Western Power: Transmission & Distribution

Network cost analysis & Efficiency benchmarks

Volume II
Theoretical framework

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Table of Contents

1 Introduction

The Western Australian Economic Regulation Authority (ERA) in accordance with its responsibilities under the Electricity Networks Access Code is undertaking a review to determine appropriate revenue controls for the distribution networks of Western Power. The review will set allowed revenues for the period 2006-2011.

As part of its pricing determination, the ERA is required to calculate capital and non-capital related expenditures. These expenditures must measure forward-looking and efficient costs which would be incurred by a prudent service provider without reducing service quality below the standards set for each covered service in the access arrangement.

Benchmark Economics has been engaged by Western Power to assist with its submission to the ERA by providing an expert view on certain aspects of its forward looking expenditures:

- an economic cost structure model to identify major network cost drivers;
- an analysis of the influence of the identified cost drivers on Western Power's distribution network;
- a comparative assessment of the cost performance of Western Power relative to tis peers; and
- an estimate of prudent operating and maintenance expenditures and capital investment for the distribution networks.

The cost structure analysis is presented in two volumes. The first, "*Western Power: Network cost analysis & Efficiency benchmarks*" presents the cost analysis and proposes appropriate expenditure levels. The second, provided in this report, details the theoretical framework for the cost model used in Volume I.

This Report is structured as follows: Chapter 2 addresses the role of benchmarking in regulated pricing and the problems arising due to the lack of a defined notion of the network "product". A theoretical framework for analyzing network cost structures is outlined in Chapter 3. This section also discusses the necessity to distinguish between costs and prices and the implications of the lack of a theoretical foundation for the notion of "efficient cost". Chapter 4 provides an overview of the networks included in the study. Using the economic principles established in Chapter 3, the next section examines the link between distribution network cost drivers and total costs. Chapters 6 and 7 examine the link between network costs drives and opex and capex respectively. Chapter 8 presents a brief conclusion.

2 Benchmarking for incentive based regulation

Price regulation for monopoly electricity networks was introduced as part of the broader restructuring of the electricity industry. Industry regulators, reflecting the intention of the reforms, have focused on improving network efficiency by implementing incentive-based pricing mechanisms in preference to the widely discredited rate of return regulation. Structured around the CPI-X formula, this pricing framework allows firms to increase prices by the rate of inflation (CPI) less an efficiency factor (X). Offering businesses the opportunity to earn a higher rate of return by outperforming the efficiency target provides the incentive to reduce costs.

To assess the potential for efficiency gains, regulators have adopted the practice of benchmarking the costs of individual networks against those of other network businesses. Effectively, incentive-based pricing has made cost performance comparisons an integral part of the regulatory landscape. A number of benchmarking paradigms are emerging throughout the world: Anglo-American (econometric methods and industry average standards), the Nordic (DEA, non-parametric methods and frontier standards) and the Hispanic (engineering-based techniques and standards).

Given the growing role of external benchmarking in pricing regulation, it is surprising how little fundamental research there has been into network cost structures. Often, the selection of variables for network cost models has been based on empirical precedent rather than assessment of actual network production processes.

This is unfortunate. Precedent in the empirical literature was established well before the emergence of the stand-alone network business. The traditional approach to electricity industry cost analysis was based on investigation of vertically integrated utilities or of stand-alone generators. However, neither structure provides a conceptual framework appropriate for analysing networks since they lack the defining spatial characteristics of electricity distribution. In consequence, network cost modelling to date has often made serious misjudgements in identifying the potential for efficiency gains.

It should not be surprising the results have proved contentious. In the UK, Ofgem in its 2004 pricing proposal expressed publicly its concern about the adequacy of its 1999 integrated econometric cost model analysis. Capital expenditure allowances increased by an inflation adjusted 48 per cent in its 2004 price review. Nordic networks have won legal appeals against the regulator's DEA analysis; networks in Chile have had successful legal appeals against the regulator's engineering model; while IPART in its 2004 Decision announced large expenditure increases that unwound the reductions of the 2000 pricing review, reductions that had been based on findings of substantial operating "inefficiencies".

Darryl Biggar highlighted the difficulties of assessing appropriate cost benchmarks in the current environment in his report to the Australian Competition and Consumer Commission (ACCC) *Incentive Regulation and Benchmarking*[1]. In a discussion on the determination of "cost benchmarks", he observed that regulators requiring guidance on the appropriateness of the submitted costs of the regulated firms had resorted to the opinion of external experts. However, as Biggar explains:

> *"The process by which the external experts arrive at a view as to the appropriate level of costs is largely a "black box".* Further, *"…it seems likely that any attempt to clarify the process by which experts approve the cost*

[1] Darryl Biggar, *Incentive Regulation and Benchmarking,* A Report for the ACCC, 2003

estimates of the regulated firm will inevitably involve restricting the discretion of these experts, and, to an extent, replacing this discretionary process with a more mechanistic process."

Not only does the "black box" view lack transparency, it is based on partial productivity measures. There are, however, theoretical problems with the use of partial productivity measures. They offer few advantages in benchmarking. Perhaps the most apparent is that they are simple to compute.

An important disadvantage is that partial measures do not control for differences in business conditions since their selection is arbitrary and not based on network cost driver analysis. Differences between businesses are overlooked. While the products may be similar, the firms may be varied; scale, customer location, end-use demand, and maintenance practices can affect quite substantial differences in cost and quality. As Alfred E. Kahn stressed in his classic text on economic regulation[2], "…*endowments matter*", they should not be omitted because of perceived difficulties in specifying an appropriate model or acquiring the relevant data.

In competitive markets these variations would be absorbed in differing profit margins and or market shares. In regulated industries this response is not possible. It therefore falls upon the regulating agency to ensure the cost impact of these factors is taken to account in any comparative analysis. This adjustment, however, is not always achieved. "Inefficiencies" identified are often due to the benefits or disbenefits of such "endowments", which lay beyond the control of the network's management.

A cost model specific to the characteristics of electricity networks will make an important contribution to lifting the quality of the cost comparisons/

2.1 Towards a network cost model

The construction of a network cost model requires the resolution of two critical issues. First, it is necessary to understand the specific function of the electricity network business, that is, what does an electricity network actually produce? Defining the network production process and its "product" should be considered a necessary pre-condition for identifying major cost drivers. However, a review of the empirical literature suggests there is little awareness of the distinctive features of network businesses. The choice of model variables is still based on "precedent" rather than "product". In one of the better analyses of network efficiency, Neuberg[3] observed:

"Hopefully, someday functional form choice will grow out of a heuristic/theoretic investigation of the actual production process being modelled."

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[2] Kahn, Alfred E. 1991. "The Economics of Regulation: Principles and Institutions", Massachusetts Institute of Technology 1988.

[3] Neuberg, Leland Gerson, 1977 "Two issues in the municipal ownership of electric power distribution", *Bell Journal of Economics*.

Despite an elapse of more than 25 years since this was written in 1977, most studies still pay little attention to the actual network production process when specifying inputs and outputs for cost models. Variables such as line length or transformer capacity are even used interchangeably, either as inputs or outputs. Energy flows are treated as a network output when in fact they are not network outputs -- they are outputs of the generation production process. A discussion of the implications of using energy flows as a network output in comparative cost analysis is provided in section 4.2 of this paper; *Distinguishing between cost and price*. Engineering parameters likely to affect cost outcomes are not even considered.

It is difficult to accept that credible judgements can be made about the "cost of production" when there is no agreement on the nature of the product.

Once the "product" has been identified, the next issue to be resolved in constructing network cost models is to identify the linkage between the product and the underlying cost base. To provide the credibility required for regulatory purposes these linkages should be verified by reference to engineering experience. Electricity networks are highly complex engineering constructs; they are governed by the laws of physics and constrained by an overall level of acceptable cost. An econometric view of cost drivers may not always reflect the underlying realities.

A study undertaken by Pacific Economics Group and Benchmark Economics for Australian network businesses[4] developed a theoretical framework based on economic aspects of electricity distribution. Using cost of production theory and basic economic principles, the analysis has defined the network product and identified major cost drivers. The outcome is a cost framework that can assist regulators and the industry to arrive at genuinely based cost comparisons. The analysis undertaken for Western Power and contained in Volume I of this report is based on this cost model.

The following sections present an overview of the cost model framework and its application within the Australian distribution network sector.

3 Theoretical framework

3.1 What do electricity networks do?

Electricity businesses provide a physical network for conveying energy flows. The network is only one link in the electricity supply chain, intermediate between generation and retail supply. In the first link high voltage transmission networks connect the generators to the low voltage distribution networks. In the next, low voltage distribution networks connect the high voltage bulk supply points directly to end-users located at varying points within the distribution franchise territory.

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[4] Pacific Economics Group and Benchmark Economics: *The cost structure of power distribution*" a five volume report for the National Electricity Distributors Forum, 2000-2001

To satisfy the varied demands of end-users, the network "product" consists of a bundle of services rather than a more typical single discrete output. In addition to the length of the network required to connect end-users to the generators, networks must also provide sufficient capacity to meet peak demand, and reduce the voltage of energy delivered to the generator bus bars to the levels suitable for end-user equipment. As an essential facility, electricity network businesses are also expected to operate networks to assure reliable deliveries and to provide prompt restoration of interrupted supply.

Defining the function of the network as the conveyance of energy flows, and not as a producer of that energy, has received support at high levels. One useful aspect of the introduction of pricing regulation has been the development of statutory definitions of the network function for use in primary and subsidiary legislation. In New Zealand the legislation established for the control of electricity network pricing contains a specific section on definitions: *The statutory language as a guide to market definition*[5]. It defines the function of network services as:

> *"The provision and maintenance of works for the* **conveyance** *of electricity: the operation of such works, including the control of voltage and assumption of responsibility for losses of electricity…"* (Emphasis added.)

This definition has support in Australia. In the case of TXU Ltd v Office of the Regulator General, the judgment by Gillard J. noted that:

> *"Distribution is to be contrasted with generation and sale and is concerned with owning and operating the poles, wires, transformers, sub-stations and other infrastructure used to* **transport** *electricity."* (Emphasis added.)

Another defining feature of network service providers is that in contrast to competitive businesses, the level of output and the conditions within which they operate are generally outside the control of management. That is, scale and business conditions are largely exogenous variables; management cannot minimise its operating costs by limiting the number of its connections, refusing to connect remote end users, or by supplying less capacity than demanded.

3.2 Identifying the network product

We have now established that the function of an electricity network is to transport or convey electricity between the generator and the end-user. However, without further analysis this tells us little about the nature of the product that the network provides.

Economics offers useful guidance for identifying the network product. In particular, cost of production theory provides a conceptual framework that facilitates identification of outputs and associated inputs, a necessary condition for measuring cost efficiency.

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[5] New Zealand legislation

Based on the firm's technological production function, cost of production theory describes the way in which firms transform purchased inputs (the factors of production) into outputs of goods and services. One example cited in text books is the bakery which uses *inputs* including labour and raw materials such as flour and sugar and capital invested in ovens to produce *outputs* such as bread and cakes. The ratio of outputs to inputs will be influenced by a range of factors including output scale, certain business conditions, and managerial efficiency.

It is this last factor, the level of managerial efficiency that is intended to be the target for the X-factor. Too often, however, cost comparisons fail to distinguish between the factors that are controllable by management and those that are not. "Inefficiencies" identified frequently measure only the impact of the non-controllable features of the operating environment.

In terms of identifying network inputs and outputs, cost of production theory provides clear and unequivocal guidance. Inputs are those resources purchased by the business and transformed into the range of network products or services. In terms of the physical production process, network inputs are wires, towers, transformers, substations, and operating systems. Measured in terms of financial flows, inputs are defined as the building blocks used to estimate regulated revenues: operating and maintenance expenditures, and the rate of return on, and of, capital.

Based on this simple construct, network outputs will represent in some way the transformation of the networks inputs of poles, wires, and transformers. Accordingly, it is held that electricity distribution businesses transform capital and other inputs into the following outputs:

- *Connectivity* - the extent of the low voltage network that connects bulk supply points to end-users; specified in the cost model as line length km -- it represents the input of poles and wires;
- *Capacity* – the capability the network to satisfy the demand of end-users; specified in the cost model as coincident peak demand measured in MW -- it represents the input of transformers and substations;
- *Connections* – the number of connections to the network; specified in the cost model as the number of end-users connected -- it represents the input of connection equipment eg poles and meters, and end-user related services; and
- *Reliability* – the availability and continuity of energy delivery to end-users; specified in the cost model as SAIDI -- it represents inputs such as equipment redundancy, multiple circuits, and operating and maintenance practices eg tree trimming.

3.3 Identifying network cost drivers

Network costs are shaped by three major cost drivers; the scale of the network, the level of reliability provided, and the conditions within which it operates.

3.3.1 Scale

Production economies obtained from changes in *output scale or volumes* can be usefully divided into economies of scale and economies of scope. Economic theory holds that the cost of production may vary according to the quantity of output produced (economies of scale). For a firm producing a single output, scale economies will occur when the change in cost is smaller than the change in output as output increases. The differential rate of change between costs and outputs may result in an average cost curve that declines with output growth.

Economies of scope exist when multiple products can be supplied by one company more cheaply than if provided by separate, specialized companies. Scope economies can arise from the existence of slack resources that can be shared between businesses. Vertically integrated utilities were considered necessary on the basis of their considerable economies of scope.

Regulated pricing for electricity networks has been justified on the basis of their natural monopoly characteristics. The presence of decreasing costs is held to provide such economies of scale that it is more efficient to have just one supplier for any given territory.

Irrespective of widespread acceptance of the benefits of scale, network cost performance is consistently compared without adjustment for, or indeed recognition of, the presence of economies of scale.

3.3.2 Reliability

The importance of reliable, high quality electricity supply continues to grow as all sectors of the economy become increasingly dependent on digital and information technology. Network service providers must provide not only a secure and reliable network connection to end-users they must also ensure that the quality of supply minimises voltage sages, surges, transients, and harmonics.

Investment in reliability and quality of supply is a significant proportion of network cost. Both capital and operating expenditures may be affected. Investment may include additional circuits, undergrounding, equipment redundancy, for example CBD networks operate major substations with at least N-2 redundancy, and system controls. Operating expenditures extend to the number of maintenance crews to speed rectification, and frequency of tree trimming.

As substantial costs are incurred in the provision of network reliability an appropriate assessment of comparative costs can only be achieved if reliability, measured in some way, is also included as an output.

3.3.3 Business conditions

Econometric analysis of a wide range of business conditions has identified two major cost drivers, they are:

- *Connection density*: measured as the number of connections or capacity provided per km line length; and
- *Customer class*: measured as the average level of energy consumption of end-users. Load factor, a variation of average consumption levels, is measured as the ratio of average demand to peak demand.

The influence of these conditions on network costs reflects the productivity of capital. Connection density reflects the productivity of capital invested per *length of line*, that is, how many end-users can be connected to a given length of line. Customer class or load factor measures the productivity of the capital invested in the *capacity* of the system, that is, how many units of energy are conveyed for a given level of capacity?

Network cost model

The network cost model used in the following analysis is constructed as follows:

Table 1: Network cost model

		Model variable
Inputs	Poles, wires, transformers, substations, system control	Total Revenue, operating or capital expenditures
Outputs	Connectivity Capacity Connections Reliability	Line length km Capacity – peak demand MW Connections –nos of end-users SAIDI
Cost drivers	Scale *Business conditions*: Connection density Customer class	Km, MW, or connections Connections/km or MW/km kWh/connection or GWh/MW.

3.4 Costs of production

3.4.1 Distinguishing between cost and price

Before moving to a discussion of the links between the product and its cost it is necessary to take a diversion to clarify what the regulators mean by "cost". It is equally import to understand the way in which it should be measured since it is to be used to set efficiency targets.

Unfortunately, a body of literature and performance comparison has evolved in network cost analysis that is often unable to distinguish between "cost" and "price". In any market these terms are not necessarily the same, in the network sector where most network **costs** (eg $/MW) are traditionally charged on a per energy flow basis, that is, $/kWh (**price)**, they are quite different. Measuring network cost performance on the basis of prices charged is not only misleading it can be damaging to the financial structure of the network business.

The first step is to check that the focus of pricing regulation is cost and not price. From an examination of the national and jurisdictional legislation it does seem that policy makers intended to focus on the **cost** of providing the network service and not on the price charged for that service. The National Electricity Code, (s6.2.2 – s6.2.5) states that regulatory regimes must achieve outcomes, which are efficient and **cost** effective. Reflecting national objectives, the Western Australian Electricity Networks Access Code 2004 in s6.5(a)(i) defines the objective of price control enabling adequate revenues to the service providers to:

> *"meet the forward-looking and efficient* ***cost*** *of providing covered services"*

If cost is to be the focus, the next step is to determine how it should be measured.

3.4.2 Measuring cost

Network cost is easily identifiable. It is the cost of producing the network outputs. Typically this is the sum of the building blocks; the rate of return on, and of, capital plus operating and maintenance expenditures; referred to in regulatory pricing determinations as the annual average revenue requirement (AARR). For partial analysis, cost could also be measured as operating and maintenance expenditure or capital expenditure.

But total cost alone conveys little or no information as to its prudency. This can only be assessed by measuring it against the network outputs. However, identifying the actual network "product" appears to be an illusive task. Despite the guidance offered by cost of production theory, "outputs" selected to normalise network cost have often been arbitrary and without theoretical justification. Inputs are confused with outputs, with network length used interchangeably. Nowhere is the misspecification of output more apparent than with the use of energy flow (MWh) as a network product.

The cause of the confusion appears to be the multiple-output nature of the network production process. There is no simple, single output than can be used as the denominator in constructing network cost indicators. In contrast, measuring the cost of a single output such as a car or a loaf of bread presents less ambiguity. Moreover, at this stage, there is no integrated indicator that can act as proxy for the multiple network outputs. Several attempts have been made to construct such an indicator but they have been unsuccessful, producing seriously misleading results.

In the absence of a readily identifiable network output, it has become accepted practice in network cost analysis to define output in terms of the *energy* flows (MWh). Accordingly, average revenue per MWh, ($/MWh), has become the most frequently used performance indicator for **cost** comparisons.

This is not correct. As energy does not represent the transformation of network inputs such as wires and poles it cannot be used as a measure of network **cost.** For electricity distributors, energy is simply the commodity conveyed along the network they provide. It is more akin to the cars on a road or the trains on the track. The indicator $/kWh measures only the **price** for the use of the system. To judge the cost efficiency of a road construction company by the number of cars travelling along the road would not seem prudent. It is no less so for networks and energy flows.

3.4.3 Prices and load factor

Distinguishing between cost and price is not simply a matter of theoretical correctness; it is critical to estimates of efficiency that are based on cost performance and not on business conditions. While cost reflects total investment and operating cost, price reflects only the average use of that system, hence DUOS. The greater the use of the system relative to the underlying investment, the lower the price ($/MWh) to end-users. Factors that affect the average use of system can result in substantial differences in price, irrespective of the underlying cost.

The most significant influence on the average use of system is load factor. Measured as the ratio of average use of system to peak demand it can drive a wedge between costs incurred and prices charged. In simple terms, this charge will be total cost (AARR) divided by the number of unit units (MWh) conveyed along the network[6]. As networks are high fixed cost businesses with little or no marginal cost for conveying an additional unit of energy, the greater the use of the system the lower the average price as the high fixed costs are spread over a greater number of throughputs. While networks may have comparable costs for providing a given level of capacity ($/MW), those with higher load factors and greater energy flows will be able to levy lower "prices", $/MWh.

Load factors vary substantially depending on the type of end-user connected. Large industrial and commercial consumers tend to require high and consistent energy flows, providing the network business with a high load factor. Alternatively, domestic users with air-conditioning loads may require large amounts of capacity but only for short periods, or low load factor. EnergyAustralia has estimated that its domestic air-conditioning load has a load factor of only 7 per cent, compared to 56 per cent for its total network. Networks with relatively low industrial loads and higher domestic loads are especially disadvantaged by the use of price - $/MWh - to measure relative efficiency.

Moreover, depending on the weather and the economic cycle, this peak capacity could remain unused for several years. The capacity growth rate does not expand at a steady pace, it tends to fluctuate widely: gaps of three to four years between successive peaks are not uncommon. Irrespective of this fluctuating demand, to avoid unexpected growth in peak demand[7] exceeding the level of installed capacity, networks must invest in a steady expansion of peak capacity on an annual base. Experience suggests that it would not be politically acceptable to do otherwise.

Though we concede that $/MWh is used widely as a measure of cost performance, and accept that it will be difficult to overcome this misunderstanding, we believe that it is incorrect to use it in this way. The analysis in this report measures cost by the use of revenues (total, operating, or capital) as the numerator and network outputs (km, MW, connections) as the denominator. Average revenue per MWh conveyed is defined as price.

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[6] In reality, of course, network tariffs are considerably more complex than this measure of average revenue.

[7] In 1997, peak demand in South Australia rose by 12 per cent above its previous peak, compared to an average rate of growth of 4 per cent for the 10 year period to 2002.

3.5 Determining "efficient cost"

The notion of "efficient cost" has become the criterion for setting regulated expenditures such as opex and capex. The Western Australian Electricity Networks Access Code at s.6.5(a)(i) states that the price controlled revenue must be:

> " *sufficient to meet the forward-looking and* ***efficient costs*** *of providing covered services..*" (emphasis added)

"Efficient cost", though widely used as a benchmark in regulatory price setting, is an illusive concept. There appears to be no established economic theory to provide a workable definition in the context of network cost performance. As the Western Australian Supreme Court found in the EPIC[8] case it is an uncertain term that is not readily defined by economic theory:

> *"determining…the efficient level of costs or the outcome of a competitive market are matters of economic theory and practice which, on the evidence, are in the course of constant revision, development and refinement."*

Professor Williams, former Professor of Law and Economics at the Melbourne Business School, and an expert witness in the EPIC appeal went beyond this. He proffered the view that the phrase did not have a technical economic meaning. In the absence of an accepted theoretical definition the Court concluded that the use of the term "efficient cost" in the regulatory context where "*the concept of economic efficiency was directly incorporated*" suggests a usage that would reflect the broader notion of *economic efficiency*. That is, efficient cost should be judged in terms of the firm's productive, allocative or dynamic efficiency.

However, the concept of economic efficiency; productive, allocative, and dynamic, is more relevant to policy issues related to efficient resource allocation within the broader economy. It is not sufficiently precise to guide regulators to the appropriate level of efficient expenditures for individual businesses. A business that is wholly efficient productively may fall short of achieving allocative efficiency, while it may not achieve the desirable level of dynamic efficiency if it fails to innovate and address customer's changing demands. The possibility exists for trade-off between the three types of efficiency and theory provides no guidance on the desirable contribution of each type of efficiency.

Overall, economic efficiency will reflect the stage of the investment cycle (lumpy network investment means that it will take some time before new investment is fully utilised), changes in factor prices, (relative prices may change but it may not be financially viable to scrap equipment before the end of its economic life), or the type of industry, (networks may require less innovation than biotechnology companies).

While the financial market models for determining the weighted average cost of capital (WACC) and the capital asset pricing model (CAPM) provide practical and quantifiable

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[8]Supreme Court of Western Australia – Court of Appeal: 2002; Re Dr. Ken Michael AM; ex parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231

criteria for determining the rate of return, economics has no equivalent model to provide quantifiable parameters for assessing *efficient* expenditures. Moreover, the industry itself has presented no comprehensive framework that could assist regulators to identify key cost drivers and hence efficient costs. One UK consultant reporting to Ofgem found there was:

> *"…little consensus on the appropriate cost driver in respect of the operating…costs of transmission companies".*

The cost model outlined in this report represents a first step in developing quantifiable parameters for assessing efficient expenditures. It is argued that efficient cost is not an exact level of expenditure. Rather it is one that fits within reasonable distance of the overall experience of the broader industry.

The cost analysis undertaken for this report is based on a series of linear regressions of the major variables to determine "best fit". The results are presented in graphic form. It is believed the use of graphics provides transparency; the regulator can make its own judgement on the relevance of the cost drivers and the strength of the relationship between the variables. Additionally, the relatively small size of the sample limits the level of confidence in some of the linkages. This factor has also precluded the development of an integrated econometric cost model for the Australian network businesses at this stage.

4 Distribution network cost structures

As a prelude to the analysis, a brief overview of the scale and business conditions of the Australian networks included in the study is provided in the next section.

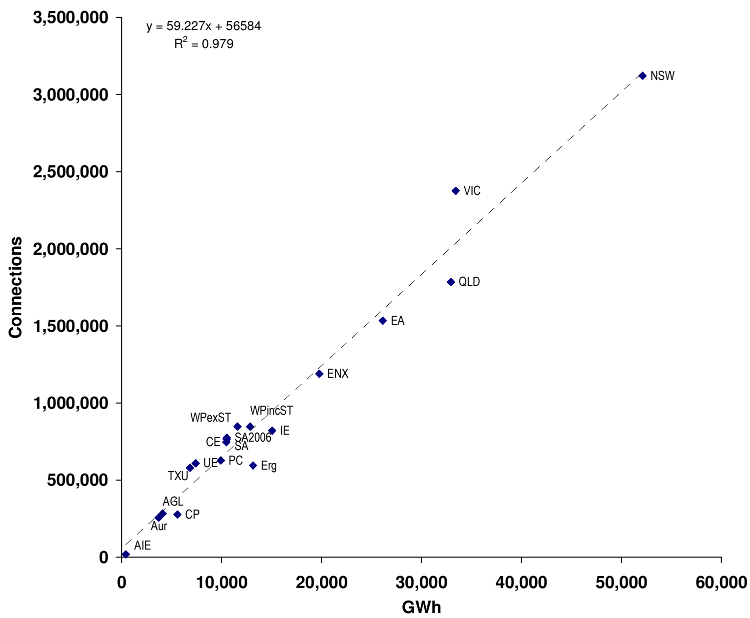
4.1 Australia's distribution networks

14 of Australia's electricity distribution networks are included in this study. Four in NSW, five in Victoria, two in Queensland, and one each in South Australia, Western Australia, and Tasmania. The number of networks in each jurisdiction presents the first challenge in assessing relative network performance. The individual networks in NSW, Victoria, and Queensland operate, to varying degrees, within specific regions. For example, Citipower services a CBD, Energex services a mix of CBD and urban, while Country Energy services a low density rural area greater than the whole of the state of Victoria. Each operating environment has a specific impact on network costs.

However, the state-wide networks of South Australia, Western Australia and Tasmania encompass the full range of operating environments; CBD, urban, and rural. At the macro level, the indicators for these networks will represent an "average" of the costs for their CBD, urban, and rural components. Credible cost comparisons for these three networks therefore tend to be hampered by the absence of similar systems. To increase the number of suitable comparators for Western Australia, three additional statewide networks have been derived by aggregating the data for the individual networks in NSW, Victoria, and Queensland. A list of the networks included in the study is included in Appendix A.

Figure 1, depicting the number of connections and energy throughput illustrates the range of network scale. Of the individual networks, EnergyAustralia, with an annual energy flow in excess of 28,000 GWh and 1.5 million connections is the largest, while the smallest; Australian Inland Energy has a throughput of only 433 GWh and 19,000 customers. Energex is the next largest network followed by a mid-range group including Western Power, and a smaller group consisting of the relatively small systems of Citipower and AGL and Tasmania's Aurora. Among the statewide systems, Western Power is around the same scale as South Australia, but considerably smaller than NSW, Victoria, or Queensland.

Figure 1: Network Scale – Connections and energy throughput



Despite the substantial range, a clear and linear trend is evident between the number of connections and energy flows. Average consumption levels may vary between networks but not to a substantial degree, ranging from a low of 12,500 kWh to a high of 22,800 kWh. Moderate climate conditions have, in part, contributed to this outcome.

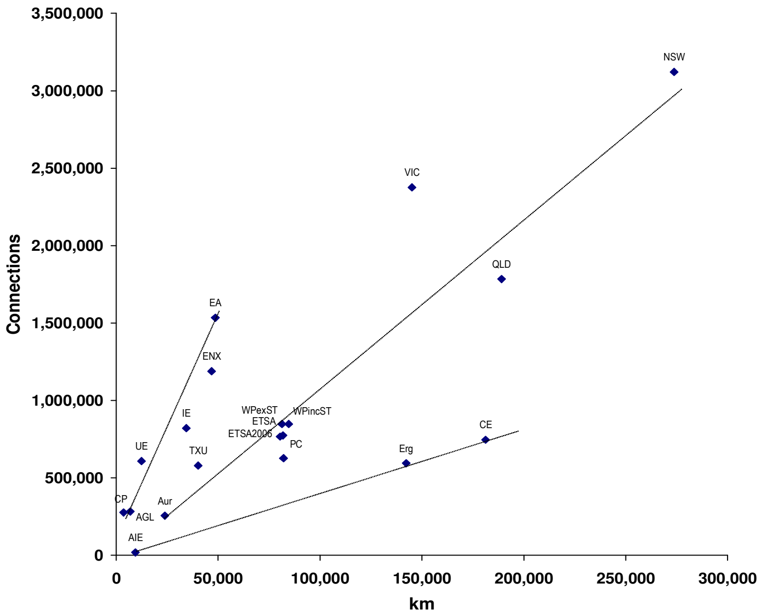
However, this close link is not apparent when connections are compared to network length. Figure 2, plotting connections against network length, (a measure of connection density) reveals at least three trends in energy density. The first, links the high density CBD and urban networks (25–77 connections/km), the second links the mid-density largely state-based networks including Western Australia (10–12 connections), and the third links the low density rural networks (2-8 connections. Interestingly, connection density shows little variation across the states with the exception of Victoria (Table 2).

Table 2: Connection density – statebased systems

	Connection density – Nos/km
NSW	11.4
Victoria	16.4
Queensland	9.4
South Australia	9.5
Tasmania	10.7
Western Australia	10.4

Clearly, there is a more complex link between connections and line length than there is between connections and throughput. Statistical analysis indicates that connection density is the single most influential cost driver for electricity distribution networks. The factors underlying this link and the strength of the relationship are discussed in the following sections.

Figure 2: Network Scale: network length and energy throughput



5 Network cost driver analysis

5.1 Scale and total network cost

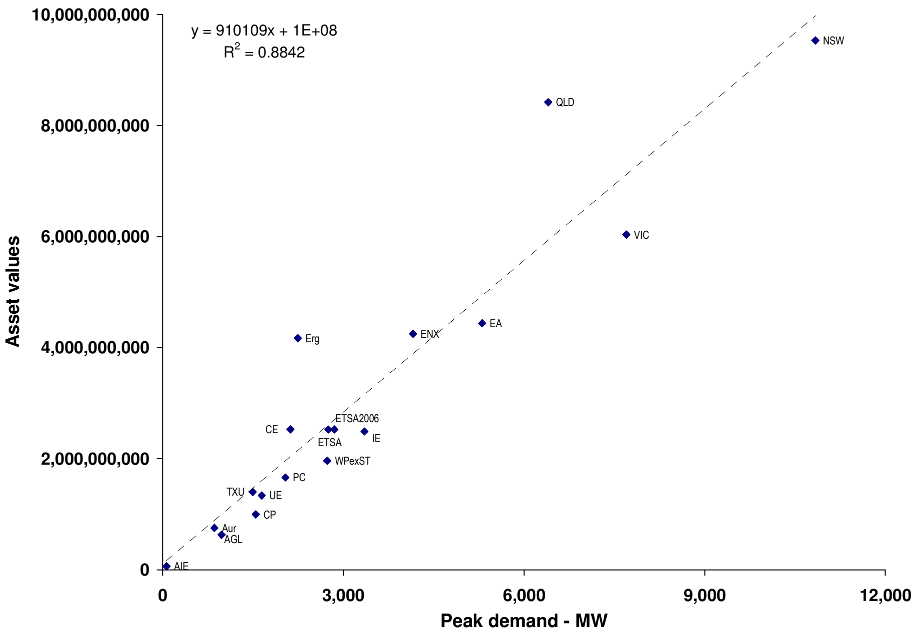
It is well established in economic cost of production theory that the scale of operation may influence production costs. This is particularly so in capital intensive industries. The opportunity to purchase more cost effective larger equipment units or to achieve lower average costs through bulk purchases of essential inputs is one aspect. Another is the ability to share the relatively fixed corporate overheads across the larger business.

There are a number of ways in which scale can be measured for network businesses. In this instance we use network capacity as the output but it would be equally appropriate to use the number of connections or the length of network.

To assess the impact of scale on network costs, it is first necessary to investigate the link, if any, between the output (capacity provided - peak demand) and the input (asset base). Figure 3 depicting RAB values and peak demand reveals a strong link between the two variables.

As would be expected, the value of the underlying asset base rises in line with the increasing level of capacity provided. Note that differences between the jurisdictions in the treatment of capital contributions introduce some distortion. Customer capital contributions are included in the asset base in Queensland lifting asset values above the trendline.

Figure 3: Network scale: Asset values and network capacity (MW)



However, to determine whether operating scale has an influence on unit costs (assets/MW) it is necessary to measure the change in cost associated with a change in network scale. In this instance, Queensland was excluded from the analysis since its asset base also included customer contributions. The change in unit cost estimated by the trend line is:

Equation 1: Network scale and unit costs

Increase in asset base for each 1000 MW peak demand = 8494x - 19.335

R^2 98%

Using this equation to calculate unit costs over the range 1,000MW to 12,000MW suggests few, if any, benefits of scale are available to the Australian networks in the sample. A similar calculation based on the link between asset values and connection numbers revealed a similar lack of scale benefits. However, these results are subject to a caveat. The sample contains a mix of network types, high and low density, and large industrial and small customers. It is possible that the higher costs of servicing say the urban networks or large industrial customers are obscuring some scale benefits. Regression analysis of a much larger sample of US networks indicates that scale benefits are present although they are not very significant.

5.2 Reliability and network costs

Reliability, defined in this analysis as the System Average Interruption Duration Index (SAIDI)[9], is a function of the level of network investment and its ongoing maintenance. Investment in multiple circuits, equipment redundancy, and higher voltage levels, will lift supply reliability. Likewise, the availability of maintenance crews and tree trimming expenditures will ensure that equipment provided remains in good operating condition and outages and remedied promptly.

Reliability investment will reflect a trade-off between the quality of supply required by end users and the commercial viability of the associated expenditures. Higher levels of reliability are generally associated with higher density networks where the greater number of connections per km provides the higher revenues necessary to fund the additional reliability investment (Figure 4).

For example, a CBD network with total revenues of $48,000 per km is able to provide its end-users with a SAIDI of 50 minutes. At the other extreme, a rural network with total revenues of only $2,500 per km will only be able to provide a reliability level of around 300 minutes SAIDI each year.

It is not common practice to include measures of reliability as an output in network cost models. Some analysts claim there are methodological issues associated with its inclusion in econometric cost models while others reject its role as a network output.

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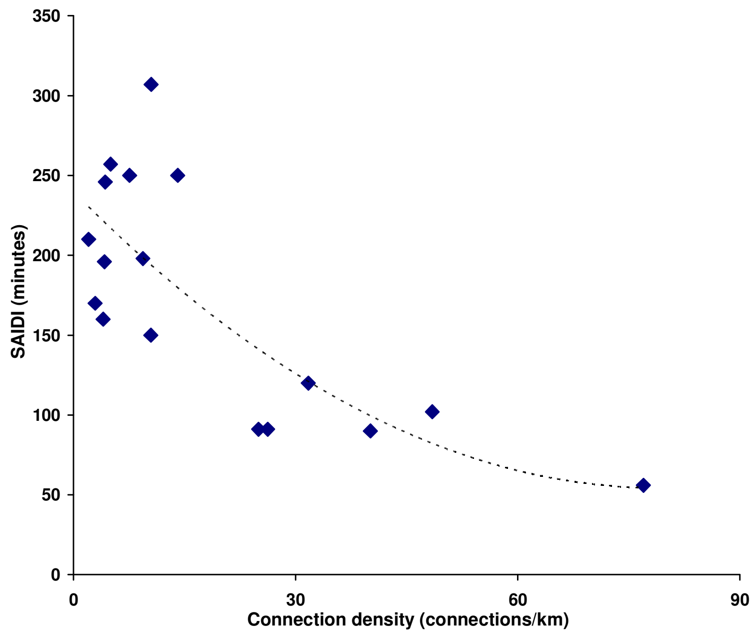
[9] The use of SAIDI in this analysis is not to suggest that it is an ideal measure of reliability; there are other more useful and appropriate indicators. However, for the purposes of this paper SAIDI has been selected since it is widely used and accepted as a measure of reliability.

Figure 4 **Reliability and energy density**



Irrespective of the justification for its omission, the outcome has been misleading cost estimations. Excluding reliability from cost models means that the explanatory power it could offer is apportioned across the other variables in the model, often distorting the cost comparisons. At the same time, omitting reliability from the cost analyses has obscured the very real investment requirements necessary to deliver higher levels of reliability.

5.3 Business conditions

Economies of scale present one potential cost benefit available to distribution networks, economies of density present another. For any given length of network, connecting a greater number of end-users (connection density) or conveying more energy to each connection for any given level of capacity (customer class), may offer significant cost benefits. Management has little control over these factors, since location and energy consumption represent choices of the end-user, not the service provider.

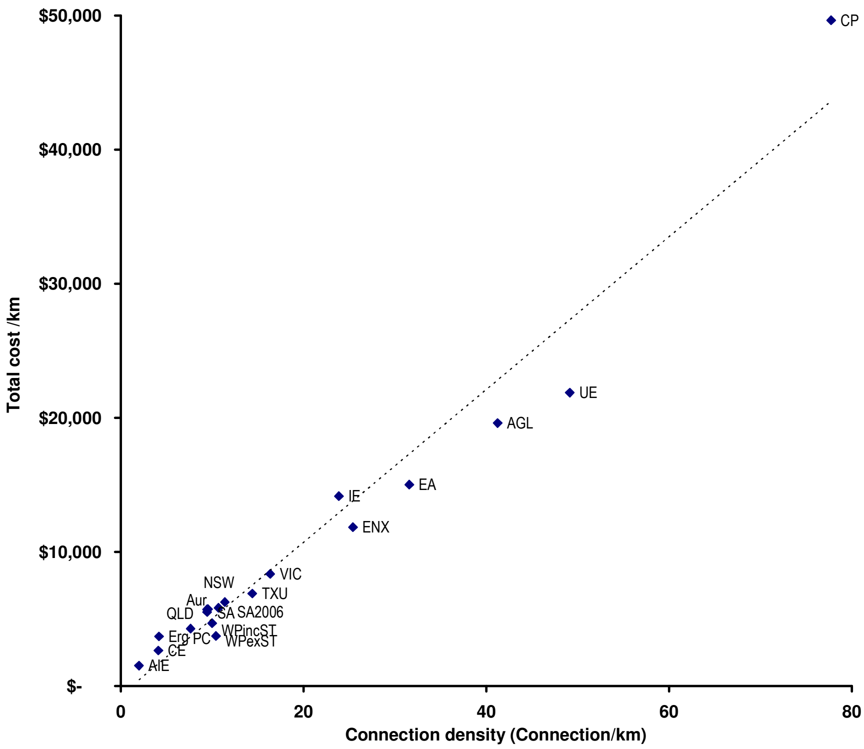
5.3.1 Connection density

Density, whether measured as connections, capacity, or energy flows per km of network length, is the single most significant cost driver for distribution networks. All else equal, increasing the number of connections per length of line substantially reduces the assets required to make each connection. For example, to connect an end-user to a CBD network may require investment in as little as 14 metres of network. This is substantially less than the 245 metres of network required to provide a connection in remote rural areas.

This relationship is underpinned by sound technical reasons relating to voltage of supply and number and size of transformers, yet it is a factor that often is omitted from cost comparisons. One possible reason for the omission of density from many network cost models appears to be the tendency to measure density as the number of connections relative to the area of the franchise territory rather than the more appropriate length of network required to connect end-users. For some businesses, the network may cover the entire franchise territory, for example the CBD system provided by Citipower. For others, the service provided might reach only a part of the franchise territory, for example Integral Energy's Blue Mountains region where large tracts are simply inaccessible. Consequently, the ratio of connections to service territory will contribute little explanation to cost variability, appearing insignificant in the statistical analysis.

The strength of the relation between costs and connection density is depicted in Figure 5.

Figure 5: Connection density and total cost per network length



Plotting average total revenue per km against the number of connections per km, the fitted trend line depicts an extremely strong link between the two variables, with an R^2 of 96 per cent. Total costs decline from $49,000/km for a CBD network down to $2,300/km for a very low-density rural network. The fit for the trend line is estimated as:

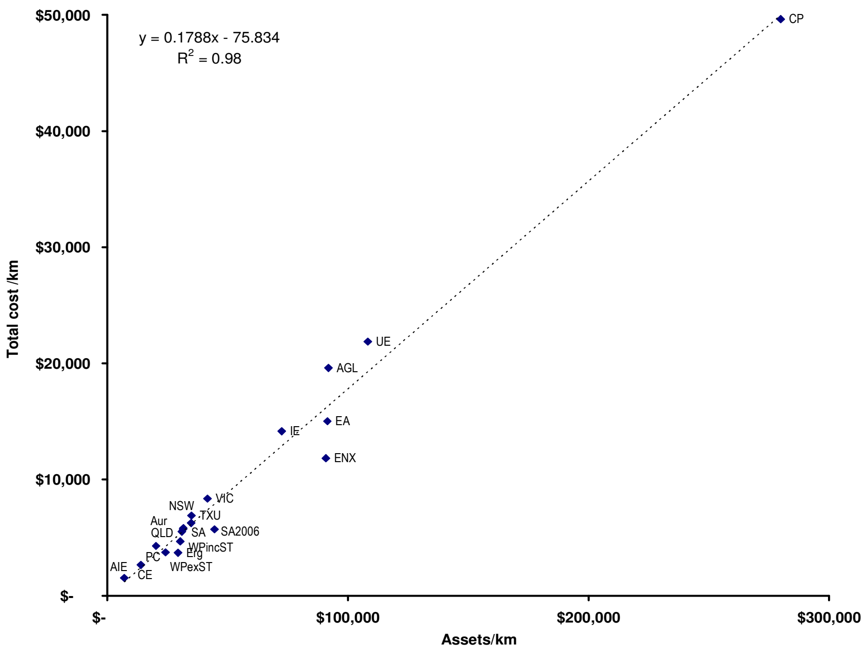
Equation 1: Connection density and cost per km

Increase in total cost/km per connection/km = 569.77x – 689.37

R^2 = 96%

As a high fixed cost industry, the strength of the link between connection density and total cost observed in Figure 5 suggests that a similar close link should exist between costs and the value of the underlying asset base. The fit between assets per km and total costs per km depicted in Figure 6 confirms that this indeed is the case.

Figure 6: Assets/km and total revenue/km



The strength of this link is indicated by the high level of explanation offered by the estimated trend line:

Equation 2: Total revenue per km and assets per km

Increase in total cost/km per asset/km = 1788x – 75.834

R^2 = 98%

The similarity of the trend line in Figures 5 and 6 demonstrates the three-way link between connection density, assets/km, and total costs/km. Networks are capital-intensive with assets and capex accounting for approximately 70 per cent of total costs with opex contributing the remainder. It is to be expected that factors such as connection density which influence the demand for, and use of, network assets will in turn also influence total costs.

The number of connections for each km of line length determines not only the type and spacing of poles but also line voltage, number of circuits, transformer/substation size and equipment redundancy. System assets range from single circuit wood poles at 100 metre intervals in remote rural areas to triple underground circuits in CBD systems. The link between density and costs is so strong that even a relatively small change in density can have a large and measurable impact on the value of assets required to make a connection.

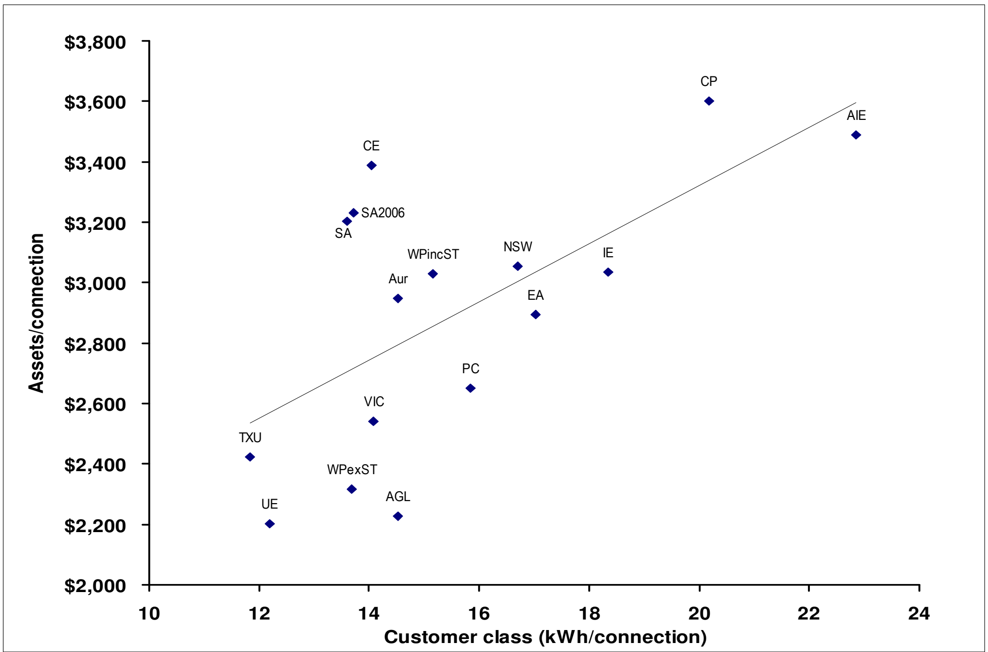
Given the evident strength of this relation, and the intuitive appeal of the underlying reasons, it is difficult to understand why connection density has been so widely neglected as a cost driver. The influence of connection density is not restricted to the asset base, and its impact on opex and capex is discussed later in this paper.

5.3.2 Customer class – load factor

Cost is also sensitive to the mix of end-users connected to the network (described in this report as *customer class)*. Assets required to provide a connection differ between residential, commercial, and industrial end-users. Importantly, different classes of customers have different levels and temporal patterns of demand and energy consumption as well as required levels of quality and reliability of supply.

In much the same way that location and density affect the type and quantity of assets required for each connection, the type of consumer connected also affects the amount and type of asset required. Whereas urban consumers are supported by more complex systems than rural connections, large consumers are supported by more complex systems than smaller consumers. Consequently, rising average consumption levels tend to be linked to rising average asset requirements (Figure 7).

Figure 7: Customer class and asset requirements



Asset investment to provide a connection for the largest industrial consumers can be double that required to connect the smallest end users.

The strength of this link is markedly less than that between density and assets. In addition, the largely written down asset base of Australian Inland Energy and the omission of the Queensland networks because of their different asset base calculations have tended to somewhat skew the trend.

Equation 3: Customer class and assets per connection

Increase in assets/connection with
increasing consumption kWh/connection = 96.235x + 1396.3
R^2 = 39%

Nevertheless, it is clear from the trend in Figure 7 that a network with an average consumption level, say, of 16,000 kWh would be required to provide a higher level of assets for each connection than a network with an average consumption only 12,000 kWh.

The influence of customer class extends beyond its impact on **costs** incurred to also affect **prices** charged. The higher average consumption levels typically associated with commercial and industrial customers lift the level of throughput relative to the under underlying asset base. With high fixed costs, the greater throughput reduces average revenues by allowing fixed costs to be spread across the increased number of throughputs. To illustrate this affect, consider the difference between South Australia and Queensland. Both states have average total costs around $168,000 for each 1,000 MW of peak capacity installed. However, in South Australia the lower average consumption level (13.6 kWh) results in an average price per MWh of $42, considerably above the $32/MWh in Queensland where average consumption is around 18,500 kWh.

Analysis of the Australian networks indicates that there is typically an inverse relationship between customer class and connection density. High consumption networks tend to service industrial consumers in more remote locations. High density networks tend to service a greater proportion on smaller customers especially the domestic sector. This interplay results in a complex matrix of cost and price indicators (Figure 8).

Figure 8: Matrix: Influence of business conditions on cost and price

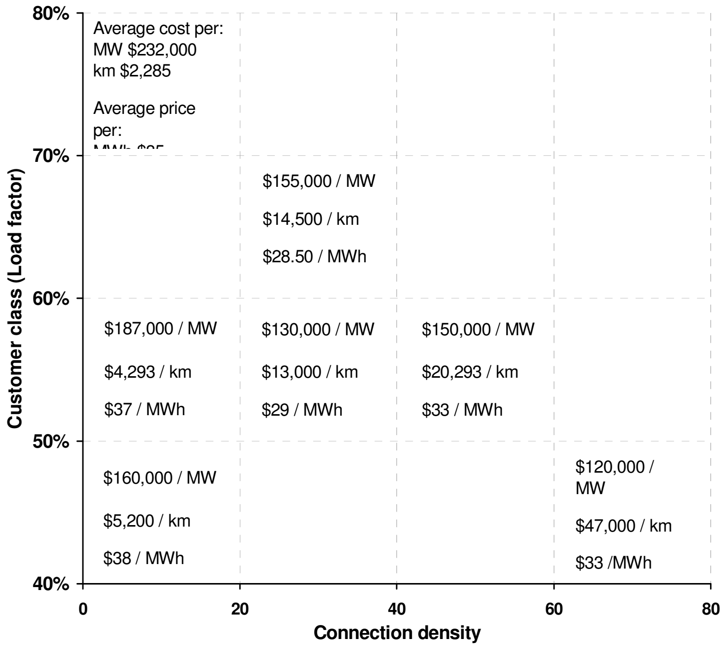


Figure 8 has been compiled by plotting connection density and load factor for each of the Australian networks included in the sample. The data in each box represents average costs and prices for the networks that share the business conditions in that box. The costs included are average revenue per MW peak capacity and per km of line length. Price is measured as average revenue per MWh energy conveyed. Those boxes without cost and price details indicate that no Australian network has that configuration. For example, there is no network that combines high connection density with high load factor, a pattern that has also been observed among US and New Zealand networks.

The trends evident in Figure 8 confirm the analysis in the previous sections. Cost measured per MW tends to rise in line with load factor but to decline when measured against line length as density falls. Conversely, cost per MW fall as density increases while rising when measured against line length. Prices, on the other hand, tend to fall with both increasing customer density and load factor.

The variation in the cost and price indicators as density or class change suggests that benchmarking on the basis of partial productivity indicators is most likely to be misleading. For example, a network with a connection density between 60 -80 would face costs of only $120,000 per 1,000 MW but as high as $47,000 when measured against line length. At the other extreme, a network with a load factor between 70-80 per cent would face costs of $232,000 per 1,000 MW but costs of less than $3,000 per km. It would not seem reasonable to make a judgement on the relative efficiency of these networks without additional information. Yet, most comparisons are little more than a comparison of such simple indicators.

6 Network costs: Operating & maintenance expenditures

The previous section discussed the influence of scale and business conditions on total cost. In practice, however, regulators tend to focus on subsets of total cost, for example, operating and maintenance expenditures (opex) and/or capital expenditures (capex). This partial approach to cost analysis makes little difference to the cost analysis, since the capital intensive nature of the network production process exerts a strong influence across all cost categories. With varying degrees of difference, we find that opex and capex are influenced by the same cost drivers as those for total costs.

Opex has become a major focus of efficiency comparisons for distribution networks, both in the empirical literature and in regulatory pricing reviews. Indeed, setting performance benchmarks over a five year period has made opex the preferred regulatory measure. It represents the only cost category with a short run timeframe offering the potential to achieve efficiency measures within the regulatory pricing period.

This restricted focus has recently been under review reflecting the growing recognition that legitimate trade-offs may exist between opex and capex. In this respect, a more suitable alternative might be to compare total expenditures, that is, a combination of opex and capex. An approach that would have the advantage of internalising any bias towards one expenditure category or the other due to such factors as: age of network; cost allocation practices; or capitalisation practices. At this stage there is no known example of this approach being adopted at the regulatory level.

Before turning to the link between opex and the key business conditions it is worth considering the usefulness of one frequently used measure of cost efficiency, the ratio of opex to assets. Using this ratio as an indicator of cost efficiency assumes that all asset bases can be maintained with a similar level of expenditure. This assumption should be treated with caution. Ratios consist of two parts a numerator and a denominator. When used as an indicator of performance, it is necessary not only to examine the factors that affect the numerator, opex, but also the denominator, assets.

For example, a relatively high ratio could simply reflect a network's aging infrastructure. In these circumstances, higher levels of opex would be necessary to maintain the assets which, in turn, would be expected to have a relatively lower value reflecting the greater level of depreciation. The opposite outcome would be observed if the assets were relatively young, requiring little opex.

Asset values might also vary because of different valuation practices adopted by the jurisdictions, with some states including the value of capital contributions in the asset base while others do not. Different asset management practices may also affect the level of maintenance. Capitalisation policies vary between jurisdictions and between businesses. Some businesses adopt a program of monitoring and reconditioning maintenance to extend the life of the asset base while others choose to replace assets at the end of their useful life to reduce maintenance costs. It is not recommended that the ratio of opex to assets be used as a performance indicator for assessing comparative efficiency.

The next section will examine the impact of connection density and customer class on relative opex levels.

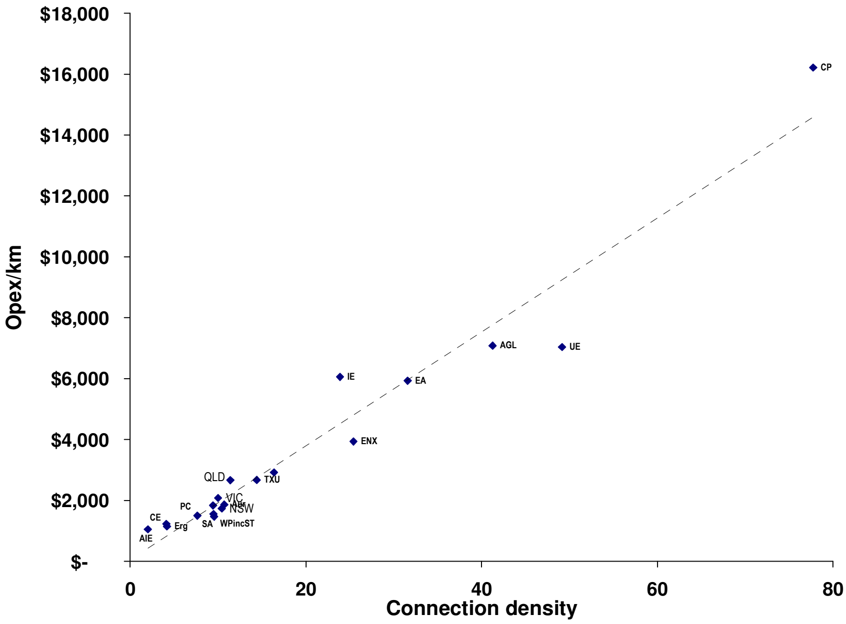
6.1 Connection density & operating and maintenance expenditure

Connection density has already been identified as a major cost driver for network total costs (s.5.3.1). In this section we will examine the relation between density and opex and between opex and the asset base. Constructing credible cost benchmarks is greatly assisted by understanding not only the key linkages but also the factors that underpin them.

Figure 9 depicting the ratio of operating expenditures to line length reveals a link with connection density that is almost identical to that of total costs (Figure 5). While some economies of scale may be expected in system operations and corporate overheads, it seems that the underlying asset base is the dominant influence.

Operating cost per km of network rises from a low of $1,130/km for a rural network with a connection density of around four up to $16,000/km for a CBD network with a connection density of over 70. Variations around the fitted trend line in Figure 9 reflect differing asset ages and hence maintenance requirements or accounting policies for expensing or capitalising costs.

Figure 9: Opex/km and connection density



Equation 5: Opex/km and connection density

Increase in opex/km with increasing density = 186.95x + 53.799

R^2 = 95%

The strong influence of connection density on the level of opex is readily understandable if we consider the purpose of the expenditure stream. An electricity distribution network consists of long lived assets that must be maintained on a regulator basis over a long period of time. The number of poles to be monitored, transformers to be inspected, and lengths of line to be cleared of trees will dictate the level of maintenance expenditure required. To confirm the link between the underlying asst base and the level of opex, the ratio of opex/km is plotted against the ratio for assets/km in Figure 10.

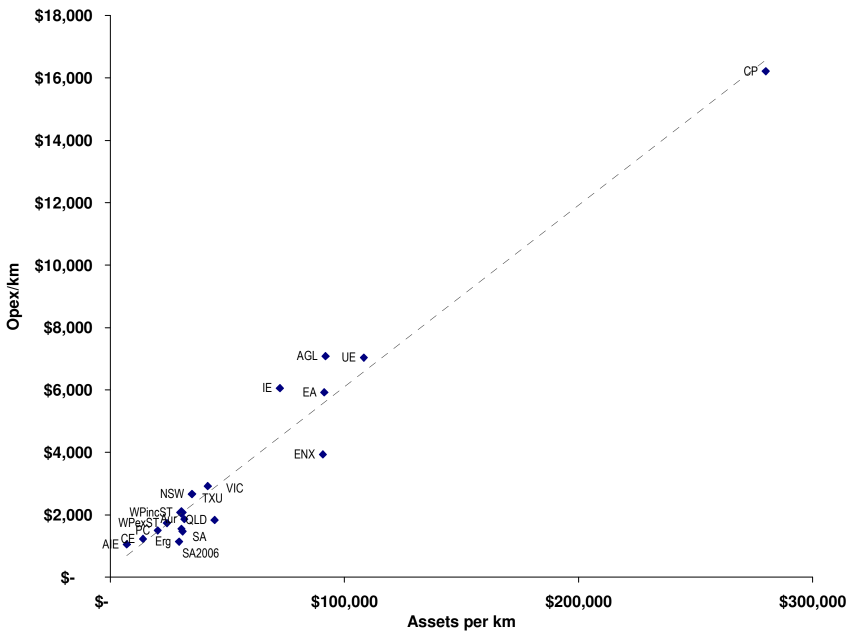
Equation 5: Opex/km and assets/km

Increase in opex/km with increase in assets/km = 0.582x + 286.86

R^2 = 96%

While it is accepted that the very high density network in Figures 9 (and also 5,6, and 10) will exert some influence on the trendline, analysis of the data suggests this is largely limited to the strength of the link rather than to the parameters of the estimated equation. For example, the R^2 for the trendline in Figure 9 reduces to 87% if this high density network is removed. There is little variation in the equation parameters.

Figure 10: Opex/km and assets/km



It is difficult to understand why comparisons of operating cost are typically made without reference to the underlying asset base that is being maintained.

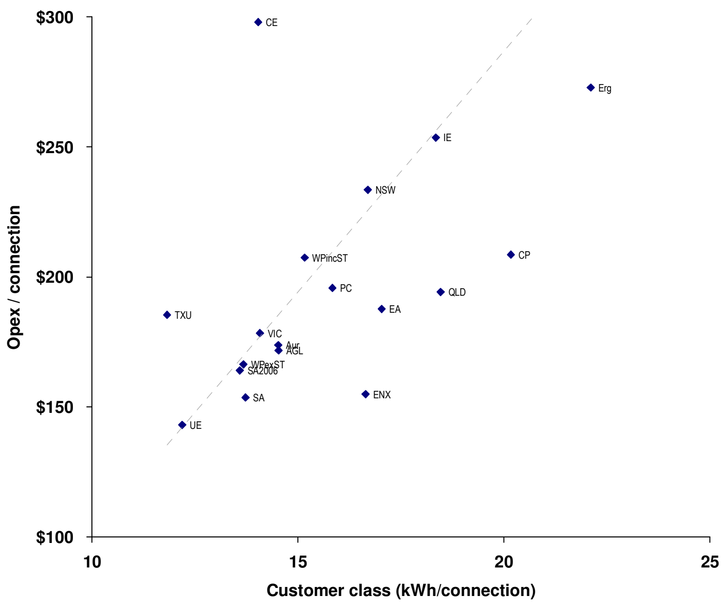
6.2 Customer class – load factor

The type of end-user connected to the network can also exert an influence on the level of opex. Again the link between the network and expenditures is through the underlying asset base. Figure 7 depicted a clear relation between asset investment per connection and the type of end user connected (kWh/connection). Given the relation between assets and opex observed in the analysis of connection density, we could expect a similar link between connection assets and opex.

Connecting larger end-users, typically large commercial and industrial entities, involves larger and more complex assets. Remote mining centres, for example, must be served by multiple circuits to ensure reliability whereas remote rural centres, in general, would be served by a single circuit. As the level of assets rises so too will the level of opex.

The link between customer class and operating expenditure per connection is depicted in Figure 11. It reflects the more scattered link between customer class and costs evidenced in Figure 7. Though not as close as the link between density and costs, a clear and upward trend between rising average consumption levels and opex per connection can be observed.

Figure 11: Opex/connection and customer class (kWh/connection)



Equation 6: Opex/connection and customer class (kWh/connection)

Increase in opex/connection

with increase in average consumption = 18.521x – 83.616

R^2 = 45%

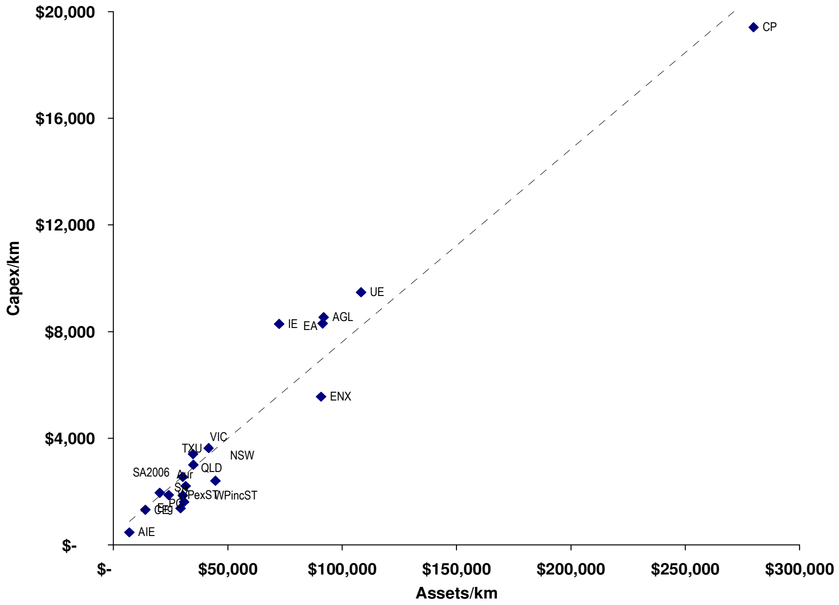
When estimating expenditure benchmarks for network businesses the influence of both connection density and customer class should be taken to account. Frequently, networks with larger end-users are located in low density areas where they could be expected to have relatively lower costs. However, as Figure 11 indicates, there are substantial costs associated with connecting large end-users and these need to be included in the analysis.

7 Network costs: Capital Expenditure

7.1 Connection density

Capital investment consists of two expenditure streams, replacement and augmentation. Cost indicators based on capital expenditures could be sensitive to the allocation of expenditures between the two. Testing the link between capex and the asset base suggests, however, that existing assets remain a dominant influence on the overall level of capital expenditure (Figure 12). Plotting capex/km against assets/km we observe a positive trend between the underlying infrastructure and its operation and maintenance.

Figure 12 Capex/km and assets/km



The noticeable divergence around the trend line could be due to a number of factors:

- value of asset base;
- age of assets and need for replacement;
- level of augmentation investment;
- cost allocations between opex and capex; and
- level of capital contributions.

The presence of these additional factors tends to create a greater diversity in capex budgets than is observed with opex. For this reason regulatory protocol has tended towards a more bottom-up estimation of "efficient" capex allowances. These estimations frequently have been subject to dispute and the link between capex and the asset base in Figure 12 can provide a useful quantitative point of reference.

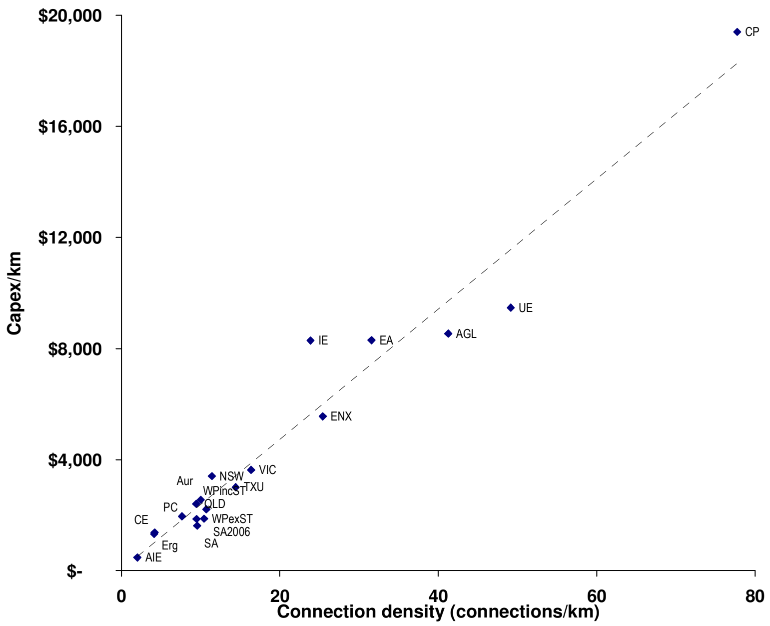
Equation 7: Capex/km and Assets/km

Increase in capex/km with increase in assets/km = 0.0723x + 374.72

R^2 = 94%

To complete the analysis of the influence of connection density on network costs, Figure 13 depicts the relation between capex/km and connection density.

Figure 13: Capex/assets and connection density



Equation 8: Capex/km and connection density (connections/km)

Increase in capex/km with increase in connection density = 234.52x + 41.735

R^2 = 94%

Once again we find that connection density has a strong and significant influence on costs. The quality of cost comparisons would be measurably improved by integrating this affect into benchmark estimations.

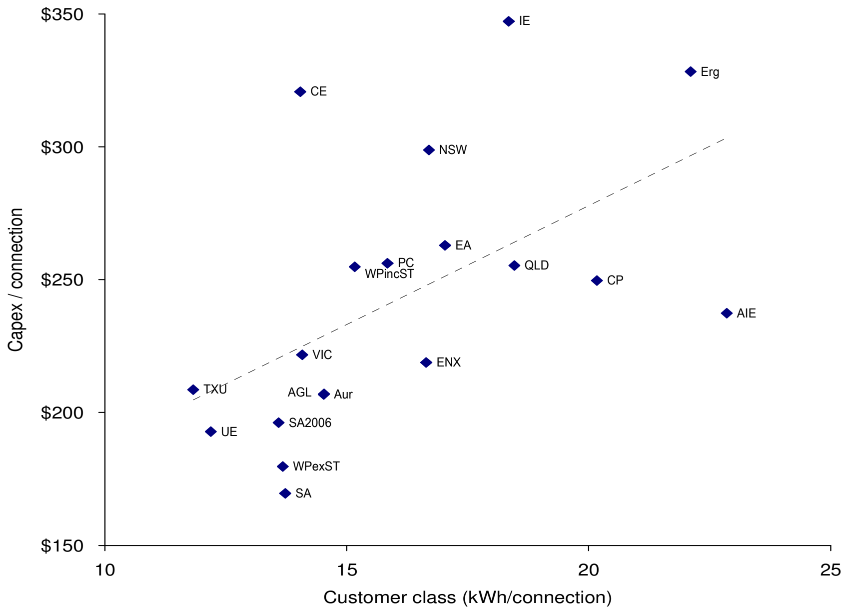
7.2 Customer class

The two-part nature of capital expenditure tends to result in a more dispersed ratio of capex per connection than was evident with either total costs or opex per connection (Figure 14). Connection of large end-users to the network is less regular than the typical domestic or commercial consumer, resulting in a less pronounced link between capex and customer class.

One other factor contributing to the dispersed link is the timing of the roll-out of regulatory pricing determinations. For example, in Figure 14 the data are for 2005, this includes substantial capex increases for the NSW networks allowed by the regulator in its 2004 decision. It does not include the large increases in capex allowed by the Queensland regulator which will only come into affect in 2006.

Nevertheless, the type of end-user serviced by the network does exert some influence on the level of capital investment and it should be included in comparative cost analysis.

Figure 14: Capex/connection and customer class



8 Conclusion

Implementation of incentive-based price regulation has created a central role for efficiency comparisons. Notwithstanding, there has been no parallel development of a network cost structure model suitable for this role. Though well-developed and widely accepted financial models are available to justify building block parameters, the same cannot be claimed of performance indicators for operating and capital expenditures.

This situation raises a number of issues that should be addressed if efficiency comparisons are to achieve the standard of credibility necessary for regulatory purposes:

- Performance efficiency should be measured by reference to an integrated cost model since the interaction of scale, businesses conditions, and network cost is too complex to be captured easily in partial productivity measures.
- The model should be based on an appraisal of the specific nature of the network business, not the electricity sector in general.
- The model should be supported by a theoretical framework (economic and/or engineering), provide transparency, replicability and be capable of quantitative assessment.

As a first stop towards the development of an integrated cost model, this report has proposed an analytical framework based on cost of production theory. It has identified major cost drivers and assessed the varying impact of these factors on comparative costs. It has demonstrated clearly that the operating environment of distribution networks can have a substantial influence on comparative cost. Cost assessments that do not take these affects to account will result in misleading efficiency targets. This may threaten the longer term sustainability of some networks. This possibility places considerable importance on improving the level of understanding of distribution network cost structures.

Appendix A: Networks included in the analysis

Energy Australia

Integral energy

Country Energy

NSW: Aggregation of above networks

Citipower

United Energy

AGL

Powercor

TXU

Victoria: Aggregation of above networks

Energex

Ergon

Queensland Aggregation of above networks

South Australia – ETSA Utilities

Tasmania – Aurora Energy

Western Australia – Western Power

Appendix B: Data used in this analysis

The quality of the data is a critical element of any quantitative analysis. To ensure comparability appropriate to regulatory benchmarking the data used in this analysis has been taken from revenue decisions by the jurisdictional regulators. Where such data were not available the networks have provided data from unpublished sources.

Building block data is for year ending June 2005. Data for SA is for 2006 to allow the large increases in the 2005 pricing decision to be included.

Every care has been taken to ensure the data are a true and faithful account of those data published by the regulators and other authorities. There will be minor variations since myriad adjustments to regulatory data can introduce complexity, and indeed, confusion. For example, smoothing, however desirable, can shift revenue from year to year.

It would greatly aid analysis of network cost structures if a complete table of annual data including network parameters and agreed building block allowances over the price re-set period were published with each pricing Decision.