DISTRIBUTED GENERATION

DISCUSSION PAPER

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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Discussion Paper No 52

ISBN 1 877049 13 1

March 2002

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Submissions must be made in writing and should be sent to the postal address, fax number or email address below by Friday April 12, 2002. Where possible submission should be provided in a computer readable format (eg, word processor, PDF or spreadsheet) either on disk or by email.

Inquiry into the Role of Demand Management and Other Options
in the Provision of Energy Services (Matter No. 01/257)
Independent Pricing and Regulatory Tribunal
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QVB Post Office NSW 1230

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Special reference must be made to any issues in submissions for which confidential treatment is sought and all confidential parts of submissions must be clearly marked. *However, it is important to note that confidentiality cannot be guaranteed as the Freedom of Information Act and section 22A of the Independent Pricing and Regulatory Tribunal Act provide measures for possible public access to certain documents.*

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FOREWORD

The Premier has asked the Independent Pricing and Regulatory Tribunal to undertake an inquiry into what role Demand Management should play in providing the State's energy services. The Tribunal's terms of reference ask it to assess the potential of Distributed Generation (DG) options to enhance electricity network capacity and reliability and meet customer energy service requirements.

The terms of reference also ask it to assess the extent to which greater use should be made of DG options, and to identify any barriers to the development of DG. In addition, they ask the Tribunal to recommend changes to facilitate DG that are likely to lead to the most economically efficient and environmentally sound provision of electricity transmission and distribution network services.

This discussion paper summarises the Tribunal's current understanding of the issues related to DG in NSW and in particular discusses:

- what is meant by DG and the role it can play in demand management
- the current regulatory framework for DG
- the main barriers to DG in NSW
- a range of options for overcoming these barriers.

The Tribunal welcomes your comments on all matters raised in this Paper and on any additional matters impacting on the implementation of DG in NSW.

Thomas G Parry
Chairman
March 2002

SUMMARY TABLE OF ISSUES FOR SUBMISSIONS

The Tribunal seeks comments on the following issues as well as any other issues discussed in the Paper:

- successful distributed generation (DG) projects which have been implemented in NSW or other jurisdictions and any insights into what factors contributed to the success of such projects
- suggested proposals to make it easier for DGs to connect to the network and in relation to ensuring more equitable treatment of connection costs
- the negotiation principles set out in Section 5.1.3 as a possible basis for the development of standard guidelines for connection agreements and whether standard offers can assist in the negotiation process
- the Tribunal's current approach to avoided TUOS (transmission use of system) costs and its proposals relating to avoided distribution network costs, to assist the Tribunal in the preparation of appropriate schedules to its PPM
- possible responses to the problems facing small generators in the NEM and the role that smart meters might play in assisting adoption of small-scale DG
- proposals to improve the incentives for implementing DG and reducing the associated risks
- proposals to reduce any institutional and structural barriers to DG in NSW.

<table>
<tr><th colspan="2">SUMMARY OF BARRIERS TO DG AND PROPOSED OPTIONS</th></tr>
<tr><th>Barrier</th><th>Proposed Options</th></tr>
<tr><td>Difficulties in negotiating fair connection agreements
• Light handed regulation and lack of incentive for DNSP to support DG</td><td>• Develop national guidelines and standard offer agreements
• Streamline connection arrangements
• Clarify regulatory approach to assessing prudent investment</td></tr>
<tr><td>• DNSP has information leverage in negotiations</td><td>• Establish guidelines for efficient, effective negotiations
• Apply NSW DM Code of Practice and extend it to include standard offers</td></tr>
<tr><td>• DG pays deep connection costs, unlike existing transmission-connected generators, and existing generators may free ride on network enhancements paid for by DG</td><td>• Provide DG with preferential access to deep connection assets it paid for
• Provide rebate to DG if, in the future, other users make use of the deep connection assets it paid for
• Amend the National Electricity Code to reflect the outcomes of NECA's 'Beneficiary Pays' Review, due to report by December 2002</td></tr>
<tr><td>Uncertainty about payment of avoided network costs
• Uncertainty on methodology for assessing avoided costs</td><td>• Demonstrate mechanisms in place for DG to capture avoided TUOS and avoided network augmentation costs
• Develop appropriate schedules to the PPM</td></tr>
<tr><td>Lack of clear framework for small generators and smart metering
• The small generator is disadvantaged by fees and metering technology</td><td>• Address in national forums and reviews
• Develop a market framework for small generators and support the development and implementation of smart metering</td></tr>
<tr><td>Institutional and structural factors
• National market institutions
• Uncertainty on reliability of DG options
• Lack of locational signals in network pricing</td><td>• Address in national forums
• Work with utilities to integrate DG into planning processes
• Create clearer regulatory incentives and endorse DG trials
• More cost-reflective pricing (refer separate IPART Research Paper[1])</td></tr>
</table>

[1] East Cape Pty Ltd, *Efficient Network Pricing and Demand Management*, February 2002.

TABLE OF CONTENTS

1 INTRODUCTION

As part of its inquiry into the role of demand management in the provision of energy services in New South Wales, the Independent Pricing and Regulatory Tribunal (the Tribunal) is currently examining Distributed Generation (DG).

The Tribunal's terms of reference ask it to assess the potential of DG options to enhance electricity network capacity and reliability and meet customer energy service requirements. The terms of reference also ask it to assess the extent to which greater use should be made of such options and to identify any barriers to the development of cost-effective DG options. In addition, they ask the Tribunal to recommend changes to facilitate DG that are likely to lead to the most economically efficient and environmentally sound provision of electricity transmission and distribution network services. (The terms of reference are reproduced in full in Appendix 1.)

The Tribunal already has considerable information on DG in NSW. For example, it established the NSW Embedded Generator Working Group to assess the National Electricity Code's requirements in relation to DG and consider any impediments to meeting these requirements. This group undertook extensive consultation and research, and reported to the Tribunal in 1999. More recently, the Tribunal received several submissions that focused on DG as part of its ongoing inquiry into the role of demand management.

This discussion paper summarises the Tribunal's current understanding of the issues related to DG, drawing on these sources as well as secondary research:

- Chapter 2 discusses what is meant by DG and the role it can play in demand management
- Chapter 3 sets out the current regulatory framework for DG
- Chapter 4 discusses the main barriers to DG in NSW
- Chapter 5 proposes a range of options for overcoming these barriers.

The Tribunal invites submissions from interested parties to further advance its understanding of these issues. In particular, it seeks comments on the current barriers to DG and on the proposed options for overcoming these barriers, as well as proposals for alternative options. The Tribunal also welcomes information on DG projects that have been implemented successfully in NSW and any insights into the factors that contributed to their success.

2 WHAT IS DISTRIBUTED GENERATION?

Traditionally, electricity has been generated by large power stations, located close to their fuel source and a long distance from the main centres of electricity use (base load generators). These remote generators are connected to the distribution networks via a high-voltage transmission network. In contrast, DG is small and modular, and can be located close to end-users - within an industrial area, inside a building or in a community. These generators are connected directly to the local distribution network for the export of power or for standby provision of power, rather than to the transmission network.

DG encompasses many different power generation technologies, including reciprocating diesel or natural gas engines, microturbines, fuel cells, photovoltaics (solar panels), wind turbines and Stirling engines. Thus Distributed Generators (DGs) vary significantly in size, application and efficiency. For example, those that use photovoltaic systems are usually small scale, with as low as one or two kWs of power. Those that use wind turbines can be several MWs, while those that use natural gas-fired cogeneration are often large-scale industrial projects with several hundreds of MW. Appendix 2 describes the range of DG technologies in more detail.

DG has the potential to contribute to demand management by enabling a reduction in peak demand on the network and/or offering an alternative source of energy to base load generators. In times of increasing demand and industry restructuring, the possibility of supply and capacity constraints is increasing. Traditional approaches that use centralised transmission-connected generation to increase local capacity can be extremely expensive, and require many years to plan and install. A DG option that involves smaller, strategically located facilities that avoid transmission (and possibly) distribution infrastructure costs may be the most timely and cost effective way to meet demand growth and relieve network capacity constraints.

The use of DG can also offer additional advantages for the environment, the electricity market, electricity customers, and regulated electricity suppliers. These advantages are discussed below.

2.1 The environment

DG can create less greenhouse gas emissions than remote generation, as DGs are often powered by cleaner fuel sources. Depending on the technology involved, these include solar and wind power, which are renewable energy sources, and natural gas, which emits less carbon gases than coal (used to fuel most remote base load generators). In addition, some DG technologies involve cogeneration - the simultaneous production of electricity and heat using a single fuel source[2] - which is typically two to three times more efficient than coal-fired plant.

2 Heat is a normal by-product of energy production and is usually wasted. In cogeneration, the waste heat is captured and used to provide a complementary product, such as steam. Cogeneration is well established in Australia as a means of reducing on-site energy costs, increasing the reliability of energy supply and reducing environmental impacts.

However, the use of DG can also lead to local air quality issues when generators are located in major urban centres. Best-practice emission controls would need to be in place to manage these issues. A more detailed discussion of the impact of DG on local air quality is provided in Appendix 3.

2.2 The electricity market

DG can increase the level of competition in the wholesale electricity market, by introducing new electricity suppliers. It can also introduce competitive pressures on network pricing by displacing the use of parts of the network, and provide alternatives to capital investments. In addition, it can lead to:

- lower transmission losses and associated costs
- lower charges for transmission services
- benefits from providing ancillary services[3]
- improved network reliability through multiple redundancy
- more efficient use of fuel through use of waste heat.[4]

2.3 Electricity customers

Locating DG downstream in the distribution network can provide benefits for customers and/or the distribution system itself. It can reduce customer costs through the deferral of costly network augmentations and also provide potentially lower cost energy alternatives. In addition DG facilities can be operated remotely and used in a broad range of customer-sited and grid-sited applications where central plants would prove impractical.[5]

2.4 Network Service Providers

The benefits of DG for Distributed Network Service Providers (DNSPs) are difficult to calculate, as the economics will vary depending on the utility's system configuration and the loads to be served. However, DG is likely to be most economically attractive to DNSPs facing system constraints, as it can enable them to defer capital augmentations and reduce transmission losses. It can also improve utilisation (load factor) of existing transmission and generation assets.

If these benefits could be shared with the owner of the distributed generator (assuming they could be applied, captured and monetised), the incentives to invest in DG would be greatly enhanced.[6]

3 Ancillary services are defined in section 3.11 of the NEC as 'services essential to the management of power system security', and include load regulation capability, maintenance of power system frequency and reactive support to prevent power system failure.

4 Walter Gerardi, Maclennan Magasanik, *The Future for Small-Scale Distributed Generation*, in Australian EcoGeneration Association, *Ecogeneration*, August/September 2001, p 7.

5 A D Little, *Distributed Generation: Understanding the Economics*, 1999, p i.

6 Ibid, p ii.

2.5 Distributed generation plants in NSW

There are currently several DG plants operating successfully in NSW. Most of these are large-scale industrial plants, such as the BHP Appin-Tower Power Plant. An overview of this plant is provided in the box below. Short descriptions of other DG plants and proposed plants in NSW can be found in Appendix 4.

BHP Appin-Tower Power Plants

In May 1995, Integral Energy (then Prospect Electricity) and BHP Steel signed a 20 year Power Purchase Agreement (PPA). Under the PPA, BHP Steel is to supply electricity generated by two power plants to be built at its Appin and Tower collieries in southern NSW, with generation commencing in January 1996.

Prospect Electricity was attracted to this DG option for a number of reasons[7]. It wanted to secure less costly power than was available from the then monopoly supplier, Pacific Power, and to improve network reliability by having a local, embedded source of power generation. It also wanted the environmental and economic benefits of reduced greenhouse gas emissions available from using methane gas rather than coal to fuel the generation plant. Finally, it wanted to assist BHP, a major industrial customer, in solving problems concerning methane drainage in its colliery operations.

The Appin-Tower Power Plants are connected to the sub-transmission network at 66 kV.

Owner	Energy Developments Limited (EDL)
Capacity (max)	95 megawatts (total capacity of both plants)
Location	BHP’s Appin and Tower Collieries, Southern NSW
Operational	January 1996
Operator	EDL
Engine generator supplier	Caterpillar
Construction contractor	Civil and Civic
Operation	Notionally base load, although off-peak output levels vary with methane gas availability
Primary fuel	Coal seam methane (supplemented by natural gas during peak and shoulder periods as needed)

However, a number of planned DG projects have been cancelled – for instance, the 350MW and 420MW plants proposed respectively by Alise Energy and Sithe Energy at Port Botany. While this may simply reflect that the projects were not economic at current energy prices it may also reflect some significant barriers to the successful implementation of DG in NSW. These barriers are explored in detail in Chapter 4.

7 Letter to IPART from Mr David Neville, Manager Regulatory and Pricing, Integral Energy, 15 November 2001.

3 CURRENT REGULATORY FRAMEWORK FOR DISTRIBUTED GENERATION

The current regulatory framework in NSW seeks to encourage DNSPs to give equal consideration to DG options and network augmentation options when planning to overcome network constraints and meet end-user energy requirements. The key components of this framework are the National Electricity Code (the Code), the NSW Demand Management Code of Practice, and the Tribunal's current pricing determination for distribution networks. This chapter provides an overview of each of these components in relation to DG.

3.1 National Electricity Code

The National Electricity Code sets out the arrangements and procedures through which electricity generators can access the transmission and distribution networks, as well as the basis for determining the charges for this access, and procedures for network planning and augmentation.

The Code requires regulators to recognise the need to "create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration" (6.10.3(e)(2)). It also requires DNSPs, to consult "on the possible options, including but not limited to demand side and generation options" when they are undertaking network planning (5.6.2(f)), and to carry out cost-effectiveness analysis to identify the option that maximises net benefits. Part 4.5 of schedule 6.6 also endorses the use of competitive processes to discover the optimum outcome.

The Code includes provisions that are of special relevance to DG - those related to:

- the process for connection to the network
- the need to pass through avoided Transmission Use Of System (TUOS) charges
- payments that may be made to or received from DGs for distribution network services
- the inclusion of DG as a possible option for addressing projected network limitations.

These references are discussed briefly below. A more detailed description of the Code's provisions relating to connection, avoided TUOS charges and network support can be found in Appendix 5.

3.1.1 Process for connection to the network

The Code takes a light-handed approach to regulating the process through which DGs connect to the grid and sell their power into the market. In Chapters 5 and 6, it sets out a four-stage process for connection that requires each prospective distributed generator to negotiate a connection agreement with the relevant DNSP. The connection agreement covers all the commercial aspects of the connection arrangement, including connection costs, standards of service and dispute resolution. There are no standard agreements.

3.1.2 Avoided TUOS charges

Electricity generated by large, remote base load power stations is transported via high-voltage transmission networks to local distribution networks before it can be delivered to end-users. Under the Code, the transmission network providers charge the DNSPs for this use of the shared transmission network (generators are not generally charged for use of the transmission system[8]). These TUOS charges are added to the DNSP's regulated cost base and included in its Annual Aggregate Revenue Requirement (AARR) so that TUOS charges can be recovered through distribution prices.

Because a distributed generator is connected directly to the distribution network, a purchaser of the electricity it generates does not need to use the transmission network and thus does not attract transmission charges on this electricity (hence 'avoided TUOS'). The potential for payment to a distributed generator of the transmission costs avoided by the DNSP is seen as an important incentive for the establishment of a DG plant.

Clause 5.5 of the Code allows for avoided TUOS charges to be passed through to the distributed generator, funded out of the DNSP's AARR. Until very recently, the Code required that DNSPs and DGs negotiate in 'good faith' the extent to which these charges were passed through.

However, as a result of an Australian Competition and Consumer Commission (ACCC) decision in September 2001, the National Electricity Code Administrator (NECA) has recently implemented changes to the Code. It now requires that a DNSP "must pass through the amount calculated … for Customer TUOS usage charges …had the Embedded Generator not been connected to its distribution network" and sets out how avoided TUOS is to be calculated (Clauses 5.5(h) and 5.5(i)).

3.1.3 Network support payments

Chapter 6 of the Code recognises that DNSPs may pay DGs for the contribution they make to network support - that is, where the existence of a local generator means the DNSP is able to avoid the costs of network augmentation.

Chapter 6, Part E of the Code (relating to Distribution Network Pricing) also deals with payments to DGs. Clause 6.13.3 requires that payments received from or made to DGs to be included in the AARR for the appropriate DNSP asset category. This part of the Code does not apply expressly in NSW, as the Tribunal has exercised its discretion to replace Part E with its own Pricing Principles and Methodologies[9] (PPM). However, the PPM broadly reflects this approach to DG.

The PPM also includes a provision to develop Schedules to the PPM that set out general principles for the treatment of DG and a negotiation framework. However, these schedules have not yet been developed.

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8 Unless the generator is directly connected to the customer via the transmission network, in which case TUOS charges may apply.

9 IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services*, March 2001.

3.1.4 Network planning

The Code assigns responsibility for network planning within regions to the relevant Network Service Provider (NSP). Clause 5.6.2 requires Network Service Providers (NSPs) to select options for addressing future network limitations that maintain the operating standards of their networks while maximising the net benefit to customers. NSPs are also required to consult with participants and interested parties to identify what these options are.

3.2 ACCC regulatory test

In December 1999, the ACCC released its Regulatory Test for electricity investments,[10] which replaced the previous customer benefits test within the Code. Clause 5.6.2 of the Code requires NSPs to apply this Test to regulated transmission and distribution system augmentation proposals when they are making investment decisions. The Test requires NSPs to:

- compare network investments with alternative options, such as DG and energy efficient technologies and practices
- take into account the costs of complying with existing and anticipated environmental requirements
- ensure that investments maximise net public benefits.

A key difference between the new Regulatory Test and the previous one is the change in its focus from 'customer benefits' to the 'market benefit'. The market benefit is defined as the total net public benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the national electricity market. Under clause 5.6.2(g) of the Code, all NSPs are required to apply the Regulatory Test. As DNSPs are included in the definition of NSP in the Code, all DNSPs are therefore required to apply the Regulatory Test.[11] This process requires DNSPs to consult on proposed network options and to publish a report for all interested parties, outlining its economic assessment of the option and its alternatives.

3.3 The Tribunal's framework for distributed generation

The Tribunal aims to provide appropriate incentives for the implementation of DG options in NSW through its regulation of DNSP's AARR and also through the principles outlined in its PPM document. The Tribunal's regulation of DNSP revenue operates in conjunction with the framework provided by the NSW Demand Management for Electricity Distributors Code of Practice[12] (the DM Code). The DM Code is administered by the NSW Ministry of Energy and Utilities.

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[10] Note that the ACCC is responsible for regulation of electricity transmission assets, with the individual states responsible for the regulation of electricity distribution assets.

[11] The ACCC has recently commenced a review of the application of the Regulatory Test. The application of the Test to DNSPs will be considered as part of this review. The recent Code changes proposed by NECA in relation to Network and Distributed Resources, which will make a distinction between large and small network assets and the application of the Regulatory Test will only apply to TNSPs.

[12] NSW Ministry of Energy and Utilities, *NSW Code of Practice, Demand Management for Electricity Distributors*, May 2001.

3.3.1 Price regulation

The Tribunal's 1999 Determination for NSW Electricity Distribution Networks[13] sets out its current framework for regulating electricity prices. In this Determination - which applies to 30 June 2004 - the Tribunal set maximum electricity prices through a fixed revenue cap and allowed a glide path (or smoothing) of base revenue gains and losses using 1998/99 as a base year.

In relation to the recovery of costs related to DG during the regulatory period, the Determination requires that:

> The aggregate annual revenue requirement (AARR) that the DNSPs can collect will include the glide-pathed base revenue as established by the building blocks together with [among other things]:
>
> - avoided transmission use of system (TUOS) payments to embedded generators[14], up to an amount determined by the Tribunal through an examination of avoided network costs;
> - payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.[15]

Under this approach, DNSPs can provide rebates to DGs up to the amount of the TUOS charges and distribution network costs avoided. The Tribunal provides for the rebates to be recovered through the regulated revenues of the DNSP. To claim avoided costs for use of the network as a result of a demand management program or investment in DG, the DNSP must make its case to the Tribunal.[16]

Obtaining a return on investments beyond the current regulatory period will be subject to a prudency assessment. The Determination stresses the need for non-network alternatives, such as demand management and DG, to be treated equally with network investment options. The Tribunal has said that a DNSP can reduce the possibility that an expenditure may not be included in its asset base by demonstrating that it has followed good process in making the investment choice.

In regard to DM strategies (including DG), the Tribunal supports a framework:

> … to investigate demand management strategies and other alternatives [which] involves public disclosure of planning criteria and capital expenditure proposals together with a call for expressions of interest in alternatives. Implementation of this approach may allow competition to disclose the best alternative and reduce the risk that the investment may be disallowed under the prudency review at the next determination.[17]

The Determination did not provide further detail on the assessment of distribution network cost savings for either DG or DM. However, it stated that:

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13 IPART, *Regulation of New South Wales Electricity Distribution Networks, Determination and Rules under the National Electricity Code,* December 1999.

14 Embedded generation is an alternative term for DG

15 *Ibid,* p vii.

16 The Determination sets out in detail the application of this approach to the assessment of avoided TUOS for the Sithe/Smithfield and Tower/Appin generators.

17 IPART *opcit,* pp 59.

> Before rolling into the initial capital asset base actual capital expenditure for the period 1 July 1999 to 30 June 2003, the Tribunal will have a prudency review conducted. Prudent investment in demand management may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.[18]

Subsequently, the Tribunal issued the PPM, which provide guidance to utilities on the setting of prices consistent with the Tribunal's Determination of network revenues. The PPM also provides for schedules on the treatment of DM and DG, but these have not yet been developed.

3.3.2 The NSW Demand Management Code

As noted above, the NSW Demand Management Code (DM Code) is administered by the NSW Ministry of Energy and Utilities. The purpose of the DM Code is to provide guidance to electricity distributors in implementing the requirement in the NSW *Electricity Supply Act 1995* to investigate and report on DM strategies when it "would be reasonable to expect that it would be cost - effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies".

The DM Code was recently updated to deal with concerns that DNSPs, in developing their networks, show a bias in favour of network augmentation rather than DM options. In particular, the updates were designed to address concerns about whether:

- more cost-effective options were being overlooked
- sufficient time was being allowed for alternative proposals to be developed and submitted
- there was sufficient transparency both in defining the system constraint and in assessing the options
- the distributors' dual role as the proponent of proposals and the arbiter of proposals was creating a conflict of interest.

The updated DM Code proposes to reduce these risks through greater transparency and greater reliance on competitive processes and market mechanisms. In principle, the processes outlined in the DM Code should reduce the DNSPs' risks in relation to investment decisions, as well as their economic, technological and regulatory risk.

> The scope of this Code is the market-based development of options for electricity system support (including demand management, embedded generation and storage options) and their evaluation at the same time and in the same manner as network investments.
>
> The approach in the Code of Practice is focused not just on the ***network***, but rather on the ***electricity system*** as a whole. Constraints that arise within the distribution network can be addressed by changes in customer behaviour, by changes in equipment used by customers or by installation of small-scale generation at a local level, as well as by enhancement of the distribution network. These options could be devised and implemented by customers or by distributors. The market based procedure in the Code of Practice is intended to ensure that all supply and demand side options developed by customers or third parties and by the distributor itself can be developed and evaluated *at*

18 *Ibid*, p 55.

> *the same time* and *in the same manner* as network augmentation, including use of a competitive process.[19]

In this way, the DM Code parallels the ACCC Regulatory Test. Both seek to implement processes that facilitate the choice of the most appropriate investment options. The key difference may be that the Regulatory Test appears to be broader than the DM Code. Importantly, the DM Code has similar purposes to the Regulatory Test - these are:[20]

> … to ensure that all network enhancement and other system support options and proposal are given fair consideration. This evaluation should include all relevant cost and benefits and should comply with the ACCC's Regulatory Test for network investment.

Thus the implementation of the new Demand Management for Electricity Distributors Code of Practice in NSW should result in a clearer framework for the consideration of DG options alongside network augmentation proposals.

An overview of the regulatory approach to DG in other states and countries can be found in Appendix 7.

19 NSW Code of Practice, *Demand Management for Electricity Distributors*, 18 May 2001, p 3.

20 *Ibid*, p 16.

4 BARRIERS TO DISTRIBUTED GENERATION

Despite the provisions within the regulatory framework discussed in the previous chapter, proponents of DG have identified a range of practical barriers to the successful implementation of DG projects in NSW. These barriers stem largely from the complex regulatory framework, the historic monopoly structure and organisational culture of the industry, the immaturity of the DG sector, and the lack of well-developed guidelines to assist all parties in the process. In particular, they include:

- the difficulties DG proponents face in negotiating fair connection agreements with DNSPs
- uncertainty about payment of avoided network costs, including avoided TUOS and avoided distribution costs
- the level of detail required to apply the ACCC's Regulatory Test
- the lack of a clear framework through which small generators can participate in the market
- the lack of incentives for DNSPs to choose DG options
- institutional and structural barriers.

4.1 Difficulties in negotiating fair connection agreements

As noted in Chapter 3, the National Electricity Code requires that DGs and DNSPs reach a connection agreement through negotiation. This agreement usually covers issues such as what costs of connecting to the network the distributed generator will be required to pay, the standards of service it will receive from the DNSP, and how much avoided TUOS charges the DNSP will pass through to the distributed generator.

Some stakeholders believe this light-handed approach to regulating the connection process, while worthwhile in principle, is inadequate in practice. This is because connection is a 'very difficult and contentious issue', as electricity distributors and retailers may perceive potential DGs as direct competitors. In addition, it may be in the DNSPs' interests to delay the implementation of DG projects, especially if revenue is at stake, or to use its 'negotiation and information leverage' to extract monopoly rents.[21]

Three issues appear to create particular difficulties - the lack of standard connection agreement, the inequitable treatment of DGs in relation to connection costs, and the lack of transparency and unequal access to information in the negotiation process. These issues are discussed below.

4.1.1 Lack of standard connection agreements

Some stakeholders see the lack of standard agreements applying across the National Electricity Market (NEM) as a significant problem for DGs. This may disadvantage smaller DGs, which are unlikely to have sufficient resources to negotiate a fair agreement.

21 Australian Ecogeneration Association, *Removing Impediments to Cogeneration and Renewable Generation in the National Electricity Market*, June 2000, pp 12-13, 19.

4.1.2 Inequitable treatment in relation to connection costs

DGs must negotiate what portion of the costs of connecting to the network they will be required to pay. Stakeholders believe it is difficult to reach a fair outcome because DGs can be required to pay 'deep' connection costs. Deep connection charges refer to a (usually significant) one-off upfront payment required from the embedded generator to cover costs relating to network protection and voltage control equipment up to the boundary of the distribution network. Alternatively, 'shallow' connection charges relate only to the specific assets required for connection, usually up to the first transforming point. In contrast to DG proponents, transmission-connected generators have historically paid only shallow connection costs.

The requirement for new generators entering the market to pay for deep connection costs is set out in section 5.5 of the National Electricity Code - in particular, clauses (e) and (f), as set out in the box below.

Section 5.5, clause (e) and (f), National Electricity Code

(e) The *Network Service Provider* shall use reasonable endeavours to provide the *generator access* arrangements being sought by the *Generator* subject to those arrangements being consistent with *good electricity industry practice* considering:

(1) the *connection assets* to be provided by the *Network Service Provider* or otherwise at the *connection point*; and

(2) the potential *augmentations* or *extensions* required to be undertaken on all affected *transmission networks* or *distribution networks* to provide that level of *power transfer capability* over the period of the *connection agreement* taking into account the amount of *power transfer capability* provided to other *Code Participants* under *generator access* or *market network service provider access* arrangements in respect of all affected *transmission networks* and *distribution networks.*

(f) The *Network Service Provider* and the *Generator* shall negotiate in good faith to reach agreement as appropriate on the:

(1) the *connection service* charge to be paid by the *Generator* in relation to connection assets to be provided by the *Network Service Provider*;

(2) *use of system services* charge to be paid by the *Generator* in relation to any augmentations or extensions required to be undertaken in respect of all affected *transmission networks* and distribution networks ('*negotiated use of system* charges")

In addition, the provisions of Clause 5.3.5(f)[22] of the Code require the DNSP to consult with the Transmission Network Service Provider (TNSP) in regard to the impact of a proposed DG connection of 10MW or greater on fault levels, line re-closure protocols and stability aspects. The TNSP is required to determine the 'reasonable costs' of these matters so these may be included in the DNSPs offer to connect. This has resulted in a number of DG proponents being asked to pay deep transmission costs.

The potential inequity of a new distributed generator paying for transmission augmentations while existing transmission-connected generators receive improved access and lower losses at no additional cost is currently being considered as part of a review being undertaken by NECA in accordance with the ACCC's September 2001 (code amendments) Decision.[23] NECA has proposed changing the Code by introducing a 'beneficiary pays' approach in relation to deep connection costs, which is discussed in Chapter 5.

4.1.3 Lack of transparency in the negotiation process and unequal access to information

Some stakeholders believe that DGs' ability to negotiate a fair connection agreement is made more difficult by their lack of information compared with DNSPs. The Australian Eco-generation Association (AEA) believes potential DGs are not always aware of their rights, or of the DNSP's duties and obligations under the Code and jurisdictional arrangements.

Kinerja Pty Ltd argued in its submission to the Tribunal's Issues Paper that a DNSP, as both a purchaser and provider of network services is incapable of competitive neutrality when considering a DG alternative. Kinerja sees the lack of transparency and disclosure of appropriate information as a major barrier to DG, as well as the lack of a clear appeals process for a party proposing a DG alternative to network augmentation. It believes 'the information imbalance could be used to advantage augmentation options over demand side management options'.[24]

In its submission, Powerline GES commented that grid connection requirements and arrangements for payment for network support services were also matters of concern for proponents of DG:

> The main issue is market access. Despite significant support in the regulatory treatment of DM investments and via the DM code of practice, there is reluctance in the DNSPs to make or facilitate non-traditional investments … There has been an information imbalance in the development of recent network augmentations where insufficient time has been provided to proponents of non-network solutions.[25]

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22 (f) If the *application to connect* involves the *connection* of *generating units* having a *nameplate rating* of 10MW or greater to a *distribution network*, the *Distribution Network Service Provider* must consult the relevant *Transmission Network Service Provider* regarding the impact of the *connection* contemplated by the *application to connect* on fault levels, line reclosure protocols, and stability aspects. The *Transmission Network Service Provider* must determine the reasonable costs of addressing these matters for inclusion by the *Network Service Provider* in the offer to *connect* and the *Distribution Network Service Provider* must make it a condition of the offer to *connect* that the *Connection Applicant* pay these costs.

23 ACCC, *Application for Authorisation, Amendments to the National Electricity Code, Network Pricing and Market Network Service Providers*, 21 September 2001.

24 Kinerja Pty Ltd, Submission to IPART's inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, p 2.

25 Powerline GES Pty Ltd, Submission to IPART's inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, p 3.

4.2 Uncertainty about payment of avoided network costs

4.2.1 Avoided TUOS charges

Several stakeholders have suggested that the uncertainty about the calculation and payment of avoided TUOS charges is a barrier to DG. For example, the Embedded Generation Working Group found that there was 'ambiguity' about how the Code's avoided TUOS framework should be implemented, and recommended that clearer guidelines be developed for calculating avoided TUOS charges and for allocating costs and benefits between the distributed generator and the DNSP.[26]

The Tribunal's 1999 Network Determination set out the principles relating to a methodology for the calculation of avoided TUOS***. The Tribunal proposes to include the specific details of this methodology as a Schedule to the PPM.***

4.2.2 Avoided distribution network costs

The use of DG can also enable DNSPs to avoid some distribution network costs. For example, it can defer the need for them to increase the capacity of a substation or line to meet growing demand from nearby customers.[27] However, these savings are sometimes offset by additional costs it can impose on the network - for example, connection assets may be required and the changed energy flows may require additional expenditure upstream of the DG.

If there are net savings from the connection of the distributed generator, it is appropriate that the DNSP pay up to that amount to the distributed generator. Under a 'with / without' test, the net saving is the difference in the expected distribution costs without the DG and the expected distribution costs with the DG.

Often, this difference can be determined by a comparison with previous capital expenditure plans. In some cases, however it will require the application of normal planning standards to a hypothetical scenario. As the expenditures with and without the distributed generator occur in different periods, the cost streams need to be calculated and compared on the basis of their net present value in a common base year.

This sets the cap on payments to the distributed generator. Where the distributed generator causes a net increase in expenditure on distribution networks, the generator would pay the equivalent amount to the networks.

The principles for the pass-through of avoided distribution costs to customers are clear:

1. the DNSP should be able to recover **at least** the actual payments to the distributed generator or provider of demand management services
2. the DNSP should be able to recover **no more than** the prudent network costs that would have been incurred in the absence of the DG or DM
3. if the payment under (1) exceeds (2), the latter is binding

[26] Embedded Generator Working Group, *Report to IPART Electricity Consultative Group on Connection Issues Associated with Embedded Generation*, March 1999, pp 14-15.

[27] The extent of deferral will depend on the capacity provided and its reliability relative to other options of network augmentation and demand management.

4. if (2) exceeds (1), the extent to which the regulator allows for a period the pass-through of costs greater than those actually incurred provides the incentive for the DNSPs to seek out the most cost-effective options.

However the actual pass-through of these payments 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 (ie the gap between (1) and (2) above) between the utilities and the network users.

Where the deferred expenditure would have been incurred within the current regulatory period, the benefits of the avoided expenditures are captured automatically for that period. Any reduction in costs in that period goes to the benefit of the distributor. However, the payments for avoided distribution costs to a DG may be made before the network expenditure would have been incurred. Hence, the expenditure on avoided distribution payments may exceed the avoided costs in the current period. Indeed it may be that the distribution costs avoided or deferred would have been incurred in the subsequent regulatory period.

Possible options for dealing with payments to a distributed generator for avoided distribution network costs are discussed in Chapter 5.

4.3 Level of detail required to apply ACCC's Regulatory Test

Some stakeholders see the ACCC's Regulatory Test as a conceptually useful tool in deciding what is prudent investment. It is also seen as useful in that it brings in competing options such as DM and DG. However, they are concerned about the detail required to perform the Test. Bringing in the costs of existing and anticipated environmental laws and regulations is one obvious example. The Tribunal notes these difficulties, but also recognises that such factors should ideally be considered in the trade off between different investment options. Although difficult, it is important that such factors be taken into account.

Other stakeholders have commented that the ACCC Regulatory Test, although probably appropriate for transmission operators, is not appropriate for DNSPs. The key issue raised in this regard is the quantity of information required to apply the Test. For example, it may make sense for a transmission operator considering half a dozen transmission developments, but applying the Test to potentially hundreds of distribution assessments every year may not be reasonable.

4.4 Lack of a clear framework for small generators

The National Electricity Code requires that all generators producing more than 5MW must register with the National Electricity Market Management Company (NEMMCO), but exempts smaller generators. Registration with NEMMCO involves significant fees and overheads, but it also creates a framework through which the generator can operate in the market and facilitates its relationships with other market players. The lack of a similar framework for small generators who choose not to join the market to avoid the overheads of participation is a barrier to DG, as such generators are only able to sell their output to a local retailer or a customer at the same connection point.

For example, if a small-scale generator using photovoltaic technology generates excess electricity in a home or commercial premises, it is restricted to 'selling' this excess power to its local retailer, provided that this retailer is prepared to co-operate. (Currently, this usually occurs via a voluntary 'net metering' approach on the part of the retailer.) There are no current market arrangements for a small generator to supply to an alternative retailer.

A further barrier for small generators is that the current costs of connection and half-hourly metering make installation of domestic/small commercial generation uneconomic. As a recent UK report noted, the current domestic metering arrangements were not designed to take account of any electricity flowing back to the Grid.[28] This report found that the spread of smart metering - high technology metering at reasonable cost - is being hindered by factors such as the cost to consumers, lack of standardisation of meter types, and energy suppliers' reluctance to let current meters become obsolete.

Unless the cost of connection falls, and systems are put in place to enable domestic and small commercial customers to participate in the market and recover an adequate price for the electricity they export to the Grid, small-scale DG is unlikely to become widespread.

4.5 Lack of incentives for DNSPs

Several submissions to the Tribunal's Issues Paper[29] argued that DNSPs do not have sufficient incentives to undertake DM initiatives such as DG. Without these incentives, they are unlikely to opt for DG options because they are perceived as being higher risk than network augmentation. This risk stems from the fact that DNSPs have limited experience with DG projects. In addition, DNSPs believe they carry the risk because of their responsibility and accountability for reliability and continuity of supply.

4.6 Institutional and structural factors

In its submission to the Tribunal's Issues Paper, Powerline GES agreed with comments in the paper that the main barriers to DG in NSW were institutional factors such as the requirement that DNSP investment in DG must be 'prudent', and the 'organisational culture' currently presiding in DNSPs, which leads to a focus on supply-side solutions to meeting capacity constraints.

In general, the transaction costs and compliance costs of undertaking DG projects can be so high that the project may not be viable. Before a DG proposal can commence, the proponent needs to have potential contractual relationships with end users, aggregators, retailers, the wholesale market and system operator (NEMMCO), distribution, and transmission network service providers (DNSP's and TNSP's) and generators. Doing so requires the generator to meet all technical standards and to comply with market rules.

28 UK Smart Metering Working Group, *Report*, 2001.

29 IPART, *Issues Paper – Inquiry into the Role of Demand Management and other Options in the Provision of Energy Services*, July 2001.

Other recent papers on DG have argued that structural, policy and institutional factors related to the operation of the NEM are major impediments.[30] These factors include:

- (until recently,) the low price of fossil-fuelled electricity sources compared with renewable sources
- the fact that environmental costs are an unpriced externality, so fossil-fuelled electricity generators do not face the full cost of production, creating a price bias against renewable sources[31]
- the 'inherent biases' in the operation of the Code against embedded renewable generators—factors such as administrative charges, transmission charges and pricing issues act in favour of large incumbent generators
- institutional factors (NECA and NEMMCO) that create barriers to entry for the immature renewable energy industry which is attempting to operate in a newly competitive market
- the disaggregation of the industry which has made it difficult for the benefits of local generation to be valued by the market and captured by their proponents
- the lack of reward for benefits created by DG and inequity in network pricing between local and distant generators and between local generators and network options.

The AEA also suggested solutions to some of these barriers and these are discussed in Chapter 5.

30 AEA, op cit, pp 5-8 and the Allen Consulting Group, *Energy Market Reform and Greenhouse Gas Emission Reductions, A Report to the Department of Industry, Science and Resources*, March 1999.

31 This issue is being considered in a broader context as part of the Tribunal's Demand Management Inquiry.

5 PROPOSED OPTIONS FOR OVERCOMING THE BARRIERS

Overcoming the barriers to DG is not a simple matter; many issues need to be discussed and considered by policy makers, regulators, DNSPs, potential DGs and other stakeholders. In developing its own regulatory framework, the Tribunal recognises that consultation is essential for the development of a workable approach that addresses the concerns of affected parties. In addition, it is essential that any framework developed is consistent among jurisdictions, and also consistent with other regulatory requirements such as the DM Code.

This Chapter summarises a range of options for overcoming the barriers discussed in Chapter 4 that have been put forward by the Embedded Generation Working Group, the AEA and stakeholders who made submissions in response the Tribunal's Issues Paper on demand management. The Tribunal seeks comments on these proposed options.

5.1 Make it easier to negotiate fair connection agreements

The Tribunal has received a range of suggestions for making it easier for DGs to connect to the network on terms that are fair and reasonable. The options suggested relate to streamlining connection arrangements, ensuring more equitable treatment of DGs in relation to connection costs, establishing guidelines for efficient, effective negotiations, and developing standard offers.

5.1.1 Streamline connection arrangements

Proponents of DG have suggested that streamlining the arrangements for connection to the network would be of great assistance to them. This could be achieved by:

- developing national technical standards and guidelines for connection
- reducing the impact of the NEM (and Code) requirements on DG (although this may not be possible in practice).

5.1.2 Ensure equitable treatment in relation to connection costs

In relation to connection costs, more equitable treatment of DGs would require that:

- new generators pay deep connection costs only if they are also able to capture the reduced costs incurred by the DNSP as a result of the DG. These cost savings would include avoided TUOS and avoided distribution network augmentation costs.
- if a distributed generator pays deep connection costs, it should receive preferential access to future network users that may connect and who make use of the deep connection assets.
- to the extent that future network users can be connected as a result of deep connection assets paid for by the embedded generator (and pay DUOS and TUOS), then these assets should be included in the DNSP's revenue cap and a rebate made to the embedded generator.[32]

[32] This is in line with the recommendations of the Embedded Generation Working Group.

As noted in Chapter 4, NECA is currently examining the potential inequity of a new DG paying for transmission augmentations while existing transmission-connected generators receive improved access and lower losses at no additional cost, as part of its 'beneficiary pays' review.[33]

NECA contends that there is a mismatch between those who benefit from new network investments and those who pay for them, and that this leads to inefficient investments and inappropriate location decisions. It has proposed changes to the Code that required beneficiaries of new investments to pay for them in accordance with the benefits that they receive.

The ACCC sees merit in NECA's proposal, but has required implementation to be delayed until satisfactory implementation arrangements are in place. NECA has been required to complete a review of the relative benefits to generators of new network investment by September 2002. In particular, it is required to:

- identify an effective methodology for determining the relative benefits to all network users (customers and generators) of new network assets, and for the recovery of costs in relation to these assets
- identify a default method for the allocation of relative benefits and costs, where this allocation is under dispute
- examine the potential for property rights associated with these benefits and costs, to enable a beneficiary leaving the network to sell its right to use the asset to another network user
- review the arrangements for pass through to DGs of avoided TUOS (under clauses 5.5(h) and 5.5(i)) once generators are required to pay for use of a new network investment.

The potential benefits for DG of the proposed 'beneficiaries pays' approach are twofold. Firstly, the amount of deep connection costs that a new DG may be required to pay will be reduced, as the costs of these deep connection assets will be shared with all network users who benefit from them, including existing generators. Secondly, all network users will have an incentive to ensure that the regulatory test process used to assess potential network augmentations considers DG alternatives that may be cheaper than the cost of augmentation.

The Tribunal supports the development of national standards and guidelines for connection and more equitable treatment of DGs in relation to connection costs, perhaps through such mechanisms as the Beneficiary Pays approach.

33 This review is in accordance with the ACCC's September (code amendments) Decision.

5.1.3 Establish guidelines for efficient, effective negotiations

The Embedded Generation Working Group proposed that a set of guidelines be developed to facilitate efficient and effective negotiations between DGs and DNSPs.[34] The group also developed a set of principles to form the basis of these guidelines. In summary, these principles are:

- Development of a simple, transparent, approach to negotiation of connection agreements, including standardised agreements where possible.
- Regulated network businesses to make information available on the planning, capacity and fault levels of key shared network elements. (This has been addressed by the NSW DM Code.)
- Data on more specific shared network elements must be made available to parties seeking to enter into a connection agreement, as required, at its incremental cost.
- In determining the benefit and cost allocation between parties entering into a connection agreement:
  - the cost to be born by the distributed generator connecting to the network must be no more than the (long run marginal) cost of providing the assets
  - the DNSP's costs and costing methodology must be transparent and unbundled and publicly available
  - the sourcing and construction of both deep and shallow connection assets must be undertaken on a competitive basis
  - benefit sharing must be based on the relative risks that parties bear
  - there must be no discrimination between parties seeking connection to the network.

The Tribunal proposes to formalise these principles into a set of guidelines for negotiation in a Schedule to the Tribunal's Pricing Principles and Methodologies.

To further assist DGs, the AEA suggests developing a connection guide to local networks to address the generators lack of information and negotiation power in comparison to the DNSPs. Such a guide would improve negotiated outcomes for DGs and reduce the time, transaction and development costs of implementing projects for all parties.[35]

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34 Embedded Generator Working Group, op cit, p 10.

35 AEA, op cit, p 25.

5.1.4 Develop standard offers

The NSW DM Code Working Group recommended further work be undertaken on the development of standard offers. Experience suggests that the existence of standard offers for DM can provide a very strong and simple signal for potential DM suppliers, and should be explored for use in NSW. Through a standard offer, the network operator offers a set price per kVA of peak network demand reduced per year, subject to that demand reduction meeting certain parameters. These parameters might include, for example:

- the ability to ensure that a sufficient amount of peak demand reduction can be delivered within a specified timeframe
- the ability to demonstrate that the DM option(s) being used will be delivered on time (and according to a timeline that allows the distribution company sufficient time to switch to a supply-side option should the DM option timelines slip)
- the ability to demonstrate the reliability of the DM option (perhaps in accordance with standards to be developed and published for each type of DM resource). This could include, for example, the requirement that different types of DM provide certain specified levels of over-subscription to account for resource non-availability or voluntary withdrawal
- performance guarantees (if deemed necessary).

With any standard offer arrangement, agreement on connection issues would need to be reached as part of the process. However, a major advantage of standard offers is that they have the potential to reduce the uncertainty and information asymmetry that currently exists for DGs attempting to negotiate connection.

The Tribunal supports the development of standard offers and seeks proposals for how this process, including trials, might proceed. It recommends that standard offers be incorporated into the DM Code as applicable.

5.2 Clarify payment of avoided network costs

To ensure that DGs are compensated with appropriate payments for avoided TUOS and other avoided network costs, clear methodologies are needed for:

- calculating avoided TUOS and avoided distribution costs
- allocating costs and benefits between the distributed generator and the DNSP.

5.2.1 Avoided TUOS charges

The Tribunal's 1999 Network Determination set out the principles for calculating avoided TUOS charges, and outlined how this methodology might be applied, using Integral Energy's and the Tower/Appin and Smithfield DG plants as an example. Under this methodology, Integral Energy's avoided TUOS charges in relation to the power it purchases from these DG plants is equal to:

- the reduction in its chargeable peak and shoulder energy as a consequence of the embedded generators (multiplied by) the TUOS energy charge
- plus the reduction in its chargeable demand as a consequence of the embedded generators (multiplied by) the TUOS demand charge

- plus the reduction in its payment for transmission through EnergyAustralia's network.[36]

Using this approach, the Tribunal recently approved an amount of avoided TUOS for Integral Energy for 2000/01 of (approximately) $5.7 million.

The Tribunal proposes to include the specific details of this methodology as a Schedule to the PPM.

5.2.2 Avoided distribution network costs

As discussed in Section 4.2.2 of this paper, the pass-through of payments for avoided distribution costs is complicated by the potential mismatch between the timing of the payments and the costs avoided, and 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 reach case-by-case decisions based on the principles outlined in Section 4.2.2, supplemented by further quantitative guidance on the sharing of the potential efficiency gains. Over time, the precedents established would provide guidance on the treatment of future cases. This approach provides 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.

There are various options for a more 'rule-based' approach. For example, possible rules include the following:

1. *No adjustment of the DNSP's AARR[37] in current regulatory period and incorporation of payments for avoided distribution costs in future AARRs as incurred.* This is a simple rule but it disadvantages the DNSP if the payments to the distributed generator exceed the avoided distribution costs in the current regulatory period. Nor does it allow the DNSP to benefit from the reduction in costs in future periods. If this approach is adopted it may be desirable to make it mandatory for the DNSP to pay the full amount of the avoided distribution costs to the distributed generator. This would increase the incentive for the distributed generator to seek out optimal locations to offset the reduced incentive for the DNSP to encourage efficient DG solutions.

2. *Adjustment of the DNSP's AARR in current regulatory period and incorporation of payments for avoided distribution costs in future AARRs as incurred.* This is the same as the first option except that it would allow for the adjustment of the AARR in the current

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36 TransGrid and EnergyAustralia both charge DNSPs for the use of their transmission networks. TransGrid's TUOS charges have a fixed component, a peak and shoulder energy component, and a demand component. TransGrid also collects EnergyAustralia's transmission revenue on EnergyAustralia's behalf. EnergyAustralia's (fixed) revenue is allocated to distributors on the basis of their share of total peak and shoulder load in 1998/99. This allocation does not vary with subsequent changes in the share of peak and shoulder load since that date.

As Tower/Appin and Smithfield were generating and exporting energy in the period used for allocation of Energy Australia's transmission charges, a smaller proportion was allocated to Integral than would have been in their absence. Hence, allowance has been made for this in the calculation of avoided TUOS charges for Tower/Appin and Smithfield. However, such an allowance would not be made for distributed generators which commenced operation after 1998/99.

37 AARR is the annual aggregate revenue requirement.

regulatory period for payments made (less the avoided distribution costs[38]) in that period. As in Option 1, it may also be desirable to make it mandatory for the DNSP to pay the full amount of the avoided distribution costs to the distributed generator.

3. *No adjustment in current regulatory period and pass-through of payments for avoided distribution costs plus a share of the efficiency gains in future AARRs.* This approach is similar to the first approach but would allow an amount on top of the payments for avoided distribution costs to be added into the DNSP's AARR in future periods. This additional amount would provide an incentive for the DNSPs to seek out efficient DG options.

4. *No adjustment in the current period, and future AARRs set on the assumption that no costs had been deferred/avoided and no payments for avoided distribution costs had been made* (ie based on costs without the distributed generator). This approach is conceptually simple and provides strong incentives for the DNSP to seek out DG options. However it may be difficult to apply in practice. It would require extended modelling of hypothetical cost savings that could become quite complex as the benefits of different DGs or demand management projects are layered on each other.

The Tribunal seeks comments on the relative merits of a case by case approach and on the possible rule-based approaches outlined above.

Capitalisation or Expensing of Payments

A common concern is that payments to the embedded generator should be capitalised and included in the asset base if demand management and DG are to be treated on a comparable basis to network investment. Arguably, such an approach would ensure that alternatives to network augmentation are treated on the same basis as network capex. It also provides greater flexibility in the timing of the recovery of payments to embedded generators.

However, if the discount rate used to capitalise the embedded generator payments is the same as the DNSP's hurdle rate of return, capitalisation of the payments does not alter the net present value of the payments. That is, the capitalised amount would be equivalent - in net present value terms - to the stream of annual payments. While, in principle, it may not make a difference to the regulator whether these payments are expensed or capitalised, further consideration of these effects on incentives and price paths may be required.

However, pending submissions received, the Tribunal does not propose to capitalise payments to DGs.

Retention of Efficiency Gains

The retention of efficiency gains is primarily an issue in regard to network support payments for avoided distribution costs. DNSPs are required to pass through avoided TUOS charges to the distributed generator, so the distributed generator captures these efficiency gains. However, with avoided distribution costs, the question arises as to whether the efficiency gains should be retained by the DNSP or passed-on over time to customers. If DG options are to be treated on a comparable basis to network augmentation, the mechanism for sharing the gains should parallel that for sharing the benefits of efficiency gains in general capital expenditure.

[38] Relevant costs would be the capitalised cost of the network augmentation options; ie rate of return and depreciation on the new assets that would otherwise have been constructed.

This sharing of benefits could be accommodated within the range of options for the pass-through of network support payments outlined above. Each of the approaches for the treatment of avoided distribution costs suggested above presumes that the AARR will be built up from a review of the cost building blocks. While this is the approach most commonly used by regulators throughout Australia, there is considerable debate about the merits of this approach compared to one that places greater emphasis on arms length benchmarks and is not linked as closely to the specific costs of the utility.

If the form of regulation is not linked to the costs of the individual utility, the incentives to pursue efficiency gains may be strengthened. It would also be more difficult to envisage how payments for avoided distribution costs would be explicitly recognised and incorporated in the regulatory control. However, if 'unlinked' regulation enables the utility to retain the benefits of efficiency gains - whatever their source - there may be less need for explicit pass-through arrangements such as this. Efficient costs will be passed through directly by the form of regulation.

Further Action

The issues in regard to the assessment of avoided TUOS and its regulatory treatment are relatively certain. The Tribunal's Determinations and practice in this regard provide considerable guidance. However, the Tribunal can assist in reducing any remaining uncertainty by documenting its approach as a Schedule in the PPM. It proposes that these schedules be completed in parallel with this review.

In contrast, while the same principles apply to avoided distribution costs the application of these principles is more complex and less clear cut. This makes it both more difficult and more important that this issue be resolved, in consultation with stakeholders, and that the regulatory approach or approaches to these costs be documented as a Schedule to the PPM.

5.3 Provide a framework for small generators

The need to provide a better framework for small generators to participate in the NEM is a national market issue. Therefore, it may be best addressed through the NEM processes and eventually, through changes to the Code.

The UK regulator, the Office of Gas and Electricity Markets (Ofgem), has recently addressed this issue, and has released a report setting out ways to enable smaller generators to sell the electricity they produce with greater flexibility and more competitively under the New Electricity Trading Arrangements (NETA). These arrangements were introduced in March 2001.[39]

39 Ofgem, *Report to the DTI of the Consolidation Working Group*, February 2002.

The report accepts that smaller generators should be allowed to sell their fixed and unpredictable output separately, to provide them more flexibility to compete for better prices. For example, they should be able to contract to sell fixed volumes of electricity to one supplier while managing less predictable output more effectively by selling it through companies providing consolidation services.[40] The report addresses the mainly technical barriers that prevented this option being available when NETA commenced and recommends rule changes to encourage the further development of consolidation services.

The Tribunal supports the development of a market framework for small generators. Comments are welcome on whether this matter should be addressed through the NEM processes, or whether there are more local solutions available.

5.4 Encourage the adoption of smart meters

Meters offering accurate, real-time measurement of power flows both into and out of a small scale DG site at a lower cost than is possible today would do much to help the expansion of the domestic DG market. The development of domestic DG could also create a demand for smart metering. Smart meters have the potential to offer a number of benefits to consumers, including better information and control of energy use, new service opportunities for companies and other organisations, enhanced power network management facilities, and alternative connection to digital services. Better information from a meter would also help consumers to save money and contribute to emissions reductions.

Given the importance of this technological development for DG and for other aspects of DM, smart metering trials and / or a targeted rollout of smart meters, may be worth considering.

5.5 Provide incentives for DNSPs

A clearer regulatory framework should improve the incentives for DNSPs to undertake DG projects, particularly if the methodologies for the payment of avoided network costs are clear and easy to apply. The Tribunal also intends to release a paper on its approach to assessing prudent investment during the next major distribution pricing review and this should also provide more certainty to DNSPs. Further, the NSW DM Code provides a transparent process for the consideration of DM options, including DG.

The Tribunal believes that if a more conducive regulatory framework is provided, the current lack of experience among DNSPS with DG projects will gradually disappear.

40 Consolidation services are provided to participants in the electricity markets to bundle together small unpredictable generation and demand to produce greater predictability and also to provide greater access to wholesale electricity markets.

5.6 Remove institutional and structural barriers

The decision to invest or not in distributed generation will ultimately depend on its commercial viability: can customers energy needs be met at a lower financial cost through DG? To the extent full economic costs (including environmental costs) are not reflected in prices, there may be pricing barriers to DG. However, the issue of whether uncertain environmental externalities should be factored into decision-making, and if so, how must be considered more broadly. There are also a number of possible barriers specific to DG.

The institutional barriers to DG, which are created by current rules established under the NEM, are more appropriately considered in national forums and in reviews conducted by NECA and the ACCC. The structural barriers, such as network prices that provide insufficient locational signals, can be addressed by the Tribunal and the DNSPs in the formulation of network prices.

There are also a number of 'soft' barriers to DG such as:

- a lack of integration of DG into network planning
- a lack of experience with DG as a means of network support and concerns as to its reliability
- a lack of experience in contracting for DG in a manner that recognises, manages and shares these risks accordingly
- the relative immaturity of the market for DG.

The development of the Somerton and Bairnsdale plants in Victoria show that these barriers can be overcome. However, given these barriers, it may be appropriate to kick-start the market in NSW through:

- better integration of DG into network planning processes and,
- the development of standard offers (as discussed in section 5.1.4).

APPENDIX 1 TERMS OF REFERENCE

A1.1 Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services

1. Identify energy services options including demand management, load management and DG options and assess their potential, where economically feasible, to enhance electricity network capacity and reliability and meet customer energy service requirements. This assessment should include consideration of:

   a. Synchronisation to the main electricity grid of existing standby generation capacity;

   b. Use of gas chilling for air conditioning;

   c. Use of large scale and small scale co-generation;

   d. Use of other fuels (including natural gas) which can economically substitute for the range of applications for which electricity can be used;

   e. Use of solar energy systems;

   f. Improved lighting efficiency;

   g. Other relevant demand management, load management and distributed generation options; and

   h. Take account of different requirements of electricity transmission and distribution networks and the impact of these options on such networks.

2. Assess the extent to which greater use should be made of such options taking into account all relevant economic and environmental benefits and costs and the quality and reliability of energy services, particularly in relation to:

   a. Deferring the need to invest in new electricity transmission and/or distribution network capacity;

   b. Reducing the demand for new generation capacity;

   c. Enhancing electricity transmission and/or distribution network system reliability and meeting other emerging customer needs;

   d. Increasing demand for energy efficiency services and products; and

   e. Reducing greenhouse gas emissions and the associated risks and costs for consumers, energy service providers, and the New South Wales economy of Australia complying with the Kyoto Protocol target and possible further international greenhouse emission reduction agreements for the period beyond 2012.

3. Assess existing and proposed procedures for managing and augmenting network services and identify any barriers to the development of cost-effective demand management, load management and DG options. This assessment should include consideration of whether the pricing of network services appropriately reflects the costs of providing those services, including environmental costs.

4. Recommend institutional and administrative arrangements and procedures to facilitate demand management, load management and DG that are likely to lead to the most economically efficient and environmentally sound provision of electricity transmission and/or distribution network services. These arrangements should take account of the roles and responsibilities of the national electricity market entities and regulatory bodies and their impact on demand management. Matters to be addressed should include:

    a. Appropriate arrangements for ensuring competitive neutrality in the provision of network services including any practical means to combine different network, energy and other benefits and costs of demand management projects and other options;

    b. The practicality and desirability of applying cost-reflective pricing in the operations of network service providers;

    c. Appropriate financial arrangements between network service providers and owners and operators of DG;

    d. Any need for new arrangements or contracts to facilitate the wider participation and financing of demand management and other options; and

    e. Appropriate arrangements and procedures for planning to meet future network service requirements and maintain system reliability.

In considering the above, demand management is meant to include but not be limited to demand management, load management and DG.

The Tribunal is to investigate and report by June 2002.

APPENDIX 2 DESCRIPTION OF DG TECHNOLOGIES

A2.1 Reciprocating diesel or natural gas engines

Reciprocating engines, developed more than 100 years ago, were the first among DG technologies. Both Otto (spark ignition) and Diesel (compression ignition) cycle engines are widespread in almost every sector of the economy. They are used on a wide scale - from fractional horsepower units for small tools to enormous 60MW base load electric power plants. Smaller engines are primarily designed for transportation, and can usually be converted to power generation with little modification. Larger engines are most frequently designed for power generation, mechanical drive, or marine propulsion.

Reciprocating engines can be fuelled by diesel or natural gas, with varying emission outputs. Almost all engines used for power generation are four-stroke, operating in four cycles (intake, compression, combustion, and exhaust). The process begins with mixing air and fuel. The mixture is introduced into the combustion cylinder, and ignited with a spark. For diesel units, the air and fuel are introduced separately, with fuel being injected after the air is compressed. Reciprocating engines are currently available from many manufacturers in all size ranges. They are typically used for either continuous or back-up emergency power. Cogeneration configurations are available, with heat recovery from the gaseous exhaust.

A2.2 Microturbines

Microturbines are an emerging class of small-scale distributed power generation in the 30 - 400kW range. The basic technology is derived from aircraft auxiliary power systems, diesel engine turbochargers, and automotive designs. A number of companies are currently field-testing their demonstration units, and several commercial units are available for purchase.

Microturbines consist of a compressor, combustor, turbine, and generator. The compressors and turbines are typically radial-flow designs, and resemble automotive engine turbochargers. Most designs are single-shaft, and use a high-speed permanent magnet generator producing variable voltage, variable frequency alternating current (AC) power. Most microturbine units are designed for continuous-duty operation, and are recuperated to obtain higher electric efficiency.

A2.3 Combustion gas turbines

Combustion turbines range in size from simple cycle units (about 1MW) to several hundred MW units (combined cycle power plant). Units with 1-15MW power are generally referred to as industrial turbines (or mini-turbines), as compared to larger utility-grade turbines and smaller micro-turbines. Very few units with less than 1MW power have been installed in the United States (US). Industrial turbines are currently available from numerous manufacturers. Historically, they were developed as aero derivatives, spawned from engines used for jet propulsion. Some, however, are designed specifically for stationary power generation or compression applications in the oil and gas industries. Multiple stages and axial balding differentiate these turbines from the smaller microturbines described above.

Combustion turbines have relatively low installation costs, low emission levels, and demand infrequent maintenance. However, their low electric efficiency has limited their use to primarily peaking units and combined heat and power (CHP) applications. Cogeneration DG installations are particularly advantageous when a continuous supply of steam or hot water is desired.

A2.4 Fuel cells

Although the first fuel cell was developed in 1839 by Sir William Grove, it was not put to practical use until the 1960's, when NASA installed this technology on Gemini and Apollo spacecrafts. Currently, there are many types of fuel cells under development in the 5-1000+ kW range, including phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline, and direct methanol fuel cells. International Fuel Cells/ONSI currently manufacturers a 200kW phosphoric acid fuel cell for commercial and industrial applications. A number of companies are close to commercialising proton exchange membrane fuel cells, with marketplace introductions expected soon.

Although numerous types of fuel cells use different electrolytic material, they are all based on the same principle. A fuel cell consists of two electrodes separated by an electrolyte. Hydrogen fuel is fed into the anode of the fuel cell. Oxygen enters the fuel cell through the cathode. With the help of a catalyst, the hydrogen atom splits into a proton (H+) and an electron. The proton passes through the electrolyte to the cathode, and the electrons travel in an external circuit. As the electrons flow through an external circuit connected as a load, they create a DC current. At the cathode end, electrons combine with hydrogen and oxygen, producing water and heat. Fuel cells have very low levels of NO and CO emissions due to the electro-chemical nature of the process of power conversion. The part of a fuel cell that contains the electrodes and electrolytic material is called the 'stack', and is a major contributor to the total cost of the system. Stack replacement is very costly, but it becomes necessary when efficiency degrades as stack operating hours accumulate.

Fuel cells require hydrogen for operation. However, it is generally impractical to use hydrogen directly as a fuel source; instead, it must be extracted from hydrogen-rich sources such as gasoline, propane, or natural gas. Cost-effective, efficient fuel reformers that can convert various fuels to hydrogen are necessary to allow fuel cells increased flexibility and commercial feasibility.

A2.5 Photovoltaics (PV)

In 1839, French physicist Edmund Becquerel discovered that, when exposed to light, certain materials produced small electric currents. His early experiments precipitated research into PV effects. In the 1940's material science evolved, and the Czochralski process of creating very pure crystalline silicon was developed. This process was used in 1954 by Bell Labs to develop a silicon PV cell that increased the light-to-electricity conversion efficiency to 4 per cent.

PV systems are commonly known as solar panels. They are made up of discrete inter-connected cells that convert light radiation into DC electricity, which must then be inverted for use in an AC system. Current units have 24 per cent laboratory efficiency, and 10 per cent actual efficiency, as compared to the 30 per cent maximum theoretical efficiency that can be attained by a PV cell.

Insolation is a term for the available solar energy that can be converted to electricity. The factors that affect insolation are the light intensity and operating temperature of the PV cells. Light intensity depends on the local latitude and climate, and generally increases closer to the equator.

PV systems produce no emission, are reliable, and require minimal maintenance. They are currently available from a number of manufacturers for both residential and commercial applications, and manufacturers continue to reduce installed costs and increase efficiency. Applications for remote power are quite common.

A2.6 Wind turbines

Windmills have been used for many years to harness wind energy for mechanical work (eg pumping water). Before the Rural Electrification Act in the 1920's provided funds to extend electric power to outlying areas, farms were using windmills to produce electricity with electric generators. In the US alone, eight million mechanical windmills were installed.

Wind energy became a significant topic in the 1970's during the energy crisis in the US, with the resulting search for potential renewable energy sources. Wind turbines were considered the most economically viable choice within the renewable energy portfolio. Today, attention has remained focused on this technology as an environmentally sound and convenient alternative. Wind turbines do not require additional investments in infrastructure such as new transmission lines, and are consequently commonly used for providing power in the remote areas. They are currently available from many manufacturers, with continued improvements in their installed costs and efficiency.

Wind turbine packages include rotor, generator, turbine blades, and a drive or coupling device. As wind blows through the blades, the air exerts aerodynamic forces that cause the blades to turn the rotor. Its rotation speed is matched to the operating speed of the generator. Most systems have a gearbox and generator in a single unit behind the turbine blades. Similar to PV systems, the output of the generator is processed by an inverter that changes the electricity from DC to AC.

A2.7 Stirling Engines

Stirling engines are classed as external combustion engines. They are sealed systems with an inert working fluid, usually either helium or hydrogen. They are generally found in small sizes (1 - 25 kW) and are currently being produced in small quantities for specialised applications.

Stirling-cycle engines were patented in 1816 and were commonly used prior to World War I. They were popular because they had a better safety record than steam engines and used air as the working fluid. As steam engines improved and the competing compact Otto cycle engine was invented, Stirling engines lost favor. Recent interest in DG and use by the space and marine industries, has revived interest in Stirling engines and as a result, research and development efforts have increased.

Table A2.1 Stirling engine overview

Commercially Available	No
Size range	< 1 kW – 25 kW
Fuel	Natural gas primarily but broad fuel flexibility is possible
Efficiency	12 – 20%
Environmental	Potential for very low emissions
Other features	Cogen (some models)
Commercial status	Commercial availability 2002-2005

The potential for very low emissions arises from the continuous combustion process in a Stirling engine which is easier to optimise and control compared to the intermittent explosions of fuel air mixtures in internal combustion Otto and Diesel engines.

Stirling engines are commercially available for marine applications and have been for several years. Trials in domestic CHP are occurring in many countries, on the scale of hundreds of units. Large scale commercial availability for DG could be expected in line with the 'commercial status' dates in the above table.

APPENDIX 3 IMPACT OF DG ON LOCAL AIR QUALITY

Local air quality is an issue in major urban centres, where concentrations of motor vehicles and industry release significant pollutant loads, coupled with geography and climatic conditions that trap emissions locally. DG can potentially add to this problem. The use of best practice emission controls should be sufficient to manage emissions at reasonable levels.

Emissions of Nitrogen Oxides (NO_x), Volatile Organic Compounds (VOCs), Carbon Monoxide (CO), Sulphur Dioxide (SO_2) and particulates from burning fossil fuels such as coal, oil and natural gas can be trapped in local airsheds, leading to photochemical smog and other pollution and health problems.[41]

The NSW Environmental Protection Agency (EPA) has established NSW Action for Air to ensure air quality in the Sydney, Newcastle and Wollongong regions is improved (see box).

Box A3.1: NSW Action for Air

NSW Action for Air

"The New South Wales Government has made a significant commitment to develop and implement a comprehensive long-term plan to protect and improve air quality across NSW. We have also recognised the challenge of putting in place Action for Air -a 25 year plan which tackles the widest range of emissions specifically affecting the Greater Metropolitan Region of Sydney, the Illawarra and the Lower Hunter. "

The Hon. Bob Carr, Premier of NSW, 31 Oct 2001.

Action item 4.5. relates to controlling NOx emissions in the greater metropolitan region (GMR). It states (in part):

Future industrial growth, such as an expansion of cogeneration (a positive greenhouse initiative), has the potential to increase NOx emissions in the Sydney region-thus generating a conflict with regional air quality goals for ozone.

The EPA will implement its NOx policy for the GMR by capping total emissions and setting up a scheme for trading within the cap. The scheme commenced in the 1999-2000 financial year. Its aim is to limit and progressively reduce emissions to achieve a long-term cap on emissions at 1998 licensed levels.

Until load based licencing and the full trading scheme are operational … the Clean Air Regulation and the safety-net requirement that new plant (replacement or greenfield) should not be allowed to cause extra exceedences of the interim air quality goals for nitrogen dioxide and ozone in local or adjacent areas.

For replacement proposals, a minimum requirement of no net increase in NOx emissions from the individual site, and an economic impact analysis of the cost of available control technologies for new plant, will apply.

For greenfield sites, the EPA will seek emission limits consistent with best available control technology, dependent on an economic impact analysis of the cost of achieving these limits.

Excerpts from http://www.epa.nsw.gov.au/publications/html/actionforair/actionforair.htm

DG technologies emit NO_x and other gases that could compromise the objectives of Action for Air. In order to assess the magnitude of this problem, the potential local emissions of these technologies was estimated and compared to existing emission levels.

41 This section is sourced from information provided to the Tribunal by Ben Kearney, Sustainergy Pty Ltd, in January 2002.

The Sustainable Energy Development Authority (SEDA) has assessed the total NSW potential of a range of DG technologies, including:

- use of diesel standby generators - 100MW
- conversion of chillers to natural gas engine drive - 200MW
- small natural gas cogeneration - 200MW
- large natural gas cogeneration - 1000+MW
- domestic hot water conversion to natural gas - 300MW.

Emissions from these measures have been estimated as follows[42]:

Table A3.1 NSW Emissions

Total NSW emissions	**Annual emissions (tonnes pa)**				
Technology (capacity)	**NO_x**	**CO**	**SO_2**	**VOCs**	**Particulates (PM_{10})**
Gas chillers (200MW)[43]	500	370	1	200	0
Diesel standby generators (100MW)	87	19	10	5	5
Small cogeneration (200MW)	1,050	770	2	428	0
Large cogeneration (1,000MW)	5,250	3,850	11	2,140	1
Hot water fuel substitution (300MW)	360	99	1	14	19
Avoided coal power station emissions	-17,380	-810	-26,500	-125	-580
Net additional tonnes	**-10,125**	**4,302**	**-26,470**	**2,660**	**-557**

Of these emissions, only NO_x is significant in relation to existing emission levels.[44] Emissions over the full year, and also on a peak summer day (when chillers will be operating at full load, standby generators are more likely to be required, and weather conditions often favour smog) were estimated. The impact on the Sydney and Greater Metropolitan airsheds is shown below[45]:

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42 Source: Sustainergy Pty Ltd, using National Pollutant Inventory (NPI) methodology.

43 Emissions from gas engines and cogeneration assume current best practice emission controls (EU and Californian air quality standards). Most engines imported to Australia already comply with these requirements. Emissions from uncontrolled engines can be up to ten times greater - which could be an issue particularly for cogeneration conversions of existing standby generators.

44 *1992 Metro air quality study - air emissions inventory,* NSW EPA 1997. DM emissions resulted in increases in GMR region emissions of 3 per cent (NO_x), 0.3 per cent (CO), 0.05 per cent (SO_2), 0.7 per cent (VOCs), 0.04 per cent (particulates PM_{10}).

45 Assuming 45 per cent and 65 per cent of measures are installed in the Sydney and Greater Metropolitan airsheds respectively. Estimate based on EnergyAustralia and Integral Energy share of total NSW electricity sales, and assuming DM measures are installed in the same proportions. Sixty per cent of NSW generation assumed in GMR airshed.

Table A3.2 Impact on Metropolitan Airsheds

NO_x emissions	**Sydney airshed**		**Greater Metro airshed** Sydney, Newcastle, Wollongong	
Technology (capacity)	**Tonnes pa**	**Tonnes per day in summer**	**Tonnes pa**	**Tonnes per day in summer**
Additional emissions from DM measures	3,140	18	4,780	27
Avoided power station emissions	Does not contain power stations, hence no avoided emissions		-10,431	-14
Net DM emissions	3,140	18	-5,649	13
Existing airshed emissions (1992)	101,730	282	238,680	660
Increase in airshed emissions	3.1%	6.3%	-2.4%	4%

While these increases are large enough to be of concern, the order of magnitude indicates they are manageable and will not severely impact air quality.

An appropriate balance between greenhouse and local environmental concerns must be found in order for the benefits and objectives of both demand management and Action for Air to be realised. Under existing regulations (Protection of the Environment Operations (POEO) Act, 1997), EPA is not able to licence or regulate generators less than 6MW (gas turbine) or 1MW (internal combustion) that operate for less than 200 hours per year. There is no power to regulate gas chillers at all.

Should these technologies be broadly adopted without appropriate pollution controls, NSW EPA has indicated it would be concerned about both emission levels and its ability to regulate those emissions. Introduction of a planned NO_x trading scheme for metropolitan areas would provide an effective means of ensuring DG technologies do not unduly affect urban air quality.

APPENDIX 4 EXAMPLES OF EXISTING AND PROPOSED DG PLANTS IN NSW

A4.1 Sutherland Leisure Centre

The Sutherland Leisure Centre is an example of grid-connected fossil fuelled cogeneration. The Centre is one of the largest leisure facilities in the southern hemisphere consisting of a variety of heated indoor and outdoor pools and dry program areas. Power is generated at 415 volt by a synchronous generator. The cogeneration plant operates in base load mode and provides approximately 100 per cent of base load power requirements and 50 per cent of peak winter heat demand.[46]

Table A4.1 Summary Details

Owner	Sutherland Shire Council
Capacity	350kW
Location	Sutherland, South of Sydney
Operational	July 2001
Operator	Sutherland Shire Council
Engine generator supplier	Gas Drive Systems
Construction contractor	Tarong
Power utilisation	100% of base load power demand
Operation	Base load
Primary fuel	Natural Gas

A4.2 Smithfield Energy Facility

The Smithfield Energy Facility is a 160MW gas-fired cogeneration plant located in Smithfield. Integral Energy, the local electricity distributor, purchases electricity from the plant and Visy Paper, a division of Pratt Industries purchases low-cost steam. Features of the plant include:

- 3 x 38MW General Electric Frame 6 gas turbines, 3 x 80 tonne per hour heat recovery steam generators and 1 x 65MW General Electric steam turbine operating in combined cycle
- use of state-of-the-art emission controls to ensure a low environmental impact. This is achieved by using 'Dry Low NOx ' burners in the gas turbines
- minimal production of greenhouse gases, by efficiently burning natural gas.

Electricity is generated at 11.5kV and stepped up to 33kV before interconnection into Integral Energy's distribution network at the Guildford Sub Station. The facility is registered in the NEM as the only Schedule Non-Market Generator, and is the first large-scale cogeneration project to be scrutinised and approved under the Environmental, Planning and Assessment Act.

46 Australian EcoGeneration Association, *Ecogeneration*, August/September 2001, p 18.

Table A4.2 Summary Details

Owner	Sithe Energies Australia Pty Ltd
Capacity (max)	176 MW
Location	Smithfield, west of Sydney
Operational	July 1997
Operator	Sithe Australia Power Services Pty Ltd
Engine generator supplier	General Electric
Construction contractor	Nepco / Transfield Joint Venture
Power utilisation	3 MW
Operation	base load
Primary fuel	Natural gas

A4.3 Sunshine Energy Co-generation Project, Condong Sugar Mill

This project is a joint proposal by the New South Wales Sugar Milling Co-operative (NSWSMC) and Delta Electricity (the NSW generator). The proposal is to upgrade the co-generation plants at NSWSMC's three sugar mills – Condong, Broadwater and Harwood. It will involve the use of bagasse, a by-product of the sugar cane crushing process, cane trash and leaves and sawmill residual as fuel to generate steam and electricity for export to the regional electricity grid.

The plant will operate as a year round facility. In the non-cane crushing season, stockpiled cane based fuels and other environmentally approved biomass fuels, including the woody weed Camphor Laurel, will be used.

Once fully operational (in 2002) the plants should provide up to 700 gigawatt hours of renewable energy, therefore saving about 500,0000 tonnes of greenhouse gases (CO_2) a year

Table A4.3 Forecast Inputs and Outputs

Inputs	
Bagasse	200 000 tonnes per year
Cane Leaves	100 000 tonnes per year
Wood Fuel	100 000 tonnes per year
Tertiary Treated Effluent	2.9 Ml/day
Outputs	
Electricity	30 MW
Ash	4.5 tonnes per hour
Water discharges	0.5 Ml/day

APPENDIX 5 NATIONAL ELECTRICITY CODE AND THE NATIONAL ELECTRICITY MARKET

In Australia, the National Electricity Code (the 'Code') establishes arrangements and procedures for generators to access the transmission and distribution networks, the basis for determining access charges, and procedures governing network planning and augmentation. Of special relevance to DG are references to:

- the process for connection to the network
- the need to pass through avoided transmission use of system (TUOS) charges
- payments that may be made to or received from DGs for distribution network services
- the inclusion of DG as a possible option for addressing projected network limitations.

The NEC seeks to ensure equal consideration of DG and network augmentation options for meeting end-users energy requirements. The regulatory regime is required "to have regard to the need to … create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration" (6.10.3(e)). In their network planning DNSPs must consult "on the possible options, including but not limited to demand side and generation options…" (5.6.2). Having consulted, the DNSPs are obliged to carry out cost-effectiveness analysis to identify the option that maximises net benefits. Part 4.5 of schedule 6.6 also endorses the use of competitive processes to discover the optimum outcome.

A5.1 Network connection

Chapters 5 and 6 of the Code set out the basis on which DGs connect to the grid and sell their power into the market. Section 5.2 sets out the connection arrangements – a four stage process which includes:

1. notification of the project to the DNSP by making a formal 'connection inquiry'
2. submission of an application to connect including a detailed technical assessment of connection issues
3. receiving an offer to connect including a proposed connection agreement
4. negotiating a connection agreement that covers all commercial aspects such as connection costs, standards of service and dispute resolution.

A5.2 Avoided TUOS payments

Under the Code, generators do not pay TUOS charges - this cost is allocated to the DNSPs and in turn, passed on to their customers. Clause 5.5 of the Code allows for avoided TUOS charges to be passed through to the distributed generator, funded out of the DNSP's Annual AARR. Until very recently, the Code requirements were based on negotiations in 'good faith' between the NSP and the distributed generator, as set out in Clause 5.5f(3):

> (f) The Network Service Provider and the Generator shall negotiate in good faith to reach agreement as appropriate on the: …
>
> (3) amount to be passed through to the Generator (where the Generator is an Embedded Generator) for avoided transmission use of system charges that would otherwise be payable by the Network Service Provider as a result of the Generator not being connected to its distribution network; …

However, this Clause has recently been deleted. This is because the ACCC decided[47] on amendments to the Code which have some impact on the issue of avoided TUOS. The ACCC has supported changes to the Code proposed by NECA whereby an embedded generator would be entitled to receive an automatic pass through of the avoided TUOS usage charges from the DNSP to which it is connected.

> To provide locational signals to embedded generators, the proposed code changes require DNSPs to pass through to embedded generators the full reduction in TUOS usage charges that arises from the generator being located within the distribution network.[48]

NECA has now implemented changes to the Code in accordance with the ACCC decision. These changes were gazetted on 6 December 2001.[49]

Clause 5.5(h) now requires that a DNSP 'must pass through the amount calculated … for Customer TUOS usage charges … had the Embedded Generator not been connected to its distribution network.' Clause 5.5(i) sets out how avoided TUOS is to be calculated. This Clause is reproduced in Appendix 6.

These requirements implement the approach first proposed by the Tribunal as the 'with-without test' and formalised in its *Guidelines for the Treatment of Embedded Generation* (May 1997). This approach is based on the view that the benefits of the avoided transmission costs must be available to the distributed generator to enable it to compete on an equal basis with generators connected to the transmission system. While the principles are widely endorsed some stakeholders were concerned that the approach may over signal costs and provide inefficient locational signals.

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47 ACCC, *Applications for Authorisation, Amendments to the National Electricity Code Network Pricing and Market Network Service Providers*, 21 September 2001.

48 Op cit, p x.

49 NECA, Code Changes ACCC Determination, 21 September 2001, Gazette Notice 06/12/01.

Whether the locational signals are economically efficient depends on the efficiency of the transmission charges. However, this is a matter of much wider significance best handled through the setting of transmission charges rather than ad-hoc corrections made specifically in regard to DGs. As the ACCC has also pointed out, avoided TUOS payments would not be needed if transmission usage costs were recovered through charges on transmission-connected generators.

A5.3 Network support payments

Chapter 6 of the Code recognises that the DNSPs may pay DGs for the contribution they make to network support - that is, where the existence of a local generator means the DNSP is able to avoid the costs of network augmentation.

Clause 6.10.5 requires that payments to DGs be included in the DNSP's revenue cap:

> (d) In setting a separate regulatory cap to be applied to each Network Owner …, the Jurisdictional Regulator must take into account each Distribution Network Owner's revenue requirements during the regulatory control period, having regard for: …
>
> (7) the right of the Distribution Network Owner… to recover reasonable costs arising from: …
>
> (iii) payments made to Embedded Generators for demand side management programs and local energy storage facilities which provide distribution service… where the Jurisdictional Regulator determines that this is appropriate;

Chapter 6, Part E of the Code also deals with payments to DGs. Clause 6.13.3 requires that payments received from or made to DGs to be included in the AARR for the appropriate DNSP asset category:

> (c) Payments to and from Embedded Generators are to be determined up to an amount of the long run marginal cost of augmenting the distribution network….
>
> (d) Any payments made under clause 6.13.3(c):
>
> (1) to Embedded Generators must be added to: and
>
> (2) from Embedded Generators must be deducted from,
>
> the aggregate annual revenue requirement for the relevant asset category…

Clause 6.14.1, recognises that in converting DNSP costs into prices:

> (e) There may be situations where the DNSP is prepared to pay for equivalent network service by DGs…. prices for such equivalent network services are to be agreed between the relevant DNSP and Jurisdictional Regulator.

This point is discussed further in part 4.5 of schedule 6.6:

> Embedded generators can in some circumstances provide significant benefits in certain parts of a distribution network…. Distribution service charges are negotiable between the Network Owner and the Generator. The charges (or payment) need to reflect the benefit available to the Network Owner from the distributed generation. This will depend on — the degree to which any benefits to the network that might accrue from the generation are shared between the NSP, the Generator and other Network Users. … The long run marginal cost (benefit) of the shared network reinforcement represents the upper limit of payment to the Generator.

Part 5 of this schedule also provides discretion for the regulator to treat services provided to DGs for reserve (or standby) capacity, other distribution services and access as competitive services that can be excluded from the revenue or price cap.

It should be noted that Chapter 6, Part E does not apply expressly in NSW as the Tribunal has exercised its discretion not to apply Part E. Hence, the provisions of 6.13.3 are not binding. However, the Tribunal's PPM[50] which has been developed as an alternative pricing methodology to Part E of the Code broadly reflects the approach in Chapter 6 Part E to embedded generation and there is provision for the development of Schedules to the PPM dealing with general principles for the treatment of DG and a negotiation framework.

A5.4 Network planning

Another benefit of DG is that it offers ways of addressing future network limitations, particularly within regions. The Code assigns responsibility for network planning within regions to the relevant NSP. Clause 5.6.2 requires NSPs to select options which maintain the operating standards of their networks while maximising the net benefit to customers. NSPs are required to consult with participants and interested parties to identify these options:

> (f) …the Network Service Provider must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand side and generation options, to address the projected limitations of the relevant transmission system or distribution system.
>
> (g) Network Service Providers must carry out cost effectiveness analysis of possible options to identify the option that maximises the net benefit to customers…

Part 4.5 of schedule 6.6 briefly discusses the competitive process that NSPs may use to ensure that the most cost effective option is identified correctly:

> As a general principle, commercial arrangements shall be made with Generators and this may include a competitive tendering process to ensure equal opportunity for other Generators. For example, a statement of opportunity for the area concerned could be issued with an invitation to bid for generation capacity in the area. This would facilitate free market forces providing the optimum outcome for the network business and existing network customers.

50 IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services*, March 2001.

APPENDIX 6 CLAUSE 5.5(I) NATIONAL ELECTRICITY CODE

Clause 5.5 (i) states:

> To calculate the amount to be passed through to an Embedded Generator in accordance with clause 5.5(h), a Distribution Network Service Provider must if Customer TUOS usage prices were in force at the relevant transmission connection point in the relevant financial year:
>
> 1. determine the Customer TUOS usage charges that would have been payable by the Distribution Network Service Provider for the relevant financial year if the Embedded Generator had not injected any energy at its connection point during that financial year; and
> 2. determine the amount by which the charges calculated in paragraph (1) exceed the Customer TUOS usage charges actually payable by the Distribution Network Service Provider, which amount will be the relevant amount for the purposes of clause 5.5(h).

Where Customer TUOS usage prices were not in force at the relevant transmission connection point throughout the relevant financial year, the DNSP must apply an equivalent procedure to that described above in relation to that component of its transmission use of system service charges which is deemed by the relevant TNSP to represent the marginal cost of transmission, less an allowance for locational signals present in the spot market to determine the amount for the purposes of clause 5.5(h).

APPENDIX 7 REGULATORY APPROACHES TO DG IN OTHER STATES AND COUNTRIES

There is currently much interest in the development of effective regulatory frameworks for DG both in Australia and overseas. Different incentives and regulatory practices are in place in the various jurisdictions. 'Avoided TUOS' as a potential incentive payment from a DNSP to a distributed generator is apparently only an issue in Australia, where generators do not pay TUOS or DUOS. In England and Ireland generators normally pay TUOS and DUOS. However, distribution-connected generators in England are not required to pay DUOS (or TUOS) and this acts as a positive incentive for DG, offset to some extent by the requirement to pay deep connection costs. In Ireland DGs receive an automatic TUOS credit, but still pay DUOS. This appears to parallel the approach in Australia.

In Ireland and the US, there are either plans to implement grants for DG, or funds have already been established. Joint funding and management of DG projects is occurring in the US. England and Ireland have established specific Working Groups to further the development of DG, and various bodies are fostering DG in the US. A common theme internationally (and in Australia) is the importance of the establishment of standard connection procedures and charges.

A7.1 Victoria

Until recently distributors in Victoria were regulated in accordance with the Victorian Electricity Supply Industry Tariff Order (the Tariff Order). Clause 5 of the Tariff Order regulated the tariffs that a distributor could charge its customers for the provision of network services. Included in the revenue from network tariffs was a pass through of transmission costs to VPX (now VENCorp) and PowerNet (now SPI PowerNet). Payments for avoided TUOS that were paid to a third party could not be passed through to customers via network tariffs because the Tariff Order did not allow for such a payment.

However, the Essential Service Commission (ESC) made a determination with respect to distribution and transmission tariffs in December 2000 that changed the previous rules to include a provision for the pass through of avoided TUOS payments.

The framework for payments for avoided network augmentation costs to embedded generators, such as provided for under clause 5.6.2 of the Code, described above has been applied in Victoria – for instance in the recent establishment of the Somerton Power Station. The Somerton power station is described by AGL Electricity as an example of a single DM resource capturing multiple benefits. The 150MW generator will provide network reinforcement and will operate as a peaking plant in the wholesale energy pool. The long terms distribution of the avoided cost benefit associated with the deferral of a major network upgrade will be 50 per cent to the generator, 35 per cent to the customer and 15 per cent to the DNSP.[51]

51 As summarised in the CRA Issues Paper, *Demand Management Technical and Financial Feasibility*, prepared for IPART in February 2002, p 8.

In its latest distribution price Determination[52], the ESC requires distributors to pay a fair and reasonable share of avoided network costs to embedded generators. It is recognised that it may not be appropriate for distributors to pay full avoided costs in all circumstances, because customers and distributors would receive no benefit (as the distributors costs would not be reduced). It also suggests that the generator might be over-rewarded given the revenue it receives from energy sales. Thus the payment to embedded generators is capped at avoided costs, to ensure that benefits are shared and ultimately flow through to customers.

The ESC also requires distributors to publish annual network planning reports and to plan and augment their network so as to minimise the cost to customers.

A7.2 South Australia, Tasmania and Queensland

Regulator's offices in South Australia, Queensland and Tasmania have advised that no specific policies and procedures have been developed in relation to DG at this point in time. The issues of payments of avoided TUOS have not arisen. However, these states are subject to the requirements of the Code, although various derogations from the Code continue to apply in each State.

A7.3 England and Wales

In England and Wales, Ofgem is responsible for energy regulation. Currently embedded generators in England[53] pay 'deep' connection charges, which can be a significant cost. 'Deep' connection charges refer to a (usually significant) one-off upfront payment required from the embedded generator to cover costs relating to network protection and voltage control equipment up to the boundary of the distribution network. 'Shallow' connection charges relate only to the specific assets required for connection, usually up to the first transforming point. The remaining reinforcement costs are regarded as general load growth and recovered through use of system charges.

Generators connected to the transmission system pay TUOS charges (in Australia, only DNSPs pay TUOS). Because they are not connected to the transmission system, embedded generators do not pay TUOS. Distribution Network Operators (DNOs) have a statutory duty to provide connection for the purposes of enabling electricity to be conveyed to or from premises.[54] However, DNOs also have a complementary right to recover expenditure reasonably incurred in making a connection. Any dispute over the terms of a connection agreement may be referred to Ofgem for determination.

A new statutory duty has recently been imposed on DNOs to facilitate competition. In view of this, the Department of Trade and Industry established an Embedded Generation Working Group, which reported in January 2001. The Working Group identified a number of impediments to DG, which included:

- technical limitations – for example fault level requirements in connection agreements
- network capacity restrictions in rural areas

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52 Office of the Regulator General, Victoria, *Electricity Distribution Price Determination 2001-2005*, Volume 1, September 2000, p 79.

53 In this context, 'England' refers to both 'England and Wales'.

54 Ofgem, *Embedded Generation: Price Controls, Incentives and Connection Charging – A preliminary Consultation Document*, September 2001, p 14.

- connection charging (in particular the 'deep connection cost' requirement)
- design standards.

The Working Group recommended, inter alia, that Ofgem review the regulatory incentives of the distribution network owners in relation to DG and assess issues in relation to connection charges and information provision.

In response to the recommendations of the Working Group, Ofgem released a consultation paper[55] in September 2001 to discuss the principles which it should apply to DG and to identify appropriate actions to eliminate barriers.

A7.4 Northern Ireland

The Northern Ireland regulator the Office for the Regulation of Electricity and Gas (Ofreg), has recently released consultation papers on renewable energy generation and environmental incentives for transmission and distribution pricing.[56] [57] Renewable energy sources currently account for about two per cent of electricity generation capacity in Northern Ireland, with the share gradually increasing. The renewable energy market is technically fully open – a renewable generator has the right to sell to any customer. Ofreg has recently established the Trading Renewables Implementation Group to address the issues relating to both small and large-scale renewable schemes.

While generators and suppliers and their transactions are subject to regulation by Ofreg, renewable electricity is not subject to price control. An Eco Energy Tariff allows customers to take a proportion of their electricity from renewable generators by paying a six per cent premium above the usual tariff. Renewable generators connected to the distribution system receive a 'transmission credit', so they are not required to pay TUOS charges. (Generators normally pay both TUOS and DUOS – Use Of System (UOS) charges are levied on all users of the network.)

Northern Ireland Electricity (NIE) is the regulated electricity service provider, including transmission and distribution services. Ofreg suggests that NIE should evaluate the avoided network reinforcement cost of DG proposals and where the outcome is favourable provide financial assistance in the form of 'grant aid'.[58] However, NIE currently has no financial incentive to consider such an alternative and the customer / generator is required to take the initiative and bring a proposal to NIE. To provide an incentive for the NIE to evaluate DG on equal terms to network reinforcement, Ofreg is suggesting that NIE should be allowed to record the grant in its assets register and earn the same rate of return as it would for capital expenditure.

55 Ibid.
56 Ofreg, *Accelerating Trading of Renewable Electricity*, August 2001.
57 Ofreg, *Greening Transmission and Distribution*, June 2001.
58 Ofreg, June 2001, p 5.

A7.5 The United States

In the US, major changes in regulation in the 'electric' and natural gas industries over the past two decades have encouraged the development of DG. The *Public Utilities Regulatory Polices Act 1978* stimulated increased use of cogeneration in industry and independent power projects. Since then, natural gas deregulation has lowered gas prices in the US. The (federal) *Energy Policy Act (1992)* also stimulated DG by initiating deregulation of power generation. Since the passage of this Act, federal, state and local policymakers have been seeking to improve the economics of power delivery through a dramatic restructuring of the electric power industry to promote competition, customer choice, greater cost effectiveness and lower energy prices.[59]

The final results of the industry restructuring are still unclear, with many states only just enacting relevant legislation. However, Arthur Little Consulting notes that industry changes are well under way and the positive trends for DG include:

- the opening of retail markets provides customers with choice resulting in a large number of competitors offering new products and services, including DG
- the emergence of performance-based ratemaking (regulation) provides an opportunity for utilities to implement DG to improve asset utilisation
- the unbundling of services and more sophisticated market mechanisms, including real-time pricing, will send price signals that will provide an economic stimulus for DG.[60]

Apparently DG's economic attractiveness for customers and utilities and its ability to provide for capacity in the near term is leading regulatory bodies in several states to address it:

> Concerns over the allocation of benefits, levying of added costs, and other competitive issues will put DG on the regulatory and legislative agendas of many more states and the federal government. An understanding of the fundamental economics of DG is essential for policymakers to address these concerns and to arrive at sound decisions regarding its future. [61]

A7.5.1 California

In California, the electricity industry is currently undergoing a transition to competition in generation. However, monopoly franchises for transmission and local distribution remain in place. Retail competition has been introduced but widely publicised problems mean it is largely ineffective for small to medium sized customers.

DG units may be owned by electric or gas utilities, by industrial, commercial, institutional or residential energy consumers, or by independent energy producers. Three state agencies are actively involved in the development of rules applicable to the DG market place – the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and the California Air Resources Board (CARB).[62]

59 A D Little, *Distributed Generation: Understanding the Economics*, 1999, p 4.

60 Ibid.

61 Op cit, p iii.

62 Source: website – Distributed Generation – California Energy Commission (www.energy.ca.gov/distgen/) 28 November 2001.

The CEC is developing standardised state-wide interconnection rules and reviewing the streamlining of Permit applications. CPUC is investigating a variety of issues in two phases. Phase one includes interconnection rules, DG ownership, distribution system planning, DG valuation, and education. Phase two addresses rate design, standard costs, distribution and permit streamlining. The CARB is involved in implementing a recent Senate bill which requires the development of emission standards for all DG units that commence operation on or after 1 January 2003.

A number of incentive programs providing financial assistance to those interested in operating DGs systems are available in California. These include:

- The Solar Energy and DG Grant Program
- The Renewable Buydown Program
- The Pacific Gas and Electric Company Self Generation Incentive Program.

A7.5.2 New York

In New York, by summer 2000 it became apparent that the combination of increased demand, limited transmission, and a lack of major new plants, particularly in New York City, was placing unacceptable pressure on energy supply. This followed a period in the mid 1990's when utility spending on energy efficiency was cut by about 75 per cent despite projections that increased demand would lower the reserve margin by the year 2000. In response, the New York Power Authority launched an emergency program to site 11 new gas-fired generators in the New York City region and the state legislature directed the Energy Planning Board to conduct a reliability study.[63]

In New York, the transition to a competitive electric power market has been described as 'complex, requiring an ongoing evaluation and assessment of regulatory and institutional issues and opportunities'.[64] The New York State Energy Research and Development Authority (NYSERDA) notes that during electric industry restructuring government involvement can encourage market development by providing financial incentives and streamlining regulations to support emerging competitive energy markets.

The NYSERDA runs various programs to assist energy-efficient, environmentally friendly, product development. The NYSERDA Energy Resources program works with more than a dozen companies interested in developing solar and wind technologies that can meet the world demand for remote power systems – in particular, wind and solar systems. The Power Systems Program is assisting NY firms to develop and commercialise advanced technologies for clean, energy-efficient electric power and combined heart and power (cogeneration or CHP).[65]

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63 Richard Cowart, Regulatory Assistance Project, *Efficient Reliability – The Critical Role of Demand-Side Resources in Power Systems and Markets*, June 2001, p 14.

64 New York State Energy Research and Development Authority, *Envisioning the Future*, 2001-2004, p 3-1.

65 New York State Energy Research and Development Authority, op cit, pp 2-1 to 2-4.

The current environment of fluctuating electricity prices, continued demand for reliable and high quality power, and the development of numerous viable DG technologies is creating opportunities for the promotion of DG and CHP. The deregulated electricity market in New York provides for potential DG/CHP growth in the long-term, but faces near-term hurdles such as utility interconnection, exit fees, standby and backup charges.

GLOSSARY

AARR	Aggregate annual revenue requirement
ACCC	Australian Competition and Consumer Commission
Demand	Measurement of customer peak load taken as the average load over a half-hour period measured in kW or kVA.
DG	Distributed Generation
DGs	Distributed Generators
Distribution network	Electricity network connecting the transmission system to customers. Voltages include 132,000 V down to typically 240 V at the customer's premise.
Distributor	A corporation constituted under the NSW Energy Services Corporation Act - includes network or wires function, and retail function.
DM	Demand Management
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System Charges
GWh	Gigawatt hour = 1,000,000 kilowatt hours or 1,000 MWh, a measure of electrical energy
HV	High Voltage
IPART	Independent Pricing and Regulatory Tribunal
kV	kV = 1,000 Volts
kVA	kVA = 1,000 Volt-Amperes which is a measure of the apparent power flow which determines the amount of capacity required to supply the customer's load.
kW	kW = 1,000 Watts which is a measure of the actual power being consumed
Load Factor	Average load divided by the peak load
LV	Low Voltage
MW	Megawatt = 1000 kilowatts
MWh	Megawatt Hour = 1,000 kilowatt hours, measure of electrical energy
NEC	National Electricity Code (the Code) - market rules governing the operation of the National Electricity Market, which commenced in December 1998.
NECA	National Electricity Code Authority – the body charged with responsibility for administering the National Electricity Code.
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company, responsible for the implementation of the Code and the day to day operation of the National Electricity Market.

Off-Peak Period	All times other than Peak and Shoulder Periods on working weekdays and all times on weekends and public holidays.
Peak Period	Generally periods 7:00 – 9:00 am and 5:00 – 8:00 pm on working weekdays.
Power Factor	A measure of the real power in kW divided by the apparent power in kVA. The optimum power factor is 1.0 where the real power equals the apparent power.
PPM	Pricing Principles and Methodologies for Prescribed Electricity Distribution Services
Shoulder Period	Generally the periods 9:00 am – 5:00 pm and 8:00 – 10:00 pm on working weekdays.
Transmission Charges/TUOS	Transmission Use of System Charge - component of network charge which covers use of the transmission network.
Transmission network	Electricity network owned and operated by TransGrid, operating at voltages between 132,000 V and 500,000 V and connecting the generators to the distribution network.