management proponent will not receive congestion payments (or save paying congestion prices), and so will not have the appropriate incentive to implement the project.

The regulated monopoly nature of electricity networks allows some flexibility in the treatment of congestion pricing and its recovery that would not be possible in a perfect market setting. That is, it is possible to artificially set the congestion price or payments in order to smooth the price path. This may be worth considering where it limits price shocks to end-users, and also where it will be more effective in bringing forth demand management solutions.

Should congestion prices reflect the actual marginal price, or is it appropriate to use an artificial or administered congestion price? Under what circumstances?

7.1.5 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. As outlined in section 7.1.3, congestion pricing schemes structured as side-payments will have higher transaction costs, and hence reduced effectiveness. For this reason, side-payments should only be used when there is good reason to do so (such as the case with embedded generators, where there is a need to contract for performance guarantees, or payments need to be specifically structured). Tariff charges that reflect the cost of supply should be the principal means of applying congestion prices.

Connection charges are a possible point for application of congestion pricing that has not received a great deal of attention. Applying congestion pricing at the time of connection has a number of advantages. Firstly, it lets users see the cost of new loads at a time when they have maximum influence over the design and specification of equipment. Secondly, it can at least partially overcome the "developer – owner" issue[19], by transferring some of the future costs of congestion to the developer. It also has some disadvantages. It is inequitable for a start, as only new entrants face congestion prices, whereas existing users received free connection. Secondly, it only applies congestion prices to new loads, or applies them to new loads twice (through connection charges, and then through tariffs).

Should congestion prices be applied to connection charges for new connections? Should congestion prices be available as side payments, and if-so under what circumstances? Why is this preferable to incorporating them in tariffs?

7.2 Regulatory issues

7.2.1 Uncertainty regarding treatment of demand management costs

A key issue for DNSPs contemplating demand management alternatives to network expansion is the recognition and treatment of demand management costs. While the Tribunal has publicly stated it will recognise prudent demand management expenditures and allow DNSPs to recover these costs, this remains an area of concern and confusion. SKM believes the treatment needs to be more

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[19] 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. Unsophisticated owners are not fully recognising the future running costs when valuing the buildings, and hence not providing economically efficient signals to developers (to build efficient buildings). To this end, there is a market failure that is a barrier to demand management. Another commonly identified barrier is the "tenant – landlord" barrier, where the tenant pays the energy bills, but the landlord controls some of the energy consuming equipment, and has no incentive to improve its efficiency.

explicit, in order to provide DNSPs with the certainty they require to invest in demand management with confidence.

There are two main options that allow these costs to be recovered:

- ***Explicit identification and recovery of costs.*** DNSPs would identify all demand management expenditures, prepare a case as to why they should be regarded as prudent, and submit this to the regulator for approval. This method will ensure that costs are explicitly recognised, and can provide DNSPs with guaranteed recovery of costs if that is the wish of the regulator. It will also have high transaction costs, and is not in the spirit of light-handed regulation.
- ***Incentive regulation.*** If the right set of incentives can be found, DNSPs will have an automatic incentive to invest in demand management where this is cost effective. This has the advantage of being light-handed, but can allow unintended outcomes to continue unchecked, or conflict with longer-term incentives (for example, DNSPs may believe that in the long term their regulatory asset base will be eroded through demand management, and that they are not adequately compensated in the short term).

These issues are dealt with in Section 1 of this report..

7.3 Technical issues

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

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).

SKM considers congestion pricing is 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.

Should interval or time-of-use meters be made compulsory for some end-users? What are reasonable criteria for targeting users (size; cost of constraint; equipment such as air conditioners…) and what safeguards or protections need to be put in place?

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 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. The development of the internet, wireless networks and other mobile technologies in the past few years has pushed the boundary of what is possible and economic, and it continues to move.

7.3.3 Identifying customers

Zone boundaries are often "blurry" and fluid in practice, as a result of the low-voltage network and switching in the distribution system. 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.

The cost of identifying end-users in a particular zone, or developing systems (GIS?) to automate this task should be considered in the costs and benefits tests for congestion pricing, but do not present a significant technical barrier to congestion pricing.

Are "approximate" borders for a congestion pricing region reasonable? For example, postcode boundaries or major roads, rather than trying to rigorously define a zone boundary. What is the trade off in terms of lost efficiency of congestion pricing, vs simplicity of implementation and communication to customers.

7.4 Market issues

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

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7.4.1 Acceptability of locational pricing signals

From the results of analysis of the range of congestion prices earlier in this report (6.3.1), SKM is of the view that locational signals be included within the congestion pricing framework.

As network constraints are defined more precisely, the accuracy and effectiveness of the price signals will improve. There is also a trade off, in that transaction costs will increase with the precision of the constraint definition by location and time. This implies there is an "optimum" level, below which it is simply not cost effective to apply individual congestion prices. In practice, this is likely to be zone substation level at present, though this may get smaller as experience improved, and the cost of communications technologies continues to fall.

Some growth trends are consistent across the entire network of each DNSP, and may appropriately be dealt with via uniform system-wide congestion pricing tariffs to signal times when the network as a whole is constrained. Time of use tariffs and increasing block tariffs would fall into this category (provided they pass the other criteria for congestion pricing, such as being calculated on a forward looking basis).

In order to keep transaction costs to a reasonable level, locational congestion pricing should only be applied where the marginal price or size of network investment exceeds a threshold level. For example, a $2m minimum investment over a 5 year period, or where the marginal cost is higher than the system average marginal cost for that DNSP by at least 50%. Without these thresholds, there is the potential for literally hundreds of separate locational prices for every zone[20] in NSW. Once DNSPs, customers, retailers and energy service providers have developed experience with the application of congestion pricing, these thresholds can be reviewed.

Note that congestion prices won't necessarily be higher in regional areas – in fact, where a regional centre is in decline, it will have zero or even negative congestion prices, which will act to encourage new loads and investments in the area compared to areas experiencing strong growth in demand.

What are appropriate thresholds for locational congestion pricing ?

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[20] There are around 400 zone substations supplying NSW, with the larger DNSPs have up to 150 each. Applying a separate price to every zone is impractical with current technology and systems, would add to the costs to DNSPs, retailers and end-users, for modest additional benefits (except for the zones with highest marginal cost, the majority are likely to have quite low and uniform marginal costs).

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Should "non-locational" congestion prices (for example, targeting hot summer day peak loads that tend to affect virtually the entire network) be allowed? What controls should be put in place to ensure this does not target loads that are not contributing to a constraint?

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.

It is likely that congestion price signals will be added to all tariffs for end-users within a congested area, otherwise all users will stay on a base (without congestion pricing) tariff. It is important that a range of congestion tariff options be available to enable end-users to manage their costs when exposed to congestion prices.

Retailers and energy service providers should be consulted in the design and development of congestion pricing schemes, in order to gain further market insights, and ensure congestion price proposals do not impose undue costs.

Compulsory tariffs (or a restricted number of tariff choices) for some users, such as large domestic customers with air-conditioning, may be required in order to achieve sufficient take-up to be effective.

7.4.3 Impact of retailers on congestion pricing

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). That said, retailers already manage significant risks in the National Electricity Market, and it may be that some end-users value simple flat tariffs sufficiently to pay a risk premium to retailers for this service.

Discussions with retailers indicate a preference to pass through network tariff structures directly, although there are some 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 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.

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[21], 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
- Shedable 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.

[21] 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 it's 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:

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 it's congestion prices based on the proportion of it's 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 interruptible loads are determined based on the expected load profile of interruptible 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[22]. 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.

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

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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 demand management 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 the 4 DNSPs. While this is superficially nice, 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 industries where consumers are exposed to locational signals:

- Natural gas network tariffs in NSW
- Housing
- Public transport (that contains both locational and congestion price signals).

In these markets, consumers have accepted locational and congestion pricing signals without question.

As recently as the 1990s NSW had 22 separate distributors charging different prices to consumers, and even more prior to that. Prices have tended to converge as distributors merged, but is this a valid reason for introducing postage stamp pricing for electricity, and what is the cost in unnecessary capital expenditure of this approach?

Should locational and congestion pricing signals be introduced for electricity distribution in NSW? If not, what characteristics of electricity distribution make it unsuitable for locational signals?

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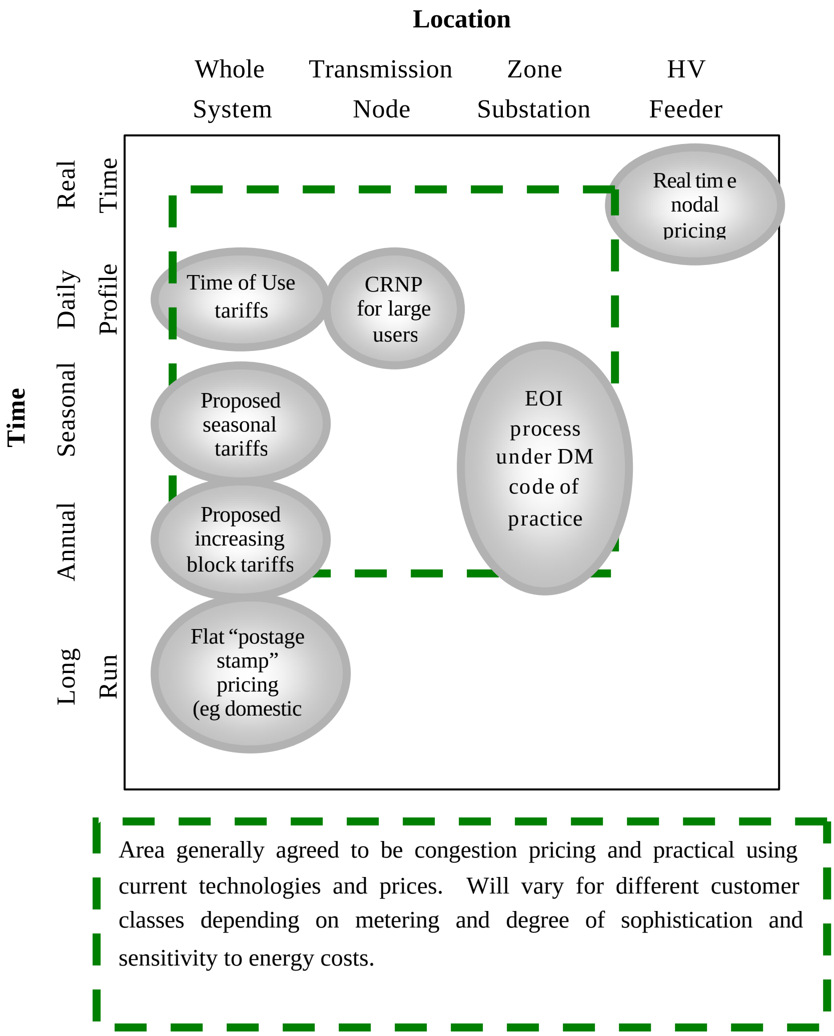
9. Proposed framework for Congestion Pricing

The following diagram provides 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 examples of tariffs and proposed pricing schemes are shown to give the model some context.



This diagram is obviously a simplification, and 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 and forward looking pricing. It does, however, provide a starting point for categorising and analysing possible congestion pricing alternatives.

Congestion pricing is proposed for timeframes of no more than 12 months (for example, increasing block tariffs defined on annual consumption), but preferably more tightly defined using seasonal and time-of-use components (where metering allows). Real time congestion pricing is considered feasible for larger / more sophisticated users already , and for smaller users through interruptability and load control.

Congestion pricing should embody locational signals, due to the wide range of marginal prices experienced on the network (see section 6.3.1). System-wide congestion prices should only be used where congestion is widespread across the whole network at the same times, otherwise congestion prices should be confined to a specific location (with boundaries set according to uniform cost and timing of constraints. This will typically be the load downstream of the constrained item of equipment).

Congestion prices would be added to base tariffs as a locational overlay. The marginal price in a constrained area would be converted to congestion price signals compatible with each of the tariffs in use in that area, and added to the base tariff. To this extent, all customers located within a constrained area will face congestion price signals. 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.

In order for congestion pricing to be effective, it is considered necessary for the total revenue from congested areas to be above the "baseline" revenue. In other words, uniform tariffs across a whole DNSP's franchise are not considered adequate to correctly signal congestion. It is unlikely end-users would switch from an "unconstrained default" tariff to a "cost reflective constrained" tariff, no matter how good their load profile or ability to shift load. For this reason, a congestion premium is proposed to be added to all tariffs in a constrained area (depending on the capability of each end-user's meters), to ensure all end-users in the area will be aware of the constraint, and provide an incentive to switch to more flexible or cost reflective tariffs (such as time-of-use or seasonal tariffs) in order to better manage costs.

Specific details of the proposed framework are outlined below. Where thresholds or limits are proposed, they should be regarded as examples for discussion purposes only.

9.1 Details of the framework

Based on the issues previously identified, and the simple model shown above, SKM proposes the following framework for congestion pricing:

- DNSPs continue to recover a significant proportion (say 80%) of their revenues on an average (historical) cost basis – that is, on the same basis they are currently recovered. Base tariffs will continue to be calculated in the usual manner (but will be slightly lower to account for the amount recoverable from congestion prices. This is in effect the "dividend" for congestion pricing to end-users in areas that are not constrained).
- The remaining proportion (say 20%[23]) of allowable revenues be set aside to be recovered through congestion pricing. Congestion prices will be calculated based on forward looking marginal prices, and applied as an additional component to base tariffs.
- A threshold test should be applied to congested areas of the network, that allows congestion prices to be applied only where the size of the investment, or the marginal price, is above a minimum threshold. This avoids having hundreds of different but low-level congestion prices, and concentrates congestion pricing in areas where it is likely to have a significant impact. The thresholds in the Demand Management Code of Practice to trigger an expression of interest (EOI) process may be a suitable starting point for these thresholds.
- The actual congestion price for each location does not have to be the "pure" marginal price. Adjustments (still consistent with forward looking marginal price) to the calculation methodology are allowed where there is a reasonable justification for the method used. The congestion price applied must not exceed the long run marginal cost of additional capacity. Objectives for adjusting the marginal price might include smoothing congestion prices over time, providing sufficient advance warning of constraints, or special payments to embedded generators or large demand management projects that materially affect the congestion price.
- Any congestion price component charged to loads should be available as a payment to embedded generators.
- Congestion prices can include positive and negative cost components. Rebates or payments for interruptions or to embedded generators are treated as negative cost tariffs.

[23] Further analysis will be required to determine the required proportion, based on the size and frequency of constraints. The purpose of allocating only a share of revenue to congestion prices is to limit the size of congestion price signals to a reasonable level, and provide revenue stability. To the extent that the proportions can be managed dynamically (as the degree of congestion changes) this should be allowed, and may even be necessary to avoid price shocks and to ensure stable revenue flows. The proportion of revenues recovered from congestion prices, and hence the sharpness of congestion price signals, could be increased gradually over time, as DNSPs, regulators and end-users become more familiar with the application of congestion pricing.

- Congestion prices are locational, with separate congestion prices applying to different constrained areas. Each area is defined according to uniform congestion prices and times, so that congestion prices accurately target constraints in space and time. For example, there may be a requirement that at least (say) 90% of the consumption subject to congestion charges be affected by the constraint, and that the actual marginal price within a single constraint area varies by no more than (say) 10%.[24]
- System-wide congestion prices (without a locational component, such as increasing block tariffs or seasonal tariffs) should only be used where they meet the uniformity criteria from the point above. If there is greater variation in the timing or size of congestion price signals across a DNSPs network, it should not be applying a uniform tariff to all end-users, or using the lowest congestion price over its network.
- Congestion prices will be subject to side constraints separate to base tariffs (which will inherit the existing side constraints). The side constraints for congestion prices will cap the maximum size of congestion prices, as well as the rate of change (but allow greater flexibility than currently exists for base tariffs). For example, congestion prices may not add more than (say) 25% to any end-user's base bill, and congestion pricing components should not change by more than (say) 5% of the base bill in any one year.
- Congestion prices should generally be incorporated into tariffs, or payments for interruptability and load control. Side payments should only be used where there is reasonable justification (including the ability to capture projects that will not proceed at the "capped" congestion price, but are viable at less than the actual marginal cost for the constraint[25], or where specific performance guarantees are required).
- Interruptible and controlled load tariffs should be encouraged as voluntary options for end-users. These can be structured around performance payments for each interruption, or as a lower price for loads that can be controlled by the DNSP (similar to existing off-peak tariffs. The EnergyAustralia LV Energy40 TOU tariff is an example of this).
- Consideration of incorporating congestion prices into connection charges will be considered where there is a reasonable justification, and the DNSP can demonstrate it has adequately addressed equity concerns.
- Targeted time-of-use or interval meter roll-outs should be considered where the cost of the meters (less any end-user contribution) is justified by the value of the response to improved congestion pricing signals afforded by the meters. Compulsory changes to end-users' tariffs

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[24] In this way, some discretion or simplification is possible in setting the boundaries of a congested area (to make it easier to administer), and several related constraints can be grouped together as a single area (provided the marginal costs are within a reasonably narrow range).

[25] For example, in a given location the calculated marginal price might be $500 / kVA per annum, but the side constraints allow a maximum of $250 / kVA per annum to be applied as a congestion price signal. In this case, payments of up to $500 / kVA per annum as side payments or negotiated incentives would be allowed, where it can be demonstrated some measures will not proceed at the $250 / kVA per annum rate.

(such as from a flat to a time-of-use tariff) may be allowed where there is sufficient justification (for example, where a user has a poor load profile and is unlikely to voluntarily switch to a tariff with sharper congestion prices). An alternative may be to charge an additional premium (say to end-users above a certain size on flat tariffs, or use an inclining block tariff), as an additional incentive to change to more cost reflective tariffs.

It is proposed that initially DNSPs would prepare a congestion pricing proposal, in line with the above framework, to be agreed with IPART prior to implementation. Once more experience has been gained with the application of congestion prices, more detailed guidelines could be developed that would allow DNSPs to implement congestion pricing without this additional layer of oversight.

Is the framework as proposed workable? Are there any aspects that are too restrictive, or might expose end-users to undue price shocks or hardship?

Is the form and level of the sample constraints or thresholds appropriate?

Should there be requirements to consult with retailers or end-users, or give a set amount of notice, prior to implementing congestion prices under the above framework?

Should DNSPs be able to compel end-users to switch to time-of-use or other more cost reflective tariffs? Under what circumstances? What controls or safeguards should be put in place?

9.2 Transition path

The above framework is for long-term, widespread application for congestion pricing signals within distribution networks. 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 the widespread rollout of congestion pricing.

The changes foreshadowed in the above framework represent a significant reform to distribution pricing in NSW. Full implementation will be a major undertaking, requiring significant support from communications, pricing models, billing and systems development. Adjustments for end-users will be significant.

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 in a subsequent period if these prove successful. If trials are commenced early in the next determination period, it is likely a full rollout would take at least 4 or 5 years anyway.

What is an appropriate number and duration for trials? Given the cost of poor pricing signals, when should the widespread application of congestion pricing proceed?

SKM

What reviews or criteria, if any, should be adopted prior to the full implementation of congestion pricing following successful trials?

9.3 Other regulatory changes to support congestion pricing

The integration of demand management and congestion price costs into the regulatory framework described in Section 1 of this report will be required in order to ensure the costs and benefits of congestion price are appropriately recognised and rewarded.

Additional changes required to support the introduction of congestion price are:

9.3.1 Need to relax side constraints for congestion pricing

The existing limits on aggregate and individual price movements, the so-called "side constraints", would severely constrain the ability of DNSPs to offer meaningful and effective congestion pricing signals to end users.

It is proposed that the existing side constraints apply to "base" (without congestion pricing) tariffs only. Congestion prices, subject to a second set of side constraints, would be added to base prices in constrained areas.

The side constraints for congestion prices will need to be more flexible than the existing side constraints if congestion pricing is to be effective.

Limits on the size of congestion prices relative to base prices (say a maximum of 30%) and annual change in congestion prices in each constrained location (say 5% or 10%) are proposed as a starting point for discussions on appropriate side constraints.

Are the side constraints proposed appropriate and reasonable? Should any additional controls or protections be put in place?

9.3.2 Other changes / issues

Item (5a) of the pricing principles and methodologies says the application of fixed costs should "not vary by location". This does not appear to be in conflict with the application of locational specific congestion prices, but may need to be clarified or resolved.

9.3.3 Congestion pricing for gas networks

The existence of different regulatory regimes for electricity and gas creates the potential for allocative inefficiencies. Gas network regulation in NSW does not include congestion pricing signals, nor do gas networks have the same demand management obligations as electricity networks.

The creates the potential for inefficient investments in gas networks, where load is transferred to gas in a constrained part of the electricity network when there is also a gas network constraint.

Consideration should be given to aligning the regulatory frameworks for electricity and gas networks.

10. Glossary of terms

Demand management	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

Appendix B Form of regulation for DNSPs from 1 July 2004

The Notice on the Form of Regulation,[26] outlined that the Transmission Use of System (TUOS) component of network tariffs will be regulated via a pass-through arrangement, whereby actual transmission charges and related costs incurred by the DNSPs will be recovered by transmission revenues. The Weighted Average Price Cap Model applies to the distribution use of system (DUOS) component of network charges only.

As part of the transmission arrangements, the DNSPs will estimate the transmission charges that they expect to pay for the year ahead and base their TUOS tariff component on that estimate. If the transmission charges set by the businesses either under or over collect the amounts paid to TNSPs and other transmission related charges (such as avoided TUOS, inter-distributor charges), then that amount will be recovered from or returned to customers through a correction mechanism.

10.1.1 Transmission pass-through elements

The Tribunal proposes to allow DNSPs to recover the following costs via direct pass-through arrangements:

– Transmission charges paid to transmission companies (eg TransGrid or EnergyAustralia) for use of the transmission system (use of system and connection charges)

– Avoided TUOS payments made to embedded generators under the National Electricity Code

– Payments to other DNSPs for use of their network (inter-distributor payments)

– Avoided distribution costs (depending on the outcomes of the SKM study)

In its paper on *Transmission pass-through arrangements* to the Pricing Issues Consultative Group on 18 June 2003, the Tribunal noted "the Secretariat's initial position is that allowing the pass through of avoided distribution costs will provide an incentive for DNSPs to implement embedded generation or other demand management solutions".

[26] IPART, *Notice under Clause 6.10.3 of the National Electricity Code – Economic Regulatory Arrangements NECR 10*, June 2002

Appendix C Questionnaires

The following questionnaires were used as part of SKM's consultation with stakeholders and data gathering for this study.

Stakeholder interview guide for identifying key issues for developing congestion pricing framework

- What are the main issues to be considered when looking at congestion pricing for distribution networks. What aspects of these issues should be explored / kept in mind?
- What is congestion pricing and how do you see it could be of benefit?
- What do you believe is the scope / potential for congestion pricing and demand management and embedded generation (DM/EG) to defer or reduce network costs?
- How would you propose to use congestion pricing? Dimensions to be considered include:
  - Does it target specific areas, or the whole network?
  - Does it target specific time periods, or whole consumption?
  - Are prices "real time", set annually, or something in between?
  - Does it utilise higher costs during constrained periods, or incentives / rebates / subsidies to end-users able to reduce demand during constrained periods.
  - Does it only involve price, or other measures (such as interruptability).
  - What equipment (meters, communications, relays etc) is required to implement it?
  - Is participation compulsory or voluntary?
  - How often to you anticipate congestion pricing periods to apply? How much notice will users be given, and how?
- Your expectation of the likely range of prices in congested areas / periods.
- What do you believe is the lead-time required for network and DM/EG options? Does this impact on your existing planning processes, and how could this be incorporated?
- What data, tools and systems are needed to implement congestion pricing? What are the likely implementation timeframe and costs? Any impacts on retailer billing systems?
- What impact will congestion pricing have on end-users not implementing DM/EG?
- What conflicts are there in the needs of DNSPs and DM/EG project proponents, and how can these be resolved?
- Experiences to date with DM/EG. Risks of DM/EG, and ways of managing these risks
- Are there any regulatory barriers or risks that hinder your ability to implement DM/EG? Are these likely to be addressed in the next pricing determination, or the change to a weighted average price cap? Are costs in one regulatory period to achieve savings in a subsequent period adequately addressed?

- How should the costs, benefits and risks of DM/EG be equitably shared between DNSPs and end-users (both participants and non-participants in the DM scheme).
- What barriers or issues besides price need to be addressed for DM/EG to be viable? For example information, better understanding of performance and reliability, longer lead times, standard offer contracts, …
- Any practical / political / PR constraints that would make an "ideal" congestion pricing scheme difficult? What compromises can be made to still deliver a workable scheme?
- What areas or projects do you have that can be used as a NSW case study of congestion pricing, or where congestion pricing could be used? What material, data, results or other information are available?
- Are there any other areas you think are relevant that have not been addressed by the other questions?

DNSP Questionnaire for calculation of average / regional / zonal congestion pricing factors, and material suitable for case studies

Background

SKM has been engaged by IPART to undertake a study of the feasibility of congestion pricing and to develop a framework for integrating congestion pricing with the WAPC and calculating avoided distribution costs.

As a part of this exercise, we are seeking input and information from the DNSP's relating to past and future costs of meeting demand growth through conventional network augmentation solutions. In addition, we are seeking information that could be used as case studies for congestion pricing, using demand management and embedded generation projects (both successful and unsuccessful) that you have investigated in the last 5 years.

Marginal cost of demand and Avoided distribution costs

As part of its study for IPART, SKM is seeking to understand the drivers for including a locational component in the congestion pricing fra mework. SKM believes it is likely that significant benefits to DNSPs and end-users could accrue from the incorporation of locational (as opposed to system-wide) congestion pricing, but needs some additional data in order to properly analyse this issue.

SKM is proposing to calculate the upper range of marginal costs ($ per MW) using three measures:

- System wide (ie across a DNSPs whole franchise territory)
- Regional (by Bulk Supply Point)
- Zonal (by Zone substation)

These marginal costs will provide an indication of the range of marginal costs to DNSPs, and the additional value from "sharper" location pricing signals at a regional or zonal level.

We seek your assistance in providing this information (or as much as can be sourced) quickly, so this analysis to be included in the draft study presented to IPART in early July.

SKM also recognises some DNSPs may have concerns regarding sensitivity to this information, and the possibility it could be misinterpreted or quoted out of context. We have asked whether you are comfortable with this information being used in the report in a desegregated manner, or if you would prefer it is only used in aggregate / anonymous manner.

If you have any questions regarding the questionnaire or congestion pricing study, please contact Ben Kearney (02 9928 2433) or Cliff Jones (07 3244 7100) to discuss. We look forward to working with you on this study.

The broad formula for marginal cost is shown below, though discounted cash flow analysis will be used to derive more accurate results.

SKM

Formula: Demand Driven Capex (DDC) = $\frac{\text{SDC}}{\text{IDI}}$

Where:

SDC = System Demand Capex ($)

System Demand Capex is that capital expenditure that is made to augment, upgrade or add to the capacity of the distribution, subtransmission and transmission systems of utilities to enable the system to adequately supply the increasing load taken by existing customers, and to meet the maximum demand of new customers.

The total amount of "demand driven" capital expenditure spent over the defined period (eg. 5 years) on all forms of augmentation and capacity increase including:

- Transmission and subtransmission major projects.
- All distribution and augmentation projects and programmes.
- New and augmented substation works.
- New and augmented feeder works.
- Power factor improvement.
- Voltage regulation improvement.

The following expenditure should "excluded":

- Any component of refurbishment works.
- Any customer connection assets.
- Any "prime purpose" reliability or quality of supply improvement.
- Any costs associated with environmental or statutory obligations.
- Any expenditure normally categorised as "customer driven" (ie. new residential estates, new assets to supply individual C&I customers).
- Expenditure on streetlighting.
- Expenditure by a TNSP.

and IDI, Incremental Demand Increase (KVA)

Incremental Demand Increase is defined as the aggregate of the growth in non-coincident maximum demand (summer or winter) at all the bulk supply points, where the DNSP takes supply from the TNSP or another DNSP. This growth in maximum demand should be measured over the same time period that the System Demand Capex is assessed, or as near as possible to the same time period. To the extent possible, the calculated incremental demand increase should exclude:

- "Artificial" demand growth created by temporary system switching operations.
- Demand growth associated with spot loads supplied directly to major customers (eg. railways, etc).

- Demand growth caused by abnormal, or one off events or conditions.

By forecasting demand at each level (system, region and zones) over say a 10 year forward looking period (two regulatory periods), and allocating the projected future "demand driven" capital costs on a regional and zonal basis, it is possible to identify those regions/zones with the highest marginal costs.

In order to assess the potential for this approach to be useful in promoting embedded generation/demand side initiatives, we are requesting that each DNSP provide the following information.

Use of data from this Questionnaire

Are you comfortable with SKM using the data from this questionnaire in a disaggregated manner, or only in aggregate / anonymous form?

Disaggregated or aggregate only?

Any further concerns / requests in this regard? Please specify below

Eg disclaimers or explanatory notes that should accompany the data or analysis

System Demand Driven Capital Expenditure (SDC)

Question 1: What has the "system wide" Demand Driven Capital Expenditure per kVA of incremental demand growth been for your DNSP for the most recent 5 year period, calculated as follows:

System Demand Capex (SDC)/Incremental Demand Increase (IDI) = $X/kVA

Response to Question 1:

1. Historical System Demand Capital Expenditure? (5 year period)	$	
2. Period over which expenditure occurred? (eg. 1996/97 to 2000/01)	Yrs	
3. Historical Incremental Demand Increase? (5 year period)	kVA	
4. Period over which incremental demand increase occurred? (eg. 1996/97 to 2000/01)	Yrs	

5. How many supply points on the network does this demand increase relate to? (No at end of the period)

No

6. What regions of your DNSP does the above information relate to?

All

or

Part

Please specify below

In addition, a system-side load duration curve for the most recent year available will be useful in assessing the range of marginal costs and benefits that can accrue from congestion pricing. Please provide this information as a separate attachment.

7. Is there any further information, assumptions, or qualifications that you would like to state in your response to items 1-6 above?

Please specify

Regional Demand Costs

At any point in time, the capital cost of augmentation of the electricity system will be different from location to location, depending on geographical, spatial, customer demographics, load patterns and electrical system constraints. These "location specific" characteristics may have a significant impact on the cost effectiveness of alternative supply side and demand side solutions to system constraints.

For the purposes of this questionnaire, SKM has defined a "region" as the network loads supplied from a single bulk supply point (BSP), and is seeking to identify the upper range of marginal costs at this level (we assume the lower range will be close to zero, and so of little interest).

SKM recognises that identifying the 5 regions with the highest marginal cost could be difficult given the short response time requested. If this information is not readily available, the 5 regions with the highest forecast growth related capex should give a good approximation. Where it is difficult or impractical to isolate a project to a single BSP (for example an area supplied by both a 33kV and 132kV BSP) please use the figures that best describe the regional issue, and a brief explanatory note.

SKM

Question 2: What are the five (5) Regions with the highest marginal cost or forecast capex applicable in your DNSP over the next two regulatory periods?

Response to Question 2:

1. For each Region 1 (R1 -5)

Name of Region Supply Point?		
Expected System Demand Capital Expenditure in this Region over next 5 years (2004/05 to 2008/09) – include Capex for transmission only.	$	
Forecast growth in demand (summer or winter) in this Region over next 5 years (2004/05 to 2008/09)	kVA	
Expected System Demand Capital Expenditure over following 5 years (2009/10 to 2013/14) – include Capex for transmission only.	$	
Forecast growth in demand (summer or winter) over following 5 years (2009/10 – 2013/14)	kVA	
In what year(s) does the next stage of demand capital expenditure occur for this Regional Supply Point?	Year	

6. Is there any further information, assumptions, or qualifications that you would like to state in your response to items 1-5 above?

Please specify

SKM

Zonal Demand Costs

Similarly with Regional Demand Costs, the capital costs associated with augmentation of the distribution and subtransmission systems will vary from location to location depending on geographical, spatial, customer demographics, load patterns, and electrical system constraints. These “location specific” characteristics may have a significant impact on the cost effectiveness of alternative supply side and demand side solutions to system constraints.

In order to capture and quantify this characteristic, further disaggregation into Zonal Demand Costs are sought. As for Regional Demand Costs, where highest marginal costs are difficult to identify, highest growth related capital costs will suffice. Where a particular area is difficult or impractical to separate into a single zone, please provide the information that best describes the problem, with a brief explanatory note.

Question 3: What are the five (5) highest Zonal Demand Factors applicable in your DNSP over the next two regulatory periods?

1. For each Zone (Z1-5)		
Name of Zone (Zone Substation)		
Expected System Demand Capital Expenditure in this Zone over next 5 years (2004/05 to 2008/09) – include Capex for distribution, subtransmission and transmission.	$	
Forecast Growth in demand (summer or winter) in this zone over next 5 years (2004/05 to 2008/09)	kVA	
Expected System Demand Capital Expenditure in this zone over following 5 years (2009/10 to 2013/14) – include Capex for distribution, subtransmission and transmission.	$	
Forecast growth in demand (summer or winter) over following 5 years (2009/10 – 2013/14)	kVA	
In what year(s) does the next stage of demand capital expenditure occur for this Zonal Supply Point?	Year	
	$/approx	

6. Is there any further information, assumptions, or

Qualifications that you would like to state in your response to items 1-5 above?

Please specify

Congestion Pricing Case Studies

We are interested in obtaining and summarising DNSP's experiences with:

- Areas experiencing high marginal costs, and how congestion pricing could assist, and
- identifying and evaluating embedded generation and demand side opportunities over recent years

Could you please provide a brief (½ page) summary of the most significant (perhaps 3 or 4 maximum) of these in the past 3-5 years. The summary should include:

- Location and nature of congestion issue
- Potential non-network solutions identified (embedded generation, cogeneration, DSM, hybrid, etc by fuel source).
- Magnitude of demand/generation.
- Total estimated project capital cost.
- Summary of costs/benefits (if available).
- Status/outcome of the investigation/proposal.

For each of the above case studies, and any others that your DNSP has investigated, could you please complete the attached table.

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.