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Productivity Commission

Electricity Network Regulatory Frameworks

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Publications Inquiries:

Media and Publications

Productivity Commission

Locked Bag 2 Collins Street East

Melbourne VIC 8003

Tel: (03) 9653 2244

Fax: (03) 9653 2303

Email: maps@pc.gov.au

General Inquiries:

Tel: (03) 9653 2100 or (02) 6240 3200

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Australian Government
Productivity Commission

Canberra Office

Level 2, 15 Moore Street
Canberra City ACT 2600

GPO Box 1428
Canberra City ACT 2601

Telephone 02 6240 3200
Facsimile 02 6240 3399

Melbourne Office

Telephone 03 9653 2100

www.pc.gov.au

9 April 2013

The Hon David Bradbury MP
Assistant Treasurer
Parliament House
CANBERRA ACT 2600

Dear Assistant Treasurer

In accordance with Section 11 of the *Productivity Commission Act 1998*, we have pleasure in submitting to you the Commission's final report into Electricity Network Regulatory Frameworks.

Yours sincerely

Philip Weickhardt
Presiding Commissioner

Wendy Craik AM
Commissioner

Terms of reference

I, Wayne Swan, Deputy Prime Minister and Treasurer, pursuant to Parts 2 and 3 of the Productivity Commission Act 1998, hereby request that the Productivity Commission undertake an inquiry into electricity network frameworks, focussing on benchmarking arrangements and the effectiveness of the application by network businesses of the current regulatory regime for the evaluation and development of interregional network capacity in the National Electricity Market (NEM).

Background

Australia's electricity sector is facing a number of challenges over the coming years. This includes a large investment requirement for networks to replace ageing assets, meet growing levels of peak demand, reliability requirements and to facilitate the transition towards Australia's clean energy future.

Recent increases in network expenditure, and the resultant flow on to increases in electricity prices for end users, have highlighted the need to ensure networks continue to deliver efficient outcomes for consumers. Network regulation is a complex task requiring difficult and technical judgements. This inquiry will inform the Australian Government about whether there are any practical or empirical constraints on the use of benchmarking of network businesses and then provide advice on how benchmarking could deliver efficient outcomes, consistent with the National Electricity Objective (NEO). In addition, a second stream of this inquiry will examine if efficient levels of transmission interconnectors are being delivered, to inform the Australian Government about whether the regulatory regime is delivering efficient levels of interconnection to support the market.

Scope of the Inquiry

The Commission is requested to assess the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure to meet the long term interests of consumers, consistent with the NEO. In addition, the Commission is requested to assess whether the current regulatory regime, as applied to interconnectors, is delivering efficient levels of network and generation investment across the NEM.

In undertaking the review, the Commission should:

- examine the use of benchmarking under the regulatory framework, incorporating any amendments introduced in the review period, in the National Electricity Rules and provide advice on how different benchmarking methodologies could be used to enhance efficient outcomes; and
- examine whether the regulatory regime, with respect to the delivery of interconnector investment in the NEM, is delivering economically efficient outcomes.

In undertaking the inquiry, the Commission should consider and take into account the work that is currently being progressed through the Standing Council on Energy and Resources, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Commission should have particular regard for the AEMC reviews into transmission frameworks, power of choice (demand side participation) and the suite of rule changes relating to network regulation currently under consideration by the AEMC in accordance with its statutory obligations.

The Commission should engage with the AEMC, the AER and the Australian Energy Market Operator in undertaking the review. In addition, the Commission should consult with Australian Government agencies, state and territory government agencies and other key stakeholders in undertaking the review.

The Commission will report within 15 months of receipt of this reference and will hold hearings for the purpose of this inquiry. The Commission is to provide both a draft and a final report, and the reports will be published. The Government will consider the Commission's recommendations, and its response will be announced as soon as possible after the receipt of the Commission's final report.

WAYNE SWAN

9 January 2012

Disclosure of interests

The *Productivity Commission Act 1998* specifies that where Commissioners have or acquire interests, pecuniary or otherwise, that could conflict with the proper performance of their functions during an inquiry they must disclose the interests.

Dr Craik has advised the Commission that she is the beneficiary of subsidised solar PV panels.

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The Commission's report is in two volumes. **This volume 1 contains the Overview, the Recommendations and findings and chapters 1 to 8.** Volume 2 contains chapters 9 to 21, Appendix A and the References. Appendices B to F will only be available on the Commission's web site (<http://www.pv.gov.au>). Below is the table of contents for both volumes.

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Acknowledgments

The Commission engaged the services of Dr John Tamblyn, a well-known expert on the National Electricity Market (who has recently been involved in two other independent reviews of aspects of the electricity industry) to review some chapters and the overview for the draft of this report. Dr Tamblyn provided valuable feedback to the Commission, for which we are most grateful. However, the views and judgements in this report are those of the Commission alone, and should not be attributed to Dr Tamblyn or any other participant, except where clearly stated.

Abbreviations and explanations

Abbreviations

AATSE	Australian Academy of Technological Sciences and Engineering
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEMA	Australian Energy Market Agreement
ASU	Australian Services Union
ATA	Australian Technology Association
CAIDI	Customer average interruption duration index
CALC	Consumer Action Law Centre
CAPEX or capex	Capital expenditure
CBA	Cost-benefit analysis
CDF	Customer Damage Functions
COAG	Council of Australian Governments
CPI-x	Consumer Price Index minus a benchmark productivity rate (x)
CPP	Critical Peak Price
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DANCE	Dynamic Avoidable Network Cost Evaluation model
DG	Distributed generation
DLC	Direct load control

DM	Demand management
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DPI	Department of Primary Industries (Victoria)
DRED	Demand Response Enabling Device
DSP	Demand side participation
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Association
ERAA	Energy Retailers Association of Australia
esaa	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code
EU	European Union
EUAA	Energy Users Association of Australia
FCAS	Frequency control ancillary services
GDP	Gross Domestic Product
HV	High voltage
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRSR	Inter-regional settlement residue
kV	kilovolt
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LRIC	long-run incremental cost
LRMC	long-run marginal cost
LV	Low voltage
LYMMCo	Loy Yang Marketing Management Company
MAIFI	Momentary average interruption frequency index
MAR	Maximum annual revenue

MCE	Ministerial Council on Energy
MDMS	meter data management system
MED	Major event days
MEU	Major Energy Users
MFP	Multifactor productivity
MNSP	Market network service provider
MW	Megawatt
MVA	Megavolt amperes
MWh	Megawatt hour
NECA	National Electricity Code Administrator
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NEO	National Electricity Objective
NEL	National Electricity Law
NER	National Electricity Rules
NGF	National Generators Forum
NGL	National Gas Law
NMS	Network management systems
NPV	Net present value
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
N-x	Measure of redundancy in network (with higher x being higher levels of redundancy)
OFA	Optional firm access
Ofgem	Office of Gas and Electricity Markets (UK)
Ofwat	Office of Water Services (UK) (On 1 April 2006, the functions of Ofwat were replaced by the Water Services Regulation Authority)
OPEX or opex	Operating expenditure

PC	Productivity Commission
PIAC	Public Interest Advocacy Centre
PSCR	Project Specification Consultation Report
PV	Photovoltaic
QTC	Queensland Treasury Corporation
QUT	Queensland University of Technology
RAB	Regulatory asset base
RET	Renewable Energy Target scheme
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCER	Standing Council on Energy and Resources
STPIS	Service Target Performance Incentive Scheme
SOC	State-owned corporation
TEC	Total Environment Centre
TNSP	Transmission network service provider
TOU	Time of use (electricity tariffs)
VCEC	Victorian Competition and Efficiency Commission
VCR	Value of Customer Reliability
WACC	Weighted average cost of capital
WAPC	Weighted average price cap

Explanations

Billion	The convention used for a billion is a thousand million (10 ⁹).
Findings	<i>Findings in the body of the report are paragraphs highlighted using italics, as this is.</i>
Recommendations	<i>Recommendations in the body of the report are highlighted using bold italics, as this is.</i>

OVERVIEW

Overview

The main messages

- Average electricity prices have risen by 70 per cent in real terms from June 2007 to December 2012. Spiralling network costs in most states are the main contributor to these increases, partly driven by inefficiencies in the industry and flaws in the regulatory environment.
- These flaws require a fundamental nationally and consumer-focused package of reforms that removes the interlinked regulatory barriers to the efficiency of electricity networks. Reforms made in late 2012, including improvements to the regulatory rules, better resourcing of the regulator and greater representation of consumers, have only partly addressed these flaws.
- Resolving benchmarking and interconnector problems will be a worthwhile addition to these recent reforms. But there remains a need for further significant policy changes to make a substantive difference to future electricity network prices, and to produce better outcomes for consumers — the latter being the primary objective of the regulatory arrangements. The changes needed include:
 - modified reliability requirements to promote efficiency
 - improved demand management
 - more efficient planning of large transmission investments
 - changes to state regulatory arrangements and network business ownership
 - adding some urgency to the existing tardy reform process. The Standing Council on Energy and Resources needs to accelerate reforms — particularly for reliability and planning — which have been bogged down by successive reviews. Delays to reform cost consumers across the National Electricity Market (NEM) hundreds of millions of dollars.
- The gains from a package of reforms are significant. Indicative estimates suggest:
 - in New South Wales alone, \$1.1 billion in distribution network capital expenditure could be deferred until the next five year regulatory period by adopting a reliability framework that takes into account consumers' preferences for reliability. The actual savings are likely to be larger
 - adopting a different reliability framework for the transmission network could generate large efficiency gains in the order of \$2.2 billion to \$3.8 billion over 30 years
 - if carefully implemented, critical peak pricing and the rollout of smart meters could produce average savings of around \$100–\$200 per household each year in regions with impending capacity constraints (after accounting for the costs of smart meters).
- Reliability is critical to electricity networks, but some consumers are forced to pay for higher reliability than they value.
 - Reliability decisions should be based on trading off the costs of achieving them against what customers are willing to pay, rather than by prescriptive (sometimes politically influenced) standards.

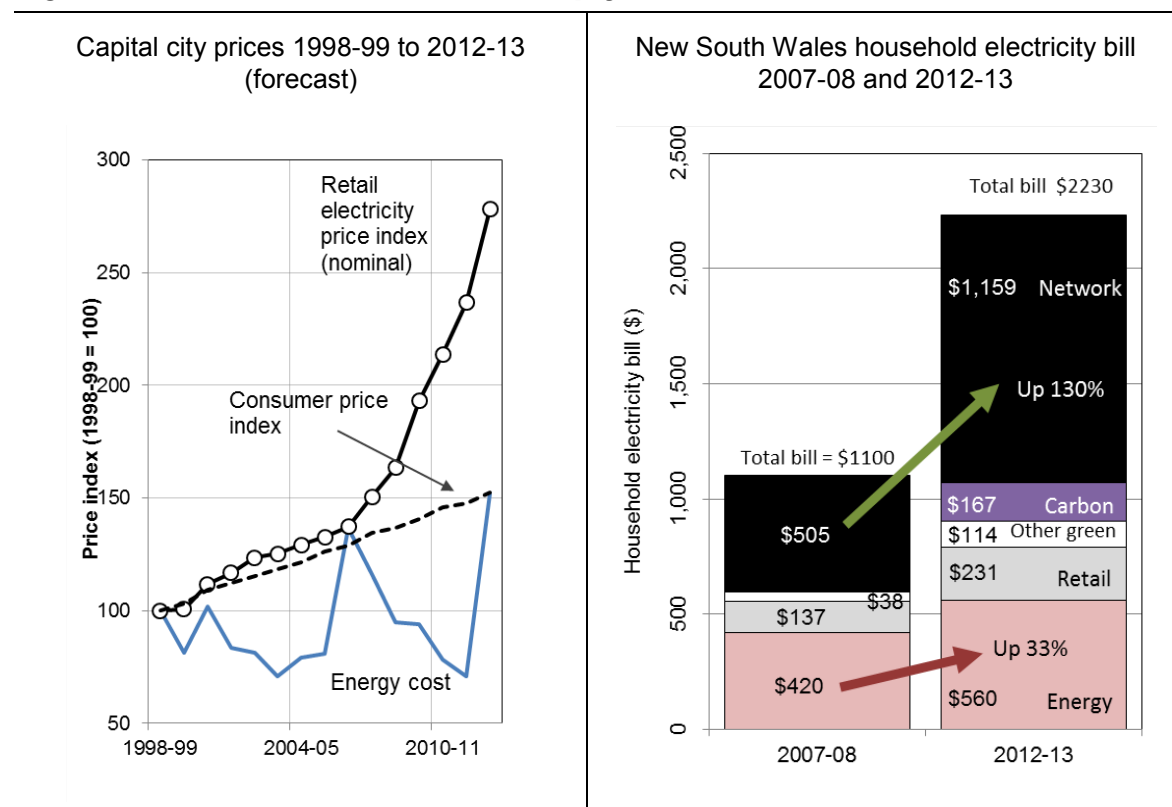
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- A large share (in New South Wales, some 25 per cent) of retail electricity bills is required to meet a few (around 40) hours of very high ('critical peak') demand each year. Avoiding this requires a phased and coordinated suite of reforms, including consumer consultation, the removal of retail price regulation, and the staged introduction of smart meters, accompanied by time-based pricing for critical peak periods.
 - This would defer costly investment, ease price pressures on customers, and reduce the large hidden cross-subsidies effectively paid by (often lower-income) people who do not heavily use power in peak times, to those who do.
 - Rolling out smart meters would also produce major savings in network operating costs — such as through remote meter reading and fault detection.
 - The Commission is proposing a process that learns from the experience of the Victorian smart meter rollout, and that will genuinely benefit consumers.
 - State-owned network businesses have conflicting objectives, which reduce their efficiency and undermine the effectiveness of incentive regulation. Their privately-owned counterparts are better at efficiently meeting the long-term interests of their customers.
 - State-owned network businesses should be privatised.
 - The efficiency and effectiveness of recently announced reforms could be enhanced.
 - Given their overlapping roles, the three fully-funded consumer advocacy bodies in the NEM should be ultimately amalgamated into a single statutory body that would act on behalf of all consumers. It should be fully funded through an industry levy, and have the required expertise to play a leading, but not exclusive, role in representing customers in all regulatory processes. Partial funding — on a contestable basis — should continue for individual advocacy groups.
 - A review of the Australian Energy Regulator is proposed for 2014. The Australian Energy Market Commission, the Australian Energy Market Operator and the new consumer representative body should also be reviewed by 2018 so that the scope for improvement in all of the main NEM institutions will have been assessed.
 - At this stage, benchmarking — which compares the relative performance of businesses — is too unreliable to set regulated revenue allowances. Nevertheless, greater and more effective use of benchmarking could better inform the regulator's decisions.
 - There is no evidence of insufficient capacity in the interconnectors carrying power between jurisdictions, as is sometimes alleged. In fact, they are sometimes underutilised because of perverse incentives and design flaws created by the regulatory regime. Changes to the National Electricity Rules should address these problems.
 - In considering the benefits for consumers, it is important not to blame network businesses for the current inefficiencies. Mostly, they are responding to regulatory incentives and structures that impede their efficiency.

Why should we care about electricity networks?

The fundamental objective of the National Electricity Market (NEM) — the need for efficient investment in, and operation of, electricity networks in the long-term interests of consumers — has been frustrated by flaws in its (ever more) complex regulatory and institutional arrangements. Indeed, at times, policy developments have been inimical to consumers' interests, resulting in price rises that cannot be justified.

Nationwide, retail electricity price increases accelerated after June 2007, rising by more than 70 per cent in real terms by December 2012 (though this varies by jurisdiction). The rising costs of the electricity network — the wires, poles and other infrastructure used to transport power from generators to consumers — have been a major driver of these prices. Network costs are around 40-50 per cent of an average household's electricity bill, so any cost pressures on the network have a major impact on people (figure 1).

Figure 1 Prices have risen steeply



Given that networks are a natural monopoly, economic regulation (and its varying supporting institutions) will need to play a continuing role in networks. This is why it is imperative to improve the arrangements. This inquiry focuses on the NEM,

which enables the trading of power throughout Australia, excepting Western Australia and the Northern Territory. Its major institutions include the:

- Standing Council on Energy and Resources (SCER), which replaces the previous Ministerial Council for Energy, and has representatives from the Australian Government, all states and territories, and New Zealand. It is responsible for broad policy and the legislative framework for the NEM (though only ministers in participating jurisdictions can change the National Electricity Law)
- Australian Energy Market Operator (AEMO), which, among other roles, manages the transmission network and operates the spot market that determines wholesale energy prices
- Australian Energy Market Commission (AEMC), which undertakes energy market reviews, provides policy advice to SCER, and sets the National Electricity Rules (the ‘Rules’)
- Australian Energy Regulator (AER), which is the economic regulator for electricity and gas markets in the NEM.

The Commission’s task is a broad one

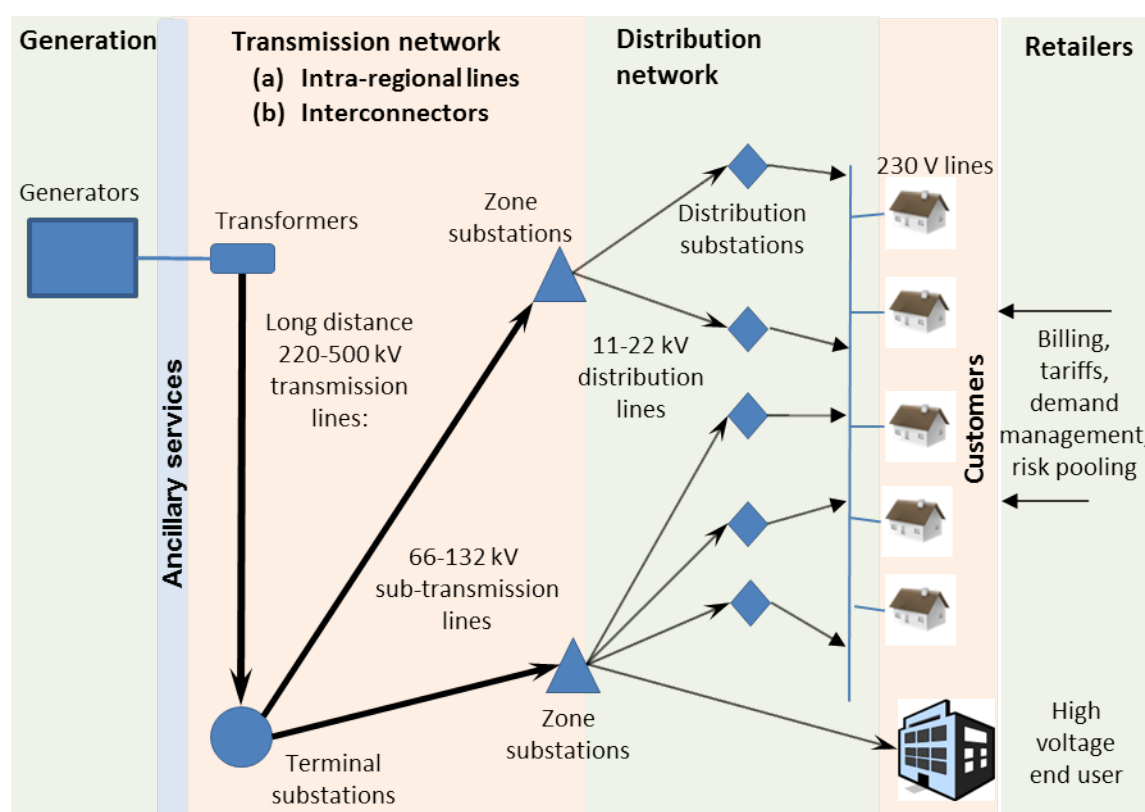
Concerns about the adequacy of the existing regulatory arrangements triggered this inquiry. The Australian Government requested that the Commission consider the problems besetting these arrangements through two lenses:

- the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure. Benchmarking typically measures the costs or revenues of an efficient network business, with the regulator using the results as the standard for assessing whether any given network business’s expenditure proposals are efficient and prudent. (An alternative benchmarking approach is to reduce each network business’s allowable annual revenue by the productivity growth rate of an efficient firm — an approach already considered by the AEMC.) The relevant network services comprise:
 - distribution networks, the lower voltage capillaries that deliver power at the local level (figure 2). The distribution networks account for the bulk of total network costs
 - the intra-regional transmission network, which comprises the high voltage components of the network that carry power over long distances within states
- the effectiveness of regulatory arrangements for ‘interconnectors’ (the inter-regional high voltage transmission network) given that some stakeholders identify future problems in the NEM arising from shortcomings in the regulatory arrangements for ‘interconnectors’. The concern is that there is underinvestment

in interconnectors, weakening the capacity for trading power across the network. Underinvestment could put more pressure on prices and undermine the efficient use of renewable energy generators.

This report includes extensive analysis of issues directly related to benchmarking and interconnectors. However, the Commission has found that it is not possible or desirable to look at those issues separately from the complex and interrelated regulatory system in which they sit. There is, in effect, no point in simply fixing a punctured tyre if the car has no engine.

Figure 2 The electricity system



Accordingly, the Commission has adopted a broader perspective, reflecting that outcomes in the NEM involve complex interactions between multiple influences: the National Electricity Rules; the behaviour of the regulator; the governance and culture of each of the regulated network businesses; and the impacts of many other (multi-jurisdictional) regulations and policies (figure 3). The Commission has considered the evidence, analysis and policy outcomes from various reviews during the course of the inquiry — most particularly various reports issued by the AEMC, and a suite of reforms announced by the Council of Australian Governments (COAG) and SCER in late 2012.

There are many problems in current arrangements, but beyond the Commission's consideration of benchmarking and interconnectors, there are several critical priority issues arising from this inquiry.

- The governance arrangements for the NEM — in which SCER, the AER, the AEMC and all state and territory governments play a major role — are neither efficient nor effective in achieving good outcomes for consumers.
 - SCER's processes for reform are too slow (and involve the AEMC duplicating much of their work in reviews and subsequent Rule change processes).
 - The AER has faced resourcing constraints and some have expressed concerns about its processes and effectiveness.
 - Consumers have had a weak voice in most regulatory processes, notwithstanding that their interests are ostensibly the essential plank on which regulation of the NEM is based.
 - The 'National' in the NEM is progressing too slowly, especially given that a Special Premier's Conference decided to establish a national grid in July 1991. State and territory governments, and their regulators, still play too large a role in setting reliability standards and in regulating retailing, and they also mandate other licence conditions for network businesses. Additionally, they have various renewable energy policies that affect network businesses' options for efficiently addressing emerging bottlenecks in their systems. They are the owners of network services in Queensland, New South Wales, Tasmania and, in part, the ACT and some governments still have a significant stake in generators (figure 4). They have mostly relinquished their ownership in retailing.
- Quite apart from the unwarranted variation in regulations across what is intended to be a national market, the actual regulatory settings for network reliability and for transmission planning are far from optimal.
- Flaws in the national regulatory regime have contributed to recent price increases.
 - The Rules led to inflated costs of capital and created incentives for inefficient investment.
 - There are significant deficiencies in regulatory arrangements for demand management.

Figure 3 **Benchmarking is one (small) piece of a complex regulatory jigsaw**

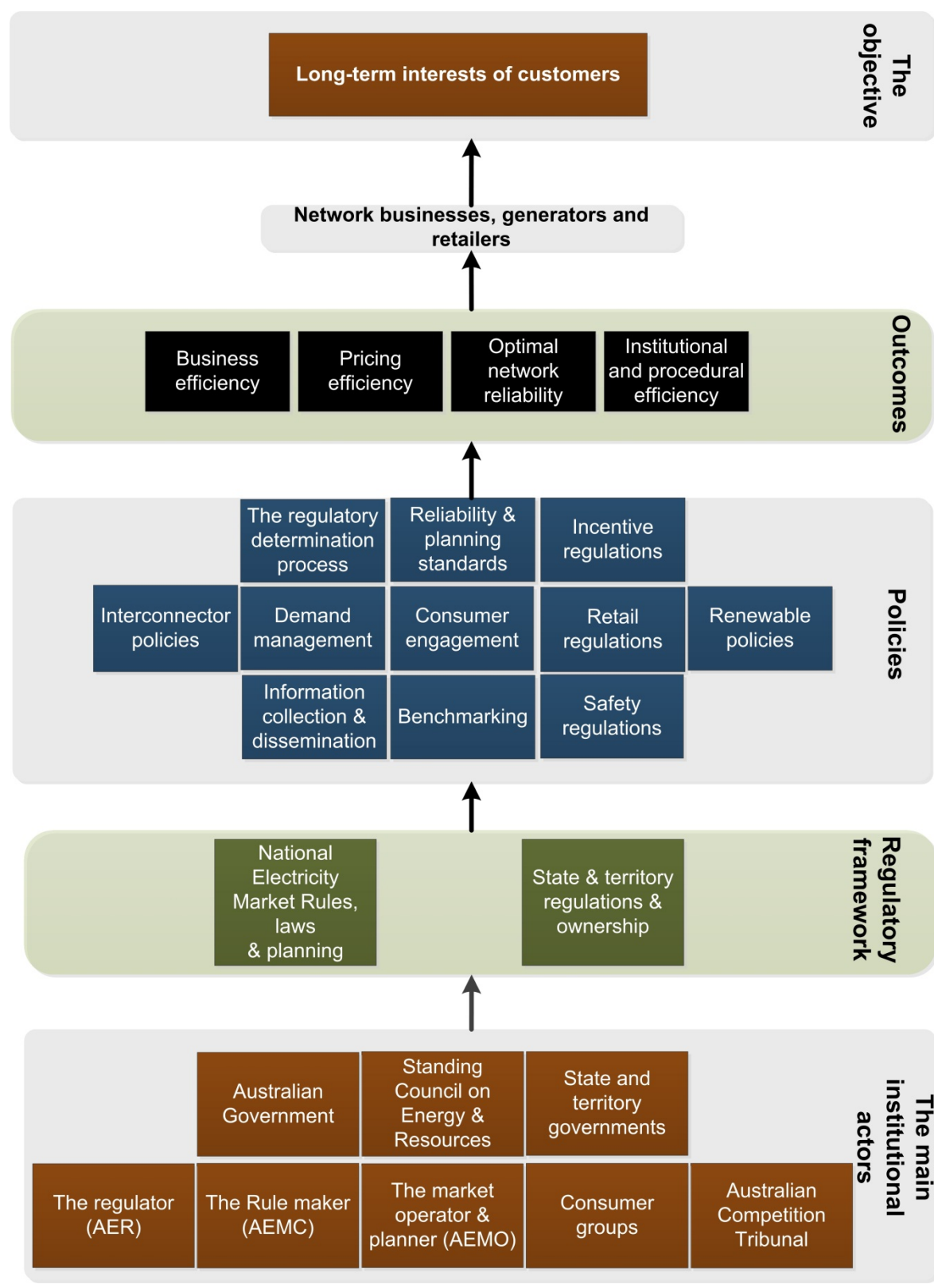
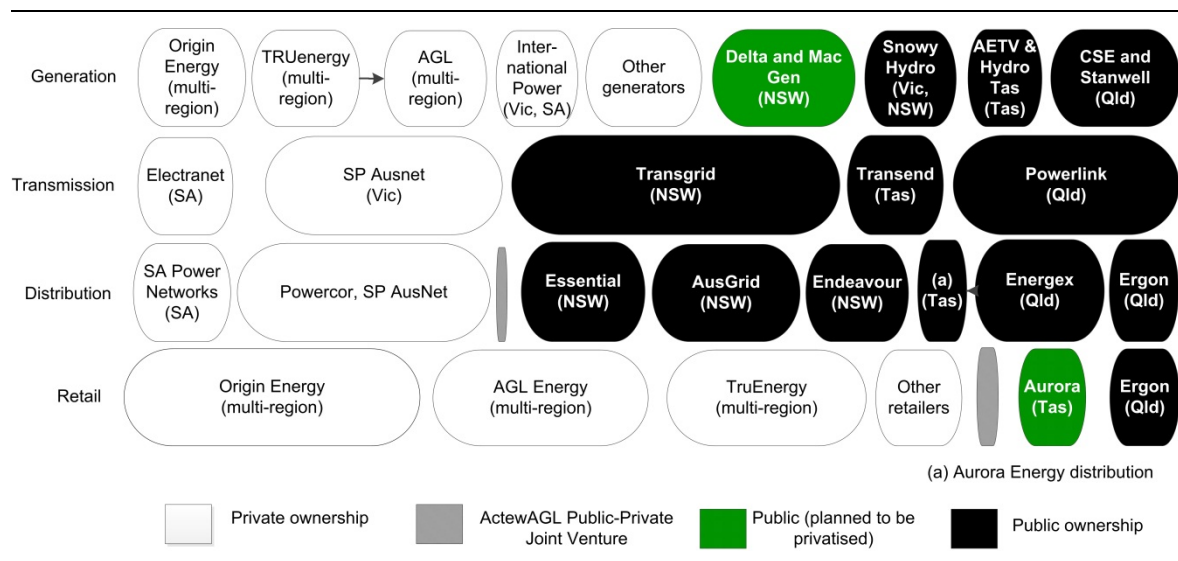


Figure 4 Participants in the National Electricity Market
By ownership and market share



Data source: Queensland Commission of Audit (2013, figure 2, p. 13).

In late 2012, major reforms to the Rules, the announcement of improved advocacy arrangements for consumers and better resourcing and governance of the AER have started to address some of these flaws. (These reforms were broadly in line with those recommended in the Commission’s draft report.)

However, the benefits of those reforms will not be felt until the current set of regulatory determinations run their course (which will occur between 2013 and 2017 depending on the service and jurisdiction). Moreover, the AER must develop guidelines to give effect to the Rule changes, and the details of those can make a difference to their benefits. More broadly, there remain major weaknesses in regulatory arrangements for demand management, reliability and transmission planning, the ownership of networks by governments, and governance.

Reform needs to be wide-ranging and timely

The Commission has proposed a suite of coordinated reforms that aim to take account of the many inter-relationships in what amounts to a complex economic ‘machine’. However, reforms will require careful implementation. A detailed summary of the reforms proposed by the Commission and their implementation timetable is in tables 1 and 2 at the back of this overview.

Moreover, the NEM has too often proved to be a graveyard for reform proposals, which then remain as inert words in dead documents. A graphic example, discussed later in this overview, is the fact that needed reforms to transmission planning and

reliability were first set out in 2002, but using the current processes will not be fully in place until 2022. Even that timing presumes that SCER agrees with the recommendations of another inquiry that it has just initiated.

A key prerequisite for reform is more timely action by SCER. Improved governance and implementation processes are discussed later in this overview. But the essential point is that SCER should reform its processes and decision making so that critical policy reviews of the NEM, the corresponding changes to the Rules, and their implementation occur much more quickly.

Consumers need a clear voice in the regulatory regime

While the objective of the National Electricity Law is to meet the long-term interests of consumers, the involvement of consumers in the processes of the NEM has been partial and intermittent.

Consumer groups have generally represented either major energy users or disadvantaged people. They have traditionally had some involvement in the AER's regulatory processes — primarily in attempting to decrease network charges or to develop better arrangements for disadvantaged consumers. They have proposed changes to the Rules, submitted to AER network determinations and participated in some Australian Competition Tribunal hearings of appeals to AER determinations. However, the smaller advocacy groups do not have many resources to do this, and do not believe that the Tribunal has given much weight to their views (the panel evaluating the limited merits review regime suggested that they are treated as 'inconvenient guests'). In general, network businesses have not sufficiently engaged with consumers, even in matters where they have aligned interests (such as addressing reliability problems or introducing smart meters and the smart grid). The AER has also not engaged well with consumer groups — an observation emphasised by the inquiry into the limited merits review regime.

There are strong grounds for improving information flows to consumers — such as through the public availability of benchmarking results, and information on the various cost drivers of electricity bills.

Equally, there is value in strengthening the institutional capacity for consumers to have a voice in regulatory and merits review proceedings. Any such arrangement should ensure that:

- consumer representation is sufficient and reliably funded. A small ongoing levy on market participants would be the most effective way of securing stable and adequate funding

-
- the consumer voice in the process is informed by expertise in the economic regulation of energy markets and, accordingly, the capacity to understand some of the complexities of the NEM and its investment and cost drivers
 - all consumers are represented, consistent with the objective of the National Electricity Law to promote the long-term interests of consumers (and with a governance structure for any arrangements that ensures that this occurs)
 - arrangements give consumers a formal capacity to engage with NEM institutions in their processes and with the scope to participate in the negotiation of regulatory determinations with network service providers, a model that has apparently worked well in the United Kingdom and the United States.

In late 2012, Australian governments recognised the need for more formalised involvement of consumers in the regulatory process. They have announced the creation of the National Energy Consumer Advocacy Body, which would perform many of the functions above. The Australian Government has also announced a Consumer Challenge Panel (to be established by the AER by 1 July 2013), which would have similar functions to the new advocacy body in regulatory determinations and would represent the same groups. The Consumer Challenge Panel could act as an effective voice for consumers in the short run, until the establishment of the national advocacy body. However, given their strongly overlapping roles, the risk of confused representation by the same consumer constituencies, and the desirability that the AER be seen as a neutral player, there are compelling grounds for the Panel to be absorbed into a single, independent statutory consumer body in the medium term.

Rolling the existing small Consumer Advocacy Panel (a grant giving body for advocacy and research) into the national advocacy body would also reduce overheads and draw on the expertise of the larger body. None of these arrangements would threaten the continued need for a voice for specific consumer groups.

- Partial funding, on a contestable basis, should still be available for such groups.
- They could provide (non-binding) advice to the statutory body through an advisory group.
- Where they felt the need, they could also continue to interact directly with the regulator and other NEM governing institutions.

Network expenditures are inefficient

The efficiency of some network businesses could be improved. The Commission's analysis of several metrics suggests that there are significant differences in the performance of the various businesses — and particularly large gaps between the performance of state-owned corporations and privately operated businesses. Differences between businesses should not be surprising. This is true for almost any industry. The distinction, however, is that the usual competitive processes that weed out less efficient businesses are non-existent for regulated natural monopolies.

Some factors are (at least partly) outside the control of the businesses — which is why benchmarking of all relevant policy influences (including non-regulatory ones) from all government levels should play an ongoing role in monitoring the performance of network businesses.

Reliability standards are mostly too high

Ensuring reliable networks requires significant ongoing investment — which ultimately customers must finance. However, there is a growing concern that some network reliability standards are too high — which some claim have reflected political responses to isolated major blackouts, rather than systemic problems — with costs that exceed consumers' willingness to pay.

The benefits of re-aligning standards to meet consumer preferences appear to be large. Some benefits could be realised soon after jurisdictions agree to a new framework. For example, AEMO cited a proposed investment in New South Wales to meet a 'deterministic' standard that implied that customers valued their electricity at around \$9 million per MWh (an estimated 150 times more than consumers would be willing to pay).

There are two principal sources of difficulty with reliability standards.

- Parochialism — there is no national framework for standards. Jurisdictions impose different reliability requirements (mostly uninformed by customer preferences), and measure reliability in different ways. Network businesses and particularly transmission businesses often appear to rely too heavily on intra-state network solutions and ignore more efficient inter-state options — a reliance reinforced by history, organisational culture, an understandable desire to control outcomes, and a greater familiarity with local rather than national requirements.
- The price–quality tradeoff is invisible to most consumers — most are unaware of the high price they pay in their electricity bills for the excessive reliability

resulting from overly stringent standards. (Equally, *were* a lower than optimal standard to be set, consumers would not know how much they would need to pay to improve it.)

The way forward must take account of the fact that the reliability issues for distribution and transmission networks are different.

Distribution networks

Given the greater and more timely observability of reliability problems in distribution, it should be possible to relinquish current jurisdictionally prescribed input standards. Instead, the regulator should impose appropriate penalties (rewards) for businesses failing (exceeding) a reliability performance target, basing the incentives on clear evidence of customers' willingness to pay for reliability. This approach would aim to replicate the signals that customers in competitive markets send to suppliers about the tradeoffs between quality and price, allowing distribution businesses to take a commercial approach to their investments in reliability. This would lead to reliability outcomes at the local level that reflected local consumer preferences rather than prescriptive standards, and that would encourage efficient expenditure (including for non-network solutions).

The new incentive regime would build on the AER's existing Service Target Performance Incentive Scheme (STPIS), which penalises/rewards businesses for their reliability performance. As well as applying all components of the Scheme to distribution businesses throughout the NEM, the Commission proposes that incentives for performance be based on an up-to-date assessment of the value that the relevant mix of customers place on reliability. Bolstering the reporting requirements under the Scheme would also increase transparency and facilitate benchmarking. An amended STPIS would remove the need for jurisdictionally-based reliability requirements for distribution businesses.

Reliability in transmission networks has proven to be a complex and controversial issue

Unlike distribution networks, transmission networks rarely experience major problems. Problems in transmission can lie latent until major loads and coincident failures in generation or network equipment overstretch the system. The resulting extreme power outages can then affect large populations and entail high costs. For example, in an international context, a major blackout in North America in 2003 led to power loss for up to two days for 50 million people, costing around \$6 billion at that time and contributing to 11 deaths.

Accordingly, the prospects of relying exclusively on an incentive scheme similar to the STPIS are weak because of the rarity of such events, the lack of good leading reliability indicators (and the potential financial inability of a network business to adequately compensate consumers for the large damages experienced).

Another characteristic of transmission networks is that power inputs into the network at any one point (say North Queensland) can affect transmission networks thousands of kilometres away. Interruptions or changes can have adverse impacts on other networks in the NEM, including major blackouts, if the system becomes unstable. As the NEM becomes more interconnected, network effects are likely to increase. Reliability standards and investment plans that are specific to a jurisdiction (or a network) do not consider these inter-jurisdictional network effects, although this is somewhat different in Victoria. Accordingly, current requirements that encourage transmission businesses to optimise only their own networks do not provide an efficient level of reliability for the NEM as a whole.

It should be emphasised that there are no easy solutions for ensuring efficient transmission reliability and planning in the NEM (and indeed this is the experience internationally). All arrangements will involve ‘big brother’ in one form or another, whether it be governments, a confederation of network businesses, or a single body. Compromises and judgments must be made. A combination of transparency, accountability, consultation, specialist knowledge, decision-making independent of the transmission businesses and giving pre-eminence to consumer preferences are the essential components of a workable arrangement.

Most stakeholders — all governments, the AEMC, AEMO and transmission businesses — agree that the current prescriptive reliability arrangements are flawed. There are many commonalities in the various solutions proposed. The Commission has drawn on the different proposals by the AEMC, AEMO, Grid Australia, and feedback following the Commission’s draft report, in crafting a model that takes account of the various tradeoffs.

- There would be a single NEM-wide reliability framework for transmission, moving away from the current state-based arrangements. This would make network planning more coherent and avoid some of the biases towards intra-regional transmission infrastructure compared with interconnectors or other solutions.
- AEMO would set planning standards at the connection point level using a ‘probabilistic approach’. Under this approach, the costs of an improvement in reliability are set against the assessed value to consumers of this improved reliability at the jurisdictional, or even more local level. This is simply a cost–benefit test. The new model (based on Australian Bureau of Statistics surveys)

would better cater for customer preferences than the current mechanistically set reliability standards. AEMO would also use this modelling to develop its National Transmission Network Development Plan to assist transmission businesses in their investment decisions.

- Transmission businesses would distinguish between ‘small’ (less than \$38 million) and ‘large’ transmission investment projects needed to meet the standards set by AEMO. The former would be included as just one of the many expenditure items that comprise the ex ante proposals by transmission businesses for revenue allowances under incentive regulations. In the ensuing regulatory period, the businesses could freely choose the timing and type of expenditure needed to meet the standard (including opex and demand management). They would not be obliged to proceed with the specific investments flagged in their ex ante bid.
- In contrast, large projects (above \$38 million) would be subject to stringent and transparent cost–benefit analysis undertaken by the transmission business using updated information closer to the time of project commencement. In assessing whether the timing, scale or the type of expenditure was efficient, the AER would take advice from AEMO. The cost–benefit test would be based on a strengthened Regulatory Investment Test for Transmission, the RIT-T. (Currently, the words ‘regulatory’ and ‘test’ are flimsy limbs to the title — since there is no independent assessment of costs and benefits, and no real regulatory consequences following an inadequate ‘test’.) The revenue to fund large projects would be provided by the AER outside the general revenue determination process and only if the project passed a cost–benefit test. A business would be able to keep a proportion of any cost-savings it made in undertaking the project, but could not decide to shelve an approved project (since to do so would undermine the goal of efficiently resolving significant impending system reliability problems).

This approach does not involve significant uncertainty since it blends a model already in existence in Victoria with an alternative model that transmission businesses generally find acceptable.

The danger of preserving parochialism is one of the largest risks to any new coherent transmission reliability framework. Some envisage an arrangement in which states would appoint their own regional planners to undertake the probabilistic analysis above. This would significantly add to costs; invite whimsical methodological differences; fail to capture national learning; would address NEM-wide effects in, at best, a clumsy, inefficient and incomplete way; and most problematically, allow the potential intrusion of political factors into what is fundamentally a technical issue. It would be bizarre if regulatory customs that were

reasonable enough when electricity networks were isolated within state boundaries persisted when the wires spanned the borders.

Implementation of the new recommended framework would occur over an extended period, even if the current excessively slow decision-making processes were overhauled and accelerated (as discussed later). State and territory governments would still have an extended period to plan. Thus, the proposed reform will not be a disruptive and sudden shock to existing planning arrangements in any jurisdiction, and therefore there should be few transition costs.

This is likely to be particularly pertinent to Victoria, which already has a more advanced reliability and planning framework than other jurisdictions, and which might be reluctant to shift given the tradeoff between the smaller benefits of reform for that state and any transitional costs. However, the degree of regulatory change for Victoria is much less than other jurisdictions and, given the timing of regulatory determinations, the Victorian transmission business would not be one of the first to be covered by the new regulatory regime. This means that the transition costs for that state would be particularly low. Given this, the Commission considers that Victorian consumers would still derive net benefits from reform.

Reluctance by *any* state to move to a unified national scheme will likely endanger the move of other states, thus threatening the delivery of the very large national savings that are available. An efficient transmission reliability framework could produce savings in the realm of \$2.2 billion to \$3.8 billion over 30 years.

Demand management is weak

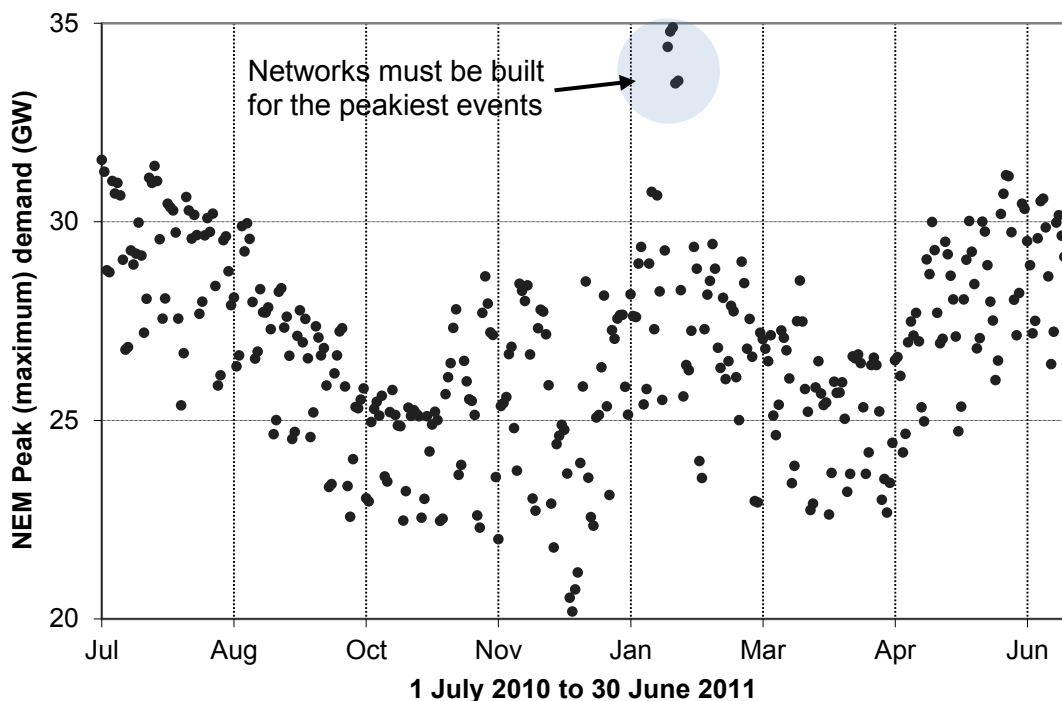
Network and generation capacity is based on meeting peak, not average, demand (figure 5). Peak demand growth has been a key driver of investment in generation and network capacity in the last five years. For example, in New South Wales, peak demand events occurring for less than 40 hours per year (or less than 1 per cent of the time) account for around 25 per cent of retail electricity bills.

The growth in household air conditioning is the major contributor to this pattern. More generally, the costs of meeting peak demand through investment in generation and network augmentation are not fully borne by those using power at peak times. Their costs are generally spread across all consumers, with the exception of some large industrial and commercial users, which do face cost-reflective prices.

Critical peak pricing is already occurring for large energy-intensive users

While they contribute less to peak demand than households, large industrial and commercial end users tend to be relatively responsive to critical peak prices, and therefore can make a useful contribution to reducing network constraints at peak times. Most of these customers have the required metering, and some are already exposed to critical peak pricing. A first step would be to extend such pricing to the bulk of the remaining businesses in this group. This could provide a relatively low cost and more rapidly achieved source of critical peak load reduction, especially for transmission assets.

Figure 5 **Networks must be built for the peakiest events**



Currently, networks (or parties acting on their behalf) pay some large industrial and commercial users to curtail their demand to relieve network constraints in peak demand periods. These arrangements could be extended to more businesses. As proposed in the AEMC's Power of Choice Review, a complementary change would be to allow reductions in load to be combined and offered by 'aggregators' to the NEM spot market, though this would involve some complexities in implementation.

The adoption of cost-reflective pricing for households and small businesses is in its infancy

Most households and smaller businesses are not exposed to time-based, cost-reflective network pricing. Thus, such users are not encouraged to shift consumption away from peak demand periods, leading to hidden subsidies between peaky and non-peaky consumers, and over-investment in peak-specific investments. Currently, a low-income household without an air conditioner is effectively writing cheques to high-income users who run air conditioners during peaky periods. For example, a household running a 2 kilowatt (electrical input) reverse cycle air conditioner, and using it during peak times, receives an implicit subsidy equivalent of around \$350 per year from other consumers who don't do this.

Accordingly, reliance on supply side investment to meet growth in peak demand is inefficient, is inequitable in some cases, and drives network prices higher than they need to be. Many major players have supported a change in principle, including the NEM Rule maker (the AEMC) and most peak industry bodies representing the supply chain (the Electricity Network Association, the Energy Retailers Association of Australia, and the Energy Supply Association of Australia). Various consumer groups acknowledge the benefits, but are concerned about the risks for low-income consumers.

Removing such buried cross-subsidies and reducing the required investment in the network (and peaking generators) could not realistically be achieved quickly. The implementation of critical peak pricing across the entire NEM would require the universal rollout of smart meters. This would entail high upfront costs, but would produce limited savings in the many areas where there are no immediate network constraints. Such a 'big-bang' approach would be likely to fail a cost-benefit test and lead to significant consumer resistance, as occurred in Victoria. In contrast, a carefully managed and staged approach has the potential to reduce price pressures significantly.

It is worth mapping out the desired end point — some years away — and then ensuring there is an orderly transition. In the long run, appropriate network pricing requires several complementary policy changes.

Cost-reflective pricing of network charges

Time-based pricing of network charges that reflect the underlying network costs is an uncontroversial principle for many. The AER would ensure that the business's network pricing proposals conformed with cost-reflective pricing, tightening the existing Rules in this area.

The Commission has recommended the use of a revenue cap as the basis for controlling the revenue collected from customers. The alternative control mechanism — the weighted average price cap — does not appear, in practice, to have achieved its theoretically greater potential for efficient pricing. It has other disadvantages, such as the risk of significant over-recovery of revenue. Given the tightening of the pricing Rules, a revenue cap will not constrain efficient pricing.

Time-based pricing would ultimately have to particularly apply to around 40 critical peak hours per year (whenever they occur). The network businesses would pass these charges onto retailers. To provide the right signals, retailers would need to reflect these charges in their tariff offerings to consumers.

There is a need to signal critical peak prices to consumers in advance

People need the opportunity to shift the time of their power use (hot days are predictable). In some cases, people may request that their distribution business or retailer control their key power-using appliances — mainly air-conditioning — during these peak hours ('peak load control'). For example, they may agree to have their air conditioner remotely controlled to cap power to the compressor during the critical peak period, thus maintaining reasonable comfort levels, while cutting costs.

Smart meters and other technologies are needed to achieve efficient pricing

Realistically, consumers cannot be charged time-based prices unless they, (along with network businesses and retailers), receive real-time information about usage patterns. Smart meters enable the measurement of electricity consumption over time and can achieve other (sizeable) operational efficiencies in networks, such as remote meter reading and fault detection.

The Commission's preferred approach is that, like other expenditure, distribution businesses would be able to include smart meter rollouts as part of their regulatory proposals to the AER (subject to the usual oversight by the AER of the claimed need for, and efficiency of, the expenditures proposed by network businesses). Currently, the Rules effectively preclude this. As for other expenditure under incentive regulation, in the ensuing regulatory period, the businesses would be free to determine the number, timing and location of smart meters. However, under the Regulatory Investment Test for Distribution, network businesses undertaking any significant rollout (or other large-scale investment) would have to produce a report that substantiated whether the investments passed a cost-benefit test. Incentive arrangements intended to address the wider efficiency gains of demand

management in other parts of the energy supply chain would need to be strengthened.

Smart meters should be subject to an appropriate, preferably international, minimum standard that allows interoperability with add-on technologies. All relevant parties would be able to access data, subject to privacy laws. Retailers and third parties (given prior customer agreement) would also be able to install smart meters, make modular additions to existing smart meters, and develop complementary technologies (such as in-home displays and software apps) that help reduce people's bills, while also relieving pressure on the network and generation at peak times. Retailers and third parties may choose to do this to differentiate their business proposition from competitors and make it more appealing to consumers.

Retail price regulation should be removed by 2015

Continued regulation would otherwise frustrate time-based charging and stifle retail competition and innovation. In particular, with the implementation of time-based network charges, any retailers that failed to adapt their business model and continued to embed significant cross-subsidies in their tariff offers would risk losing market share (including to new-entrant retailers).

The pathway to reform is crucial

While specifying the long run is relatively straightforward, the pathway involves tricks and traps. Any transition would require:

- the engagement of network businesses, retailers and especially consumers in the process, comprising provision of information, consultation, and a transition that takes into account the costs of change. (The process should take account of the lessons from the Victorian smart meter rollout, which experienced several major problems, and has made some consumers wary of imposed technological change in this area.)
- coordination by distribution businesses of the gradual and localised rollout of smart meters to maximise their net benefits. The advantage of the Commission's approach is that — by incorporating the decision-making into the incentive regulation regime — distribution businesses would have the right incentives (and information) to deploy meters when and where it was efficient to do so. For example, they would be most likely to roll out meters in areas subject to impending network bottlenecks, using critical peak pricing to lower peak demand, and thereby defer costly network extensions. In contrast, a NEM-wide rollout at a given time would be costly, and in many uncongested regions make

no difference to the required network investments, thereby reducing benefits. One of the further benefits of the Commission's staged approach is that it can take account of policy decisions, learning from experiences elsewhere, and technological changes that might affect the payoff from demand management over time

- sensible transitional network charges (and accompanying changes to time-based charging by retailers). The transitional arrangements might include the initial use of poorly targeted 'time-of-use' tariffs, which only have simple broad peak, off-peak and shoulder rates. While AusGrid's experiences in New South Wales show these do not achieve major network efficiencies, they might at least raise consumer awareness that costs vary over time and may ease the adjustment path. However, financial analysis suggests that the transition to critical peak pricing should not be too slow because the rewards from critical peak pricing are the major network savings. If the transition is too slow, then the Commission's quantitative assessment is that it would be better not to rollout smart meters in the medium term at all
- endorsement of reform and a commitment by governments to achieve it in a given time frame.

Given the importance of the transition and its relative complexity, the Commission proposes that the Council of Australia Governments, through the Standing Council of Energy and Resources, should oversee the process. However, it should avoid prescriptive approaches that do not take into account the cost-benefit framework described above, and should proceed without further reviews or other processes that would unnecessarily delay reform.

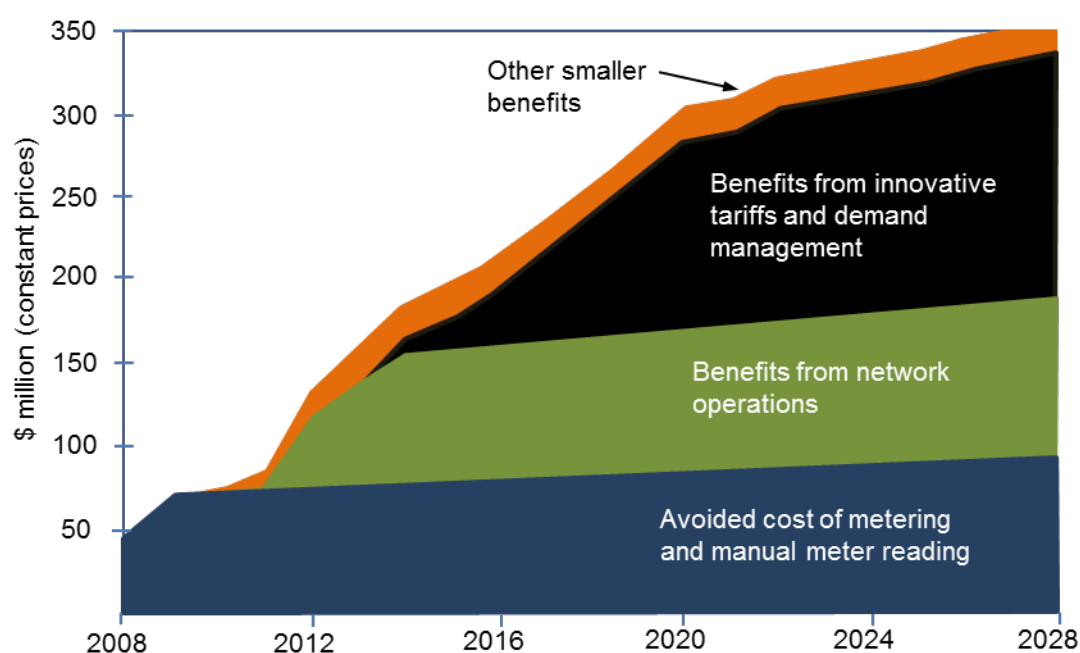
If carefully implemented, critical peak pricing and the other benefits from rolling out smart meters could produce average savings of around \$100–\$200 per household each year in regions with impending capacity constraints (after accounting for the costs of smart meters). Even in Victoria, where the rollout process has been flawed, it now appears that some significant gains will ultimately be realised (figure 6). The Commission's recommended approach to smart meters would mean that in other jurisdictions, the benefits from innovative tariffs and demand management would be realised sooner after any rollout, because the investments would not be driven by a mandate, but by their value to consumers. In some areas, the benefits could be realised reasonably soon after the critical reforms have been completed.

A further critical issue is whether retail price deregulation and the capacity for cost-reflective prices would result in exposure by consumers to the large fluctuations in *wholesale* energy prices that sometimes (albeit rarely) occur for short periods.

However, even if permitted to adopt cost-reflective prices for wholesale energy variations, it is unlikely that retailers would change their current practice of hedging, or contracting with generators (thus smoothing price volatility in the wholesale energy market) for residential customers. This is because such events are not predictable — but can arise from generator failure, strategic behaviour by generators and transmission failures at any time. Consequently, it would be hard to pre-notify consumers of such pricing events.

Nor is it clear that where the pricing events result from such unpredictable events (compared with the predictably high costs associated with network capacity built for the hottest days) that it would be efficient to pass on these volatile unhedged wholesale prices to consumers. Consumers value insurance for such unpredictable events. A retailer that failed to provide such a service would be unlikely to retain customers. Large energy users fall into a different category — and will sometimes agree (with the possible involvement of an intermediary) to voluntary load shedding in return for a fee during high price events, thus lowering their overall costs. Such firms or their intermediaries have the facility to continuously monitor five-minute interval wholesale electricity prices and have the ability to take very rapid action to curtail consumption. Households are unlikely (even with the aid of an intermediary) to ever be able to respond in this sort of manner.

Figure 6 Victoria: smart meters can produce large benefits over the longer run



Data source: Deloitte (2011a).

Distributed generation

Distributed generation — which produces power close to the point of consumption — could potentially perform a similar role to demand management. It may sometimes help to relieve network congestion, meet peak demand or improve system reliability, thereby avoiding or deferring network investment.

However, the current policy environment sends opposing signals to distribution networks and consumers about the economic value of distributed generation. On the one hand, the capacity for local generation to substitute for network investment is frustrated by regulatory obstacles, although many of these — such as a lack of information about network constraints and uncertainty about connection charges — have been, or are soon to be, substantially resolved.

On the other hand, various subsidies to certain types of distributed generation — particularly rooftop photovoltaic units — have led to unbalanced incentives and inefficiencies (though again some recent policy reforms have reduced these). The take-up of rooftop photovoltaic units has, to date, produced minimal, if any, network savings, as existing time-invariant tariffs do not encourage householders to orient units to the west to maximise generation in periods of peak demand late in the summer afternoon. Moreover, the effective use of distributed generation to produce network savings needs to ensure that take-up is maximised in those parts of the system subject to the greatest constraints, which again has not yet happened.

The remaining subsidies to particular forms of distributed generators have few benefits for the network and, in the face of carbon pricing, play a redundant (and inefficient) role as a measure for reducing emissions. Governments should therefore phase out as quickly as practicable subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via premium feed-in tariffs and the small-scale component of the Renewable Energy Target Scheme.

State and territory governments should change the feed-in tariffs for any uncontracted small-scale distributed generators exporting power into the grid, so that their tariffs reflect the market wholesale prices at the time of energy production, and the (net) value to network businesses from reducing loads on their equipment at critical peak periods.

State-owned enterprises

Transmission and distribution businesses in Tasmania, New South Wales and Queensland remain state-owned (and partly state-owned in the ACT), whereas network businesses in Victoria and South Australia are privately owned or operated.

While governments have a legitimate role in owning and operating many services in Australia, the rationale for state-ownership of electricity network businesses no longer holds. This reflects the development of sophisticated incentive regulations that function best when the regulated businesses have strong cost-minimising and profit motives.

State governments often impose multiple constraints on state-owned corporations that are incompatible with maximising returns to their shareholders. These constraints can include:

- social and environmental obligations
- requirements to procure locally
- a lack of coherence of governments in their dealings with the businesses over time. Governments may make decisions to reduce dividends when price increases are politically sensitive, limit capital spending when governments are concerned about debt levels, or encourage capital expenditure if there are pressures for greater reliability
- employee benefits and job security for employees that are out of kilter with those associated with most businesses
- poor governance, including appointment of board members on a non-merit basis.

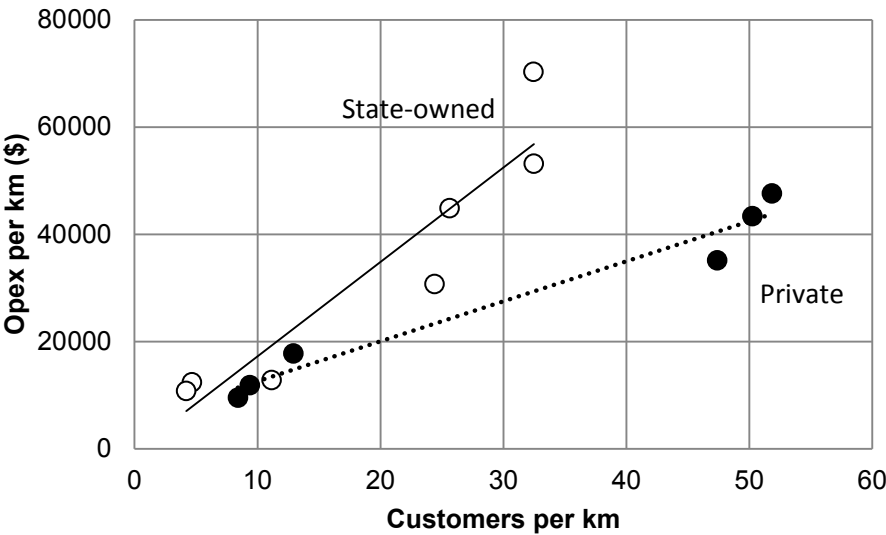
For example, in New South Wales, the Acts governing the state-owned corporations include non-commercial goals, which, where appropriately justified, would be better met through explicit government regulation or budgetary measures. At a minimum, the objectives should be prioritised. For example, in New South Wales, s. 8 of the *State Owned Corporations Act 1989*, requires state-owned corporations to give equal weight to commercial success, social responsibility, ecological sustainability, and a sense of responsibility towards regional development and decentralisation.

State ownership can involve employee protection arrangements that would not be typical in most private businesses. For instance, in New South Wales, Ausgrid is required to provide a five-year employment guarantee to award staff and is subject to requirements to procure locally in some cases, a hidden cost that electricity consumers bear.

While analysis of relative efficiency is difficult given the number of other differences between network businesses, the empirical evidence suggests that, although some perform relatively well, as a group, the aggregate productivity outcomes of state-owned businesses are poorer than their private peers (figure 7). This is likely to reflect the mixed incentives they face. Some participants in this

inquiry claim that a risk-averse focus on ‘building things for the future’ still permeates some of these businesses.

Figure 7 Operating expenses for state-owned and private businesses
\$ per kilometre of line



There are strong arguments for privatisation of these businesses. There is no evidence that the productivity, reliability, quality or cost performance of private sector electricity network businesses is worse than their public sector equivalents. To the contrary, the evidence in Australia and internationally suggests that such private sector enterprises are more efficient. It should also be emphasised that privatisation is not de-regulation. In fact, there is a symbiosis between regulation and privatisation. Strong regulation is needed to achieve the private provision of secure, reliable and appropriately priced electricity network services. And privatisation strengthens the effectiveness of incentive regulation.

Privatisation is not a radical move. There have been few problems in Victoria or South Australia.

In the event that privatisation does not occur, there are strong grounds for different governance arrangements, with the goal of re-invigorating the original purpose of corporatisation of the old state-owned businesses. Among others, this includes merit-based appointment of all board members, public disclosure of ministerial directions, and the removal of non-commercial objectives and obligations (such as procurement and employment policies).

The critical role of the Australian Energy Regulator

The NEM involves multiple interested parties and institutions with clearly defined roles. Ensuring these institutions work well is critical to effective regulation and, in the context of this inquiry, to the degree of discretion that they may wield in using benchmarking, determining new rules and planning the network.

Governments and stakeholders have expressed concerns about the governance of the AER, including its accountability, capability, communication with stakeholders, independence from the Australian Competition and Consumer Commission, and transparency. Many of these perceptions are not backed by solid evidence and may reflect the usual tensions between an economic regulator and the parties it regulates. Others have more foundation, but can be remedied.

While the AER appears to be strongly independent from industry and government influence, there are perceptions that it is unduly influenced by its close links with the ACCC and lacks transparency. Such concerns would be ameliorated by giving the AER more control over its budget and resources, and making it more accountable for how it manages those resources. Concerns about resourcing, capability and accountability should largely be addressed by additional funding announced by the Australian Government in late 2012 and agreement for governance changes to the AER. In that light, further reforms, such as removing the AER from the ACCC and establishing it as a separate entity are not justified at this stage. With modest but important modifications, the AER can improve its reputation and can then take on further responsibilities from state and territory regulators, thereby becoming, as originally intended, the single national energy economic regulator.

Nevertheless, an independent review of the AER — which has also been agreed by COAG — should also assist in addressing any remaining limitations in its operations, and would address any ill-founded perceptions about the organisation. More broadly, all the major institutions of the NEM should be subject to review by 2018 (and every 10 years after that), recognising that institutional arrangements and the NEM have changed and likely will continue to evolve. Most recently, the merits review process has been reviewed, leaving AEMO, the AEMC and any new consumer representative bodies as the remaining institutions that should be assessed for their scope to improve.

The recent assessment of the merits review process proposed a significant institutional change, creating a new merits review body, locating it within the AEMC, and establishing routine consultations between the two bodies. Too close a link between these two institutions is not, in the Commission's view, a desirable

change. The AEMC, while notionally a body that converts broad government policy into precise Rules, in many ways also acts as a policymaker, or at the very least, an influential policy shaper. For obvious reasons, merits review bodies are best the cold and distant relatives to the policy process.

Incentive regulation is a ‘work in progress’ inextricably linked to the effectiveness of benchmarking

Under incentive regulations, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually five years), which it uses to set a revenue allowance for that period. The business makes higher profits if it reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator’s determination in the next period. Accordingly, incentive regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices. Benchmarking — which measures a network supplier’s efficiency against a reference performance — is just one way of assessing whether any given business’s expenditure proposals are efficient.

The theory is simple. Its practical realisation is not. The regulatory arrangements underpinning incentive regulation are protracted and costly. The Rules that stipulate many of the requirements for proposals are lengthy and subject to regular changes — currently around 1500 pages, and by early 2013 up to the 55th version in just seven years. (The sections of the Rules most relevant to this inquiry are around 200 pages in length.) Proposals and the regulator’s determinations have also become increasingly detailed over time. The decision documents for Victorian electricity distributors were around 450 pages in 2000, around 1000 pages in 2005 and 1800 pages in 2010 — reflecting the complexity of the proposals and the large network revenues involved (now around \$13 billion annually in 2011 prices across the NEM). The AER has felt obliged by the Rules to engage in the detailed consideration of business’s proposals in reaching final revenue determinations. For example, there have been debates about the efficient number of locks and keys, the length of insulated conductors and appropriate pole treatment processes. In this context, it is not surprising that the approximate administrative costs for the regulator and the businesses of the last complete cycle of revenue determinations were around \$330 million (which excludes merits review costs).

This focus on detail is counter to the conceptual underpinnings of incentive regulation. The intention of the framework is to limit monopoly pricing (through regulated weighted average price or revenue caps), while leaving it to *businesses*, not the regulator, to work out the minutiae of input and output decision-making in

any given regulatory period. However, to date the AER's ex ante revenue allowances have been based on examining and then summing, item by item, the detailed forward cost projections proposed by businesses, even if, ex post, the businesses choose an entirely different set of inputs. Some forms of benchmarking aim to:

- ex ante estimate the *aggregate* efficient capex and opex of any business (based on the unique characteristics of its customers and network, and assessing efficiency using the performance of other network businesses)
- if possible, avoid engaging in the summation of a large set of what may turn out to be irrelevant costs.

If this were feasible, it might reduce the paper, time and hence financial burdens of the current processes and lead to a greater focus on the National Electricity Objective.

In late 2012, the AEMC made changes in the incentive regulation regime that provide a more promising environment for benchmarking:

- in making regulatory decisions, the AER could, but would not be obliged to, dissect, bit by bit, a business's revenue proposal. Accordingly, it would be free to use benchmarking (and other techniques) to make judgments about a reasonable revenue allowance
- it eliminated flaws in the Rules that permitted (some) businesses to exceed the forecast level of capital spending, which flowed directly into higher network prices without review by the regulator. (The Commission proposed similar reforms as part of its draft report.) This strengthens the role of benchmarking, as networks that spend more than the efficient benchmark will be exposed to closer scrutiny and may lose revenue related to such over-expenditure
- it allowed the AER to introduce a scheme that provides more consistent incentives to reduce inefficient capital and operating expenditure (the 'Efficiency Benefit Sharing Scheme')
- it removed excessively prescriptive arrangements for calculating the weighted average cost of capital (WACC) and clarified that any merits review of the AER's WACC determinations should take account of the interdependencies in its constituent elements. The AER is developing guidelines in this area. The Commission has largely not addressed the detailed aspects of estimating the WACC in this report, but proposes that the AER consider using a long-term trailing average to estimate the debt risk premium and the risk-free rate. Averages taken over a longer period are more stable predictors of market conditions and are more likely to represent the actual borrowing patterns of the

firms involved, as no firm would normally roll over its entire debt portfolio in a two-week period every five years. The Commission also recognises that state ownership of network businesses may confer certain financing advantages on businesses. The remedy is not to develop a WACC that depends on ownership, but to ensure that state-owned network service providers obtain financing (both debt and equity) at rates that reflect the risk of the investment. Privatisation would provide one solution, but so too would genuine competitive neutrality.

What is the practical role of benchmarking?

Given the difficulties outlined in box 1, benchmarking is not *yet* sufficiently reliable and robust to directly set regulated revenue allowances. A particular concern is that it is difficult to distinguish between inefficiency and errors arising from model misspecification, poor data, different regulatory settings and varying operating environments.

Such difficulties are less severe if the purpose of benchmarking is to identify broad efficiency concerns about network businesses. However, in setting regulatory allowances, badly configured benchmarks could lead to under-remuneration of businesses, with risks for efficient investments and business solvency.

In the immediate future, benchmarking would be most useful:

- as a diagnostic tool to help assess the reasonableness of bottom-up detailed proposals. Operating expenses, such as the costs of vegetation clearance around poles and wires, are more generally amenable to benchmarking than capital expenditure. Such specific benchmarking may be reasonably reliable because there are fewer confounding variables. It may also be possible to expand the number of comparisons by analysing performance outcomes from the many regions of any given network business. The AER has already made some use of such benchmarking, as have the network businesses themselves for commercial purposes, underlining that it is sufficiently robust to be useful. The implication of this role for benchmarking is that it is unlikely to reduce to any degree the page counts of regulatory proposals and counterproposals, though it should improve the quality of the outcomes
- in providing information to consumers and others, thereby providing pressure for improved performance by network businesses. The 2012 Rule change requiring the AER to produce annual benchmarking reports about the performance of network business should assist (so long as the benchmarking measures are meaningful and appropriately explained).

Box 1 The difficulties with benchmarking

While benchmarking methods are often sophisticated, there are many problems in applying them and uncertainties about the accuracy and robustness of the results:

(a) There are many different methods for estimating ‘efficient’ costs. They revolve around the assumption that unexplained differences in the performance of firms reflect managerial inefficiency. Different approaches can result in divergent measures of efficiency — which may not be a sound basis for regulating future revenue or prices.

(b) Incentive regulations require a reward for the vigorous (and risky) pursuit of cost efficiency. Setting the benchmark to that of the highest performer dulls those incentives since no one would have an incentive to be the leader. However, setting the benchmark at the lower end of performance takes pressure off inefficient businesses. The decision about where to set the line is difficult and involves judgment.

(c) Quality must not be overlooked. A business subject to incentive regulation may appear to be performing efficiently in cost terms, but may lower its quality. This is why, regardless of the regime used to set revenue allowances, complementary regulation or incentive schemes specifically related to reliability and safety, are also necessary. This is much more difficult in transmission where there are few good leading output measures of likely future reliability performance.

(d) Different reporting systems produce measurement errors.

(e) Any comparisons between businesses must take into account differences in their operational circumstances (such as topography, customer density, and differences between jurisdictions about which assets lie within transmission or distribution networks) and policy constraints (such as higher or differently defined reliability standards or statutory requirements for non-commercial goals for state-owned corporations). Much of the international academic literature on benchmarking uses too few variables to draw strong inferences about the efficiency of specific firms.

(f) There are only 13 distribution businesses, five regional transmission businesses and three separate DC interconnectors in Australia, which reduces the capacity for elaborate models that take into account (e). It also means that the performance bar might be set quite low if the highest performing Australian business were still quite inefficient. International benchmarking might assist, but has to be interpreted carefully given that adjusting for the differences noted in (d) and (e) may increase the number of variables at a higher rate than the additional number of businesses used in benchmarking.

If its rigour and accuracy improves, aggregate benchmarking could also encourage early settlement in determinations, short-circuiting the current costly processes. Depending on the divergence between benchmarking and the business proposal, the AER could immediately accept a proposal as reasonable, following consultation with consumers (through the National Energy Consumer Advocacy Body). Alternatively, if the proposal were in the ‘ballpark’, it could initiate a settlement process between the advocacy body and network businesses. The AER could also

request further information (a ‘please explain’ notice) to assist the early resolution of an agreement. Failing a quick resolution, the AER would adopt the current forensic and protracted processes. The risks and costs of those processes would encourage parties to seek negotiated settlements. Negotiated settlements of this kind (overseen by a regulator) have proven practical and effective in utility regulation in several overseas jurisdictions, such as California, Florida, and Italy.

A Rule change would be required to allow the AER to use benchmarking (or any other evidence at its discretion) on a standalone basis, where it led to an early and *mutually agreed* outcome between the business, the regulator and consumers.

What is a reasonable benchmark?

Any use by the AER of benchmarking to estimate values for opex and capex allowances in determining regulated revenue allowances should be accompanied by two protections of the long-run interests of consumers.

First, the AER should use detailed publication and peer review to help demonstrate that the benchmarking results are robust enough to serve that purpose.

Second, in making any judgments about allowable revenues, the AER should choose a yardstick more akin to that applying in competitive markets — which would be a firm close to, but not at the efficiency frontier. The current requirement under the Rules that the AER must accept a ‘reasonable’ proposal appears to be consistent with this standard for gauging efficiency. Using such a standard recognises that the likelihood of error in trying to estimate the perfectly efficient level of costs is (exactly) 100 per cent. Under incentive regulation, under-remuneration is likely, ultimately, to lead to larger costs than over-remuneration of an equal magnitude. This is because the costs of underinvestment affect the long-run provision of reliable network services to consumers. In contrast, if the incentive regime were performing its role, any over-remuneration would not lead to over-investment by a well-governed, profit-motivated network company. Rather it would result in slightly larger profits (which have lower efficiency costs), which the regulator could reduce in subsequent regulatory periods.

This suggests there should be the retention of some bias towards encouraging investment, but not too large a one.

Processes and resources for benchmarking

A major study ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks. Recognising this, the AER has recently reviewed the use and methods of benchmarking by other energy regulators, and is collecting data that would allow it to undertake more elaborate benchmarking. However, the AER should adopt further measures to ensure the successful use and evolution of benchmarking, including:

- the development of publicly available databases and full transparency in the processes and methods the AER uses in its benchmarking. The standard of reporting of benchmarking and testing of its rigour and robustness would need to be high before the results could play a major role in revenue determinations
- the development and retention of internal expertise, strategies that maximise learning and greater international collaboration with other regulators and benchmarking agencies
- peer review of its benchmarking practices ('benchmarking of benchmarking')
- appropriate consultation with stakeholders about the required data and appropriate methods and regular checking to ensure that the benefits of its benchmarking practices exceed the compliance and resource burdens
- effective communication of the results of benchmarking to its diverse audiences, and in particular to consumer groups, which may use the information to place greater pressure for improved performance by network businesses.

Such initiatives may eventually allow benchmarking to serve a greater role in making regulatory determinations and policy reforms. If benchmark methods become sufficiently robust, the current onus of proof might be switched, with a business having to explain why its alternative proposal would be reasonable. Setting the benchmark target at a slightly less demanding level than that of a fully efficient firm could provide some protection against regulatory error.

Interconnectors

In contrast to concerns about over-investment in each region's own network, some stakeholders argue that there has been underinvestment in interconnectors, citing the presence of interconnector congestion as an indicator of this. They claim that underinvestment has led to insufficient trade in energy across borders and the use of market power by some generators, and acted as a barrier to the wider use of low carbon emitting generators (particularly wind).

However, there are several major flaws in these claims.

- Congestion is not inherently bad. Just as in roads, some congestion is efficient because the costs of lowering congestion can exceed the benefits. The current evidence suggests that interconnector capacity is close to its optimal level.
- There is a cost–benefit process for determining the desirability of augmentations of interconnectors. One imminently prospective interconnector upgrade — the Heywood interconnector between Victoria and South Australia — appears to pass a cost–benefit test. (Options for upgrading another interconnector, between New South Wales and Queensland, are also currently being considered.)
- The problems attributed to apparent underinvestment in interconnectors — such as the exercise of market power by some generators — are often the consequence of other aspects of the network and the regulatory system. Simply increasing interconnector investment would often not resolve these problems, or would not be the most efficient way of doing so.

In fact, the current major problem is that existing interconnector capacity is not always efficiently used (quite the opposite of a problem with congestion). This arises because the Rules may sometimes affect the bidding behaviour of generators in perverse ways. Moreover, the regulatory regime for transmission (of which interconnectors are a part) should be future looking. Accordingly, while existing interconnection infrastructure may be satisfactory, the current system may not deliver efficient future investment.

The reasons for this are highly technical, but there are two main factors undermining the efficient use of interconnectors:

- intra-regional transmission networks are not necessarily planned to optimise the use of interconnectors. As AEMO has pointed out, it is a fallacy to depict interconnectors as simply a single piece of wire passing over a state border and linking in an uncomplicated way to the networks on each side of the border. In fact, an apparently ‘single’ interconnector can be composed of several lines of varying capacity and location, and the operation of an interconnector is affected greatly by the capacity and structure of the transmission networks to which it connects. State based transmission planning regimes currently give insufficient attention to the impacts of their decisions on the effectiveness of transmission systems in other states and on the interconnectors themselves
- strategic behaviour by generators, which is encouraged by the design of the spot market in the NEM, the physical configuration of both transmission and generation in the NEM and the way that transmission services are priced.

When transmission constraints bind, it may be necessary to dispatch higher cost generators ahead of more efficient ones to meet demand. But this can also be the result of, or be exacerbated by, strategic behaviour by generators (so-called ‘disorderly’ bidding) located behind a constrained transmission line. They can also prevent the dispatch of efficient generators in another state and thereby reduce traffic on an interconnector, sometimes precisely when maximising flows would be helpful to meet peak demand in another jurisdiction. Indeed, in certain bizarre instances, generator bidding behaviour may result in ‘counterflows’, in which the pattern of trade violates the usual assumptions of comparative advantage. Generators with higher costs send power to a state with lower-cost generators. Disorderly bidding can be a highly profitable strategy for generators.

In the short run, this conduct mainly results in income flows between parties, but little inefficiency. However, despite arguments to the contrary from some generators, the Commission believes that this problem leads to significant long-run inefficiencies (a view also held by the AER and the AEMC):

- generators face inefficient signals about where to locate
- older higher-cost generators may not be decommissioned early enough
- the capacity of inter-regional contracting across interconnectors to provide insurance through hedging instruments is undermined, forcing parties to use more costly hedging, or to avoid inter-regional trading altogether (raising electricity prices to consumers in either case)
- the signals for the efficient investment in interconnectors are distorted, and with that, network planning across the NEM.

The Commission largely agrees with the option proposed by the AEMC in its transmission frameworks review. The adoption of ‘optional firm access’ (OFA) can remove the incentives that lead to disorderly dispatch. Under OFA, generators can choose to pay for a privileged financial right to a given amount of the capacity of a transmission network (‘firm access’). The generator does not have to actually physically dispatch power, but any other generator displacing the purchased capacity must pay the generator that has acquired firm access. OFA would achieve short-term gains by addressing disorderly bidding and provide long-run signals about the optimal location and investments in transmission and generation.

However, the implementation of OFA will require a reasonable transition. This reflects:

- its complexities

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- the need to ensure that parties do not find ways of gaming the new arrangements, (on the one hand, the risk that a transmission business might overprice access, and on the other, that generators may find new ways to game the spot market)
 - a requirement to undertake adequate consultation on arrangements that will affect all transmission businesses and generators throughout the NEM.

However, in the meantime, the AER has proposed a relatively simple option based on imposing congestion pricing on generators in constrained parts of the transmission network. This would address some of the most serious aspects of disorderly dispatch, and assist the transition to OFA. This should be implemented within two years. The Commission envisages that, subject to the outcomes of cost–benefit analyses (including relative to the AER’s proposal), OFA would commence operation in 2018.

Over the very long run, a shift from OFA to a more refined transmission pricing model — ‘nodal’ pricing — may be beneficial, but this should be tested in a review ten years after the commencement of OFA.

Quite apart from reforms to transmission pricing, the Commission’s preferred NEM-wide planning approach (as discussed earlier) is likely to overcome biases against interconnectors arising from a tendency to favour intra-regional transmission options.

Implementation and outcomes

Notwithstanding some progress in reform — or at least in reviews proposing reform — much of the detail of the necessary reforms has yet to be determined, and some crucial policy decisions have yet to be made. This is apparent in the:

- continued lack of a nationally consistent framework for network reliability and planning that takes into account the customer value of reliability. There remains a genuine risk that the ultimate policy outcomes may preserve a backdoor for parochialism
- prolonged gradualism of electricity retail reform, and indeed in reform more generally
- absence of decisions about how a coherent and workable smart meter rollout should proceed
- continued government ownership of networks, and in some cases, retailers and generators

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- as yet, no decision about the best processes for reviewing or appealing the AER's regulatory decisions.

Major stakeholders, particularly investors in long-lived network assets, are understandably nervous about any changes to the rules and regulatory environment that might adversely affect their investments. Meeting the *long-run* interests of consumers requires that investors are confident that the regulatory regime will deliver adequate returns on their investment. Some may argue that the Commission's suite of recommendations represent an unacceptable rate of change and risk to investor confidence. To this, the simple but fundamental point is that the recommendations made by this inquiry do not represent any change to the 'goal posts' of the NEM — with the inherent uncertainty that would entail for consumers and network businesses. Rather, the recommendations are designed to re-orient the framework to better achieve its original objective.

There have been some legitimate reasons for price increases over the last few years, but the system as a whole is inefficient, and price pressures could be reduced substantially over the longer term if a coordinated set of reforms were introduced. Consumers have much to gain from the proposed reforms.

Reform needs to be more timely

Some of the more critical reforms in the NEM have already taken far too long. While the complexities of the NEM, the number of stakeholders involved, and the issues relating to investor confidence noted above, justify a considered and thorough examination of reforms before they are implemented, the current system has sometimes descended into paralysis by analysis. Reform appears to have been frustrated by complex processes, constant and overlapping reviews, and a lack of agreement by relevant governments about either the reforms themselves or the need for more timely progress to a genuinely NEM-wide approach to energy regulation.

This is exemplified by the processes for reforming transmission planning and reliability. Sweeping national reform was first proposed in 2002, with follow-up reviews commencing in 2006, 2007, 2009, 2010 (the latter AEMC review taking three years) and in 2012 (this inquiry). Notwithstanding this extensive pre-existing analysis, SCER has just initiated a new AEMC review, covering much of the same territory. This will trigger to a further protracted process, including:

- the time required to complete the review (scheduled for completion by November 2013)
- the need to alter the National Electricity Law at the conclusion of that review (provided SCER reaches a consensus). SCER would also need to develop an

implementation plan and then request that the AEMC initiate a Rule change process

- the time taken to complete the Rule change process (expected to be around one year)
- the time for transmission businesses to understand the new Rules and to incorporate them into their initial regulatory proposals
- the fact that regulatory determinations are staggered over several years.

As a result, under current arrangements, the most optimistic outcome is that national reform could be in place by 2019, but a significant risk that a fully national framework for transmission planning and reliability would not be in place until 2022 — or 20 years after initial national reform was proposed. At any point in the next nine years, even that extended reform process could be derailed by further reviews or indecision.

This is despite the fact that reform of this area is one of the most critical components to enable achievement of the National Electricity Objective. Slow reform progress has already been costly, and further delays will cost consumers hundreds of millions of dollars of avoidable costs to their electricity bills. It appears that consumer interests have been subordinate to process. Yet, paradoxically, all jurisdictions, transmission businesses, AEMO, and the AEMC have agreed to many elements of the reforms suggested by the Commission (or close alternatives to these).

There would be equal concern that other major reforms — such as those relating to smart meters and time-based pricing — could also be unduly delayed. As emphasised earlier, SCER must change its processes to accelerate reform. The current review into transmission and distribution reliability should be converted into an AEMC Rule change process to be completed by the end of 2013, and should draw on the Productivity Commission's recommendations and other inputs. This more speedy process means that the reform process would be completed by 2018. By bringing forward reform from the current likely completion date of 2022, the Commission estimates that even under conservative assumptions, the gains in transmission alone could generate over \$500 million in additional benefits.

How can the Commission's review fit into the reform agenda?

The Commission was struck during this inquiry by an anomaly in policy decision-making in the NEM that adds yet another friction to efficient decision-making. The Commission has undertaken an extensive public inquiry into many aspects of network regulation and made many highly specific recommendations that could be

given effect in Rule changes. The same could be said of several other reviews concerning electricity network regulation — for example, the independent panel carrying out the limited merits review commissioned by SCER, the inquiry of the Senate Select Committee on Electricity Prices and, indeed, many of the AEMC’s own reviews. Yet, even if SCER considered that any such recommendations should be implemented, this could not happen with any speed, if at all. This is because under the present regime, SCER would have to make a request to the AEMC to consider a Rule change. The AEMC would normally then go through a lengthy review process (a review of a review), which at best would cause delays and, at worst, might end up with a less effective reform than intended. (In contrast, a change to the National Electricity Law could be made quickly, despite the fact that it and the Rules are both statutory instruments giving effect to policy.)

Three adverse consequences of this are that the usual sovereign powers of parliaments are weakened, the large benefits from reforms are delayed, and there is an added consultation burden on stakeholders and duplication in the resourcing of reviews. The burdens posed by inertia and compliance costs could be resolved by amending the National Electricity Law so that SCER can request that a Rule change process be completed within six months, where the reform proposal is underpinned by an independent and consultative review undertaken by an appropriate agency, including the AEMC itself. The role of the AEMC would then be to draft the relevant Rule changes and seek (expedited) commentary on these, in a manner similar to the release of an exposure draft bill at the Commonwealth level.

Table 1 A summary of the Commission's main proposals

<i>Current problem</i>	<i>Proposed response</i>	<i>Main benefits from reform</i>
<i>Timeliness in decision-making and Rule changes</i> SCER processes and decision-making, and AEMC Rule change processes take too long.	A commitment by SCER to identify the critical areas for reform, and to prioritise these through tighter timetables for their implementation. SCER should avoid overlapping and protracted reviews. Speed up the current review into transmission and distribution reliability. Accelerated AEMC Rule changes for SCER requests arising from independent appropriately conducted reviews.	A more coherent reform process and a more rapid realisation of benefits for consumers.
<i>A focus on consumers</i> The NEO (the long-term interests of consumers) has lost its pre-eminence in regulatory decisions.	The National Energy Consumer Advocacy Body to cover all consumers, and have the expertise and funding to be an effective participant in the regulatory process. The limited merits review process should also be reformed.	Customers would have more power in the regulatory process, keeping the NEO in sight and preventing undue focus on technical, financial and legalistic details.
<i>Reliability</i> Reliability is critical to electricity networks, but the current standards are not set efficiently, and often bear little relationship to the value to customers.	Reliability decisions should be based on customers' valuations, not prescriptive standards. For distribution, a new national reliability framework should be introduced, and incentive schemes reformed to reflect customer preferences. For transmission, reliability standards should be set at the connection point level across the NEM. Investment decisions should be made by the transmission businesses, but with scrutiny by the AER and AEMO for large projects (and subject to a cost-benefit test and consideration of NEM-wide impacts and efficiency).	Distribution: in New South Wales alone, \$1.1 billion of network capital expenditure could be deferred until the next five year regulatory period. The actual, NEM-wide, savings are likely to be larger. Transmission: were it implemented in a timely way, a new reliability framework could defer around \$2.2 to 3.8 billion of investment across the NEM, over the next 30 years.
<i>Demand management</i> Some 25 per cent of (expensive) system investment is required just to meet 40 hours of critical peak demand each year (in New South Wales).	A coordinated suite of reforms should be introduced over time, including consumer consultation; removal of retail price regulation; the capacity for distributors to include the installation of smart meters as part of standard regulatory arrangements; common meter standards; a capacity for all parties to install meter add-ons or upgrades; and time-based pricing for critical peak periods. Direct load control options would also play a role.	System use and investment would be better aligned, reducing the amount of expenditure required just to meet peak periods. Critical peak pricing and smart meters could produce average net savings of around \$100–\$200 per household each year in regions close to capacity constraints.
<i>Network ownership</i> State-owned network businesses and their owners have conflicting objectives, frustrating the effectiveness of incentive regulation. State-owned businesses perform worse than private ones.	State-owned network businesses should be privatised. If not, governance should be improved, and non-commercial objectives and policies should be removed. An orderly, well planned privatisation process, with consumer engagement.	In the first instance, the efficiency of network businesses can be expected to improve, reducing costs to customers. Incentive regulation would also become more effective, reinforcing efficiency improvements.

Table 1 **continued**

<i>Current problem</i>	<i>Proposed response</i>	<i>Main benefits from reform</i>
<i>Incentive regulation</i> The current incentive regulation regime encourages businesses, especially state-owned ones, to build too much.	<p>Ensure that state-owned network service providers obtain financing (both debt and equity) at rates that reflect the risk of the investment.</p> <p>The AER should use a long-term trailing average to estimate the debt risk premium and the risk-free rate.</p>	<p>Incentive regulation would be more effective at encouraging efficient investment.</p>
<i>Governance of NEM institutions</i> AER governance arrangements are not clear. There are mixed perceptions about the capacity of the AER to fulfil its current obligations. Future reforms would only add to these obligations. Other bodies need periodic review.	<p>The AER to issue a separate annual report; have administrative control over its budget and resources (including a capacity to acquire specialist expertise); publicly reveal its strategies for improving its performance; negotiate resource sharing agreements with other agencies as it feels appropriate; strengthen and retain its specialist expertise; and develop a program for regular consultation with all stakeholders.</p> <p>All NEM institutions should be reviewed by 2018 and, thereafter, at regular 10 yearly intervals.</p>	<p>Ensure effective performance of the AER, AEMC, AEMO and the new consumer advocacy body.</p>
<i>Benchmarking</i> Information asymmetries make it difficult for the regulator to accurately assess the efficiency of businesses' proposals.	<p>Benchmarking is currently too unreliable to set regulated revenue allowances, but could better inform the regulator's decisions. In the future (after the rigour and accuracy of benchmarking improves), reforms could be made to underpin negotiations for 'early settlements' with businesses, and potentially to base allowances on benchmarking.</p>	<p>Better information could improve the accuracy and effectiveness of incentive regulation, lowering prices to consumers.</p> <p>Additionally, in the future, lengthy regulatory determinations could be avoided, reducing compliance costs.</p>
<i>Interconnectors</i> There is no evidence of insufficient physical capacity of interconnectors at present. Indeed, they are sometimes underutilised due to perverse incentives in the structure of the wholesale market. Underutilisation may often coincide with periods of peak demand when the interconnectors would be most valuable.	<p>Reform the wholesale market to influence generator bidding behaviour, and change the way they pay for access to the transmission network.</p> <p>Ensure intra-regional transmission networks are planned to optimise the use of interconnectors. Implement a short-term congestion pricing mechanism as the precursor to the potential adoption of the 'optional firm access' package currently being considered by the AEMC.</p> <p>In the long term, the potential for 'nodal pricing' with a system of financial transmission rights should be considered, pending a review of its merits compared with the firm access arrangements.</p>	<p>Generator bidding behaviour (and locational choices) would be more closely aligned to efficient levels. In the long term, this would allow better flows along interconnectors; improve certainty in (electricity) financial markets; and improve interconnector planning.</p> <p>Introduction of 'optional firm access' would lead some transmission investments becoming market-driven, improving the alignment of investment expenditure with user benefits.</p> <p>The networks on either side of an interconnector would be better designed to help utilise its full potential.</p>

Table 2 The timing of reform

<i>Timing</i>	<i>Measure (and corresponding recommendations)</i>
Already underway	<ul style="list-style-type: none"> • Changes to incentive regulation were made in a Rule change in November 2012, but the AER must develop guidelines to give effect to some of these (r. 5.2).
Initiate now	<ul style="list-style-type: none"> • SCER to commit to more speedy reform and acceleration of the current review into transmission and distribution reliability (r. 21.7, 21.8). • SCER to establish an accelerated process for Rule changes where policies arise from the recommendations of independent and appropriately undertaken reviews (r. 21.6). • Ensure guidelines for the WACC take account of long-run conditions (r. 5.1). • State and territory governments to phase out retail price regulation, subject to effective retail competition (r. 12.2). • State and territory governments to introduce feed-in tariffs that reflect the value of providing power to the grid at peak and non-peak time (r. 13.1). • The AER to: <ul style="list-style-type: none"> – at this stage, use aggregate benchmarking to inform (but not use as the exclusive basis for) determinations (r. 8.1, 8.5) – begin (ongoing) development of detailed benchmarking performance and control variables, with periodic review for relevance and compliance costs (r. 8.2, 8.3, 8.6, 8.8, 8.9, 8.10, 8.12). Benchmarking results and data to be public (r. 8.7, 8.11) – be given greater control over, and accountability for the resourcing and management of its functions (r. 21.1). • AEMO to: <ul style="list-style-type: none"> – review the technical aspects of probabilistic planning, in consultation with network businesses and experts (r. 16.5) – assist the AER in its compliance and auditing of transmission networks (r. 16.6) and act as planner of last resort where it considers underinvestment could expose the network to serious reliability problems (r. 16.7) – oversee the contestability arrangements for the connection of new generators to the NEM (r. 16.10). • Transmission businesses that do not already use them should transition to dynamic capacity ratings (r. 16.9). • Amend the Rules so smart meter investment can be part of regulatory determinations for distribution businesses (r. 10.3).
By end 2013	<ul style="list-style-type: none"> • Reliability standards in the NEM to be based on the value customers place on reliability (r. 14.1) and AEMO to commission the Australian Bureau of Statistics to undertake surveys to identify the value of customer reliability (r. 14.2). • SCER to develop common criteria for assistance to vulnerable consumers (r. 11.8). • Change the RIT-D and finalise advanced metering infrastructure standards (r. 10.1 and r. 10.2). • The AER to complete a review of the Service Target Performance Incentive Scheme for transmission to ensure consistency with the new reliability framework (r. 16.8); and amend the Service Target Performance Incentive Scheme for distribution (r. 15.2) and move to determinations based on revenue caps (r. 12.1). • A short-term congestion pricing mechanism be introduced as a precursor to the 'optional firm access' package of reforms (r. 19.1). • The proposed new National Energy Consumer Advocacy Body should have certain characteristics, including adequate funding and expertise (r. 21.5).

(continued on next page)

Table 2 continued

<i>Timing</i>	<i>Measure (and corresponding recommendations)</i>
2013–2018	<ul style="list-style-type: none"> • SCER to remove jurisdiction-specific distribution reliability requirements. Distribution reliability settings to be contained in the Service Target Performance Incentive Scheme, with the reliability settings driven by consumer preferences (r. 15.1). • Undertake the 2014 review of the AER, and in a 2018 review, consider further changes, including to its location within the ACCC (r. 21.2, r. 21.3). • AEMO to take on the role of a national transmission reliability setter, using probabilistic planning and a cost–benefit framework for the entire NEM network to set standards at the connection point level (r. 16.1, 16.2). • Transmission businesses to plan reliability investments and be subject to a RIT-T for large projects (r. 16.3, r. 17.1, 17.2, 17.3, 17.4, 17.5). • The AER to review the adequacy of AEMO’s transmission standard setting role (r. 16.4). • State and territory governments to adopt a single set of licence conditions for network businesses, expressed in the National Electricity Rules and administered by the AER (r. 11.2, 11.3, 11.4). • Time-based network charges to be implemented after guideline development, consultation and policies for vulnerable consumers (r. 11.1, 11.5, 11.6, 11.7, 11.8, 11.9). • Complete phase out of retail price regulation by 2015 (r. 12.3). • State and territory governments should privatise network businesses (r. 7.1), after announcing the new reliability framework, ensure adequate communication to all stakeholders, and follow a coherent privatisation pathway (r. 7.3). If not, they should improve the governance of those businesses (r. 7.2). • Subject to the completion of cost–benefit analyses, the AEMC’s ‘optional firm access’ package to be implemented by 2018. It should: <ul style="list-style-type: none"> – operate for at least 10 years – be monitored by AEMO for effects on network planning and, in concert with the AER, for changes in observed patterns of generator bidding behaviour. AEMO should also provide information to applicants for firm access relating to the (long term) upgrades required, and benchmark indicators of their cost (r. 19.2). • Incentives for more efficient investment in distributed generation (r. 13.1) would be created by: <ul style="list-style-type: none"> – fully phasing out subsidies that stimulate inefficient investment in and positioning of rooftop photovoltaic units (but existing feed-in contracts should be honoured) – distribution businesses remunerating distributed generation providers at a level that reflects the network value of the distributed generation capacity and output. • Review the AEMC, AEMO and the proposed new National Energy Consumer Advocacy Body by 2018, and, thereafter, review these institutions and the AER at 10 year intervals (r. 21.4).
2019	<ul style="list-style-type: none"> • If benchmarking becomes robust enough, and where the divergence between estimates is narrow, the AER to have discretion to reach a mutually acceptable negotiated settlement with a network business, with the involvement of the representative consumer body (r. 8.4).
2028	<ul style="list-style-type: none"> • Conduct a review to consider whether the introduction of nodal pricing is warranted on cost–benefit grounds, or if other reforms (such as alterations to the ‘optional firm access’ model) offer greater benefits (r. 19.3).

Recommendations and findings

The process for reform is part of the problem and must change

RECOMMENDATION 21.7

The Standing Council on Energy and Resources should reform its processes and decision making so that critical policy reviews of the National Electricity Market, the corresponding changes to the National Electricity Rules, and their implementation occur in a timely fashion.

RECOMMENDATION 21.6

The National Electricity Law should be amended to require the Australian Energy Market Commission (AEMC) to accelerate the process for making Rule changes within six months where they:

- *are requested by the Standing Council on Energy and Resources, and*
- *arise from the recommendations of an appropriately conducted independent review, including previous AEMC reviews, relevant to the National Electricity Market.*

RECOMMENDATION 21.8

The Standing Council on Energy and Resources (SCER) should convert the current Australian Energy Market Commission's (AEMC's) review of distribution and transmission reliability into an accelerated Rule change process (as set out in recommendation 21.6) to be completed by December 2013. SCER should request the AEMC to draw on the Productivity Commission's recommendations 15.1, and 16.1 to 16.7, as well as the quantitative assessment of the benefits of the recommended reforms, in formulating the proposed Rule changes.

The institutions need to change too

RECOMMENDATION 21.1

The Australian Energy Regulator should have greater control over, and accountability for, the resourcing and management of its functions. It should:

-
- *submit a separate annual report of its performance*
 - *have administrative control over its own budget, which would need to be adequate for it to manage its functions efficiently and effectively, including acquiring, developing and retaining the necessary specialist expertise*
 - *publicly reveal its strategies for addressing current stakeholder concerns and those raised in future stakeholder surveys*
 - *have an independent capacity to negotiate resource sharing arrangements with a range of agencies, not just the Australian Competition and Consumer Commission*
 - *ensure that it strengthens and retains the necessary specialist expertise to competently carry out its role, in accordance with recommendation 8.6*
 - *develop a program for regular ongoing communication and interaction with network businesses, their customers and other relevant stakeholders, with those interactions not just confined to periods of regulatory determinations.*

RECOMMENDATION 21.2

The 2014 independent review of the resourcing and capacity of the Australian Energy Regulator (AER) should be undertaken by a small group of senior and experienced persons.

- *These persons should be external to the Australian Competition and Consumer Commission and the AER, have an appropriate understanding of the competencies required to undertake utility regulation, and include some contemporary international experience from counterpart regulators.*

The review should, among its other tasks:

- *specifically address any difficulties the AER has in attracting and retaining specialist staff*
- *consider the commissioning of an independent stakeholder survey covering the relevant review issues*
- *consider funding options for the AER.*

RECOMMENDATION 21.3

The Australian Energy Regulator (AER) should remain located within the Australian Competition and Consumer Commission (ACCC). However, a follow-up independent review should be carried out in 2018 to examine if the reforms to the AER's resourcing and transparency (recommendation 21.1) have had the desired impacts. If not, the issue of the AER's structural separation from the ACCC should be examined together with other possible changes to improve its performance.

The operation and performance of the Australian Energy Market Commission, the Australian Energy Market Operator and the proposed new National Energy Consumer Advocacy Body should be independently reviewed by 2018 to identify opportunities for improvements. All these institutions and the Australian Energy Regulator should be reviewed at least at 10 year intervals after that time.

Consumers need a clear voice in the regulatory regime

The new National Energy Consumer Advocacy Body proposed by the Standing Council on Energy and Resources should:

- *have expertise in economic regulation and relevant knowledge and understanding of energy markets*
- *represent the interests of all consumers during energy market policy formation, regulatory and rule-making processes, merits reviews, and negotiations with providers of electricity networks and gas pipelines*
- *subsume the role of the existing Consumer Advocacy Panel into its broader functions, but only provide grants to consumer bodies where the research proposal is judged to have merit and unlikely to proceed without some government funding*
- *ultimately subsume the role of the Consumer Challenge Panel*
- *receive adequate ongoing funding through a levy on market participants, drawing on the approach used to currently fund the Consumer Advocacy Panel*
- *have a governance structure that involves an expertise-based board of members appointed on merit, and an advisory panel to give the board advice on the needs of the mix of customers concerned*
- *be independent from the Australian Energy Regulator.*

The recently commissioned independent review into the best design of the National Energy Consumer Advocacy Body should take these recommendations into account.

Effective demand management requires pricing and other regulatory reform

RECOMMENDATION 10.2

The Standing Council on Energy and Resources should finalise a minimum technical standard for advanced metering infrastructure, including smart meters, which should:

- *ensure that distribution businesses and other parties can purchase off-the-shelf equipment from global manufacturers of smart meters with no, or minimum, modification*
- *incorporate capacities for:*
 - *interoperability with add-on technologies that distributors, retailers and third parties wish to offer customers*
 - *open access to information for distributors, retailers and third parties, subject to privacy provisions*
 - *direct load control.*

RECOMMENDATION 10.3

The National Electricity Rules should be amended so that distribution businesses would be able to include the rollout of advanced metering infrastructure, including smart meters, as an eligible category in their regulatory revenue proposals to the Australian Energy Regulator. During the regulatory period, distribution businesses should be able to decide on the timing, location and number of smart meters in any rollout. These changes should be accompanied by:

- *engagement with consumers and retailers about the process, and the implications of smart meters for them*
- *the development of an incentive program by the Australian Energy Regulator that takes account of the benefits of smart meters:*
 - *in reducing network expenditures in subsequent regulatory periods*
 - *accruing to others in the energy supply chain*
- *time-based network charges to retailers (recommendation 11.1)*
 - *options for direct load control.*

RECOMMENDATION 10.1

The Regulatory Investment Test for Distribution in the National Electricity Rules should be altered so that a preferred investment option cannot have costs that exceed the benefits. The current \$5 million threshold value and the use of exemptions should be reviewed if the test imposes unjustifiably high compliance costs on distribution businesses, the Australian Energy Regulator and other parties.

RECOMMENDATION 11.1

The Standing Council on Energy and Resources should oversee the progressive implementation of cost-reflective, time-based pricing for distribution network services, predicated on the long-run marginal costs of meeting peak demand. Amongst other things, the Council should:

- *following consultation with key stakeholders, set timelines for the various steps in the development and implementation process, having regard to:*
 - *the Commission’s proposed process (recommendations 11.2 to 11.9)*
 - *progress in making necessary changes elsewhere in the system*
- *monitor compliance with those timelines*
- *address any areas where greater engagement between key stakeholders (distribution businesses, retailers, state and territory governments, the Australian Energy Regulator and customer representatives) would assist the expeditious implementation of the new pricing regime*
- *if and as necessary, take specific steps to address implementation delays.*

RECOMMENDATION 11.2

The Standing Council on Energy and Resources should initiate a process to establish uniform licence conditions for all transmission and distribution network businesses in the National Electricity Market.

- *The uniform licence conditions should have regard to the Commission’s proposed changes to the reliability framework (recommendations 15.1 and 16.1) and should not conflict with, or impede, the implementation of that framework.*
- *The uniform licence conditions should be included in the National Electricity Rules and replace the current state and territory licence conditions.*

-
- *Standardised provisions governing technical standards and safety should ultimately be encompassed in the national licence conditions, but with a transition to recognise the practical implementation difficulties of any rapid changes in this area.*

The Council should task the Australian Energy Market Commission to undertake a framework review to assist the transition to uniform licence conditions.

- *The supporting framework review should clearly spell out the justification for any jurisdiction-specific conditions included in the new licensing regime.*

RECOMMENDATION 11.3

Before incorporation into national licence conditions, preparatory work should be undertaken to develop a common approach to the identification of customers in need of special support to meet their electricity bills (recommendation 11.8).

Pending agreement on appropriate national criteria and approaches to funding, each state and territory government should continue to be responsible for targeted financial support to address affordability.

RECOMMENDATION 11.4

The Australian Energy Regulator should be responsible for ensuring compliance with most new licence conditions, with the exception that a relevant independent national, state or territory regulator should have responsibility for compliance with national safety licence conditions.

- *The Australian Energy Regulator would still oversee any economic incentive schemes relating to safety and would need to ensure that revenue determinations took into account the agreed national safety standards.*

The Australian Energy Regulator should be given authority under the National Electricity Rules and the National Electricity Law to:

- *issue and revoke licences*
- *seek advice from relevant agencies on any technical matters relating to compliance assessment.*

RECOMMENDATION 11.5

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the National Electricity Rules should be amended to:

-
- *ensure that any time-based tariff is determined by (rather than ‘take into account’) a reasonable estimate of the long-run marginal cost for the service concerned*
 - *ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than ‘having regard to’ it)*
 - *make it explicit that significant differences in the long-run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures*
 - *with any deviation from this principle arising from any state or territory government decisions about community service obligations transparently funded by the relevant jurisdiction.*

RECOMMENDATION 11.6

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the requirements governing assessments by the Australian Energy Regulator of pricing proposals by distribution businesses should be amended such that the regulator:

- *can only approve a distribution business’s peak demand forecasts if they include reasonable estimates of the likely demand response to critical peak time-based pricing*
- *subject to the above condition, must approve any reasonable estimate by a distribution business of the long-run marginal costs of meeting peak demand.*

To support these changes, the Australian Energy Regulator should develop a capacity to model demand responsiveness to time-based pricing.

RECOMMENDATION 11.7

The National Electricity Rules should be amended to:

- *require the Australian Energy Regulator to publish guidelines on the appropriate methods for estimating the long-run marginal costs of meeting peak demand, and the factors that should be encompassed in those estimates*
- *give the Australian Energy Regulator the authority to publish guidelines about efficient, time-based tariff structures, including definitions of ‘peak’ pricing events.*

These guidelines should be developed in consultation with the relevant stakeholders and should be improved over time as the implementation of time-based pricing progresses.

RECOMMENDATION 11.8

The implementation of cost-reflective, time-based pricing for distribution network services should be accompanied by assistance for vulnerable consumers, which should target those who:

- *are potentially exposed to large price increases and who do not have reasonable opportunities to switch their demand to non-peak periods*
- *will potentially face significant difficulty in meeting the fixed component of network charges.*

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance and how it should best be delivered. These criteria should be based on the outcomes of a review commissioned by the Council of Australian Governments of concessions for utility services across all levels of government (consistent with recommendation 8.1 of the Productivity Commission's Urban Water Sector report).

These criteria, and a commitment to transparent funding of the electricity sector-specific support, should then be reflected in the new National Electricity Market-wide licence conditions for network businesses (recommendation 11.2).

RECOMMENDATION 11.9

The Australian Energy Regulator should require:

- *distribution businesses to demonstrate that they have actively engaged with retailers very early in the development of new time-based pricing structures, including on ways to incorporate those charges in retail prices to clearly signal to customers the costs of meeting peak network demand*
- *distributors and retailers to demonstrate that they have engaged with, and educated, customers prior to the introduction of smart meters, and again prior to the introduction of new time-based tariffs. Such engagement should occur sufficiently early to ensure that customers have been:*
 - *given sufficient information and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand)*
 - *informed about the implications for their electricity bills*
 - *given clear guidance about the way in which advance warning of critical peak pricing events will be communicated*

-
- *provided with support mechanisms in the event that the new pricing regime creates financial difficulties for them.*

RECOMMENDATION 12.1

The Australian Energy Regulator should use revenue caps, rather than weighted average price caps, in the regulation of all distribution businesses.

RECOMMENDATION 12.2

State and territory governments should implement, as soon as practicable, any advice from a retail competition review by the Australian Energy Market Commission to remove retail price regulation, and/or undertake consumer awareness measures and structural reforms to improve the effectiveness of retail competition.

RECOMMENDATION 12.3

The Standing Council on Energy and Resources, in consultation with the Australian Energy Market Commission, should revise the current timetable for retail competition reviews to enable all retail price regulation to be removed no later than 2015.

RECOMMENDATION 13.1

Governments should, as soon as practicable, discontinue subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via feed-in tariffs and the small-scale component of the Renewable Energy Target scheme.

State and territory governments should change the way small-scale distributed generators are reimbursed by:

- *instituting arrangements for network businesses to remunerate such generators at a level that reflects the savings in network costs from distributed generation capacity and output, particularly taking into account the extent to which distributed generation reduces the requirements for peak network capacity*
- *setting feed-in tariffs that approximate the wholesale price of electricity at times of peak and non-peak demand.*

To provide a transition to the new arrangements, current feed-in tariff schemes should continue for existing customers until the end of their contract period or until those schemes expire (whichever is earlier), but be closed to new entrants one year from the governments' formal acceptance of this recommendation. Prior to that date, state and territory governments should develop replacement feed-in schemes with tariffs that approximate the wholesale price of electricity.

Network expenditures are inefficient

RECOMMENDATION 5.1

The Australian Energy Regulator should consider the use of long-term trailing averages to estimate the debt risk premium and risk-free rate used in the calculation of the weighted average cost of capital.

RECOMMENDATION 5.2

Where the Australian Energy Regulator considers that the National Electricity Rules constrain its capacity to make appropriate revenue determinations, it should publish its preferred estimate along with the final determination, explaining the differences. In any subsequent merits review of its determination, the Australian Energy Regulator should ensure that the reasons behind its preferred estimate are clearly communicated to the merits review body.

Using benchmarking in incentive regulation could improve efficiency

RECOMMENDATION 8.1

The Australian Energy Regulator's regular aggregate benchmarking of the performance of network businesses should include comparisons of:

- *multifactor productivity — the output of services for given inputs*
- *separate productivity of capital, labour and intermediate inputs.*

The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the age of relevant capital assets.

RECOMMENDATION 8.2

Subject to compliance and other costs (recommendation 8.12), the Australian Energy Regulator should accompany aggregate analysis with detailed benchmarking of particular aspects of the performance of the businesses, including:

- the rate of investment relative to the age-weighted capital stock by asset class*
- the efficiency of major maintenance activities*
- the adoption rate of best-practice commercial processes and equipment, including the use of customer panels and surveys, outsourcing, demand management, information technologies, financial controls, procurement practices, occupational safety, and project management.*

In determining relevant benchmarking performance and control variables, the Australian Energy Regulator should consult with:

- network businesses, generators, retailers and network equipment suppliers*
- customer representatives*
- relevant experts within Australia and internationally.*

RECOMMENDATION 8.3

The Australian Energy Regulator should periodically assess the comparative performance of network business units within particular sub-regions of the National Electricity Market, where:

- those sub-regions share similar physical operating environments*
- the costs and informational requirements of doing this are not too great (recommendation 8.12).*

The comparisons should relate to units within a particular business, as well as comparable units in different businesses.

The Australian Energy Regulator should place most emphasis on comparisons of the efficiency of distribution networks in metropolitan areas.

RECOMMENDATION 8.4

When benchmarking is sufficiently reliable, the National Electricity Rules should be changed to allow the Australian Energy Regulator (AER) to have the discretion to initiate a three-way negotiation of a mutually acceptable settlement. This should involve itself, the network business and the representative and qualified customer body identified in recommendation 21.5:

-
- *Negotiation would only be triggered if the AER judged that the divergence between aggregate benchmarking estimates of forecast spending and the business's proposal were sufficiently narrow.*
 - *Where an agreement was successfully negotiated using this process, the AER should not be obliged to go through the current formal draft/final determination processes.*

RECOMMENDATION 8.5

In any of the next rounds of regulatory determinations, the Australian Energy Regulator should not use aggregate benchmarking as the exclusive basis for making a determination. Instead, it should use aggregate benchmarking as a diagnostic tool in responding to business cost forecasts.

RECOMMENDATION 8.6

The Australian Energy Regulator should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.

RECOMMENDATION 8.7

The Australian Energy Regulator should make all benchmarking input data publicly available (recognising that the businesses being benchmarked are regulated monopolies) except where the data can be demonstrated to be genuinely commercial-in-confidence.

Where the latter holds, the Australian Energy Regulator should still make the full datasets available to:

- *independent researchers who are using the results for non-commercial purposes*
- *the consumer body involved in any negotiations described under recommendation 8.4.*

Provision of data should be subject to statutory requirements for non-disclosure of information predetermined as commercial-in-confidence, drawing on existing models for data protection.

RECOMMENDATION 8.8

When making its revenue allowance determinations, the Australian Energy Regulator should make judgments about capital expenditure forecasts that take account of:

-
- *any discrepancy between the Australian Energy Market Operator's top-down demand forecasts and the aggregate of network businesses' bottom-up demand forecasts*
 - *any discrepancy between previous expenditure forecasts and actual outcomes by different parties.*

RECOMMENDATION 8.9

The Australian Energy Regulator should collaborate with other leading regulators, academic experts and global commercial benchmarking specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies. The collaboration should include cooperation in developing:

- *the most meaningful measures of performance*
- *consistent data collection*
- *consistent reporting of results*
- *best-practice analytic frameworks.*

RECOMMENDATION 8.10

The Australian Energy Regulator should submit its major benchmarking analyses of electricity networks for independent expert peer review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to gauge the degree of uncertainty in the results.

RECOMMENDATION 8.11

The benchmarking analysis produced by the Australian Energy Regulator should include:

- *accessible reporting of the results to inform consumer groups, network businesses, and others*
- *disclosure of the importance of factors outside the control of businesses, but that may be controllable by governments*
- *publication of the modelling strategy used to produce the results*
- *the sensitivity of the results to changes in key assumptions*
- *the performance of any statistical models against accepted scientific standards, including confidence intervals, parameter stability, and specification testing.*

RECOMMENDATION 8.12

The Australian Energy Regulator (AER) should periodically examine its benchmarking methodologies and processes — with input from an independent expert referee — to assess their usefulness in the determination process and the costs they impose on stakeholders. It should compare these costs with the likely benefits when determining the appropriate frequency and type of detailed benchmarking. In undertaking such assessments, the AER should consult closely with network businesses.

The AER should make all such assessments publicly available.

State-owned enterprises are part of the efficiency problem

RECOMMENDATION 7.1

State and territory governments should privatise their government-owned network businesses.

RECOMMENDATION 7.2

If state and territory governments do not implement recommendation 7.1, then they should promote more efficient outcomes for their government-owned network businesses by ensuring that:

- *directors are appointed on merit, following a transparent selection process*
- *ministerial directions are publicly disclosed at the time they are made and are also disclosed in the annual report*
- *directors and officers are subject to the obligations under the Corporations Act*
- *governments review objectives currently given to network businesses and:*
 - *remove those that would be more appropriately allocated to other agencies*
 - *remove those that are non-commercial and make it clear that the board is expected to deliver a dividend payout and rate of return on the equity invested in the network business that would be considered acceptable by a commercial investor*
 - *where conflicting objectives remain, provide publicly transparent guidance on how to prioritise them.*

RECOMMENDATION 7.3

In giving effect to recommendation 7.1, governments should:

- *be guided by the overarching objective of maximizing the net benefit to the community, with clear identification and prioritisation of any subsidiary goals*
- *undertake key regulatory reforms prior to sale*
- *avoid the transfer to the new owner of unjustified liabilities, obligations or restrictions that may inhibit the future efficiency of the business*
- *establish an expert unit within the relevant treasury to oversee the process, and develop clear milestones and a timetable*
- *undertake genuine consultation with the public and key affected groups, including likely beneficiaries, accompanied by effective communication of the benefits of privatisation*
- *ensure adequate accountability through independent auditing of the privatisation process.*

Reliability standards are mostly too high

RECOMMENDATION 14.1

Reliability standards throughout the National Electricity Market should be based on the value that customers place on network reliability.

RECOMMENDATION 14.2

The Australian Energy Market Operator (AEMO) should commission and pay the Australian Bureau of Statistics to undertake regular, detailed, disaggregated surveys based on best practice methodologies to reveal the value of reliability for different categories of customers, with the methodologies and results made public.

AEMO should commission suitably qualified experts to consider and measure the costs of interruptions not likely to be captured in the Australian Bureau of Statistics surveys. This should include the costs associated with citywide disruptions, including to telecommunications, water services and public transport, and the resulting loss of international reputation from lower reliability. AEMO should use these measures to supplement the results of the surveys.

RECOMMENDATION 15.1

All jurisdictions should adopt the Australian Energy Regulator's Service Target Performance Incentive Scheme as the basis for setting efficient reliability requirements for distribution businesses. The Scheme should replace all existing jurisdiction-specific distribution reliability requirements.

RECOMMENDATION 15.2

The Australian Energy Regulator should make the following amendments to the Service Target Performance Incentive Scheme:

- *reliability performance targets for the system average interruption duration index, system average interruption frequency index and momentary average interruption frequency index should be adjusted annually, according to a rolling five-year average of annual performance*
- *incentive payments for deviations from the reliability performance targets should reflect the preferences of customers by using the estimated values of customer reliability, as spelt out in recommendation 14.2, and should be specific to the distribution business*
- *revenue at risk should be negotiated as part of the Australian Energy Regulator's revenue determination process*
- *the reporting and information component of this scheme should require distribution businesses to report their reliability performance at the zone substation level. Worst performing feeders should be identified as part of this process*
- *reporting by all distribution businesses of performance against the parameters in the scheme should be published annually and be at least as detailed and comprehensive as current reporting mechanisms for distribution businesses in Victoria.*

RECOMMENDATION 16.1

The Standing Council on Energy and Resources should, in consultation with the Australian Energy Market Operator and the Australian Energy Market Commission, develop a National Electricity Market-wide transmission reliability framework in which reliability settings would be determined by customer preferences (recommendation 14.1).

This framework should replace all jurisdiction-specific transmission reliability settings.

A new approach to transmission reliability planning should be adopted. The Australian Energy Market Operator (AEMO) should carry out probabilistic cost–benefit transmission planning for all transmission networks in the National Electricity Market in order to set reliability standards and demand forecasts at each connection point. AEMO should:

- *use Values of Customer Reliability (as obtained through recommendation 14.2)*
- *use best practice probabilistic processes in its cost–benefit analysis of efficient standards*
- *make public all methodologies, parameters, data and other inputs used in the analysis*
- *work closely with each of the transmission companies concerned to make sure that their experience and input is fully understood and, where mutually agreed, appropriately incorporated into the analysis*
- *work closely with the relevant distribution companies in determining demand forecasts and cross checking the reliability settings for each connection point*
- *use its best estimate of peak demand forecasts, having sought input from all relevant stakeholders*
- *set standards reflecting the probabilistic analysis at the connection point level throughout the National Electricity Market.*

The regional transmission network service providers should plan necessary augmentation and replacement investments with reference to the reliability standards set by the Australian Energy Market Operator (AEMO) and the National Transmission Network Development Plan. This should have two components.

For augmentation and replacement projects below a threshold value:

- *the regional transmission network service provider should submit plans and seek funding for investments to meet reliability standards as part of the ex ante revenue determination process with the Australian Energy Regulator (AER), but could, ex post, decide to solve reliability problems in any way it decided was most efficient.*

For augmentation and replacement projects above a threshold value:

-
- *the regional transmission network service provider should submit details and seek funding of investments to meet reliability standards as part of the improved Regulatory Investment Test for Transmission process under which the AER would approve the allowable expenditure, having taken advice from AEMO.*

At the next regulatory reset, the actual capital spent on such projects should be included in the transmission business's Regulatory Asset Base, subject to any ex post review if expenditures exceeded the allowable revenues as set out in the approved Regulatory Investment Test for Transmission. If an ex post review identified instances of over-expenditure linked to inefficiently timed capacity increases, inclusion of the over-expenditure in the Regulatory Asset Base should be deferred until such time that the additional capacity would have been net beneficial. For cost overruns, only the efficient investment spend should be included in the Regulatory Asset Base.

RECOMMENDATION 16.4

The Australian Energy Regulator should ensure that, in the Australian Energy Market Operator's role as a transmission standard setter, its public reporting and planning processes are adequate, transparent and meet the National Electricity Objective.

RECOMMENDATION 16.5

The Australian Energy Market Operator (AEMO) should review and, where necessary improve, the technical aspects of its probabilistic processes, particularly those relating to low-probability, high-risk events. In undertaking the review, AEMO should closely consult with network businesses and seek independent peer review of its technical methods.

RECOMMENDATION 16.6

Where necessary, the Australian Energy Market Operator should assist the Australian Energy Regulator in its compliance and auditing of transmission networks, to ensure that the agreed projects are completed, appropriate maintenance and operational standards are being achieved, and intrinsic network reliability is maintained.

RECOMMENDATION 16.7

The Australian Energy Market Operator (AEMO) should act as the planner of last resort where it considers that underinvestment could expose the network to serious reliability problems, with the right to direct investment should AEMO believe that not to do so could seriously compromise the reliability of the National Electricity Market. The Australian Energy Regulator would act as an arbitrator in any disputes.

RECOMMENDATION 16.8

The Australian Energy Regulator should review the Service Target Performance Incentive Scheme for Transmission to ensure the incentives and targets are consistent with the recommended National Electricity Market-wide reliability framework.

RECOMMENDATION 16.9

Transmission businesses not already using dynamic capacity ratings on all critical equipment should transition to this approach.

RECOMMENDATION 16.10

The Australian Energy Market Operator (AEMO) should oversee the technical details of connection of new generators to the National Electricity Market to allow for contestability. AEMO should:

- on receipt of an application for connection from a generator determine, in consultation with the relevant transmission business, the details of the augmentation and upgrades to shared network infrastructure that would be required to implement the connection, as well as the detailed specifications that ensure that the safe operating state of the network is maintained. This would complement information provided by the transmission business. The transmission business would have the opportunity to review and provide commentary on AEMO's proposed specifications but AEMO would make the final decision on the required specifications*
- provide the specifications to enable the generator to seek tenders to build the connection assets.*

The Australian Energy Regulator should provide guidelines on the provision of information from transmission businesses to new connection applicants.

This framework should replace the existing arrangements in Victoria immediately and be implemented elsewhere in the National Electricity Market once Victorian arrangements are finalised and any regulatory barriers have been overcome.

RECOMMENDATION 17.1

The Regulatory Investment Test for Transmission process should be revised. The new test should continue to be performed by transmission businesses, but:

- be accompanied by parallel independent analysis from the Australian Energy Market Operator. This analysis should be published, and provided as advice to the Australian Energy Regulator (AER). The advice should have presumptive force in the AER's deliberations***
- be used by the AER as the basis for a revenue determination for the individual project in question, in a manner similar to the current 'contingent projects' process. The AER should assess and approve both the merit and process of the analysis.***

RECOMMENDATION 17.2

The revised Regulatory Investment Test for Transmission should apply to all large projects, subject to a uniform threshold value, whether augmentation, replacement or a combination of both.

RECOMMENDATION 17.3

The revised Regulatory Investment Test for Transmission, and the associated project-specific revenue determination, should be triggered when a project (or any of the considered options) exceeds a threshold value. In the first instance, this should be based on the current threshold for application of the full test (\$38 million), which should then be indexed over time to maintain its real value.

RECOMMENDATION 17.4

The Regulatory Investment Test for Transmission should be changed so that reliability is only assessed as a component of overall benefits and not as a separate criterion.

When a Regulatory Investment Test for Transmission is triggered for a major project, a full cost–benefit analysis involving a (public) probabilistic reliability assessment should be conducted.

RECOMMENDATION 17.5

The Regulatory Investment Test for Transmission should not be amended to include indirect effects of investment decisions.

Regulatory policy on interconnectors and transmission pricing should take a long-term view

FINDING 18.1

The available evidence suggests that, given the existing network conditions, the current physical capacity for interconnection is appropriate.

RECOMMENDATION 19.1

As an interim measure before the potential full introduction of the Australian Energy Market Commission's optional firm access package, a short-term congestion pricing mechanism as suggested by the Australian Energy Regulator should be introduced to the National Electricity Market.

RECOMMENDATION 19.2

Provided that cost-benefit analyses show net benefits (including incremental net benefits in moving from short-term congestion pricing), and once technical matters have been resolved, the Australian Energy Market Commission should commence implementation of the optional firm access package for generator access to the transmission network.

- *It should operate for a period of at least 10 years.*
- *The Australian Energy Market Operator (AEMO) should provide information to applicants for firm access and the Australian Energy Regulator relating to the (long-term) upgrades required, and benchmark indicators of their cost.*
- *Optional firm access should be monitored by AEMO for its effects on network planning and performance and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour. Monitoring results should be made public annually.*

RECOMMENDATION 19.3

After the optional firm access package has been operational for 10 years, a review should be conducted to consider whether the introduction of nodal pricing is warranted on cost-benefit grounds, or if other reforms (such as alterations to the optional firm access model) offer greater benefits. The review should have particular regard to the structure of the National Electricity Market at the time, the views of consumers and other stakeholders, and any remaining barriers to the introduction of nodal pricing.

1 About the inquiry

1.1 What are the perceived problems?

This inquiry relates to electricity network services in the National Electricity Market (NEM), which covers all jurisdictions excepting Western Australia and the Northern Territory. The network comprises the wires, poles, easements, substations and other infrastructure used to transport power from generators to customers — with around 800 000 kilometres of lines extending from Tasmania to Queensland. Network charges account for around 40-50 per cent of an average household's electricity bill.

Network services are 'natural' monopolies — often still state-owned — with little scope in any given location for a competitor to duplicate the network efficiently. Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, government must regulate the prices and other aspects of these services to ensure reliable and affordable electricity. In contrast, Australian governments have opened the generation and retailing segments of the electricity sector to greater competition. While not yet fully realised, the need for regulation in these segments has diminished.

However, regulation of natural monopolies is not straightforward. Recent large increases in electricity prices — much of them attributable to growing network costs — have sounded alarms about the effectiveness of current regulatory arrangements. Nationwide, retail electricity prices rose by around 70 per cent in real terms from June 2007 to December 2012 (chapter 2). Moreover, a Productivity Commission staff working paper separate to this inquiry (Topp and Kulys 2012) found significant reductions in measured productivity in the Australian electricity sector over the past decade, which may have contributed to these price pressures (discussed in chapter 2).

Against that background, the overarching questions underlying this inquiry are 'why have network costs been rising, will they continue to do so, are increases justified, and if not, how can the underlying problems be fixed?'

Price pressures are posed by regulatory flaws and business inefficiency, but also legitimate investment costs

Regulatory arrangements for electricity transmission and distribution changed significantly in 2006 and 2008 respectively. As the intent of these changes was ‘to improve the environment for investment’ (AEMC 2006a, p. iv; AER 2011a, pp. 3-4), some price increases would be expected. A reduction in productivity would also be anticipated because businesses must invest ahead of the full utilisation of capital.

Nevertheless, some key stakeholders claimed that the regulations had substantial flaws and had inefficiently raised prices. These stakeholders included the Australian Energy Regulator (the AER — which has responsibility for regulating the NEM), various electricity user groups, and the Garnaut review of climate change policy. They attributed much of the price increase (and to some extent, the reductions in productivity) to two interrelated flaws in the post-2008 regulatory arrangements for electricity networks. They argued that:

- the design of regulatory incentives encouraged excessive investment (‘gold plating’) in networks. Gold-plated investments increase the capital stock without a commensurate increase in output (although they may do so at a future date). Excessive investment leads to price increases and wastage of resources best used elsewhere in the Australian economy
- the regulated return to capital was excessive, directly leading to higher prices (as well as encouraging too much investment).

In that context, the AER said that some price rises it had allowed were ‘difficult to justify’, and arose from deficiencies in chapter 6 of the National Electricity Rules (the ‘Rules’) that it was obliged to enforce (AER 2011b, p. 4). The New South Wales Independent Pricing and Regulatory Tribunal (IPART 2012a, p. 4) has echoed this sentiment. Indeed, a body representing large commercial users of power, Major Energy Users, suggested that the relevant regulations had ‘more than reversed the benefit gained from energy reforms initiated since the mid-1990s’ (MEU 2011a, p. 3). In May 2012, the Queensland Government created an Independent Review Panel to oversee reform of power delivery in that state, with the rationale for the review being the ‘blow out ... in network costs, relative to service provision’ (McArdle 2012, p. 1), though it did not attribute the alleged blow out to any particular source.

In this context, in 2011, the AER and others sought new regulatory approaches that they considered would better align investment and pricing with that which an efficient market would deliver. In response to those requests, in late 2012, the

Australian Energy Market Commission (AEMC —the policymaker) introduced Rule changes that gave the regulator more discretion in its regulatory decisions (AEMC 2012r). The AER will develop guidelines about how it will exercise this greater level of discretion (AER 2012q, p. 13). One of the goals of this inquiry is to inform those guidelines, and to indicate how benchmarking could assist the AER in its decisions under the new regulatory regime.

Not surprisingly, network businesses have disputed that prices and costs have been too high. They have argued that the price increases only reflect the efficient response to the investments needed to meet:

- the long-term growth in connections
- the rising trends in ratio of peak to average demand ratios
- governments' requirements for higher reliability
- the need to replace a stock of capital that is reaching the end of its economic life
- the greater obligations to place lines underground
- demand from the increasing levels of distributed wind and solar power generators.

Of course, legitimate cost pressures and inefficiencies could both be at work — an important issue for this inquiry. For example, an investment might be built to address peak demand, but be built in advance of its real need due to regulatory flaws. Similarly, regulated reliability standards may exceed their efficient levels, raising costs without commensurate benefits. These two issues are critical to this inquiry.

Interconnectors or how the 'N' got into the 'NEM'

In addition to the above cost pressures, some claim there are shortcomings in the regulatory arrangements for the transmission lines ('interconnectors') that allow trade in power between eastern Australian states. Trading in power between regions has implications for electricity pricing; the required network infrastructure; system security and reliability; the need for generator capacity to meet end users' needs; and access by the broader network to new renewable power sources.

In his update on climate change, Professor Garnaut claimed that there was inadequate investment in interconnectors — a result he ascribed to fragmented and parochial transmission planning, market design flaws and other regulatory failures (Garnaut 2011a, pp. 153-55). While not widely regarded as a major contributor to recent price increases, there is concern that any such inter-regional barriers to trade

have (and will increasingly) lead to inefficiency in the electricity industry. Underinvestment in interconnectors could put more pressure on prices and undermine the efficient use of renewable energy generators, which are suited more to some regions than others.

Considering the issues through two lenses

The Australian Government has requested that the Commission consider the above issues through two lenses:

- the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure
- the effectiveness of regulatory arrangements for interconnectors.

An important starting point is defining the nature of the market and its principal institutions.

1.2 Overview of the regulatory framework and its institutions

The NEM enables the trading of electricity throughout Australia, excepting Western Australia and the Northern Territory.¹ It has several common institutions (figure 1.1). The overarching legal framework is the National Electricity Law (NEL), which is ‘template’ law enacted by South Australian law and adopted in all participating jurisdictions. Among other things, the NEL specifies the National Electricity Objective:

The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability and security of supply of electricity and (b) the reliability, safety and security of the national electricity system. (*National Electricity (South Australia) Act 1996* (SA), s. 7)

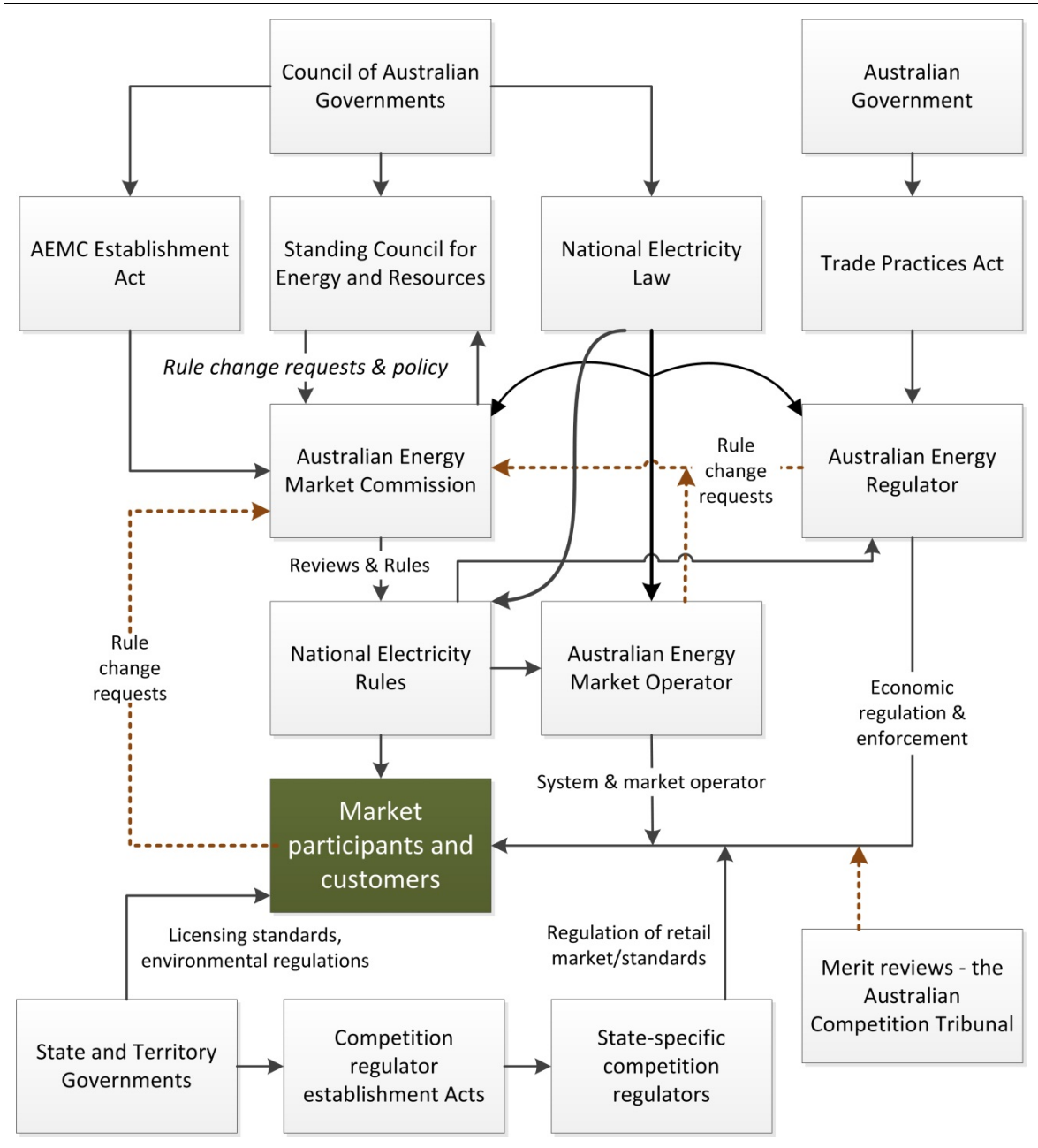
The institutions responsible for electricity policy and regulation also perform these roles for natural gas.

The responsibility for energy policy rests with the Standing Council on Energy and Resources (SCER), a recently formed Council of Australian Governments (COAG)

¹ The origin of the national grid was a 1991 decision by a Special Premier’s Conference in July 1991, and a subsequent decision by COAG in 1993 to endorse the creation of an interstate electricity transmission network (Smith 1997, pp. 6-7).

standing council, which has assumed the functions of the Ministerial Council on Energy (MCE).²

Figure 1.1 Institutional arrangements in the National Electricity Market



The responsibility for making Rule changes rests with the AEMC, an independent national body funded by all state and territory governments (and employing around

² However, the National Electricity Law still specifies the MCE as the responsible COAG policymaker.

60 people).³ The AEMC makes rules that meet the objectives and other aspects of the NEL for the NEM (and gas for Australia as a whole), and undertakes market reviews and provides advice to SCER. The AEMC has a strictly limited independent capacity to initiate Rule changes, and responds to requests by other parties, such as the ministerial council, the regulator, market participants, and end-users.

The regulator, the AER, is an independent Australian Government statutory authority with its own expertise-based board, although it is located within the Australian Competition and Consumer Commission (ACCC).⁴ It employs around 130 people of whom around 60 concentrate on electricity network issues. The AER regulates network providers, subject to the NEL and the detailed requirements of the Rules. Its main role is the determination of network revenue allowances (which are realised through price limits or revenue caps), although it also ensures business compliance with regulations, and collects information on the energy market. It would be the main body responsible for benchmarking of network efficiency.

The Australian Competition Tribunal is responsible for adjudicating on merits appeals of the AER's determinations.

The Australian Energy Market Operator (AEMO) is also an important part of the institutional arrangements for electricity (and natural gas).⁵ It employs around 500 people. It is structured as a corporation with an expertise-based board comprising government and private members. Its electricity responsibilities include managing the electricity market and playing a coordinating role in ensuring system security when demand exceeds supply. It takes bids and determines spot prices for generators, and ensures demand and supply are matched. AEMO also provides long-term planning reports and regional demand forecasts, and directly manages the planning of the Victorian electricity transmission system to ensure existing and expected demands are met. In other jurisdictions, the state government or the transmission service provider undertakes these functions.

³ The AEMC was established under a South Australian Act, the *Australian Energy Market Commission Establishment Act 2004*. The Consumer Advocacy Panel was also established under this Act.

⁴ The AER was established under Part IIIA of the *Competition and Consumer Act 2010* (Cwlth).

⁵ The National Electricity Law prescribes AEMO's functions, while the Rules prescribes the procedures and processes for market operations, power system security, network connection and access, pricing for network services in the NEM and national transmission planning. AEMO is fully funded by market participants. Ownership of AEMO is divided between government members (60 per cent of the votes) and industry members (40 per cent of the votes).

State and territory governments and their regulators play a major role in regulating reliability standards and retailing in the NEM. State and territory governments also have various renewable energy policies that affect network businesses' options for addressing emerging bottlenecks in their systems. They are the owners of network services in Queensland, New South Wales, Tasmania and, in part, the ACT. Some also own generators.

The existing regulatory arrangements for the NEM are detailed, prescriptive and frequently amended (with the Rules being around 1500 pages in length). The Rules consolidated and amended regulatory arrangements that previously operated at the state and territory level. Nevertheless, the 'N' in the NEM is a work in progress.

There is no uniform regulation of network services in the NEM, with major variations in the treatment of:

- the intra-regional transmission network, which comprises the high voltage components of the network that carry power over long distances within states
- the inter-regional high-voltage transmission network ('interconnectors') used to transport power between states
- the distribution network, the lower voltage capillaries that deliver power at the local level (The distribution network accounts for the bulk of the infrastructure and costs. The distinction between lines and assets characterised as belonging to the distribution and transmission network varies between jurisdictions)
- the electricity retail markets in each jurisdiction, which has implications for the extent to which consumers face the real costs of supplying power.

1.3 The Commission's approach to its terms of reference

The Commission's approach to this inquiry takes into account the specific issues raised in the terms of reference, and ultimately is underpinned by the general policy guidelines in the *Productivity Commission Act 1998*. Among other things, section 8 of the Commission's Act directs it to:

- (a) improve the overall economic performance of the economy through higher productivity in the public and private sectors in order to achieve higher living standards for all members of the Australian community
- (b) reduce regulation of industry where this is consistent with the social and economic goals of the Commonwealth Government

-
- (c) encourage the development and growth of Australian industries that are efficient in their use of resources, enterprising, innovative and internationally competitive.

In pursuing these objectives, the Commission is required to recognise the interests of the community generally, as well as those (such as consumers or industries) likely to be affected by its proposals. The Commission may make recommendations on any matters relevant to the inquiry.

The Commission is aware that the regulatory environment is evolving, and that the complex inter-relationships between changes in one aspect of the regulatory environment can have significant impacts elsewhere. There are numerous ongoing or recently completed reviews by the AEMC, the AER and others focusing on specific regulatory aspects of the NEM (tables 1.1 and 1.2). Given this, the Australian Government asked the Commission to take account of work being undertaken by SCER, the AEMC and the AER. In particular, the Government emphasised the relevance of the:

- AEMC’s review of transmission frameworks (AEMC 2011f, 2012j, 2012n)
- major Rule change proposals, of which the most important — the AER’s 2011 proposal for regulatory reform — was completed by the AEMC in late 2012 (AEMC 2012r)
- the review of demand side participation — the *Power of Choice* (AEMC 2012u).

Reflecting these regulatory developments, the Commission had ongoing discussions with the AEMC, the AER and AEMO throughout the inquiry. The Commission has also taken into account the policy announcements made by COAG, SCER and the Business Advisory Forum Taskforce in late 2012 about key aspects of the regulatory environment (SCER 2012a,b; COAG 2012; BAFT 2012).

Given this, and the Commission’s statutory obligation to consider the long-run benefits to the community as a whole, the Commission has taken a broad approach to its terms of reference. The Commission released an issues paper in February outlining this wide-ranging approach. Some participants’ submissions addressed the broad set of matters raised in the paper,⁶ while others considered that a narrower approach on benchmarking methods was preferable, and provided useful inputs mainly confined to this area.

⁶ For example, the Major Energy Users (sub. 11); the Consumer Action Law Centre (sub. 5); AEMO (sub. 32); and the Energy Supply Association of Australia (sub. 23).

Table 1.1 AEMC reviews and Rule changes

<i>Review/Rule change report</i>	<i>Scope</i>	<i>Key dates</i>
Economic Regulation of Network Service Providers	Assessment of rule changes relating to the AER's approval of future expenditure and the regulated rate of return on capital	Consultation papers 20 October 2011 and November 2011, directions paper March 2012, draft determination August 2012, final report December 2012
Power of Choice	Demand side participation (or management), including the role of new technologies, such as smart grids, energy efficiency initiatives, and the efficiency of price signals in the NEM	Directions paper March 2012, draft report September 2012, final report 30 November 2012
Review of Distribution Reliability Outcomes and Standards (NSW)	Examines the extent to which investment in distribution networks reflect consumers' willingness to pay for reliability	Issues paper November 2011, best practices paper January 2012, draft report June 2012, final report August 2012
Review of Distribution Reliability Outcomes and Standards (National)	Analyse the different approaches to setting distribution reliability outcomes across the NEM and consider scope for national regime	Issues paper June 2012, draft report November 2012. Final report now subsumed into broader review also covering transmission
Transmission Frameworks Review	Proposals to reform the role and provision of transmission networks, including charging for the use of the transmission system, generator access rights, and planning	First interim report November 2011, second interim report August 2012, final report March 2013
Review of National Frameworks for Transmission and Distribution Reliability	New approaches for the regulation of electricity distribution and transmission reliability across the National Electricity Market	Final reports are due September 2013 for distribution and November 2013 for transmission
Distribution Planning and Expansion Framework	Consultation on a rule change about annual planning and reporting of investments, demand-side engagement strategy, and a Regulatory Investment Test for Distribution	Consultation paper September 2011, draft determination in June 2012, final report October 2012
Differences between actual and forecast demand in network regulatory determinations	Advice to SCER on the implications of such differences for incentive regulation, particularly focusing on how the AER should factor such gaps into successive determinations, and whether changes should occur to the NER	31 March 2013
Inter-regional Transmission Charging	Consideration of inter-regional transmission charging	Discussion paper August 2011, final rule determination early 2013

Table 1.2 Other reviews and major papers

<i>Review</i>	<i>Scope</i>	<i>Key dates</i>
Limited merits review arrangements	Review of statutory merits appeal processes (requested by SCER)	Stage 1 report June 2012, Stage 2 report October 2012. Any legislative change by end 2013
Energy White Paper (Australian Government)	Policy framework to address challenges in the energy sector	December 2012 (final)
AER review of information collection processes	Aims to provide appropriate inputs into analytical tools	Implementation by June 2013
Senate Select Committee on Electricity Prices	Examines reasons for rising prices and appropriate policy responses	November 2012
Queensland Independent Review Panel on Network Costs	Government-commissioned review of the source of network cost rises and possible policy responses	Interim report November 2012 Final early 2013.
Proposal for a National Energy Consumer Advocacy Body	Developing a proposal for consideration by SCER on the design of a consumer advocacy body	Final report 30 April 2013
Independent review of the Australian Energy Regulator	Australian Government commissioned review of the AER and its operational requirements	Review commences July 2014
Better Regulation reform program	AER will develop guidelines — with consultation — that will implement the new Rules relating to network regulation	November 2013

The Commission continues to believe that it can only discharge its responsibilities appropriately in this inquiry by taking a broad and holistic approach, while drawing on the other reviews taking place. The panel appraising the limited merits review regime similarly recognised the need to comment on the regulatory regime as a whole when considering any part of it:

... the Panel is minded not to refrain from commenting on how different pieces of the policy jigsaw, of which development of the LMR [limited merits review] regime is just one, might fit together. (Yarrow et al. 2012a, p. 12)

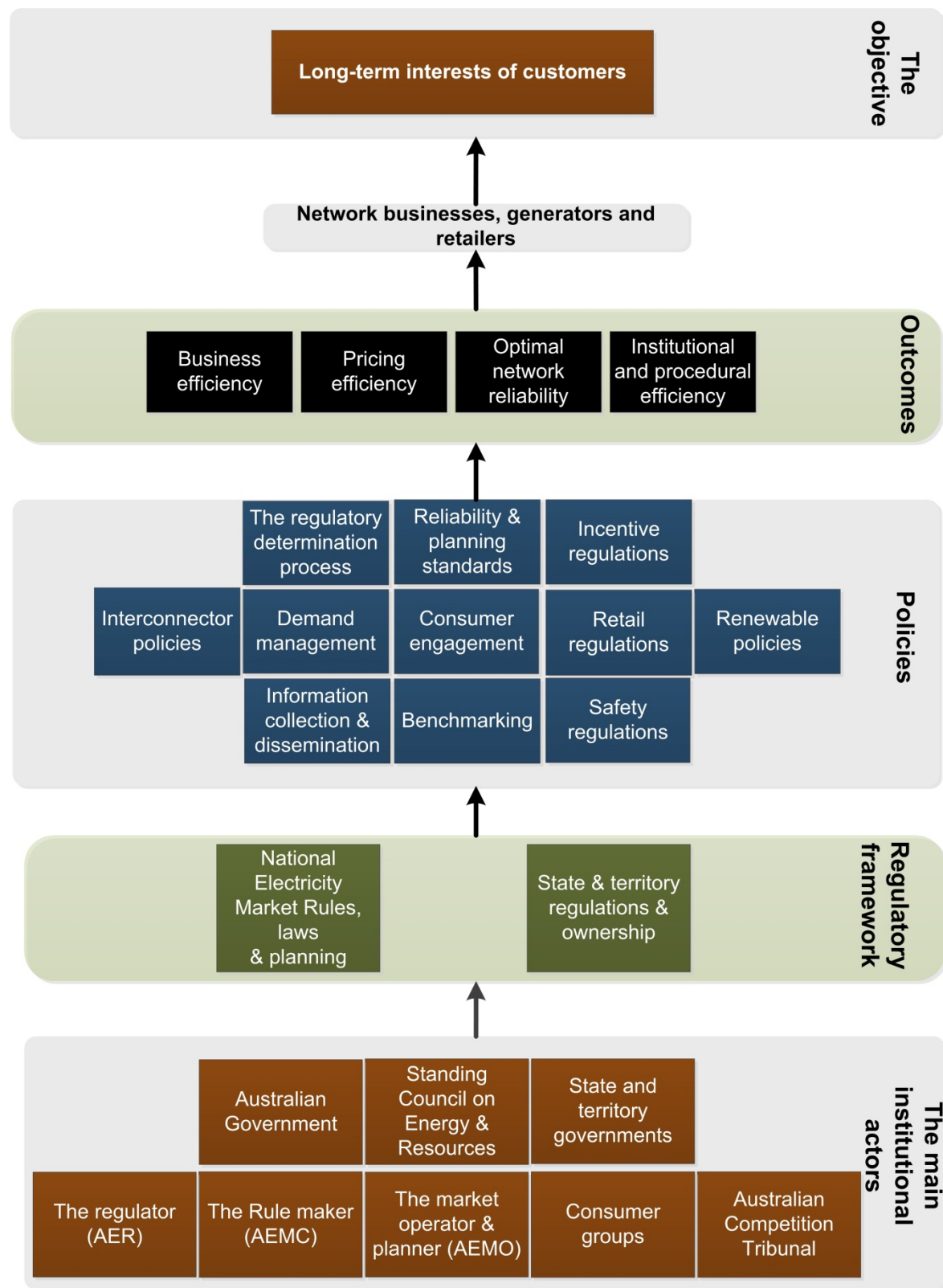
Given this policy jigsaw, this inquiry:

- *considers the overall efficiency of electricity networks and the resulting impacts on costs for consumers — in keeping with the National Electricity Objective of meeting the long-term interests of consumers.* Benchmarking is a generic tool to measure inefficiency and to promote efficient conduct generally. So while one use of it is to set ‘efficient’ business prices in a regulatory determination, another common application is to assess efficient regulatory options — ‘regulatory benchmarking’. Accordingly, the Commission has identified regulations outside the control of businesses that undermine efficiency and increase costs (and that

may act as a greater drag on efficiency than managerial inefficiency). Where possible, the Commission has identified and quantified the things that matter to efficiency — the hallmark of benchmarking

- *takes account of the interdependencies between the regulatory, institutional, business governance and planning features of the NEM* (figure 1.2). These are pivotal to good overall outcomes for the community. There are significant dangers in bolting-on ‘solutions’ based on benchmarking and changes in interconnector policies if the surrounding regulatory edifice is rotten. For example, prescriptive reliability standards set at the state level may reduce businesses’ capacity for efficient cost minimisation, while the current appeals process may undermine the usefulness of certain types of benchmarking analysis. Regulations that presume that network businesses will be motivated by profits, may not work effectively where government ownership removes or weakens such motivations. An interconnector is a transmission line (or group of lines), privileged with a special name because it connects into a more meshed network either side of a state border. An interconnector has a similar effect to the entry of new generators to the connected regions. Optimal interconnector policies depend on the planning framework for transmission generally, its pricing and the degree to which policies can limit game playing by some generators. Accordingly, any assessment of regulatory arrangements for interconnectors necessarily overlaps with the regulatory issues for intra-regional transmission and, to some extent, the conduct of generators
- *analyses the best institutional framework for achieving efficient outcomes.* Regulatory reform involves much more than writing new laws and regulations, but requires facilitating institutions and processes. For instance, to meet its objectives effectively, a regulator must have independence (financial, cultural, legislated and perceived), expertise and adequate resources, and use the right processes. The more power and discretion given to any agency in using benchmarking to set prices, the more important it is that the institutional and governance arrangements are sound. Similarly, a sound appeals process is required, on the one hand, to prevent gaming by businesses and, on the other, to minimise regulatory errors
- *considers the future* — including potential imminent Rule changes, changing technologies and carbon pricing — when making judgments about regulatory arrangements. However, the Commission is also aware that the current arrangements are relatively new. Any radical reforms should be considered carefully given the uncertainties and risks that these entail.

Figure 1.2 Everything in electricity policy is interconnected



Consultations

Beyond the Commission's consultations with the AER, the AEMC and AEMO, the Commission also consulted with state and territory governments and their competition regulators, various Australian Government agencies, transmission and distribution businesses, generators, consumer stakeholders, and other interested parties in undertaking the review. The Commission also considered international regulatory experiences in achieving efficient investment and pricing in networks and interconnectors, and held discussions with overseas experts and regulators in the United Kingdom and the United States.

To encourage and guide submissions, the Commission released an issues paper on 23 February 2012 outlining the key matters on which it was seeking comments and information from participants. A draft report was released in October 2012. The Commission held public hearings into the draft report in November and December 2012 in Canberra, Melbourne and Sydney. Transcripts of these hearings are available on the Commission's web page. The Commission held two roundtables (network transmission planning and reliability; and demand management) in November 2012. The Commission received 44 submissions prior to publication of the draft report and a further 65 submissions prior to completion of the final report. The Commission thanks all those who have contributed to this inquiry.

1.4 A guide to the report

Introductory material

Electricity networks are one of Australia's most important, costly and extensive forms of infrastructure. The desirability, feasibility and design of any new policies for benchmarking and interconnectors is dependent on the nature of electricity networks and their associated regulatory arrangements. Chapter 2 sets out the characteristics of electricity networks, the broad nature of the existing regulatory arrangements across the NEM, and describes the industry's aggregate performance under current regulatory arrangements.

While most argue that there are strong grounds for regulation of an essential service with natural monopoly characteristics, it is important to understand how and why likely problems will be manifested, since that affects the design of the regulatory remedies. This also helps identify the appropriate objectives of, and limits to, regulation — including the role of benchmarking in regulatory determinations.

Recently, this has been an area of some controversy. Chapter 3 addresses these issues.

Using benchmarking to set regulated prices and revenues

Benchmarking comprises a set of tools for measuring business efficiency and performance against some best practice benchmark, and for creating incentives (financial or political) for managerial efficiency and for best practice regulations. Chapter 4 describes benchmarking and its methodologies, strengths and limitations.

Some envisage that benchmarking could play a larger role in the regulatory regime. However, the benefits of an expanded role depend on whether the design of the regulatory regime frustrates its effective use. A benchmark, no matter how accurate, is of little value if the regulator is unable to use it or if it does not influence the behaviour of the regulated firm. Chapter 5 examines these issues, taking into account recent Rule changes giving the AER greater regulatory discretion. Among other matters, the chapter considers the investment biases in the weighted average cost of capital and how these might be remedied, the impacts of competitive neutrality on state-owned corporations, and how the regulator should consider regulatory errors in making its decisions.

It is useful to consider whether there is a *prima facie* case that significant inefficiency exists among network businesses. That would strengthen the case for further benchmarking — and for it to play a greater role in future regulation. Chapter 6 considers existing studies of network efficiency and undertakes some preliminary analysis of the performance of network businesses (an exercise that also sheds light on the practicality of undertaking benchmarking). Due to limitations in the data and the problems of undertaking precise benchmarking, the results are necessarily not authoritative. The Commission has used several data sources and information to make its judgments in this area.

State-owned corporations remain the most common suppliers of network services. These businesses face particular challenges. It is important to assess the degree to which ownership makes a difference to productivity performance and the extent to which such businesses respond to incentive regulations. Chapter 7 considers this question, drawing on chapters 5 and 6, as well as other evidence. It also discusses the appropriate pathway to privatisation of state-owned electricity network businesses.

In light of the findings of chapter 4 to 7, chapter 8 examines how the regulator might use benchmarking in regulatory determinations.

External factors constraining business efficiency — regulatory benchmarking

As emphasised earlier, many sources of inefficiency in networks may be outside the control of the businesses themselves. For example, network businesses do not set reliability standards, feed-in tariff rates, demand management incentive schemes, or retail price regulations. Weighing up existing regulatory and policy measures against best practice — regulatory benchmarking — can reveal the degree, if not the precise magnitude, of the costs associated with policy-induced inefficiencies, and also the direction for reform. Any benchmarking of managerial inefficiency aimed at assisting the regulator to determine prices and revenues must also attempt to control for the impacts of factors that a business must take as given. Accordingly, the Commission has considered the degree to which:

- demand management can improve the efficient investment in, and operating costs of, networks. Chapter 9 examines the problems posed by prices that do not fully reflect the costs of infrastructure (especially during critical peak demand periods), and benchmarks the potential cost savings from improved policy. However, the size and timing of these potential savings depend on a suite of coordinated reforms and sensible processes. The critical requirements are:
 - technological change (such as smart metering) that underpin the capacity for network businesses to set time-based charges for their services, and that allow retailers to develop new services and create pricing packages that reflect the charges passed onto them from the network businesses (chapter 10)
 - the long-run adoption of cost-reflective pricing of network services, but accompanied by processes that ensure proper consultation with all stakeholders, that drive a coherent transition to that long run, and that address concerns about the effects of change on vulnerable consumers (chapter 11)
 - changing how the regulator constrains prices or revenues over the regulatory period (the so-called ‘control mechanism’), ensuring that incentives for distribution businesses to undertake demand management take into account the flow-on benefits throughout the supply chain that they cannot capture, and implementing policies that motivate retailers to develop products and tariffs that allow improved demand management (chapter 12)
- distributed (small-scale) generation can avoid or defer network investment by helping to relieve network congestion, meet peak demand or improve system reliability (similar to the goals of demand management). However, the appropriate role of distributed generation depends on whether there are any regulatory obstacles to its use, the extent to which it has adverse effects on the network (which has largely been designed for one-way flows of power), and

whether there are subsidies or other measures that distort people's choices in this area (chapter 13)

- reliability standards affect the costs and efficiency of electricity network businesses. Chapter 14 provides a framework for assessing reliability issues and diagnoses the problems of the current arrangements. While there are some overlapping factors, reliability issues vary considerably between distribution networks (chapter 15) and transmission (chapter 16), and so too do the optimal policy approaches. The Regulatory Investment Test for Transmission (RIT-T) potentially could play an important role in ensuring that efficient transmission investments are made, but the existing arrangements lack any teeth (effectively the RIT-T is neither 'regulatory' in nature, nor a 'test'). Chapter 17 addresses this issue.

Interconnectors

Chapter 18 considers the role of interconnectors in the NEM, the framework for assessing any problems, and the magnitude and implications of any current inefficiency. Chapter 19 examines the efficient utilisation of interconnectors, including the potential long-run adoption of more fundamental pricing reforms.

Most interconnectors are 'regulated', which means that the AER sets the maximum revenue they receive over a given regulatory period. However, at the commencement of the NEM, it was envisaged that unregulated private interconnectors (often called 'merchant' interconnectors) would play a more significant role. An important question is whether the virtual absence of merchant interconnectors reflects aspects of the regulatory arrangements, and whether they could or should play a role in linking the regions (chapter 20).

Governance and institutions

Policy and practice sits within an institutional framework. Chapter 21 assesses the best institutional structures for progressing reform, including the potential to empower consumers; the need to ensure the regulator is funded adequately and has sufficient access to expertise; and the role of SCER. (Other institutional arrangements — such as those relating to the role of AEMO in planning and demand forecasting — are largely covered in previous chapters.) Implementation issues are discussed in the relevant chapters and summarised in the overview to this report.

Appendix A describes the conduct of the inquiry and participation by various stakeholders. The report is accompanied by several other appendices that address particular issues raised in lesser detail in chapters, and by a technical supplement on the costs and benefits of demand management (with an associated spreadsheet). These are on the Commission's inquiry web page.

2 The structure and performance of the National Electricity Market

Key points

- The NEM comprises six groups of direct participants: generators, ancillary services, transmission and distribution networks, retailers and customers.
- The structure of the electricity supply industry has shifted over time, with vertical separation of generation and retailing from the natural monopoly elements of the industry, and horizontal integration of network businesses. However, increasingly generators and retailers have integrated to form 'gentailers'.
- Collectively, state governments are still significant asset holders — owning all transmission and distribution assets in Queensland, New South Wales and Tasmania.
- Network services are the most costly single component of electricity supply, accounting for around 45 per cent of total electricity prices.
- From June 2007 to December 2012, real Australian retail electricity prices rose by around 70 per cent, with network costs playing an important role in the last few years, particularly for New South Wales. The initial part of this price surge occurred under state based regulatory regimes.
- Any price increases in network services have particularly large relative effects on poorer households, one of the motivations for concerns about price pressures.
- Residential network charges are diverging between jurisdictions. Network charges in New South Wales, Queensland and South Australia are projected to be around double those in Victoria in 2013–14.
- Power consumption per customer fell by around 2.5 per cent in both 2010–11 and 2009–10. Peak demand to average demand has generally been rising over time.
- New patterns of network development may occur as generation shifts away from conventional energy sources, with cost and planning challenges.
- While rising network price pressures partly reflect peak demand trends, more undergrounding of lines, higher reliability requirements and the need for asset replacement, this does not mean that there is no scope for efficiency improvement.
- Even modest improvements in network business efficiency could produce billions of dollars of economic benefits to Australians.
- Network services are a ubiquitous input for all industries, accounting for around 1–1.5 per cent of the value of inputs for most industries. Given this dispersion of interests, it would be hard for a representative user group to form spontaneously and to negotiate from a position of power with network businesses.

This chapter provides a brief overview of the National Electricity Market (NEM) as a whole, covering the:

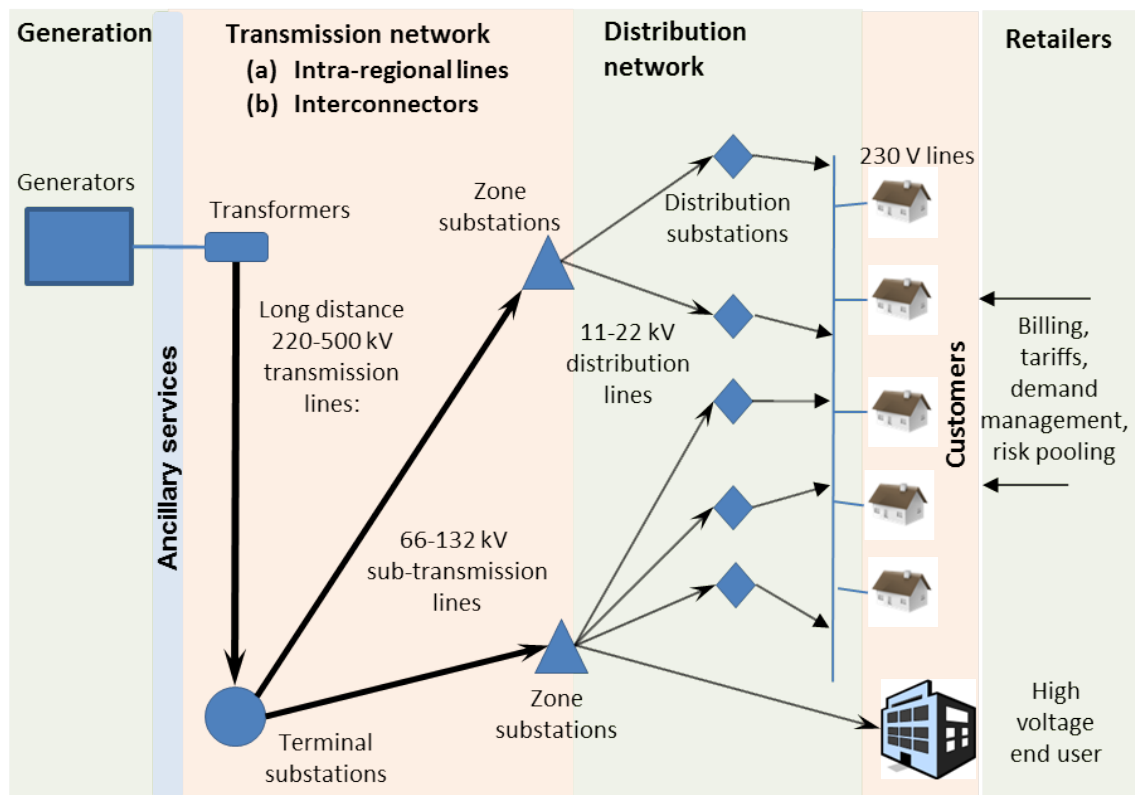
- structure of the NEM, including brief coverage of some recent developments in generation and retailing that are relevant to networks (section 2.1)
- scale of the network and its costs — the significance of which explains why cost pressures in this part of the electricity industry have large impacts on the prices customers face (section 2.2)
- characteristics of demand (section 2.3). This is important from many perspectives. It affects the capacity for consumers to exercise countervailing power and partially motivates new approaches to involve customers in the regulatory process (an issue explored in chapter 21). It shows why benefits from any lower network costs cascade across the entire community. And, given its nature as an ‘essential’ service, any cost pressures on network services have particularly adverse effects on low-income households under current pricing structures, underlining why network cost increases are so sensitive for the community
- recent price changes (section 2.4) and their proximate causes (section 2.5)
- basic reliability performance of the network (section 2.6), since customers value uninterrupted power and good frequency control. (In their own right, some governments’ requirements for improved reliability have also been a significant source of cost pressures)
- potential economic gains from improving the performance of the network — which motivates the value of the policy reforms outlined in subsequent chapters (section 2.7).

This chapter does not provide a detailed description of the regulatory environment governing networks, since this is addressed in a focused way in the policy chapters that follow.

2.1 The structure of the National Electricity Market

The NEM is a highly elaborate system for managing the production and transport of power throughout eastern Australia. On the supply side, there are four principal parts of the system: generation, network transmission and distribution services, and retail services (figure 2.1).

Figure 2.1 The structure of the National Electricity Market



Data source: Based principally on Powercor (2006).

The network

The electricity network (the focus of this inquiry) is a massive transportation system that takes the power from generators and delivers it to an end user's electricity switchboard. It comprises several parts:

- transformers, which take the power from the generators and convert it to high voltage (which lowers transmission losses when power is transported over any significant distance)
- high-voltage transmission lines — mainly strung overhead on steel lattice towers — that transport power over long distances. These include intra-regional lines and inter-regional lines (interconnectors)
- substations that convert very high voltage to lower voltage
- the myriad of lower-voltage substations, poles, trenches and wires that make up the distribution system — the 'capillaries' of the system — which distribute lower voltage power to multiple users in local areas
- the provision and maintenance of certain services, such as street lighting

-
- meters at the business or household that record electricity consumption and, in some cases, provide real time control of the delivery of power to customers, and provide information on time-of-use prices to customers and usage patterns to suppliers. While distributors are mainly responsible for metering equipment and associated services, there is some competition from other businesses (Metropolis 2012).

Although the information technology systems to control the network are sophisticated (such as those deployed by the Australian Energy Market Operator (AEMO) and network businesses), much of the *cost* of the electricity network involves relatively mature technologies, such as trenches, poles and wires (a feature it shares with telecommunications). The research and development undertaken by electricity networks across Australia was estimated to be less than 1 per cent of value added or \$50 million in 2008-09 (just a little more than in the log sawmilling and timber dressing industry) (ABS 2011a).

Regulatory arrangements for networks

The regulatory arrangements for networks are highly complex. (The Australian Energy Regulator (AER) provides an accessible summary for readers of the key aspects of the regulatory framework.)¹ The National Electricity Law and the Rules set out the NEM-wide arrangements for the economic regulation of networks. Reliability standards and planning are largely decentralised — and are overseen by the network businesses, state and territory regulators and their governments. The relevant aspects of these arrangements, (including around 200 pages of the Rules that are most important for this inquiry), are discussed in the chapters that follow and are, accordingly, not duplicated in this chapter. However, most of the roughly 1500 pages of the Rules have little bearing on this inquiry, as they cover market dispatch and financial settlement procedures, prudential requirements for market participants, administrative functions, power system security, connection arrangements, and system standards, among other matters.

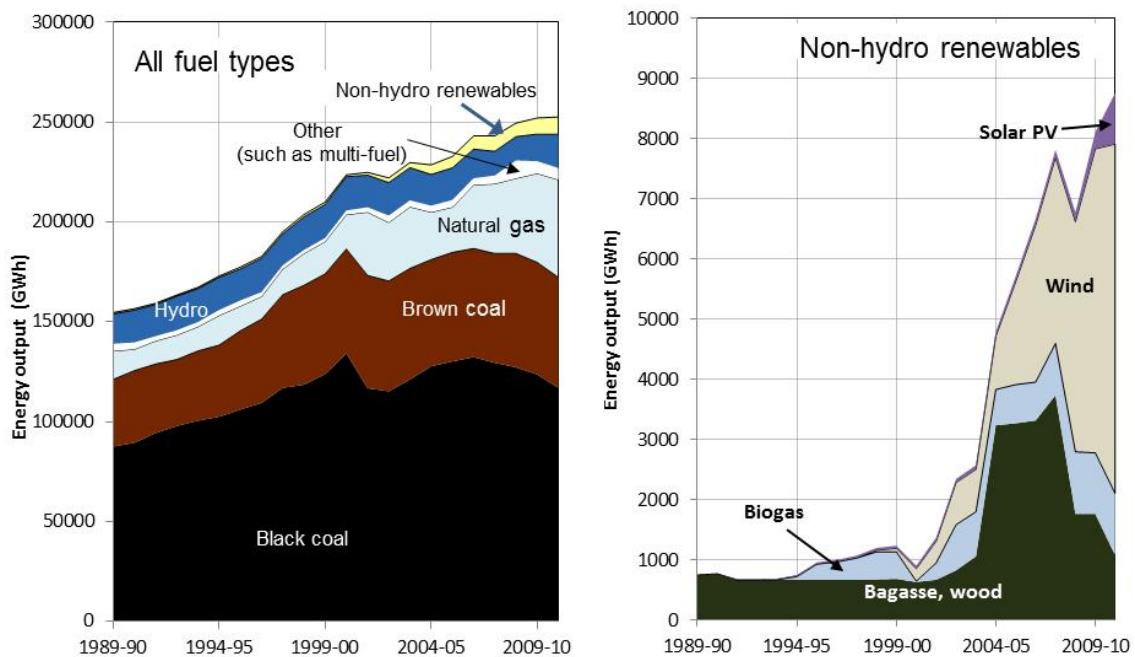
Generation and the spot market for electricity

Most power in the NEM is generated using coal (79 per cent of output) or gas (11 per cent out of output) as its fuel source (AER 2012q, p. 30, p. 32). However, carbon pricing (currently effectively achieved as a carbon tax on high CO² emitters) and the renewable energy target are designed to encourage investment in more diverse and lower carbon-emitting sources of generation. While only accounting for

¹ AER (2012q, pp. 64-7, 79-81).

4 per cent of current power capacity (and 3 per cent of output) in 2011, wind generation is an increasingly important source of power (figure 2.2).

Figure 2.2 Growth in generation by fuel type
Australia, 1989-90 to 2010-11



Data source: BREE (2012).

Wind generation accounted for around two thirds of investment in new installed (summer) capacity in 2010-11, around 45 per cent of the new capacity associated with committed investment in June 2011 and 65 per cent of capacity in publicly announced projects (table 2.1). In South Australia, wind accounts for nearly one quarter of nameplate capacity² and has sometimes accounted for around 86 per cent of generation for a trading interval (but its overall contribution to energy output in that State is around 27 per cent).³ In contrast to the burgeoning role of wind generation, little new hydro capacity has been installed in the last decade, with similar future prospects. (However, existing hydro-electricity plants are important sources of energy in Tasmania, Victoria and New South Wales.) In 2010-11, solar

² Nameplate capacity refers to the maximum amount of electrical power that can be generated under optimal circumstances. For example, the nameplate capacity of generators using renewable energy — such as those using wind, hydro and solar power — is measured at the highest manageable wind speeds, water flow and sunshine respectively. Accordingly, actual generation capacity may be affected by such things as the operating conditions (or the age of the asset) and hence may differ from nameplate capacity.

³ AER (2012q, p. 32) and BREE (2012).

generation provided less than 1 per cent of Australia's total generation output in this period (BREE 2012).

The greater diversity of generation has several implications for the electricity network. Much of the existing transmission infrastructure is close to the raw materials used to power conventional generators (such as the coal reserves in the Latrobe Valley and the Hunter Valley, and the rainfall and topography of the Snowy Mountains). That means that new transmission infrastructure may be required to connect renewables generators to the grid, sometimes across state boundaries. That then raises the issue of the best arrangements for regulating interconnectors (and likewise transmission generally — chapters 18 to 20). An associated issue is that while entry barriers to new generation are lower, incumbent generators may sometimes wield market power, affecting whether and where network businesses build new transmission lines.

Table 2.1 Investment in generation: installed and anticipated

<i>Fuel type</i>	<i>Installed in 2010-11</i>	<i>Announced in 2011</i>	<i>Committed in 2011</i>
	Share of summer MW capacity (%) ^a	Share of nameplate capacity (%) ^b	Share of nameplate capacity (%)
	%	%	%
Brown coal	0.0	4.1	0.0
Natural gas	35.5	26.8	43.7
Bagasse/black coal	0.0	2.3	10.7
Geothermal	0.0	1.3	0.0
Solar	0.0	1.7	0.0
Hydro	0.0	0.1	0.0
Wind	64.5	63.6	45.4
Methane	0.0	..	0.1
Total	100.0	100.00	100.00

^a The AER gave data for summer capacity only. This is the maximum power of a generator during summer (which can vary from other seasons, for example, due to the temperature of cooling water for thermal power plants). ^b Where a range of nameplate capacity (MW) was provided in the data, the lowest value was used. A generation investment is categorised as 'committed' by the Australian Energy Market Operator (AEMO) if most of the pre-conditions for future investment are in place (such as finance, land purchase, and contracts to build). Announced projects are ones that have a lesser degree of certainty, but an intention to build has been publicly made.

Source: AEMO (2011a); AER (2011b, p. 44).

The price of wholesale electricity is determined in a spot market in which demand and supply are constantly matched. Every five minutes, generators bid to supply a given quantity of power. With a few exceptions, all power supplied to the grid must be supplied through the wholesale spot market. Offers to generate are stacked in order of rising price, and are then scheduled and dispatched into production, though sometimes constraints on the technical capacity of the transmission network mean

that generators can be scheduled out of price order (AEMO 2010f). Much of base load power is supplied by relatively low-cost large coal-powered generators that must run for 24 hours a day. During peak demand periods or where there are significant outages, the additional power required is supplied by switching on high-cost ‘peaking’ plants — usually gas turbines burning natural gas. Some generators are built only for extreme events, such as heat wave conditions, and may be idle for all but a few hours a year.

The marginal cost of the last (highest priced) megawatt of electricity dispatched by AEMO determines the spot price. All generators receive the same spot price for their dispatched power, regardless of their bid price. Accordingly, a low bidder will typically receive revenue well above the marginal cost of their dispatched power. Such a premium is required to provide an ex ante incentive for investment in generators, though changes in demand, fuel costs and competitive technologies mean that ex post a generator may either receive more or less than was needed to justify the initial investment.

AEMO sets a spot price floor (-\$1000 per MWh) and ceiling (\$12 900 per MWh).⁴ The former is required because it can be costly to turn a generator off, so that a generator may want to guarantee dispatch by bidding at negative prices (although this feature also has some unintended impacts as discussed in chapter 19). The latter is required because demand is very unresponsive to price over the very short run (due to the way in which prices are signalled to customers and their capacity to respond to them). Without a price ceiling, prices would rise astronomically during extreme peak load events or times of reduced base load capacity (Frontier Economics 2010a), as would wholesale electricity costs. There is some concern that a large generator could use transient market power to withhold enough low-cost base load output to raise market prices for the residual amount of power it provides. The ceiling places a limit on that capacity.⁵ There is a further safeguard provision that limits the price to \$300 per MWh (the administered price cap) if high spot prices are sustained.⁶

⁴ The market price cap re-calibrated by AEMO annually based on a formula set down in the Rules (clause 3.9.4).

⁵ The story is more complex than this because investors in generators will typically reduce their risks from fluctuating spot prices through derivative contracts. As noted by Frontier Economics, generators usually enter into swap contracts for most of their capacity and so do not benefit from pushing up the spot price for their swap contracted capacity (2010a, p. 13), limiting the gains from strategic behaviour.

⁶ Clause 3.14.2 of the Rules. Unlike the market price cap, the administered cap is not indexed, but can be reviewed from ‘time to time’.

Retailing

The other major segment of the system — retailers — purchase electricity from the national market, pay access fees to networks, and sell power to end users. They manage billing, develop packages of services tailored for different customers and, through various risk management techniques, insure final customers against volatile electricity spot prices.

In contrast to network services, there is a genuine capacity for entry into retailing, and therefore greater scope for effective competition. Customers are able to choose their own retailers ('full retail contestability') in all NEM jurisdictions apart from Tasmania. Many retailers specialise in providing services to larger customers only, with less than 50 per cent of retailers providing services to small customers (AER 2011b, pp. 105-6).

In most jurisdictions, a few retailers provide most of the services, with a particularly high concentration of supply in Tasmania and the ACT (AER 2012q, p. 118-121). Victoria has the greatest level of competition, as indicated by customer switching patterns and a less concentrated market structure.

There has been an increasing shift to harmonised retail regulations across the NEM. In 2006, the Council of Australian Governments agreed to develop a new national framework governing the sale and supply of electricity and natural gas to retail customers. The goal was to reduce regulatory burdens for energy businesses operating across jurisdictions, while retaining appropriate consumer protection. A lengthy process of consultation, negotiation and regulatory development ensued after the 2006 agreement.

A National Energy Customer Framework (NECF) has now been (notionally) created. The NECF transfers several major regulatory functions currently performed by the relevant jurisdictions to the Australian Energy Regulator (AER), including:

- monitoring compliance and enforcing breaches of the National Energy Retail Law and its supporting rules and regulations
- authorising energy retailers to sell energy, and granting exemptions from the requirement to be authorised
- approving retailers' policies for assisting with customers facing hardship
- providing an online energy price comparison service for small customers (see the energy price comparison website, Energy Made Easy)
- administering a national retailer-of-last-resort scheme, which protects customers and the market if a retail business fails

-
- reporting on the performance of the market and participants, including on energy affordability, disconnections and competition indicators.

As in other aspects of the NEM, the ‘N’ in the NECF remains somewhat ethereal. Implementation across jurisdictions has been slow. By July 2012, the largest states had yet to pass the legislation, with the law commencing only in the ACT and Tasmania at that time (AER 2012q, p. 119). South Australia adopted the NECF in February 2013. As in the case of network regulation, the NECF excludes Western Australia and the Northern Territory.

Moreover, the NECF also provides scope for jurisdictions to carve out aspects of the National Energy Retail Law. For example, the Victorian Government will not adopt the prepayment meter regime and will maintain certain consumer protections that it considered superior to those in the NECF (DPI 2012a).

And while the AER will take over the non-economic functions of retail regulation, retail price regulation remains a state and territory government responsibility. In 2006, the Council of Australian Governments agreed to remove retail price regulations in any jurisdiction where the Australian Energy Market Commission (AEMC) found competition was effective. However, that process has not moved quickly. Jurisdictions have not always acted when the AEMC has proposed deregulation following its assessment that competition was effective. The ACT Government did not accept the AEMC’s recommendation to deregulate prices, and the South Australian Government took five years to implement the AEMC recommendation. In June 2011, the Standing Council on Energy and Resources announced that future reviews would be New South Wales in 2012, Queensland in 2013, the ACT in 2016, and Tasmania no sooner than 18 months after full retail contestability is implemented.⁷ The upshot is that retail price regulation remains in all jurisdictions other than Victoria (AER 2012q, p. 126) and South Australia. Under regulated arrangements, customers can choose to purchase their electricity from the ‘non-market’ retail segment, which is subject to price controls by the relevant state regulator, or the market segment, in which there is pricing flexibility.

As in other aspects of electricity supply, imperfections in one part of the system carry over to other parts. By acting as an obstacle to cost-reflective pricing and incentives for adopting direct load control, retail price controls adversely affect the efficiency of investments in electricity network and generation (chapter 12). As emphasised in chapter 1, this affects the use of benchmarking in incentive

⁷ The Tasmanian Government has responded to a 2012 report issued by an expert panel on the electricity supply industry by announcing full retail competition from 1 January 2014.

regulations, but also raises the importance of testing the cost effects of different regulatory regimes across the NEM.

Benchmarking in retailing

Benchmarking has been incorporated into the national approach to retailing (ACIL Tasman 2011 and EnergyConsult 2010), and is based on survey data from more than 5000 households on their power use. The purpose of the ‘Electricity Bill Benchmarking initiative’ is to provide households with information on their relative use of power given their household characteristics, so that they can make informed choices about their electricity use.

The initiative reveals some of the inconsistencies in the goals of policies across the electricity supply industry. Relatively short periods of peak use, mainly during hot summer days, are responsible for a significant amount of network infrastructure investment (chapter 9). However, the information provided in the retail benchmarking exercise concerns total power usage, which is a poor proxy for expensive peaky use. Accordingly, the information does not inform consumers about the true underlying costs of their power usage. If critical peak pricing were introduced — as recommended by the Commission — the retail benchmarking model would need to be elaborated. The Commission has recommended surveys to estimate the value of lost load⁸ for setting appropriate reliability standards (chapter 14). These surveys could replace the existing electricity bill benchmarking surveys, and would provide better information to assist informed choice by consumers

Other services

Outside these major parts of the system, there are some direct transmission lines from generators to major industrial users, some industrial co-generation feeding into the grid, increasing micro-generation at the customer end (such as solar panels) and an array of financial and technical services (for example, in financial instruments that address the risks, mainly related to pricing, of generators, retailers and ancillary services⁹).

⁸ The value of lost load is the amount of money customers would be willing to pay to avoid a disruption to their electricity service. It is generally measured in dollars per unit of electricity.

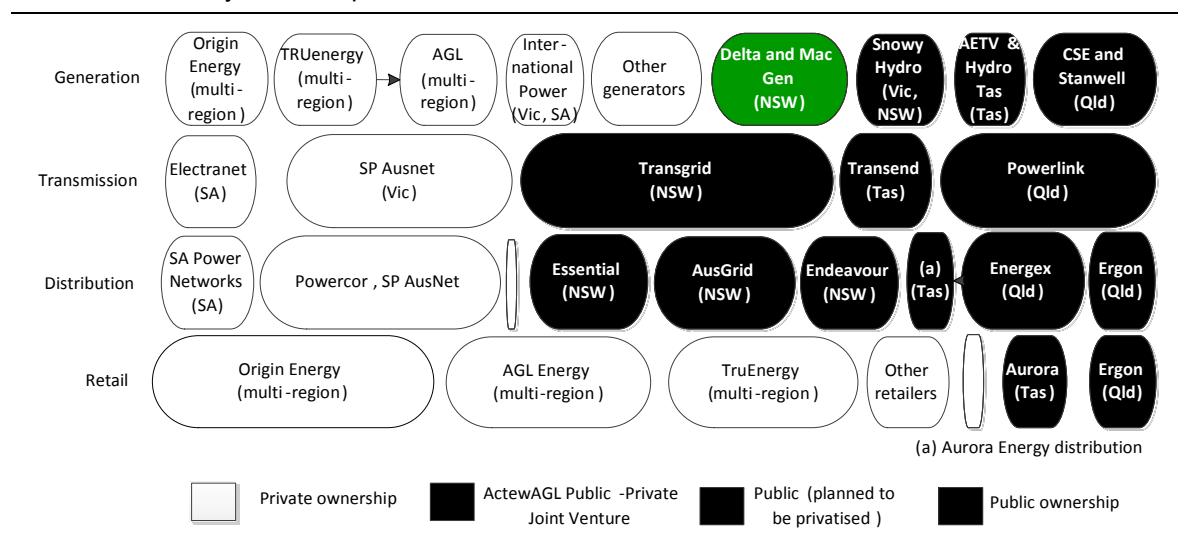
⁹ Ancillary services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes (AEMO 2010a). AEMO operates eight separate markets for the delivery of frequency control ancillary services (akin to the wholesale energy spot market) and purchases network control ancillary services from

Ownership and linkages

Competition reform in the 1990s led to the disintegration of the management of the electricity system in each state and territory by a single vertically integrated state-owned business (spanning generation, transmission, distribution and retailing).

Generation and retailing are now open to competition, while the natural monopoly segments of the industry — network services — remain heavily regulated and are often still owned by governments (figure 2.3). The New South Wales, Queensland and Tasmanian governments own the distribution networks in their states. In contrast, private entities own the South Australian and Victorian distribution networks (though the former involves a long-term leasehold rather than outright ownership). The ACT distributor is part government-owned. Overall, governments own around 75 per cent of distribution assets in the NEM (and a similar share of transmission assets).

Figure 2.3 Participants in the National Electricity Market
By ownership and market share^a



Source: Queensland Commission of Audit (2013, figure 2, p. 13).

Moreover, there are still strong ownership and management links between parts of the system. Vertical integration between generators and retailers — ‘gentailers’ — is becoming increasingly common (AER 2012q, p. 40, pp. 119-24; Pearce 2011, p. 16), as is integration into fuel supply. For example, Origin Energy — one of Australia’s largest energy businesses — has integrated operations spanning gas exploration and extraction, gas pipelines, power generation and electricity retailing. AGL Energy and EnergyAustralia also have interests in gas production and/or gas

transmission businesses and system restart ancillary services under agreements with service providers.

storage that complements their interests in gas fired electricity generation and energy retailing.

State governments also sometimes jointly own transmission, distribution, generation and retailing. For example, the Tasmanian Government owns the sole transmission business in that State (Transend), the overwhelming majority of generation capacity (principally through Aurora Energy and Hydro Tasmania), the only distribution business (Aurora Energy), the dominant small customer retailer (Aurora Energy) and a major business retailer (Momentum Power). However, following a recent review (Electricity Supply Industry Expert Panel 2012a), the Tasmanian Government will sell Aurora Energy's retail arm and combine the distribution network with transmission (Green 2012, AER 2012q, p. 60). In most other states, there is usually greater scope for competition from private businesses in the contestable parts of the system (generation and retailing).

The vertical separation of networks from the other parts of the electricity system has had many desirable benefits, including the capacity to develop a genuinely national market and to provide stronger market-based incentives for efficiency. However, it has also diminished the capacity for coordination of the various parts of the networks and has reduced economies of scope.¹⁰ For example, exploitation of transmission congestion; weakened incentives for demand management; difficulties in planning; and the requirements for sophisticated financial hedging instruments reflect the problems that vertically separated businesses have in transacting with each other. Many of the regulations in the NEM can be seen as alternative ways of encouraging efficient transactions between businesses that no longer have aligned interests. This poses fundamental challenges for regulatory design — some of which have not yet been fully resolved, such as regulations for smart meter rollouts (chapter 10) and strategic bidding behaviour by generators (chapter 19).

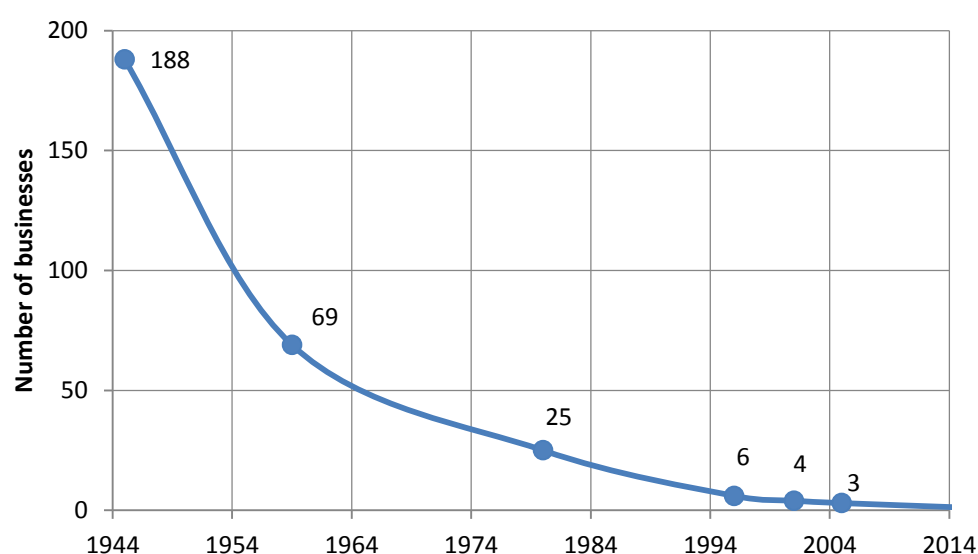
While policy reforms have required vertical disintegration, governments as owners have encouraged horizontal integration of network distribution businesses. This appears to reflect significant economies of scale in networks¹¹ and the progressive shift from local small generators to large-scale generators more remote from population centres. In New South Wales, the merger process has been the most pronounced (figure 2.4). However, mergers involving common management appear to have been confined to businesses within state boundaries, reflecting the importance of state ownership (and a state-specific orientation to service

¹⁰ A consequence explored in a large literature on the economics of integration in electricity and other similar utilities (summarised in Lafontaine and Slade 2007 and Saal 2011).

¹¹ See for example, Farsi et al. (2010) and Kwoka (2004).

delivery).¹² There is no obvious reason why common management of businesses should be constrained by state borders. In the United States — at least among transmission businesses — the story is quite different. For example, American Electric Power owns transmission infrastructure throughout the United States and Canada. This raises the question of whether state-ownership may be a barrier to efficient horizontal mergers (chapter 7).

Figure 2.4 Progressive merger activity
NSW, distribution businesses 1945-2014



Data source: NAS (2009).

2.2 The scale of the network and its costs

In 2011-12, 308 generators with an installed capacity of more than 48 000 MW fed 9.7 million customers through the network of five jurisdictional transmission networks, 13 major distribution networks and 6 interconnectors (AER 2012q, p. 28, p. 61). Collectively, state governments are significant asset holders in all of the above segments of electricity supply. The NEM accounts for around 90 per cent of the line length of the entire Australian electricity distribution system and provides

¹² Currently, Essential Energy provides some services outside New South Wales, principally in the area around Goondiwindi in Queensland, Victoria and the ACT (Essential Energy, sub. 30, p. 3). There is common ownership (compared with common management) among private network businesses. For example, Cheung Kong Infrastructure and Power Assets Holdings and Spark Infrastructure jointly own Powercor, Citipower, and ETSA Utilities, while Singapore Power International has ownership interests in Jemena, United Energy and ActewAGL and SP AusNet.

energy to about the same share of Australian customers (Wessex Consulting 2010). The actual and forecast regulated network revenues summed over the (mostly five-year) regulatory periods that were still in force in late 2012 was \$62 billion in June 2011 prices — \$14 billion for transmission businesses and \$48 billion for distribution businesses (AER 2012q, pp. 62-3). (Taking account of the slight variation in the regulatory periods, the average *annual* revenue was \$12.2 billion.)

The NEM is one of the most geographically dispersed electricity networks in the world (figure 2.5). The network comprises more than 40 000 kilometres of high voltage transmission lines and 770 000 kilometres of lower voltage distribution networks (AER 2012q, pp. 60ff). There are also around 1500 kilometres of interconnectors that transmit power from one jurisdiction's electricity system to another, thus creating the 'national' market. To give a perspective on this, in the United Kingdom, there are around 25 000 kilometres of transmission lines and 800 000 kilometres of distribution lines serving a population of more than three times that of the NEM (UK Department of Energy and Climate Change 2011).

The total asset value of the NEM network was around \$60 billion in 2010, with an expected five yearly investment of more than \$40 billion (in 2011 prices — table 2.2). The distribution network accounted for around 75 per cent of the total network assets and nearly 85 per cent of investment. This is why concerns about the efficiency of investment mainly relate to distribution networks. Interconnectors account for an estimated share of total network asset values of around 5 per cent. Transmission accounts for the residual network assets and investment.

There is less information about other aspects of network businesses in the NEM because the AER concentrates on investment, assets, and regulatory revenues, rather than broader measures of the importance of the industry.¹³ Value added is estimated to be around \$10.7 billion in 2010-11.¹⁴

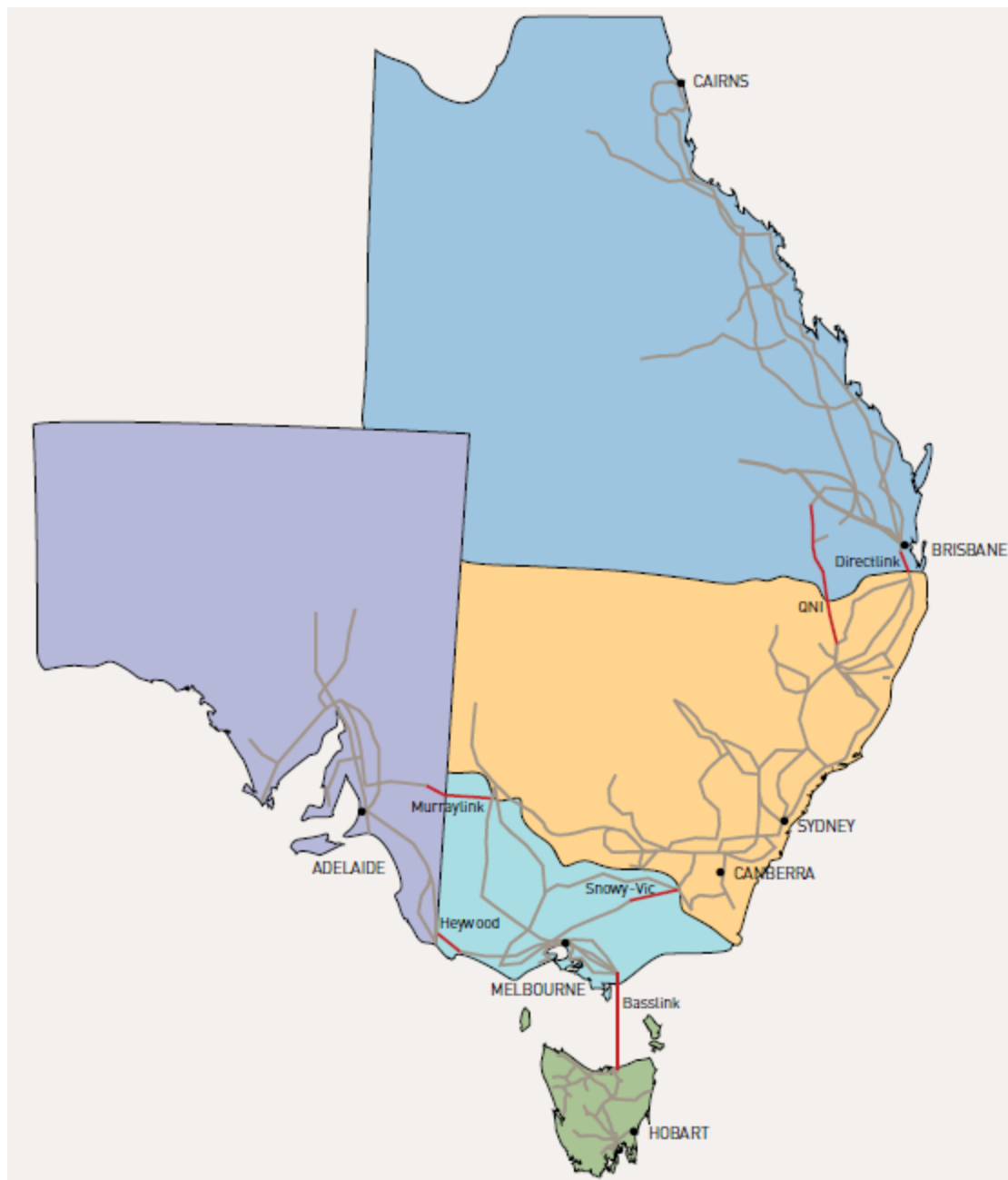
Employment in network businesses was around 30 000 at 30 June 2011, but this is for all jurisdictions, not just the NEM (ESAA 2012, p. 10). Given that the NEM accounts for around 90 per cent of total customers (Wessex Consulting 2010), a

¹³ The employment and outputs of the industry are important in gauging the potential economic impacts of reforms (section 2.7).

¹⁴ 'Industry value added' refers to the value of a productive process, after taking into account the inputs into that process from other industries. It is a measure of an industry's contribution to GDP after accounting for both upstream and downstream industries. The value added by NEM businesses is estimated by applying the 2006-07 network service share of the value-added of the electricity, gas, water and waste services (EGWWS) industry to EGWWS value added in 2010-11 (from the ABS National Accounts), and then multiplying by 0.9 to remove non-NEM regions.

reasonable employment estimate for NEM businesses is around 27 000. Somewhat dated Australian Bureau of Statistics (ABS) information on the industry for June 2007 suggests a number consistent with this (table 2.3).

Figure 2.5 Transmission network infrastructure in the NEM



Data source: AER (2009a, p. 126).

Table 2.2 Assets and investment in the NEM^a

	<i>Asset value circa 2010 (billion)</i>	<i>Estimated investment circa 2010</i>	<i>Investment rate (investment to assets)</i>	<i>Share of total assets</i>	<i>Share of total invest.</i>	<i>Segment's contribution to electricity price 2010-11^f</i>
	\$ billion 2011 prices	\$ billion 2011 prices	%	%	%	%
Generation ^b	40.0	1.2	3.0	39.0	12.1	34.5
Transmission and interconnectors ^c	16.7	1.5	8.9	16.3	14.9	7.7
Distribution ^d	45.8	7.2	15.8	44.7	73.0	37.3
Total for above components ^e	102.4	9.9	9.7	100.0	100.0	79.5

^a The asset data for networks relate to the regulatory asset base at the beginning of the regulatory period. The beginning of the regulatory period varies by business, but its mean value is around 2010. The data are in June 2011 prices (AER 2012q, pp. 62-63). ^b The asset values are for 2008 for the major power generators in the NEM, which account for nearly 100 per cent of installed capacity (NGF 2011, p. 1). The investment relates to the data available so far for 2011-12 for all commissioned generators in the NEM (AER 2012q, p. 54). ^c The estimates for investment are one fifth of the investment for the five yearly regulatory period. The estimates also exclude any investment by Directlink, Murraylink and Basslink. However, these interconnectors amounted to only around 8 per cent of the total asset base for all transmission and interconnector assets. That, and the fact that it is known that little investment has occurred in interconnectors, suggests that the estimates will be close to its correct magnitude. ^d The estimates for investment are one fifth of the investment shown for the five yearly regulatory period. ^e The data exclude other cost contributors to electricity prices, such as feed-in tariffs, renewable energy target subsidies and, most importantly, retail costs. The Commission could not find data on assets and investment for the retail segment of the market. However, this segment mainly comprises operating expenses, rather than physical capital investments. The overall contribution of the retail segment to electricity bills is about 15 per cent, so the asset share is likely to be much smaller than this. ^f These values are estimated as each segment's share of the Australia-wide price per KWh. The three cost sources do not add to 100 per cent because some other cost influences, such as retailing, are excluded. The generation share is estimated as the wholesale share.

Average annual employee benefits are estimated to be around \$128 000 per person in 2010-11 (based on adding wage inflation rates to the data from table 2.3).¹⁵

2.3 The nature of demand

Power consumption has been falling in recent years.¹⁶ The ESAA (2012) estimates that consumption per customer fell by around 2.5 per cent in both 2010-11 and

¹⁵ The wage inflation rate was calculated as the weighted average of private and public of the growth rates in labour earnings for the electricity, gas, water and waste services industry (ABS 2012a).

¹⁶ There are anomalies between the three estimates of electricity consumption made by ESAA (lowest), the Bureau of Resources and Energy Economics (highest) and the AER (the middle). The AER's measure appears to relate to supply, which must be greater than actual consumption. The ESAA's data relate directly to consumption by various customers types and

2009-10. Indeed, even total consumption fell in these two years despite rising population and household formation. (The implication is that, all other things being equal, unit prices must rise to cover the high fixed costs of network infrastructure.) Supply-based data suggest that this pattern has persisted in the year from 2010-11 to 2011-12 (AER 2012q, p. 28).

Table 2.3 The significance of electricity networks
2006-07, Australia-wide, current prices^a

	<i>Unit</i>	<i>Generation</i>	<i>Transmission</i>	<i>Distribution</i>	<i>Retail</i>	<i>Electricity supply</i>
Employment end June	No.	9 487	2 572	27 223	4 620	43 902
Labour costs	\$m	1 074	307	2 914	358	4 653
Sales & service income	\$m	10 776	2 180	13 506	13 053	39 516
Value added	\$m	5 075	1 595	6 857	1 036	14 564
Gross fixed capital formation (GFCE)	\$m	2 662	1 175	4 371	321	8 528
Employee benefits per worker	\$	113 208	119 362	107 042	77 489	105 986
GFCE share of value added	%	52.5	73.7	63.7	31.0	58.6
Industry value added per person employed	\$m	534 943	620 140	251 883	224 242	331 739
Profit margin	%	13.6	20.7	22.2	1.2	12.8

^a The full definitions of these terms are in the ABS publication below (pp. 37-47) and have not been reproduced. Labour costs are the full cost of employment (of which of around 90 per cent are wages and salaries). 'Value added' represents the additional increment of value to the intermediate inputs used by the industry. Gross fixed capital formation is measured by the total value of a producer's acquisitions, less disposals, of fixed assets during the reference period (and so is not equivalent to investment in new capital). The profit margin is the percentage ratio of operating profit before tax to sales and service income.

Source: ABS (2008).

In contrast to average demand, the ratio of peak demand to average demand has generally been rising over time,¹⁷ reflecting the increasing penetration of air

likely to be the better measure (derived from ESAA 2012 — tables 3.2 and 3.3). Either way, the AER's data also suggest falling demand. AEMO's data (2012a) also shows an estimated decline in customer sales of around 2.4 per cent in 2011-12, but rising sales by 2013-14.

¹⁷ Critical peak demand use (the rare but large spikes in energy use, such as on the hottest days) has also declined in recent years — mostly due to milder weather — but is forecast to rise again

conditioning and the value people place on cooling during hot days (Topp and Kulys 2012, p. 42). This is a significant determinant of increased investment because networks must be built for peak use (AER 2012q, p. 15).

There were around 9.1 million electricity customers in 2010-11, up by around 1 per cent from the previous year (table 3.2 in ESAA 2012).¹⁸ While around 90 per cent of customers are residential (some 8.1 million), these account for about 30 per cent of total consumption.

The importance to network businesses of the *demand* by various industries is quite different from the importance to other industries of the *supply* of network services.¹⁹ As far as the:

- former is concerned, network businesses have a wide customer base, although some industries, such as non-ferrous metal manufacturing and non-ferrous mining are particularly important revenue sources
- latter is concerned, of all industries that supply inputs to other industries, network services are characterised by close to the most uniform pattern of use (figure 2.6). Network services account for around 1-1.5 per cent of the value of inputs for the bulk of industries, although they are more important inputs for a few industries, such as ceramics and glass manufacturing (figure 2.7).

The implication of this pattern of use is that any individual business user has relatively little capacity to negotiate from a position of power with network businesses. However, the Major Energy Users (sub. DR66) and the Energy Users Association of Australia (sub. 24) have nevertheless been able to act as stakeholders in requesting Rule changes and in representation during the regulatory process. In comparison, in the case of another regulated industry, airports, the number of direct users is small, and there is a much greater capability for negotiated arrangements.

An issue in this inquiry is whether network customers could play a larger role in determinations, drawing on the information of benchmarking, and with resort to the regulatory powers of the AER as the ‘stick’. Given the fragmented customer base, achieving that outcome requires a policy stimulus (chapter 21). The other implication of the pattern of use is that network businesses probably have little

(AEMO 2012a and AER 2012q, pp. 29-30). Regional maximum demand reached new peaks in NSW, South Australia and Tasmania in 2010-11 (ESAA 2012, p. 16).

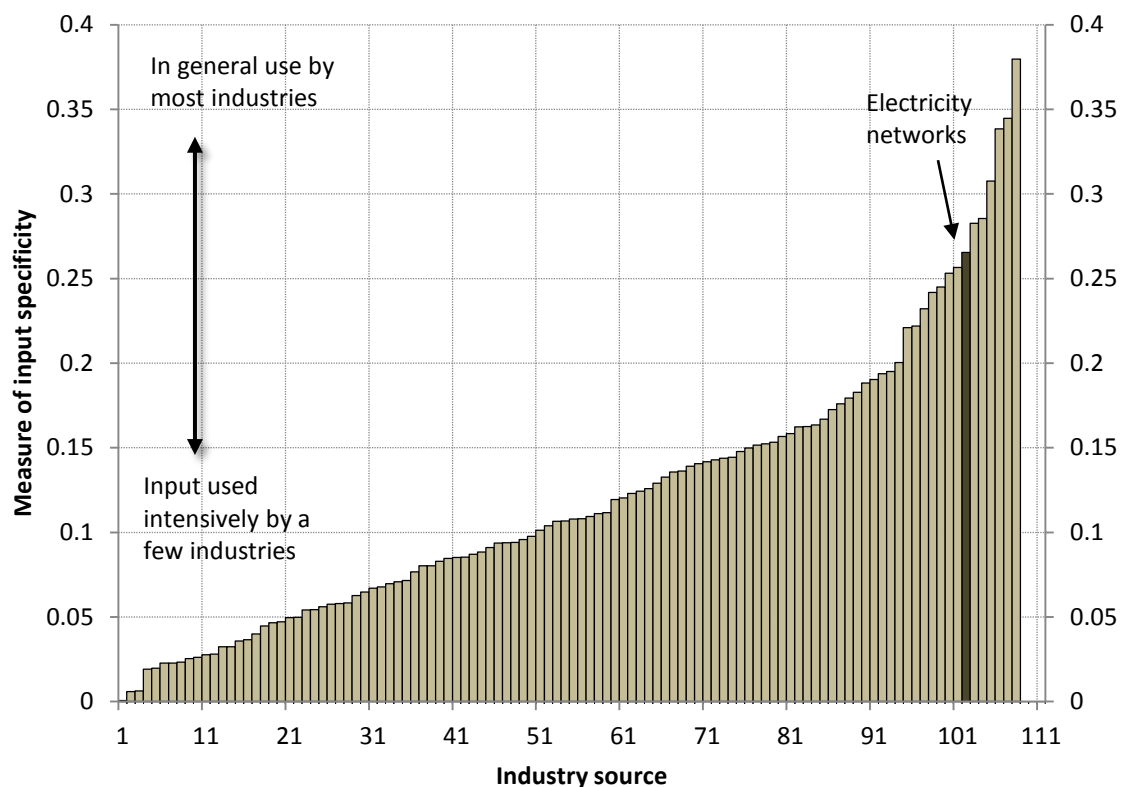
¹⁸ In contrast, the AER (2012q p. 63) identified around 9.7 million customers of distribution networks around the same period (with the difference for the estimates being unclear).

¹⁹ For example, an industry might be highly dependent on electricity as an input, but have low overall output and low consumption of electricity, and consequently, provide little revenue to network businesses.

genuine capacity to ‘hold-up’ the investments of their customers — an issue relevant to the rationale for, and design of, the regulations (chapter 3 and appendix B).

Another facet of demand is its responsiveness to prices, which is relevant to the economic efficiency of addressing any network inefficiencies.

Figure 2.6 Network services are general-use inputs
2007-08^a



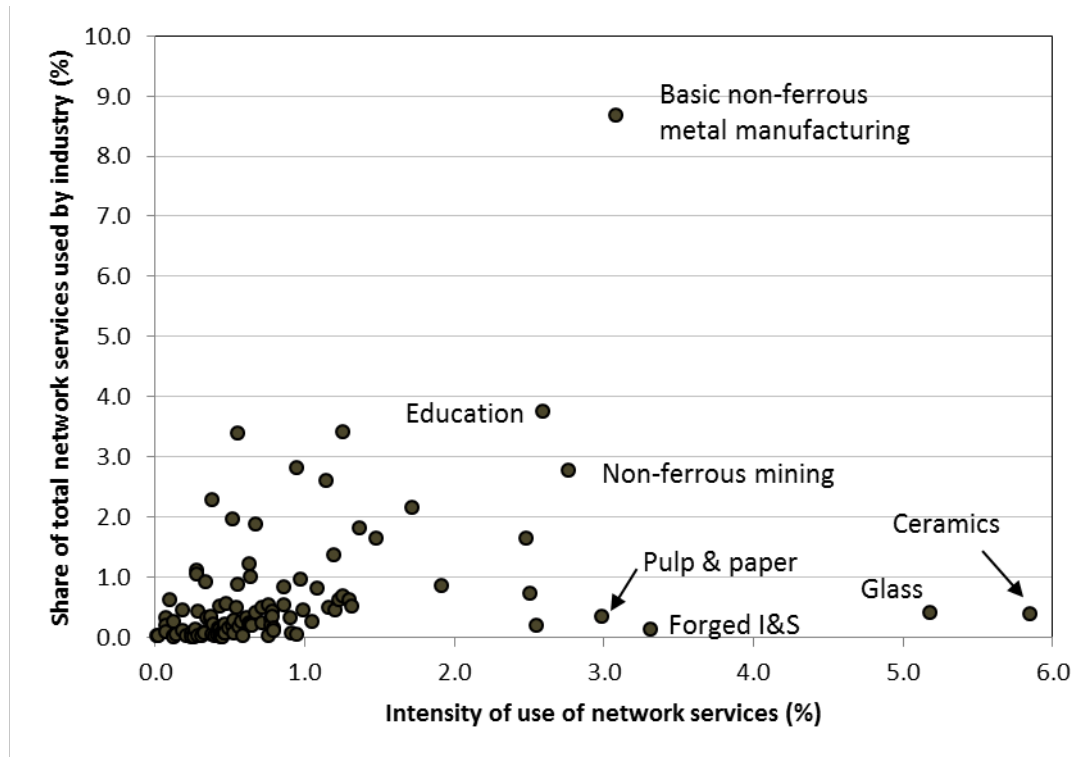
^a The measure of specificity is calculated as follows. Let there be N industries. Define an input share (α) each industry in the total intermediate inputs (TotalUse) of each other industry:

$$\alpha_{jk} = \text{Input}_j / \text{TotalUse}_k \text{ for } j, k \in (1 \dots N)$$

For any given industry (m) in the group 1 to N , there will be a vector of alpha values (\mathbf{V}_m) representing the importance of that industry as an input into other industries ($\alpha_{m1}, \alpha_{m2}, \alpha_{m3}, \dots, \alpha_{mN}$). Calculate the ratio (R_m) of 20th and 80th percentiles of \mathbf{V}_m . Were a given input industry to account for one per cent of the total intermediate use of each other industry, then $R_m = 1$. That means that industry m would be a general-use input. In contrast were R_m to be small then it implies that many industries make little use of that input and some a large amount — a high level of specificity. The data show that electricity network services are a general-use input (though typically a small share of each industry’s total inputs – as shown in figure 2.7). Indeed, it is close to being the most general-use input among the large group of industries covered by the ABS input-output tables.

Data source: ABS (2012b).

Figure 2.7 Network services are a small share of inputs for most businesses, 2007-08^a

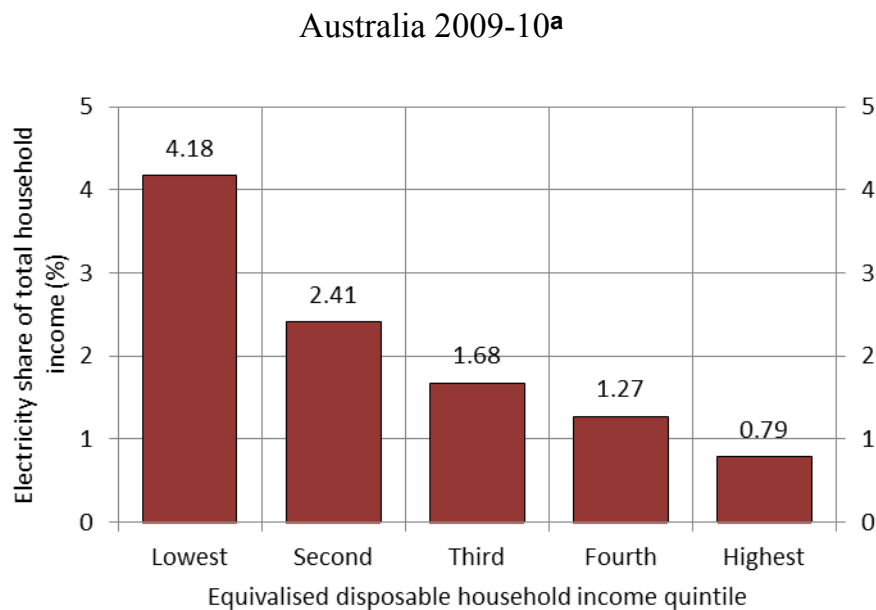


^a Based on table 5, industry by industry flow matrix with direct allocation of imports (so that the table relates to domestically produced network services only). The shares relate to intermediate inputs into industries. The horizontal axis shows that network services are a relatively small share of total intermediate inputs of most industries. The vertical axis shows that, with one exception — non-ferrous metal manufacturing — networks rely on a wide range of industries for their revenue. .

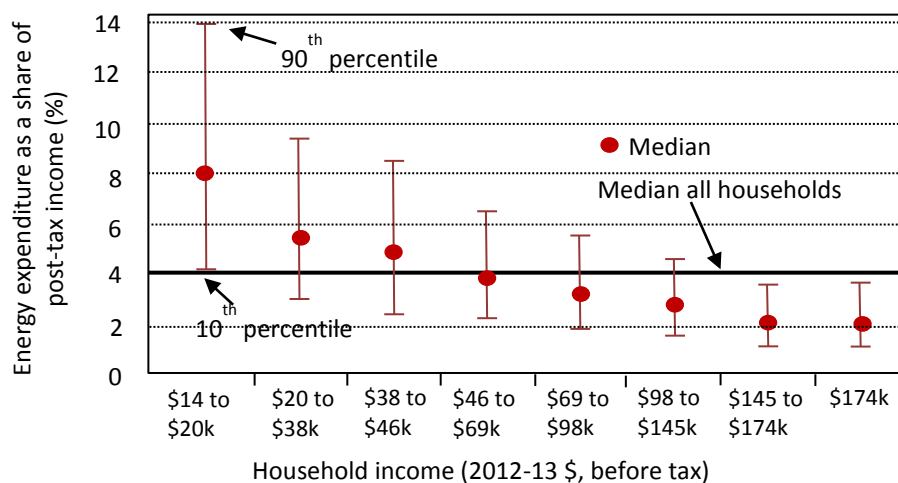
Data source: ABS (2012b).

Demand is not very responsive to prices in the short run, with a 10 per cent increase in prices likely to reduce electricity demand by somewhere between 2 and 4 per cent. The reduction is significantly greater — somewhere between 5 and 7 per cent — over the long run (Fan and Hyndman 2010, p. 8; Langmore and Duffy 2004). It is higher again for peak periods (PC technical paper). Consequently, some of the recent falls in electricity demand may reflect the impacts of the large price increases described in section 2.4. There is also significantly greater responsiveness to time-based tariffs, which shift demand from one period to another, rather than necessarily reducing daily demand by much. The responsiveness of demand to income is important for considering the distributional outcomes of any price reductions from reforms of network regulation. It appears that levels of electricity consumption are not very sensitive to income compared with most other goods and services. Consequently, the share of income spent on energy use falls significantly as household income rises (figure 2.8).

Figure 2.8 Lower-income households are hit harder by rising prices



Sydney and surrounding regions, 2012-13^b



^a Equivalised income quintiles take account of household size and composition in determining the values of income and spending in each quintile (ABS 2011b, p. 46ff). The ABS publishes aggregate household energy use (non-transport) on an equivalised income basis, but does not do so for domestic electricity use alone. However, both measures of energy use are available for non-equivalised household income quintiles, and these data have been used to estimate electricity usage on an equivalised basis. Note that the data for quintiles are averages. Many households in each group will be spending a greater (or lesser) share of their incomes than those shown. Higher than average spending shares are particularly relevant for the lowest income quintile. ^b Households have a distribution of spending from high to low. Percentiles measure the spending at various points in that distribution. For the lowest income group (\$14 000 to \$20 000), 10 per cent of households have a spending level below around 4 per cent of their household income (the 10th percentile), while 10 per cent of households in this income group have spending above 14 per cent of their income (the 90th percentile).

Data sources: ABS (2011b); IPART (2012a, p. 13).

Domestic energy use accounts for more than 4 per cent of household income for the lowest quintile and less than 1 per cent for the highest quintile, or a ratio between the two of around 5.3 to 1. Other analysis suggests that this ratio is the third highest among the 35 broad commodity groups in the ABS Household Expenditure Survey — suggesting the inherently ‘essential’ nature of energy. More disaggregated analysis by the Independent Pricing and Regulatory Tribunal (IPART) for the Sydney region reveals that electricity spending can be as high as 14 per cent of income for the poorest households.²⁰ This income pattern of consumption is one of the reasons why concerns about network efficiency and their flow-on price effects have been given such prominence.

2.4 Prices have been rising

Concerns about rapidly rising electricity prices have been a major source of concern to governments, businesses and the general community (figures 2.9, 2.10, and 2.11). Until the mid-2000s, Australian retail electricity prices grew at around the same rate as economywide inflation, but then began to rise rapidly. From June 2007 to December 2012, Australian retail electricity prices rose by around 100 per cent, while general inflation increased by around 16 per cent, so that real electricity prices rose by around 70 per cent. (Box 2.1 explains what real prices mean.) Electricity prices facing businesses have also risen strongly, albeit by not the same degree.²¹

Electricity retail prices rose most strongly in Victoria (109 per cent) and New South Wales (111 per cent) over this period, more than 10 percentage points higher than any other jurisdiction in the NEM (figure 2.11). Future retail electricity prices in the NEM — at least partly locked in through regulatory agreements — are projected to increase by 21 per cent from 2011-12 to 2014-15 (AEMC 2013a, p. vi)

Growth rates in retail electricity prices accelerated in 2007 for Melbourne and Hobart, 2006 for Brisbane and Canberra, 2008 for Sydney and in 2010 for Adelaide. In all but the last case, the regulatory determinations in force had been authorised by state-based regulators,²² not the AER (and therefore were not encumbered by any

²⁰ Nevertheless, while lower income households reveal that they have little capacity to substitute away from electricity, there is some (weak) evidence that they are more willing to face power interruptions (chapter 14).

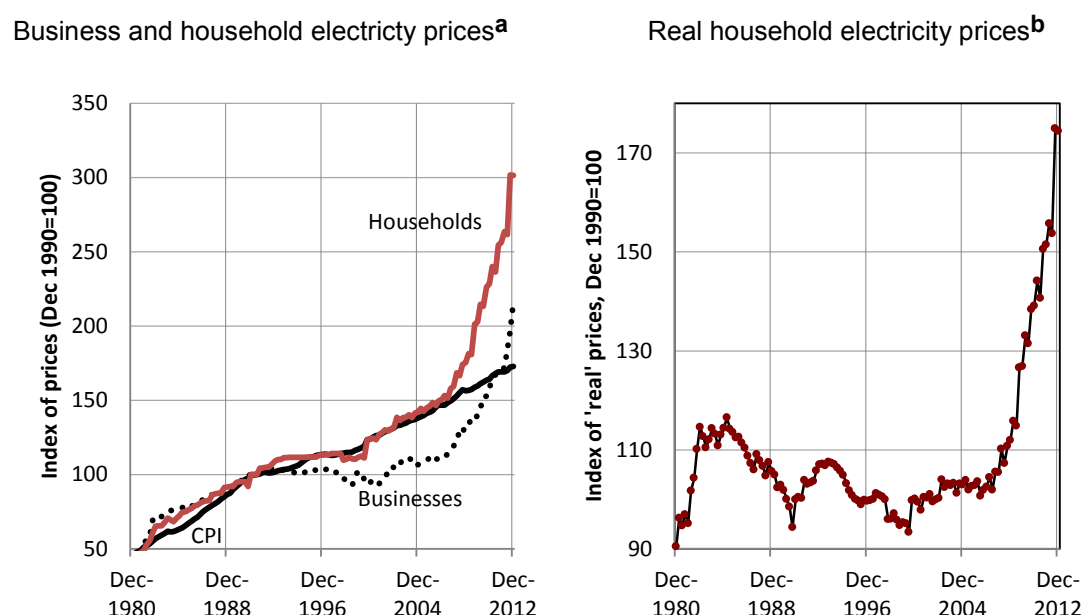
²¹ The reason for the lower price growth is uncertain, but may be due to re-balancing of tariffs (which may also reflect the wider adoption of time-based charging for businesses, which tend to have a less peaky load profile than households — chapters 9-11).

²² This relates to distribution businesses (which account for the bulk of network costs), not transmission businesses. However, the Australian Competition and Consumer Commission

unique flaws in chapter 6 of the Rules). While the Rules may have contributed to recent and forthcoming electricity prices, the price growth that preceded the new regulatory arrangements originated from other sources.

Community concerns about electricity prices have been accentuated by their coincidence with similarly large increases in the costs of other regulated essential services — water and sewerage (74 per cent from June 2007 to December 2012) and gas and other fuels (64 per cent over the same period).

Figure 2.9 Electricity prices
December 1980 to December 2012



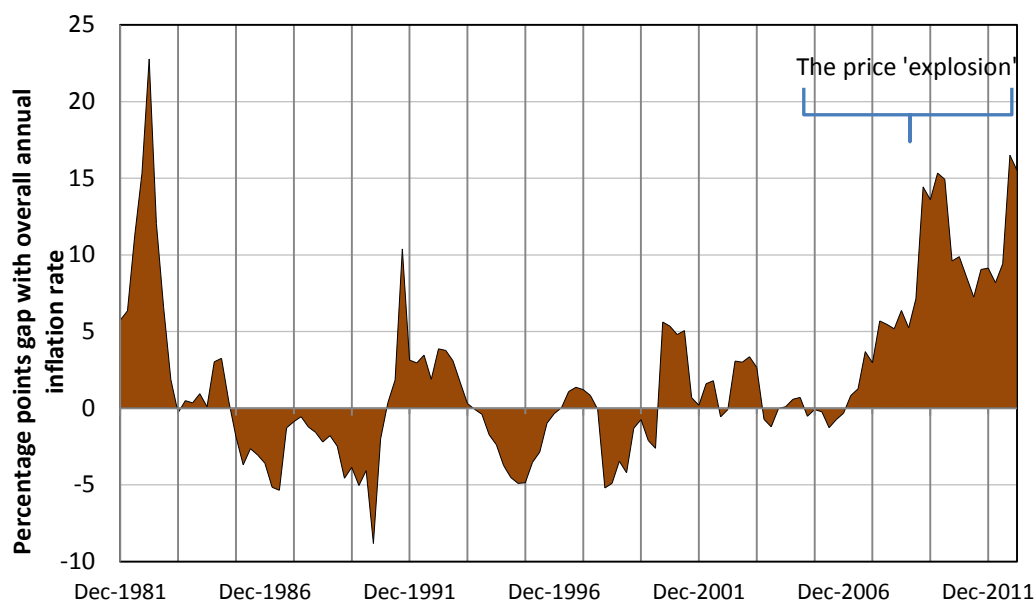
^a Data are from December 1980 to December 2012, rebased so that December 1990 = 100. The data relate to all Australian electricity prices, not just those in the NEM, but the trends will be similar. ^b 'Real' prices are household prices divided by the CPI average for capital cities. The index shows how much electricity prices have increased above inflation.

Data sources: ABS (2012e, 2012f).

(not the AER) had authorised most of the transmission determinations that were in force at the time that prices began to accelerate.

Figure 2.10 The price explosion

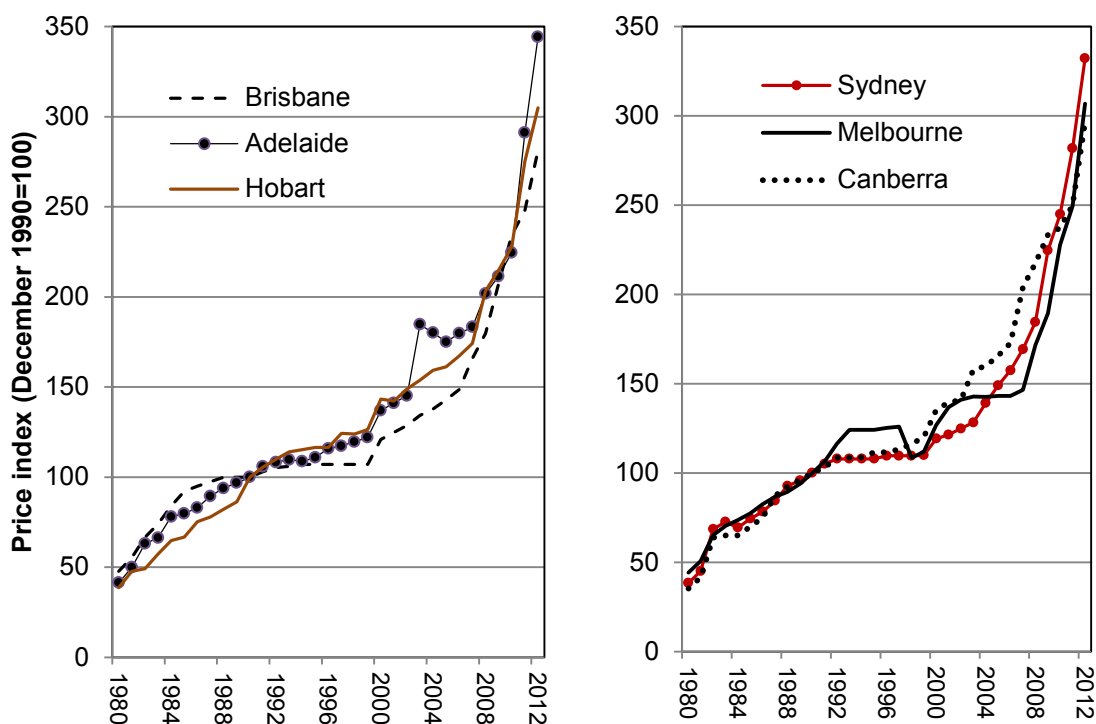
Annual growth rates (December 1981 to December 2012)



Data source: Figure 2.8.

Figure 2.11 Relative residential electricity prices by NEM jurisdiction

December 1980 to December 2012



Data source: ABS (2012e).

Box 2.1 What are electricity prices?

It is important to clarify what household ‘prices’ denote. This report uses the standard ABS definitions. Unless otherwise stated, the price of electricity at any given time is the charge levied for power use by a household (or an index of this price), taking account of connection fees that are included in the price (ABS 2011c, p. 64). Both concessional and standard rates are included in the ABS approach. The ABS produces series only for capital cities and the Australian total is the weighted average of these series. The prices are the final retail prices, and incorporate wholesale costs (generation), network charges and retail margins, among some other costs.

While statistical agencies avoid the nomenclature, the ratio of the electricity price index to the consumer price index is sometimes referred to as the ‘real’ price of electricity. This is a relative price measure, not a price per se. As it indicates how far electricity prices have shifted relative to prices in general, it identifies the price pressures unique to electricity. We explicitly indicate when we use relative or ‘real’ prices to distinguish them from the conventional meaning of prices. Note that where the percentage price increase between period t and $t+n$ is π_e and the inflation rate over the same period is π_c , then the relative price change is $(\pi_e - \pi_c)/(1 + \pi_c)$. Given this complexity, it is sometimes better to give π_e and π_c as separate (or at least as complementary) measures, especially in cases where real prices may be hard to interpret. For example, when comparing price movements *between* states, real price differences will reflect both changes in electricity prices in different states and changes in their separate CPIs. Similarly, a real producer electricity price might use an average business input price index as the denominator, which may be quite different from the CPI.

Ergon Energy pointed out some problems in interpreting retail electricity prices (sub. 8, p. 12), though these concerns are not likely to affect the broad patterns identified in the ABS data.

Source: ABS (2011c).

Many people are unaware that the costs of generating power are not the major contributor to their electricity bills. In 2011-12, the costs of network services represented between 34–56 per cent of the typical annual household electricity bill across the various jurisdictions in the NEM (and around 45 per cent for the entire NEM) (table 2.4; AEMC 2013a).²³ This represented a household cost for network services of between \$350 to \$700 per year.²⁴

In contrast, wholesale electricity prices from generators accounted for an average share of NEM-wide costs of around 35 per cent. The introduction of carbon pricing

²³ The AER (2012q, p. 127) derive a slightly different range of 43–52 per cent for 2012, but exclude Victoria (where retail prices are misleading). However, both sources indicate an average network share of around 45 per cent (AER 2012q, p. 5).

²⁴ This takes account of the varying typical power consumption patterns across jurisdictions.

— which raises wholesale prices (generation costs) and retail margins — does not alter the relative importance of wholesale versus network costs to any great extent (figure 2.12). (Moreover, changes to its design announced recently are further likely to reduce its relative influence compared with network cost pressures.)

Apart from Victoria and the ACT, network costs have been the largest contributor to price increases since 2010 (AEMC 2011a; AER 2011b, pp. 4-5, 20). For example, in New South Wales, network costs accounted for 80 per cent of the price increase in 2010-11 and 50 per cent in 2011-12. In contrast, in Victoria, changes to network costs had, at best, marginal impacts on electricity prices in 2011. The AEMC has forecast a similar pattern until 2014-15, with the exception of New South Wales, where the contribution of network costs to rising electricity costs is predicted to abate (table 2.4).

Table 2.4 Projected network costs 2011-12 to 2014-15

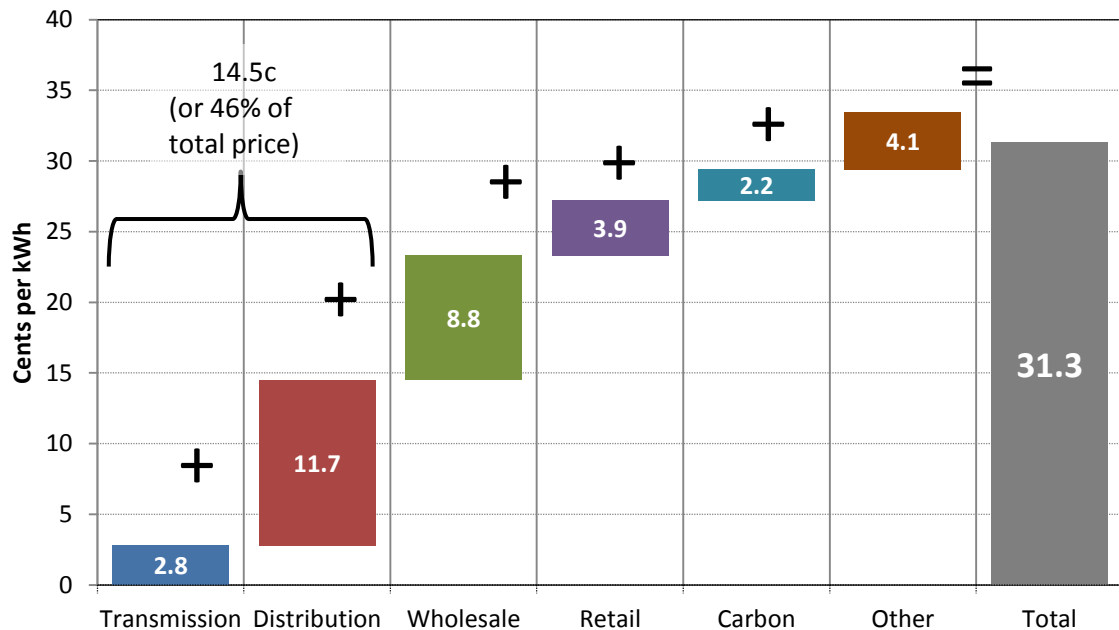
	<i>Network costs</i>			<i>Network share of total residential electricity costs^a</i>		<i>Contribution to price increases from 2011-12 to 2014-15^b</i>	
	2011-12	2014-15	Increase	2011-12	2014-15	Distribution	Transmission
	Cents/kWh		%	%	%	%	%
Qld	11.0	14.6	32.7	49.8	52.3	58.6	3.4
NSW	14.1	16.0	13.5	55.5	51.6	0	33.9
ACT	7.3	8.9	21.9	43.2	44.1	33.3	15.2
Vic	9.8	13.2	34.7	34.0	37.5	51.6	1.6
SA	13.8	18.2	31.9	46.2	54.7	108.8	20.6
Tas	14.2	17.5	23.2	54.2	56.3	40.8	26.5
WAC ^c	9.0	10.7	18.9	34.4	36.0	31.4	17.1

^a The cost shares in 2014-15 are affected by the introduction of carbon pricing, which raises wholesale electricity prices and the retail margin (but also involves some offsets). ^b The estimates are calculated as the change in the cost of power (in cents per kWh) attributable to transmission and distribution as a share of the total increase in the cost of power over the relevant period. ^c Electricity prices in Western Australia relate to the South West Interconnected System (SWIS). The prices in this state exclude the tariff equalisation contribution to areas outside the SWIS, as these represent transfer payments rather than cost-related prices.

Source: AEMC (2013a).

Figure 2.12 Projected residential price cost components in 2014-15, Australia

Cents per kWh



Data source: AEMC (2013a).

Transmission costs are far lower than distribution costs, and so their projected contribution to overall electricity price growth is muted. However, as noted by industrial businesses, the significance of transmission costs may be much greater for businesses close to the transmission supply point (Energy Consumers Group 2011, p. 9).

There are significant differences in the costs of network services in various jurisdictions. By 2014-15, the AEMC forecasts that total network costs in cents per kWh in Queensland, New South Wales, South Australia and Tasmania will be 11 per cent, 21 per cent, 38 per cent and 33 per cent higher respectively than the costs in Victoria. Much of the debate about network performance rests on the degree to which these gaps reflect excessive and inefficient costs or different operating conditions and capital vintages (chapter 6).

Notably, AEMC data show that the disparities between network costs appear to be growing over time, instead of converging (unlike other costs, which are converging). Given that the physical environment of businesses do not change

rapidly over time,²⁵ spatial differences in the topography and climatic conditions of network businesses cannot readily explain this divergence (figure 2.13).

2.5 The proximate reasons for higher network charges

Some of the contributors to network price increases have reflected input cost increases, which are typically outside the control of either network businesses or government. For example, rising steel, copper and (to a lesser extent) aluminium prices have increased costs (AER 2009a, pp. 485ff; Plumb and Davis 2010; figure 2.14). Wage rates for public sector electricity, gas and water utilities have increased at a faster rate than wages in their private sector counterparts, and all industries (figure 2.14).

Since they are determined as part of the regulatory process, increases in the regulated weighted average cost of capital are also major determinants of regulated revenues, and of resulting prices (chapter 5).

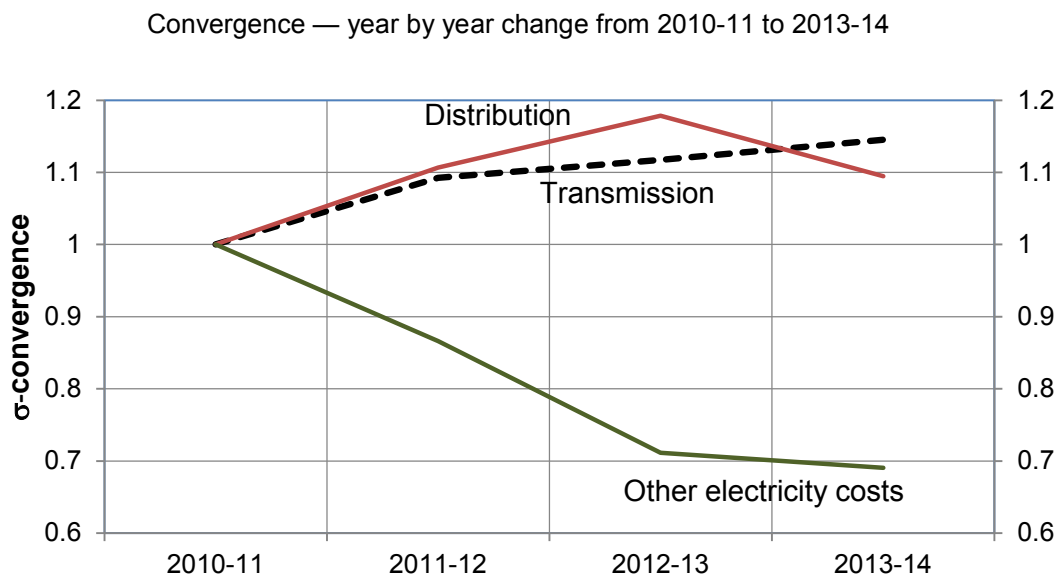
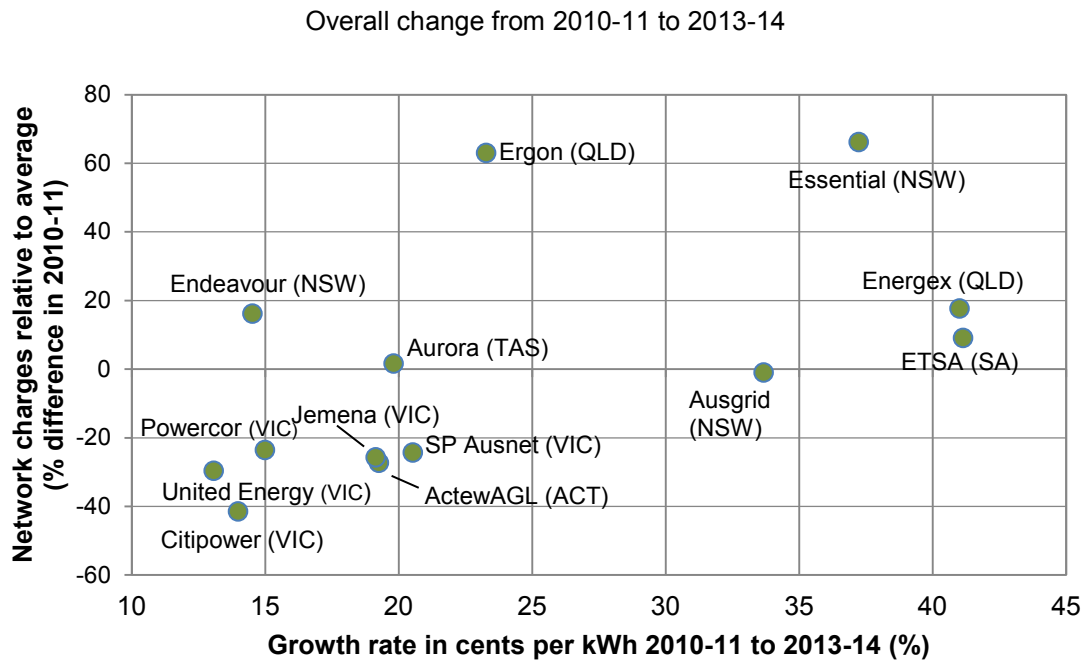
Above all, lower productivity appears to have been a major pressure on network charges. In recent years, the stock of electricity infrastructure has risen rapidly and, unusually by historical experiences, labour inputs have risen. As output has not risen as rapidly as average inputs, measured industry efficiency has fallen, and with it, prices per unit of power have risen. While it is less clear what has happened to the multifactor productivity (MFP)²⁶ of network services specifically, most of the factors driving lower productivity in the electricity industry appear to relate to the network (Topp and Kulys 2012). Evidence from IPART (2010) supports this, finding that in New South Wales there were more pronounced productivity reductions for network businesses than for generators. Topp and Kulys identify three phases of multifactor productivity growth in the electricity industry (figure 2.15):

- moderate growth phase from 1974-75 to 1985-86
- a rapid growth phase from 1985-86 to 1997-98
- a negative growth phase 1997-98 to 2009-10.

²⁵ Peak demand in summer between 2012 and 2021 is projected to grow at different rates. The forecast growth rates are low for South Australia, New South Wales and Tasmania, and highest for Victoria and Queensland, (AEMO 2012a).

²⁶ MFP measures the extent to which output growth cannot be explained by labour and capital inputs. Over the long-run, it measures greater efficiency and technical progress, while over the short-run it may reflect the business cycle or any other factor that leads to temporary underutilisation of capital or labour.

Figure 2.13 **Network costs differ between businesses and the gap is widening^a**



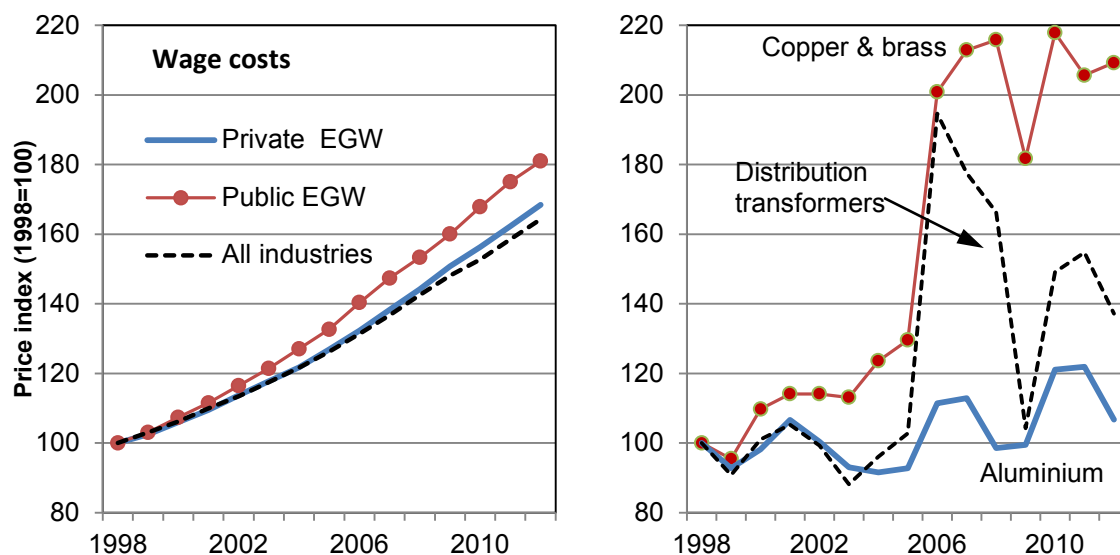
^a Network costs are the sum of the transmission and distribution costs for each business. The top graph shows that businesses with costs well above the NEM average in 2010-11, tended to have faster forecast percentage growth rates in costs from 2010-11 to 2013-14. Given this depiction of the data can sometimes give biased estimates of the extent of convergence or divergence (Friedman 1992), measures of so-called σ -convergence rigorously test whether convergence is present or not. σ -convergence occurs when the coefficient of variation between states declines over time. In this case, the data reveal divergence. The data are based on the AEMC's forecasts made in 2011 (rather than its more recent 2013 forecasts, reflecting that no data at the business level was published).

$$\sigma - convergence = \left(\frac{var(R_{2013-14})/average(R_{2013-14})}{var(R_{2010-11})/average(R_{2010-11})} \right)$$

Data source: AEMC (2011a) and PC estimates.

Figure 2.14 Input prices

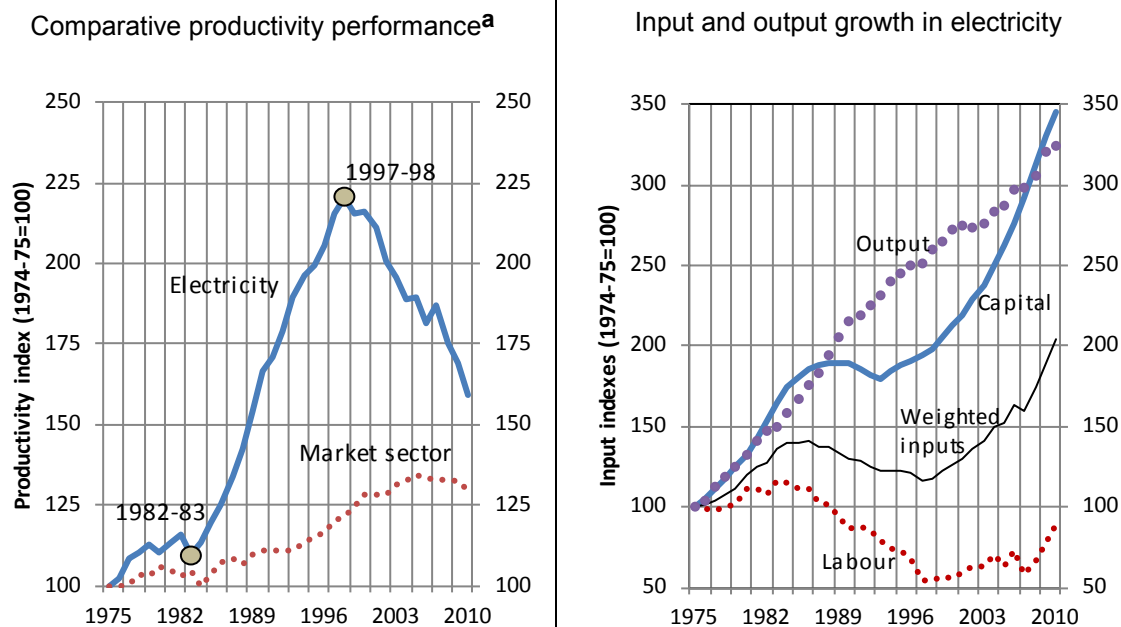
June 1998 to June 2012



Data sources: ABS (2012a; 2012d).

Figure 2.15 Measured electricity sector productivity has been falling

1974-75 to 2009-10



^a Multifactor productivity estimates are increases in real output after taking account of changes in labour and capital inputs. The market sector includes all industries, with the exception of a few industries (public administration and defence), where reliable measures of productivity are difficult to calculate.

Data source: Topp and Kulys (2012).

Much of the negative growth rate appears to reflect capital growth without commensurate measured output growth. At face value, that suggests inefficiency. However, at least some of the growth in the capital stock reflects replacement capital for ageing assets, and new capital to meet the demand for greater reliability levels, growing peak demands, and requirements for greater undergrounding of lines (noting that underground lines are significantly more costly than overhead lines). Network businesses pointed to some of these pressures (for example, Ergon Energy, sub. 8, p. 11). The ABS's output measures for electricity fail to take account of the value of customer reliability, the benefits of undergrounding or the additional value of capacity at peak times. Were these counted as output benefits, MFP growth would have been higher.

Nevertheless, the fact that some pressures have legitimately led to rising capital investment, and therefore a measured fall in productivity, does not necessarily mean that network businesses have performed as efficiently as they could. The regulator and many customers claim that regulatory flaws have led to premature and inefficient investment. These investment patterns (and the possibility of addressing them through benchmarking) are the preoccupation of chapters 5 to 8.

Moreover, even though customers value reliability, it is not clear that many of the investments have actually increased reliability or, to the extent that they have, that the benefits to customers have outweighed the investment costs (and the associated price increases that these entail). Similarly, while rising peak to average demand requires network reinforcement, it is an open question whether other approaches — such as demand management — could have been used as a more efficient alternative. Accordingly, there is a potentially large difference between the *proximate* causes of rising network investment and the real underlying forces at work.

2.6 Reliability

The reliability of networks has many dimensions — such as the number of outages per customer, average interruption durations and the geographical reach of outages (chapter 14). Generally, transmission networks are very reliable due to their high level of redundancy (built-in additional, or spare, capacity), and the rarity of events likely to trigger outages. Consequently, the most meaningful measures of network performance over short periods relate to distribution networks.

There are marked differences in reliability levels between states, with a persistent gap between that of Queensland distributors and those in other jurisdictions (figure 2.16), only some of which appears to reflect lower customer densities.²⁷

The AER has observed that the reliability levels, as measured by average annual outage durations²⁸ and the annual number of interruptions per customer²⁹ have been relatively stable over time. The Commission found only one statistically significant trend — an increase in average minutes of outages per customer of 10 minutes per year in Victoria.

While there is a positive relationship between annual interruption frequency and interruption duration, it is not a strong one (figure 2.16). Since, all things being equal, any reduction in interruption frequency should lead to reductions in average annual hours lost per customer, this implies that average durations of interruptions³⁰ are tending to rise as interruption rates fall. There are statistically significant (but small) trend increases in average durations per outage in Queensland, Victoria and Tasmania, whose cause is unknown.

Regardless, the reliability data show that many of the shifts from year to year reflect random events — shown by the gyrating movements in figure 2.16. It is certainly not evident that the large increases in capital expenditure across the NEM have yet achieved greater reliability. While this suggests inefficient investment, there may be other confounding factors at work (an issue that benchmarking analysis at the business and sub-regional level might shed light on).

2.7 What is at stake?

As shown in tables 2.2 and 2.3 and figure 2.6, the electricity network industry commands a large amount of resources and provides services throughout the economy.

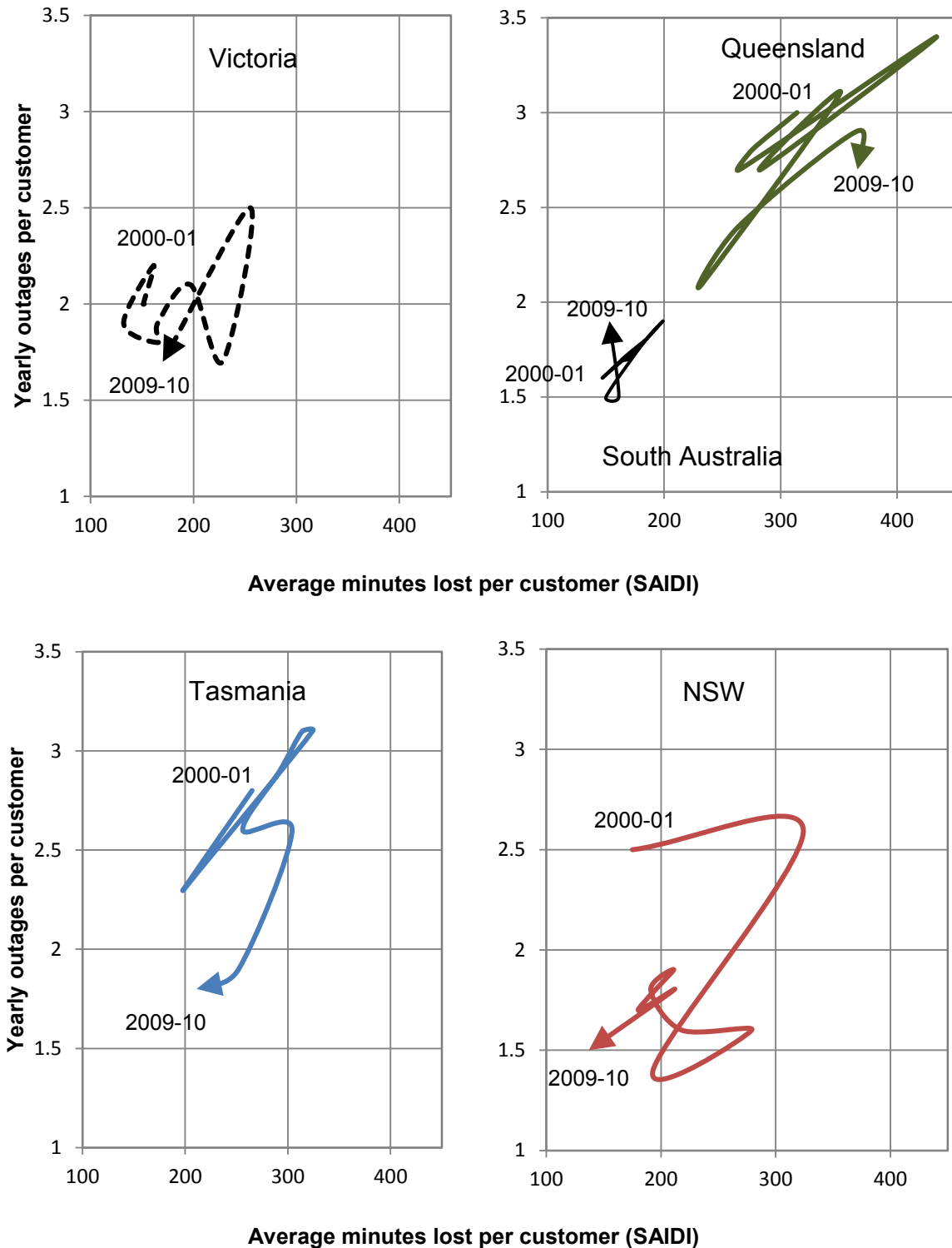
²⁷ Even when controlling for rural location, reliability tends to be lower for Queensland network businesses (AER 2008a, p. 162).

²⁸ System Average Interruption Duration Index.

²⁹ System Average Interruption Frequency Index.

³⁰ This is the Customer Average Interruption Duration Index or the average restoration time.

Figure 2.16 Reliability varies significantly^a



^a The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control, although problems due to major weather events have been excluded. SAIDI denotes System Average Interruption Duration Index.

Data source: AER (2011b, p. 68).

That suggests potentially large benefits from reducing even small inefficiencies, let alone those of the magnitude suggested by some participants. Like unhappy families in Tolstoy's *Anna Karenina*, inefficiency can be manifested in many ways.

- Businesses may invest prematurely in what would ultimately be productive investment (the likely outcome of insufficient demand management or excessive reliability standards).³¹
- Businesses may use existing capital inefficiently (lower capital productivity). For example, poor maintenance arrangements may require more redundancy than necessary.
- Businesses may make investments that are not required at all to produce output (the conventional definition of 'goldplating').
- Investment costs may be excessive due to poor project management.
- Labour may be in excess of what is required or poorly used (resulting in lower labour productivity).
- Physical investments and labour inputs may be at efficient levels, but may be priced excessively. This could arise if the weighted average cost of capital is too high or if unions are able to negotiate higher wages (which appears to be true — figure 2.14 — especially for the state-owned corporations). High network prices lead to so-called allocative efficiency losses for customers (chapter 3). The structure of prices may also be inefficient if they are not cost-reflective (an issue particularly relevant to time-based charging — chapter 11).

The incorporation of benchmarking into incentive regulation (or even the publication of benchmarking results) attempts to eliminate such inefficiencies. However, the magnitude and timing of any such benefits depend on the nature of the policy reform and the source of the inefficiency.

Since most regulatory determinations have some years to go (table 2.5), at best, any reforms of incentive regulations would not have effects on the most costly part of the system (distribution) until after mid-2015 at the earliest. Reforms to incentive regulations may take some time to deliver benefits. This (and the period taken to roll out smart meters) also extends the timing of major demand management initiatives by some years (chapter 10). The issue of aligning reform to regulatory determinations is discussed further in chapter 21, and especially the risk that slow reform can inordinately delay benefits for consumers.

³¹ In principle, businesses might also underinvest in reliability — though currently this does not appear to be a significant issue.

Table 2.5 Timing of regulatory determinations

<i>State</i>	<i>Prior to AER role</i>	<i>Current and future AER determinations</i>
Distribution network businesses		
Qld	1 July 2005 to 30 June 2010 (QCA)	1 July 2010 to 30 June 2015 1 July 2015 to 30 June 2020 ^a
NSW	1 July 2004 to 30 June 2009 (IPART)	1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015 ^b 1 July 2015 to 30 June 2019
Vic	1 January 2006 to 31 December 2010 (ESCV)	1 January 2011 to 31 December 2015 1 January 2016 to 30 December 2020 ^a
SA	1 July 2005 to 30 June 2010 (ESCOSA)	1 July 2010 to 30 June 2015 1 July 2015 to 30 June 2020 ^a
Tas	1 July 2008 to 30 June 2012 (OTTER)	1 July 2012 to 30 June 2017 1 July 2017 to 30 June 2022
ACT	1 July 2004 to 30 June 2009 (ICRC)	1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015 ^b 1 July 2015 to 30 June 2019
Transmission network businesses		
Qld	1 January 2002 to 30 June 2007 (ACCC)	1 July 2007 to 30 June 2012 1 July 2012 to 30 June 2017 1 July 2017 to 30 June 2022
NSW	1 July 2004 to 30 June 2009 (ACCC)	1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015 ^b 1 July 2015 to 30 June 2019
Vic	1 January 2003 to 31 March 2008 (ACCC)	1 April 2008 to 31 March 2014 1 April 2014 to 31 March 2017 ^c 1 April 2017 to 31 March 2022
SA	1 January 2003 to 30 June 2008 (ACCC)	1 July 2008 to 30 June 2013 1 July 2013 to 30 June 2018 1 July 2018 to 30 June 2023
Tas	1 January 2004 to 30 June 2009 (ACCC)	1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015 ^b 1 July 2015 to 30 June 2019

^a Preliminary determination with mandatory re-opener. ^b Placeholder determination under old rules. ^c Old rules for 3 years.

Sources: Various determinations by the AER and by state and territory regulators; AER (2013c)

Even when the AER makes new regulatory determinations, it would not be possible to deploy existing genuinely ‘goldplated’ capital elsewhere — these are sunk

investments. The best that can be achieved is a lower future level of investment to avoid goldplating.

The better use of the existing capital stock and improved project management could have more immediate efficiency effects — for example, arising from eliminating some of the constraints on the performance of state-owned network businesses. Given incentive regulations, this would increase network profits, but not reduce prices until the next reset. However, higher profits are better than unnecessary investment. They permit greater investment elsewhere in the economy or can increase consumption.

‘Back-of-the-envelope’ calculations suggest that deferred investment can yield substantial economic benefits. Based on relatively modest assumed deferral (of three years), the net present value of the benefits were around \$8 billion over a 30 year period. Whether such savings can be realised depends on how far reliability standards (or other factors affecting the desirable timing of investment) are away from their optimal level.

There could also be large benefits on the employment side. Employable people are footloose in a flexible economy. This means that if there is a productivity improvement in one industry, people usually find jobs elsewhere at close to their former wages. In the case of electricity networks, employment is as geographically dispersed as are the wires and poles. Accordingly, the frictions in movements of employees sometimes associated with employment losses concentrated in a particular location would be less likely. Given estimated employment levels in network businesses, a 10 per cent improvement in labour productivity would release around 2500 workers to other industries, with annual economic benefits of around \$300 million. Since these benefits would be sustained over future years, the net present value of the benefits would be substantially greater.

The above estimates of the economic benefits of higher labour and capital productivity are illustrative. They depend on assumptions about future growth in investment, capital and labour and use scenarios that may not be realistic. Nevertheless, one conclusion is robust — small improvements in the efficiency of electricity networks have large absolute benefits for Australians.

Any household consumption-side efficiency benefits from reform are likely to be much smaller as electricity demand is relatively inelastic (section 2.3) and because network infrastructure is only a share of total electricity retail costs. However, the gains may be larger for globally footloose industrial businesses, which will tend to be more responsive to prices and in particular to their likely future trajectory (chapter 3). The consumer transfer benefits from reform would be more important,

and as discussed in chapter 3, are still relevant in gauging the beneficial impacts of competition regulations.

General equilibrium effects

General equilibrium (GE) analysis takes account of the multiple linkages between industries (reflected in the importance of electricity networks to all other industries shown in figure 2.6), and of how price and productivity shocks cascade throughout an economy. GE benefits often exceed the benefits of reform revealed by partial equilibrium analysis (like that above). GE benefits could readily be between 20 and 30 per cent higher.

3 The rationale for regulation of electricity networks

Key points

- In any given geographical area, electricity networks are natural monopolies as it would be uneconomic for another business to duplicate the infrastructure.
- The theory and evidence about the behaviour of natural monopolies suggests that without strong regulation, network businesses could be expected to set excessively high prices and potentially provide too low a quality of services.
 - They would also face fewer incentives for internal efficiency and greater motivations for rent seeking to shore up their unregulated status.
- These resulting static and dynamic economic inefficiencies provide a compelling rationale for regulation of network businesses.
- Moreover, while not necessarily an economic inefficiency, high unregulated prices:
 - lead to potentially undesirable transfers from customers to businesses
 - would be regarded as unfair by many consumers.
- These provide further grounds for regulation, though they do not greatly assist the actual determination of the right price.
- Concerns about the impact of higher prices on particular customers are a less credible basis for competition regulation since their correction requires cross-subsidies between customers. Unless a special case can be made, such equity concerns should be addressed through other means.
- Recently, the importance of the above rationales for competition regulation has been questioned. Instead, it has been argued that the main goal of regulation is to prevent the monopoly business from holding customers to ransom once they have made sunk investments that use the inputs of the monopoly business. Were this true, it would discourage customer investment in the first place (the 'hold-up' problem).
- However, the market circumstances that would lead to the hold-up problem are mostly absent, markets have other solutions to the problem were it to occur, and regulators can create the same problem for the investments in the monopoly essential service (with even worse efficiency and distributional outcomes for customers).
 - The orthodox rationales for strong regulation of natural monopoly are sound.

The appropriate regulation of electricity networks depends on the features of those networks (section 3.1) and the problems that would arise were they to be unregulated (section 3.2). The fact that electricity networks have market power is not controversial. However, the various rationales for regulating a natural monopoly — a core issue for regulatory remedies, including the role of benchmarking — remains complex and contested (section 3.3). Indeed, most recently, there have been challenges to the conventional wisdom on why regulation is necessary. Drawing on a new theory, different policy approaches have been proposed (section 3.4 and 3.5). The rationales implied by the considerations above help frame the appropriate policy goals of the regulator (section 3.6).

3.1 The characteristics of electricity networks

Electricity networks have several distinctive characteristics that affect the desirability and nature of regulation (most especially economic regulation).

In each geographic segment, supply of electricity costs are minimised through supply by a single distributor or transmission business — or a ‘natural monopoly’. This reflects some collective features of electricity networks, including the:

- very large fixed costs of the network (and low marginal operating costs)
- scarcity of easements required by distribution networks (and the opposition by householders and local governments to any potential duplication)
- safety concerns for consumers and workers were there to be multiple wires (overhead or underground) owned by separate businesses
- need for the system to act as a coherent network, with appropriate frequency and voltage control
- need for power on demand, and the incapacity to store power efficiently, which restricts the use of many distributed energy options and requires a very reliable network built to peak demand
- advantages of having generators located close to cheap energy sources that may nevertheless be some distance away from end users
- millions of customers, most with very limited countervailing bargaining power (unlike, for example, airports with airlines).

As such, there is no genuine capacity for new entry by a rival in any given area, unlike electricity generation or retailing. For example, an urban street would not sensibly have two sets of power lines owned by different suppliers.¹

In addition to its standard natural monopoly characteristics, there are special features of electricity networks that could lead to significant advantages to incumbents even where the networks expand to new geographical areas. For instance, to bring power to a new customer zone from generators already connected to the incumbent's transmission system, a potential transmission rival must either:

- build a new line all the way to the existing generators (a high fixed cost) or
- need access to the incumbent's network. As discussed in chapter 18, the high voltage inter-regional transmission lines (interconnectors) might feasibly provide contestability in some parts of transmission, since each new transmission line in an interconnected system can act as a substitute for other lines. However, there would need to be a regulated requirement for any-to-any connectivity, as in telecommunications, which without access requirements, the incumbent would not be obliged to provide. (In fact, in the absence of regulated technical standards, it might be justified in withholding access given the potential externalities posed by network effects.)

Even were the transmission businesses to negotiate a commercial agreement, non-cooperatively determined charges for transmission rights could lead to higher prices than for an integrated monopolist. This reflects that each party acting independently could add a mark-up on marginal cost whose overall impact would be higher than the mark-up chosen by a horizontally integrated transmission business — the 'double marginalisation problem' (Laffont and Tirole 2000, pp. 184ff). In the United States, this has actually materialised, with customers and suppliers facing double margins on charges as their power crossed a utility's corporate boundary (Massey 2007, p. 6).

The natural monopoly characteristics of networks could also allow a network business to foreclose supply upstream (generation) and downstream (retailing), so that vertical integration of these activities would occur. However, structural separation of most monopoly networks has occurred through privatisation, new entry and the creation of separate state-owned corporations in the contestable part of the market, so this particular risk has vanished. Nevertheless, there remain some concerns about:

¹ Though there may be 'underbuild' when distribution wires are strung under higher-voltage wires on a sub-transmission line.

-
- the integration of generators and retailers — ‘gentailers’. Whether this is genuinely a problem is not considered in this inquiry
 - the market power that can be wielded by some incumbent generators (a matter discussed in chapter 19), which also has implications for the efficient use of interconnectors
 - the potential for common share ownership of generation and network businesses, (albeit in separated entities) to influence decision making. Even though the Queensland and New South Wales Governments have structurally separated their network and other electricity businesses, they still own a significant share of generation capacity in their states (AER 2011b, p. 29). In a private situation, the Australian Competition and Consumer Commission would not approve (a transaction that led to) common shareholding of businesses that would be likely to ‘substantially lessen competition’ (increasing the ability to wield market power) in a market (s. 50 of the *Competition and Consumer Act 2010* (Cwlth)). It is unclear whether common government ownership of generation and network assets would necessarily have such an effect.

The above features of electricity networks need not eliminate the scope for some competition. The relevant market should not be defined as the technology for transporting power, but by the responsiveness of customers to increases in electricity prices, which in turn, will depend on the extent to which customers can choose alternatives. For example, gas already provides some competition as an energy source for cooking, and water and household heating.

In the future, standalone distributed generation — such as rooftop photovoltaic cells or small gas-powered generators — may provide some competition to the network. However, the prospect of widespread competition of this form is not imminent. Even where they do exist, most distributed generators are still typically linked to the distribution network. This enables customers to feed their excess power into the grid, and access power at times when their generators have failed or cannot meet peak capacity requirements (chapter 13).² Accordingly, their network savings will more likely apply to transmission. At least for inter-regional transmission lines, pipelines that transport gas to generators, which then feed power into regional transmission networks, is a more realistic source of competition.

For the immediate future, it is likely that without regulation, electricity networks could exercise substantial and enduring market power. (In this respect, they are not

² Of course, in some circumstances, distributed generators are not linked to the grid at all — especially in non-metropolitan areas.

like innovating businesses that create momentary rents that competing innovative rivals then bid away — as in many electronic products or drugs.)

3.2 Evidence about the costs of market power

The *a priori* case for at least some regulation of businesses with enduring monopoly power in key goods and services is so strong that, at least in advanced economies, governments typically regulate them. Therefore, it is hard to find much detailed evidence about the actual behaviour of such businesses under a counterfactual when that regulation is absent. Some of the most notable exceptions are distantly historical — such as the US Standard Oil Trust, United States railroads in the 19th century, and salt monopolies in 17th century France — all of which engaged in the price gouging anticipated for monopolies.³ Gas distribution in the United States was initially unregulated, until prices rose to high levels after the formation of a monopoly gas trust (Troesken 2006). Private water companies appear to have set inefficiently high prices and delivered dangerously low-quality water to United States citizens in the late 19th century (Troesken 2006, pp. 274-5).

The main, and hardly unsurprising, lessons from unregulated monopolies wielding market power are that they charged high average prices and that they spent significant resources trying to maintain that power.⁴ That provides little empirical guidance about the magnitude or source of welfare costs that might exist for an unregulated electricity network in contemporary Australia. It is likely that an unregulated essential service monopoly today would be far more sophisticated — for example, in its pricing strategies and in its bargaining with different groups of customers.

The problems in gathering evidence about the counterfactual have several implications.

³ There have been many ostensibly unregulated state-owned utilities, but they were often charged with social goals that meant they were, in effect, partly regulated. Moreover, they did not usually face the same incentives as private firms due to their affiliation with government, and were often less exposed to even the risk of competition due to statutory barriers to entry. In that sense, their conduct may not be representative of an unregulated private monopolist.

⁴ Monopoly per se does not *necessarily* confer significant market power. For example, there may be countervailing power from customers (Oxera 2012). Airlines and airports are one illustration (PC 2011b, pp. 74-5, 80-2, 193, 331-33). Moreover, a monopolist that exploits its market power for most customers may do so to a much lesser extent for a commercial customer that uses the monopolist's output as an input into the production of a good exposed to very competitive markets.

Arguments about the nature and magnitude of the costs of the market power of electricity network businesses (and guidance on the best counteracting forms of regulation) will draw more strongly on theories and ‘reasonable’ assumptions than in many other areas of economics.

As a result, it is hard to rigorously test rival theories about the exact nature of the costs of natural monopoly, and consequently, the best type and benefits of regulation. The situation is akin to observing a patient’s health after receiving a treatment, but with less information about their health status before treatment. There is, however, the possibility of testing competing theories based on internal consistency, empirical evidence about behavioural relationships that hold more generally (for example, that businesses with high fixed costs often use two-part tariffs for efficient recovery of those costs) and based on the observation of partly regulated monopolies and unregulated businesses with transient market power. It is also possible to test rival theories about the impact of alternative regulatory regimes on efficiency and prices (a form of benchmarking).

Given the magnitude of the potential economic and social effects of different degrees of regulation, it is critical to separate the wheat from the chaff, else the community could become the victim of the ingenuity of particularly persuasive theorists. The last 150 years of competition theory demonstrates that alternative theories often reach radically different policy conclusions about the appropriate reach of regulation (none in some cases, to complete regulatory oversight or public ownership in others). No theory has proved entirely satisfactory, and some have appeared to excuse anti-competitive conduct (Crew and Kleindorfer 2004; Melody 2003). As Melody put it acerbically:

... the essential criteria around which public utility regulation has revolved are the reasonableness of prices and the universality of service coverage. It is on this skeleton regulatory framework that a little meat and an enormous amount of fat has been hung during the last century. (2003, p. 7)

Finally, there is enough uncertainty about the effects of (unregulated) natural monopolies that regulators also face uncertainty about the degree to which they have succeeded in their endeavours. Regulators have to be particularly mindful that they have less market and engineering expertise than the businesses they regulate.

3.3 The case for regulating monopolies

Putting aside foreclosure risks, the usual basis on which governments regulate natural monopolies are concerns about the impacts of higher prices and lower

output. In the case of electricity networks, lower output may take the form of reduced quality and not just less network capacity.

There is no single adverse consequence from these outcomes. Over several hundred years, economists and legal experts have identified multiple channels by which these outcomes can affect people's welfare. These multiple channels can represent a challenge to regulators because some types of regulatory responses may address one channel, but not another, in which case regulation may need to involve tradeoffs.

(i) Consumer preferences are not fully and efficiently met

If a network business were to charge a price to consumers that exceeded the full cost to the business of transporting power, then customers forgo some consumption that was valuable to them, and that the business could have economically supplied. (A similar outcome might occur if the network business skimmed on quality.) The immediate customers of a network business may often be other businesses. High electricity prices could have significant effects on their output and investment, especially if they compete on global markets. But the long-run effects are experienced by households.

(ii) Production inefficiencies

Unless it has perfect price discriminating capacity, monopolists produce less output than is efficient. The inputs that the business would have used to produce that forgone output would be allocated elsewhere in the economy, but to lower-value uses.

The inefficiencies resulting from (i) and (ii) are the most commonly cited conventional sources of welfare losses from monopoly power. These inefficiencies can be static or dynamic. For example, the latter would include adverse effects on investment or on the drive for innovation or cost minimisation by a customer or upstream supplier of an unregulated monopolist.

Since they are well understood, this chapter devotes little space to (i) and (ii), but brevity should not imply that they are not significant (especially once their long-run effects are considered).

(iii) 'X-inefficiency' or business underperformance

Regardless of the degree of competition in a market, it is in the interests of shareholders to minimise costs to maximise profits.

However, there are several theoretical reasons, backed by empirical evidence, that suggest that persistently low levels of competition may weaken the internal *managerial* incentives for cost minimisation and innovation — creating so-called x-inefficiency.⁵ This does not contradict the shareholder goal of profit maximisation.

For example, employees and managers may (rationally) work less hard, knowing that shareholders find it hard to observe their lack of effort (so-called 'principal-agent' problems) and that the business will still survive without strenuous effort because of the absence of competitors or, in the case of state-owned corporations, the risk of takeovers. Some of the signals available to shareholders about the performance of enterprises in workably competitive markets are weaker in the case of natural monopolies:

- it is harder to establish yardsticks against which to compare performance, whereas in workably competitive industries, comparative prices and product innovation of rival businesses are more easily observable
- persistently poor managerial performance does not result in lost market share (preserving 100 per cent of the market in a perfect natural monopoly) nor in losses, since a monopolist can apply a margin to its inflated costs and still earn a positive return.

While the term x-inefficiency originated with Leibenstein (1966), the nexus between the absence of competition and managerial underperformance has been persistently observed since economics began as a discipline. Nearly 250 years ago, Adam Smith (1776) observed, 'monopoly ... is a great enemy to good management', while 80 years ago Hicks (1935) argued that the 'best of all monopoly profits is a quiet life'. Australia's principal competition regulator, the Australian Competition and Consumer Commission (ACCC), has recently echoed this sentiment, observing that market power can be manifested as a 'lazy monopolist with a quiet life' (Pearson 2011, p. 4).

⁵ However, x-inefficiency is not all waste. A quiet life is valuable to those enjoying it, and to that extent, x-inefficiency is a transfer from shareholders to employees (Alchian and Kessell 1962). However, there may still be waste because many employees would prefer to take the rent as wages, but cannot do so because wages are observable to shareholders.

There is substantial empirical evidence from 30 years of international studies that x-inefficiency is a major source of economic waste in industries protected from fierce competition — particularly essential services. These inefficiencies are potentially larger than the allocative efficiency losses described in (i) and (ii).⁶ There is a parallel literature in trade policy providing further empirical support for the debilitating efficiency effects of weaker competition (in this case arising from barriers to import competition).⁷

As an illustration of its potential importance, empirical research found x-inefficiency of around 20 per cent in the Australian electricity industry prior to microeconomic reform, though this may partly reflect state ownership of vertically integrated electricity businesses, as well as statutorily guaranteed market power (Whiteman 1998). Mountain and Littlechild (2010) and Mountain (2011) claim even more profound inefficiencies for both state-owned and private network businesses.

One of the dilemmas of regulation of natural monopolies is to ensure that it does not create x-inefficiency in its own right.⁸ Conventional rate-of-return regulations — which limit the rate of return of a regulated monopoly — reduce rents, but create incentives for inefficiency by encouraging cost padding. Indeed, a strong motivation for benchmarking of regulated monopolies is to identify and penalise x-inefficiency (and not just the targeting of monopoly rents). The regulator may use benchmarking results as one source of evidence about the acceptably efficient operation of business to help determine regulated prices or revenues. Incentive regulation is based on rewarding businesses using the performance of a leading practice firm close to (but not usually at) the efficient frontier as the benchmark. In that sense, while the avoidance of x-inefficiency may (partly) motivate regulation in the first place, it also partly motivates the regulator's choice of regulation.

(iv) Rent seeking

Given the monopoly 'rents' achieved through transfers from consumers to businesses, well-run monopolies have the potential to earn high rates of return on assets. This can prompt wasteful lobbying and other 'rent seeking' — a term coined

⁶ As discussed by Perelman (2011) and documented by Frantz (2007) for many industries, De Witte and Marques (2010) for water, Brons et al. (2005) for urban transport, and a large number of studies of the electricity sector (described throughout this report).

⁷ See Panagariya (2002) for a survey.

⁸ Indeed, one of the empirical difficulties in assessing the degree to which monopolies create x-inefficiency is that most natural monopolies are heavily regulated, so that it is hard to disentangle the effects of monopoly and the effects of the regulation of monopolies.

by the World Bank Chief economist, Anne Kreuger — to preserve monopoly power.

In theory, rent seeking (and its protection) could dissipate all or, indeed some multiple, of the rents as unproductive activity, though in practice that is unlikely (Congleton et al. 2008). Certainly, academics and others have identified rent seeking in almost all areas of economic activity where governments, through statute or regulation, have the discretion to restrain or increase market power. This is one reason why excessive regulatory discretion can be inefficient. Concerns about such rents apply to areas as disparate as preferential trade agreements (Cutbush 2010), water (Goesch and Hanna 2002), taxi regulations (Moore and Balaker 2006), union market power (Connolly et al. 1986), import protection (Olson 2005; Ville 2007) and pharmacy (Philipson 2003).

The desire to preserve rents can also lead to excessive political power to the monopoly business or other parties, such as unions, that may share the rents. For example, this was apparent in some unregulated railroad monopolies in the United States in the 19th century. The ‘Camden and Amboy’ monopoly railroad acquired sufficient political power that the State of New Jersey became known across the United States as the ‘State of Camden and Amboy’ (Stein 2012). One executive of the railroad famously said ‘he carried the State in his breeches pocket, and meant to keep it there’ (Rutgers University Libraries 2011).

However, the regulation of natural monopolies does not eliminate rent seeking since the monopoly business and its customers have strong incentives to influence the regulator to re-cast the regulatory contract to their own advantage. Indeed, sometimes incumbent utilities have lobbied government for the creation of a statutory monopoly, arguing that the quid pro quo of economic regulation is the guarantee of insulation from competitive entry (a strategy used by the giant United States telco, AT&T, in the early 20th century — Melody 2003). Nonetheless, to the extent that a regulator significantly reduces rents, the resources that competing parties are willing to use to secure the remaining prize are also diminished.

The relevance of rent seeking for competition policy is the need to have a credible commitment to long-run constraints on monopoly power (without excessive discretion). As for other major natural monopolies, in electricity networks this is best achieved through clear regulatory objectives and statutes, a politically independent regulator (such as the Australian Energy Regulator or ‘AER’) and institutional arrangements that give customers sufficient visibility and negotiating power to counter the monopoly businesses (chapter 21). Biggar (2011b, pp. 18-19) and Littlechild (2009) have given particular emphasis to the latter. The Commission agrees with this emphasis.

(v) The distributional effects of consumer to business transfers

Consumers and regulators often raise distributional matters. However, they are much less straightforward than the above issues. Monopoly rents are transfers from consumers to those with a stake in the monopoly business (shareholders and those employees who are able to achieve the ‘quiet’ life or can negotiate higher wages). Even where the initial impacts of monopoly are higher prices for downstream business customers or lower prices for upstream suppliers, the costs are ultimately likely to be borne by households.

Such ‘consumer-to-business’ impacts *may* matter in several ways. Society may value consumer welfare more than the welfare of shareholders or the business’s employees (Armstrong and Sappington 2006; Sims 2012a). That might occur because the shareholders that have benefited from the rents are foreign so that their welfare is not relevant to maximising the welfare of Australians. Or, it may be because, as a group, the relevant consumers facing higher prices have lower income than shareholders. That presupposes that the marginal benefit to lower-income consumers of an additional dollar is higher than for shareholders. While this appears to be a reasonable claim, there is significant debate about when that should be considered in policy analysis (PC 2011a, pp. 955-956).

Distributional issues raise questions of fact and careful interpretation.

- If foreign shareholders purchased the monopoly business at a price that already fully capitalised the rents, then the preceding owners acquired the rents, not foreigners (a point made by Posner 2001). In some cases — and this is true for all Australian electricity networks and many other businesses with market power in Australia — state and territory governments were the original owners. Accordingly, it is possible that citizens acquired the stream of any future rents as a lump sum from the asset sale at privatisation. (Whether that is true depends on whether the sale process effectively captured all rents.)
- Monopolies are often state-owned. If the monopolies wield market power, the transfers are from consumers to citizens generally (either through reduced taxes or additional services). Whether there are any adverse distributional outcomes depends on judgments about the capacity of governments, through the political process, to make wise distributional decisions.
- While there may still be distributional effects, they may be mitigated by diversified share ownership. For example, superannuation funds, which hold many of the retirement savings of Australian workers, sometimes have significant holdings in businesses with market power. In theory, the implicit taxes that monopoly imposes on consumers may be less for lower income consumers (depending on how the monopoly business sets its tariffs). In that

instance, it is possible that transfers from consumers to shareholders have distributional benefits. Whether that occurs is a question of empirics, not principle. Currently, Australian private electricity networks are largely foreign-owned.

- There is little question that society values some re-distribution of income from higher-income to low-income people — as revealed by the tax and transfer system, and by people's private voluntary re-distribution of resources. However, the overall level of re-distribution in a society depends on the cumulative effects of the myriad ways in which re-distribution occurs. There is a point after which people see further re-distribution as undesirable. Accordingly, without knowing this bigger picture, it is unclear whether any single policy with re-distributive impacts is optimal. This aggregate perspective is overlooked in populist views about the desirability of achieving re-distribution in every instance where a policy has income or wealth effects.

The policy implication of the latter point is that the desirability of different re-distributive policies depends on their relative efficiency costs. It is possible to be strongly in favour of re-distribution of income in a society, but to be doggedly opposed on efficiency grounds to a particular policy that attempts to achieve that.

A possible argument for curbing any re-distributive effects of unregulated monopoly is that passing monopoly rents back to consumers resembles the outcomes of an efficient rent tax (Armstrong and Sappington 2006; and more broadly, Laffont 2005).⁹ *If* correctly calibrated so as not to take too much from the monopolist, rent taxes should not raise relative prices or reduce production and investment incentives.

In achieving a desirable level of re-distribution in an economy, rent taxes could displace other inefficient taxes. Another way of looking at this is to imagine the political calls for greater family transfer payments, higher pensions and allowances, and more utility assistance to relieve cost-of-living pressures were essential services to be priced at monopoly levels. Any such fiscal measures would involve new taxes to fund these outlays, with their associated inefficiencies. The excess marginal burden of taxes vary considerably,¹⁰ but the most commonly applied taxes for gathering new revenue are income taxes. The accompanying technical paper to the Henry Tax Review found that labour income taxes, payroll taxes and corporate

⁹ This is subject to the proviso that the rents are not the outcomes of innovation or risky investments. Taxing such 'rents' would reduce incentives for risk-taking. That proviso is not likely to hold for standard investments in electricity networks.

¹⁰ This measures the deadweight inefficiency costs as a share of each dollar of revenue that government raises. These costs arise because taxes affect decisions to invest and to work.

income taxes had marginal excess burdens of 24, 41 and 40 per cent respectively, while municipal rates (a rent tax) had a burden of 2 per cent (KPMG Econtech 2010, p. 44).

Consequently, there may be *efficiency* grounds for removing genuine rents through the regulation of natural monopolies and passing these back to customers as lower prices. The main drawback to this observation is that an implicit monopoly rent tax distributed in proportion to consumers' use of electricity is not equivalent to the outcome were the tax to be collected by government and then used to reduce debt or distortionary taxes. Nevertheless, there may be some efficiency benefits.

Regardless, addressing the conventional efficiency costs of monopoly will limit transfers from consumers to a monopoly business. As noted by Banks (2012, p. 12), the focus of National Competition Policy 'on promoting efficiency should not be seen as contrary to distributional goals.'

This is consistent with the National Electricity Objective (NEO) (as described in chapter 1), and particularly its emphasis on promoting 'efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity'. The NEO captures the central rationales for the regulation of monopoly businesses:

- efficient production by network businesses (static and dynamic)
- the efficient use of network services by customers (both households directly purchasing electricity and downstream business users that ultimately supply goods to customers)
- the necessity of ensuring efficient investment and other required expenditure needed to ensure long-term reliable supply.

While it would also imply a preference for transfers to favour consumers where efficiency was not at stake, the NEO can be seen as fundamentally an efficiency objective.¹¹ As noted in the second reading speech for the Bill containing the NEO:

The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response

¹¹ The NEO suffers from some ambiguity — a point made in the Commission's analysis of the similar object clause in telecommunications competition regulation (Part XIC of the then Trade Practices Act); by the Energy Networks Association at the time of the Exposure Draft of the National Electricity Law (ENA 2004); and by Kerin (2012). However, these concerns are largely allayed given the guidance on the interpretation of the NEO in the second reading speech.

to changes in consumer needs and productive opportunities. The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised. (Second reading speech, *National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*)

In their stage one interim report on the limited merits review regime, the panel (Yarrow et al. 2012b, p. 40) noted that the NEO has the advantage that it is both clear and emulates the outcomes of effectively competitive markets:

The primacy of the long term interests of customers as an evaluation criterion, set out in the NEO and the NGO, gives the conduct of regulation the same focus as that of the supply-side of an effectively competitive market (how can we improve the consumer offering?). This is admirably clear, and avoids the confusions of multiple, conflicting objectives that have had adverse effects in jurisdictions such as Great Britain.

However, 'equity' is a problematic goal

A quite distinct distributional concern relates to the desirability or otherwise of reducing the costs of essential services for *specific* groups of consumers (regional dwellers, the old, the disadvantaged) financed through higher regulated charges for other customers, rather than financed by taxpayers generally. This is generally not a persuasive rationale for *competition* regulation. However, social concerns provide a rationale for other measures, such as hardship measures implemented by the businesses,¹² and sometimes financial assistance to particular groups.

The reason such policies often accompany competition regulation is that:

- once a government regulates to address the market power of an essential service, it is easy to add other regulations with social (and environmental) goals
- a major reason that essential services have market power is because people cannot take or leave the services they offer — these are services critical to the everyday lives of all people. This characteristic also means that governments see it is as highly desirable that essential services are universally available and affordable for all people, regardless of their circumstances.

Whether such re-distributional policies should attach themselves to economic regulation depends on the desirability of such subsidies and on the relative

¹² These are measures adopted by the businesses that provide advice on energy use, and allow people to make instalment-based payments and deferred payments. They are not usually subsidies.

efficiencies of the alternatives for financing them. Either way, they should not be an objective of the *competition* regulator. Budget-funded measures — such as utility allowances — have the advantage of transparency, clear parliamentary accountability and can use the same (targeted) eligibility criteria for other distributional policies to create a more coherent framework. In contrast, it can be hard to target price regulation for social welfare purposes (ERAA 2012a, p. 4).

However, where social goals are achieved through regulatory means, they should be:

- targeted as best as possible and be as consistent as possible with budget-funded social welfare measures
- imposed as an explicit government directive so that it is clear who is responsible for the policy, but leaving some flexibility in how they should be met. The danger is that prescribing particular tariff arrangements to meet equity goals might undermine the main objectives of the regulator to set prices as efficiently as possible, with unintended long-run impacts for consumers generally
- accountable and transparent, with full disclosure of their revenue equivalents, to avert another source of rent seeking.

This issue is relevant to this inquiry in that it may affect the appropriate ‘efficiency’ benchmarks in incentive regulations for businesses subject to extraneous social goals, and if poorly undertaken, could undermine some approaches for achieving network cost-savings through demand management (chapters 9–12).

(vi) Unfairness and ‘injustice’

‘Unfairness’ has several dimensions. One is the distributional issue described above. The other concerns justice. For example, a common example of this aspect of fairness is the desirability of procedural fairness.

While little empirical work on this issue has been undertaken in Australia, the history of anti-trust regulation in the United States demonstrates that addressing unfairness is a key objective of utility regulation, with requirements for prices to be ‘just and reasonable’ (Beecher 2010). A survey of the 207 state and federal utility regulators in 2001 found that the majority of commissioners considered fairness to be a central and often more important goal of utility regulation than efficiency (Jones and Mann 2001). Their view of unfairness extended beyond unreasonable prices, suggesting that the distribution of transfers were not the only consideration.

One specific case is the Michigan Public Service Commission, which lists, among other factors in determining utility prices, the desirability of fairly apportioning

costs among consumers, fairness to both the regulated utility and ratepayers, and avoidance of unjust or undue discrimination between rate classes or consumers.¹³

Likewise, competition law in the European Union gives strong weight to fairness. Abuse of a dominant position may consist in ‘imposing unfair purchase or selling prices’ (Akman and Garrod 2010).

In Australia, the *Competition and Consumer Act 2010* (Cwlth) also places significant weight on prohibiting unfair practices, but does not refer explicitly to unfair prices. The competition and consumer regulator, the ACCC, has some (limited) capacity to oversight prices under Part VIIA of the Act. However, the ACCC has on occasions characterised its price monitoring role in terms of fairness:

A price inquiry is conducted to determine whether buyers are getting a fair deal in the supply of goods and services. (2005, p. 8)

While unfairness is hard to define, people clearly identify it as an important feature of transactions. As scholars in this field have noted:

While the idea of fairness is elusive and perceptions differ, it clearly is a potent force in regulation, as indicated by the vehemence with which participants complain when they feel they have been treated unfairly. (Jones and Mann 2001, p. 153)

... few persons give much thought to what is fair. But they know when they have been treated *unfairly*; perceived unfair treatment is what makes people shout, “I have been had (screwed, taken to the cleaners, etc.)! ... the sense of unfair treatment typically comes from a perception that a contract, explicit or implicit, has been broken. (Zajac 1996, p. 117)

People regard transfers made under circumstances of duress or with significant unequal bargaining power as unjust, even if they do not entail significant distributional consequences. For example:

- even if the perpetrator is disadvantaged and the victim not, most people would regard the theft of money as an undesirable and unfair form of re-distribution
- survey research has shown that most people regard the use of market power to raise prices as unfair, and that the degree to which prices are raised does not affect their judgment of unfairness by much (Kahneman et al. 1986, p. 735). The present chair of the ACCC (Sims 2012a) characterises public attitudes to monopoly pricing in fairness terms (although he suggests that the best rationale for regulation lies elsewhere)
- in cases of costly litigation, people are sometimes willing to use significant resources to pursue matters where the economic losses are small, revealing the

¹³ Information provided by Darryl Biggar (pers.comm.).

value they place on correcting what they perceive to be injustice and unfair treatment

- in its inquiry into consumer policy, the Commission found people had an aversion to ‘unfair’ contracts that related to far more than their transfer effects.

The desire to enforce social norms against the unfairness or injustice that sometimes accompanies unequal bargaining provides an additional rationale for the regulation of natural monopolies wielding market power.

However, in practice, unfairness and injustice present difficult challenges for the price regulation of utilities, in contrast with the clear relevance of these concepts to misleading and deceptive conduct, anticompetitive actions, fraud and other forms of misconduct generally prohibited by, and redressed through, general trade practices and the common law. It is notable that the test of the misuse of market power in s. 46 of the Competition and Consumer Act requires that a business uses its power for an illegal purpose — not that it sets prices too high. Indeed, one of the targets of s. 46 is exactly the opposite — the strategic use by a business to strangle competitors by initially setting prices too low (‘predatory’ pricing).

The fact that some form of overpricing is widely seen as unfair indicates that some regulation may be warranted, but does not provide any analytical tools for calculating a ‘fair’ price. As with the issue of transfers to consumers, pursuing efficiency objectives will typically achieve the goal of fairness without any need for supplementary policies.

Moreover, judgments of fairness are highly subjective and depend on how a situation is framed (as shown in the many careful survey questions posed by Kahneman et al. 1986). Even where a monopoly business’s prices are heavily regulated, many will still claim that the prices remain unfairly high (a point apparent in submissions made as part of regulatory determinations for electricity revenue and price caps).

Deadweight costs as an umbrella concept

The costs represented by (i) to (iv) are the standard ‘textbook’ economic efficiency losses of monopoly, with a parentage stretching back at least 50 years. Sometimes these costs are categorised collectively as ‘deadweight’ costs.¹⁴ Even (v) can be

¹⁴ Any basic textbook would categorise (i) and (ii) as deadweight costs. Moreover, many economists would argue that x-inefficiency and rent seeking also result in deadweight losses (for example, Crew and Kleindorfer 2004; Dobson 1992; Johnston and Trembath 2005, p. 24). Some argue that x-inefficiencies should not be *labelled* as deadweight costs because they arise from non-profit maximising behaviour by the business. However, x-inefficiency is consistent with profit maximising behaviour subject to principal-agent costs.

categorised as a deadweight cost, since its relief through regulation may also yield potentially substantial economic efficiencies.¹⁵

There is little evidence about the magnitude of the above costs were electricity networks to be unregulated. However, some of the important aspects of the story are:

- electricity is an ‘essential’ service (a basic service that few households can do without)
- electricity is used by every business and government (chapter 2). Any monopoly price effects cascade throughout the economy, before being ultimately borne by households (domestic and foreign). Accordingly, the price of a soft drink to the consumer will, among other things, reflect the impacts of excess electricity prices on the glass used to manufacture the bottle, the manufacturing process used to produce the drink and bottle it, the cost of power to make the bitumen and concrete for the roads that transport the drink, and for the power costs of wholesalers and retailers
- the distortionary impacts of monopolies depends on the responsiveness of customers to higher prices (‘demand elasticities’), which may vary by customer type. The existing evidence suggests relatively low elasticities of electricity demand for households (Fan and Hyndman 2010 and AEMO 2012a, pp. A.1-A.5). In part, this is because it is an essential service. Since conventional deadweight losses are a function of such demand elasticities, this suggests relatively small *static* consumption-side deadweight losses. However, the existing demand studies relate to an industry that is already highly regulated. Demand elasticities may well be greater for an unregulated monopoly, and so too, the degree of inefficiency.¹⁶ Moreover, long-run price elasticities are typically higher than short-run elasticities. This reflects many factors. For example, with high prices, technological developments would favour energy-saving equipment and dwellings. While people might not immediately replace energy-intensive technologies, they would eventually do so. Distributed generation would become more attractive. Accordingly, the long-run distortionary impacts of monopoly are likely to be significantly larger than the

¹⁵ Some also argue that failure to address unfairness in (vi) is economically inefficient because fairness is a ‘good’ included in people’s utility functions, with people willing to give up the consumption of other goods to increase it (such as in altruistic behaviour). This may be technically correct, but enumerating the inefficiency effects of unfairness is difficult, and as such, the point is conceptual rather than practical.

¹⁶ For example, if a demand curve is linear, an unrestrained (profit-motivated) monopolist will price up to the elastic portion of the demand curve.

static costs inferred from short-run price elasticities applying to already regulated monopolies

- even small increases in electricity prices can entail significant losses for some commercial customers that have electricity as a major input into their outputs and that sell in competitive global markets. That could have large long-run effects on investment by these customers, even if it does not substantially affect current output. (The long-run effect can be much larger because over the short run, the assets in such businesses are sunk.) This was the primary reason for offsetting the effects of carbon pricing on trade-exposed emissions intensive industries
- to the extent that demand is not responsive for any given group, transfers from customers to businesses are large for that group. This has several implications. First, it means that the distributional issues raised in (v) above may become relevant. Second, since demand is least responsive when the monopoly business faces few risks of entry by others, it suggests that x-inefficiency may be high. Third, the prize from preserving monopoly rents through lobbying and the political process is large, encouraging wasteful resource use.

3.4 Are deadweight losses passé? New theories of why monopolies should be regulated

The effectiveness and role of benchmarking as a regulatory tool depend critically on the underlying problems that regulations are intended to resolve. Recently, some prominent Australian economists have disputed the relevance of deadweight costs to competition policy, indicating that most economists (including the Productivity Commission) poorly understand the issue:

The fundamental rationale for public utility regulation has not been well understood, particularly by economists. Mainstream neoclassical economists have argued that the primary rationale for regulation is the minimisation of [the] so-called ‘deadweight loss’. But, on close inspection, this hypothesis does not fit the observed facts. (Biggar 2011b, p. 6)¹⁷

The alternative perspective is that the rationale for price regulation is to create an implicit contract that protects customers’ investments from expropriation by the monopolist (a hypothesis explained further below). If this alternative is the correct rationale, this could constitute a major break from the primary expressed basis for

¹⁷ Biggar has also expressed these concerns in a range of other papers (2009, 2010, 2011a). The chair of the ACCC, Sims (2012a) has also raised similar issues.

regulation of essential services by many international competition authorities.¹⁸ New theories abound in economics and most are not influential. However, when they originate from Australia's premier competition regulator, and have implications for the way it might regulate or advocate policy change, these ideas should be listened to carefully.

In that context, Biggar claims that the contractual approach leads to the imperative for a quite different¹⁹ regulatory framework from the current version. He proposes that:

- consumers should play a bigger role because they are a key party to the 'contract' and more informed about their preferences than the regulator
- the regulator should be an independent arbitrator, not a consumer advocate as its role is to construct the right contract between a monopoly supplier and customers. Accordingly, there would be no grounds for appeals on merit because, as an arbitrator, the regulator would have already fairly addressed both parties' concerns. Appeals should be limited to matters of law, which would also allow the regulator to exercise significant discretion and judgment, rather than to use significant resources 'covering its back' on every issue, given the risk of merits review
- the Rules should not require that the regulator apply the highest cost that just passes a reasonableness criterion, rather than using its best cost estimate, since this favours one party to the implicit contract. Instead, the regulated entity should prove that the regulator's price/revenue proposal is unreasonable
- the object clause in the National Electricity Law should be changed to include long-term price stability, non-discrimination, and a 'no disadvantage' test, so that no customer could be made worse off following a regulatory change (such as those that would arise from a tariff change — for instance, peak load pricing).

These issues are central to aspects of this report, affecting the potential role of benchmarking in incentive regulation and the scope for increasing network efficiency by removing some of the regulatory constraints network businesses face. Given the above policy conclusions partly depend on the credibility of the new

¹⁸ The Commission examined the criteria for regulating among various prominent regulators — which all emphasised traditional economic efficiency as a major (if not always the only) motivator for regulation. For example, these included the New Zealand Commerce Commission and major UK regulators (such as Office of the Gas and Electricity Markets, the Water Services Regulation Authority, the Utilities Regulator (of Northern Ireland), and the Financial Services Authority).

¹⁹ In fact, some elements are already features of the current framework — a point raised later.

theory, this chapter briefly examines the validity and insights of the theory that led to these conclusions (with a detailed discussion in appendix B).

The new theory: protecting the sunk assets of customers

Biggar's alternative view of the rationale for regulation of monopolies is based on the problem that customers can be held to ransom once they have made sunk investments that use the inputs — such as electricity — of a natural monopoly. A sunk cost is an investment that, once made, cannot easily be recovered by selling it to another party. Some clear examples include the special dies made by a supplier of automotive panels,²⁰ a person's investment in a qualification, or a specialised product for a particular customer. Not all fixed assets are sunk. For example, as they are usually leased, aircraft are called 'capital with wings'. Nevertheless, many saleable assets would still recover only a proportion of their value when sold — and so are partly sunk. 'Sunkness' is therefore ubiquitous.

Biggar's claim is that:

... the *primary* economic rationale for public utility regulation is the protection of the sunk (relationship-specific) investment of customers of the regulated firm. (2011b, p. 30) (emphasis added)

The logic underpinning this is that:

- customers of the monopolist make sunk investments whose value is dependent on continued supply of the monopolist's inputs (a 'relationship-specific' investment in the language of this literature)
- customers know that after they have made the investment, the monopolist can raise prices significantly because, once the investment is sunk, the customer only needs revenue sufficient to cover the marginal costs of supply. The monopolist can therefore expropriate all of the returns that would otherwise have made the investment profitable. Prices would be unstable, varying before and after the investment was made
- customers are unable to write *binding* long-term contracts with the monopoly supplier (but regulators can do so on their behalf)
- vertical integration to internalise the long-term contract within a single firm is often not possible

²⁰ This is the classic example given by Klein et al. (1978).

-
- As customers know that the monopolist can behave opportunistically after the investment is made, they do not make the investment at all (the ‘hold-up’ problem).

Under the hold-up problem, the customer knows that the unregulated monopolist has incentives to expropriate the value of a customer’s relationship-specific sunk investments, and the monopolist knows that the customer knows this. Accordingly, the customer will be unwilling to invest (or if so, to a less than optimal level). A customer’s decision not to invest reduces the revenue of the monopolist. So, the key hold-up problem is not that the monopolist *will* expropriate the sunk investments of a supplier, but that it must credibly commit *not* to do so to preserve its long-run monopoly profits (which it earns as a mark-up on long-run prices). Biggar suggests that regulation solves the problem because it re-creates the long-term contract that parties would have negotiated to protect each party from later opportunistic behaviour.

Moreover, he argues that the theory’s validity is strengthened because only it explains why regulators behave as they do. He claims that it explains, among other things, why they apparently:

- encourage price stability to ensure ex ante and ex post prices are the same
- dislike price discrimination because ex post a customer with a large sunk asset has a very low elasticity of demand, and so would face a high price. This would appear to be efficient as a means of recovering the fixed costs of the monopolist, but would do so at the cost of undermining the investment incentives of customers
- do not generally accept peak load pricing, despite its benefits for reducing deadweight losses
- want monopolies only to cover their full costs and not additional rents (because the rents would most likely arise from expropriated sunk investments).

Is the theory compelling as the primary rationale for regulation?

As discussed in appendix B, there are attractions to conceptualising the regulation of natural monopolies in contractual terms. The broad implications of the ‘contract’ approach appear to echo those resulting from maximising community welfare. That is not surprising given that the only contract that two parties with equal bargaining power would mutually agree to would be one that involved no removable inefficiencies. The real difficulties arise when the contract approach gives primacy to the ‘sunk investment’ problem.

Without repeating the detail in appendix B, the main flaws in the ‘hold-up’ argument are that:

- there does not need to be a single meta theory of regulation of natural monopolies. Hold-up may sometimes be relevant, but in other instances, the concern will simply be that, absent regulation, the consumer would be exposed to excessive prices and the monopolist might live an inefficiently ‘quiet’ life
- most users of electricity do not make the large irreversible investments that underpin the hold-up problem. Moreover, from a pragmatic perspective, it would be very costly for an unregulated monopolist to behave opportunistically in the way supposed by the hold-up problem for millions of customers
- even those business customers making very large investments would often be able to write long-term contracts that would preclude the hold-up problem. Moreover, other non-regulatory solutions like vertical integration could be used where contractual difficulties appear insurmountable
- it is also not clear that even were a dominant business to ex post exploit a customer making sunk investments that the solution would be price regulation. Competition laws (as in Article 82 the European Union Competition Law) or oversight of particular long-term contracts that may be subject to hold-up might address any issue in a more targeted way
- the notion that regulations (and their underpinning laws) create credible long-term contracts belies how regulations change and how regulators behave. By early 2013, there had been 55 versions of the National Electricity Rules. Over an asset life of 40 years (easily possible for network assets), the economic value of the asset would be exposed to nearly 300 sets of possible new regulatory influences during its life. The hold-up problem may be larger under regulation than under unregulated monopoly, which is why the National Electricity Law should be designed to reduce that risk
- regulators do not, in fact, say that their actions are based on the hold-up problem — something that would be expected were it to be their true underlying motive for the regulation of natural monopolies. Indeed, they typically refer to conventional arguments about the problems of natural monopoly. Regardless, the idea that a good rationale is revealed by the actions of regulators presumes those actions are always appropriate. The ultimate test is not what regulators do, but whether, given market behaviour and its outcomes, regulation is justified on welfare grounds.

3.5 The alternative policy implications of different theories of monopoly regulation

As noted in section 3.4, the proponents of hold-up reach strong policy conclusions, with significant implications for this inquiry. However, those conclusions are not convincing.

The conclusions could arise from alternative theories. For example, the importance of empowering consumers and, where possible, involving them in regulatory decisions is consistent with conventional theories of competition regulation. This approach can sometimes overcome asymmetries of information for regulators, achieve ‘buy in’ by consumer groups that recognise the need for compromise in regulation, and may allow less heavy-handed regulation (where supported by the potential for intervention by the regulator if negotiations are imbalanced). The Commission is in strong agreement with Biggar’s (and the ACCC’s) views on the importance of a consumer role. The difference is only in the reasoning to reach that conclusion.

Often the policy conclusions are non-sequiturs. It is not clear why the existence of hold-up would justify a no-disadvantage test. The implicit contract struck by the regulator on behalf of a large heterogeneous group of customers and a monopoly business would usually not advantage all consumers. For instance, a prohibition on peak pricing would disadvantage those consumers who use less power in peaky periods (who will often be poorer customers)

Similarly, the fact that the AER should be an impartial arbitrator rather than a consumer advocate — a position the Commission supports — does not preclude significant regulatory errors. Customers or businesses should be able to contest any material errors. The proposed reversal of the onus of proof so that businesses would be obliged to prove the unreasonableness of a determination by the AER would need to be justified on other grounds. This inquiry finds that benchmarking is a useful but inexact tool (chapters 4 and 8). The existence of merits review creates strong incentives for the regulator to be prudent in its application.

The conclusions also fail to consider the long-run interests of customers as a group by taking a narrow approach to the implications of regulatory error on investments. Where a monopoly business provides inputs to many diverse customers — as in electricity networks — opportunistic behaviour by a monopolist can only affect a small share of customers (as shown in appendix B), whereas regulatory error by the regulator can affect the investment adequacy of the monopoly business to the disadvantage of all of its customers. Moreover, the intention of incentive regulation is to offer some rents (‘headroom’) as the carrot for a regulated business to

minimise its costs and to innovate. Setting the ex ante regulated price at a point equal to that of some hypothetically most efficient business does not allow such headroom, and would be likely to reduce dynamic efficiency — with losses to consumers.

3.6 In summary

This chapter has devoted considerable space to the issue of hold-up because it:

- appears to have gained purchase in some regulatory circles, albeit not uniformly in either its rhetoric or practices
- is a useful thought experiment, whose flaws highlight many of the practical necessities of competition regulation (such as merits review and compromise).

The hold-up problem is a hypothetical and theoretically elegant example of a particular deadweight loss that might sometimes arise were monopolies to be unregulated. However, it is not persuasive as ‘the’ reason for economic regulation of electricity network businesses, and nor have energy users, the AEMC, AEMO and other major stakeholders perceived market power in this way.

The hold-up idea does not displace the usual efficiency concerns of regulators, governments and economists, and is not required as a basis for the sensible regulation of network businesses. Ironically, were it to actually inform regulatory policy to any great extent, the hold-up construct has the potential to undermine the long-term interests of end users, as it could threaten investment by the monopolist in long-term assets, innovation and cost minimisation. It does not appear to be compatible with incentive regulation (and one possible use of benchmarking). It would be unfortunate were it to assume primacy as the conceptual basis for Australia’s economic regulation of electricity networks (or indeed other infrastructure).

There are points of substantial agreement

The differences of view on this issue do not change one essential point. Electricity customers, the ACCC, the AER and the Commission all strongly argue for the economic regulation of electricity networks, broadly along the lines set out in the recent Rule changes (AEMC 2012r). Unregulated network businesses would have significant market power, with the potential for adverse effects on customers. Correcting that market power requires nuanced but powerful regulation. Subsequent chapters specify the desirable characteristics of such regulations.

4 A framework for benchmarking

Key points

- Regulatory benchmarking encompasses any method for comparing firms to each other, to themselves over time, or to an ideal firm, in order to measure, and (potentially) encourage, efficiency in the regulated business.
- The literature on benchmarking is confused. There are:
 - multiple methods for benchmarking, with little consensus about which is best
 - divergent views about the appropriate inputs and outputs of electricity network businesses.
- Nevertheless, in Australia and overseas, network regulators have made extensive use of benchmarking, mainly as a tool for assisting their regulatory judgments.
- In Australia, the more sophisticated use of benchmarking in regulating the National Electricity Market has been frustrated by inadequate data (and potentially by limitations in the National Electricity Rules) and limited sample sizes.
 - International comparisons can only partially address these limited sample sizes, and create their own challenges in reaching valid comparisons of business performance.
- Incentive regulation aims to improve managerial performance and business efficiency. Accordingly, benchmarking needs to take into account factors outside the control of the businesses.
 - Such an exercise is useful in its own right, as it may help identify policies or regulations that stifle efficiency.
- The path to better benchmarking depends on specifying clear criteria for appropriate benchmarking and systematically applying them. This needs to recognise that the degree of rigour required is dependent on the extent to which benchmarking is used to determine the regulatory outcomes for businesses.
- Benchmarking is not about identifying a single number denoting the efficiency of a business, but rather the potential range of likely numbers.
 - Any benchmarking exercise must take into account the consequences of being wrong.

This chapter is one of five relating to benchmarking of business efficiency. It:

- introduces the concept. Despite its worldwide use, there are many complexities in defining what benchmarking is and its purposes (section 4.1)

-
- discusses briefly the different methods that are routinely used to undertake benchmarking, and their major technical pitfalls and advantages (section 4.2)¹
 - considers the appropriate measures of network performance and the cost drivers the businesses face (section 4.3)
 - reviews the historical use of benchmarking by Australian regulators, including the Australian Energy Regulator (AER) (section 4.4). This section also describes the relevant clauses in the Rules regarding benchmarking. However, whether in fact the AER can actually use benchmarking effectively depends on interpretation of other facets of the Rules — an issue addressed in the next chapter
 - discusses the appropriate criteria for the coherent evaluation of benchmarking approaches and the methods used to test these criteria (sections 4.5–4.8). The question of appropriate benchmarking *processes* is distinct, and is addressed in chapter 8.

4.1 Benchmarking managerial efficiency and performance

Regulatory benchmarking encompasses any method for comparing a firm to other businesses, to itself over time (or between its various divisions) or to an ideal firm. Utility regulators around the world use static (and dynamic) ‘benchmarking’ to encourage regulated businesses to achieve the long-run efficiency outcomes of decentralised, workably competitive, markets. Benchmarking is a well-established method for analysing network businesses’ performance, and has been used by:

- Australian regulators, including state based electricity regulators (Meyrick and Associates 2005, Pacific Economics 2008)
- international regulators such as OFGEM (United Kingdom), CER (Ireland), NZCC (New Zealand), and OEB (Ontario Canada)
- various academics in the Australian, European, American and other contexts (see AMP Capital, sub. DR55, Chanel 2008, Farsi and Filipini 2005, London Economics 1999, Mountain and Littlechild 2010).

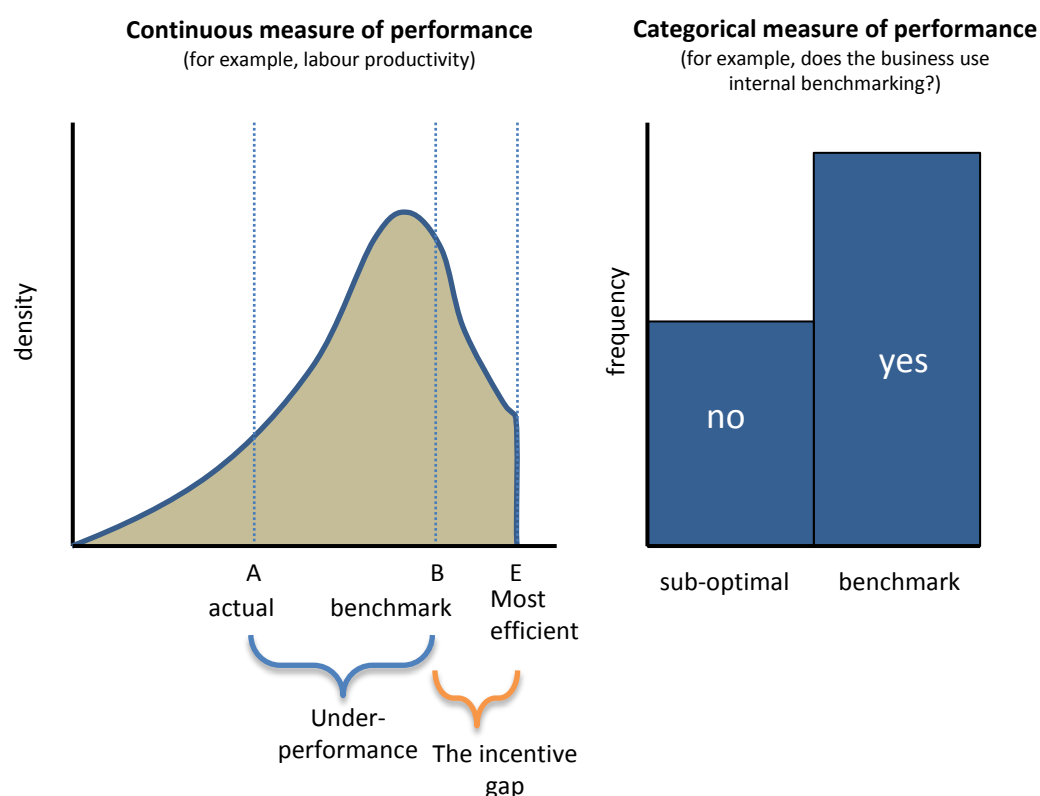
Figure 4.1 depicts the broad types of comparisons underpinning benchmarking. In the left hand chart, a group of utilities have a distribution of efficiency from poor to

¹ At times, this chapter covers some technical matters in order to be useful to practitioners, but the treatment is as simple as possible. The chapter provides references to more comprehensive technical material.

best (the ‘frontier’). The challenge of benchmarking is to estimate the distribution and make a judgment about some level of acceptable efficiency — the ‘benchmark’. It could be at the frontier — but as explained in chapter 5, there are grounds for an incentive gap to provide a reward for dynamic efficiency and to address regulatory error — an issue touched on later and in chapter 8.

Sometimes, benchmarking will relate to a categorical, rather than a continuous measure of performance (or proxy for it). The example in the right hand chart is simply of the yes/no kind, but there could be more than two categories. The surveys used to measure management performance shown in figure 4.1 are based on Likert scales from one to five (Bloom and van Reenen 2010, p. 206).

Figure 4.1 **Benchmarking^a**



^a The distribution relates to the measured productivity outcomes for a group of businesses from some benchmarking exercise, with A denoting the measurement for a given business. A is a point estimate — it does not show the degree to which the measured efficiency of A or B is reliable.

Data source: Bloom and van Reenen (2010).

What does efficiency mean and how is it relevant to incentive regulation?

Since benchmarking aspires to increase efficiency, it is critical to unpack this concept. Efficiency has three main dimensions, and relates to the extent to which a business has:

- achieved the maximum possible output from their given inputs (productive or ‘technical’ efficiency). A simple example would be the labour productivity of vegetation clearance around transmission towers (in a common terrain)
- allocated resources to their highest value purposes (‘allocative’ efficiency). The extent to which a business achieves this depends on whether it prices its outputs efficiently (for example, with no cross-subsidies) and uses input mixes that truly reflect their relative prices. The current prices paid for power and capacity from photovoltaic cells provides a good illustration. The physical energy outputs of photovoltaic panels is maximised with time invariant feed-in tariffs (an example of productive efficiency). But the *value* of the output (largely derived as network cost savings and as reduced needs for costly peaking generators) is highest at peak use times (chapter 13). In the case of monopoly network businesses, allocative efficiency particularly relates to the potential for businesses to charge prices well above the total costs of output with adverse impacts on businesses using inputs, consumer surplus and the optimum amount of output (chapter 3). In the regulated case, allocative inefficiency is most likely the outcome of inefficient mixes of capital and operating expenditures
- maximised the potential for increasing efficiency over time (dynamic efficiency). For example, this could occur through product and process innovation; investment in management and labour skills that allow flexible responses to changing economic circumstances, and exposure to the risks of insolvency and downsizing.

While all three efficiency measures are important, most benchmarking analysis focuses on the first aspect of efficiency, because it is tractable, and can be used in so-called incentive regulation to encourage the other forms of efficiency. Chapter 5 examines incentive regulation in more detail,² but the thrust of the idea is that the regulator:

- calculates some measure of the ‘efficient’ cost of producing the output of the business using benchmarking, controlling factors outside the influence of the business, so as to target managerial inefficiency

² Joskow (2007) provides a summary of the issues.

-
- allows the business to set prices to recover those efficient costs (including a return on capital).

Under this form of incentive regulation, there is no direct link between the business's actual costs and the prices it charges, encouraging businesses to minimise their costs in order to maximise their profits. If the regulator sets a benchmark close to the attainable technical efficiency level, the business has little prospect of setting excessive prices (thus encouraging allocative efficiency), technically inefficient businesses exit or learn quickly (achieving technical efficiency), while businesses that aggressively reduce costs through better management or innovation make higher than 'normal' profits (dynamic efficiency). This ideal is not a feasible option, but at least it illustrates the principle.

Many of the network businesses covered in this inquiry have queried the suggestion that they are inefficient in any substantive way. Were that true, the main goal of benchmarking would be to eliminate excessive rents (allocative inefficiency) over time, rather than to penalise technical inefficiency. This would suggest no gain from benchmarking differences in levels of productivity between various businesses. Rather, it would imply that a regulator reimburse the business's existing costs in a base year and then adjust allowed revenues over succeeding periods, using an estimate of the rate of total factor productivity (TFP) change, based on historical data, evolving network industry productivity trends, or another unregulated industry. (This is often referred to as the CPI-x or TFP methodology, where x is the relevant TFP growth rate — AEMC 2011b).³ The Australian Energy Market Commission (AEMC) has carefully reviewed the various disadvantages and (many) advantages of this approach. Its largest advantages are its apparent relative simplicity, the strong incentives it creates for dynamic efficiency and its amenability to being used in negotiated settlements (Cunningham, sub. 28; Kaufmann 2006; Pacific Economics Group, sub. 35 and sub. DR48).

Nevertheless, the CPI-x approach has several drawbacks. First, its simplicity may be more apparent than real. As Bruce Mountain (representing the ESAA) noted:

I've just seen it degenerate into the most arcane arguments of definitions and inputs and outputs (trans. p. 109).

³ The terminology can be misleading. For example, OFGEM's RPI-x mechanism (where RPI denotes the retail price index) is not much different in practice to the approach currently adopted by the AER. This is because the approach still requires an assessment of the efficiency of any given business, and then some decision about the allowable revenue over the future regulatory period based on a judgment about the pace of convergence to an efficient benchmark. Fearon (2007, p. 7) defines two types of CPI-x approaches — one based on the building blocks approach as used currently by the AER and one that calibrates x on an industry-wide TFP trend. In this report, we refer to the latter as the CPI-x approach.

While a strong advocate for the CPI-x approach, Paul Fearon (at the time, the chief executive of the Victorian Essential Services Commission), acknowledged that:

Introducing TFP methodologies does present some operational and transitional challenges. In the United States, pure TFP based price caps ... are unusual and have been modified by regulators. For example, they have introduced off-ramps, earnings and revenue sharing mechanisms and 'z' and stretch factors, to deal with differing circumstances in relation to risk, firm performance and other uncontrollable exogenous factors (e.g. environmental factors). (Fearon 2007, p. 10)

Second, regulators have more often applied CPI-x to opex than capex. As Joskow (2008, pp. 553-54) observes, there are many difficulties in operationalising a CPI-x approach that incorporates the complexities of investment and the heterogeneity of the businesses (for example, in relation to the vintage of their assets):

The limited attention paid to capital-related costs in the academic literature on price cap regulation provides a potentially misleading picture of the challenges associated with implementing a price-cap mechanism effectively. ... Thus, the implementation of price cap mechanisms is more complicated and their efficiency properties more difficult to evaluate than is often implied and places a significant information collection, auditing and analysis burden on regulators.

It is notable that transmission capex is particularly lumpy at the firm level. Any incentive mechanism based on industry-wide productivity growth rates would need to ensure sufficient revenue flows to underpin such investments. In particular, unlike electricity distribution, the inherent reliability of a transmission network may not be observed until a major system failure, suggesting the requirement for some regulatory oversight of required investment (chapter 16).

Finally, and probably most importantly, the assumption of efficiency in the base year is a strong one, in which case, some kind of return to benchmarking of the level of efficiency re-emerges. As noted by the Major Energy Users (MEU):

TFP is a form of benchmarking which does result in less prescription but is dependent on the initial allowance being efficient first. If the initial allowance is not efficient, TFP provides for the inefficiency to be perpetuated. Therefore benchmarking is seen as the essential first step to reach the efficient frontier. (sub. 11, p. 30)

If the assumption of efficiency is not correct, the regulator should re-adjust base year costs to the efficient level before applying the conventional CPI-x approach. Without such an adjustment, businesses could either still survive while remaining inefficient, or make permanent profits above the normal return by closing the

efficiency gap.⁴ Neither would be desirable. For example, were the total industry costs around \$15 billion in a base year, but efficient aggregate costs were 10 per cent lower, then under reasonable assumptions, using the TFP methodology without base year adjustment would result in one of three outcomes:

- (i) At worst, if businesses' average level of productivity did not catch-up to the frontier, the economy would forgo an efficiency dividend of around \$22 billion in net present value terms.⁵
- (ii) Alternatively, if the businesses quickly reached the efficient frontier, they would earn rents of \$22 billion — a transfer from customers to the network businesses. This would involve lower efficiency costs (although higher prices would still have some inefficiency impacts — chapter 3).
- (iii) A combination of the two could occur.

Regardless, the incorrect assumption of efficiency in the base year would be equivalent to foregoing the opportunity for customers to receive free electricity network services for one and half years.

The hypothesis that network businesses are currently efficient would be an astonishing result on several grounds.

- As discussed in chapter 3, incentives for cost efficiency are blunted when businesses are not exposed to fierce actual or potential competition and have legacy 'cultures' reflecting their past status as effectively non-corporatised government departments.
- The usual factors encouraging dynamic efficiency are, at best, weak in an industry, where, even *after* regulation:
 - businesses cannot be allowed to become insolvent (with the disruption costs and difficulties of ensuring continuity of service quality were that to occur)
 - many businesses, through their state-owned status, cannot ever be taken over in hostile takeovers or merge across state boundaries
 - revenue allowances have tended to reward over-capitalisation
 - network businesses are free from normal market competition given their monopoly status, and through the regulatory arrangements, have greater security about returns on their sunk investments than would occur in

⁴ IRIC (2003) explains why it is therefore necessary to have a base year adjustment or apply higher initial TFP growth rates for businesses estimated as less efficient than the static benchmark in the base year. This means that some static benchmarking would be required.

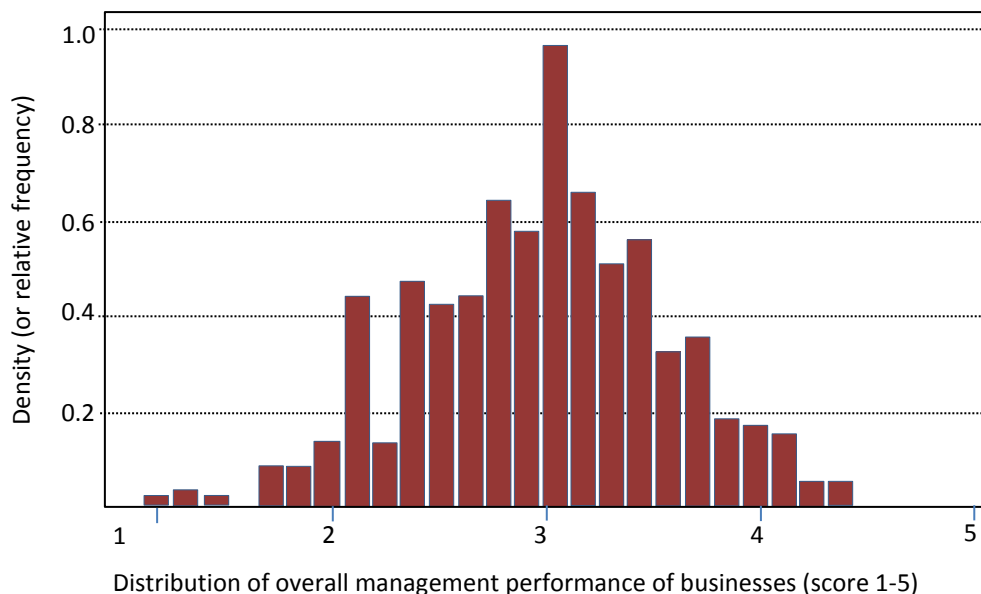
⁵ This illustration assumes a TFP rate of 1.5 per cent per annum, a discount rate of 8 per cent and an economic growth rate of 3 per cent per annum.

unregulated markets. Lower levels of competition are generally associated with reduced efficiency (Bloom and Van Reenen 2010)

- the industry is characterised by large lumpy investments, which makes businesses susceptible to long-lived efficiency impacts from poor decisions. The existing international empirical evidence for highly capital-intensive industries — such as electricity, airlines and telecommunications — suggests that wide divergences in efficiency are unexceptional, notwithstanding the sophisticated nature of the businesses concerned.

Even in competitive markets, there is a continuum of efficiency and performance (Bloom and van Reenan 2010; Syverson 2011). This is demonstrated by figure 4.2 for a large sample of Australian businesses operating in typical market conditions. There is a long tail of poorly performing businesses. A similar dispersion of performance is apparent in similar studies using the same methods over a large number of countries.⁶

Figure 4.2 Management performance of Australian businesses generally
2009



^a The data relate to a mixture of business ownership types, sizes and sectors (though mainly in sectors, such as manufacturing, where competitive forces are high). The data were collected as part of a collaborative performance study overseen by the London School of Economics, Stanford University. McKinsey & Company. A higher score represents better performance.

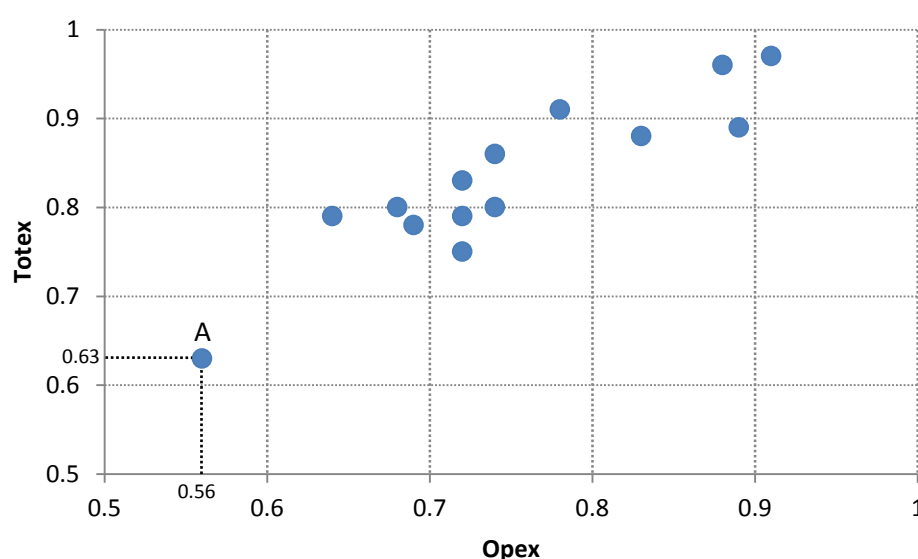
Data source: Macquarie Graduate School of Management et al. (2009, p. 30).

⁶ Bloom et al. (2007), Bloom and Van Reenen (2007), Bloom and Van Reenen (2010).

And regardless of the sample size and data deficiencies that might limit the usefulness of benchmarking analysis of Australian network businesses, most overseas studies of electricity network businesses find many are not even close to the efficiency frontier (figure 4.3 presents an example). For example, putting aside the sometimes disputed Australian results of Mountain (2011) and Mountain and Littlechild (2010), a large sample study by Chanel (2008, p. 7) found that the least efficient distribution businesses in the European Union had costs more than 80 per cent higher than the most efficient. It is hard to argue that Australian network businesses are exempt from what appears to be a ubiquitous pattern among their international peers (and businesses generally).

The key question for benchmarking is not whether there is inefficiency, but whether there is enough to matter for regulatory purposes. One of the attractions of privatisation is that it may strip away enough inefficiency that simpler benchmarking methods — such as conventional CPI-x — might become more realistic options (chapter 7 and 8).

Figure 4.3 **Technical efficiency in electricity distribution in the United Kingdom^a**



^a For both axes in the chart, a business with a score of one is at the efficiency frontier for the relevant measure of expenditure, while scores below this indicate the degree of inefficiency. For example, firm A is 37 per cent below best practice totex and 44 per cent below best practice opex. In principle, and considering totex, firm A could increase its output by around 59 per cent (that is $1/0.63 \times 100$), without any changes in its inputs.

Data source: Yu et al. (2006).

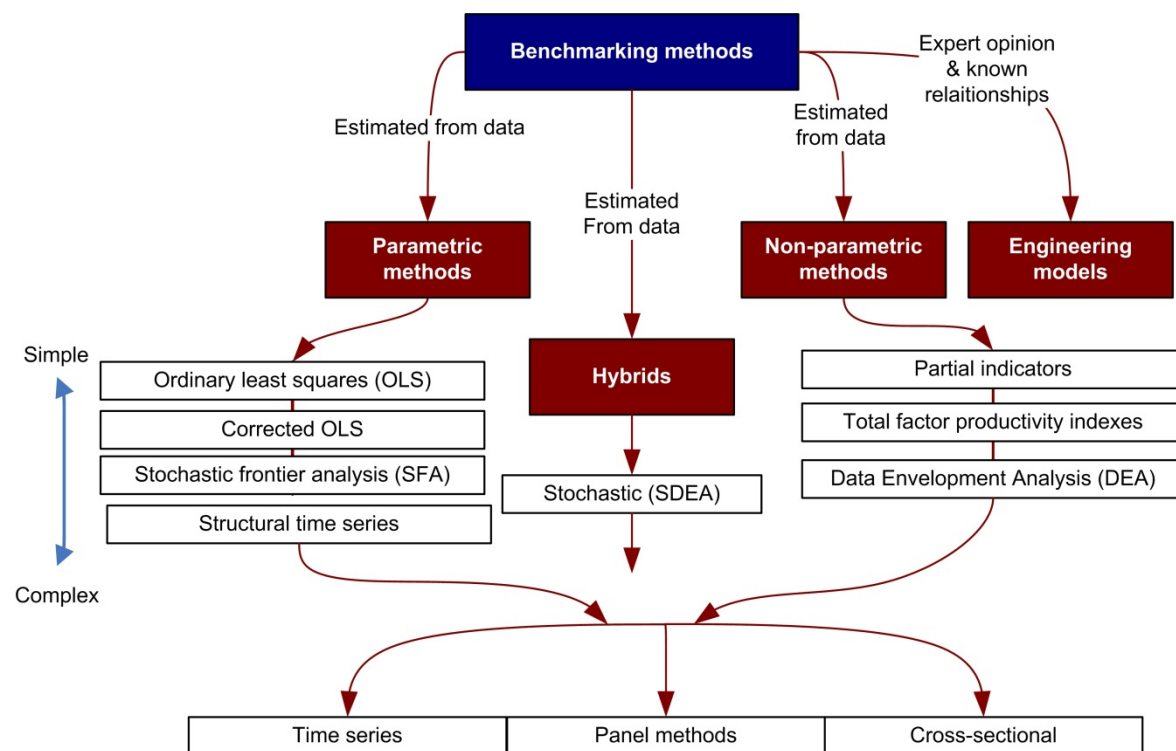
4.2 Benchmarking techniques

Aside from engineering models, the methods used to benchmark electricity networks are similar to productivity analysis of any industry, with the major difference being the relevant variables (figure 4.4).

There are four basic approaches to benchmarking:

- statistical methods provide estimates of parameters of a production or cost function, but with information about the imprecision of those parameters

Figure 4.4 Different benchmarking approaches^a



^a OLS is a regression approach that minimises the sum of squares of the errors of a line passing through the data. The dependent variable could be in log form or some other transformation. (While not shown above, non-linear least squares — a variant of OLS — does not impose linearity.) Corrected OLS shifts the line up just until there is one observation with a measured efficiency index of one. Stochastic frontier analysis takes account of the fact that errors around the regression line comprise statistical noise and systematic (one-sided) inefficiency. Structural time series models take account of the fact that parameters may shift over time (for example due to structural shifts or slowly declining or increasing productivity growth). Non-parametric methods are simple ratios (akin to those used in chapter 6). Total factor productivity (TFP) indexes are based on weighted inputs and outputs over time. Data envelopment analysis is a linear programming approach that connects the outer envelope of productively efficient businesses, while stochastic DEA takes account of the influence of statistical noise. The approaches can apply to a snapshot of businesses at a given time, time series for specific businesses, or panel data methods that use cross-sectional and time series data.

- non-parametric methods do not make any assumptions about the distribution of the population. Such approaches include simple ratios, indexes and linear programming methods

-
- hybrid methods combine non-parametric and parametric methods (Daraio 2012)
 - engineering and reference models are bottom-up models, based on expert knowledge about the operation of networks and the efficient costs of building and operating them. These models (such as the Swedish NPAM model) — create an artificial firm based on engineering and cost information to use as a benchmark, and then feeds in the characteristics of a given network business — such as its customer numbers, location, and capacity for each transformer station (Jamasb and Pollitt 2007a; Strbac and Allan 2001). In Australia, Elder and Beardow (2003) developed a model of an idealised electricity distribution network for regulatory pricing (among other reasons), but it is not clear it has been used for that purpose.

Figures 4.5 and 4.6 depict graphically how the various methods measure efficiency.

The literature on the various methods is vast. This inquiry does not examine these methods in any detail since there are multiple textbooks, software tools and review papers in this area. The AER has been responsible for two of the most comprehensive and useful papers.⁷

Notwithstanding the volume of research and empirical work, there is no consensus about the best benchmarking measures (or even the appropriate inputs and outputs — section 4.3). In 2001, two leading economists in the area effectively said they did not know what approach to advocate:

... there is no firm consensus on how the basic functions of the utilities are to be modelled. (Jamasb and Pollitt 2001, p. 114)

That view did not change much in the ensuing decade. For example, in their consideration of the issue, Growitsch et al. (2010, p. 3) reiterated:

Although, from a technical point of view, distribution networks can be regarded as relatively simple activities, there is no consensus in the academic literature or among the regulatory practitioners as how to model this activity.

In the United Kingdom, Frontier Economics (2010b, p. 6) recommended ordinary least squares (OLS) or corrected OLS (COLS), but not stochastic frontier analysis

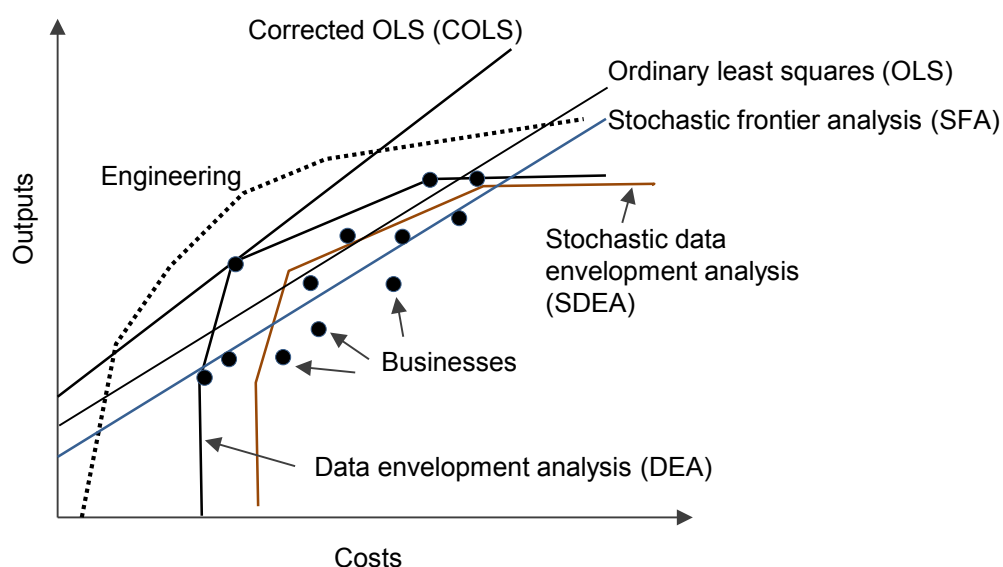
⁷ The ACCC/AER (2012a) provides a comprehensive update on benchmarking approaches. The AER also commissioned a thorough analysis of European approaches (Schweinsberg et al. 2011) as input into ACCC/AER (2012b). In this inquiry, Cunningham (sub. 28) provides an accessible treatment of the different methods and their use in incentives regulation. Filippini et al. (2005) also covers the various techniques. There are numerous software packages for undertaking benchmarking, such as the various programs from the Centre for Efficiency and Productivity Analysis at the University of Queensland (DEAP, DPIN, Frontier, and TFPPI); LIMDEP, STATA, and OpenSolver for Excel.

and data envelopment analysis (DEA). Other analysts suggest that DEA is more robust and makes fewer underlying assumptions. Yet again, others regard the TFP index approach as the most simple because it uses overall industry productivity growth as the basis for incentive regulation, without reliance on the specific performance of the business.⁸

The various preferences of regulators are revealed by significant variations in benchmarking practices around the world (table 4.1). Even in countries where benchmarking has been routinely applied, regulators of different utilities have tended to adopt different approaches, without any sign of convergence. As one analyst in this area noted in the United Kingdom context:

Moreover, it is not obvious that over time there has been a movement towards some form of consensus across the regulatory offices on the role of benchmarking. (Dassler et al. 2006, p. 172)

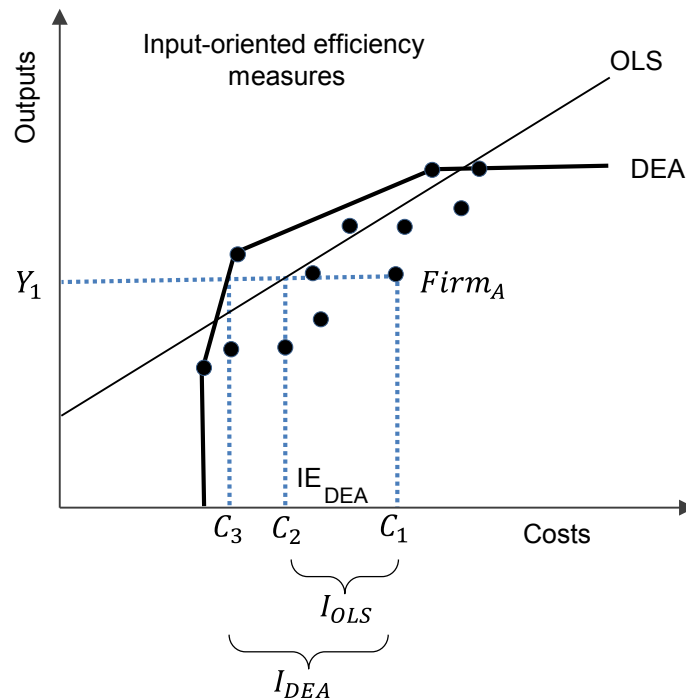
Figure 4.5 Benchmarking methods



Source: CREG & SUMICSID (2011, p. 26).

⁸ Kaufmann (2009) has argued that TFP benchmarking is less vulnerable to data inconsistencies than the building block process currently employed. This is true if TFP benchmarking is based on the growth rate of State-wide TFP, as had been suggested by the Victorian Essential Services Commission. Lawrence's judgment is that it depends on the context and that TFP results can still be quite sensitive to data errors (Lawrence 2009, p. ii).

Figure 4.6 Illustrating the measures of inefficiency^a



^a An input-oriented measure of inefficiency is the reduction in inputs for a given output level that a firm could achieve if it became efficient. So, firm A produces output Y_1 at cost C_1 . Using the linear regression approach, it could produce Y_1 at cost C_2 , so that its current inefficiency is C_2/C_1 . Using data envelopment analysis, it could produce Y_1 at cost C_3 , so that its inefficiency is C_3/C_1 . Similar measures can be obtained by using the same approaches for the other estimation methods shown in the previous chart.

Table 4.1 What do other countries do?
Network benchmarking around the world

Location	Method	Source
Chile	Engineering	Farsi et al. 2007
Denmark	Ratios	Nordic Energy Regulators 2011
Finland	DEA/SFA/SDEA	Nordic Energy Regulators 2011
Netherlands	DEA/Ratios	Farsi et al. 2007
Norway	DEA	Nordic Energy Regulators 2011
Sweden	DEA/Engineering	Jamasb and Pollitt 2007b
Spain	Engineering	Schweinsberg et al. 2011
Austria	COLS/DEA	Schweinsberg et al. 2011
Ireland	COLS	ACCC/AER 2012b
New Zealand ^a	TFP index	ACCC/AER 2012b
Ontario	TFP, ratios	ACCC/AER 2012b
Japan	Econometric	ACCC/AER 2012b
California	TFP, econometric	ACCC/AER 2012b

^a The New Zealand Commerce Commission (2010, pp. 640-45) has recently proposed a novel application of benchmarking. Independent verifiers, effectively external auditors (paid for by the businesses), must provide independent evidence in support of the business's proposal — and are free to use a range of quantitative techniques, including benchmarking.

In this context, the AER's verdict about the state of the technology is not surprising:

There is no clear consensus in the literature in relation to which benchmarking approach should be used by economic regulators. As identified previously, each method has relative strengths and weaknesses. (ACCC/AER 2012a, p. 136)

4.3 What should be benchmarked?

In many industries, it is clear what inputs and outputs are. This is not so straightforward in electricity networks (and other networks, such as rail⁹ and telecommunications). In part, this is because electricity networks are very complex. For instance, there may be discontinuities in cost functions and counterintuitive relationships:

... the effects of Kirchhoff's laws lead to bewildering irregularities in the relationship between outputs and capacities ... As a result, transmission cost functions are likely to have strange properties that make them interesting for an audience outside electricity. Where else can you expect to have negative marginal costs? (Rosellón et al. 2009, p. 1)

These esoteric complexities aside, a comprehensive analysis of benchmarking prior to 2001 found no unanimity about the appropriate variables to include (Jamashb and Pollitt 2001, p. 114). Given the ACCC/AER's (2012a and b) recent literature review, this situation has persisted. As Turvey (2008a, p. 2) put it:

Comparisons between networks of the costs of these activities can only illuminate differences in the efficiency with which operations and maintenance are carried out if the magnitudes of the tasks of operation and maintenance can be compared. This is a platitude, yet failure to articulate it has led some authors to scabble around among available data to select a set of "explanatory" variables without displaying any understanding of what an enterprise does and how it does it. Confusion about these matters is rife, as witnessed, for example, by the fact that while some econometric efficiency estimates for electricity distribution treat MWh distributed, km of overhead lines or number of customers as an input, others treat one or more of these variables as an output!

As an illustration, while some consider that energy transfer across networks is an output, in fact, network businesses do not determine how much power is transferred across their lines (in contrast with generators). The APA Group (sub. 2, pp. 1-2) observed:

The benchmarking of electricity business' productivity (and TFP benchmarking in particular) almost always uses energy delivered as the output measure ... This is highly problematic, as energy delivery (and hence apparent network productivity) is responsive to price changes for reasons such as the carbon tax and fuel prices.

⁹ As noted by IRIC (2003, p. 18).

Fundamentally, network businesses provide capacity and quality to customers, analogous to the services provided by roads (Frontier Economics 2010b, pp. 41ff). Accordingly, outputs (or cost drivers) would include:¹⁰

- customer numbers (new connections raise costs) by type (commercial and household)
- the capacity to carry power to dispersed customers (through transformers, network kilometres, by the level of kV) when it is required. This would need to consider network types, such as the mix of central business district, urban, short rural or long rural assets (ETSA Utilities et al., sub. 6, p. 32)
- ensuring adequate quality (reliability requirements) and low transmission losses
- the capacity to cater for peak demand (the load factor or peak to average demand measures).¹¹ If this variable is not available, then energy supplied may be a practical control variable, since otherwise an over-engineered network with excessive capacity may appear to be efficient
- input prices (as suggested by Ergon Energy, sub. 8, p. 10 and the ENA, sub. 17, p. 30).

If there is an insufficient sample for estimation, composite cost drivers may be relevant (widely used by OFGEM, but declared to be ‘arbitrary’ by NERA 2007, p. 3, pp. 29ff).

It is also important to distinguish short-run efficiency (where the focus is on operating expenditures) from long-run efficiency (where capex *and* opex are the relevant cost). While generally in favour of the greater use of benchmarking in regulatory determinations, the MEU acknowledged this limitation:

... benchmarking of capex is less readily applied due to the “lumpiness” inherent in some of the capital investments required in the energy transport sector. This, of course, should not be a reason not to benchmark. ... This requires the excision of the large augmentation projects (the “lumpiness”) from the capex program and then benchmarking becomes essentially straightforward and useful. The few “lumpy” elements can be assessed in their own right. (sub. 11, pp. 17-18)

The ratio of replacement investment to the age-weighted value of existing capital stock provides one indicator of whether rising capex reflects the (efficient) need for

¹⁰ Several participants made suggestions about the appropriate variables. These resembled the diversity of those suggested in an international context (Ergon Energy sub. 8, p. 10; ATSE sub. 9, p. 1).

¹¹ EnerNOC (sub. 7, p. 4) considered that the best measure was the proportion of the peak load that appears for 40 hours or less in a year, but acknowledged that 40 hours was a fairly arbitrary choice (with values from 10 to 80 hours all being reasonable).

the orderly replacement of older assets (Ausgrid, sub. 19, p. 6). Others — such as NERA (appendix B of ENA, sub. 17) — argue that the relevant metric is the share of assets close to expiry.

4.4 The use of benchmarking for Australian electricity networks

The use of benchmarking under previous regulatory regimes

Prior to the creation of the AER, state and territory regulators often used benchmarking of electricity networks as a tool, but not in determining revenue allowances (box 4.1). Several regulators used benchmarks to test the reasonableness of proposals (ICRC, IPART, QCA). Others used benchmarks to flag areas that might need further analysis (ETSA) or to assess a base year expenditure (ERA). In other instances, benchmarking has apparently not been influential (OTTER, NTUC). Chapter 6 examines these studies' empirical estimates of network inefficiency.

Notably, the Northern Territory relies particularly heavily on comprehensive benchmarking to determine the rate of growth in their CPI-x framework.¹²

Benchmarking in the current regulatory framework

The Rules specify that from late 2014, the AER *must* prepare annual benchmarking reports of the relative efficiency of distribution and transmission network businesses in the NEM (box 4.2). Amongst other sources of information, the AER must 'have regard' to these reports in assessing the reasonableness of business's building block and revenue proposals. Prior to the recent Rule change, there was no requirement for formal and regular benchmarking. Nevertheless, the AER used benchmarking in its regulatory determinations (box 4.3), albeit with some limitations.

- While the AER has commissioned various consultants to undertake benchmarking analyses in the various distribution determinations, the

¹² The X factor is of the form $X1 + X2 - X3$ where: X1 is the difference between the TFP growth for the electricity distribution industry in Australia and that for the economy as a whole; X2 is the difference between the best observed opex partial productivity level in comparable electricity distribution businesses in Australia and that of Power and Water Power Networks (PWPN); and X3 is the difference between the input price growth for PWPN and that for the economy as whole (GHD Meyrick 2008, p. ii).

consultants have used different benchmarking techniques, with varying access to industry-knowledge and data.

- Not all networks have been analysed using the same modelling processes. For instance, the Repex model was only developed in time for use in the Victorian distribution determination, and has yet to be applied to several other jurisdictions (AER 2011a, p. 11).
- The results of any benchmarking exercise have typically only informed the AER's state-specific revenue determinations, even though there may be clear implications for other jurisdictions.
- The AER (and others) have indicated that it has made limited use of benchmarking and has focused on ratio analysis (AER, sub. 13, p. 14).¹³ The MEU (sub. 11, p. 12) claimed the regulatory use of benchmarking had 'been supported in principle but has become somewhat inconsequential in practice.' The AER has claimed that the Rules have frustrated its capacity to set a revenue allowance using benchmarking (sub. 13, p. 14), thus limiting its usefulness. The Rules have now been amended.

4.5 Criteria for judging benchmarking

There are many benchmarking methods (as discussed above), multiple uses for these, varying processes for testing them and different regulatory practices for gathering data, communicating results, and addressing compliance burdens. A key question is how to separate the wheat from the chaff among the various competing approaches, recognising that this will typically involve balancing various criteria (figure 4.7).¹⁴

¹³ What 'limited' means is a matter of judgment. ETSA Utilities et al. (sub. 6, p. 3) indicated that the AER has used benchmarking extensively. The difference of view centres on the sophistication and function of the benchmarking, not the number of times it has been used. As the ENA (sub. 17, p. 4) pointed out 'the key question is how the AER's use of benchmarking can be enhanced in order to improve the accuracy of [network expenditure forecasts] (sub. 17, p. 4).

¹⁴ Participants in the inquiry had overlapping criteria for judging benchmarking. For example, ETSA Utilities et al. (sub. 6, p. 25) identified nine criteria: communication, consultation, consistency, predictability, flexibility, independence, effectiveness and efficiency, accountability and transparency. Ausgrid (sub. 13, p. 5) and the ENA (sub. 17, pp. 4-5) recommended robustness, transparency, promotion of efficiency, consistency with the wider regulatory framework, reasonableness of data requirements, adaptability and resource costs. These are similar criteria identified by Frontier Economics (2010b) for OFGEM in the United Kingdom. Kaufmann and Beardow (2002) noted similar criteria, but added the importance of capturing business conditions — an issue to which this chapter returns later.

Box 4.1 **State and territory regulators' use of regulatory benchmarking**

State and territory regulators have used partial productivity indicators to benchmark electricity network performance:

- IPART compared various expenditure ratios over time for New South Wales distribution networks, using data from the years 1999-2000, 2003-04, and 2008-09. The results were used to test the reasonableness of expenditure allowances.
- ICRC compared ActewAGL with five Victorian distribution networks across various opex ratios, using data from 2002-03. The results were used to test conclusions about expenditure allowances.
- ESC (Essential Services Commission Victoria) compared a deconstruction of operating expenditure (opex) growth to measure partial factor productivity. Trend analysis was also carried out for capex, comparing networks from Victoria, New South Wales and New Zealand. The opex comparisons were carried out to determine the 'rate of change' and 'growth factor'.
- QCA compared opex ratios between Energex, AGL, United Energy and EnergyAustralia. Capital expenditure (capex) ratios were compared between Energex, Ergon and Victorian distribution networks. The results contributed to the assessment of reasonableness for expenditure proposals.
- ESCOSA compared expenditure ratios between ETSA and 10 other distribution networks. The results were used to identify areas requiring further analysis.
- Office of the Tasmanian Economic Regulator (OTTER), conducted trend analysis for opex and capex using data from 2002-03 to 2011-12. The results were not considered in the determination.
- Economic Regulation Authority (ERA WA) compared actual opex between Western Power and all other Australian distribution networks for 2007-08. The results were used to assess the base year expenditure for 2007-08.
- NTUC used a 'multilateral unit opex' method to benchmark opex for water and energy utilities.

Regulators have also undertaken benchmarking using comprehensive indices such as TFP:

The Northern Territory operates a CPI-x framework for the escalation of network prices, using estimates of productivity to determine the X factor. The industry TFP growth trend is used in the calculation of the x factor (see footnote 12 above).

Source: ACCC/AER (2012a), tables 2.2 and 3.3.

Box 4.2 The Rules and benchmarking

The National Electricity Rules (v. 54) makes 53 references to ‘benchmarking’ or ‘benchmark’, predominantly relating to the financial variables that determine the weighted average cost of capital. However, for the purposes of this inquiry, the most important references are to the opex and capex of distribution and transmission networks. Considering distribution networks, the Rules stipulate various decision-making stages:

Publication of an annual benchmarking report:

The AER must produce an annual benchmarking report of the relative efficiency of each distribution network business (s. 6.27) — a Rule change that occurred after the Productivity Commission’s draft report. The AER must publish the first by September 2014. In preparing the report, there must be consultation with NSPs and the jurisdictions, and the capacity, but not the requirement to consult with people with an interest in the subject and the public (s. 8.7.4(b)).

The AER must accept reasonable opex:

Clause 6.5.6(c): The AER must accept the forecast of required operating expenditure of a distribution network business that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects: (1) the efficient costs of achieving the operating expenditure objectives; (2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The AER must reject unreasonable proposals:

Clause 6.5.6(d): If the AER is not satisfied as referred to in paragraph (c), it must not accept the forecast of required operating expenditure of a distribution network business that is included in a building block proposal.

The AER must have regard to benchmarking when evaluating reasonable and unreasonable proposals:

Clause 6.5.6(e): In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the operating expenditure factors): ... (4) the annual benchmarking report published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network business over the regulatory control period [among 10 categories].

The AER can make its own reasonable estimate (clause. 6.12.1(4)(ii))

While it must give reasons for its rejection of the business proposal (cl 6.12.2), the AER has the discretion to accept or reject any element of a proposal (cl. 6.12.3(a))

There are parallel requirements for capex for distribution network businesses (clauses 6.5.7(c), 6.5.7(d), 6.5.7(e), and 6.12.1(3)(ii)).

Box 4.2 continued

Transmission businesses

There are also similar, but not identical, clauses for transmission network businesses:

- an annual benchmarking report (clause 6A.31)
- for opex (clauses 6A.6.6 (c), 6A.6.6 (d), 6A.6.6 (e)(4))
- for capex (clauses 6A.6.7 (c), 6A.6.7 (d), 6A.6.7 (e)(4))
- a capacity for the AER to put in its own estimate (cl. 6A.13.2), with reasons (cl. 6A.14.2)

The two important differences are that for transmission network business, the clauses relate to the business's revenue proposal, and the issue of discretion is implicit, not explicit.

Source: National Electricity Rules, version 54.

Box 4.3 Examples of benchmarking in AER determinations

On behalf of the AER, Nuttall Consulting (2011) benchmarked Aurora's expenditure levels against several other networks. This included various ratios of capex and opex. Comparisons were made against other networks, states, or regions (for example, rural Victoria). Nuttall Consulting (2010a) also benchmarked Victorian distribution expenditure levels and ratios against those of other networks and States.

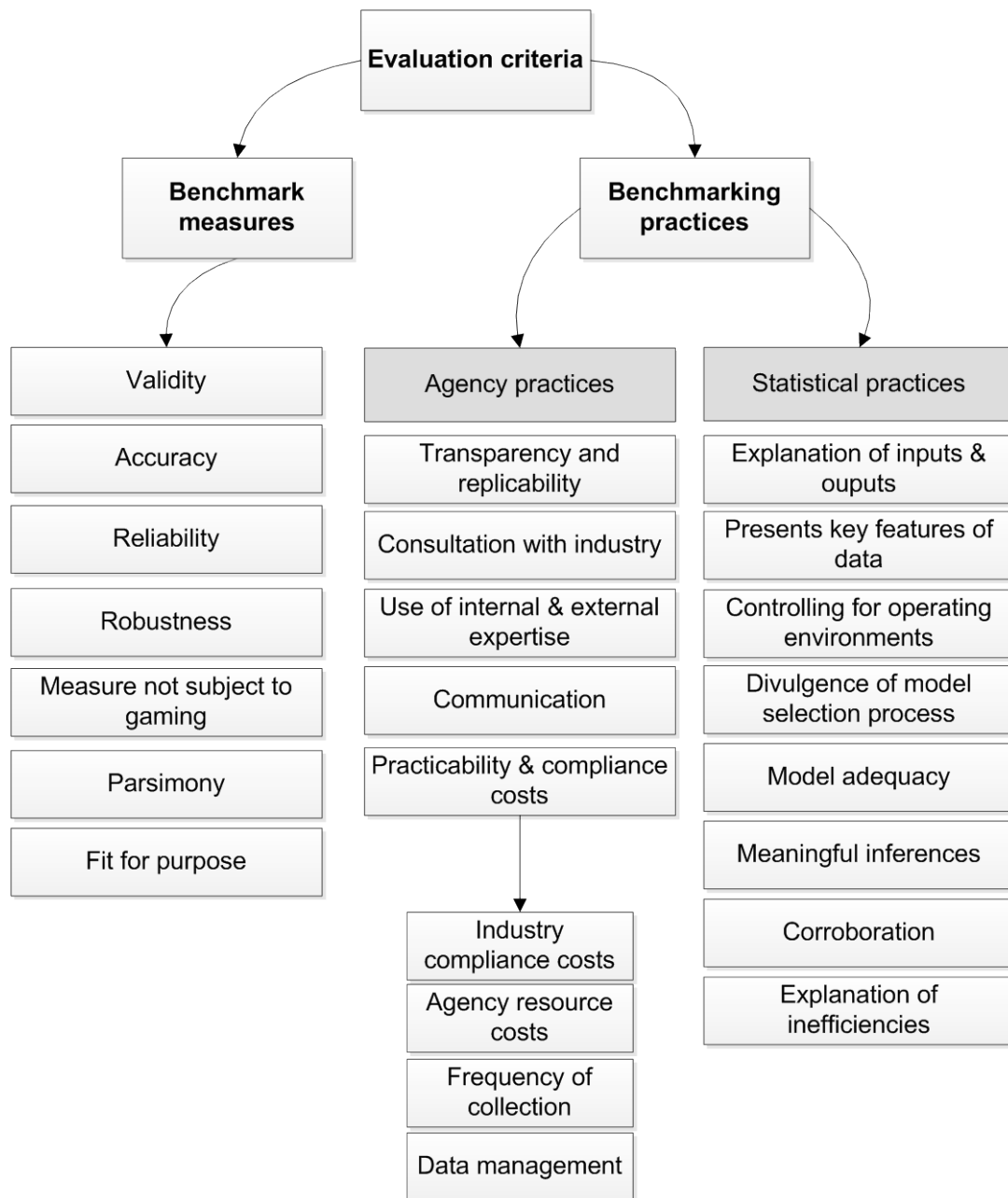
Wilson Cook (2008) analysed measures of expenditure for distributors in the Australian Capital Territory and New South Wales, and compared them with a subset of other networks. A bottom-up analysis was also undertaken, and recommendations were based on both sets of results.

Parsons Brinckerhoff (2009a, 2009b and 2010) compared opex measures for Queensland and South Australian distributors against other networks.

ETSA Utilities et al. (sub. 6, p. 24) noted that network businesses themselves have submitted benchmarking results, for example in relation to opex. These businesses (pp. 60ff) also gave a comprehensive account of the benchmarking undertaken by the AER in respect of Victorian distribution network service providers (and how these results demonstrated the efficiency of the Victorian businesses).

Sources: Nuttall (2010a, 2011); Parsons Brinckerhoff (2009a, 2009b, 2010); Wilson Cook (2008).

Figure 4.7 Evaluation criteria for benchmarks and benchmark practices



It is useful for any discussion of such criteria to break them into three subgroups:

- the characteristics of a good benchmark from a scientific perspective, of which validity is the initial consideration (sections 4.6 and 4.7)
- the statistical processes used by the analyst to test whether any result is likely to be useful for its regulatory purpose (section 4.8)
- the processes used by the regulator in undertaking benchmarking. (This issue is examined in chapter 8, which relates to how the AER should use benchmarking.)

4.6 Validity — does the measure test what it claims to?

A valid benchmark should relate to the relevant concept — efficiency (or conversely inefficiency) in one or more meaningful dimensions.

A low failure rate (in say minutes lost per customer) is not a measure of efficiency if customers do not value the reliability benefits above the costs of achieving them (chapter 14).

Similarly, while higher revenues per connection *could* be a reasonable measure of inefficiency:

- that is not necessarily true. For example, higher revenues of one business compared with others may reflect a regulator's reasonable decisions about the weighted average cost of capital (WACC) at the time of the regulatory determinations
- it is not clear to what type of inefficiency it relates. A high revenue per connection could reflect an inefficiently high WACC (leading to excessive prices, with deadweight costs for customers, but not necessarily excessive investment), or low productivity, or both. Accordingly, it is not a valid measure of its separate components. Data permitting, a better approach would be to break revenue per connection down into its price and productivity components, since these have different implications for policy. For instance, if the business were technically efficient, but the WACC was too high, the regulator would concentrate on the latter in its determinations.

An overarching concern is that any valid benchmarking measure should reflect the way that the businesses are run. As Turvey (2008a, pp. 2-3) put it in relation to opex benchmarking:

Applying different econometric methods to find which method and which of such variables give the 'best' results is very different from the down to earth approach of understanding the industry sufficiently well to identify and describe the immediate determinants of the operations and maintenance work actually required.

Valid benchmarks of efficiency will often need to take account of time

Efficiency has a time dimension. It can be efficient to 'over-invest' in certain assets ahead of their full utilisation because investment must precede production or because it can be less costly to build in spare capacity at a given time, than to

re-invest at a later time to add further capacity.¹⁵ One of the reasons for the recent slowdown in measured productivity of the Australian economy is that mining companies made large investments ahead of the extraction of output. Few suggest that the Australian mining industry is inefficient for this reason.

Benchmarks that fail to recognise the implications of timing can be misleading. For example, suppose that a business makes its investment too early compared with a peer that invests optimally, but that both start and finish with the same capital stocks. Assume for illustrative purposes that the outputs of the businesses are identical in each year. In the example shown in figure 4.8, the comparative investment levels required to achieve a given output — a measure of their relative investment efficiency — suggests that the ‘inefficient’ firm is grossly inefficient in the initial years and then more efficient in later years. Yet in present value terms over the relevant period, the early investing firm’s relative inefficiency is only around four per cent. Using snapshot efficiency measures for the first few years would not provide a valid measure of the real efficiency gap between the businesses. Static measures are still useful, but need to be carefully interpreted.

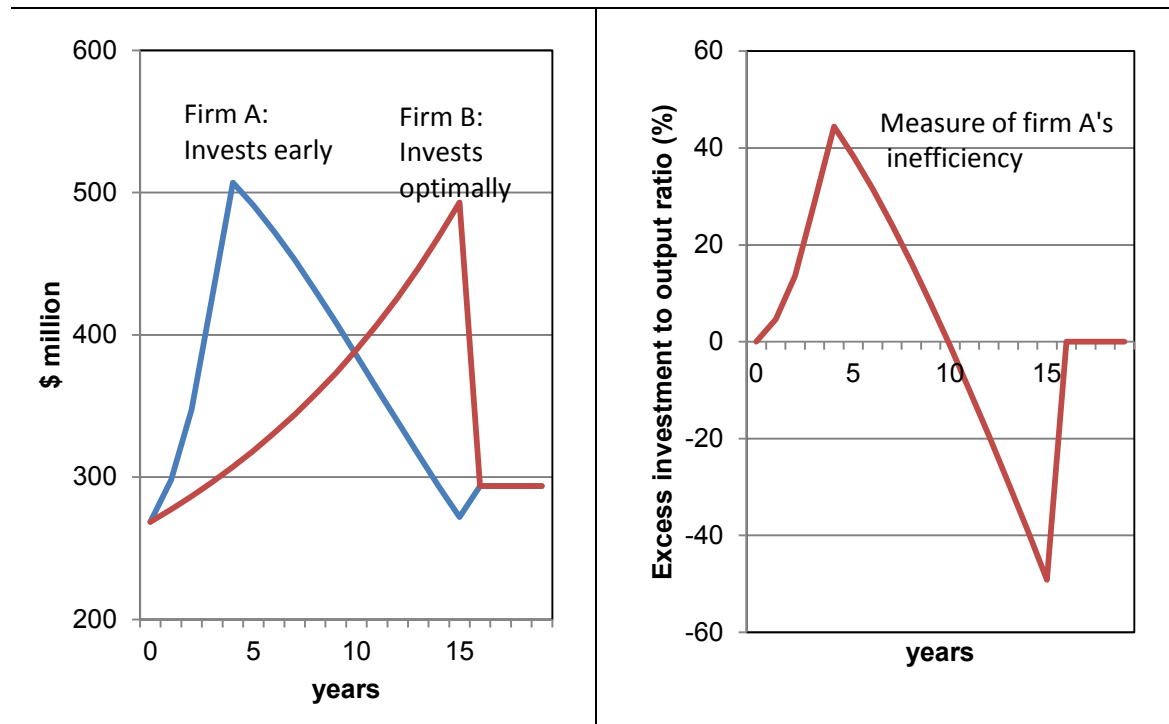
Controlling for factors outside the control of business and their relevance to valid conclusions about inefficiency

There is a large literature on estimating the comparative costs of businesses, with much of that literature concentrating on using the ‘right’ techniques. However, it is equally important to be clear about how to interpret benchmarking results for policy purposes because the misuse of good technical analysis can result in adverse outcomes for consumers and businesses. In particular, comparing the costs between businesses in different jurisdictions without accounting for factors outside the control of the business could provide misleading indicators of managerial efficiency. If used in incentive regulation, this could lead to underinvestment or unwarranted transfers from consumers to the businesses.

The measured level of comparative business performance across Australian and international jurisdictions reflect four broad factors.

¹⁵ Growth rates in past demand also have implications for the asset type and scale economies (ENA, sub. 17, p. 30). A business experiencing low and steady growth will tend to (efficiently) have a large number of smaller transformers and other equipment that will need to be operated and maintained. In contrast, a business that has experienced large waves of growth will (efficiently) have a smaller number of large-scale assets that need to be operated and maintained (because large-scale assets can be built with less average underutilisation when demand is growing faster).

Figure 4.8 Efficiency often needs to be dynamically assessed



^a This figure compares the efficiency of a firm that 'prematurely' invests (firm A) and a firm that invests at the optimal time (firm B). The illustration assumes that both firms have the same initial and final capital stocks and investment levels, and the same output levels throughout the period. However, firm A builds up capacity ahead of its productive use. In contrast, firm B uses its capacity efficiently throughout, but must increase its investment rate towards the end of the period to maintain its capital stock and productive capacity. A period-by-period measure of the inefficiency of firm A is the difference between its investment level and that of firm B as a share of output. This is clearly worst at the point where its investment growth rates are high early in the period. For example, looking at year 4, firm A has a level of investment to output ratio more than 40 per cent higher than firm B — an apparently very low level of efficiency. However, by year 15, a snapshot view suggests that firm B is less efficient. An overall view of the relative inefficiency of firm A is the difference between the net present value of its investment stream over the period and that of firm B, divided by the net present value of output. In this illustration, firm A uses just over four per cent more resources to produce the same output as firm B. Snapshot measures can therefore mischaracterise the longer-run level of efficiency differences between businesses.

Data source: Commission estimates.

Managerial inefficiency

Managerial inefficiency may be manifested in many ways. A network business may not organise itself efficiently, resulting in higher than necessary costs and/or poorly structured prices. It is important to emphasise that managerial inefficiency is primarily not about the performance of managers per se, but primarily about how the governance and organisation of a business can affect any aspect of its performance. For example, a business may be overstaffed, have insufficient expectations of workplace productivity, be overly combative or passive in its dealing with its unions, and over-invest. Managerial inefficiency does not always mean ineptitude or lack of industriousness — highly competent people can pursue

inefficient outcomes with hardworking gusto. Moreover, a business could make the most efficient use of its resources at a given time, yet still be encumbered with an inefficient (sunk) capital stock that reflected investment decisions made by previous managers.

Inefficiency also comes in different sizes. The critical concern is not the presence of inefficiency per se, as no industry is perfectly efficient, but whether the divergence in efficiency matters from a policy perspective.

Environmental differences outside the control of the businesses and government

Network businesses are justifiably concerned about ‘like with like’ comparisons.¹⁶ Many of the criticisms levelled by network businesses against the findings of Mountain and Littlechild (2010) reflect their concerns that the analysis did not control sufficiently for extraneous differences in the operating environments of the businesses.¹⁷

Network businesses operate in different environments that are outside their and government control, including the physical aspects of that environment (topography, forestation, climate, soil type, temperature and wind), customer density and type, the form and location of generators, and the prices of inputs, such as wage costs and the costs of wires and substations.¹⁸ For example, the efficient costs per customer of providing network services to highly dispersed customers in a rural region are greater than the costs of providing services in a city suburb (figure 4.9). In relation to its own network, Ergon Energy indicated that its:

... network area covers more than one million square kilometres, which is over six times the size of Victoria. This network characteristic would impact on our

¹⁶ Some accepted that it was possible to meaningfully benchmark the weighted average cost of capital (ETSA Utilities et al., sub. 6, p. 29). The Commission considers some of the problems in this area in chapter 5, as they relate mostly to the capacity for the AER to effectively use other kinds of benchmarking in incentive regulation.

¹⁷ On the other hand, the MEU (sub. 11, p. 24) argued that ‘networks try to minimise the use of benchmarking on the grounds that their network is different.’ This is why statistical testing and engineering appraisal of benchmarking models to test for important omitted variables is critical.

¹⁸ This was reflected in submissions from Ergon Energy (sub. 8, p. 7), ActewAGL (sub. 14, p. 2), the AEMC (sub. 16, p. 2), the ENA (sub. 17, pp. 30ff), Ausgrid (sub. 19, p. 8), the EUAA (sub. 24, p. 7), Essential Energy (sub. 30, p. 4), Grid Australia (sub. 44, p. 3) and GDF Suez Energy Australia (sub. DR68, p. 4). As an illustration, the difficulties in controlling for environmental factors meant that the Brattle Group (2012a, p. 48) found there was no clear relationship between the costs of the distribution networks they reviewed and the reliability performance they achieved.

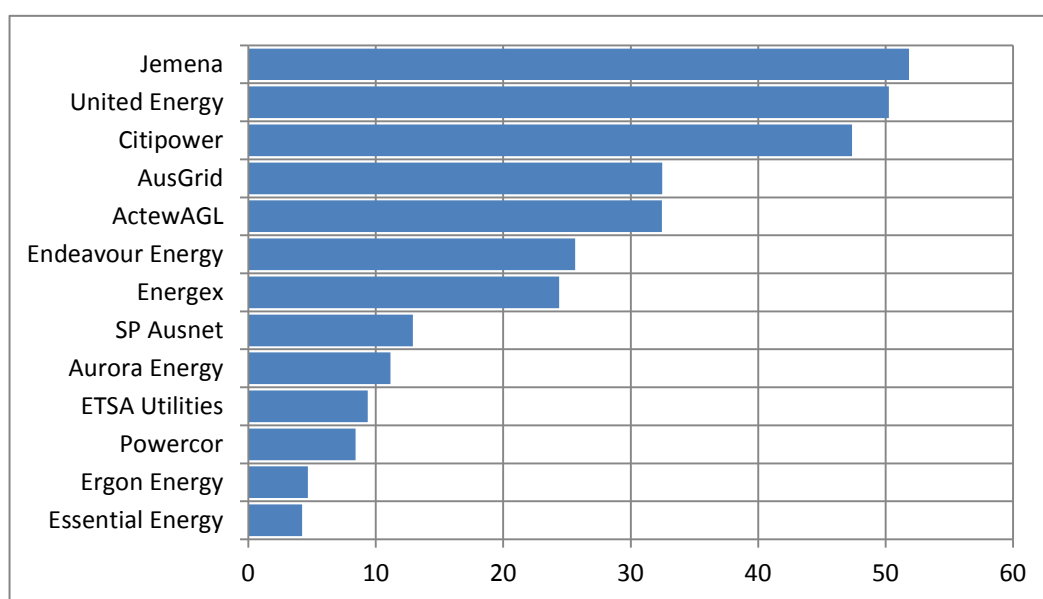
performance against reliability standard targets due to accessibility issues and distance to travel to faults. (sub. 8, p. 3)

Some participants pointed out the need to engage with the business's actual operations at a detailed level:

... it may be that poles are twice as expensive in one jurisdiction compared with the other (e.g. due to different proximity to a hardwood industry - noting that poles are expensive to transport). (ENA, sub. 17, p. 28)

Figure 4.9 Customer density differs between networks

Customers per km of distribution line



Data sources: AER (2011b); distribution businesses' websites and annual reports.

In certain instances, it is difficult to categorise definitively whether a factor is fully outside the control of the business:

- peak demand can be partly controlled by the businesses given they can undertake demand management programs (AER 2010a). Failing to account for this in benchmarking could discourage further improvement of demand management programs (chapters 9 to 12)
- businesses provide advice on reliability standards
- in many cases governments, rather than network businesses, make the decision about whether to put cables underground — which lies clearly outside the control of the businesses. However, in some other instances, network businesses will make the decision to install cabling underground ('undergrounding') because it increases reliability and reduces vegetation clearing costs, or because there is a mutual benefit to them and to co-contributing customers from

undergrounding. Consequently, were businesses sometimes to overinvest in undergrounding then this would not show up as inefficiency were a benchmarking exercise to control for all undergrounding.

Policy differences

Network businesses in different jurisdictions are sometimes subject to different regulatory and policy frameworks, which are outside the business's control, but within governments' control. Such policies and regulations can affect a network business's practices, costs and productivity. For example, governments may set reliability standards (ENA, sub. 17, p. 7), may own the business concerned (a policy choice of government, not the business), and where state-owned, stipulate their governance arrangements or give them non-commercial directions (chapter 7). Governments may also mandate various environmental policies — such as feed-in tariffs for household photovoltaic generation — that may physically affect the efficiency of the network and add to overall customer prices, reducing power demand, and utilisation of the network (chapter 13).

This is relevant to policy in two ways:

- benchmarking for incentive regulation needs to control for any important policy/regulatory arrangements that affect business performance
- the information from controlling for such arrangements in any benchmark modelling can be used to improve aspects of the policy environment (such as divergent and unjustified differences in reliability standards; or limits on the use of demand management through price controls). When reporting on its benchmarking modelling results, the AER should highlight publicly any major effects on productive efficiency from policy and regulatory settings.¹⁹ A major reason for the Commission's consideration of ownership, demand management, and reliability is that these may be a source of greater inefficiencies than the managerial practices per se. For example, IPART (2010, p. 49) commented that the quality of network planning and the decisions on the licence conditions that drive capital expenditure will be critical for future productivity performance in electricity distribution. It is also possible that the parameters indicating the productivity and cost impacts of policy settings are more statistically reliable than the efficiency estimates for any given business.²⁰

¹⁹ Such reporting may also be helpful in that it emphasises that managers of network businesses may sometimes be quite efficient given the policy environment they face.

²⁰ As an illustration, the parameter estimates of an OLS regression on productivity or costs will be unbiased regardless of the variance of the error terms (the error terms being the measures of business inefficiency). This is not true for any given business's efficiency measure.

The policy benefits from exploiting benchmarking models in this way have a long lineage. Indeed, where regulations and policies particularly affect business performance, this is sometimes the major reason for benchmarking.²¹ Some of the impetus for regulatory reform of Australian utilities a decade ago arose from evidence about its beneficial impacts in overseas countries.

Interactions between policy and managerial inefficiencies may also be important

While it is important to distinguish managerial inefficiency from economic efficiency generally, it can be equally important to consider their interaction. Trade policy provides a well-understood illustration of the issue. Import tariffs have adverse impacts on efficiency by distorting people's consumption choices and diverting resources to industries that have a lower comparative advantage. That type of inefficiency need not involve any managerial inefficiency in that the business managers may still seek to minimise costs and set prices as efficiently as they can in the constrained world they face. However, tariffs may also have a dynamic effect on efficiency by lowering the incentives for managerial performance. This might occur because business managers feel insulated from competition or believe that governments will adapt tariffs (or provide subsidies) to maintain their business's profits regardless of their competitiveness. The managers may be intrinsically highly competent, but they respond to the incentives they face.

In the case of network businesses, the factors outside managers' control that may affect their managerial efficiency include, among other things, private or state ownership (and any associated issues with labour relations and governance), and the regulatory arrangements used to constrain monopoly profits. An enterprise has less pressure to rigorously test all investment and other spending options for its efficiency if it is partly shielded from the consequences of its decisions. This represents a form of 'moral hazard' of the kind that makes people less careful where they are insured against the consequences of certain risks.

For instance, to the extent that an enterprise can link much of its spending to the imperative to meet reliability standards (thereby receiving regulated returns for its spending), then it has weaker incentives to control that spending. This is more likely where a reliability standard is not anchored to the customer value of reliability, and where the knowledge about how to achieve the standard lies mainly with the business, rather than the regulator. If the business is particularly sensitive to public

²¹ This approach has been used across many industries and contexts, such as in electricity, rail freight, telecommunications, road freight, waterfront, coastal shipping, aviation and gas supply industries (BIE 1995), privatisation (Mota 2004), reliability and pricing (McLennan Magasanik Associates 2007), and international comparisons of stevedoring (PC 2003).

perceptions of instances of unreliability then it may spend too much to reduce these risks, even if the standard did not require that. Moreover, as high reliability standards require greater capital expenditure, they provide a capacity for greater costs from inefficient management practices.

Once an external factor outside the control of the business also affects managerial efficiency, then fully controlling for that external factor in benchmarking analysis means that managers do not face the full incentives for efficient behaviour — subverting the goal of benchmarking.

Data problems

Any data inputs into benchmarking models are subject to error due to measurement problems, small differences in the definitions used by different businesses and the periods to which the data relate, and simplification of the relationship between costs, inputs and outputs. Businesses may not report reliable information. The AEMC (2009a, p. 8) pointed out:

One regulator stated that the data provided by a service provider was so unreliable that it was difficult to conduct an independent audit of the data.

Before the AER assumed responsibility as the distribution network regulator, state and territory regulators collected data on network businesses, but did not employ a common framework (AER, sub. 13, p. 18). Lawrence (2009) notes that coverage of key variables such as opex has varied over time (p. v). Ergon Energy (sub. 8, p. 4) observed that the AER has only recently begun to implement consistent data collection. Such data limitations lay behind the AEMC's view that TFP methods could not yet be used to set x factors in CPI-x methods.

There are also significant data gaps. Some of the recent capital expenditure has reflected the need to replace assets close to their end of life (chapter 2; Topp and Kulys 2012), but data on asset vintages is incomplete.²² More generally, leading benchmarking practitioners identified gaps in physical network data, which the AER is only now systematically addressing:

For instance, regulatory reporting guidelines deal almost exclusively with financial matters required for building block regulation with little or no mention on any physical system data. Thus, while they examine the moneys received and spent, and the financial characteristics of assets used, created and depreciated, there is no quantification of *what* assets are built, maintained or operated to deliver the network service. Jurisdictional regulators noted that their efforts to date had almost exclusively been directed at obtaining

²² An observation also made by the AER in its justification for accepting substantial expenditure increases in various regulatory determinations.

the financial data required for building blocks regulation and they had had little time to assemble data on physical characteristics and outputs. (Lawrence and Kain 2009, p. 19)

Others point to the expedient use of easily available data for benchmarking, rather than the variables most suited to efficiency measurement (APA Group, sub. 2, pp. 1-3).

Nevertheless, *any* quantitative method is subject to error and data problems. The key question is whether it matters for the regulator's intended purpose (an issue to which this chapter returns). The MEU identified data limitations but — with some reasonableness — pointed to the fact that:

There is a need for a consistent approach for the gathering, manipulation and display of data to make the best use of benchmarking. However, even imperfect data can provide useful insights and should not be excluded, even though its use might be minimised. ... 'rough and ready' can provide a strong indication as to whether the proposed opex, capex and WACC outcomes are grossly inefficient and whether deeper analysis is required to ensure a more efficient outcome is possible. (sub. 11, p. 25)

Australia has few observations

There are only 13 distribution businesses, five regional transmission businesses and three separate direct current interconnectors in Australia.²³ This reduces the feasibility for more elaborate models that take into account the multiple environmental factors affecting inter-firm performance.²⁴ As the Consumer Action Law Centre argued:

However, with a relatively low number of network businesses to start off with, this may cause a particular challenge for the NEM that has been more easily overcome in overseas markets. (sub. 5, p. 4)

The case of interconnectors is even more problematic:

²³ In contrast, Germany has nearly 900 distribution network operators (Schweinsberg et al. 2011, p. 29).

²⁴ In a comprehensive survey of the use of benchmarking methods by individual countries, Haney and Pollitt (2011) argued that small numbers of network companies act as a constraint on the use of advanced benchmarking methods. The ENA observed that the greater the level of aggregation in the analysis, the greater the number of variables that should be included in the analysis, such as the type of street transformer, the distribution of asset vintages and climatic conditions (ENA, sub. 17, pp. 24-5). Of course, some factors that affect performance must be omitted from any benchmarking analysis given sample size limits. For example, an inefficient local government may be slow at processing planning proposals for a given network business, and no practical benchmarking approach can fully take account of such micro-factors. The extent to which a model should include variables must therefore depend on their materiality and statistical testing.

In the case of ‘single’ electricity transmission assets such as Murraylink and Directlink, benchmarking is not an appropriate way to establish the price or revenue path. Their ‘output’ is the continued availability of full interconnection capability ... These assets are unique and have no logical comparators on which benchmarking could be based. (APA Group, sub. 2, p. 2)

Given sample size problems, benchmarking is most likely to be effective in its application to distribution businesses (Grid Australia 2009), although Ergon Energy argued that even here, the numbers were too small to provide meaningful results (sub. 8, p. 3). The latter suggested that benchmarking reliability might be improved by including both transmission and distribution businesses in the analysis (sub. 8, p. 10).

Would international benchmarking help?

While international benchmarking might increase the number of observations, it raises other challenges for valid comparisons. For example, ETSA Utilities et al. (sub. 6, p. 27) and the ENA (sub. 17, p. 25, p. 49) noted that results are affected by differences in exchange rates, reliability standards, accounting policies, tax laws and corporate structures.²⁵ The question of whether Australia has high, medium or low electricity prices — a potential test of efficiency — has proved difficult to resolve (Mountain 2012a in contrast to NERA 2012b). However, it appears that the results are sensitive to choices about the appropriate exchange rate and the retail tariff (regulated versus market rates). It merely serves to highlight some of the complexities of comparisons of this kind.

On the other hand, the Australian Academy of Technological Sciences and Engineering cited the value of the International Transmission Operation and Maintenance benchmarking (ITOMs), which is conducted every two years, covering about 30 businesses (ATSE, sub. 9, pp. 1-2). Australian transmission businesses are included in ITOMs and use it for internal purposes. ATSE also recommended the inclusion of Western Australia and the Northern Territory as comparators. While the MEU (sub. 11, p. 25) noted the difficulties of international comparisons, it considered that it could ‘still provide some useful information’.

The Council of European Energy Regulators (2012) has undertaken extensive benchmarking of the quality of electricity supply — arguing that successive benchmarking analyses in this area may have prompted improvements in quality.

²⁵ There was general opposition to international benchmarking by network businesses in both the Commission’s informal consultations and in submissions made by them to this inquiry (for example, Ergon Energy, sub. 8, p. 9). However, as shown later, they do participate in international benchmarking for commercial reasons.

However, even in this narrow area, it encountered significant differences in definitions, which complicated its benchmarking.

Overall, international benchmarking should not be dismissed, especially as the businesses use it themselves. However, it is likely to be most useful in specific aspects of the performance of the businesses where measures of physical inputs and outputs are available (such as reliability or certain labour productivity measures), for assessing business processes (such as the use of tendering and outsourcing) and for raising issues of concern that the regulator might pursue in further detail.

4.7 Other scientific criteria for judging benchmarking

While the validity of any benchmarking measure is a prerequisite for its use, there are also other criteria important for assessing the quality and interpretability of various benchmarks.

Accuracy and reliability

Accuracy is the degree to which a benchmark provides an unbiased estimate of efficiency, while the reliability (used here in the normal sense of reproducibility) is about the variance of the measure. For example, a bathroom scale that is consistently out by exactly 10 per cent is inaccurate, but reliable. As discussed above, a failure to adequately control for differences in operating environments can lead to heavily biased measures. More subtly, certain statistical models of productivity may use underlying assumptions at odds with the known properties of the variable of interest.²⁶

Robustness

This is a subset of accuracy and reliability, but worth emphasising in its own right. A particularly useful robust measure is one that provides information about the efficiency of an enterprise regardless of its operating environment. Although affected by other kinds of errors, some measures of management performance (such as those underpinning figure 4.2) might fall into that category. However, such measures are likely to be the exception rather than the rule.

²⁶ For example, using ordinary least squares regression for categorical data (for example, yes/no answers, or ratings from one to five) will lead to biased estimates and a poor capacity for statistical inference.

If the results of a model are sensitive to small perturbations in the underlying data, the addition of control variables with little expected impact, the removal or addition of a single network business, or to modest changes in assumptions and estimation techniques, then benchmarking results are at best indicative, and at worst, useless.

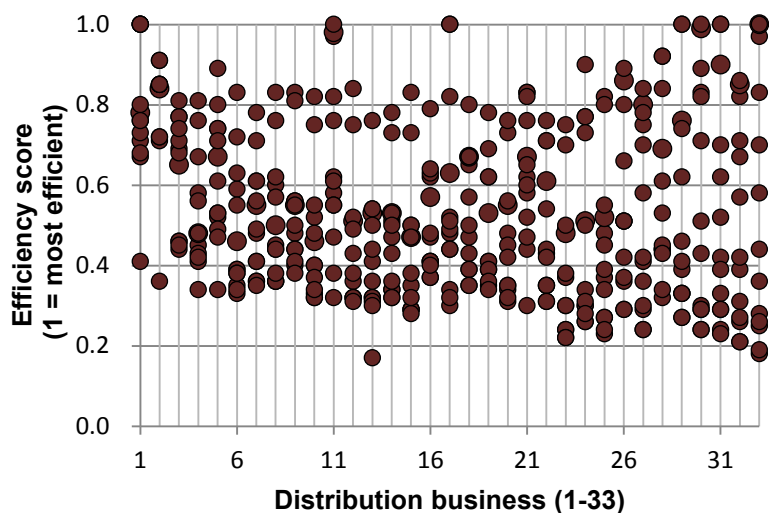
- Farsi and Filippini (2005) found that in a study of 52 distribution companies, the efficiency scores and rankings were significantly different across various methods, and especially between parametric and non-parametric models.
- A study of 33 Polish distribution businesses found a large dispersion in efficiency results for any given business (figure 4.10). These results would not be usable for regulatory purposes unless model specification tests were able to eliminate most of the models. This underlines the importance of testing.
- IPART's (2010) analysis of state-owned corporations, which included electricity networks, showed that the choice of input variables changed the rankings of firms and their TFP scores.
- The use of partial productivity indicators is also sensitive to specification. For instance, in their report to the WA Economic Regulation Authority, Wilson Cook (2009, p. 86) made several partial productivity comparisons between Western Power and network operators in other states. Three comparisons were made of distribution opex, separately accounting for customer numbers, line length (km), and electricity consumption (kWh). While these comparisons produced consistent *rankings* at a state level, they did not provide consistent measures of opex efficiency.
- Complex non-linear models appear to be particularly prone to problems. For example, in their review of European benchmarking of electricity networks, Schweinsberg et al. (2011, p. 55) found unstable convergence on parameters in stochastic frontier analysis (a common benchmarking approach), such that it was not possible to distinguish inefficiency from statistical noise.

Limited susceptibility to manipulation or gaming

As in all systems where rewards and punishments depend on incomplete measures of performance, the measured party has incentives to 'look' like a highly performing entity (whether it be a hospital, school, a student, CEO, employee, or in this case, network businesses). As the Consumer Action Law Centre observed:

It is thus important to be mindful of this when designing benchmarking mechanisms, but even more so when interpreting and applying the results. If given the opportunity, we can assume that the network businesses would seek to strategically influence the benchmark indicators and as such, the result could be just another layer of 'gaming'. (sub. 5, p. 5)

Figure 4.10 Estimates of inefficiency vary depending on the method
Results for various measures of efficiency^a



^a The results are based on applying 14 benchmarking methods (variants of DEA, COLS and SFA) to 33 Polish electricity distribution businesses. Each vertical line shows the various efficiency measures corresponding to the 14 methods. (Often there will not appear to be 14 observations per business, because the measures sometimes coincide.)

Data source: Cullmann et al. (2006).

Accordingly, the regulator should consider the capacity of any particular benchmarking measure to create unforeseen business behaviours.

- A benchmark measure might be a proxy for some hard-to-observe characteristic of efficient businesses or be sufficiently vaguely represented that firms can meet the benchmark, but not the underlying goal (CREG and SUMICSID 2011, p. 36). For example, a business may be able to meet some benchmarks by changing their cost-allocation methods (Jamashb et al. 2003), even if the underlying resource allocation is not optimal.
- The regulator also needs to consider the interdependence between some efficiency measures.²⁷ Measuring one aspect of efficiency (such as opex per kilometre of line), but ignoring another due to measurement difficulties (capital productivity), may result in inefficient substitution in distribution systems. This is one of the advantages of the CPI-x methodology and aggregate benchmarking.

²⁷ The ENA observed that the ‘level of aggregation needs to be high enough such that material interdependencies between different expenditure types are captured in the analysis. For example, network augmentation expenditure on the sub-transmission system may be a substitute for augmentation expenditure on the distribution system and vice versa’ (sub. 17, p. 24).

-
- Distorted information may directly affect the incentives of complying firms (NERA, appendix B of ENA, sub. 17, p. 34).

Parsimony

A good model should be no more complex than required. This is important in assisting interpretability, avoiding data mining, achieving robust results, reducing data collection costs and allowing greater comparability of results across countries (since it is easier to ensure common definitions for a few variables).

An important facet of parsimony is to forgo complexity where it adds little explanatory power. For example, a Productivity Commission Staff Working Paper (Sayers and Shields 2001, p. 178) investigated the sources of price differences between Australian electricity distribution businesses, and found that many factors had small impacts. For example, at that time, the study found vegetation growth and its management had small impacts. (Whether that result remains true is uncertain, but the point is that it will sometimes be possible to identify factors that are largely immaterial for costs, and that can be eliminated as control variables.)

Similarly, in an exhaustive study of Belgium distribution network businesses involving multiple measures of outputs and inputs, the only relevant outputs were total circuit length of lines, customer numbers, and the total number of connections (CREG & SUMICSID 2011). One of the valuable aspects of international benchmarking analyses is they may be able to identify the variables that matter for networks more generally.²⁸ This may then allow greater confidence in using a small range of variables in the Australian context where the sample size is low.

Fitness for purpose

As discussed further in chapter 8, benchmarking has multiple purposes. Some require great accuracy, reliability and robustness. This is particularly important where benchmarking is used to determine a business's revenue allowance. Such benchmark estimates should be highly reliable across time, business types and jurisdictions. The concerns are less where benchmarking is indicative — used to identify areas for possible future investigation, or to reach some *prima facie* judgment. This is how the Commission regards the preliminary results presented in chapter 6.

²⁸ So long as there is sufficient variation in the cost drivers concerned (such as varying levels of forestation, wind, and temperature).

4.8 Testing the credibility of results

Benchmarking models do not actually estimate inefficiency, although this is how they are generally interpreted. The results of any benchmarking model show the extent to which the model *fails* to explain performance:

... it is incorrect and misleading to ascribe the residual to ‘inefficiency’, or to describe the benchmark as a measure of ‘efficient costs’. Instead, one must acknowledge that the residual measures no more than the element of observed costs that the model has *failed to explain*. (Shuttleworth 2005, p. 315)

... an observation of difference does not itself constitute *diagnostic* evidence, the gold dust of effective assessment. (Yarrow 2012, p. 4)

That is, the inefficiency of any business is the difference between the business’s observed performance and that predicted by a set of cost drivers. This can reflect missing cost drivers, data errors, incorrect estimation methods, and invalid assumptions about the functional form and error distributions.

The way of appraising the credibility of the results is through systematic investigation and reporting, including:

- explanation and graphical presentation of inputs and outputs and their main statistical features (averages, variances)
- divulgence of model selection processes, how data may have been manipulated, and why potentially relevant variables have been omitted
- comparisons with alternative models, and why the ultimately selected model(s) is superior to others
- tests of model adequacy, such as tests of linearity, normality or otherwise of the residuals, parameter stability with different sub-samples, the influence of outliers, and, subject to the caveats spelt out later, statistical significance
- corroboration tests, which include assessment of the consistency in business’s efficiency measures rankings based on different methods and over different periods. For example, if efficiency measures are reasonably stable over short periods of time, this increases the confidence in the results (since most businesses cannot improve their efficiency in very short periods of time)
- explanation of what the results practically mean, and the possible flaws in the modelling.

The Commission examined a host of benchmarking studies. Very few undertook comprehensive testing of the models. This is acceptable where the results are ‘indicative’, but not where a regulator might use them to determine a business’s revenues.

The capacity for statistical inference

This is probably the most neglected issue in interpreting various benchmarking measures, although essential to its meaningful use. This is why it is worth carefully dissecting.

Many people think of a benchmark as ‘a’ number. However, given the points made above, no model or measure is perfect. Accordingly, any benchmarking methodology should be able to identify a justifiable confidence interval around a predicted benchmark result. As an illustration, a benchmarking model might predict an efficiency score of 75 per cent for a given business compared with an industry average of 85 per cent (say the ‘benchmark’). By themselves, these are not useful numbers. There are two broad ways of considering such estimates.

It is frequent for economists to argue that the difference between two estimates is, or is not, ‘significant at the 0.05 significance level’.²⁹ The implicit notion is that 0.05 or some other lower probability that the difference could have arisen purely by chance somehow legitimises the value of the estimate. Under this approach, were the 85 per cent estimate to have a wide confidence interval then the regulator would be reluctant to use the 75 per cent estimate as a sign of genuine inefficiency for the business concerned (and probably be right in the context). On the other hand, if the confidence interval around the benchmark was very tight, they might regard 75 per cent as a reasonable measure of inefficiency for benchmarking.

However, this approach is often not useful in deciding what policy action to take (McCloskey 1985a and McCloskey and Ziliak 1996, 2008). The appropriate framework to use is the so-called ‘loss function’, which considers the costs of errors around any point estimates. This is not esoterica — failing to do this can have major adverse effects on the economic efficiency and the distributional impacts of regulatory policy. Part of the reason that the Rules were designed in their current form was the view that making an error that led to lower investment would be more costly than the alternative. An international review of benchmarking methods and their practical application observed:

The principal disadvantage of benchmarking is the potential that a model of poor quality can expose utilities to undue risk. While regulation must protect consumers from monopoly abuses, it must also not compromise the financial viability of regulated entities. ... regulatory opportunism that violates the [need for the utility] to raise funds, operate successfully and reward its investors for the risk they assume, must be prevented. (Lowry and Getachew 2009, p. 1325)

²⁹ The interpretation of such a statement is that the probability that the estimate is truly different from zero (or some other favoured null hypothesis) is 95 per cent.

Biggar has questioned whether the costs of errors lie in this direction (as discussed in appendix B), but accepts that the costs of errors is an important one, a perspective that is unrecognised in many benchmarking studies.

These issues have several key implications for any benchmarking practices where the regulatory stakes are high, such as determining revenue allowances.

- The regulator should test assumptions about the nature of the distribution around a benchmark estimate. It is common to assume errors are normally distributed, though in practice, this is impossible for some benchmarking measures. For example, any simple regression — say of opex against customer numbers — cannot have normally distributed errors, because opex cannot be negative. That may not matter much in many applications, but it will in some.³⁰
- The regulator should attempt to estimate, or at least make explicit its assumptions about, the loss function it believes is reasonable. That is not a trivial exercise, but at least transparent assumptions would be a useful step.
- Consultation with independent engineering experts with good knowledge of network business operations can help provide a basic credibility test of model results or of assumptions by parties not familiar with the actual operations of businesses. Similarly, as Pollitt (2005, p. 283) notes, as much as possible, it is desirable to test the consistency of a business's benchmark with financial market perceptions of its relative performance. The 1986 Challenger Shuttle disaster provides a graphic illustration of the potential divergence between expert engineering advice and hunches or statistical misunderstandings. NASA management claimed that the chance of a catastrophic failure of a shuttle was 1 in 100,000 based on misinterpretations of safety factors and unjustified optimism. The engineers thought it was between 1 in 50 and 1 in 100 (Feynman 1986), a verdict that was found to be more compelling. It is quite conceivable that over-confident benchmarking modellers might make errors analogous to this — at least in terms of the consequences for a business (or consumers). This suggests the importance of engineering and financial analysis as a supplement in interpreting statistical benchmark results (and one of the reasons that the AER needs further resources to access such expertise).

³⁰ A preferable approach would be to consider the likely distribution (for example, log normal) or to data-intensive methods in inference, such as bootstrapping (Varian 2005).

Explanation of inefficiencies

Surprisingly, this is a rarely mentioned aspect for evaluating alternative benchmarking models,³¹ and yet one of the most crucial for policy (and management purposes). Even if the measured inefficiencies of various businesses are regarded as accurate, it leaves open the question of why some businesses are managed less well than others. Some of the factors that may be relevant include the use of obsolete technology, little innovation, weak corporate governance or the form of ownership. If a benchmarking model can credibly unearth the behaviours that lead to managerial inefficiency, it corroborates the measures of inefficiency, and is useful for the businesses themselves. As Berg notes: ‘performance rankings ... are catalysts for promoting critical thinking about the sources of inefficiency’ (2010, p. 54).

4.9 No perfect measure is possible

Benchmarking is a demanding quantitative (and qualitative) task. As in many other cases of firm-based modelling, the results are often fragile to data errors, statistical assumptions and variable choices. Prima facie, this appears to doom benchmarking as a useful tool, at least for the time being. However, this is overly pessimistic.

- Criteria (such as those above) can be used to separate poor from better benchmarking.
- It is possible to address inaccuracy and unreliability in using benchmarking (applying the loss function principles spelt out previously).
- Regardless of whether satisfactory aggregate benchmarking models can be estimated, benchmarking will often still be useful for specific performance measures (such as the efficiency of vegetation management or the use of tendering).
- Improvements in data collection are likely to improve benchmarking models.
- It may have a role in policy-relevant areas other than revenue determinations (section 4.6 and chapter 8).
- It can provide a rough test of the reasonableness of building block and revenue proposals, which could be the basis for further more detailed assessment. In that vein, in his testimony to the Commission, Bruce Mountain, representing, the Energy Users Association of Australia, pointed out that it was easy to dismiss

³¹ Berg (2010, p. 54) is a notable exception.

benchmarking, but that this ignored its role of giving a *sense* of whether business proposals were right or wrong:

Benchmarking can always be criticised and shot down for some reason or the other. It's intrinsic, it's the very nature of it. ... I think those who stand to lose from benchmarking comparisons will be able to mount a convincing argument that it's never quite good enough, it's always not quite satisfactory. I think that that completely misses the point. Users and consumers in all number of industries benchmark all the time. They do it crudely and it's part of the business process. People select and they choose and they make decisions. ... the question arises: how is [the regulator] going to do the more aggregate assessment? That always will translate into some sort of benchmarking exercise. You can't get a sense of a big number as being right or wrong unless you actually compare it to others. I would also add, just going back to this 1999 distribution reset in Britain where Stephen Littlechild was castigated for having done such a simple benchmarking exercise. Ofgem has since then spent a great deal of money on benchmarking. ... In the most recent price reset they compared the results they got using these more advanced technologies against what Stephen said back in 1999 and they found the answer was in fact jolly similar. (trans. pp. 91-2)

5 Incentive regulation and benchmarking

Key points

- Regulators commonly use incentive regulation to limit a natural monopoly's ability to exercise market power, while maintaining strong incentives for the business to minimise costs and to innovate.
- Incentive regulation is applied to network businesses in the National Electricity Market using the building block approach to determine an allowable level of revenue. Firms that spend less than forecast are allowed to keep a proportion of the savings. There are also targeted incentives to promote specific goals, such as reliability and demand management.
- The building block approach generally works well and is a suitable model for the regulation of electricity networks. Recent Rule changes have largely addressed the major deficiencies of the building block approach, although the success of those changes will depend on appropriate implementation and regulatory guidelines. The best regulatory outcome will arise by:
 - ensuring that state-owned network service providers receive financing (both debt and equity) at 'arms length' rates that reflect the risk of the investment
 - using the ex post review of capital expenditure sparingly, and in a way that complements the existing ex ante incentive structure
 - using a cost of debt that is transparent, readily calculable and that is not materially influenced by short-term volatility in debt markets. (A long-term trailing average of the debt risk premium and the risk-free rate would be a pragmatic candidate.)
- By enhancing the information available to regulators, benchmarking can improve the effectiveness of the regulatory process. In the past, the Australian Energy Regulator (AER) has felt constrained by the Rules in using benchmarking techniques in this way. A recent rule change should allow the regulator to use all available information to scrutinise a network business's revenue proposal. However, in doing so they should still err on the high side of an estimate due to the asymmetric cost of errors in these calculations.
- Transmission planning arrangements in Victoria rely on the institutional arrangements of a not for profit planner (the Australian Energy Market Operator (AEMO)), probabilistic planning and a cost-benefit approach, rather than financial incentives, to achieve efficient network planning decisions. However, once a planning decision is made, and the relevant funding agreed, the transmission business faces strong financial incentives to deliver that project at the lowest cost.

Incentive regulation can be a useful tool for encouraging network businesses to minimise costs and implement cost-reducing investments aimed at improving the operating efficiency of a network. As discussed in chapter 4, benchmarking can assist in this process by enhancing the information available to regulators. However, the value of benchmarking to the regulatory process is dependent on how well the process of incentive regulation is working. A benchmark, no matter how accurate, is of little value if the regulator is unable to use it or if it does not influence the behaviour of the regulated firm.

This chapter briefly describes how incentive regulation works (section 5.1) before examining how it is applied to Australia's National Electricity Market (NEM) (section 5.2). Section 5.3 looks at improvements to the incentive structure, including those that have resulted from clarification of, and changes to, the Rules (AEMC 2012r) while section 5.4 discusses whether the AER is currently constrained in applying benchmarking.

5.1 Incentive regulation

The economic regulation of electricity networks attempts to achieve two major goals. On the one hand, it is important to stop a network business from exploiting its natural monopoly position by setting prices well in excess of efficient costs. On the other hand, retaining strong incentives for network businesses to pursue profits is important for driving efficiency in production and management decisions. Incentive regulation is designed to balance these goals by attempting to align the commercial goals of the business to the goals of society — efficient, reliable and low cost electricity supply.

Incentive regulation is a commonly used technique in the management of natural monopolies. While there are many different forms of incentive regulation,¹ their common feature is that they specify a goal, such as maintaining network reliability, and an estimated budget. If the business can outperform the predicted budget, it can keep a proportion of the savings, with the remainder passed through as lower prices for end users. The larger the proportion of savings that network businesses are allowed to keep, the stronger (or more 'powerful') the incentive regime is said to be. This approach contrasts with rate of return regulation (box 5.1), which does not reward cost minimisation or innovation, but nonetheless has some advantages in certain contexts.

¹ Joskow (2008), Newbery (2010) and Vogelsang (2010) provide a more detailed discussion of incentive regulation.

Box 5.1 **Rate of return and incentive regulation**

Pure rate of return regulation specifies the return on capital that a firm is allowed to recover, regardless of its performance. This ensures that a regulated firm is unable to exploit its monopoly position through price gouging. However, it also means that there are low incentives to provide services efficiently or develop more efficient practices through innovation.

Rate of return regulation was historically the standard practice for regulating monopolies (Vogelsang 2002) and continues to be widely used in the United States.

A common criticism of rate of return regulation is that it suffers from the Averch-Johnson effect — in which firms subject to rate of return regulation have incentives to overinvest to increase the capital base on which they are guaranteed a return. While this criticism has had a strong influence on the move away from rate of return regulation (Vogelsang 2002), there is little empirical evidence of its impact on network investment (Joskow 2005a).

In contrast to rate of return regulation, incentive regulation allows businesses to profit by outperforming expectations. In theory, this provides a stronger incentive for the business to find productive efficiencies in its operations. However, it is more informationally demanding than rate of return regulation as the regulator must still set an expected level of performance that is neither too ‘soft’ (leading to excessive rents) or too ‘demanding’ (leading to inadequate maintenance of the network or the insolvency of the business). If the regulator cannot obtain sufficiently reliable information on a business’s costs, either through the direct examination of the network’s business plan, comparing network costs from previous years or through benchmarking, it may be possible for the business to game the regulatory process by presenting information that leads to a high revenue allowance. In that case, rate of return regulation may achieve better outcomes.

Incentive regulation is used to partially overcome the information asymmetries between the regulator and the regulated business. Absent these asymmetries, it would be possible to regulate the monopoly business using ‘optimal’ prices, which could be set using either marginal cost pricing or Ramsey-Boiteux pricing² techniques (Vogelsang 2002). However, these conditions are rarely, if ever, met in practice.

Another important feature of incentive regulation is that it is based on high-level outcomes, such as yearly expenditure and network reliability. It is designed to leave the day-to-day decisions, such as project choice and the timing of asset replacement, to the network business.

² Under Ramsey-Boiteux pricing, revenue is recovered by placing higher prices on consumers with more inelastic demand.

The incentive regulation framework is not the only mechanism designed to promote efficient network investment. The regulatory test (distribution)³ and the Regulatory Investment Test for Transmission (RIT-T) provide some (currently relatively weak) disciplines on investment, while the broader planning framework will also influence the network business's choice of investment. As a result, even if in a particular circumstance the incentive framework does not provide appropriate investment incentives, these other mechanisms may still facilitate good outcomes. The transmission planning framework and the RIT-T are considered in chapters 16 and 17.

The challenge of designing and implementing incentive regulation

Designing and implementing incentive regulation must address several challenges. The first is that the twin goals of stripping away monopoly rents and encouraging cost minimisation are inherently conflicting. As Kaufmann (2006) said:

Regulators have the unenviable task of attempting to achieve inherently conflicting objectives. One important regulatory goal is promoting efficient behaviour by regulated utilities. Regulators must also ensure that customers share in the benefits of realised efficiency gains, but transferring benefits to customers reduces companies' incentives to undertake actions that lead to efficiency gains in the first place. Regulators therefore face a trade-off in trying to create incentives for utilities to behave efficiently, while ensuring that customers share in benefits from efficiency gains. (p. 1)

In principle, one of the benefits of the combination of incentive regulation and benchmarking is to reveal the true costs of a network business, and use that cost as the basis for the revenue determination of the next regulatory period. However, using past information to set future targets reduces the incentives of a firm to lower costs since it knows that it will decrease its revenue in the future.⁴ Setting the appropriate level of incentive is therefore difficult as it involves judgments about the accuracy of any benchmarks and about businesses' reactions to the incentive regime.

This problem reflects information asymmetries between regulators and network businesses. Regulators do not have complete information about businesses' actual costs, expenditures, demand and service quality, but they need to make judgments about what the 'efficient' cost might be and how long it should take a business to close any efficiency gap. As Joskow (2006) put it:

³ A recent rule change has replaced the regulatory test with the Regulatory Investment Test for Distribution (RIT-D) (AEMC 2012c).

⁴ Discussed further in Biggar (2004).

Fully informed regulators clearly do not exist in reality. Regulators have imperfect information about the cost and service quality opportunities and the attributes of the demand for services that the regulated firm faces. Moreover, the regulated firm generally has more information about these attributes than does the regulator or third parties which have an interest in the outcome of regulatory decisions. (p. 3)

A third challenge is to maintain the relative balance of power between the regulator and the regulated firm. If the regulator has too few resources and too little discretion in its operation, it is likely that the regulated firm will use their informational advantage to push for higher prices and profits. If the regulator has too much discretion, there is a risk that it could set the price too low, either due to a lack of information or for political reasons (Yarrow 2012 and Newbery 2010). This could reduce investment below efficient levels.

Given these challenges, incentive regulation will necessarily be imperfect. Nevertheless, there are several features that such regulation should desirably have, including:

- incentives that ensure that firms can never profit by artificially increasing costs
- incentives for firms to maintain or improve service quality levels as well as to reduce costs. This ensures that improvements in cost-efficiency are not at the expense of quality of service
- where possible, neutral incentives for capital expenditure (capex) and operating expenditure (opex), as well as constant incentives over time. If this is not the case, firms have incentives to inefficiently substitute between the categories of expenditure or change the timing of projects
- limits on the rents captured by firms, although some rents may be necessary to deliver other goals⁵
- a linkage between the strength of the incentives and the level of confidence regulators have in their forecasts of efficient spending (the more accurate the forecast the stronger the incentive can be)
- as simple a system as is practically possible, and that is well understood by all parties involved
- some certainty for businesses that their investments (which often have long lifetimes) will yield a reasonable return

⁵ Yarrow (2011b) gives a number of reasons why a regulator may want to provide some rents when applying a regulatory regime. These include that a firm that earns a stable return is more likely to look to long-term payoffs and is less likely to engage in short-term opportunistic behaviour.

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- a system that improves over time. The regulatory process can be seen as a repeated game between the regulator and regulated firms. Over time, incentive regulation should use the information revealed by firms to develop better forecasts of efficient expenditure. This will reduce the scope for firms to earn excessive rents and allow the regulator to apply stronger incentives for further cost reduction.

5.2 Incentive regulation and the electricity sector

The National Electricity Rules (the Rules) govern the operation of the NEM. The economic regulation of network service providers is described in chapter 6 (distribution) and chapter 6A (transmission) of the Rules. The Rules are designed to meet the national electricity objective of promoting efficient investment in, and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, safety and supply. The details of the regulatory structure differ between distribution and transmission networks (with the specific provisions spelt out in box 4.2 in chapter 4).

The AER makes revenue determinations for regulated transmission and distribution businesses every five years (though the Rules permit it to make determinations for different periods). This process involves the AER forecasting the revenue requirements needed to cover efficient costs and provide a commercial return on capital investment.

In keeping with incentive regulation (as set out above), businesses that provide network services at a lower cost than forecast can keep the resulting margin within the five year regulatory period, after which the network revenue is reset to incorporate actual expenditure levels from the previous period and updated expenditure forecasts for the upcoming period.⁶ In effect, this system allows networks to retain a proportion of any savings they can achieve (with the remainder being returned to consumers in the form of lower prices), although the amount that a firm can gain (lose) from underspending (overspending) depends on a number of factors, which are discussed in section 5.3. There are also additional incentive payments for achievement of other goals — or penalties for non-achievement — including the Service Target Performance Incentive Scheme (STPIS) payment for

⁶ Within the current regulatory period, all capital spending is rolled into the regulatory asset base at the end of the five-year regulatory period. However, a recent rule change (AEMC 2012r, p. 116) has introduced an ex post review mechanism. Ex post reviews are discussed in section 5.3.

network reliability and the Demand Management and Embedded Generation Connection Incentive Schemes.

Network businesses recover the revenue allowances from electricity customers through a variety of ‘control mechanisms’, including price caps and revenue caps (described below).

Calculating the maximum allowable revenue

The maximum allowable revenue that a network business can recover is based on the ‘Revenue and Pricing Principles’ of the National Electricity Law (s. 7A (1)), which state that:

A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in:

- (a) providing direct control network services; and
- (b) complying with a regulatory obligation or requirement or making a regulatory payment.

The costs that a network can recover are determined using the building block approach (box 5.2).⁷

The main components of a network’s recoverable costs are:

- operating and maintenance expenditure
- capital expenditure
- asset depreciation costs
- taxation liabilities
- a commercial return on capital
- incentive payments for reliability demand management and embedded generation.

Each of the building blocks must be estimated for the five years that follow.

Determining revenue allowances is a complicated and lengthy process with formal procedures beginning up to two years before the regulatory period begins. Regulated businesses are required to submit highly detailed proposals that detail the network plans for the following regulatory period, which are then scrutinised by the

⁷ The building block approach does not apply to network augmentations in the Victorian transmission network, which are governed by an alternate set of arrangements that are described in appendix F.

AER. The process also involves input from consultants and other interested stakeholders.

Box 5.2 The building block approach

The building block approach is used to ensure that the expenditure of each network business is appropriately amortised over time. As a result, each network business, given efficient expenditure practices and decisions, is adequately compensated for the long-run costs of providing network services.

The building block model consists of two equations, which are known as the revenue equation and the asset base roll forward equation. These two equations are used to determine an allowed stream of revenues for each network business for as long as it remains regulated. Ignoring any incentive rewards or penalties, these equations together ensure that the present value of the allowed revenue stream is equal to the present value of the expenditure stream of the regulated firm.

The building block equations are as follows:

$$\begin{aligned}\text{MAR} &= \text{return on capital} + \text{return of capital} + \text{opex} + \text{tax} + \text{incentive payments/penalties} \\ &= (\text{WACC} * \text{RAB}) + \text{D} + \text{opex} + \text{tax} + \text{incentive payments/penalties}\end{aligned}$$

and

$$\text{new RAB} = \text{previous RAB} - \text{depreciation} + \text{capex}$$

where:

- MAR = maximum allowable revenue
- WACC = post tax nominal weighted average cost of capital
- RAB = regulatory asset base
- D = depreciation
- opex = operating and maintenance expenditure
- capex = capital expenditure
- tax = expected business income tax payable

Forecasting capital and operating expenditures

The building block process requires that the AER and the businesses estimate the operating and capital expenditure required to operate a network for the following five years. This requires assumptions about the efficient costs of running a network business, as well as projections of future demand and required network expansion.⁸

⁸ Which can be influenced by efficient network pricing, as discussed in chapter 11.

The revenue determination process follows a ‘propose–respond’ approach in which a network business develops a detailed plan and proposes the capex and opex it requires, with the AER responding to the proposal. The AER must either accept the plan if it *reasonably reflects* the costs of an efficient business or, if not, propose an alternative plan.⁹

Whether the AER has enough power to scrutinise the proposals made by network businesses, including through the use of benchmarking, is discussed in section 5.4.

The weighted average cost of capital

The weighted average cost of capital (WACC) is the expected rate of return required by investors to induce them to commit funds to the network business (box 5.3).

There are two sources of funding, or capital, for businesses — debt and equity. For both sources, there are costs — interest must be paid on debt, and those providing equity expect a return on their investment commensurate with the risks that equity provider faces. The WACC for any firm is determined by the return that it pays on debt and equity, weighted in accordance to their relative use and adjusted for the operation of the tax system.

As part of the building block process (revenue determination), the regulator estimates the WACC of an efficient network business at the start of the regulatory period. It is an *estimate* of the financing costs of a typical network business with an efficient capital structure and is used to determine the revenue allowance that network businesses may recover. For clarity, this estimate is referred to as the regulatory WACC, while the actual capital costs that businesses face to fund their investments is referred to as the ‘actual’ WACC.

The regulator does not consider the individual circumstances of any particular firm when calculating the regulatory WACC. In theory, this creates incentives for businesses to source debt and equity financing efficiently, while considering the financial risks associated with different financing strategies. For instance, if a network operates in a low risk way, and as a result, they can access lower cost financing, they can keep the difference between the actual WACC and the regulatory WACC. However, as discussed later, it is unlikely that state-owned networks are subjected to the same level of scrutiny as privately owned networks when obtaining capital, and as a result, they are unlikely to face the same financial incentives to manage risk efficiently.

⁹ The Rules, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

The impacts on incentives of having an incorrectly specified WACC are discussed in section 5.3.

Box 5.3 Calculating the WACC

The WACC is calculated by weighting the returns to debt and equity in the proportion that these financing sources are used:

$$\text{WACC} = k_e(1 - T) \frac{E}{V} + k_d \left[\frac{1 - T}{1 - T(1 - \gamma)} \right] \frac{D}{V}$$

Where k_e is defined as the return on equity, k_d as the return on debt, and E/V and D/V are the weights in which debt and equity financing are used.¹⁰ T is the corporate tax rate and γ (gamma), also known as the dividend imputation rate, is the proportion of imputation credits that can be used by shareholders.

The return on equity is calculated as:

$$k_e = r_f + \beta_e \times \text{MRP}$$

Where r_f is defined as the risk-free rate, β_e is the firm specific equity beta and MRP is the premium per unit of market risk (calculated using the capital asset pricing model).

The return on debt is calculated as:

$$k_d = r_f + \text{DRP}$$

Where r_f is the risk-free rate and DRP is the premium per unit of market risk.

Source: The Rules, version 54, clause 6.5.2.

Incentive schemes

The AER currently applies an efficiency benefit sharing scheme (EBSS) for opex and a service target performance incentive scheme (STPIS) to transmission businesses. In the case of distribution businesses, the AER applies a STPIS, an EBSS for opex and a Demand Management and Embedded Generation Connection Incentive Scheme.

The EBSS determines the way in which benefits of efficiency gains are shared between network businesses and network users, and attempts to provide incentives for efficiency that do not diminish over time. Currently, the AER has only developed an EBSS for opex, although it has had the option of applying an EBSS to

¹⁰ As stated in the Statement of Regulatory Intent on WACC parameters, revenue determinations assume that D/V is equal to 0.6 and E/V is equal to 0.4 (AER, 2009b, p. 6).

capex for distribution businesses (but not transmission businesses) for some time. However, recent Rule changes have given the AER the power to apply an EBSS to capex for all network types (version 54 of the Rules), as well as expanded the range of EBSS design options that the AER can choose to implement.¹¹ This is discussed in section 5.3.

The STPIS provides financial incentives for networks to achieve high levels of service performance (chapter 15). The Demand Management and Embedded Generation Connection Incentive Scheme provides incentives for distribution businesses to utilise non-network alternatives, including embedded generation, where these are efficient. In part, this scheme is designed to counteract the incentives that exist under a price cap for networks to encourage higher demand (though these incentives are imperfect — chapter 12).

An ‘F-Factor’ scheme applies to distribution businesses in Victoria. This scheme provides financial incentives for a network to pursue fire safety goals. This is discussed in section 5.3.

Managing forecasting uncertainty

Expenditure forecasts are inherently uncertain as they include a wide range of assumptions about the cost drivers of network businesses. To create strong incentives for cost minimisation, businesses should, ideally, bear the consequences of poor management of the costs they control. However, for costs that are not under the control of a business there is a case for electricity users, rather than network businesses, to bear the risk of increases.¹²

For costs outside the control of the business, the regulator can allow the business to use a cost pass through, in which some categories of costs are included in the revenue allowance without needing to be in the building block forecasts. Chapter 10 of the Rules defines pass through events to include:

- a regulatory change event
- a service standard event
- a tax change event

¹¹ The nomenclature has changed in the Rules for the EBSS for capital to a Capital Expenditure Sharing Scheme for both distribution and transmission networks (for example, pp. 634ff and pp. 755ff of the Rules v. 54). The Commission has continued to use the term EBSS for any efficiency sharing scheme, regardless of whether it applies to opex or capex.

¹² In the case of regulatory intervention, such as a tax change, cost pass throughs stop governments appropriating the value of a sunk asset.

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- a terrorism event.

In addition, transmission businesses may consider a prescribed insurance event¹³ as a pass through, while distribution businesses may nominate additional events during the revenue determination process.

A further mechanism for reducing uncertainty in revenue forecasts is the treatment of so-called contingent projects in revenue determinations. If it is unclear whether a project will be needed during the forthcoming period due to difficulty in forecasting demand and generator entry, a project may be entered into the revenue determination as a contingent project.¹⁴ This means that the business can only recover the costs of the project if a trigger event occurs, in which case, the AER initiates what is effectively a ‘mini’ revenue determination. Currently, contingency provisions only apply to transmission projects. However, following a review by the Australian Energy Market Commission (AEMC) (2012r), the Rules now include a contingent projects framework for distribution businesses (Version 54 of the Rules, pp. 663ff).

The Productivity Commission has recommended that large investment transmission projects be subject to the same kind of arrangements as contingent projects (chapters 16 and 17).

Applying the revenue allowance

The maximum allowable revenue calculated using the building block methodology is converted into network prices using demand forecasts. This methodology, known as a control mechanism, varies between networks such that:

- a revenue cap applies to all transmission businesses and to distribution businesses in Queensland and Tasmania
- a weighted average price cap applies to distribution businesses in New South Wales, Victoria and South Australia
- a maximum average revenue cap applies to the distribution businesses in the ACT.

¹³ Defined in chapter 10 of the Rules, an insurance event occurs where either (a) the cost of insurance through premiums or deductibles is greater than 1 per cent of the maximum allowable revenue, (b) insurance is not available, or (c) the terms of the insurance arrangements change materially during the investment period.

¹⁴ As described in schedule S6A.1.3 (10) of the Rules and by the AER (2007c).

A revenue cap control sets the maximum allowable revenue for each year of the regulatory control period. To comply with this revenue constraint, a business forecasts demand across different services for the next regulatory year and sets prices so that the expected revenue is less than or equal to the revenue cap. The business can recover more or less than the allowed amount, but knows that the maximum allowable revenue in future years will be adjusted for any difference between the expected and actual revenue of previous years (using an ‘unders’ and ‘overs’ account).

Under a weighted average price cap, prices are set so that network businesses will receive the regulated revenue target if the demand forecasts used to calculate the price caps are accurate. If demand turns out to be more (less) than expected, the network business will receive more (less) than the target.

A maximum average revenue cap puts a cap on the average revenue per unit of electricity sold (usually kWh). That average is calculated by dividing the maximum allowable revenue by the quantity of energy demanded from the most recent year available (rather than using a forecast as is the case with a weighted average price cap).

The rationale for the different methodologies between distribution businesses is largely historical, reflecting the state-based arrangements that were in place prior to the AER taking over regulatory responsibility. The relative merits of different control mechanisms, and in particular their ability to assist in efficient network pricing, are discussed in chapter 12.

Incentives provided by building block regulation

Despite the apparent complexity of the regulatory regime, the incentives provided to network businesses are relatively straightforward. To increase its level of profit in the period following a regulatory determination, a network business must either:¹⁵

- underspend the capex or opex target (or both)
- obtain capital financing at a lower cost than the regulatory WACC (discussed in section 5.3)
- improve its performance in the incentive schemes, such as the STPIS
- have actual demand volumes greater than forecast volumes (if operating under a price cap)

¹⁵ Based on the supplementary paper ‘Power of Choice Review’ (AEMC 2012b, p. 3)

-
- improve performance in other business activities that are treated as competitive and thus not subject to regulatory determinations.

The strength of the incentives, as reflected by the proportion of any cost reduction retained by the network business, varies across each category, and across time within each category.

Also noteworthy is the fact that the regulatory regime does not make a distinction between the ways in which opex and capex reductions occur. This means that a business would be equally rewarded in the period following a regulatory determination for an equivalent cost saving from:

- finding a way to reduce construction costs
- finding an alternative cheaper project that achieves the same goal
- deferring a project into the next regulatory period.

As the incentives apply to the difference between forecast and actual expenditure, any incentive that is applied to cost reductions must also apply in equal strength to the motivation to push for increased capex and opex forecasts in the determination process. For example, if a network business can increase the revenue forecast by \$1 million by challenging the AER's decisions through the limited merits review process, they will improve their measured performance (forecast minus actual spending) by the same amount as if they had cut costs by \$1 million.

This creates a dilemma when setting the power of the incentive scheme. Regulators are likely to want to provide stronger incentives for cost minimisation in the project management and maintenance activities of the network business compared with the incentives provided for project deferral, as most new projects are still likely to provide some ultimate benefits to the network.¹⁶ It is also undesirable to have strong incentives encouraging network businesses to attempt to increase the revenue determinations. While creating their own dilemmas, the Victorian transmission planning arrangements for network augmentations are not subject to the AER's incentive regulations and so avoid some of these problems (box 5.4).

¹⁶ Such as increased access for generators or reliability for customers.

Box 5.4 Incentives present under the Victorian Transmission Planning Framework

In the Victorian transmission network, network augmentations are planned and authorised by AEMO, and the funding for these projects is only allocated once a project has been confirmed. This process is discussed in further detail in chapter 16 and appendix F.

Some participants have criticised this arrangement as contrary to incentive regulation (Grid Australia, sub. 37, p. 6) since a not-for-profit entity (AEMO) determines the timing and scale of any augmentation, along with the associated revenue, using cost-benefit analysis.

However, while the Victorian system relies on AEMO in the reliability setting and planning process, once an investment is chosen, there are still strong incentives for the network business to complete the chosen investment at the lowest cost. In Victoria, separable transmission projects are put through a process of competitive tendering, in which the business that wins the tender knows that if they were to spend in excess of their tendered amount, they would not be compensated for the overspend. In contrast, under building block regulation, a firm that overspends an extra dollar on construction will only lose a portion of that cost, as the actual costs will still be entered into the regulatory asset base at the end of the regulatory period and yield a return. Non-separable projects in Victoria are subject to similar incentive arrangements as in other states as actual capital spending is used to calculate the adjustment to the regulatory asset base.

5.3 Ensuring effective incentives

In recent years, there were mounting concerns that the building block framework, and the Rules that gave it effect, was not providing networks with incentives to deliver efficient outcomes. These concerns led to a major Rule change request by the AER and the Energy Users Rule Change Committee, which culminated in significant changes to the Rules in late 2012 (AEMC 2012r). In general, these rule changes have received wide support.¹⁷ Nevertheless, while the Rule changes have given the AER greater powers and regulatory options, there is still room for interpretation about how these powers can be used.¹⁸ The AER is developing guidelines and methodologies in several of the key areas of concern (such as the

¹⁷ Including from Ergon Energy (sub. DR63 p. 3), the Major Energy Users (sub. DR66, p. 23), the AER (sub. DR92, p. 12) and Grid Australia (sub. DR91, p. 9).

¹⁸ For example, the AER is required under the Rules to develop guidelines for the rate of return by late 2013 (p. 638 of the Rules v. 54).

WACC and the EBSS).¹⁹ In effect, the recent Rule changes have not provided the detailed solutions to the problems of the previous regulatory regime, but rather have empowered the AER to address them.

This section considers how the AER may be able to use the new Rules to address the deficiencies in the previous regime. It also considers other areas where the incentive framework could be improved.

An Efficiency Benefits Sharing Scheme for capex

The recent Rule change has allowed the AER to develop an EBSS for capex to complement the existing scheme that operates on opex. The Rule change has also expanded the options available for the AER to design this scheme. For instance, the new scheme need not be symmetric and continuous in the strength of the incentives applied (AEMC 2012r, p. 116).²⁰

Developing a well-designed EBSS for capex depends on a clear understanding of why such a scheme is necessary. In the absence of an EBSS, network businesses face weaker incentives to minimise costs as the regulatory period advances. As put by Jemena:

The shortcomings of current capex incentive arrangements are well understood. There are strong incentives for businesses to defer capex within a regulatory period and generally to spend less than the regulatory allowance. These incentives are amplified, particularly for short-lived assets, when actual depreciation rather than forecast depreciation is used in the RAB roll-forward calculation. (sub. DR77, p. 4)

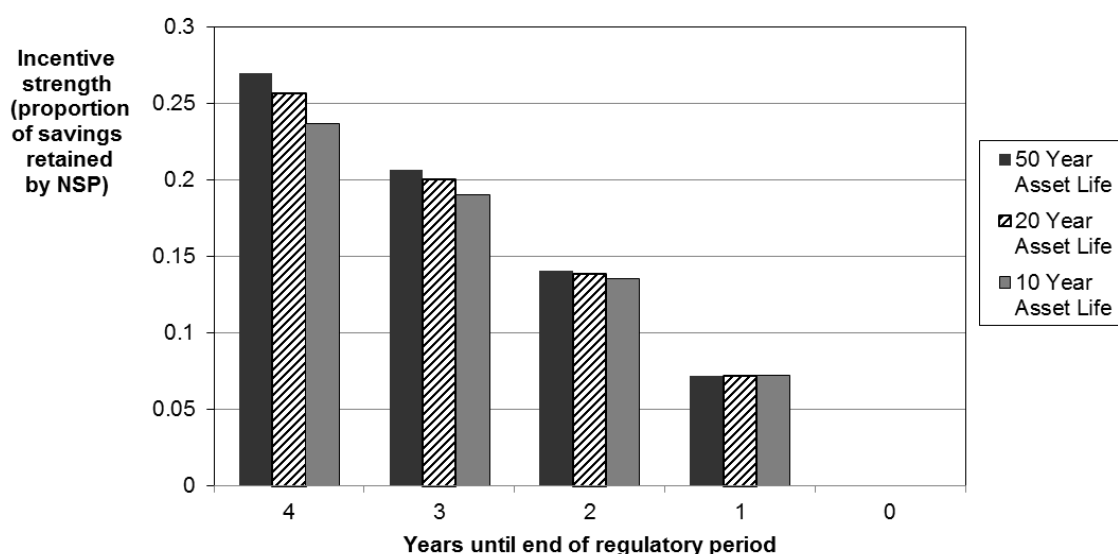
The declining strength of incentives is depicted in figure 5.1.²¹ The value on the vertical axis represents the increase in the net value of the business from reducing capex spending by \$1. As an example, reducing capex spending by \$1 in the first year of the regulatory period yields a profit (in net present value terms) of around 25 cents for an asset with a 20 year life. As the incentive system is symmetric, this figure can also be interpreted as the cost to a business of increasing spending by \$1.

¹⁹ These guidelines are currently being developed through the AER's Better Regulation reform program (AER 2012s).

²⁰ A continuous incentive scheme would apply equal incentive strength to spending through time. A symmetric scheme would reward underspending at the same rate as it punishes overspending.

²¹ A similar calculation can be found in AER (2011a, p. 40) and Jemena (sub. DR77, attachment 1, p. 6).

Figure 5.1 Capex incentives vary across the regulatory period^a



^a Commission estimates based on assumptions including both the regulatory WACC and the actual WACC are equal to 9 per cent. The value on the vertical axis represents the increase in the net value of the business from reducing capex spending by \$1. As an example, reducing capex spending by \$1 in the first year of the regulatory period yields a profit (in net present value terms) of around 25 cents for an asset with a 20-year life.

Data source: Commission estimates.

Incentives that change across the regulatory period in this way can be problematic. As well as creating incentives for network businesses to defer spending from early in the regulatory period, when the reward from reducing spending is higher, to later in the period, when the penalty for overspending is lower, they may also encourage substitution between capex and opex (box 5.5).

Box 5.5 An example of capex opex substitution — ageing assets

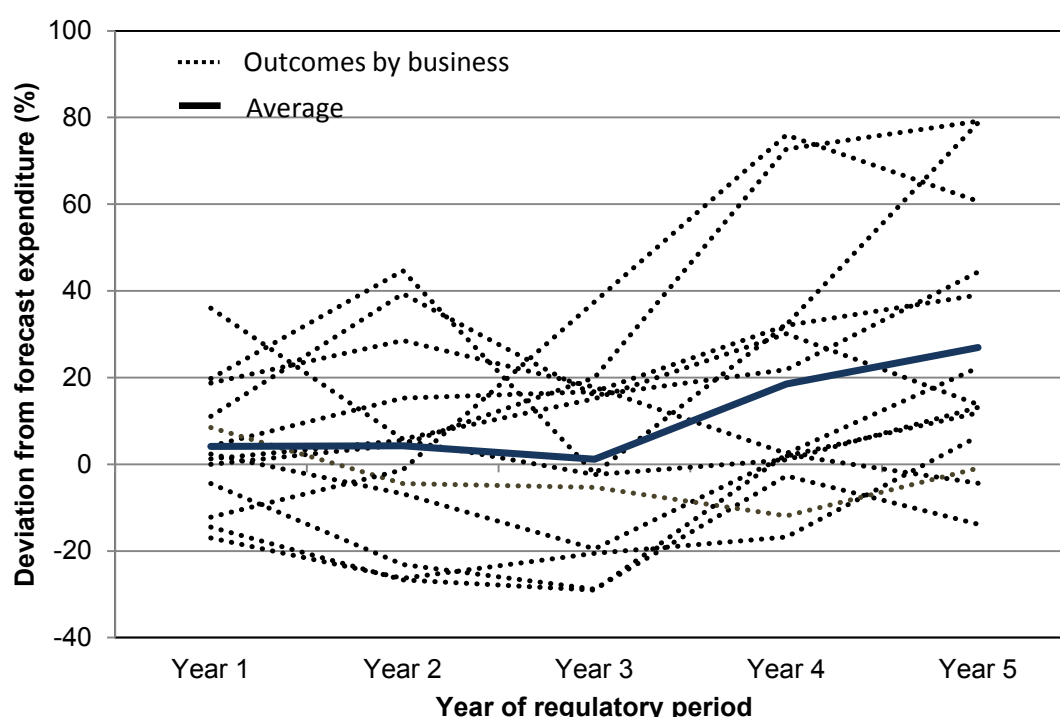
Ageing assets require more monitoring and maintenance than new assets. Therefore, the decision to replace an old asset involves a tradeoff between upfront capital costs of replacement and ongoing costs of maintenance. Ideally, a network will replace the asset at the time that minimises the net present value of the associated costs.

In the last year of the regulatory period, a network business has weak incentives to reduce capex, while its incentives to reduce opex are still relatively strong due to the efficiency benefit sharing scheme applying to this component of expenditure. In this situation, the tradeoff faced by network businesses is distorted, and they may inefficiently bring forward capex spending.

The extent to which networks actually shift capital spending over the regulatory period or substitute between capex and opex is unclear. Network projects are

usually planned years in advance, and project approval requires a number of regulatory clearances, such as the regulatory test or RIT-T, that make changing the timing of projects difficult. There are also accounting standards that limit the way firms can capitalise expenditure. However, as shown in figure 5.2, the empirical evidence is that overspending (spending more than the forecast amount) tends to increase later in the regulatory period.

Figure 5.2 **Overspending tends to increase later in the regulatory period^a**



^a Each dotted line denotes a distribution network business. The vertical axis shows the ratio of (actual capex – forecast capex) / forecast capex. Cost pass throughs are considered as part of forecast capex. Data are from the last completed regulatory cycle. Jemena provide a similar calculation (sub. DR77, attachment 1, p. 4).

Data sources: Parsons Brinckerhoff (2009a, 2009b, 2010, 2012); Wilson Cook and Co. (2008).

An EBSS for capex would allow network businesses to retain a given proportion of any efficiency gains made by reducing or deferring capex.²² If designed correctly, it would also provide a constant incentive over time to pursue such savings and, if the incentive rates were set the same between expenditure classes, remove any incentive to substitute between capex and opex. Firms that were considering investments that improved reliability and, thereby, generated increased returns through the STPIS would

²² The existing EBSS for opex allows firms to retain the benefits of an efficiency improvement for five years, after which the improvement is incorporated into the revenue calculations. For example, if an efficiency gain is made in year three of the regulatory period, the revenue allowance will not adjust to incorporate this until year three of the next regulatory period.

also face more consistent tradeoffs under an EBSS than under the existing arrangements.

Given the empirical findings above and the theoretical concerns about distorted incentives, there are strong grounds for the AER to implement an EBSS for capex for distribution and transmission network capex as soon as possible.

However, the AER would need to resolve several technical issues before it could introduce such a scheme. Reflecting these difficulties, in 2008 the AER decided not to implement an EBSS for distribution network capex because of concerns that projects could be included in more than one forecast, and as a result, that an EBSS would provide overly strong incentives to defer projects between periods.²³ However, a scheme that need not be symmetric or continuous should be less susceptible to such issues. Care would also need to be taken to ensure that the design and implementation of an EBSS complements (rather than undermines) the STPIS and the Demand Management and Embedded Generation Connection Incentive Scheme.

However, there is experience of capex sharing schemes that have worked, both in Australia and overseas, suggesting that implementation problems are not insurmountable (AEMC 2012a).

Increasing the accuracy of the WACC

The building block process requires the estimation of the efficient return on capital of a typical network business. If this estimate is not accurate, it will distort the investment decisions of networks and increase customer prices (entailing transfers and, if enduring, pricing inefficiencies).

These impacts depend largely on the expected difference between the actual and regulatory WACC over time. Given the typically long lives of their assets, network businesses' return on capital expenditure depends on the WACC determinations over many regulatory periods.²⁴ Hence, a short-term expected difference between the regulatory WACC and the actual WACC is likely to have only a small impact

²³ To successfully implement an EBSS for capital expenditure, it is necessary to distinguish between expenditure that has been saved through more efficient construction or planning outcomes, and expenditure that has been deferred. If spending that is deferred between periods is included in the next regulatory determination as a new project, it may appear that the entire project has been avoided and the costs counted as long-term savings, for which the networks will receive a large payment.

²⁴ A point made by the Energy Networks Association (ENA 2011a, p. 30).

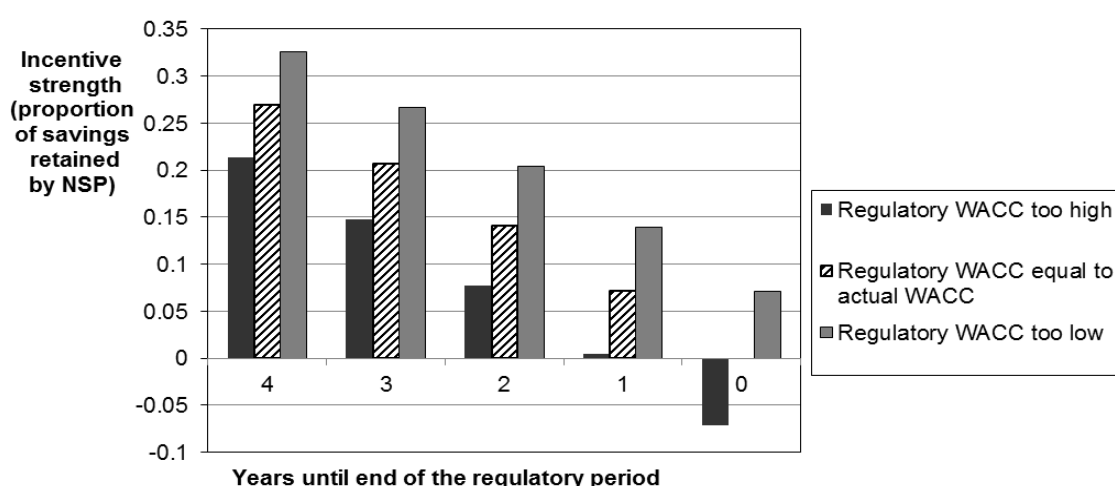
on long-term investment decisions. However, it would result in income transfers between consumers and network businesses.

As discussed in chapter 3, while the allocative inefficiency effects of small price increases are modest in the short term, they still matter in other respects, and the transfers to producers from setting the WACC too high would potentially not be consistent with the National Electricity Objective. On the other hand, while setting the regulatory WACC too low would lower prices to end users in the short run, it might make it difficult for firms to recover their efficient costs in the long term. This would contravene the revenue and pricing principles of the National Electricity Law, and in any case would not be in the *long-term* interest of consumers.

If network businesses expect a long-run positive divergence between the regulated and actual WACC, it can create incentives for businesses to over-invest. While the business would not receive a revenue allowance for any investment above the agreed regulatory forecast during the initial regulatory period, the assets would be rolled into the RAB at the commencement of the next regulatory period. The business would receive returns for the remaining (typically long) lives of the assets. If the WACC is sufficiently high, then over-investment may be profit maximising. (The capacity for the AER to examine the prudence of investments after they have been made — as discussed later — may limit this.)

Figure 5.3 shows the strength of the incentives throughout the regulatory period if the regulatory WACC is 0.5 per cent above or 0.5 per cent below the actual WACC.

Figure 5.3 Impact of error in the regulatory WACC^a



^a This assumes an asset life of 50 years and an actual WACC of 9 per cent compared with a regulatory WACC of 8.5 per cent in the low case and 9.5 per cent in the high case.

Data source: Commission estimates.

As was the case for figure 5.1, the value on the vertical axis represents the increase in the net value of the business from reducing capex spending by \$1. As shown in the diagram, having a regulatory WACC that is too low will strengthen the incentive to reduce costs, while a regulatory WACC that is too high will weaken this incentive.

In the first few years of the regulatory period, the cost saving incentives in the building block regime outweigh the incentives provided by an overly generous WACC and result in net incentives to decrease expenditure. However, the incentives to reduce capital expenditure diminish throughout the period and at the end of the period, there is potentially an incentive to over-invest.

Is the regulatory WACC higher than the actual WACC?

It is difficult to compare the actual cost of capital with the regulatory cost of capital due to issues in measuring costs of equity.²⁵ However, it is possible to compare the actual borrowing costs of firms with the forecast cost of debt used in the revenue determinations (table 5.1).

The average regulatory cost of debt is 1.25 per cent higher than the estimated borrowing costs, which equates to a WACC that is 0.75 per cent higher than the actual WACC. Care should of course be taken in interpreting such a figure, as the numbers are based on several simplifying assumptions and abstract from some of the complexities of financial markets.²⁶ Moreover, a similar calculation performed by the Energy Users Rule Change Committee (EURCC 2011) has drawn a number of responses that provide, at least in part, an explanation for the apparent differences.²⁷ However, even considering these factors, network businesses may have been overcompensated for the cost of debt in recent years. Further evidence to support this conclusion can be found by comparing the acquisition price of networks with the regulatory asset base (box 5.6).

²⁵ The return on equity is determined by investors' expectations of future returns, which can only be partially observed through the experienced return and cannot be measured reliably. The Gratton Institute (2012, p. 18) has analysed the methodology for calculating the regulatory cost of equity and found that it is also likely to overestimate the true cost of equity for networks.

²⁶ The calculation uses data from the end of the financial year, which may not be typical of the rest of the year. The calculations also abstract from issues such as short versus long-term financing and refinancing risk.

²⁷ In particular, networks have argued that businesses have been forced to borrow funds with a shorter date to maturity, and that the lower cost of debt has been offset by an increased refinancing risk. A summary of these responses is provided by the AER (2012c, p. 55) and by Jemena (sub. DR77, attachment 1, p. 12).

Table 5.1 Comparing the regulatory cost of debt with estimates of actual borrowing costs^a

Network Business	Regulatory cost of debt	Actual cost of debt	Difference
	%	%	% points
CitiPower	8.81	8.17	0.64
Powercor	9.35	8.17	1.18
SP AusNet (distribution)	9.19	7.52	1.67
ETSA Utilities	8.87	8.10	0.77
Aurora Energy	8.00	6.50	1.50
Ergon Energy	8.98	7.48	1.50
Energex	8.98	5.94	3.04
Essential Energy (Country Energy)	7.77	7.48	0.29
Ausgrid (EnergyAustralia)	7.77	7.03	0.74
Endeavour Energy (Integral Energy)	7.84	7.55	0.29
Powerlink	8.10	6.98	1.12
SP AusNet (transmission)	8.20	5.99	2.21
Transend	7.79	6.14	1.65
Transgrid	7.78	6.63	1.15

^a The actual cost of debt is taken from the annual reports of the network businesses. It is an average, reflecting the five most recent years available and is calculated as a business's finance costs as a proportion of its interest bearing short- and long-term liabilities. The level of liabilities is estimated by averaging the liabilities at the beginning of the period and the end of the period. Of course, this is an imperfect estimate, however, it is the best estimate that can be made with the available data. Similar calculations are performed by the Grattan Institute (2012, pp. 21-9) and the Energy Users Rule Change Committee (EURCC 2011, p. 13).

Data source: Commission estimates.

Improving the estimation of the regulatory WACC

Following a recent AEMC review (2012r, p. ii) the AER has been given responsibility to design a single WACC framework for electricity transmission, distribution and gas networks. The AEMC provided high-level guidance to the AER about how to calculate the WACC, but has left the detailed design to the AER.

In developing the new WACC framework, the AER should make the best possible estimate of the WACC at the time of the regulatory determination. In practice, this will mean overcoming the problems — as described below — that have troubled the current system.

The interdependence of different WACC elements

Until the Rule change in November 2012, the regulatory arrangements for determining the WACC were relatively inflexible (AEMC 2012r, p. 40).

Box 5.6 Using a business's acquisition price to assess the WACC

If the regulatory WACC is equivalent to the actual WACC, then the commercial value of the network, which can be observed when networks are sold, should be equal to the regulatory asset base. If the regulatory WACC is greater than the actual WACC, the commercial value will exceed the RAB.

There are several exceptions to this. The sale price of a business will incorporate any anticipated efficiency and synergy gains, creating a wedge between the RAB and the sales price, even if the regulated and the actual WACC were the same. On the other hand, if the market is thin, the business may be sold at a discount. Furthermore, asset sales are based on profit forecasts, which can prove to be either optimistic or pessimistic. Nevertheless, the sale price of a regulated network business gives some guide to any major divergences between the long-run regulated and actual WACCs.

So how do asset sales compare to the regulatory asset base?

To date, networks have been privatised in Victoria and South Australia. In these cases, the assets have sold for significantly more than the regulatory asset base. Infrastructure Partnerships Australia (2011, p. 23) calculate that asset sales to the DUET group, SPARK infrastructure and SP AusNet were sold for between 1.11 and 1.32 times the RAB.

Infrastructure Australia (2012) estimate that the remaining state-owned electricity networks would be sold for between 1.1 and 1.2 times the regulatory asset base, while Deloitte (2011c, p. 5) suggests that prior to the global financial crisis regulated assets traded at a ratio as high as 1.5, but that after the financial crisis the expected ratio was 'closer to 1.0'.

Given the variety of factors that influence sales values, it is difficult to conclude that the regulatory WACC is too high using this method. However, it does provide further evidence that networks may be overcompensated in this area.

Furthermore, notwithstanding statements to the contrary,²⁸ there appears to have been at least some doubt about the capacity for the AER to consider the inter-relationships between various aspects of the WACC. The new Rules require that the determination of the WACC *must* have regard to such relationships (for example, NER v. 54, p. 637). This was in accordance with the Productivity Commission's draft recommendation 5.2. In implementing the new Rules, the AER should examine the relationships between the:

- debt risk premium and the risk-free rate
- market risk premium and the risk-free rate
- market risk premium and the utilisation of corporate tax credits

²⁸ For example, ETSA Utilities et al. (sub. 6, p. 40) and to some extent the Queensland Treasury Corporation (sub. 12, p. 4).

-
- market risk premium and the equity beta.

It will be similarly critical that any merits review process relating to any specific element of the WACC take account of these interdependencies, a point considered by a recent review of the limited merits review regime (Yarrow et al. 2012b, p. 52).

Exposure to short-term conditions in the debt market

The building block process is forward looking, and is designed to provide an accurate estimate of the costs of a network business for the upcoming regulatory period. Where possible, these costs are based on forward looking data. However, in some cases, historical data are used to provide an estimate of the expected future market conditions. Where historical data are used, the regulator faces a tradeoff: shorter observation periods are more representative of the current financial situation, but are also more sensitive to short-term fluctuations in the financial markets than longer observation periods.

In previous revenue determinations, both components of the cost of debt — the risk-free rate and the debt risk premium — have been based on market observations. Although, the Rules specify that the risk-free rate be evaluated using a moving average, this average rate has been observed over the short term. The debt risk premium has also been assessed over the short term in order to maintain consistency across the components of the cost of debt.

Using short-term averages to determine the cost of debt exposes businesses and customers to the risk of unusual market circumstances during the averaging period, of which the global financial crisis is the most recent compelling example. Firms that had revenue determinations in the immediate aftermath of the crisis had high borrowing costs built into the WACC for the following five years. The AER estimate that setting the debt risk premium at a level closer to the actual borrowing costs of businesses would have reduced the amount consumers that paid for electricity by \$400 million in 2011 (AER 2011a, p. 65).

Averages taken over a longer period — such as a five year trailing average — are more stable predictors of market conditions and are more likely to represent the actual borrowing patterns of the firms involved, as no firm would normally roll over its entire debt portfolio in a two-week period every five years.

In developing the new rate of return framework, the AER has discretion to use a wide range of methodologies, including trailing averages, to estimate the WACC. Trailing averages represent a potentially important improvement in the methodology for estimating the DRP and the risk-free rate. However, as past

experience has shown, locking in a particular methodology can have unforeseen consequences. Therefore, the AER should only use this methodology where it considers that this will improve the accuracy of the estimate of the WACC.

RECOMMENDATION 5.1

The Australian Energy Regulator should consider the use of long-term trailing averages to estimate the debt risk premium and risk-free rate used in the calculation of the weighted average cost of capital.

Limited merits review

In 2008, a limited merits review regime was introduced into the National Electricity Law. It is designed to help ensure that decisions made by the AER are appropriate and thereby to provide confidence and security to investors in the network businesses.

Many of the limited merits reviews have focused on the WACC and have resulted in substantial increases in the revenue determinations (table 5.2). The figures should not be interpreted as necessarily indicative of inefficient increases in determinations, as the AER may well have underestimated the correct WACC in some instances. Regardless, they underline the financial importance of the limited merits review process.

Table 5.2 Limited merits review decisions regarding the WACC^a

<i>Business</i>	<i>Year</i>	<i>Focus of Review</i>	<i>Increase in revenue allowance</i>	<i>Increase as a percentage of allowed revenue</i>
			\$ million	%
Integral Energy	2009	Risk-free rate	338	9
EnergyAustralia	2009	Risk-free rate	945	11
Country Energy	2009	Risk-free rate	467	8
Transend	2009	Risk-free rate	80	8
Transgrid	2009	Risk-free rate	374	10
Energex	2010	Gamma	288	4
Ergon	2010	Gamma	200	3
ETSA	2010	Gamma	246	6
SP AusNet	2011	Gamma & DRP	31	1
CitiPower	2011	Gamma & DRP	31	3
Powercor	2011	Gamma & DRP	58	2
United Energy Distribution	2011	Gamma & DRP	41	2
Jemena	2011	Gamma & DRP	31	3
Total			3 183	8

^a DRP is the debt risk premium (discussed above); Gamma is the assumed utilisation of imputed tax credits.

Source: CME (2012).

In 2012, the Standing Council on Energy and Resources (SCER) appointed a panel to undertake an examination of the limited merits review regime. The Limited Merits Review Panel has observed that the process has not worked as intended. Its stage one report found that:

... the regime has failed to address the realities of regulatory decisions summarised in this [Administrative Review Council] statement. Instead, a narrower, more formalistic and more formulaic approach to review has developed, which has been relatively detached from the promotion of the objectives set out in the [National Electricity Law] ... and particularly from the requirement that regulatory decisions be directed toward encouraging outcomes that are in the long term interests of consumers. (Yarrow et al. 2012b)

One key concern regarding the current operation of the limited merits review process is that network businesses have a capacity to ‘cherry pick’ the aspects of a proposal where they believe the regulator is in error. In contrast, they obviously have little interest in revealing where the regulator has been too generous. In some instances, this has led to the situation in which a ruling has been made on one aspect of the AER’s determination to correct an error, while ignoring that such an error must have countervailing impacts on a related matter. (This has particularly applied to the way in which the WACC is calculated.) The National Electricity Law appears to allow the regulator the capacity to bring such broader considerations to the notice of the Australian Competition Tribunal, but in practice, the regulator has not taken this approach (an issue discussed further in chapter 21).

The changes to the Rules to require consideration of interdependences in the WACC when making revenue determinations is likely to resolve one source of cherry-picking (though the actual rulings of the merits review body on such matters has not yet been tested). The final report by the Limited Merits Review Panel suggested that broader reforms to the merits review processes were warranted and that, in particular, the review body should give primacy to the long-term interests of consumers (the National Electricity Objective) as its guiding principle in making its rulings. The Commission supports this finding. The Council of Australian Governments has set a timeline for any possible changes by the end of 2013 (COAG 2012).²⁹

Incorporating safety in incentive regulation

Electricity networks are inherently dangerous. Managing risks, such as fires that result from network malfunction, is a key responsibility of network businesses. In the absence of regulation, networks would still have some incentive to manage these

²⁹ A regulatory impact statement process has been initiated.

risks, as even in the presence of insurance, they bear some of these costs directly (such as a fire damaging parts of the network).³⁰ However, given that the community also bears some of these risks, a network may deliver a less than optimally safe network.

Safety considerations are addressed primarily through state-based safety legislation and associated regulations, which are enforced by state-based safety regulators. These regulations are based on safety case management schemes, in which networks must identify the major safety issues, make plans to manage these risks and have the plans agreed to by the safety regulator. This approach is in contrast to prescriptive regulation and is designed to ensure that the responsibility of managing and achieving an appropriate safety outcome is left clearly with the business (ESV 2011).

There are potential complications arising from the interactions between the economic regulator, the network business and the safety regulator:

- While state-based regulators implement safety regulation, the funding required to achieve safety goals is determined by the AER. Without good coordination between these bodies, network businesses may exaggerate their expenditure forecasts based on safety requirements, with the AER unable to challenge these easily as it is not a technical regulator.
- In common with other estimates of capital expenditure, a network business has an incentive to persuade the regulator that some capital expenditure is necessary but then to defer expenditure on this project until the next regulatory period. The AER will be able to identify areas of expenditure that are intended to address safety concerns, but they will typically not wish to direct a business to make some explicit investment (in which case the regulator starts to take on responsibility for safety outcomes rather than leaving this responsibility with the business itself). This may allow the network to consistently over-recover the cost of safety based network expenditure.

An alternative approach to the intersection of economic and safety regulation is to use a performance-based incentive scheme, such as the Victorian F-Factor scheme. This scheme is directed at fire safety and provides financial rewards and penalties based on the incidence of fires started by networks. The main advantage of this

³⁰ While the presence of insurance policies covering loss from fire damage may reduce the network business's exposure to fire damage, insurance contracts are generally written so that the insured party still has an incentive to manage risk. This can occur through a policy excess or through specific terms written into the contract that specify expected behaviour such as maintenance practices or fire safety plans.

approach is that networks have a direct financial incentive to achieve particular goals. Consequently, they are less likely to reduce their effort where this effort is difficult to observe. It also allows networks to choose the best approach to meet these goals.

There are, however, several downsides to using this approach.

- Incentive regulation can only be used where the desired safety outcome can be clearly defined and measured. As a result, when designing the F-Factor scheme, choices had to be made about what constituted a fire, whether all fires should be treated equally or whether larger fires or those on high fire danger days should be given greater weight.
- Using self-reported data provided by the networks could be problematic. As suggested by United Energy (2011), an incentive scheme may ‘place incentives on businesses to not report [fires]’.
- There are setup costs involved with designing and implementing an incentive-based scheme.

Given these difficulties, it is unlikely that incentive based schemes will ever be able to achieve safety outcomes on their own. However, they may be a useful complement to other prescriptive regulations. The AER should monitor the success of the F-Factor scheme in Victoria before choosing whether to expand this type of program.

Incentives faced by state owned enterprises

In Australia, electricity networks were originally fully state-owned. While some jurisdictions have chosen to privatise their electricity businesses, public ownership is still widespread in the sector.³¹ The building block arrangements, which are designed to provide (profit motivated) firms a financial incentive to lower their costs, can work differently when applied to state-owned enterprises.

State-owned utilities obtain new capital from state governments by borrowing from state treasury corporations or retaining earnings that might otherwise be paid to the relevant government in the form of dividends. This funding is sourced by the state government by issuing debt, which, given the high credit rating of state governments, is acquired at a relatively low cost. Competitive neutrality arrangements should ensure that state-owned utilities enjoy no advantage with

³¹ Network businesses are publicly operated in New South Wales, Queensland and Tasmania and privately operated in Victoria and South Australia. ActewAGL in the ACT is partially privatised.

respect to their funding costs because of their government ownership. However, some parties claim that state governments provide low-cost debt and equity financing to state-owned electricity networks, as this will encourage investment and increase the overall return to the state treasury.³²

The Rules specify that the regulatory WACC should not take into account specific details of the firm in question, with the implication that the regulatory WACC should be the same for public and private firms. This has led to an ongoing debate about whether state-owned networks overinvest in order that their shareholders profit from the difference between their financing costs and the regulated rate of return. In turn, this has raised the question of whether the regulatory WACC should be lowered for state-owned businesses to remove any such incentive.³³

Risk should be priced by project rather than by institution

In principle, the return on an investment in the electricity sector should generally reflect the risk of the project, and not the underlying creditworthiness of the entity that funds it (a point also made by Grid Australia, sub. 22, p. 8). One way to illustrate this principle is that if a highly credit-worthy body, such as a state government, issues bonds and re-lends the money to a more risky body, it marginally decreases its own credit rating (because it is exposed to the higher riskiness of the borrower). Accordingly, the project risk cannot be removed just because a creditworthy lender provides the finance. As a result, the WACC should not be lower in these circumstances.

However, there are potential incentives for state governments to provide debt and equity financing to state-owned networks at a lower rate than an equivalent private company would receive. This could occur because electricity networks represent a significant source of revenue for a state treasury. Offering the network businesses a lower financing cost would encourage them to increase their level of investment, which would flow through to higher electricity prices and returns for the state

³² State governments' actions suggest that they are sometimes willing suppliers of 'low cost' equity and debt financing. This may occur because the opportunity cost of their funds is effectively the cost of the relevant state government debt, which is significantly lower than that of similar private sector firms and that allowed by regulators.

³³ Those involved in this debate include: Garnaut (2011b, p. 42), the AEMC (2012a, p. 80), Major Energy Users (sub. 11, p. 32), Grid Australia (sub. 22, attach. 1, p. 30), the Energy Networks Association (sub. 17, app. C, p.16), Ergon Energy (sub. 8, p. 16) and the Energy Users Association of Australia, (trans., p. 94).

government.³⁴ Supporting the state-owned corporation in this way could be achieved directly by offering debt financing at a lower rate than an equivalent private business or, more likely, being willing to accept a lower dividend stream in the shorter term than a private-sector shareholder (effectively providing low cost equity).³⁵

To the extent that governments behave this way, it may lead to greater than optimal levels of investment — a potentially significant source of economic inefficiency. Therefore, it is important that state governments:

- behave as an ‘arms length’ equity investor would, including demanding a return on equity and dividend payments that a private investor would require from a similar investment
- lend to state-owned network businesses (through their treasury corporations) at a rate that includes a properly calculated competitive neutrality fee. This is an adjustment that increases the borrowing cost to a level that the business would face were it to borrow in the private debt market.

If either of these conditions are not met, the state-owned business’s capital costs will be effectively subsidised, in turn encouraging it to over-invest.

Difficulties around estimating the return on equity (as discussed above), prevent a direct comparison of these costs between private and publicly owned networks businesses. However, it is possible to compare estimates of the debt financing costs of different network businesses. Table 5.1 (above) shows that the average estimated cost of debt in state-owned electricity businesses is 6.86 per cent compared with 7.59 per cent in privately owned businesses. Prima facie, there appears to be a difference between the borrowing costs of state owned and privately owned businesses, even after the application of a competitive neutrality fee.

However, there is a large degree of variation between different businesses, both public and private, that reflects the individual credit rating of businesses, the timing of their capital programs and balance sheet management strategy (including dividend policy and debt and equity raising strategies) in inherently volatile capital markets. As a result, it is difficult to determine whether competitive neutrality principles are being applied in such a way that publicly owned businesses are facing borrowing costs equal to those faced by an equivalent private sector firm.

³⁴ In effect, given its high credit rating and legal restrictions binding what it can invest in, the state treasury may be willing to accept a lower rate of return in order to increase the total level of investment, and therefore increase the total level of overall return.

³⁵ If the discount rate used by a state treasury is lower than a private sector creditor, they will be more patient when trading off current and future dividends.

Even if competitive neutrality principles were not being applied in a way that gives full effect to the principle underlying them, and state-owned enterprises were receiving capital at a cheaper rate than an equivalent private business, the regulatory WACC should not be adjusted to take this into account. If nothing else, it would be pragmatically difficult in any ex ante determination by the AER to estimate what an alternative WACC should be for any given state-owned business (noting the variability of margins shown in table 5.1). Instead, it is preferable to focus on ensuring that state governments provide networks with financing (both debt and equity) that reflects the risk of the investment (and to the extent it does not, reveal to state and territory citizens the likely magnitudes of any subsidies to state-owned businesses through low cost finance). Privatisation of state-owned networks, discussed in chapter 7, would resolve the issue without such complications.

Availability of debt and equity financing

The issue of cheap access to financing for state-owned network businesses is amplified by the fact that state treasury corporations appear to have been more likely to provide access to finance than if that finance were being provided to a privately owned network business, a point made by the Major Energy Users:

The clear indication is that the privately owned firms have the access to capital constrained more so than government owned firms which generally access needed capital in the form of debt from the government treasury corporations. That government owned energy firms have much more access to debt than privately owned firms have provides the government owned firms an incentive to invest more. (sub. 11, p. 18)

Such access was particularly important during the global financial crisis. During this time, state treasury corporations appeared to be willing to continue to fund large capital expenditures by their network business while most privately owned corporations appeared to find raising either equity or debt both expensive and problematic.

To avoid concessionary financing of state-owned enterprises, such enterprises should be subject to financial market disciplines (that is, they should access finance on the same terms and with the same disciplines applied as the private sector).

Tax neutrality

The goal of shareholders in a private firm is to maximise the long-term, post-tax returns of their business. However, under current competitive neutrality arrangements, a state-owned business pays an income tax equivalent to the state government (not the Australian Government). To the degree that a government

shareholder can increase the capital spending of a network business, which is then rolled into the state-owned business's regulatory asset base, it can trade off any decrease in the post-tax rate of return and its greater receipt of the income tax equivalent payment. A state government might conceivably influence a state-owned business in several ways. It could:

- be less aggressive in demanding only investment with adequate returns, and depending on the economic cycle, might be a more permissive financier than their private sector equivalents
- influence other aspects of the network business — for instance, by increasing the reliability standards beyond the level that corresponds with customers' willingness to pay for increased reliability — which can inflate the business's capital requirements and its regulatory asset base.

In saying this, the Commission is not arguing that state governments explicitly or strategically set out to exploit their effective capacity to earn pre-tax returns on such investments. However, shareholders' usually strong incentives to constrain spending are likely to be muted.

It is hard to verify the extent to which this issue affects state government behaviour, but the incentives exist, as do perceptions by other stakeholders that governments react to these incentives (box 5.7).

As discussed above, it would not be appropriate to amend the WACC. Nevertheless, there are several policy responses that would reduce or remove the incentive problems.

In the absence of privatisation (which is the first best option), there are strong grounds to improve the effectiveness of competitive neutrality principles by removing the capacity of state governments to influence the capital expenditure decisions of the state-owned businesses. This would involve refining the governance arrangements of state-owned corporations (chapter 7). While not the main purpose of reform, the introduction of a NEM-wide probabilistically-based reliability framework for transmission businesses and the creation of a single incentive regime for appropriate reliability in distribution networks, would remove one avenue for governments to influence capital expenditure (chapters 15 and 16). In theory, and in line with Garnaut's diagnosis of the source of the problem, it would be possible to amend the Commonwealth Grants Commission's GST allocation principles for the company tax receipts of state-owned corporations. The Commission has not considered this as an option, because among other factors, it would involve all state-owned corporations in all states and territories. The practicability, impacts and desirability of such a broad-ranging change are not clear.

Box 5.7 Perceptions of governments influencing network decisions

Major Energy Users:

What does matter is that the government owner is incentivised to drive the government owned firm to chase increased profits as the government receives both the higher dividend and the higher corporate tax receipts which occurs when the government owned firm profit is unnecessarily high. As the government provides lower cost debt through the T-corps, and does not significantly limit the access to the debt, then the investment decisions of the government owned network are influenced by their shareholders. State governments set the reliability standards with little reference to the cost of these standards and thereby essentially influence the capital needs of the network firm. (sub. 11, p. 32)

The Garnaut Climate Change Review:

Further, where the State Government is the owner, it retains the tax allowance for which provision is made in the weighted average cost of capital. Unlike taxation, royalties and many other sources of revenue, the profits of state-owned businesses are exempted from the equalisation rules under which the Commonwealth Grants Commission allocates GST revenues amongst the states. So there are cascading mechanisms through which the shareholders of state-owned businesses — like most electricity distribution businesses outside Victoria — do well out of over-investment. (Garnaut 2011b, p. 42)

Bruce Mountain:

The combinations of profit, the income tax on the profit and the debt guarantee/competitive neutrality fees have provided government owners of network service providers with extra-ordinary profits. In 2010 for example, the NSW Government received \$596m in income tax equivalents and competitive neutrality fees from its distribution and transmission service providers and retailers. By comparison, dividends of \$575m were paid in that year from these utilities ... This can be expected to have increased the sympathy that government owned NSPs [network service providers] have had towards higher capital expenditure. This is because higher capital expenditure has led to a larger regulated asset base which in turn has delivered higher returns to state governments since the profit, income tax on profits and debt guarantee / competitive neutrality fees on the debt provided to fund the assets has risen as the asset base has expanded. (2012b, p. 18)

AMP Capital:

Although a state government does not have day-to-day control of its utilities, it exerts shareholder control and can effectively influence behaviour by demanding higher levels of dividends. In the absence of effective capital rationing, management can meet these demands most easily by maximising the capital spend, rather than implementing the degree of operational reform that would be necessary in an private sector-owned utility. (sub. DR55, p. 5)

The Gratton Institute:

In states where distribution companies are publicly owned, governments receive dividends from them. Governments acting as financiers also charge their companies competitive neutrality fees as well as interest on financing ... These income streams mean that governments' dual role as owners and financiers can provide incentives for government owned companies to spend more on their networks than they need to. Without proper separation between their two roles, governments can be tempted to treat competitive neutrality fees and tax equivalents as windfall revenues. (2012, p. 30)

However, of all the options, privatisation — as recommended in chapter 7 — would automatically resolve any problems, while bringing a range of other benefits.

Treatment of overspending

Under the current regulatory arrangements, all capital spending — regardless of its efficiency — is rolled into the regulatory asset base (RAB) at the end of the five-year regulatory period.³⁶ However, the AEMC has made a Rule change that allows the AER to conduct an ex post review of network spending commencing in the next regulatory period.³⁷ Under the new Rules, the AER can review network spending where the network has exceeded the previously forecast levels, after adjusting for cost pass throughs.³⁸ If the AER finds that the network spending has not been efficient, it may reduce the allowable capital up to the difference between the forecasts and actual capex.

The Productivity Commission made a similar recommendation in its draft report, and, accordingly, supports the Rule change. The Commission considers that such an ex post review should also be triggered for overspending on large projects covered by the transmission reliability and RIT-T arrangements spelt out in chapters 16 and 17.

The essential feature of ex post reviews is that the regulator only allows capital expenditure that it deems to be prudent and efficient (given the information available to the network business at the time of its investment decisions) to be rolled into the RAB. The approach is widely used overseas and was a feature of the NEM prior to 2006 (AER 2011a). Ex post reviews would not attempt to reoptimise the entire RAB. Rather, they would only look at investment spending from the previous regulatory period before allowing it to be included in the RAB. Also, given the difficulty that the AER will face in showing that spending, either on an individual project or across a portfolio, was inefficient, it is unlikely that ex post reviews will exclude significant levels of expenditure.

However, ex post reviews do contain some potential pitfalls. For instance, there is some risk of mistakenly identifying an efficient investment as inefficient. (If

³⁶ Jemena (sub. DR 77, attachment 1, p. 9) point out that while capex is automatically rolled into the RAB, if excess spending in one period led to lower capex allowances in the following period, it could provide similar incentives to excluding funds from the RAB.

³⁷ National Electricity Rules v. 54, pp. 730ff and 850ff.

³⁸ The AER can also exclude funds from being rolled into the regulatory asset base where they relate to inefficient related party margins or a change in capitalisation policy. This can occur regardless of whether the network has exceeded the capital forecast.

material, these risks would need to be reflected in the WACC.) The AER itself acknowledged that:

... ex post reviews may add to regulatory risk by creating potential for investment write downs. In addition, the evidentiary burden that the regulator must satisfy before it could disallow an investment is so high that ex post reviews may offer limited protection against inefficient expenditure. (2011a, p. 43)

As summarised by the AEMC, the industry view was (unsurprisingly) negative:

NSPs [network service providers] are not in support of ex post prudency and efficiency reviews of capex. They consider that a well-designed ex post prudency and efficiency review does not provide any additional incentives compared to a well-designed ex ante regime. (2012a, p. 119)

There have also been concerns that using ex post reviews to control the spending of network businesses may result in the AER needing to micromanage every aspect of network spending.³⁹

For this reason, the AER should not use ex post reviews as the major tool to incentivise networks. Rather, the Commission believes that ex post review should be seen as a complement to the ex ante incentive arrangements, to be used where there is persuasive evidence that overspending is inefficient (rather than reflecting cost pressures outside the control of the network business, such as increasing prices for key inputs into investment). It is likely that cases of overspending will decrease as a result of other reforms, such as the new WACC framework, an EBSS and the privatisation of networks, which will in turn decrease the importance of ex post reviews. Nevertheless, if used sparingly by the AER, the ex post review will provide a useful tool to encourage network efficiency.

5.4 The AER's ability to determine expenditure forecasts

In determining expenditure forecasts, the AER must accept a network business's revenue proposal if it 'reasonably' reflects the efficient costs of that business.⁴⁰ However, prior to a recent Rule change, other parts of the Rules were interpreted by several stakeholders, including the AER, as requiring the regulator to undertake a line-by-line assessment of a business's revenue proposal and to make its determination only on the basis of the proposal put forward by the business. The extent to which the Rules (as they applied at the time) actually constrained the

³⁹ Such as Jemena (sub. DR77, p. 7) and the AER (sub. DR92, p. 13)

⁴⁰ NER clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c), and 6A.6.7(c).

AER's decision-making or required it to take such a forensic approach has been vigorously debated.⁴¹ Certainly, the AER appeared to have successfully contested large initial proposals by network businesses (table 5.3).

Table 5.3 Distribution capex through the determination process

<i>Network operator</i>	<i>Network proposal</i>	<i>AER draft determination</i>	<i>Network revised proposal</i>	<i>AER final decision</i>	<i>Percentage reduction from original</i>
	\$m	\$m	\$m	\$m	(%)
CitiPower	1 167	676	1 005	830	28.8
Powercor	1 879	1 300	1 826	1 567	16.6
Jemena	657	372	621	473	27.9
SP AusNet	1 484	1 066	1 582	1 481	0.2
United Energy	911	652	949	887	2.6
Country Energy	4 041	3 955	3 989	3 826	5.3
EnergyAustralia	7 381	7 158	7 050	6 638	10.1
Integral Energy	2 953	2 914	2 735	2 721	7.8
Energex	6 466	5 718	6 286	5 783	10.6
Ergon	6 033	5 013	6 274	4 989	17.3
ETSA	2 249	1 628	1 793	1 588	29.4
ActewAGL	287	278	298	275	4.0
Aurora	675	536	618	535	20.7

Sources: Various AER determination papers.

Nevertheless, through a recent change to the rules that included removing two ambiguous Rules,⁴² the AEMC has clarified that, while the AER must accept a reasonable proposal, the Rules do not place any restrictions on the analytical techniques that the AER can use to scrutinise and, if necessary, amend or substitute the network business's capital expenditure or operating expenditure forecasts.

The Commission agrees with this amendment, but considers that the (retained) requirement for reasonableness plays an important role in the incentive regime, and needs to be interpreted carefully by the AER. This also has major significance for the role of benchmarking (chapter 8).

In that context, while it is unclear how effectively the process will work following the AEMC ruling, it is worth stepping back from the Rules and considering how the determination process should ideally operate. From the Commission's perspective,

⁴¹ For example, AER (2011a, p. 13; 2012c, appendix 2), the ENA (2011a, appendix C, p. 50), (AEMC 2012a, p. 104), Allan Fels (2012, p. 57), Ergon Energy (sub. 8, p. 14), The Consumer Action Law Centre (sub. 5, p. 4), ETSA Utilities et al. (sub. 6, p. 3), The Brattle Group (2012b, p. 10) and Michael B Cunningham (sub. 28, p. 13).

⁴² Clauses 6.12.3(f) and 6A.13.2(a).

some principles, however embodied in regulations, appear to be reasonable. In particular, the determination process should:

- in the first instance, be aimed at effectively achieving the National Electricity Objective
- be based on an economic, rather than a legalistic, mindset⁴³
- take into account the incentives faced by the interested parties and the information asymmetries between them
- take account of all information that can cost-effectively be incorporated into the analysis, including bottom-up and top-down approaches (and benchmarking), while recognising the relative strengths and weaknesses of such approaches (chapter 8)
- recognise that, over the longer term, under-compensation of network businesses resulting from regulatory errors is likely to have greater costs for customers and the wider community than ‘symmetric’ overcompensation (chapter 4).

Given these principles, a best practice approach for making determinations would work as follows:

- The business would put forward its proposal, with enough information for the AER to commence its assessment.
- The AER and the business would interact while the AER considered the proposal. There might be many points where the AER required clarification or further information, and instances where the AER might seek feedback from the business (for example, ‘Given the forecast demand, why couldn’t this substation be deferred by two years?’). This process — and engagement — would reduce information asymmetries, help develop expertise among AER staff and allow the AER to test its views about any alternative cost forecasts it had developed. The additional resources allocated to the AER would assist this consultative approach. It would also provide information that could be used in developing and interpreting benchmarking models.
- If, as a result of this process, the AER thought that the proposal was ‘reasonable’ it would accept it. In determining ‘reasonableness’ it would use the approach shown in figure 5.4. The AER would not seek to set the revenue allowance at the exact level that it perceived was necessary to provide the services required over the regulatory period (C_B). Rather it would set the

⁴³ A point made by the Energy Users Association of Australia (sub. 24, p. 11).

revenue allowance at the highest level that would be considered reasonable (which would be C_H in figure 5.4).⁴⁴

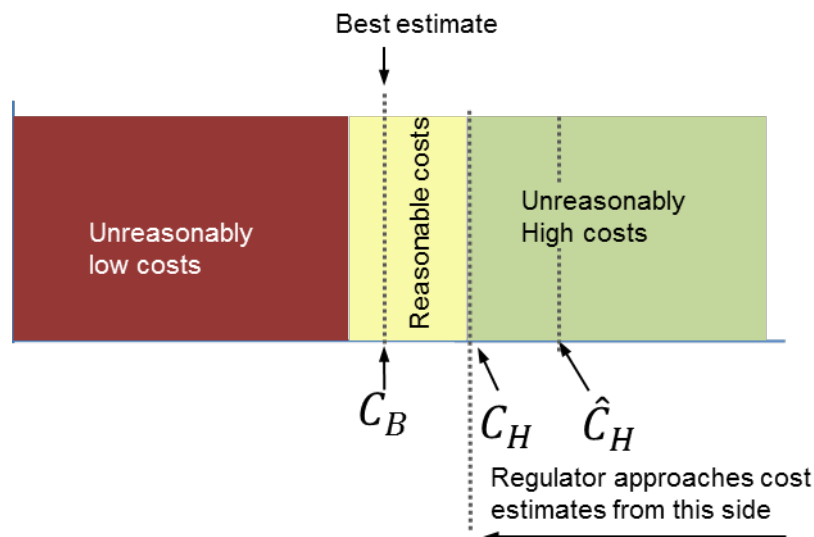
- Setting the cost forecast above the best estimate reflects the fact that all estimates have errors, and that in this case, the impact of errors is asymmetric. In other words, the cost of providing a high forecast is less than that of a low forecast. This is also consistent with setting the benchmark performance of businesses below the frontier. This approach would create an expected rent for the business, but given uncertainty over cost forecasts would also insure the community against the risks of under-investment or poor management of assets.
- The AER could use any method that it regarded as appropriate — including aggregate and partial benchmarking, engineering models, and highly disaggregated information in forming its views about what C_H should be. It would not be restricted to the original business proposal (as reinforced by the recent rule change). The AER would test the reasonableness of the overall capex and opex expenditure proposals, rather than the merits of all of their parts (an issue discussed further in chapter 8).⁴⁵ This would increase the potential for the sensible use of benchmarking. However, given the difficulties associated with benchmarking identified in chapter 4, chapter 8 and by the AER itself, benchmarking would not play a determinative role.
- The expectation should be that the gap between C_H and C_B should not be too large, especially as the regulatory determination process is not a one-shot game. If the distribution network's performance appeared to be degrading (reasonably easily established in the case of distribution networks), and the business appeared to be otherwise efficient, then the next regulatory period would take account of this.
- The AER should be transparent in the way that it determines C_H and use a similar framework for each revenue determination. While this process will present a technical challenge for the AER (as discussed in their submission (sub. DR 92, p. 14)), it is a natural extension of the benchmarking process.

⁴⁴ While this may appear to re-establish the principles set down in the now abandoned clause 6.12.3(f)(2), it is quite different because it does not constrain the AER in respect of the matters or methods it can bring to bear in making a judgment about reasonableness. It remains consistent with the remaining clauses specifying the requirement for 'reasonableness' (clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c), and 6A.6.7(c)). Above all, the Rules do not preclude the AER from taking this approach.

⁴⁵ Given a margin of error around each component of a revenue determination, erring on the high side of every component would translate to an excessively high (and therefore unreasonable) aggregate expenditure estimate.

- The AER's final determination would be subject to merits review if its holistic assessment were seen as failing the test graphically depicted in figure 5.4.
- The above process should, where possible, be the same whether it is considering transmission or distribution networks. However, in some other areas, such as reliability (chapters 15 and 16), incentive regulation will appropriately differ between distribution and transmission. In response to a request for feedback by the Commission, the AEMC argued that harmonisation of the incentive regulation arrangements was desirable where the policy intent was the same, but that given transactions costs, it was not clear that full harmonisation would be justified at this stage (sub. DR89, p. 3).

Figure 5.4 **What is a reasonable cost?**



Generally, the above practical approach to determinations would not require Rule changes, but rather a set of practices adopted by the regulator and the businesses.

Nevertheless, it is possible that the recent changes to, and the AEMC's clarifications of, the Rules, will not be sufficient to deliver outcomes that are closely aligned with the principles outlined above. The AER may find that instead of being permitted to set C_H , continued flaws in the way the revised Rules work in practice mean that it ends up being obliged to set \hat{C}_H . For this reason, if in the future, the AER feels unduly constrained in the way that it can challenge a proposal, it should publish its preferred estimate alongside the official estimate used for revenue purposes. This should lead to any issues being brought into the public domain and resolved in a more timely manner. The information would also be relevant to any merits review of the AER's determination.

RECOMMENDATION 5.2

Where the Australian Energy Regulator considers that the National Electricity Rules constrain its capacity to make appropriate revenue determinations, it should publish its preferred estimate along with the final determination, explaining the differences. In any subsequent merits review of its determination, the Australian Energy Regulator should ensure that the reasons behind its preferred estimate are clearly communicated to the merits review body.

6 Empirical evidence of network efficiency

Key points

- The scale of network capacity expansion has varied by a wide margin between networks. While much of the recent increase in network capacity appears to be related to peak demand, it is not clear that increased investment was an efficient response.
- Expanding capacity has been more costly in some states than others, in that larger expansions in the regulated asset base (RAB) have occurred for a given increase in network capacity. This is partly attributed to differences in replacement capital expenditure, which is an area of expenditure that should be investigated further.
- Much of the recent increase in network revenues reflects the coincidence of increases in the weighted average cost of capital and increasing capital expenditure. This particularly applies to New South Wales.
- Some network businesses may have benefited from being able to exceed regulatory allowances for capital expenditure in the previous regulatory period. Not only has this expenditure been rolled into the subsequent regulated asset base, but it has also influenced the regulator's decisions about what is reasonable expenditure in future periods. It is possible that some of this overspend could have reasonably been reduced or deferred.
- There are significant differences in the behaviour of network businesses and in the apparent efficiency between state and privately owned networks. Reliability standards are also likely to be a factor.

While the Commission has not undertaken elaborate benchmarking analysis, it found it useful to consider whether there is a *prima facie* case that significant inefficiency exists. That would shore up the basis for further benchmarking — and for it to play a greater role in future regulation. However, in light of the many qualifications emphasised in chapter 4, the results are indicative, and certainly would not constitute a reliable basis for any downward adjustment in revenue allowances in imminent regulatory determinations. In particular, this chapter has concentrated on partial indicators. None of the partial indicators would themselves provide definitive evidence of inefficiency, but collectively they may provide more robust evidence.

This chapter first outlines the prevailing evidence on network inefficiency, including some of the more contentious findings (section 6.1). Section 6.2 considers further evidence on various contested issues, such as the relative role of changes in the regulated weighted average cost of capital (WACC), (largely outside the control of individual businesses, save for the appeals mechanism), and increases in expenditure (which is largely controlled by the business). On the decisions made by network businesses, this chapter discusses various arguments including:

- how decisions on physical augmentation have related to peak demand (section 6.3)
- whether measures of the regulated asset base can be useful as indicators of efficiency, and how these relate to both growth capital expenditure (capex) and replacement capex (section 6.4)
- the significance of overspending, given the incentives outlined in chapter 5 (section 6.5)
- whether the state-owned networks operate differently from the privately-owned businesses (section 6.6).

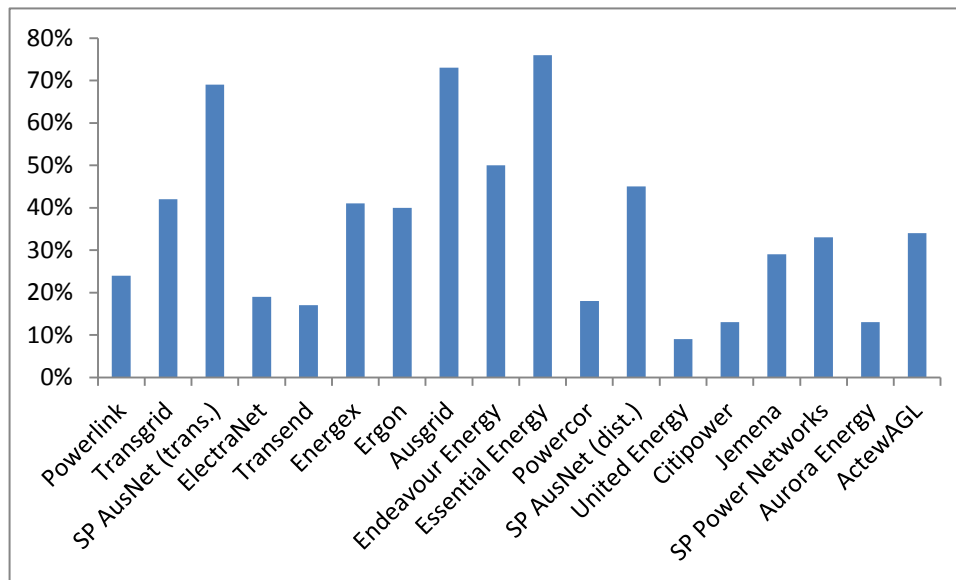
6.1 Existing evidence and arguments

As discussed in chapter 2, the electricity supply chain as a whole has recorded negative productivity growth in recent years. Topp and Kulys (2012) note the negative growth phase in multi-factor productivity coincided with a trend of rising peak demand, as well as declining network capacity utilisation. As such, the increase in network capacity is likely to have been a factor in the recent fall in productivity.

The expansion in network-related costs is confirmed by data that shows network revenue allowances have risen significantly in the current determination period (figure 6.1). This expansion is expected to have a significant effect on electricity prices — the Australian Energy Market Commission (AEMC 2011a) estimated that distribution charges will account for 42 per cent of the expected electricity price increases between 2011 and 2014, with transmission accounting for 7 per cent.

Figure 6.1 Approved network revenues have risen^a

Percentage rise in approved revenues from the previous to current regulatory period



^a Current regulatory period revenues are forecasts in regulatory determinations amended by the AER for merits review decisions by the Australian Competition Tribunal. It should be noted that in contrast to the figures published by AER (2012q), CitiPower et al. (sub. DR90) calculate the increase in revenue as being 4 per cent for CitiPower and 12 per cent for Powercor (p. 24). This difference is likely due to methodological differences, as CitiPower/Powercor use actual revenues in their calculations as opposed to approved revenues.

Data source: AER (2012q).

Some studies suggest there is widespread inefficiency

The AER (2011a) questioned the efficiency of recent expenditure increases in its rule change proposal to the AEMC.

Recent increases in network charges have been driven in part by the need for increased investment to replace ageing assets and to meet increased peak demand, growing customer connections and higher reliability standards. Higher forecasts to cover expected increases in labour and materials costs have also contributed to increases in network prices. However, these drivers do not fully account for the level of observed increases. (p. 6)

There are legitimate reasons for some increases in capex from previous levels. However the sharp and significant step change in expenditure forecasts draws into question whether the current framework is meeting the [National Electricity Objective] in ‘promoting efficient investment’ or whether it is stimulating investment above efficient levels. (p. 8)

The AER cites as evidence the large and rapid increases in both forecast and actual expenditure. For instance, capex forecasts in the AER’s first round of distribution

determinations were 64 per cent higher on average than the actual expenditure incurred in the previous period, while operating expenditure (opex) forecasts were 34 per cent higher.

Several other commentators have also characterised recent network expenditure as inefficient, with network over-expenditure contributing significantly to price outcomes. For instance, Garnaut stated:

There have been large recent electricity price rises that are not related to a carbon price, and without changes in the regulatory arrangements this would continue. The increases are mainly because of large investments in the networks of poles and wires that distribute electricity, and the high rates of return on those investments that are recouped without risk from consumers. (2011a, pp. 149-50)

Mountain and Littlechild (2010) and Mountain (2011) provided more extensive evidence on the degree of potential inefficiency by comparing selected Australian States and the United Kingdom. They found that:

- revenue and expenditure allowances (on a per customer basis) were substantially higher in New South Wales and Queensland than in Victoria and South Australia, and increasingly so
- state-owned networks (New South Wales and Queensland) were more costly in terms of their regulated asset base, revenue and expenditure per customer compared to private networks (Victoria and South Australia). This remained the case when they were split into urban and country networks
- in comparisons with New South Wales and Victoria, the United Kingdom appeared to have much lower allowed revenues, expenditure and regulated asset base (RAB) per customer.

The estimated efficiency gaps were also particularly large (box 6.1). Mountain summarised the outcomes of the quantitative work:

Efficiency benchmarking using regressions shows that government owned distributors are, on average, half as efficient as the privately owned distributors. In other words, their total expenditure would need to halve to reach the level of efficiency of the privately owned distributors. ... Furthermore, comparison with the performance of electricity distributors in Britain suggests that Australian distributors are lagging behind: distributor revenues per connection are twice as high in Victoria, three times in South Australia and four times as high in Queensland and New South Wales. (Mountain 2011, p. vi)

It is doubtful that these gaps genuinely reflect differences in the underlying productive efficiency of the businesses alone. This is because it is very likely that other factors, such as differences in the cost of capital, exchange rates, and some important environmental factors would also contribute — criticisms that are

addressed in the next section. Nevertheless, even if the apparent inefficiency of the New South Wales businesses (as measured against a Victorian benchmark) were to be reduced significantly — by 75 per cent, for example — it would still amount to a high level of inefficiency.

Box 6.1 Contentious findings

Mountain and Littlechild (2010) compared partial productivity indicators of New South Wales, Victoria and Great Britain. The variables used included allowed revenue per customer; allowed capex and opex per customer; RAB per customer, and the WACC. The latest available exchange rate was used, which was 56 pence per dollar. They found that allowed annual revenue per customer in Victoria was about 61 per cent of the level in New South Wales in 2010. They also found that network revenue in New South Wales was around twice that of Great Britain in the year 2000, and would be nearly four times as much in 2014.

If New South Wales had assumed the same level of opex per customer as Great Britain in the third price control, the allowed revenue per customer in 2014 would have been 24 per cent lower. If it had used the same WACC as applied to Great Britain, the allowed revenue per customer for New South Wales would have been 21 per cent lower. The combination of capex and RAB accounts for the remaining 28 per cent difference.

In a report for the Energy Users Association of Australia, Mountain (2011) found that state owned distributors had 60 per cent more capex allowed per customer than privately owned distributors in 2002, and this was expected to rise to almost 300 per cent in 2014. The allowed revenues per customer in New South Wales and Queensland are expected to be of a comparable level in 2014, at roughly 1.5 times the level in South Australia, twice the level in Victoria and four times the level in Great Britain.

In a separate report for the Energy Users Association of Australia, Mountain (2012a) compared household electricity prices between Australia and various countries. In 2011-12, average household electricity prices in Australia were around \$0.25 per kWh — this was 12 per cent higher than average prices in Japan, 33 per cent higher than the European Union average, 122 per cent higher than the United States average; and 194 per cent higher than Canadian average. However, Mountain also shows that the results are somewhat sensitive to the choice of exchange rates. Using 2007 exchange rates, Australia was on par with the European Union average, while still around 30 per cent higher than Japan. Under Purchasing Power Parity, Australia's average price was below those of Japan and the European Union. Other estimates such as those of the Department of Resources, Energy and Tourism suggest that Australia's *household* electricity prices were either below or marginally above the OECD average in 2011 (SSCEP 2012).

Other benchmarking studies of Australian network businesses, many of which were undertaken or commissioned by regulators, suggest that performance has varied significantly between businesses at various points in time (box 6.2).¹ The degree to which some networks outperform other networks depends on which measures are used, indicating the importance of the choice of indicator.

Has the case for inefficiency been made?

As Yarrow (2012) observed, opposing commentators in the industry often cite different forms of evidence, and so it is not surprising that some of the studies mentioned above have been strongly disputed.

While Mountain and Littlechild did not draw direct conclusions on the differences in efficiency between distributors (Mountain, sub. DR49), Mountain (2011) goes further in concluding that state-owned distributors had undertaken ‘wasteful expenditure’ (p. 61).

Network businesses have acknowledged that both prices and expenditures have risen, although they have collectively argued that the increases are in response to peak demand, replacement of ageing infrastructure and changes to regulatory compliance. The Electricity Networks Association (ENA), for example, said:

The ENA contends that ... the increases are efficient because the regulatory framework under the Rules accurately reflects a range of relevant changes including:

- increases in the prevailing cost of capital due to the global financial crisis;
- increases in the need to replace assets due to an increasingly significant proportion of asset stock reaching the end of its economic life;
- changes to network planning standards; and
- continuing increases in peak demand that outstrip growth in energy usage due, for example, to the increased penetration of air conditioning. (sub. 17, p. 7)

In particular, network businesses have questioned the conclusions of Mountain’s various studies. NERA, on behalf of the ENA (sub. 17, appendix B), examined the various Mountain studies, concluding that:

Our assessment of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs and a reliance on inappropriate comparisons

¹ These studies did not compare networks using the same parameters as Mountain and Littlechild (2010) or Mountain (2011), and so are not directly comparable. Nevertheless, they tended to find smaller gaps in the relative performance of the businesses than Mountain and Littlechild.

has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. (p. i)

NERA's criticisms of Mountain's studies were far-reaching.

Box 6.2 Efficiency gaps identified by recent studies

Several studies examined partial indicators of efficiency:

- BRW (2004) undertook several comparisons between Energex and various other distributors for the Queensland Competition Authority. Indicators included reliability measures, and various expenditure ratios. Compared to the three most comparable firms, Energex had the lowest opex per circuit km, opex per customer and opex per GWh (with EnergyAustralia being 85–99 per cent higher than Energex in these measures). This helped to explain why Energex's opex grew by around 63 per cent over the subsequent three years.
- Meyrick (2005) undertook comparisons between Western Power and all other Australian distribution networks who remained unidentified. Meyrick used a number of partial productivity measures, although mainly reported rankings. Opex productivity indexes ranged from around 0.6 to 1.8, while capex productivity ranged from around 0.6 to 1.5.
- Wilson Cook (2009) made several partial productivity comparisons between Western Power and the distribution businesses in several other states. Comparisons were made of opex ratios, although the comparisons did not offer a consistent conclusion on the size of efficiency gaps between networks. Victoria had a similar level of opex per customer as South Australia, which was around one third less than Western Power, New South Wales/ACT, and Queensland. However, when comparing opex per circuit km, Victoria was close to on par with Queensland, and more than one third higher than South Australia.
- The Independent Review Panel on Network Costs assessed the performance of Queensland distribution network expenditure against other Australian distributors (IRPNC 2012). Comparisons were made with regard to capex per customer and opex per customer, while controlling for customer density. Ergon tended to be a higher cost network in terms of operating and capital expenditure when compared with other networks with comparable customer densities. Comparisons of corporate overhead costs also showed the Queensland distributors to be 'amongst the least efficient' (p. 10).

(Continued next page)

Box 6.2 (continued)

Comprehensive indicators of efficiency have also been used with Australian networks:

- London Economics (1999) compared New South Wales to other distribution networks using data envelopment analysis (DEA) and total factor productivity (TFP) methods. The comparisons were made to distribution networks in the United States, England, Wales and New Zealand. Based on adjusted DEA scores, it was estimated that New South Wales distribution networks would need to reduce their input use by between 13–41 per cent to meet the efficiency frontier.
- Meyrick (2005) undertook multilateral TFP comparisons, where Western Power is ranked sixth out of thirteen, and is 6 per cent below the group average.
- ESC and PEG (2006) estimated Total Factor Productivity (TFP) trends for distribution networks in four Australian States. They estimated that from 1995 to 2003, TFP trends have grown at about 2.14 per cent per annum in Victoria, compared to about 1.8 per cent in Tasmania, 0.14 per cent in New South Wales and -0.03 per cent in South Australia.
- IPART (2010) assessed the productivity of New South Wales state owned corporations including electricity network operators. Among distributors, it estimated a TFP decrease between 2001-02 and 2008-09 of between 17 and 24 per cent. Using an alternative model specification, it measured decreases of between 7 and 19 per cent.
- The Independent Review Panel on Network Costs reported some results from confidential benchmarking exercises undertaken by the International Transmission Operations and Maintenance Study (ITOMS) (IRPNC 2012). The results showed that Powerlink compared favourably with other transmission operators in regard to a composite measure of line and substation maintenance, as well as overall service provision.
- AMP Capital undertook a linear regression analysis using Australian private sector distribution networks (sub. DR55). The regulated asset base was regressed against customer numbers, network length and peak network demand. The resulting estimates were then used to forecast RAB values for both private and state-owned distribution networks within Australia, as well as distribution networks in the United Kingdom. They found that the actual RABs of New South Wales and Queensland distributors were 2.5 to 5 standard errors higher than the model forecasts.

Mountain's Australian evidence

NERA raised several issues with Mountain's 2011 study, (particularly the regression analysis), including that it:

-
- used a model specification that ignored the fixed costs of networks (by setting a zero intercept in his regression model)
 - failed to report any specification tests
 - did not systematically consider the ratio of peak to average demand or the lumpy nature of investment
 - did not control for all differences in the operating conditions between firms.

Of these points, the first two are correct, albeit it is not clear that much of a bias is associated with Mountain's assumption about the intercept. Statistical tests could have been used to assess the statistical significance of the dependent variables and of the model as a whole, and to test for model misspecification.

The third point is true in terms of the regression analysis since Mountain did not include a measure or proxy for peak demand as a regressor. Whether its omission matters is an empirical issue.² In any case, Mountain (2011 p. 35) did consider the role of peak demand when assessing the outcomes in Victoria (which was rated as the state with the most efficient businesses). He did not find peak demand as an important driver of the difference in investment levels between New South Wales and Victoria.

The fourth point is true, but inevitably so for any model based on a limited sample.³ Perhaps one of the most important concerns is the fact that, ideally, benchmarking analysis should take account of business's need to replace assets close to the end of their lives. Instead, Mountain compared the (weighted average) remaining life of assets of distribution network businesses in Victoria and South Australia with businesses in New South Wales and Queensland (finding the latter longer). NERA's concern is that what matters is the quantum of assets getting close to the point of expiry, not the weighted average age.⁴ NERA provides data comparing the distribution of asset lives for Ausgrid and SP AusNet, which suggests that Ausgrid

² Mountain indicated that peak demand was collinear with the other explanators. In this instance, omission of the variable may bias the coefficients on the remaining explanators, but will not bias the in-sample prediction errors of the regression.

³ It is also not necessarily a damning finding. Any regression model will have omitted variables. If important causal variables are left out of the model, this leads to 'omitted variable bias'. If, for example, there are several important variables omitted, then the inclusion of some (or one) of them may reduce the bias or simply change the magnitude or direction of the bias — the effect is not necessarily clear (Clarke 2005).

⁴ Mountain rightly points out that it is difficult for those outside network companies to accurately estimate the quantum of assets that is close to expiry (sub. DR49, p. 4). Detailed data on asset condition, age and expiry is not generally available, and moreover, asset lives may be extended to some degree.

would need a greater capex expansion rate given its asset vintage distribution. However, the expansion rate in New South Wales is not just moderately higher than Victoria. Mountain finds that the New South Wales distributors received four times more capex per customer to replace ageing assets than Victorian businesses. If nothing else, this is an issue warranting further investigation.

The UK–Australia comparisons

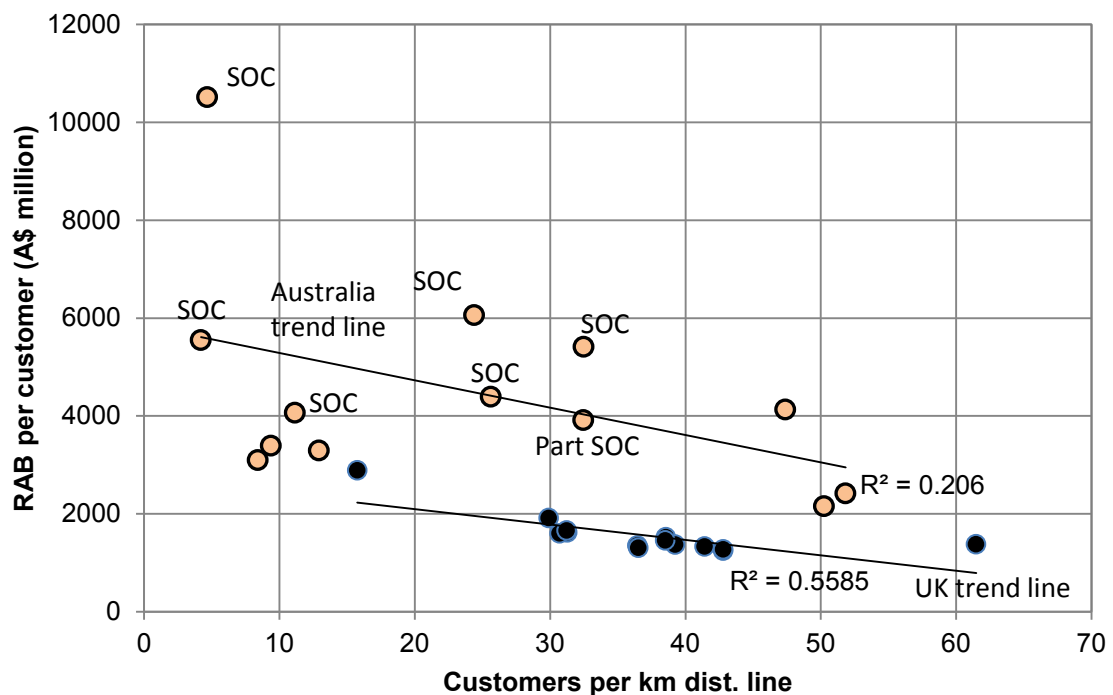
In the case of the international comparisons of Australia with the UK, NERA correctly pointed out that both Mountain (2011) and Mountain and Littechild (2010) used market exchange rates, not purchasing power parity rates (for which there is more theoretical justification). It noted that peak demand was higher in Australia. Finally, it speculated that different accounting practices might also be present and that the asset replacement cycle might have been different between the two countries.

However, to assess some of these criticisms, the Commission adjusted for purchasing power parity rates (figure 6.2). It appears that the RAB per customer for every Australian distribution business (after controlling for customers per kilometre of lines) is higher than that for distribution businesses in the UK. It is also apparent that the dispersion in apparent inefficiency scores (measured against the best practice performer) is much greater in Australia than in the UK. Many of the higher relative inefficiency scores relate to state-owned corporations, though there may be other variables correlated to ownership that lead to this pattern.

NERA is correct to point out the differences in peak demand between Australia and the UK as a potentially important driver of network costs, although they do not mention other factors that may lead to countervailing cost pressures, such as a greater degree of undergrounding in the UK.

There are significant drawbacks in international comparisons (chapter 4) and, as such, Mountain's results and figure 6.2 are best seen as providing an indicator to be weighed up against others, rather than as a robust measure of relative efficiency.

Figure 6.2 Australian versus UK asset bases per customer^a



^a Note the importance of taking care when interpreting RABs, as discussed in section 6.4 of this chapter. Purchasing power parities have been used to convert currencies. SOC denotes a state-owned corporation.

Data source: Commission estimates.

Some participants questioned whether the studies should be given *any* weight in policy considerations (NSW DNSPs, sub. DR85, attachment B). However, it is not the case that Mountain's results were technically incorrect — rather, there are limits to what may be concluded from them. In this sense, all empirical results have limitations, and further analysis is always desirable. The key concern is whether there are persuasive reasons why they are materially wrong.

The case against Mountain's results would be strong were an alternative, econometrically convincing model to find contrary results. The Commission is not aware of any such modelling exercise. In fact, more recent studies that have undertaken relatively simple benchmarking exercises have found results that were in the same direction as Mountain's general findings, though with econometric caveats of their own (IRPNC 2012, AMP Capital sub. DR55).

While there are limitations to what may be concluded from Mountain's evidence, the counter-evidence has not been so strong as to invalidate (or reverse) the basic thrust of his conclusions. If nothing else, his results provide reasonably suggestive evidence of a problem, while simultaneously being an advertisement for the difficulty of making specific policy-relevant conclusions based on high-level

comparisons. In its recent draft determination for the AER's Rule change proposal, the AEMC (2012a) reached much the same conclusion:

... no analysis has been provided which would challenge Mountain's conclusion that the average privately-owned DNSP [distribution network service provider] is more efficient than the average state-owned DNSP. (p. 97)

But more evidence is needed

Several commentators have highlighted the need for more detailed evidence of inefficiency (ENA, sub. 17, appendix A or B; Yarrow 2012). For example, Yarrow noted that:

... much more specificity in the identification of causal links is required, even to [begin] to pin down the elements of the wider system of relationships that might usefully be considered to be candidates for reform.

... In relation to capital costs for example, it can be asked: if there is a tendency for networks to over-forecast, why do a number of utilities then tend to over-spend relative to such inflated forecasts?

... Is it that utilities simply take on too many projects, or that they over-engineer projects? Or is it that utilities undertake the wrong projects? Or then again, is it just that whatever they do, they do it at a higher cost than necessary? None of this is very clear. (pp. 10-11)

The Commission has identified many data and model development problems (chapter 4 and 8), for which resolution would be the necessary precursor for more definitive benchmarking. However, there is some evidence — beyond that analysed by Mountain — that provides further information about the cost drivers behind recent network price increases.

6.2 The relative impacts of the WACC, capex and opex

As noted earlier, the network business does not *determine* the regulatory WACC (while of course trying to maximise it through the regulatory process). As a result, movements in the revenue allowances from changes in the WACC do not have direct relevance for efficiency, though they do potentially undermine the incentive regime (chapter 5). Accordingly, it is useful to separate the effects of the WACC from other influences, such as the levels of capex and opex.

In a report prepared for the ENA (sub. 17, appendix A), NERA undertook an extensive analysis of these drivers between the current and previous regulatory

periods.⁵ NERA's calculations first involved considering what network prices would have been if both the WACC and expenditure allowances had remained constant from one regulatory period to the next. It then calculated the percentage difference between this price and the actual network charge, noting the percentage contribution from changes in capex allowances, opex allowances and the WACC (table 6.1).

In explaining the expenditure increases, NERA found that 'real cost escalators'⁶ had a small negative effect on the capex allowance since the last period, meaning that the unit costs associated with capex had fallen. Hence, with respect to capex, the main drivers were likely to be the increased scope and number of capex projects rather than their cost escalators. At the same time, real cost escalators had a significant effect on opex, resulting in increased opex allowances. They contributed between 1.9 and 2.4 per cent to distribution opex allowances, and up to 3.5 per cent for transmission allowances (ENA sub. 17, appendix A p. 48).

NERA's analysis usefully indicates that WACC changes — which are outside the control of the business — played an important role in changes in costs from regulatory period to period. However, NERA's estimates do not take account of the multiplicative interactions or 'mix' effects between the WACC and capex (appendix G). (NERA made its estimates by holding one variable constant and measuring the impact of another variable.⁷) As such, there is some amount of revenue that is attributable to both capex and WACC, but that NERA includes into a separate 'other' category in table 6.1.

NERA's analysis implicitly used the previous regulatory period as a benchmark. This is a reasonable specification for NERA, given that the analysis focused on the impact of the new regulatory framework on costs. However, in considering the efficiency of networks more generally, other benchmarks could be used. For instance, the analysis could reasonably be extended to prior regulatory periods.

⁵ NERA analysed the regulatory period corresponding with the regulatory period in each region current in 2012, as well as the regulatory period immediately prior to that. The analysis measures increases in network prices using the AER's Post Tax Revenue Model. The increase is measured as a step change which encapsulates all of the incremental increases which would occur in each year of the period (that is, the analysis assumes the X-factor is set to zero for the final four years of the regulatory period).

⁶ Real cost escalators are indices representing the change in prices faced by network businesses. These may include prices for materials, construction costs, and wages.

⁷ NERA acknowledged that the results from its decomposition analysis ignore these interaction effects, but considered that their approach was the most appropriate method available.

Table 6.1 NERA's breakdown of network charge increases from previous regulatory period to current regulatory period^a

Percentage contribution to overall network price increases

<i>Network operator</i>	<i>Ex ante capex allowance</i>	<i>Ex ante opex allowance</i>	<i>WACC</i>	<i>Other^b</i>	<i>Total</i>
	Per cent	Per cent	Per cent	Per cent	Per cent
Ausgrid	18.6	15.6	14.6	12.2	58.3
Endeavour	9.5	9.9	11.2	3.8	32.9
Essential	15.7	20.2	11.4	4.5	49.7
TransGrid	9.4	4.3	8.7	(2.8)	18.2
Ausgrid (transmission)	29.9	4.9	16.0	3.7	46.8
Energex	8.8	2.7	18.9	14.2	42.6
Ergon	7.2	7.9	17.8	16.2	47.5
ETSA	10.6	10.0	10.4	7.8	36.4
ElectraNet	8.5	2.7	14.1	10.3	33.9
ActewAGL	4.6	18.2	(0.6)	0.7	22.7
Transend	9.1	10.6	7.5	5.9	32.5
CitiPower	1.2	1.2	4.9	(5.5)	1.4
Powercor	3.4	3.7	4.1	(4.4)	6.3
Jemena	1.6	(3.6)	6.6	6.8	11.0
SP AusNet (distribution)	6.8	9.2	6.3	2.3	19.2
United Energy	4.2	2.8	3.8	(4.9)	5.6
SP AusNet (transmission) ^c	3.1	1.1	3.2	5.5	15.3

^a For distribution companies, NERA analysed the regulatory period corresponding with the first AER distribution determination for that region, and with the prior determination of the relevant state regulator. Aurora Energy is not included in the analysis, as their first determination by the AER had yet to be completed. For transmission companies, NERA analysed the regulatory period in each region which was current in 2012, as well as the immediately prior regulatory period. ^b 'Other' factors contributing to network charge increases include capex and opex overspends. For networks subject to price cap regulation, 'other' factors may also be attributed to differences in forecast and actual demand. When decomposing the percentage change in a multiplicative measure, there are 'mix' effects that pick up the interactive movement of the variables. 'Other' factors also includes these 'mix' effects. Overall, the implication is that the effects on network charges of the WACC, capex, and opex are likely to be larger than identified above. ^c It is unclear whether SP AusNet's transmission capex would account for 'separable' projects. As such, their capex may not be directly comparable to that of other transmission networks.

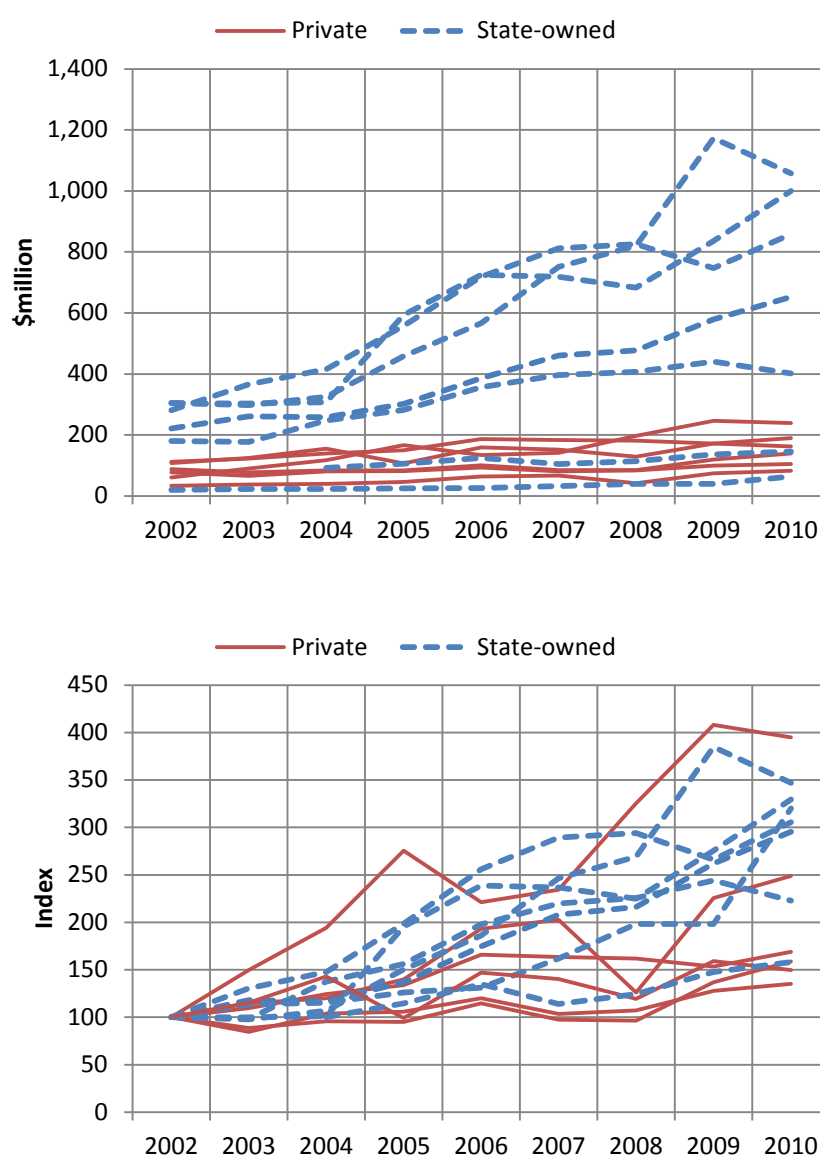
Source: ENA sub. 17, appendix A.

The analysis of prior regulatory periods would be particularly useful, given that the recent growth in network revenue and expenditure has not been confined to the current regulatory period. For example, the scale of capital expenditure has been increasing for a number of years, including the years prior to the AER's role as the network regulator (figure 6.3). And while expenditure in the largest states of the National Electricity Market, (New South Wales and Queensland), has increased several times since 2002, so too has the expenditure of some private networks.

Importantly, neither the analysis of NERA nor the trends in figure 6.3 are designed to distinguish between efficient and inefficient expenditures. They are helpful only in indicating the relative impact and scale of expenditure — which is sufficiently large that it requires further analysis.

Figure 6.3 The scale of recent capital expenditure for distribution networks

Annual capital expenditure



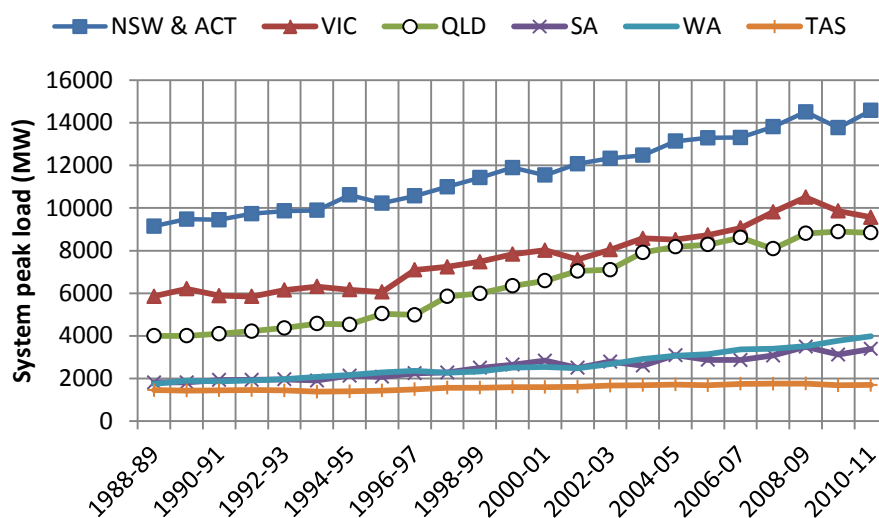
^a The first year of the AER's responsibility for regulation of distribution networks was: 2009-10 for New South Wales and ACT; 2010-11 for Queensland; 2011 for Victoria; 2011 for South Australia; 2012-13 for Tasmania. Some networks' data are based on fiscal years, others on calendar years. The index is uses 2002 as a base year.

Data source: AER unpublished data.

6.3 Demand driven augmentation

Recent decades have seen the rise of peak demand (Topp and Kulys 2012). This has been evident in most jurisdictions, although Queensland has had a particularly rapid increase, with its peak load doubling since the early 1990s (figure 6.4). Growth in peak load levels has slowed in most states since 2008-09, and has been lower than forecast in New South Wales and Queensland (NSW Government 2010).⁸

Figure 6.4 Rising peak demand, 1988-89 to 2010-11



Data source: ESAA Electricity Gas Australia, various issues.

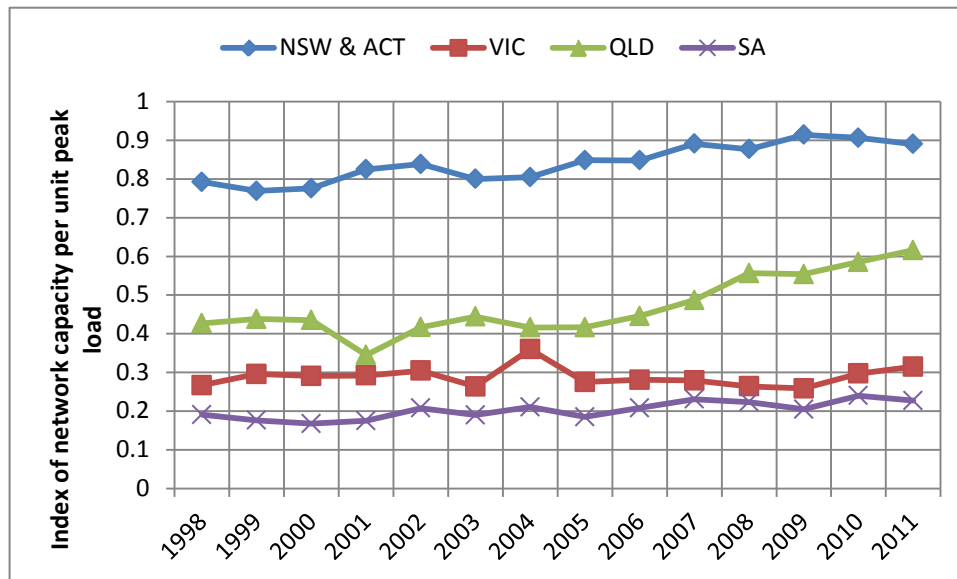
Unsurprisingly, the capital expenditure increases in New South Wales and Queensland were mainly on system assets — this includes network augmentation and replacement, and excludes non-system assets such as monitoring and IT systems. Since 2001, expenditure on system assets has accounted for more than two-thirds of New South Wales capex and over 84 per cent in Queensland. As Nuttall notes:

To counter these external pressures, a very large augmentation program has been undertaken in Queensland. ... In both Queensland and NSW, the majority of the [transmission] line developments have occurred since 2006 – noting that this is during the period when growth rates have been at their lowest and actual peak demand has been lower than forecast. (AEMO, sub. 42, p. 5)

⁸ Although data is unavailable on an individual network basis, it is likely that each distribution network experiences a different level of peak demand even where they exist within the same state.

The result can be seen in indicative comparisons of ratios of network capacity per unit of peak load (figures 6.5 and 6.6).^{9 10} For example, Queensland experiences a drop in distribution network capacity per unit of peak load in 2001, and steadily increases its capacity thereafter through ongoing network augmentation (figure 6.5).

Figure 6.5 Index of distribution network capacity per unit of peak load^a



^a Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA). The graph shows the ratio of network capacity per unit of peak load. Peak load is a state-wide measure, and was not corrected for weather. The ratio is indicative only, and is intended to compare trends.

Data source: ESAA Electricity Gas Australia, various issues.

Not all networks have taken the same approach. While peak demand has also risen in Victoria, its augmentation levels have been relatively lower than New South Wales and Queensland. As AEMO have described:

Victoria, on the other hand, has seen relatively modest augmentation levels, making use of load shedding control schemes, line uprating opportunities, and additional capacity released through the real-time rating system adopted in Victoria. [Transmission level]

⁹ Network capacity is measured by the product of total installed transformer capacity (measured in MVA) and the aggregate length of network lines (in circuit km). It is a physical measure of network supply capacity — a similar measure is used by Topp and Kulys (2012). The ratio of network capacity to peak load is used as an indicative measure only, to illustrate the trends in network capacity relative to trends in peak load and to make relative comparisons between networks. It is not intended to be an accurate measure of asset utilisation levels.

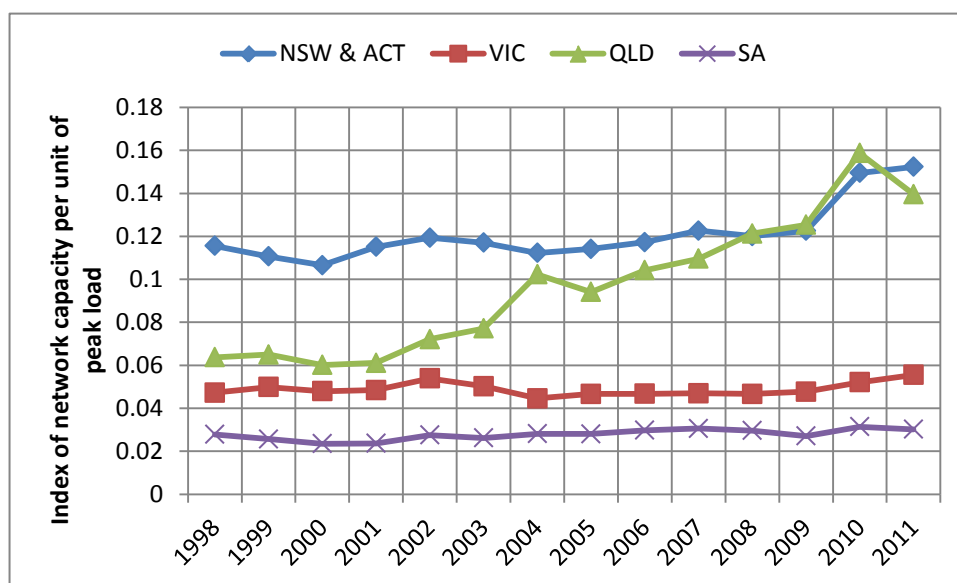
¹⁰ The ratio of network capacity to peak load is represented in figures 6.5 and 6.6 such that the index is higher for networks with more capacity per unit of peak load. That is, South Australia tends to have the least network capacity in relation to the amount of peak load it experiences, while New South Wales has the most network capacity compared to its peak load.

transformer capacity over 2000 to 2011 increased by around 25 per cent, with line capacity only increasing by approximately 3 per cent. (sub. 42, p. 5)

The same is true of South Australia — while peak demand has almost doubled since the late 1980s (figure 6.4), measures of network capacity do not show the kind of growth that has been evident in Queensland (figures 6.5, 6.6).

The comparisons suggest that trends in network augmentation relative to peak demand have historically differed between states, and that these differences have not been created solely by the events in the last regulatory period. This high-level evidence also suggests that while Queensland had changed its approach during the last decade, the increases in peak demand of the last decade are unlikely to explain *all* of the physical differences between networks, particularly between Victoria and New South Wales. A similar conclusion was reached by the EUAA (2012b), which found significant differences between States in augmentation expenditure per unit of peak demand.

Figure 6.6 Index of transmission network capacity per unit of peak load^a



^a Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA). The graph shows the ratio of network capacity per unit of peak load. Peak load is a state-wide measure, and was not corrected for weather. The ratio is indicative only, and is intended to compare trends. ESAA reports do not make any note of distinction between contestable and non-contestable transmission projects in Victoria — as such, the Commission assumes that physical measures of network characteristics relate to the whole state network, regardless of actual financial stake and ownership.

Data source: ESAA Electricity Gas Australia, various issues.

The main form of augmentation in Queensland has been through the rapid increase in transformer capacity. Queensland has increased its transformer density in

response to peak demand (AEMO, sub. 42). In the ten years from 2001, transformer capacity in Queensland grew by 130 per cent — more than it had grown in the preceding 23 years. Based on these high-level data, Queensland has not simply adjusted for recent increases in peak demand, but has also increased its transformer capacity relative to peak load.

This change in trend appears to have begun after a dip in the transformer capacity per unit of peak load in 2001 (figure 6.7). For much of the 1990s, the ratio of transformer capacity to peak load was similar between Queensland and Victoria. However, following a surge in the utilisation of transformer capacity, Queensland has maintained a strong expansion whereas Victoria has not.

The need for more detailed information on asset utilisation

There are limitations to what can be decisively inferred from high-level comparisons of average network utilisation. As Grid Australia said:

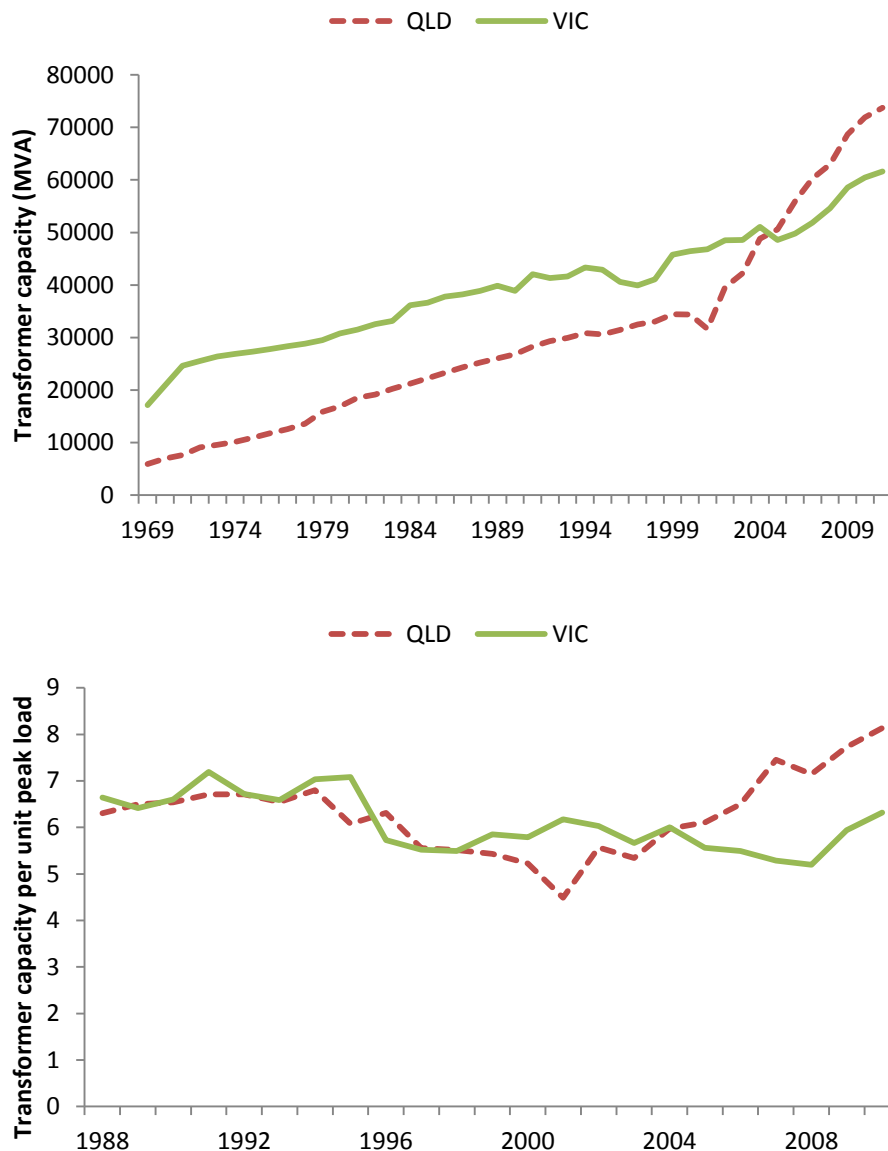
The difficulties associated with comparing outcomes across transmission networks means that caution is required when comparing the relative performance of transmission networks. That said, there are a number of shortcomings with the measure of relative utilisation that has been used to test the pressure for augmentation and efficiency of transmission planning across the states.

First, the use of asset utilisation at an aggregate level is misleading and inappropriate. The driver of augmentation expenditure is the utilisation of individual assets. The Evans & Peck's analysis demonstrates that, on an individual asset basis, jurisdictions outside of Victoria have higher utilisation than indicated by AEMO's analysis. (sub. 44, pp. 3-4)

Grid Australia illustrate this point with the use of more detailed asset utilisation data, showing that the utilisation rates of Victorian transmission assets are at times lower (figure 6.8). That is, while Victoria has a higher utilisation rate with regard to substations, the same does not appear to be true for lines. As such, it is difficult to make an overall ranking of state performance.

Figure 6.7 Transformer capacity in Queensland and Victoria relative to peak load^a

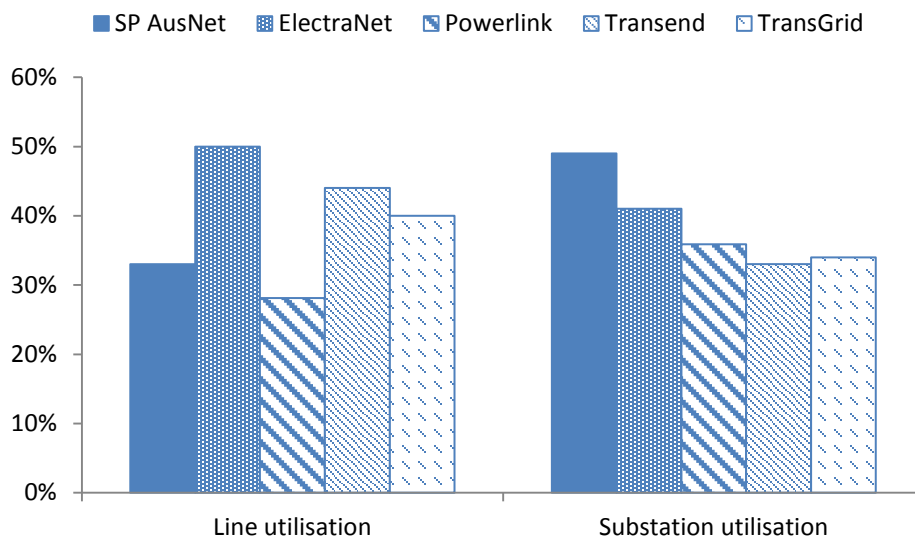
Transmission and distribution level transformers



^a Includes distribution and transmission level transformers. Transformer capacity per unit of peak load is calculated using annual figures. ESAA reports do not make any note of distinction between contestable and non-contestable transmission projects in Victoria — as such, the Commission assumes that physical measures of network characteristics relate to the whole state network, regardless of actual financial stake and ownership.

Data source: ESAA Electricity Gas Australia, various issues.

Figure 6.8 Transmission asset utilisation^a



^a Grid Australia also calculated peak and average utilisation for individual circuits and substations. While they had presented the above chart, they noted their general concern in using average utilisation as a benchmark.

Data source: Grid Australia, sub. 44.

The need for analysis of more detailed data is similarly true of distribution networks.¹¹ Hence, while the analysis in this section may be indicative of the growth of distribution networks in relation to demand, more accurate comparisons could be made if further data were made public.

Are the different approaches efficient?

It is clear that networks have taken different approaches to augmentation and network capacity in recent years. There is a question of whether the levels of augmentation undertaken in states such as New South Wales and Queensland was justified by demand growth, given that Victoria also experienced rising levels of peak demand.

In a report for Grid Australia (sub. DR91, attachment 1), Evans and Peck examine similar measures of growth in physical assets for transmission networks. While they also find an accelerated growth in Queensland's transformer capacity, they assume

¹¹ The Commission had also undertaken comparisons of line capacity between distribution networks, using four different sets of conversion factors as set out in Parsons Brinckerhoff (2003, p. 12). The results did not provide consistent comparisons between networks, nor did they provide consistent levels of capacity. Hence, it was not possible to make a sufficiently reliable estimate of line utilisation (a comparison of line capacity and peak load).

that Queensland was ‘underbuilt’ at the beginning of the 2000s.¹² Mountain, who observes a similar growth trajectory,¹³ implicitly assumes Queensland’s transmission network was not ‘underbuilt’ at that time (EUAA 2012b). In any case, the concept of being underbuilt is not well defined, and hence it is difficult to judge from these comparisons whether the networks are now ‘adequately built’ or ‘overbuilt’.

There is also a question relating to where the appropriate benchmark would be for having adequate capacity relative to peak demand. What has been deemed reasonable by networks has differed by a wide margin across states. This suggests that it should be possible for some networks to reduce their rate of expansion and still have a level of capacity utilisation that would be within a reasonable range. This question is related closely to the issue of reliability standards (discussed in chapters 14 to 16).

A further question relates to whether it is efficient to continue to build networks to keep up with forecasts of peak demand. This relates to the drivers of peak demand and the potential efficiency gains of managing demand (discussed in chapters 9 to 12).

6.4 What does the RAB tell us?

Recent increases in the RAB have not uniformly reflected the increases in network capacity (figure 6.9). There are several possible reasons for this.

- Some states have a larger stock of depreciated assets than others. This means that their RAB does not reflect the full scale of their network, and also means that greater replacement capex is required.
- Increased undergrounding adds value to the RAB but not necessarily longer lines (and hence is not captured by calculations of network capacity).

¹² Evans and Peck cite as evidence the jurisdictional differences in installed transformer capacity per MW of load (MVA/ MW) in the years 2000 and 2011. They find that, per megawatt of load, Victoria had the most installed transformer capacity in 2000, with New South Wales having roughly 75 per cent of the Victorian capacity, and Queensland having 43 per cent. By 2011, Victoria’s capacity had decreased slightly, while Queensland’s capacity had become marginally greater than Victoria’s. Evans and Peck conclude directly from this comparison that Victoria was in ‘good shape’ in the year 2000, while Queensland was ‘under built’, while noting that this conclusion is ‘subject to the need for very rigorous analysis’ (Grid Australia, sub. DR91, attachment 1, p. 6). This conclusion is restated later in the report (p. 7, 9).

¹³ EUAA (2012b) measures the growth of financial measures such as the RAB and expenditure, while accounting for some physical variables such as demand. This differs from Grid Australia (sub. DR91), who use physical measures such as MVA.

-
- Some asset installations may be more difficult and expensive in particular regions.
 - In Victoria, some transmission network augmentations are ‘contestable’, meaning that AEMO issues a tender to build, own and operate those particular assets.¹⁴ As such, at a given point in time, there may be some network assets that do not form part of SP AusNet’s transmission RAB.
 - Some states have made better use of non-network options, such as load shedding control schemes or line uprating opportunities. This includes the real-time rating system in Victoria.

Not all of these factors would indicate inefficiency. With the analysis of more detailed data than is currently available, it would be possible to determine the contribution of each of these factors. It would also help determine whether firms have simply differed in the unit costs of assets and services. On this issue, the AER is currently collecting further data on relevant unit costs.

What does the RAB say about efficiency?

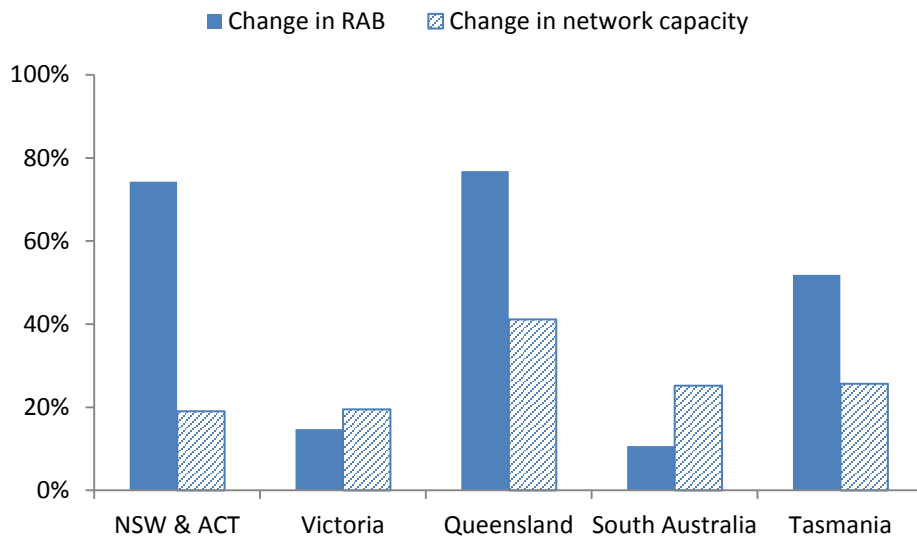
The size of a network’s RAB is highly relevant to the discussion of efficiency, given that networks are remunerated on the basis of their asset base. However, inferring efficiency on the basis of the size of the RAB is difficult for several reasons:

- the RAB itself is a culmination of various decisions made over time
- the size of the RAB will be related to many drivers that are unlikely to be influenced by managerial discretion, including the size of the serviced area; aspects of its topology; the number of customers; and levels of demand
- the RAB is also related to drivers that may or may not be influenced by managerial discretion, such as the levels of network capacity; the types of assets purchased; the prices paid for assets; and the timing of capital expenditures

¹⁴ In Victoria, separable transmission projects are subject to a process of competitive tendering. The business that wins the tender then builds that particular network augmentation project, and is responsible for its operation for a number of years in return for the agreed (tendered) amount (appendix F). The outcomes of these tenders are commercial in confidence and are not communicated to the AER, and the expenditure is therefore not incorporated in the regulated asset base at the start of the next regulatory period. In all likelihood, these projects may account for a small proportion of SP AusNet’s total RAB. Nonetheless, SP AusNet’s RAB is not directly comparable to that of other transmission network businesses.

Figure 6.9 Percentage changes in RAB and network capacity for distribution networks^a

Difference between previous and current regulatory periods



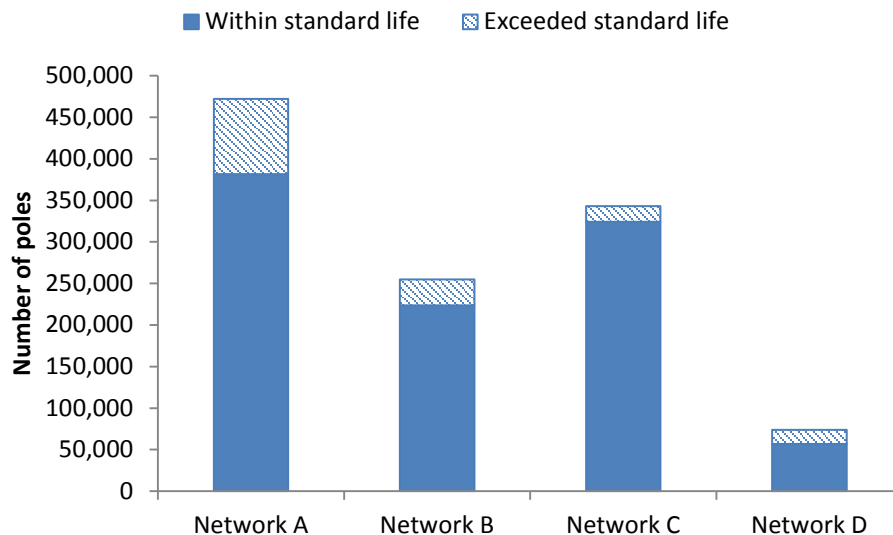
^a The change in RAB is measured as the difference between the opening RAB at the beginning of the previous regulatory period and the opening RAB at the beginning of the current regulatory period. Network capacity is calculated as the length of network line (km) multiplied by transformer capacity (MVA).

Data source: AER determinations.

- the RAB is depreciated over time, and this can pose a considerable measurement risk where:
 - accounting decisions regarding rates of depreciation are *not* uniform across firms (as is the case among electricity networks)
 - the depreciation of an asset in accounting terms does not reflect its physical or practical depreciation. Many networks have assets still in use which have outlived their standard lives (figure 6.10). The RAB would therefore not account for the ongoing value of these assets, nor their replacement costs. For one distribution company analysed by the Commission, the *replacement value* of assets which had reached or surpassed their standard lives amounted to 20 per cent of their reported asset base (AER unpublished data).

Figure 6.10 **Number of poles that have depreciated to zero^a**

Approximate number of poles in use that have exceeded their accounting life



^a This comparison is indicative only. It assumes that the reported standard life is commensurate with accounting life for depreciation purposes. The data for networks A to D were taken from the latest available point in time for each network, and refer to various years between 2008 and 2010.

Data source: AER unpublished data.

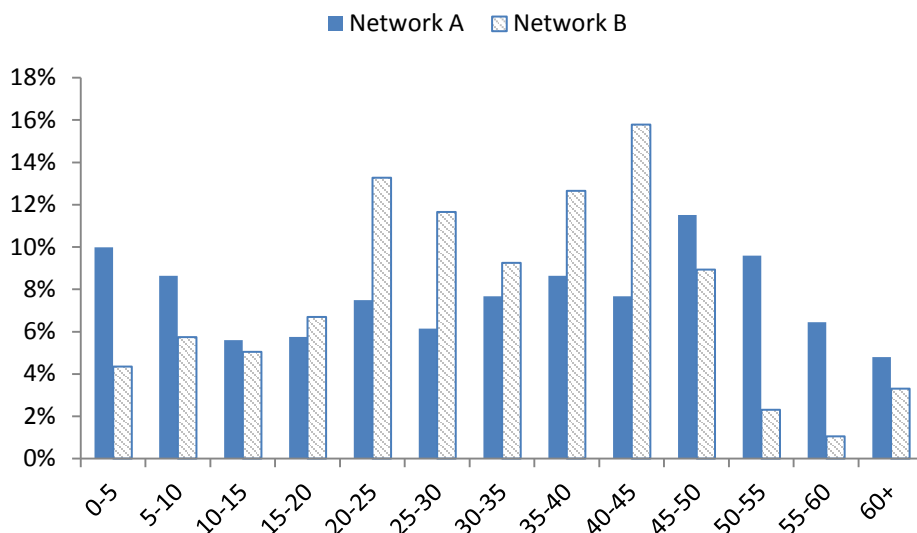
Replacement capex and asset vintage

An in-depth understanding of asset vintage would not only aid in assessing levels of the RAB, but also in the analysis of replacement capex — though this has been difficult using publicly available data. The AER has only used its replacement-capex (Repex) model in determinations for Victoria and Tasmania, and is only beginning to collect data on asset vintage from other networks. Even with data on asset vintage, it is difficult to forecast replacement capex without reliable estimates of standard asset life. Over time, the AER's Repex model will itself improve the accuracy of estimates of asset life.

Asset age distributions differ between networks (figure 6.11). Mountain (2011) noted that privately owned networks tended to have a higher weighted asset age than state-owned networks, and that they should be expected *a priori* to spend more on replacement capex. However, in any given year, the level of replacement capital expenditure is a small fraction of the replacement value of assets that have reached the end of their asset life. Again, this relates to the difference between standard asset lives and the useful life of an asset.

Figure 6.11 Network assets follow different age distributions

Age distribution of poles



Data source: AER unpublished data. The data for network A and B were taken from the latest available point in time for each network, and refer to 2008 and 2009 respectively.

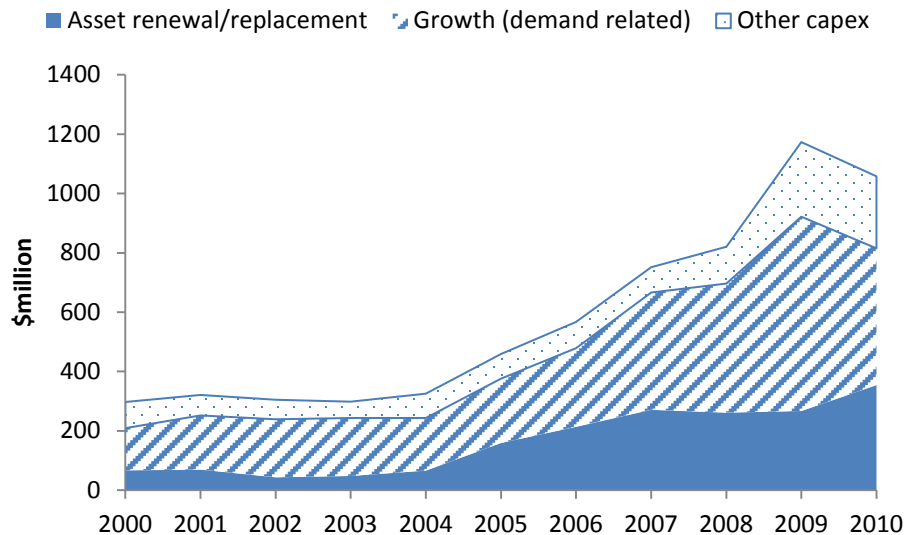
Moreover, standard asset lives may be more useful as an indicator of asset replacement for some categories of assets than for others. For example, a network may only have a small number of transformers of a particular category, which makes it more difficult to forecast failure rates. The Commission has also been told by stakeholders that given the high unit costs of transformers, they would be more likely to be replaced based on condition rather than age. An example of how decisions can be made regarding condition-based replacement was given by Ausgrid with respect to the failure of a particular circuit breaker during the previous regulatory period:

This equipment had been identified for replacement in EnergyAustralia's regulatory submission but rejected by the regulator. Following identification of the failure mechanism, similar defects were found in the remaining population requiring the immediate replacement of all remaining equipment of this type. (Parsons and Brinckerhoff 2012, p. 14)

The timing of replacement capex remains a significant factor in determining the efficiency of network expenditure, and for many networks it has followed a similar trajectory as growth-related capex. For one state-owned distribution network, annual replacement capex was 300 per cent higher in 2010 than in 2000 (figure 6.12). At the same time, demand related capex had grown by a similar scale.

Figure 6.12 Breakdown of capex for one state-owned distribution network

Annual capital expenditure associated with Demand Growth, Asset Replacement, and Other Areas



Data source: AER unpublished data.

Replacement capex is of even greater significance for transmission networks. For example, the five-year expenditure forecasts across the NEM at the transmission level showed that replacement capex comprised around 54 per cent of expenditure, with the remainder comprised almost equally of network augmentation and maintenance expenditure (Grid Australia, sub. DR101, p. 10).

Whereas growth capex may be examined in light of publicly available forecasts of peak demand, the drivers for replacement capex are more obscured. The coincident increases in both replacement capex and growth capex in some networks have led to significant additional revenue for networks, although there is little independent verification of whether any of the replacement capex could have been deferred.

The overall differences in replacement capex between networks may not be visible for some years. Even if some state-owned networks have replaced assets prematurely, their replacement capex may eventually slow down. Networks that have deferred asset replacement will eventually have to increase their rate of replacement capex. At the very least, benchmarking will be an important retrospective tool for determining whether previous expenditures were premature or excessive.

6.5 Expenditure, allowances and timing

As in the case of replacement capex, the timing of capital expenditure more generally has important implications for efficiency. It has been suggested that recent high levels of capex have been partly influenced by time-sensitive incentives. That is, the transitional Rules governing capex overspends allowed for the full rollover of capex into the RAB for the subsequent period (NSW Government 2010, AER 2011a). To the extent that the timing of capital expenditures was brought forward unnecessarily, this would be associated with inefficient investment.

Spending above capex allowances

There is still incomplete information on the overspending¹⁵ of ex ante capex allowances for the current regulatory period (where the AER has regulated distribution networks). Nevertheless, there are data for prior regulatory periods, (which were overseen by State regulators), although the availability of data differs somewhat between states.¹⁶

There is some evidence that above-allowance expenditures have differed between state-owned and private networks. For example, capital and operational expenditure levels for Victorian distribution networks had generally been below both regulatory allowances and network forecasts between 1996 and 2006 (AER 2010b). In comparison, all of the New South Wales distribution networks had exceeded capex allowances between 1999 and 2004 (IPART 2004).

During the regulatory period immediately prior to the AER's commencement as the network regulator, capital expenditure exceeded allowances by a significant amount, particularly (but not exclusively) for state-owned distribution networks (figure 6.13). As the New South Wales Government (2010) noted:

The [NSW distribution and transmission network] businesses overspent by about \$1.4 billion in the previous price period with more than half the overspend occurring in the final year (2008/09) ... All businesses have spent less than their capital expenditure allowance in 2009/10. (pp. 33-4)

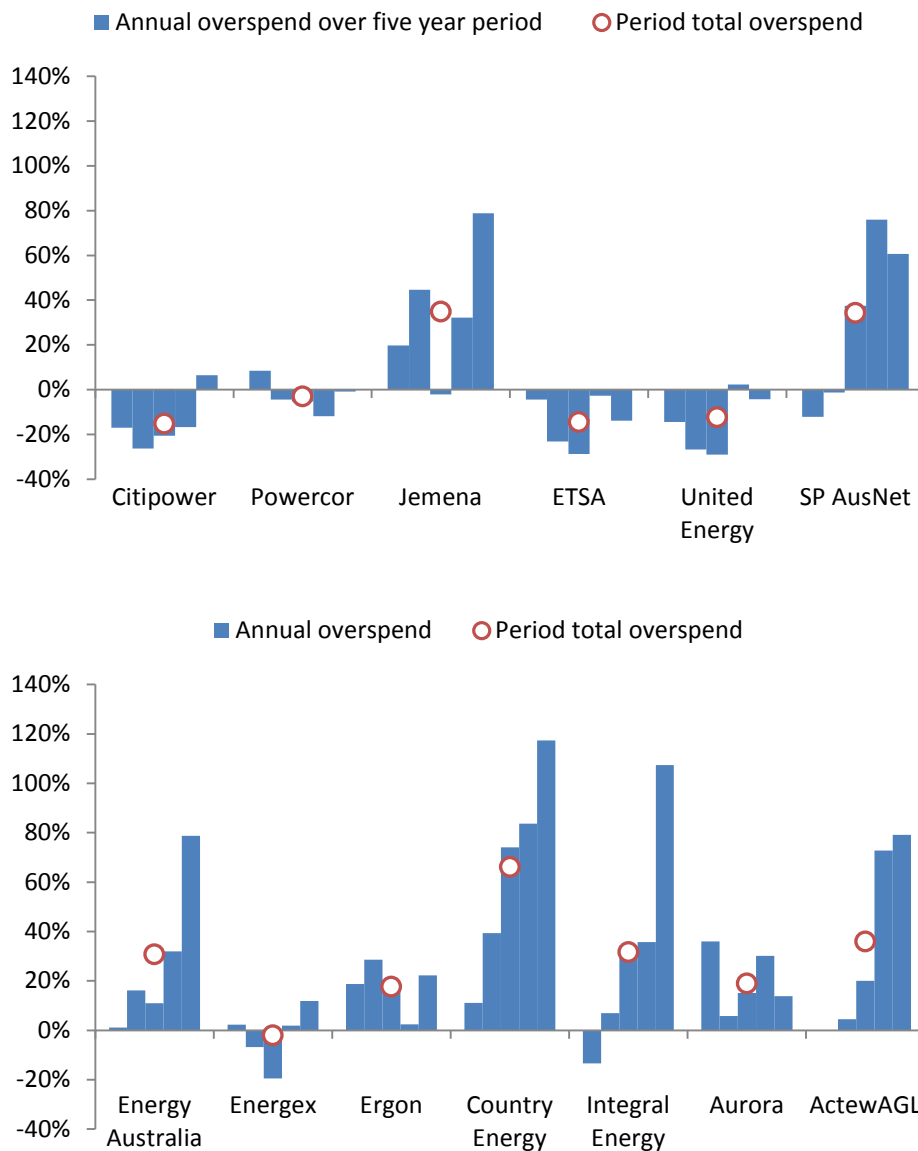
¹⁵ In this section, the term 'overspending' is not intended to imply that the expenditure is prima facie inefficient. The term is used in a similar vein by Parsons Brinkerhoff (2012).

¹⁶ There have also been some discrepancies between the data published on capex overspends. For example, the capex overspends reported in figures may not be directly compatible between AER (2010b), Jemena (2009), AER (2012b) or Parsons Brinckerhoff (2012). Further data on actual expenditure held by the AER were considered confidential. As such, the Commission has made indicative comparisons based on the available data.

The evidence suggests that many businesses had overspent, but particularly so as the regulatory period progressed.

Figure 6.13 Annual distribution capital expenditure above allowances in the period prior to AER regulation^a

Actual distribution capex as a proportion of capex allowance



^a This bar chart shows the pattern of actual expenditure over time relative to regulatory allowances in the regulatory period immediately prior to the AER's commencement as the distribution network regulator. For each firm, the bar chart includes observations from the five years immediately prior to the AER's commencement as the distribution network regulator. The chart does not distinguish between cost-pass through events and other overspends.

Data source: Parsons Brinckerhoff (2009a, 2009b, 2010, 2012); Jemena (2009); Wilson Cook (2008); AER (2010b); CitiPower et al., sub. DR90.

There are several factors that may contribute to the overspending of capex allowances, some of which network business could not control. For example, new licence conditions relating to planning criteria and reliability were introduced in 2005 for New South Wales networks (discussed in chapter 16) — this was associated with a cost pass-through provision that accounted for around half of the overspend by New South Wales distributors (Wilson Cook 2008, Parsons Brinckerhoff 2012). As such, much of the overspend was due to decisions by the New South Wales Government rather than the networks.

To some degree, however, overspends appear to be subject to operational decisions by networks, as described by Ausgrid for example:

A major contributor of the overspend in the [2004-09] period was the decision by the business that it was necessary to address asset replacement needs over the period, despite insufficient funding being provided for this purpose by the regulatory determinations. (Ausgrid as quoted by Parsons and Brinckerhoff 2012, p. 14)

To the extent that allowance overspends result directly from network decisions, the overspends should be considered in light of the prevailing incentive framework.

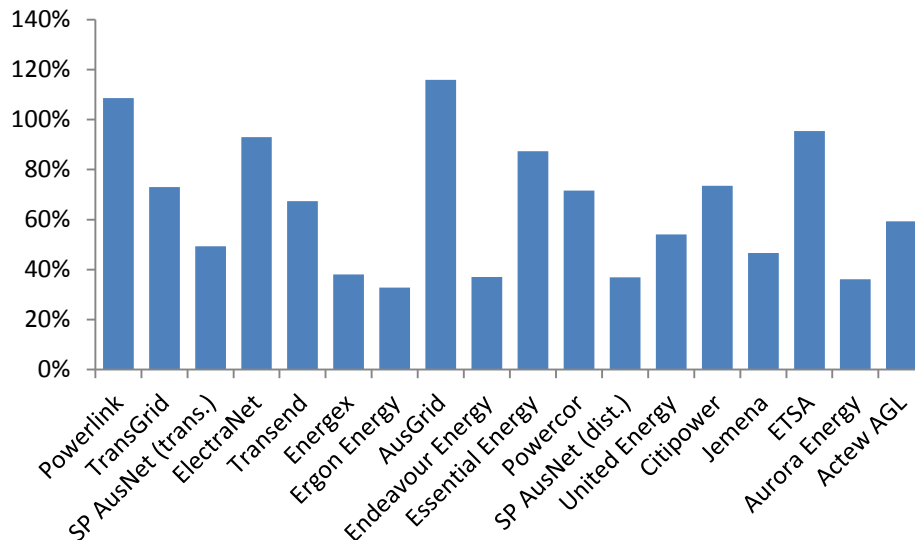
The AER (2011a) estimates that the above-allowance expenditure in New South Wales and Queensland accounted for roughly 25 per cent of the subsequent price increases. Furthermore, high levels of expenditure also influenced subsequent determinations by the AER. For example, where evidence is lacking in a determination, an emphasis is sometimes placed on historical trends:

There is little information presented that supports the scale of the increase in the current period. ... That said, given that the next period appears to be broadly in line with the historical trend (2006-2008), the forecast for the next period is not unreasonable. (Nuttall 2010a p. 196)

As such, although it is often unclear whether the level of incurred expenditure of the previous period was justified, they are often treated as such. None of the network businesses experienced a decrease in their capex allowance in the most recent determinations compared to the actual expenditures of the previous period (figure 6.14). These findings appear to be consistent with inefficient overspending induced by the flaws in incentive regulations discussed in chapter 5.

Figure 6.14 Increase in network forecasts relative to previous period actual capex

Percentage difference between network forecasts of capex and the actual capex in the previous period



^a Transmission network augmentation in Victoria is comprised of both separable and non-separable projects, the former of which is subject to competitive tender for construction, operation and ownership and may not be included in SP AusNet's regulatory asset base. The AER did not include any note on the treatment of such projects in the publication of this data. As such, the growth in capex shown in this figure for SP AusNet (transmission) may not be directly comparable with other transmission networks, given that some capex projects may not be included.

Data source: AER (2011a).

6.6 Public and private ownership

Chapter 5 points out that state-owned businesses often face weaker incentives than private businesses to control costs. The empirical evidence discussed in this chapter generally suggests that there are differences in the way private and state-owned businesses operate. For example:

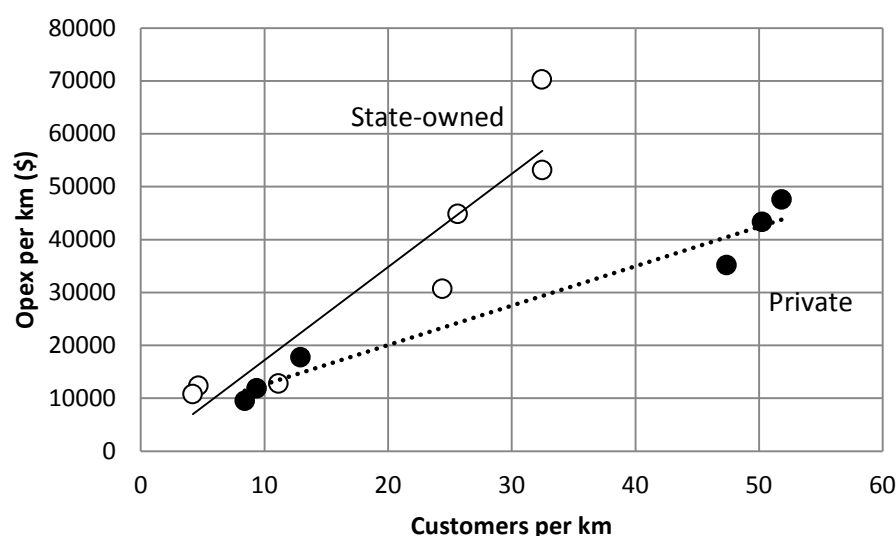
- state-owned businesses in New South Wales and Queensland have increased their network capacity to levels well above those of private firms in Victoria for a given level of peak demand
- state-owned businesses have had relatively large increases in the RAB for a given increase in network capacity.

While these points are not proof of inefficiency, it is unclear whether the scale and timing of the expenditure has been entirely justified.

More specific analysis of expenditure further illustrates the divergence between private and state-owned firms, such as the relationship between expenditure per circuit kilometre and customer density (figure 6.15).¹⁷

Figure 6.15 Opex and customer density for state-owned and private firms

Opex per km by customer density for distribution networks



Data source: Data requested from the AER based on AER (2011b), p. 64.

The available evidence also suggests that operational practices differ between state-owned and private networks. For example, state-owned networks generally have a lower ratio of customers per employee after accounting for customer density (figure 6.16). During the previous regulatory period, staff numbers for the New South Wales networks rose by 42 per cent (NSW Government 2010). Some increases in the labour force of the New South Wales and Queensland networks reflected increases in capital works over recent years.

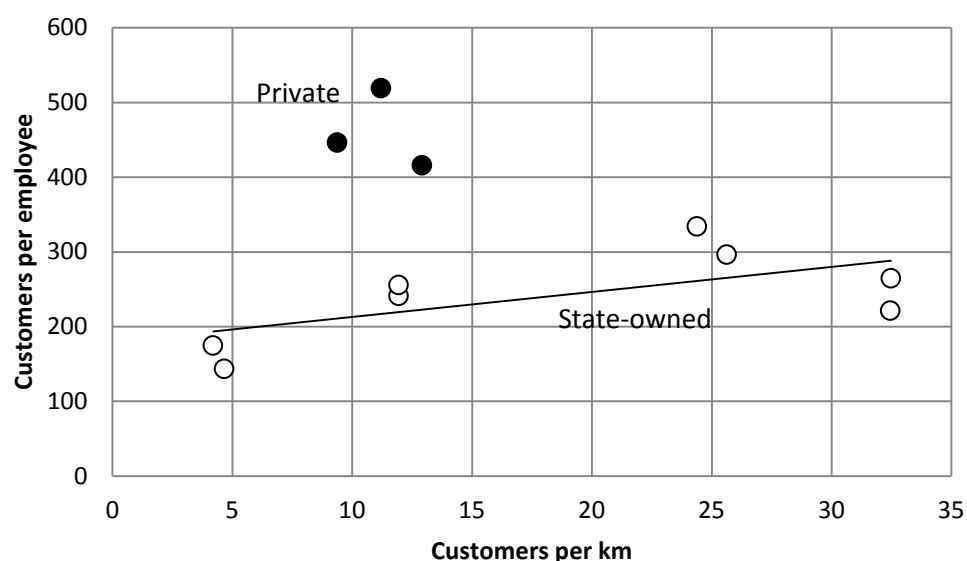
The share of in-house labour to contractors also seems to differ between state-owned and private firms, with the ratio being much lower for some private firms (figure 6.17). That is, expenditure on labour, materials and contractors (LMC) is allocated to both capex and opex. None of the state-owned networks spent less than 13 per cent of LMC capex on in-house labour, which was the average share spent by private firms. State-owned networks also spent an average of 47 per cent of LMC opex on in-house labour, compared to 32 per cent for private networks. This

¹⁷ Similar trends are observed for capex.

suggests that some operational and labour practices may differ between state-owned networks and profit-motivated private networks.¹⁸

These high-level comparisons do not indicate the causes of operational differences between state-owned and private networks. In regard to labour conditions in particular, there are different opinions on what the underlying differences may be. On the one hand, the Electrical Trade Union stated that wages and conditions were ‘virtually identical’ between states (ETU 2012). On the other hand, the NSW Auditor General (2012) noted that levels of overtime payment in Ausgrid were high and required close monitoring, while the independent panel examining electricity networks in Queensland (IRPNC 2012) also expressed concern about high overtime payments. Data on wages (chapter 2) also suggest a margin between state-owned and private businesses. The New South Wales Government also suggested that overtime payments were ‘excessive’ and that several labour practices were ‘inefficient’ (NSW Government 2012b p. 3). These issues are discussed further in chapter 7.

Figure 6.16 **Customers per employee^a**



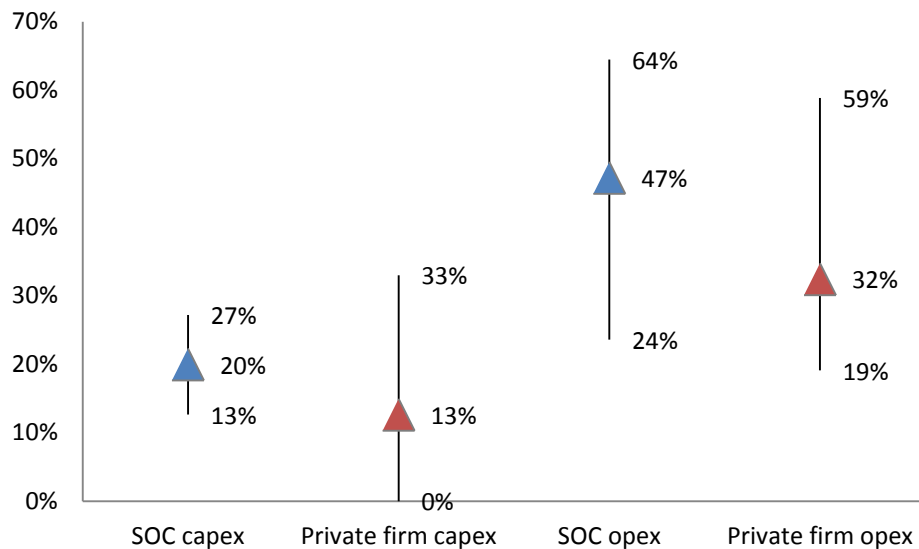
^a For firms where data is available. Unlike data collected by regulators, figures included in annual reports are often representative of an entire company rather than for the distribution business alone.

Data source: Network annual reports.

¹⁸ It is unclear from these data whether private network businesses are strictly more cost efficient than state-owned networks, as the increased use of contractors may account for the decreased use of in-house labour among private businesses. What is clear is that the state-owned network businesses appear to differ from private businesses in terms of hiring and procuring.

Figure 6.17 Relative importance of in-house labour compared to materials and contractors^a

Range and averages for state-owned corporations and private firms



^a Expenditure on in-house labour as a proportion of the total expenditure on labour, materials and contractors. Highest and lowest firm results are presented, as well as group average.

Data source: AER unpublished data.

6.7 Conclusions

The empirical evidence based on the best available data shows that performance, as measured by a number of indicators, varies significantly between networks. This is unsurprising, as previous benchmarking studies have concluded that some networks perform more efficiently than others. More detailed data would be useful in quantifying the impacts of various drivers (improvements to data access are discussed in chapter 8).

The evidence suggests that both network expenditures and the WACC have had a significant effect on network revenues. To the extent that the WACC has been a driver, the efficiency of overall network revenue outcomes will depend partly on the processes involved with setting the WACC.

Network revenue outcomes are also heavily dependent on the investment decisions made by networks. For example, networks tend to differ significantly in their capacity utilisation, and in recent years, some networks have expanded their network capacity relative to peak demand while others have not. Capital expenditures have also differed by a wide margin, although this relates to the scale of both augmentation and asset replacement.

Judging whether the various levels of expenditure have been efficient would be strengthened by further information, such as the engineering justification of particular capital works, longer-term comparisons between firms and more authoritative benchmarking. However, from the high-level evidence analysed in this chapter, it appears that the levels of expenditure observed for some networks are not easily justified. Where firms have overspent ex ante regulatory allowances (and in some cases, may have profited from it), there is uncertainty about whether that expenditure has been reasonable. Furthermore, the timing of capex overspending is consistent with suggestions that some inefficiency has been induced by flaws in incentive regulations. Still, the Commission has not presented a single definitive quantification of the efficiency gaps between networks.

Several issues raised in this chapter warrant further consideration.

- The significant impact of the WACC on network revenues warrants particular attention, not only with regard to the methods used in its calculation (chapter 5), but also in the role of the Australian Competition Tribunal in determining it during merits reviews (chapters 5 and 21). At least in relation to the former, the recent Rule changes (AEMC 2012r) provide the AER with the discretion to examine these issues without undue constraints from the Rules.
- Reliability standards have had a significant effect on expenditure levels in those States using deterministic standards. Unless modified, these standards will continue to influence the way in which networks respond to increases in peak and average demand. As such, it is necessary to consider whether these standards are set efficiently, and whether the resulting costs of augmentation are commensurate with value of reliability for consumers (chapters 14 to 16).
- Network decisions on expenditure are also subject to the various incentives inherent in the regulatory framework (discussed in chapter 5). These incentives are particularly relevant to network forecasts of demand and the timing of expenditure. There is potential to improve the regulatory incentive framework, particularly through the use of benchmarking (chapters 5 and 8). Beyond this, networks may also be able to play a larger role in influencing the actual rates of peak demand — to this extent, demand side policies should also be investigated (chapters 9 to 12).
- While firms have taken different approaches to network capacity, the networks that have undertaken the most rapid expansion have been under state ownership. The potential issues with public ownership are discussed further in chapter 7.

7 Ownership

Key points

- While governments have a legitimate role in owning and operating many services in Australia, the rationale for government-ownership of electricity network businesses no longer holds.
- This reflects the development of sophisticated incentive regulations that function best when the regulated businesses have strong profit motives.
 - Government ownership produces perverse interactions with the existing Rules, which are likely to lead to overinvestment and ineffective cost controls.
- State governments often impose multiple constraints on state-owned corporations that are incompatible with their central purpose of maximising returns to their shareholders. These constraints include:
 - social and environmental obligations
 - requirements to procure locally
 - requirements to reduce returns to restrain prices
 - requirements to limit capital spending when governments are concerned about debt levels
 - employee benefits and job security for employees are out of kilter with those associated with most businesses
 - poor governance.
- The evidence appears to suggest that state-owned enterprises are less efficient than their private sector peers.
- The best remedy is privatisation. However, in the event that governments do not privatise their state-owned network businesses, the original intent that they act as truly independent corporate entities should be reinstated, with their governance and statutes changed to give effect to this clearer role.
- The process of privatisation requires clear communication and explanation to the community and other stakeholders, oversight, accountability, clear milestones and timetables, and early regulatory reform. But realistically it should be capable of being achieved over a two year period.

Governments have a justifiably central role in the direct supply of many services in Australia. This chapter explains why this no longer holds for the provision of electricity network services. Yet, Australian governments currently own about

75 per cent of electricity network assets in the National Electricity Market (NEM) and a greater share for Australia as a whole (chapter 2).

Section 7.1 sets out a simple framework for making coherent choices about ownership, and explains why the circumstances that would justify government ownership are no longer present for electricity networks.

The regulatory incentive arrangements for the NEM were designed to encourage cost minimisation by profit-maximising businesses. The implicit assumption was that corporatised state-owned businesses resembled private entities and that they would behave the same way. That does not appear to have occurred. Drawing on chapter 5, section 7.2 explains why incentive regulation is more compatible with privately-owned enterprises.

Notwithstanding the removal of state-owned electricity network businesses from direct government control, as shareholders, governments still have mixed incentives. They have imposed a range of non-commercial objectives on their businesses. These increase the costs of those businesses and, in some cases, send mixed messages to managers about their priorities. Section 7.3 considers such mixed objectives, as well as examining some of the government constraints and poor governance arrangements in state-owned corporations (SOCs) antithetical to desirable commercial practices, and to the delivery of the National Electricity Objective — efficient operation of, and investment by network businesses for the long-term benefit of consumers.

An important question is whether the deficiencies in governance and weaker incentives for cost minimisation are revealed in lower productivity rates or in other performance measures. Section 7.4 examines this question, drawing on the findings of chapter 6, some recent judgments by other reviews, and the findings of the international literature on the effects of government ownership.

Some parties argue that privatisation involves many risks — an issue considered in section 7.5.

Section 7.6 discusses the Commission's overall view about privatisation and other governance reforms, while section 7.7 examines the appropriate transition to the sale of state-owned network assets.

7.1 A framework for considering ownership

Australian governments 'own' many organisations responsible for producing goods and services. They play a dominant role in parts of the economy where people do

not pay directly for the services — defence, policing, courts, customs, foreign embassies, policy formation, the tax office, government schools and public hospitals. On the other hand, governments have largely relinquished their role in many other activities funded by customer charges, such as banking, telecommunications, airlines, airports, publishing, manufacturing (and in the more distant past, fish and butcher's shops, building workshops and brickworks — Goot 2010).

Nevertheless, they still own and operate some activities where users pay at least some of the costs of the service, such as public transport and housing. And — relevant to this inquiry — governments are still often owners of utilities, such as water and electricity networks.

In this case, the main challenge is to determine where it is appropriate for governments to act as owners of anything, and then to assess whether these circumstances apply to electricity networks. The strongest (sound) rationale for government ownership is where governments find it difficult to write good contracts with private businesses or to regulate them effectively and where those contractual problems can be effectively overcome through government ownership.¹ This may occur in several circumstances:

- (i) Businesses may sometimes produce social goods or bads, as well as the goods they sell on markets. From the community's perspective, the goal should be to maximise the net value of the private and social goods (King and Pitchford 1998). For example, a national park earns market income from entry fees, but they also have major non-economic roles, such as preserving species. In theory, a government could contract these non-market activities to private businesses, or regulate the businesses so that they are obliged to provide them. However, it may be hard to verify whether the business has fulfilled its side of the bargain given the difficulties of measuring the outputs. In that case, a private business has an incentive to make higher profits by producing less than the desirable amount of the non-market output. A government-owned business does not have any such incentive, since it does not keep any surplus as a private return.
- (ii) Government ownership may be preferred to procurement from private parties if it is difficult to write a contract that realises government's preferences and

¹ Some may propose broader arguments for government ownership — such as social norms about what the community should own collectively and what should be held in private hands. However, beyond assertion, it would be difficult to verify when those circumstances arise. Regardless, for the present purposes, it would be hard to argue that government ownership of wires and poles meets an Australian social norm.

priorities. This is similar to the considerations of private businesses when deciding how much to outsource an activity or undertake in in-house.

- (iii) Quality and performance may be higher where an employee has a motivation beyond their pay and conditions to achieve a goal common with the objective of the organisation. For example, this may be a soldier fighting for his or her country (Besley and Ghatak 2005).
- (iv) There may be intrinsic conflicts of interest in private ownership. One United States economist posed the question of whether a private business could run the US State Department. The answer was (obviously) no, but as Dixit (2002) explores in some detail, the fundamental reason centres on the difficulties in creating appropriate incentives, monitoring performance, ensuring probity and motivating employees.
- (v) Government ownership might be an alternative to regulated private enterprises — especially in the provision of essential services — if it is difficult to construct effective regulations. In that instance, government ownership might result in outcomes closer to the competitive ideal (Goot 2010 and Yarrow 2012a, p. 3).²

In the case of electricity networks, it is less clear that (i) to (iv) has ever applied as a legitimate basis for government ownership of electricity networks. However, a good case could be made that (v) was relevant prior to the development of sophisticated competition regulation. There is also a view that government ownership was important to achieve social goals that were fluid and implicit.

However, circumstances have changed with several major developments.

- Australia has an elaborate system of regulatory arrangements for controlling prices and ensuring quality of services in network businesses, underpinned by independent regulators. Ownership can no longer be seen as a substitute for regulation.
- All the state-owned businesses have now been corporatised, so that they are at much greater arm's length from government than they were in the past (though, as discussed later, not as distant as desirable). In that case, to the extent that they ever existed, rationales (i) to (iv) can no longer apply, since the contractual difficulties between government and a corporatised entity are similar to those between a government and a private entity.

² While in some instances, government ownership has served as an alternative to a regulated private monopoly, in many others, entry by state-owned businesses was apparently intended to ensure adequate investment and to intensify competition in what remained largely private markets. This was an important driver of government ownership in the first half of the 20th century (Goot 2010).

Accordingly, the rationale for government ownership of electricity networks has now disappeared. That might not matter much if corporatisation of government owned businesses had created sufficient incentives for cost-minimisation. If corporatised entities behaved like private businesses, then even if their ownership status were no longer justified, the transactions costs of privatisation might mean that they should remain publicly-owned. However, as the remainder of this chapter shows, the premise that they do or can behave like private businesses is doubtful.

7.2 Incentive regulation and state-owned corporations

Incentive-regulations are built on a simple premise. Where the regulatory rewards to the business are (at least significantly) separated from their actual costs, profit-motivated businesses face strong incentives to cost minimise in any given period. Over time, the regulator can rein in the rents this creates by raising the performance benchmark.

However, as discussed in chapter 5, the investment incentives for state-owned corporations are more complex than for privately owned businesses, and can work against the cost minimising incentives in the regulatory regime. Without repeating the analysis in that chapter, this reflects several factors.

- Finance appears to be easier to access for SOC's than private businesses (certainly over recent times). The consequence is that, in comparison with private businesses, the weighted average cost of capital (WACC) actually facing SOC's is more likely to be lower than the regulated WACC. The larger the gap between the 'true' and the regulated WACC, the weaker is the penalty from overspending. Indeed, a large enough gap can make it profitable to overspend. This effect is accentuated by the fact that state and territory governments are effectively able to receive a pre-tax rate of return on their SOC investments because they receive the company taxes that would otherwise have gone to the Australian Government. This could weaken the usual incentives of shareholders to constrain overinvestment. It would also mean that setting a higher reliability standard (with its associated requirements for additional investment) could produce positive financial returns.
- Financial market accountability is concentrated in just one party (the government). In contrast, private businesses must typically secure their equity or debt from multiple parties, all of which monitor the performance and potential risks of the business when deciding whether to provide finance. The consequences of poor management by a private network business— and the reputational effects that ensue — are likely to have enduring effects on the capacity of the business to obtain further capital (and on the cost of that capital).

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- Insolvency is effectively impossible.
 - Governments have non-commercial incentives that constrain their SOCs — an issue examined further in section 7.3.
 - Governance arrangements may not encourage tough-minded management (also considered further in section 7.3).

The Commission's diagnosis on the above is not new, with many others having identified the mismatch between incentive regulation and government-ownership of electricity network businesses.³ The most recent consideration of these issues concluded that the current regulatory regime is essentially incompatible with state-owned businesses:

The NER [National Electricity Rules] and NGR [National Gas Rules] are based upon an economic approach developed for the regulation of *privately owned* utilities. Whilst the approach can, and has, been applied to state owned entities international experience tends to indicate that it is more difficult to get to work effectively. Underlying issues include a relative lack of incentives to reduce costs in publicly owned monopolies, and intra-government conflicts relating to the supervision of publicly owned monopolies (most typically between that part of government responsible for performing shareholder functions and the regulatory authorities). (Yarrow et al. 2012a, p. 12)

More generally, Yarrow (2012) has emphasised that while the interactions of incentive regulations with private utilities are relatively predictable, this does not hold for state-owned network businesses. In commenting on the problems apparently besetting the National Electricity Rules, Yarrow drew some parallels to the experiences of the Island of Guernsey to provide a lucid illustration of the difficulties in this area (box 7.1).

Collectively, these factors suggest weaker incentives for cost controls in state-owned businesses, a position endorsed by some privately-owned businesses:

The Businesses believe that privately-owned businesses have stronger drivers to operate efficiently and to respond to the incentive arrangements provided in the current Rules than publicly-owned businesses given the nature of private shareholder requirements. This has been borne out by the experiences of privatisation in Victoria and South Australia. ... The Businesses support the privatisation of the publicly-owned DNSPs [Distribution Network Service Providers] in New South Wales, Queensland and Tasmania and believe that it presents significant opportunities to achieve efficiency

³ These include Sims (2012b); Biggar (2011b, pp. 14ff); the Energy Users Association of Australia (EUAA 2009, p. 1); Mountain and Littlechild (2010), Mountain (2011); the NSW Commission of Audit (2012, p. 204); and an IPART paper by Cox and Seery (2010, p. 22), Energy Australia (sub. DR82, p. 3) and the independent review panel examining the source of network cost pressures in Queensland (IRPNC 2012, p. 39)

savings, which will be beneficial to end customers through lower distribution prices. (ETSA Utilities et al., sub. 6, pp. 41-2).

Recent changes to the National Electricity Rules (AEMC 2012r) — broadly in line with those recommended by the Productivity Commission in its draft report — partly address some of the above concerns. For example, the new Rules give the Australian Energy Regulator (AER) a capacity for ex post scrutiny and potential rejection of capex overspending by network businesses. While not its explicit purpose, this is likely to apply mainly to SOCs (where overspending has been more common — chapter 6). The creation of an Efficiency Benefit Sharing Scheme and adjustments to incentives schemes affecting demand management should also address some of the present biases against opex and non-network solutions (chapters 5 and 12).

Box 7.1 Lessons from the Island of Guernsey

In a detailed micro study of competition regulation on the Island of Guernsey, two leading competition economists found that standard incentive regulation worked reasonably well for the privately-owned telco sector, but poorly for the publicly-owned postal and electricity sector. In the latter instance, the problems centred on:

- a relatively inactive shareholder
- the capacity for the business to retain earnings for discretionary investment at a time of its choosing
- a flawed appeal mechanism
- perhaps most oddly, the fact that there were implicitly two incompatible regulatory systems sitting next to each other. On the one hand, there was an independent regulator charged with the usual responsibilities for setting efficient prices. On the other, the electricity business had, in effect, its own regulatory charter. It was obliged to balance its commercial objectives against the effect on the community of any increase in its charges.

Guernsey is an interesting case study of the importance of the confusions that arise when a regulatory regime intended for profit-minded managers is applied to a business that has non-commercial objectives — which clearly has a resonance in the Australian context.⁴

Source: Yarrow and Decker (2010).

⁴ In Australia, the tensions are even more complex. The AER acts as the regulator of network prices, while state-based regulators still regulate retail prices (though this is hopefully due to change). State-based regulators may bring (government-mandated) non-commercial considerations to their determinations of retail prices (for example, QCA 2012), while the AER is purely an economic regulator.

Moreover, if adopted, the Commission's recommended reliability framework will reduce the tendency for network businesses in some states to build to excessive reliability levels, while independent scrutiny of large projects outside the incentive regulation regime should constrain overspending for those projects (chapters 14 to 17).

However, as noted in chapter 5, other measures that might target some of the unbalanced incentives facing state-owned corporations, such as applying a lower regulated WACC for state-owned rather than private businesses, are not practically feasible or desirable. It is not sensible to craft new Rules whose purpose is to address the distortions created by government ownership of some utilities.

7.3 Non-commercial imperatives and interference

As indicated above, in contrast to privately owned businesses, state-owned businesses are exposed to many government requirements, including non-commercial goals, ministerial directions, and obligations for local procurement and greater employment benefits. Arrangements vary by jurisdiction.

Multiple and conflicting objectives affect some businesses

Several jurisdictions explicitly include multiple objectives in the Acts governing the conduct of their SOCs. For instance, in New South Wales, s. 8 of the *State Owned Corporations Act 1989* (NSW),⁵ requires state-owned corporations to give equal weight to commercial success, social responsibility, ecological sustainability, and a sense of responsibility towards regional development and decentralisation. Some participants in this inquiry saw this as appropriate. For example, the Australian Services Union (ASU) noted:

... a state-owned corporation has got responsibilities to balance out environmental concerns, regional employment and some other government operations, as well as the cost of charges. It's also under a bit of political pressure to make sure there are jobs created in those towns, apprenticeships and employment numbers ... (trans, p. 325)

The legislation for ACT-owned corporations appears to be modelled on the New South Wales Act, with requirements for management to give equal weight to a range of commercial and non-commercial obligations.⁶

⁵ These multiple objectives are repeated in the *Energy Services Corporation Act 1995* (NSW).

⁶ S. 7 of the *Territory-owned Corporations Act 1990* (ACT).

The statutes for Queensland's SOC's appear to be less in conflict with commercial behaviour. Commercial success is the prime goal, and as a principle, businesses must not have conflicting goals.⁷ Any community service obligations (CSOs) of the business must be clearly identified in the business's statement of corporate intent and separately costed (with the business to be 'appropriately compensated for its community service obligations and any funding will be made apparent'). One of the advantages of explicit budget-funded CSOs is that they increase shareholder pressures for business performance. The Queensland Commission of Audit (2012, p. 165) noted that the CSO for Ergon Energy (the regional distribution business in Queensland):

... represents a significant funding risk to the State which highlights the need for appropriate incentives for Ergon to contain costs and manage its business appropriately in order to limit the State's financial exposure.

The virtues of transparency aside, the Queensland Commission of Audit (2012, p. 159) noted the Queensland Government still has the potential to issue non-commercial directives (discussed further below). It also found 23 other policies and guidelines for SOC's that were outside the Government Owned Corporations Act and the Australia-wide Corporations Act, indicating the challenges for management in running their business on a purely commercial basis.

In Tasmania's case, SOC's must, on the one hand, operate in accordance with sound commercial practices and as efficiently as possible, yet also 'have regard' to the economic and social objectives of the State.⁸ The treasurer has the power to specify the economic and social objectives of the state relevant to any SOC (but must do so transparently by gazette).

There is some evidence of tensions between these commercial and non-commercial objectives. The final report of the Independent Review of the Tasmanian Electricity Supply Industry (Electricity Supply Industry Expert Panel 2012), noted:

Stakeholders from the SOEBs [state-owned electricity businesses] indicated that they have difficulties in resolving the inherent tension between their obligations under legislative and other instruments to act commercially on the one hand, and the expectations that the Shareholders may or may not have explicitly stated with regard to delivering broader policy objectives (for example reducing the impact on cost of living for customers or the retention of members of the local Tasmanian workforce as employees of the businesses). (p. 47)

Interestingly, that report also observed:

⁷ S. 16 (a) Principle 1 of the *Government Owned Corporations Act 1993* (Qld).

⁸ s. 7(1)(i) of the *Government Businesses Enterprises Act 1995* (Tas).

The CSO [Community Service Obligation] process is a key component in minimising the potential disconnect between directors' duties and the legislative framework on the one hand and the delivery of broader policy objectives on the other. (2012, p. 60)

But that process often fails:

The Panel has observed other examples where the CSO framework has not been deployed where it would have been appropriate to do so. For instance, in 2009 the Government wrote to Aurora Energy to express a desire for tariff increases charged under the Aurora Energy Pay as You Go (APAYG) billing system to be effectively 'capped' for concession cardholders at a rate below that at which Aurora Energy was intending to charge. (2012, p. 61)

Sims (2012b), chair of the ACCC, summarised the dilemma:

We still have key network businesses in Government hands in Tasmania, Queensland, New South Wales and Western Australia. Good regulatory policy is important, but regulation is not a substitute for good governance. The incentives of Government shareholders are unavoidably mixed and complicated by multiple and disparate objectives. (pp. 4-5)

If state-owned businesses are not privatised, the original intent of corporatisation should be re-instated, with the businesses purely oriented to commercial purposes. This does not mean that governments need relinquish any social or community goals that they best see delivered through electricity network businesses. These decisions are reasonably those of government. However, any non-commercial objectives of government should be separated from ownership, and independently financed.

If such objectives are maintained, they should be prioritised and the business given guidance on their application. Given the tendency for weak or changeable shareholder disciplines, it would be appropriate to specify expectations of equity and dividend returns that the boards and management of the state-owned enterprises were expected to achieve, commensurate with those considered acceptable by an independent investor for a comparable business.

Procurement policies

SOCs face several obligations to meet procurement guidelines set down by their governments.

The New South Wales Government's procurement policy — the Local Jobs First Plan — includes two mandatory components to address industry development for purchases made by New South Wales Government agencies, including SOC (NSW Government 2009). Consistent with the New South Wales Government's

international obligations, such as Free Trade Agreements, the beneficiaries are limited to small and medium enterprises (NSW Government 2009, p. 4). This suggests that the agreements are seen as risking violating the principles of free trade.

The plan includes various price preferences.

- The Country Industries Preference Scheme is applied to support approved manufacturing industries in country New South Wales by adding margins of 2.5 per cent or 5 per cent only to the prices of other New South Wales suppliers.
- The Australia and New Zealand (ANZ) Price Preference Margin provides for a 20 per cent price discount to be applied to that part of the tendered price related to the ANZ content of goods and services offered in a tender response.

It also requires tenderers to draw up industry participation plans. As part of this process, tenderers must estimate the various consequences of winning any contract tender over \$4 million. This includes consequences for existing and new employees engaged in delivering the contract and their location; the number of local suppliers that will win work as a result of the contract and their employment numbers; the number of apprentices and trainees supported by the contract; and the regional economic impact, skills enhancement and technology transfer that will result.

Queensland state-owned network businesses are subject to similar provisions as part of the government's *A Fair Go for Local Industry* policy (Queensland Government 2008, 2011). For example,

... as part of value for money due consideration in the tender evaluation is given not only to price but also to environmental sustainability, quality and delivery, whole-of-life costs and/or administrative and risk mitigation advantages *and the advancement of the priorities of Government arising from local sourcing* [italics added for emphasis]. (Queensland Government 2011, p. 5)

Less intrusive procurement policies appear to be in place in the ACT and Tasmania.

Such procurement arrangements increase input costs and create compliance burdens for state-owned network businesses. In this regard, it was notable that the Ausgrid board assessed their obligations under the Local Jobs First Plan as non-commercial, noting that:

The costs of complying with that policy have not been separately funded, although the direction was given to implement the plan by the Minister (Ausgrid 2011b, p. 10).

EnergyAustralia (the predecessor to Ausgrid) estimated that complying with the Plan would cost them \$6 million in 2011-12, rising to \$50 million per annum by 2015-16 (Industry and Investment 2010, p. 25). These costs will not be reflected in

electricity bills since they do not meet the AER's guidelines, but they will affect dividends to the New South Wales Government. They are indicative of the problematic links between state-owned corporations and government.

Employment policies

Employment policies of the state-owned utilities have several distinct features. First, they appear to pay higher wage rates than private utilities (chapter 2).⁹

Second, employment policies appear to involve more generous non-wage conditions. In its submission to the Senate Select Committee on Electricity Prices, the New South Wales Government observed:

It is important to note that inefficient work practices have been occurring across the energy industry and have been allowed to become part of the expected wage structure within network and generation businesses. Examples include:

- Excessive overtime payments because rostering arrangements do not take into account that electricity networks operate 24 hours a day, 7 days a week;
- Generous long service leave provisions providing additional leave for long-term employees;
- Employer contributions to superannuation well above standard level for some employees;
- Bonuses paid to permanent employees just to allow contractors to undertake capital projects;
- Planned night work is paid at double time with employees then stood down the next day effectively receiving triple time for the shift;
- Income supplements that can double or triple the base level income of regular employees. (NSW Government 2012b, p. 3)

Particular concerns have been raised about the use of overtime. The New South Wales Government's economic development agency, Industry and Investment (2010, p. 50), observed that overtime levels were projected to rise significantly (and

⁹ These data relate to electricity, gas and water utilities as a whole, but it would be surprising if it did not hold at the disaggregated level. Other evidence also suggests that overall labour returns are higher (such as the significant overtime levels apparent in the state-owned enterprises, as discussed later) and the higher apparent opex for given customer density for SOCs (chapter 6). The New South Wales economic development agency, Industry and Investment (2010, p. 29) noted that New South Wales network businesses' wages increased faster than the New South Wales average from 2004–05 to 2009–10. On the other hand, the Electrical Trade Union (ETU 2012) contested claims of differences between wages, saying that that wages and conditions were much the same between the states (despite the private ownership of networks in Victoria and South Australia). However, they did not provide evidence on this matter.

over 100 per cent in a single year for one business). It identified this as an area for possible cost containment.

The New South Wales Auditor-General (2012) found that over one million hours of overtime was paid by Ausgrid in 2011-12; the highest overtime amount paid to an individual was just over \$180 000, representing nearly twice the person's annual salary; and that in 2011-12, 865 employees were paid 50 per cent or more of their annual salary in overtime. He noted that:

Management attribute the high levels of overtime to the nature of Ausgrid's operations requiring some work to be completed outside of employees' scheduled operating hours. Risks from excessive overtime include work, health and safety issues and less than optimal staff resourcing. The level of overtime is high and needs close monitoring to ensure business needs are met efficiently. (NSW Auditor-General 2012, p. 26)

There have also been concerns about overtime levels in the Queensland network businesses. The independent review panel examining the source of network cost pressures in Queensland (IRPNC 2012, pp. 21ff), found that across the three network businesses, 647 employees earned in excess of 1.5 times their base pay and in many cases twice their base pay. The panel considered that this was highly undesirable and likely to weaken incentives for productivity.

A third feature of employment policies is that they provide greater protection for their workers from structural changes in their businesses. The Queensland Commission of Audit (2012, p. 159) noted that restructures of various government-owned corporations (such as ports and electricity generators) included amendments to enterprise bargaining agreements safeguarding employees from forced redundancies and forced relocations for a period of three years after the restructures. As a result, the Commission of Audit observed that the enterprises were unable to rationalise their workforces in response to changed asset portfolios. Instead, the businesses were required to incorporate excess staff across their respective organisations, with associated inefficiencies. While Queensland's network businesses have not been re-structured, these other instances reveal that the Queensland Government has placed significant weight on matters that would usually be left to routine industrial relation practices (or otherwise through generic employment assistance measures). In addition, the provision of such safeguards is likely to weaken the incentives for employee efficiency in any of the state-owned corporations.

In New South Wales, Ausgrid is required to provide a five-year employment guarantee to award staff or separate senior contract staff in accordance with their contracts, a requirement that came into play following the removal of the retail arm from Ausgrid (2011b, p. 7).

On a potentially more positive note, the Australian Services Union (ASU, sub. DR57, pp. 5-6) claimed that state-owned enterprises placed a greater emphasis on technical training than their private sector peers — as suggested by apprenticeship numbers. However, there are significant limitations in the ASU's data.

- The ASU categorises NT Power and Water, Aurora, ActewAGL and Alinta as private distribution businesses. In fact, the first two are government-owned, the third has split ownership and the fourth is not a distribution business (although Jemena had its origin through an earlier re-structuring of Alinta).
- The ASU under-enumerates apprenticeship numbers and recruitment in the private distribution businesses. It records SP AusNet as recruiting no apprentices in 2010-11, yet data from SP AusNet (sub. DR102) indicate that 34 new starters joined the existing 128 apprentice, trainees and graduates in that year.¹⁰ The ASU indicated that CitiPower and Powercor recruited about 19 apprentices, yet information from CitiPower and Powercor (2011, p. 20) suggested 37 new apprentices and trainees in 2011 and a stock of 111. Jemena and ETSA Utilities were not included in the ASU's data. The former took on 39 new apprentices and trainees in 2010 (2011 p. 19), while ETSA Utilities employed 163 apprentices at the end of 2011 (ETSA Utilities 2012c, p. 25) and recruited 30 new apprentices in 2012 (ETSA Utilities 2012d).

Nevertheless, despite these errors and omissions, the available data do suggest that state-owned corporations recruit more apprentices and trainees than the privately-owned network businesses. For example, Ausgrid alone recruited 153 new apprentices in 2010-11, taking apprentice training numbers to 590 at the end of June 2011 (ASU, sub. DR57, p. 5 and confirmed by data from Ausgrid 2011a, p. 13).

However, while training is critical for sustaining the capabilities of a network business, it is not clear that the private businesses are engaged in too little training. Training is not a good in its own right, but an input into performance. As noted below and in chapter 6, the actual performance of the private networks appears to be superior.

Sponsorships

While relatively small in scale, sponsorship behaviour provides a revealing window on some of the differences between state-owned and private network businesses.

¹⁰ Of the stock of people in this category, the majority were apprentices and trainees — some 112 in July 2011 (SP Ausnet 2011b).

There are instances where SOC's have provided community sponsorships and donations that appear to be of a magnitude at odds with the goals of most commercially-oriented businesses. It is particularly hard to characterise such sponsorships as building a brand name to attract customers, since customers have no choice but to deal with monopoly network businesses.

For example, in 2010-11, Ausgrid provided \$4.3 million in sponsorship (but including employee payroll contributions) to various community groups, including around \$500 000 to the Sydney Symphony Orchestra. The New South Wales Government recently required Ausgrid to terminate this and other sponsorships (Hartcher 2012). The level of sponsorship is relatively large and at odds with the sponsorships generally provided by most other network businesses (as shown below). Moreover, the directive from the relevant minister to cease the sponsorship reveals the capacity for the government to direct the management of ostensibly independent corporations.

The AER rejected Energex's proposed \$9.1 million of sponsorships over the 2010-11 to 2014-15 regulatory period, noting:

However, in general the AER considers that sponsorship activities do not represent expenditure required to comply with the opex objectives. The AER considers that sponsorships are generally designed to increase brand awareness or demonstrate community support. Such activities may provide a benefit to the community but do not relate to the provision of standard control services by regulated electricity DNSPs, nor do they relate to the opex objectives. The AER considers that Energex has not demonstrated how its \$9.1 million forecast sponsorship expenditure is required to achieve the opex objectives, nor has it outlined how it is relevant to the provision of standard control services. The AER is not satisfied that this forecast level of expenditure is efficient and prudent expenditure. (AER 2009c, p. 648)

In contrast, other SOC's had levels of sponsorship more commensurate with private network businesses (though still on average higher), recognising that it can be in the interests of a business to build its community standing. For example, sponsorship amounts for the various businesses in 2010—11 were around \$300 000 (Transgrid — SOC); \$600 000 (Endeavour Energy — SOC); \$1 100 000 (Ergon Energy — SOC); \$500 000 (Aurora Energy — SOC); \$170 000 (SP AusNet — private); \$200 000 (Jemena — private); and \$125 000 (CitiPower and Powercor, including employee donations — private). These sponsorships are not included in allowable revenues.¹¹

¹¹ Based on various annual reports and plans issued by the businesses (SP AusNet 2011a; CitiPower and Powercor 2011; Ausgrid 2011a; Jemena 2011; Endeavour Energy 2011a).

Political intervention

The concept of independent shareholders is that the running of the business should be left in the hands of the board and the management team. However, SOCs are routinely subject to directions — implicit or tacit — by governments. As the Energy Reform Implementation Group (ERIG 2007, p. 8) — appointed by the Council of Australian Governments to provide advice on energy sector reform — commented, ‘political factors’ appear to play a prominent role for government shareholders. In commenting on the apparently greater environmental performance of SOCs, the ASU cited the importance of political influence:

But the state government ones do do more I think because they’re required to, both in a sort of political sense, there’s pressure on the local backbenchers. (trans. p. 326)

Some recent examples of more explicit government directions include:

- a directive by the Queensland shareholding ministers that Energex not recover the 2011-12 increases in revenue arising from the Australian Competition Tribunal’s determination on 19 May 2011, or of the costs of the 2010-11 floods
- as noted above, directions by the New South Wales Government in relation to its procurement plan
- in 2009, the Tasmanian Government requested that Aurora Energy provide tariff relief for some customers (as discussed earlier).

These directives reduced the income flows of the businesses to their shareholders. No private shareholder would contemplate this unless there were compelling, well-articulated reasons why it would raise long-term shareholder value.

Moreover, as noted earlier, governments can affect the capital spending of the businesses by changing reliability standards, or (as has happened in the past) by constraining expenditure through a government austerity or debt reduction program. Recently, these businesses have spent more than their forecast expenditure, while in the more distant past, some state-owned network companies appear to have spent less than is desirable. Cycles of underspending followed by reliability problems and then periods of overspending are not consistent with efficiently providing network services in the long-term interests of consumers, and appear to reflect political, rather than economic considerations.

Governance structures

Quite aside from the various constraints posed by regulations and ministerial directions, the governance arrangements of state-owned network businesses are

sometimes flawed. In particular, not all state-owned network businesses are subject to the Corporations Act or merit-based board appointments.

The *Corporations Act 2001* (Cwlth) sets out the laws dealing with commercial business entities in Australia. It regulates such matters as the formation and operation of companies and appointment of company directors. However, not all state-owned businesses are subject to the Act (for example, Ausgrid).

Moreover, in New South Wales, the *Energy Services Corporations Act 1995* (NSW) provides that an ‘energy services corporation’ (which includes network businesses) is to have a board of directors that includes a Unions NSW nominee.¹² The voting shareholders appoint the Unions NSW nominee on the recommendation of a selection committee comprising representatives of the portfolio minister and Unions NSW. Regardless of whether, in fact, the person selected is of high calibre, this process conflicts with open merit-based appointments, which are central aspect of the good governance of commercial enterprises (an observation also made by IPART 2010, p. 79).

Furthermore, industrial relations matters, such as outsourcing policy, are a central concern for management and the presence of a compulsorily appointed union-based director creates a perceived, if not actual conflict of interest. (The Commission understands that the New South Wales Government intends to remove the union appointment provisions from the Energy Services Corporations Act.)

7.4 The productivity and performance of state-owned network businesses

While analysis of relative efficiency is difficult, the empirical evidence suggests that as a group, the aggregate productivity outcomes of the state-owned network businesses are poorer than their private peers. While the main evidence is reported in chapter 6, it is useful to consider some more qualitative indicators.

New South Wales

On the positive side, poor overall outcomes does not mean poor performance on all counts or for all businesses. For example, IPART (2010, p. 48) noted that TransGrid, the New South Wales state-owned transmission business, was in the ‘leader’ quadrant in the International Transmission Operations and Maintenance

¹² New South Wales is an exception, with Queensland and Tasmania requiring merit-based appointments.

Study (ITOMS), with low cost and high service performance. IPART was more cautious in its judgments on the performance of the distribution businesses in New South Wales, reaching the conclusion that on some limited benchmarks, the operating costs of the New South Wales distribution businesses appear ‘comparable’ with their peers.

On the other hand, IPART saw considerable room for the improvement of all state-owned corporations in New South Wales, including the network businesses. The main focus for policy reform was the removal of some of the constraints on their performance resulting from their ownership, and in particular a need for more effective shareholder monitoring (IPART 2010, p. 13). IPART sought feedback from the businesses themselves, and while it is not clear to what extent these concerns applied to electricity network businesses, some pointed out that:

- some inefficient work practices were deeply entrenched (IPART 2010, p. 67)
- there were government constraints and interventions on hiring and firing (including a ‘no forced redundancies’ policy), and on out-sourcing and in-sourcing, and the conditions and types of employment offered. (The apparent processes for outsourcing for Ausgrid appear to be laborious — box 7.2).

When combined with the evidence in chapter 6, it seems likely that significant changes to governance or privatisation would lift the performance of the New South Wales businesses. However, to achieve this, it is important not to enshrine the current arrangements through long-term commitments that constrain the ability of new owners to operate the businesses efficiently.

Tasmania

In Tasmania, the most recent review considered that the state-owned businesses had underperformed, citing consistent overspending (Electricity Supply Industry Expert Panel 2012, p. 203):

The apparent willingness of the regulated businesses to regularly overspend regulatory allowances and the preparedness by Boards and the Shareholder Ministers to accept the financial consequences of this through poor financial performance and lower returns to the Budget has created an environment where there is an inconsistent and at times relatively weak focus on driving business performance.

Box 7.2 The Ausgrid Agreement: Outsourcing

7.1 In circumstances where Ausgrid is examining outsourcing or contracting out of work activities:

7.1.1 It will advise the employees and their union(s) and provide them with at least 28 days' notice to respond with suitable proposals about possible alternative arrangements to outsourcing or contracting out;

7.1.2 Prior to expressions of interest or tenders being called, where employee generated alternatives are received, such alternatives will be considered;

7.1.3 If it is subsequently determined that expressions of interest or tenders are to be invited, Ausgrid will provide the union(s) with a copy of the document which has been prepared.

7.1.4 Expressions of interest or tenders when advertised shall be timed so as to provide the employees with an opportunity to submit a conforming expression of interest or tender to do the work to an equivalent standard, timetable and price.

7.1.5 If an employee generated conforming expression of interest or tender is submitted, it shall be evaluated together with external submissions received.

7.2 Work will only be outsourced or contracted out when it can be demonstrated that either;

7.2.1 insufficient overall resources are available to meet the current Ausgrid overall work commitment and work timetable, or

7.2.2 the failure to complete the work in a reasonable time would jeopardise the safety of the public or impact adversely upon system performance, or

7.2.3 the use of outsourcing or contracting out the work is commercially the most advantageous option taking into account quality, safety, performance, cost and the overall strategic direction of Ausgrid.

7.3 When a decision is made by Ausgrid to outsource/contract out work not already outsourced or contracted out, or in a review of existing contracts, Ausgrid will only award a contract to a contractor that demonstrates it has established appropriate industrial relations policies and practices and that it complies with industry safety standards, environmental standards and quality standards.

7.4 In evaluation of conforming expressions of interest or tenders, any comparisons will be made on a basis discounting any overheads that would continue even if the work was outsourced or contracted out. Such overheads would typically include tendering costs, contract administration, contract supervision and the cost of any redundancies which may arise as a result of the decision to outsource or contract out.

7.5 In the event that it is determined to outsource or contract out work, affected employees will have access to the full range of options available under the Ausgrid policies which apply at the time, including training and/or retraining.

Source: Ausgrid (2010a).

Queensland

In the case of Queensland, the Independent Review Panel on Network Costs (IRPNC 2012) used several benchmarking and other qualitative indicators of the efficiency of that state's state-owned network businesses. It found evidence that:

-
- there was seemingly poor management of overhead costs
 - capital expenditure (capex) per customer was higher for the two Queensland distribution businesses — Ergon Energy and Energex — than would be expected given customer density (p. 9). The best performers on this measure in Australia were the privately owned businesses
 - operating expenditure (opex) per customer was higher than efficient levels for Ergon Energy (though not Energex), with private operators being again the best NEM-wide performers (p. 9). The panel also concluded that the corporate overhead and support costs suggested Queensland's distribution businesses were 'amongst the least efficient' in comparison with their interstate peers (p. 10)
 - Powerlink — the Queensland transmission network business — performed relatively well using the ITOMS database (described above) and had relatively low corporate costs compared with their Australian peers (p. 10-11). On the other hand, the panel drew attention to information from the AER that showed that capex per line length was higher for Powerlink than most other transmission businesses and had trended up over time.

The Panel concluded that '... there is a compelling case for privatisation of DNSPs in Queensland that can unlock further cost savings to ultimately benefit consumers' (p. 39).

Victoria as a comparator

As noted in chapter 6 and apparent from some of the results above, Victorian network providers appear to have performed relatively well. Fearon and Moran (1999) noted that by any standards, privatisation in that state was an 'immense success' (p. 10).

- In terms of standards of service, regular reports by the Office of the Regulator-General have demonstrated that private entities have improved performance in terms of reliability of supply and meeting customer demands for connections and response to problems.
- All the distributors had considerably pruned and rationalised their workforce since privatisation. Numbers have been reduced from 6000 at the time of the creation of the five corporatized distributors to less than half of this. One central business district distributor now employed 40 per cent of the staff it employed at

the time of its sale, prior to which numbers had already been reduced.¹³ Its rule of thumb had been that the employment saving yielded a 30 per cent cost saving with about 70 per cent of the jobs being essentially outsourced. Another Victorian business had outsourced much of its maintenance to an electrical contractor and made comparable savings.

- With regard to the sale process itself, investors paid \$8.3 billion for the five distribution businesses with initial valuations of \$3.8 billion.
- The Victorian Auditor General estimated the outcome in terms of savings to the State revenue at a net gain of \$317 million for 1997-98 after taking into consideration revenue foregone and debt savings. In addition, the reduction of State debt further enhanced State finances by contributing to an improved credit rating.

Though incomplete, the empirical evidence strongly suggests that SOCs have lower levels of efficiency than their privately-owned peers. In the Commission's discussions with participants, several highlighted that the state-owned businesses tended to be more risk averse and had an historical engineering focus on building things — 'if in doubt make it stout', or as EnerNOC (sub. 7, p. 3) characterised it: 'capex good, opex bad'. Some claimed that this attitude had persisted to a greater degree in the corporatised state-owned enterprises.

What does the international literature suggest?

Only a few studies have examined the privatisation of network businesses alone — and these have consistently shown improvements in performance.¹⁴

However, our preliminary reading of the remaining literature on privatisation is that it mostly does not control for other coincident events, which confuse estimates of the impacts of privatisation of network businesses with other changes. In many instances, privatisation was associated with broader liberalisation of the electricity sector, particularly changes in regulatory arrangements and vertical separation of generation and retailing from network provision (Pollitt 2012, in a wide-ranging meta study).

As an example, in the United Kingdom, Crouch (2006) concluded:

¹³ Accordingly, privatisation has been a continuation of the process of shedding labour and increasing efficiency that commenced with corporatisation (a point also made by Marsden 1998).

¹⁴ Anaya (2010); Bradbury and Hooks (2008); Söderberg (2011); and as summarised by Pollitt (2012) — Domah and Pollitt (2001); Galal et al. (1994); Mota (2003); and Toba (2002).

This system has worked well since privatisation. Costs have fallen significantly, distribution charges to domestic customers have reduced by 50% in real terms and companies have broadly delivered the requirements that have been placed on them to the benefit of consumers, including improvements in the quality and security of supply.

However, much of this gain would have reflected the joint implementation of CPI-x regulation and privatisation. Jamasb and Pollitt echo this conclusion, arguing that ‘when accompanied by effective regulation, privatisation has achieved efficiency improvements’ (2007a, p. 6164). This is certainly consistent with the empirical evidence for Australia.

7.5 The perceived risks of privatisation

Are network prices higher?

Some have claimed that privatisation may increase electricity prices. For example, the ETU (2012) noted that South Australia (which had privatised network businesses many years ago) had the highest prices for electricity. However, the relevant issue for privatisation of network businesses is not electricity prices — which are strongly influenced by generation and other non-network costs — but the network contribution to those costs. In 2010-11, New South Wales and Queensland had significantly higher network costs than other states (chapter 2), which are likely to reflect genuine differences in the nature of their networks, but also lower levels of efficiency (chapter 6).

The story might be different were private networks to be unregulated (a point made in section 7.1). However, regardless of ownership, all network businesses in Australia are subject to the National Electricity Rules, which constrain the exercise of market power. Consequently, assertions that market power justifies government ownership (as argued by Toner in an accompanying paper to the submission made by the ASU to the Commission — appendix A, sub. DR57) are not compelling, and the evidence on prices substantiates this.

Do private networks have lower reliability?

The evidence suggests that privatisation does not adversely affect reliability (chapter 2). Measures of reliability (such as the system average interruption duration or SAIDI and the system average interruption frequency index or SAIFI) are not worse in Victoria or South Australia. Indeed, over the 10 year period from 2000-01 to 2009-10, Victoria and South Australia had the lowest SAIDI among the

NEM regions, while South Australia had the lowest SAIFI (and Victoria the third lowest).

Moreover, the Commission has proposed a new framework for reliability that should ensure that all network businesses know the reliability standards they must meet and are incentivised to do no more or less than valued by the community (chapters 14 to 16). Currently, the mostly costly reliability standards apply in those states with SOC's.

Bushfire Risk

The Electrical Trade Union (2012) expressed concern about infrastructure neglect and fire risk, arguing that the Productivity Commission had overlooked this issue in its draft report:

“Saving a bit of money from neglecting maintenance starts to look like a pretty false economy when you actually weigh up the real risks,” Mr Hicks said. “Of course it’s not just major disasters like Black Saturday that you risk when you neglect power assets, any number of minor fires and shocks are also likely to occur. The key point is that the terrible cost of those bushfires is not being borne by the private operator, but by the Victorian taxpayer. Recent Australian history shows privatisation of electricity assets is far more of a win for private operators than for the public.

The ASU (sub. DR57, Attachment, p. 7) also claimed that there were large reductions in maintenance expenditures following privatisation, and said that the Victorian Bushfires Royal Commission (VBRC) found inadequate maintenance to be an important factor in the 2009 Victorian bushfires. SP AusNet strongly contested these claims (sub. DR 102, p. 2).

The Productivity Commission was unable to identify any specific finding by the Royal Commission that *neglect* of maintenance had caused the fires, though the Royal Commission did partly attribute the fires to failed electricity assets, and recommended improved inspection processes (VBRC 2010b, p. 148-185).¹⁵ However, the relevant issue for this chapter is not any judgment about the alleged negligence of SP AusNet or any other electricity network business — the subject of a class action that commenced in March 2013 — but whether privatisation itself was a risk factor. On this score, a relevant indicator would be whether the incidence of fires increased after privatisation. The Royal Commission provided evidence that the incidence of network-related fires did not appear to have risen over time from periods when the network was state-owned (VBRC 2010b, p. 150). Moreover, state-

¹⁵ SP AusNet has separately contested the Royal Commission’s conclusion about the role of inspections as a factor in the fires (2013a, pp. 2-3)

owned businesses in other jurisdictions report numbers of fire ignitions by network assets of a similar magnitude. In 2010-11, there were around 130 fire ignitions by network assets for the four New South Wales networks (which sometimes excluded fires that caused no public damage).¹⁶ In comparison, there were 119 fire ignitions by network assets in the five private Victorian networks, of which half appear to have only affected network assets (Energy Safe Victoria 2012, p. 27). Consideration by an expert group on bushfires concluded:

Based on the data gathered in the survey, Victoria's rate of fire starts from rural electricity networks appears to be not unusual when compared with other jurisdictions. However, this measure (fire starts from electricity assets as a proportion of total fire starts) is not tracked in a nationally consistent way and not tracked at all in some jurisdictions. Victoria's methods of measurement could be expected to result in higher figures than some other jurisdictions, e.g. where distributors count only those fires actually attended by fire services. (Nous Group 2010, p. 40)

Furthermore, non-Victorian networks have responded to the Victorian Bushfire Royal Commission by reforming their fire safety arrangements — suggestive that, regardless of ownership, all networks have perceived a heightened risk in this area (for example, Essential Energy 2011a, p. 59).

Finally, in its analysis of the causes of the 2009 Victorian bushfires, the Royal Commission concluded that inadequacies in regulation, not the ownership of the businesses, were a significant factor:

Victoria's electricity assets are ageing, and the age of the assets contributed to three of the electricity-caused fires on 7 February 2009 — the Kilmore East, Coleraine and Horsham fires. Distribution businesses' capacity to respond to an ageing network is, however, constrained by the electricity industry's economic regulatory regime. (VBRC 2010a, p. 12)

To that extent, the concern is not with ownership per se, but with the design of incentive regulation and other regulations. All states and territories have safety regulations in place, regardless of the ownership of the networks, and Victoria has now (alone among jurisdictions) introduced an incentive scheme, the F-Factor Scheme, that penalises networks for fires caused by network asset failures. The Victorian Department of Primary Industries (DPI 2013a) notes:

The f-factor (and the related reliability incentive schemes) has been introduced to balance the incentive for network monopoly businesses to reduce service levels and increase profitability, by rewarding (penalising) the electricity distribution businesses for improved (decreased) service in the area of fire mitigation ... the incentive will

¹⁶ Based on data from Transgrid (2011, p. 17), Endeavour Energy (2011a, p. 44), Essential Energy (2011b, p. 42) and Ausgrid (2011d, p. 38).

operate by linking annual changes in an electricity distributor's regulated revenue to the number of fires started by its electricity distribution assets each year.

Chapter 5 examines the nexus between state-based safety regulation and incentive regulations, while chapter 15 examines the F-Factor Scheme in the context of the broader reliability framework (and the extent to which it complements or complicates the NEM-wide Service Target Performance Incentive Scheme).

7.6 The bottom line on private ownership

The rationale for government ownership of network businesses no longer holds. State-owned status is ill-suited to the current incentive regulatory regime. State-owned network businesses appear to be less efficient than their private sector peers. This is not surprising given their multiple objectives, political intervention and the imposition of non-commercial restrictions.

Privatisation is not a radical move despite some of the political concerns (and was regarded favourably by most stakeholders — box 7.3). As it is accompanied by regulation, it does not allow the businesses to exploit their market power nor to lower reliability and safety. Indeed, notwithstanding the concerns expressed by some, most evidence points to the community being better off after privatisation — when it is properly managed.

There have been few problems in Victoria or South Australia, and indeed, on the whole they appear to give consumers better value. (Moreover, privatisation of generators and retailers also do not seem to have produced adverse outcomes.)

There are compelling grounds for privatisation of all electricity network businesses in the NEM. In saying this, the Commission is not criticising the managements of the existing state-owned network businesses. They have had to respond to the long-running structures and incentives presented to them by their shareholders.

RECOMMENDATION 7.1

State and territory governments should privatise their government-owned network businesses.

In the event that privatisation does not occur, jurisdictions should undertake reforms to the governance of their state-owned network businesses that create, as much as is possible, the same incentives that exist for private businesses. The degree of reform required would vary between jurisdictions, but reforms should aim to mitigate the deficiencies identified by the Commission above.

Box 7.3 **Stakeholder views about privatisation and shareholder disciplines**

... there is no rationale for state ownership of electricity network businesses given the sophisticated economic and technical regulatory regimes in the NEM. As noted in the draft report, state ownership also creates perverse interactions with incentive based economic regulation (EnergyAustralia, sub. DR82, p. 3).

... the national regulatory regime is moving towards greater use of incentives to drive improved performance. The Panel considers that Government owned entities are much less responsive to regulatory incentives due to less constrained access to capital and because the strict commercial charter that should apply under corporatisation is often compromised by the collateral social and economic objectives of Government. ... The experience of private ownership and operation of NSPs in Victoria and South Australia is that this essential service can be safely, reliably and more cost effectively provided under the national regulatory regime that applies to all NSPs regardless of ownership (IRPNC 2012, p. 39).

If privatisation occurs, there will be a reduction in community service standards, a reduction in employment, skills and training, and a reduction in many service aspects to the community, plus there will be an added cost to the community (ASU, sub. DR57).

The Australian regulatory framework is an incentive based approach predicated on profit being a motivating factor. Whilst this is true for privately owned DNSPs, it is not solely the case for publicly owned DNSPs who face multiple competing objectives of which profit is only one. Acknowledging these conflicting objectives for publicly owned networks, the Businesses consider that the regulatory framework changes being promulgated in themselves will not deliver the efficiencies being sought. ... the Businesses consider there to be a need for a greater focus on structural reform rather than further regulatory reform. (CitiPower et al., sub. DR90, pp. 5-6).

... we remain convinced that the commercial disciplines driven by the values of private owners ultimately result in lower costs for consumers. (GDF Suez Energy Australia, sub. DR68, p. 5).

The ENA has no comment to make on ownership of network businesses as this is a matter for the relevant shareholders (ENA, sub. DR71, p. 3 of attachment A).

I think issues of ownership is ultimately a decision for government. I think people can advise, but to the extent that government have no intention of privatising, that's their issue. I think the task is to make the best of whatever ownership arrangements the governments choose. So I think in principle, regulatory choices shouldn't be conditioned by changes in ownership. (Bruce Mountain for EUAA, trans. p. 96).

These recommendations [the PC's draft recommendations for privatisation and better corporate governance] are strongly supported by the MEU. Governance arrangements applying to State owned businesses are particularly important, especially in the light of the AEMC's [Australian Energy Market Commission] inadequate final position in relation to the prescribed treatment of the financing costs of the State-owned networks by the AER in pricing reviews. (Major Energy Users, sub. DR66, p. 7).

Other stakeholders also identified the importance of good governance arrangements for state-owned network businesses. For example, in responding to the Productivity Commission's draft recommendation for improved governance arrangements for

state-owned network businesses, the Australian Energy Market Commission considered that:

... effective corporate governance by shareholders of network service providers is a very important component of delivering good outcomes for consumers. The rules and application of the rules are only part of delivering an effective outcome for consumers. (AEMC, sub. DR89, p. 18, in response to draft recommendation 7.2).

The Queensland review panel went further. It strongly favoured consideration of privatisation, but in the event of continued government ownership, it proposed the establishment of a holding company that brought together the two Queensland distribution businesses under a single CEO, senior management group and board (IRPNC 2012, p. 26). It considered two other alternatives: reform of the businesses as separate entities and a legal merger. The first it saw as ineffective because of concerns that the ‘prevailing culture’ of the businesses would stymie the capacity to achieve the identified efficiency savings. It saw the second as involving relatively high level of implementation complexity and costs.

The Commission does not have a view about the particular solution suggested by the panel, which has had the opportunity for detailed consultation on governance with the businesses concerned. Instead, the Commission has focused on the principles for a better governance model.

RECOMMENDATION 7.2

If state and territory governments do not implement recommendation 7.1, then they should promote more efficient outcomes for their government-owned network businesses by ensuring that:

- ***directors are appointed on merit, following a transparent selection process***
- ***ministerial directions are publicly disclosed at the time they are made and are also disclosed in the annual report***
- ***directors and officers are subject to the obligations under the Corporations Act***
- ***governments review objectives currently given to network businesses and:***
 - ***remove those that would be more appropriately allocated to other agencies***
 - ***remove those that are non-commercial and make it clear that the board is expected to deliver a dividend payout and rate of return on the equity invested in the network business that would be considered acceptable by a commercial investor***
 - ***where conflicting objectives remain, provide publicly transparent guidance on how to prioritise them.***

7.7 The transition to privatisation

Privatisation involves a range of complex activities that require careful management and leadership. Indeed an essential precursor before initiating a formal privatisation process is one of governments communicating effectively with the community and with other key stakeholders about the fundamental drivers and justifications for privatisation. The privatisation process itself involves the preparation of necessary legislation, identifying policy and regulatory issues that require attention, obtaining expert advice on the sale of the businesses, further restructuring of businesses in preparation for sale, valuing the businesses, managing and selecting among bidders, negotiating contractual agreements, and continuing to effectively engage with stakeholders and the wider community.

The privatisation experiences of the Victorian and South Australian government provide some guidance about possible pathways.

In Victoria, an Electricity Supply Industry Reform Unit was established in mid-October 1993 within the Department of Treasury and Finance to advise the State Government on the reform of Victoria's electricity industry, in particular the State Electricity Commission of Victoria. (In May 1996, responsibility for electricity industry reform, along with gas and aluminium industry reform, was moved to an integrated Energy Projects Division within the Department.) The Reform Unit engaged legal, accounting, financial and electricity industry advisers. The Reform Unit's first tasks were to:

- undertake a rigorous analysis of the Victorian industry
- examine electricity supply industry reform worldwide
- examine national industry reform considerations
- develop appropriate recommendations.

The sale process took around two years for the state-owned distribution businesses and four years for transmission businesses — but in the context of a much broader privatisation agenda, which could have constrained the speed of achieving sales of the assets.

The South Australian Government followed a roughly similar course. It announced its decision to privatise its electricity assets in February 1998, a process it completed in 2000-01. To achieve this, the Government established an Electricity Reform and Sales Unit within the Department of Treasury and Finance. The Government provided very clear guidance about the timing of privatisation and the desirable process. It indicated that the reforms, to be completed over a two-year period, would consist of three stages:

-
- a three month preparatory period for information gathering and for a detailed study of proposed market reforms and business structures
 - a period of implementation of the reforms and for restructuring ETSA Corporation and Optima Energy over three to nine months
 - the sale of the businesses over approximately a one year period.

Unlike Victoria, the electricity networks were not sold in perpetuity, but rather through long-term leases (of 200 years). Some have suggested that such long-term leases may be more popularly acceptable, but from an economic perspective, the long length of the lease makes them effectively equivalent to the full sale of the assets.

The privatisation processes used in Australia drew on some of the experiences in the United Kingdom. In particular, the UK Government failed to anticipate the magnitude of the cost and efficiency gains, which resulted in windfall gains to the privatised businesses. Given this, the Victorian Government lifted the performance of the businesses before privatisation to maximise the public benefit from the sales.

Some principles

Given the Australian and United Kingdom experiences, the best practice guidelines developed by the OECD (2009, 2010), and first principles, a successful pathway to privatisation should include several features.

Adopt a cost–benefit approach

When privatising their electricity network businesses, governments should be guided by the principle of maximizing the net benefit to the community. Within this objective, governments may have multiple goals for privatisation, such as obtaining productivity improvements for the businesses, lowering consumer prices, and increasing government revenues from the proceeds of sales that could be used to retire government debt or to spend on other activities of benefit to the community. Governments should identify and prioritise such goals, as these will further guide decisions on particular elements of the privatisation process (such as when to start the process, and the choice of sales method).

Clarify the regulatory environment before sale

Asset sales should take place in a regulatory environment that is well understood. Any significant regulatory uncertainty can affect a purchasers' view of the value of

the business and thus affect potential sale proceeds. Accordingly, reforms that are likely to significantly affect the value of the businesses should proceed apace. In particular, decisions about the reliability and planning framework — chapters 14 to 17 — should not be delayed or perpetuate the parochialism of the current arrangements.

Establish a responsible entity for managing privatisation

The Victorian and South Australian experiences indicate that creating a dedicated unit in government to oversight privatisation facilitates an orderly and coherent process. Given that, governments should establish a unit in a central agency to manage privatisation, with an appropriate governance structure, expertise, terms of reference and timetable for achieving specific milestones. Given their greater comparative advantage in this area, state treasuries are likely to be the most appropriate.

Consult appropriately

While privatisation is not a radical option, it nevertheless can be popularly controversial, and would typically lead to some reduction in employment in the relevant businesses. Accordingly, a best practice feature of a privatisation process is that governments consult with all affected parties to outline the rationale for privatisation and explain the consequence of privatisation for them (Auditor-General of Victoria 1995, p. 27). Consultation should include consumers — which are likely to be the main long-run beneficiaries. A related issue is public confidence in the process. There are strong grounds for all aspects of the privatisation process to be subject to independent monitoring and review by the state auditor-general.

Expert advice is needed to determine the best form of sale

Based on expert advice at the time, none of the sales of network assets in Victoria or South Australia was achieved through public flotation. Trade sales and long-term leases appear to be less costly methods of privatisation compared with initial public offerings. Trade sales are more likely to offer higher sales proceeds than long-term leases (because the latter does not involve ownership control). Long-term leases may be more acceptable to a community that has a strong preference for ongoing public ownership of network businesses. However, in principle, there is no inherent advantage to any of these sale processes, and the form of sale should be addressed as part of any process for privatisation of the existing SOCs.

In giving effect to recommendation 7.1, governments should:

- *be guided by the overarching objective of maximizing the net benefit to the community, with clear identification and prioritisation of any subsidiary goals*
- *undertake key regulatory reforms prior to sale*
- *avoid the transfer to the new owner of unjustified liabilities, obligations or restrictions that may inhibit the future efficiency of the business*
- *establish an expert unit within the relevant treasury to oversee the process, and develop clear milestones and a timetable*
- *undertake genuine consultation with the public and key affected groups, including likely beneficiaries, accompanied by effective communication of the benefits of privatisation*
- *ensure adequate accountability through independent auditing of the privatisation process.*

8 How should the Australian Energy Regulator use benchmarking?

Key points

- Recent rule changes are likely to increase and improve the AER's use of benchmarking. The AER will be able to use benchmarking to consider whether network expenditure proposals are reasonable and, potentially, to estimate values for some cost categories. The AER will also begin to publish annual benchmarking reports.
- At this stage, aggregate benchmarking models are ill-suited to setting regulatory revenue allowances (in place of building blocks). In the immediate future, benchmarking would be most useful:
 - as a diagnostic tool to help assess the reasonableness of bottom-up proposals
 - in providing information to consumers and others, thereby providing pressure for improved performance by network businesses.
- Over time, benchmarking may take a larger role in determining revenue allowances. Where benchmarking is used to estimate substitute values for opex and capex allowances, this should involve:
 - demonstration that the results are robust through detailed publication and peer review
 - choosing a yardstick more akin to that applying in competitive markets — which would be a firm close to, but not at the efficiency frontier.
- In the future, benchmarking may also facilitate negotiated arrangements that bypass the current costly and protracted regulatory processes.
- The AER will need to adopt various processes to ensure the successful use and evolution of benchmarking, including:
 - the development of publicly available databases and full transparency in its processes and methods
 - the development of internal expertise, and strategies to maximise learning
 - international collaboration and peer review of its benchmarking practices ('benchmarking of benchmarking')
 - appropriate consultation with stakeholders about data and methods
 - effective communication of the results of benchmarking to its diverse audiences
 - regular checking to ensure that the benefits of its benchmarking practices exceed the compliance and resource burdens.

A major international survey ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks (Haney and Pollitt 2011). End users have also criticised the limited use of benchmarking in the current regulatory regime:

Our view is that benchmarking has generally had an insignificant role in the AER's determination of expenditure allowances. We have observed that in most of its determinations there is no evidence that the AER has benchmarked capitalised expenditure allowances at all. The benchmarking that it has done of operating expenditures has not, in our opinion, been adequate. Even where there is some evidence of benchmarking by the AER, there is no evidence of how this information affected its view of the appropriate expenditure allowances. (EUAA, sub. 24, p. 4)

The AER has not used benchmarking effectively and yes it should adopt different practices. The reasons for this probably lie with the regulatory approach (propose/respond) the AER must implement. (MEU, sub. 11, p. 30)

This raises the question of the appropriate aspirations for benchmarking in an Australian context — recognising the limits raised in chapter 4. The appropriate type of benchmarking and the manner of its application will depend on the purposes of its use — the policy imperative is 'do not use benchmarking on its own account'. There are many such purposes, with implications for the degree to which the tests set out in chapter 4 would need to be met.

Rule changes introduced in late 2012 require the AER to undertake routine benchmarking and give it the discretion, though not the obligation, to use benchmarking in making price and revenue determinations (AEMC 2012r; box 8.1; and box 4.2 in chapter 4). Given this greater discretion, it is particularly important to be clear about how the AER should use benchmarking, both now, and as the sophistication of the data and methods evolve — the subject of this chapter.

Some potential uses of benchmarking are alternatives, but some are complementary.

- Section 8.1 considers whether the AER should use benchmarking as the primary basis for its revenue determinations, and highlights some of the major drawbacks in that approach at this stage.
- Section 8.2 examines the degree to which higher-level benchmarking could indicate the overall effectiveness of the regulatory regime, which would have implications for policy settings, as well as provide a guide to whether the regime is achieving its intended purposes.
- The bottom-up approach in determining revenue allowances is often exhaustive in its detail — one of the reasons for the increasingly lengthy documents used in the propose-respond model. The AER could use benchmarking to determine the areas where detailed analysis is required, while avoiding excessive analysis in other areas — in effect a filter for more targeted analysis (section 8.3).

Box 8.1 **Recent AEMC rule changes on benchmarking**

There will be a published benchmarking report each year

The first most important change is that the new Rules stipulate that the AER will undertake and publish regular benchmarking reports, with the contents of the reports to be decided by the AER:

The AER must prepare and publish a network service provider performance report (an annual benchmarking report) the purpose of which is to describe, in reasonably plain language, the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12 month period. (s. 6.27 of the Rules, v. 54)

Such reports will require data of a sufficient detail, quality and comparability. The AEMC indicated that this will require an expansion of the AER's data collection (2012r, p. 108) — an issue that this chapter covers.

The initial benchmarking report is due by September 2014, but the Rules are (understandably) quiet about the scope of the reports or any requirements for testing the validity and reliability of the results, or in meeting any of the other criteria set out in chapter 4. It is notable that in the Rule change report, the AEMC indicated that in undertaking the annual benchmarking analyses of network businesses, the AER should take 'into account the exogenous factors that distinguish them' (AEMC 2012r, p. 25). No such requirement exists in the Rules themselves, but such a principle would be important in any AER benchmarking exercise.

In preparation for the annual benchmarking report and for the regulatory use of benchmarking, the AER (2012y) released an issues paper in late December 2012 concerning guidelines for assessing efficient expenditure forecasts for network businesses.

The AER may use benchmarking results to determine substitute estimates in revenue determinations

The AER must accept reasonable proposals by network businesses. However, the processes by which it determines reasonableness — which may include benchmarking — can also be used to set alternative revenue allowances where a proposal is deemed unreasonable. As the AEMC put it:

While the AER must form a view as to whether a [network service] provider's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. For example, benchmarking the [network service provider] against others will provide an indication of both whether the proposal is reasonable and what a substitute should be. Both the consideration of 'reasonable' and the determination of the substitute must be in respect of the total for capex and opex. (AEMC 2012r, p. 112)

Accordingly, the Rules would enable the AER to use benchmarking in a determinative sense. This clarification does not compel the AER to use the results of benchmarking models as substitute values — it may still rely on other methods (such as bottom-up analysis).

Sources: Version 54 of the Rules and AEMC (2012r).

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- Currently, end-users (whether households or commercial users) are disenfranchised from the regulatory process. While greater engagement should occur regardless of the form of the regulatory model (chapter 21), it may also be possible for end-users to play an active role in reaching negotiated settlements in regulatory determinations — avoiding the complex and protracted processes currently in place. Benchmarking would support such a framework (section 8.4).
 - Benchmarking need not always directly inform regulatory decisions. In some cases, the publication of benchmarking results may itself create pressures for improved performance (section 8.5).
 - While this chapter is sceptical of the degree to which benchmarking could play a major role in determining regulatory allowances in the near future, that may change over the longer-term with the increasing sophistication of the models and with better data. In that instance, benchmarking could assume a more prominent role (section 8.6).

Regardless of the particular purposes of benchmarking, the regulator has to develop competencies in benchmarking and follow processes that ensure that others can interpret and use the results, and that compliance and other costs associated with benchmarking are moderated. Section 8.7 spells out the processes that will achieve cost-effective and useful benchmarking.

8.1 Should benchmarking be used in a mechanistic role to set revenue allowances?

The apparently greater simplicity and clarity of using aggregate benchmarking as the primary basis for price and revenue determinations lies behind its attraction for some parties. In principle, its aggregate nature would require less data than for bottom-up analysis, while using it mechanistically to set allowances might avoid the prolonged processes apparent in recent regulatory determinations. In some circumstances, it might create stronger incentives for cost minimisation than the current arrangements.

There are several options. The AER could use benchmarking to:

- set expenditure allowances within the existing building block framework
- set revenue growth, based on a total factor productivity (TFP) growth framework, but without building blocks
- set revenue, based purely on benchmarking results, without building blocks.

Setting aggregate capex and opex in building block models

A regulator (or indeed a business proponent) could use aggregate benchmarking models to determine forecasts of total efficient opex and capex, which would then be included as the key inputs of the standard building blocks model.¹

This use of benchmarking resembles that outlined by the AEMC (2012r), where it clarified the AER's ability to determine estimates of total opex and capex using benchmarking models (box 8.1). It would still represent a significant departure from what was common practice in the first round of AER determinations, where deriving the total cost forecasts in the building blocks model involved aggregating many detailed sub-components of total spending (as described by Major Energy Users, sub. 11, p. 10), with benchmarking at best informing that process.

Setting revenue growth based on total factor productivity growth (CPI-x)

A second mechanistic approach would be to allow benchmarking results to determine the trajectory of a business's annual price or revenue increases (under a CPI-x model).² This would involve setting a starting price, P_0 , based on efficient or reasonable costs. The trajectory would be then determined by setting x to the *industry-wide* total factor productivity growth calculated using standard index methods.

This would not require a building blocks model at all, since it would focus at the highest possible level of aggregation (AEMC sub. 16, p. 1). The National Electricity Law already allows the AER to use the TFP approach as either a replacement for, or a complement to, the building block approach (clause 26J).

As the TFP approach uses industry-wide data to determine x , individual businesses would have strong incentives to cost minimise, and would have few opportunities for gaming, such as by exaggerating their efficient costs or by producing unrealistic

¹ The term 'building blocks', refers to the procedure for determining the total revenue allowance (for example, AER 2012x) based on the capital assets of the business, total investment in capital (capex), operating expenditures (opex), depreciation, tax rates, the weighted average cost of capital and various rewards and penalties (such as an Efficiency Benefit Sharing Scheme — chapter 5). The building blocks model can be either simple or complex, depending on how its inputs are estimated. In that sense, benchmarking is not inconsistent with the use of a building blocks approach (ETSA Utilities et al., sub. 6, p. 10).

² However, the term CPI-x can sometimes relate to a weighted average price cap, with x not related to productivity growth (chapter 4). However, this chapter refers to the CPI-x approach as necessarily capping the growth of average prices or revenues by inflation less TFP growth.

demand forecasts (Kaufmann 2006, 2007; ESC 2006, 2009; DPI 2009, p. 4; Pacific Economics Group, sub. 35 and sub. DR48).

Setting revenue based on ‘supra- aggregate’ benchmarking model

A third approach would use ‘supra-aggregate’ benchmarking at the commencement of any regulatory period to set the required total revenue allowance. Similar to the CPI-x approach above, this would not require any reference to the role of the separate WACC, capex and opex allowances. However, in contrast to the CPI-x approach, there would not be any reference to the historical costs of the business (since this model would not set P_0 and its trajectory).

Rather, the model could estimate revenues for a given regulatory period — similar to models used by Mountain (2011) and Mountain and Littlechild (2010).³ Each network business would then make all the relevant choices about how to provide its services, including choices between capex and opex. Furthermore, the regulator would not need to formally roll any capital into a regulated asset base (RAB) in the next period, but would need to ensure that the benchmark method related to the long-run marginal costs of supplying services. If the regulator took such a long-run perspective, the risk of asset stranding (devaluation of assets) would be low.⁴ (The National Electricity Objective’s long-term focus would oblige the AER to do this.)

This approach would still need to estimate future levels of demand at efficient prices (similar to the approach discussed in chapter 11), and take account of differences in network operating environments. Accordingly, it would not eliminate the need for some sophisticated analysis. Nevertheless, on the face of it, it would be simpler than the current building block approach.

Problems with deterministic approaches

While apparently simpler than the approaches used by the AER thus far, all of these approaches have their own theoretical and practical difficulties:

In respect of the CPI-x method, the AEMC (2011b) did not believe that the available data were adequate yet, but that it could work as an alternative mechanism for setting allowances in the future. Even if the basis for x were productivity growth

³ Neither Mountain and Littlechild (2010) nor Mountain (2011) intended their benchmarking analysis to be used to determine revenues directly.

⁴ Regulatory asset stranding would occur if the regulator were to (ex post) set an allowance that under-remunerated previously made, but still productive, investments — in effect, pricing at less than long run marginal cost.

within the network industry, it may still be optimistic to expect CPI-x benchmarking to occur over the medium term, given the wave of prospective mergers of New South Wales distribution businesses (and uncertainties about future structural change in the industry), the potential privatisation of networks, and slowly developing data collection.⁵ Chapter 4 also noted that a ‘pure’ CPI-x approach could preserve inefficiency or perpetuate rents.

Neither is it clear how regulators would derive x in practice. Comprehensive reviews by Farrier Swier Consulting (2002), the AEMC (2011b) and London Economics (2008) found a wide range of methods used by regulators to actually set x . This includes setting the value of x :

- as an assumed value⁶
- as a catch-up factor to improve business performance over several years
- as a means to freeze prices ($x = \text{CPI}$)
- based on business proposals, or
- as the result of technical analysis using index or econometric methods.

Many of these are pragmatic rather than scientific choices. However, so long as x is not too high,⁷ and adjustments to initial revenues are not too dramatic,⁸ CPI-x approaches provide strong incentives for productivity, while ensuring business viability and placing a (arbitrary) cap on network price changes for consumers. Accordingly, a reasonable operational rule would be to set an x sufficiently low that it gives the business some scope to keep some of the gains of higher productivity growth.

⁵ Pacific Economics group (sub. 35, pp. 8-9) argued that the AEMC was too pessimistic about data inadequacies, and that the Victorian use of CPI-x exemplified the practicality of the approach. Nevertheless, Pacific Economics Group acknowledged that in modelling Victorian TFP growth, it was necessary for the analysis to begin in 1998, rather than 1995, because of the atypical TFP growth occurring immediately after privatisation of electricity distribution businesses (p. 3). The Commission has proposed privatisation of all state-owned network businesses (chapter 7), which should create a similar burst in TFP growth, presenting exactly the problem identified by Pacific Economics Group.

⁶ For example, while Ofgem is often seen as one of the most prominent users of the CPI-x approach, the AEMC (2011b, p. 45) notes that in their case x is based on a productivity growth ‘assumption’.

⁷ An x above the industry-wide achievable productivity growth rate would not provide enough revenue *over time* for the businesses overall to fund efficient opex and capex.

⁸ Too dramatic a cut in revenue for any given business in the first year of a CPI-x regime would expose the business to immediate insolvency.

Given its positive features, ongoing development of TFP indexes would still be useful. If nothing else this would ensure that the AER collects the appropriate data and would allow the AER to assess the degree to which the indexes are reliable. Moreover, there may be greater benefits from using the CPI-x approaches if governments privatise networks across the NEM, as recommended by the Commission — an issue explored further in section 8.6. Nevertheless, as the AEMC notes, the practical realisation of the CPI-x approach is some way off.

Similar — if not greater problems — would beset any deterministic use of benchmarking models reliant on cross-sectional data.⁹ Their use would require strong confidence in the results, which would be misplaced given the findings in chapter 4. The deterministic approach has five other significant risks (to which the ‘supra’ aggregate approach would be particularly susceptible).

(a) Regulatory opportunism

Were electricity prices to be rising rapidly, there could be pressure on the regulator to choose tougher benchmarks (recognising that even were sophisticated benchmarking models to develop over time, it is likely that they could be tweaked to give higher or lower benchmarks).

As explained by Yarrow (2012), the assumption of regulatory impartiality may not hold given opportunism:

By way of further example of the difficulties with the arguments as they presently stand, consider the argument that the current ‘propose-respond’ process precludes the AER from substituting ‘impartial’ forecasts of costs for what are claimed to be the biased forecasts of costs that are submitted by the companies. This argument begs a fundamental question. As discussed above, the working presumption in the relevant economics is that a regulator with unconstrained discretion to set price controls will be tempted to opportunism, and that the temptation will be particularly great in circumstances of rate-shock. That is, at bottom, there is an underinvestment problem associated with the regulation of private monopoly. (Yarrow 2012, p. 9)

The extent of regulatory risk perceived by the industry would depend partly on the specific characteristics of the AER itself, including its objectivity; its independence; its abilities and funding; and its general reputation in the industry (a matter discussed further in chapter 21).

⁹ While methods that jointly use cross-sectional and time series (panel) data would help, given their better capacity to control for different operating environments, there has not been widespread testing of their reliability (Frontier Economics 2010b, p. 59).

(b) Future network developments present a challenge for benchmarking models

Unlike some investments where, once made, the additional investment requirements are relatively modest (say a toll road), electricity networks require significant ongoing maintenance, replacement, new connections and other augmentation. Many network costs reflect expectations about the future characteristics of demand and supply, and these can change over time given the effect of climatic variations and peak loads. As such, many costs would be hard to incorporate into ex ante aggregate benchmark models (at least without significant further development). There would need to be a process for approving contingent projects.

(c) Benchmarking, information and efficient contracting

The AER's revenue allowance determinations are effectively contracts over the regulatory period between network businesses and a regulator acting on behalf of end users. Setting efficient contracts requires shared and sufficiently rich information about the nature of costs and contingencies.

In the current regulatory regime, network businesses have large information advantages over the regulator, which they may be able to exploit to increase regulatory revenue allowances. For example, ex ante, they may claim the need for allowances to meet additional demand or to replace specific ageing assets, and then, ex post, invest at lower levels, taking the residual as a surplus. Ex ante, the regulator may not know enough information to challenge highly detailed 'bottom-up' costs and demand forecasts. However, the scope for gaming the regulator can be reduced (and the scope for efficient contracts strengthened) if a benchmarking model can be built that:

- uses a small set of verifiable data
- takes account of the key operating differences of the businesses
- adequately predicts efficient costs.

Few participants in this inquiry suggested that such benchmarking models were currently available.

Rather than forcing both regulators and businesses to act as blind players in their dealings with each other, a preferred approach would be to:

- use the recent Rule changes (chapter 5) giving the AER more regulatory discretion to avoid 'line by line' assessments of businesses' regulatory proposals, thus eliminating the principal avenue for the businesses to exploit their informational advantages

-
- ensure adequate provision of relevant detailed information (and not rely on the exclusive use of aggregate benchmarking).

Reliance on too lean an information set would increase regulatory risk and require the regulator to pay a premium to cover that risk. There would then be a tradeoff between simplicity and cost.

(d) Detailed analysis would creep in via the back door

The checks and balances required to ensure aggregate benchmarking was reliable as the sole basis for setting revenue allowances would re-create the need for scrutiny of bottom-up data to test the results (thus losing simplicity after all). At the very least, these checks and balances would need to address capex, opex and the WACC separately (thus reinstating the RAB as an important facet of the regulatory arrangements).

(e) Uncertainties about the merit review process

Moreover, it is not clear how merit review would proceed if regulators used aggregate benchmarking to determine revenue allowances. The outcomes would depend on how merit review arrangements were structured (a matter still under consideration following the review by the Limited Merits Review Panel, 2012). But regardless, it is likely that merit reviews would involve:

- battles between econometricians.¹⁰ For example, significant tensions between alternative ways of estimating TFP emerged during the AEMC's assessment of TFP growth as a viable benchmark (AEMC 2011b and Pacific Economics Group sub. DR48). Such battles would have some advantages to the extent that it encouraged good statistical processes, clear statements of how to interpret the results, better data collection, and the development of expertise (as set out in figure 4.7 in chapter 4). However, given the data and modelling problems afflicting benchmarking, it is doubtful that a merits review body could reach a well-based judgment on whether it is meaningfully possible to, say, disentangle 'the heterogeneity from inefficiency in one step, using a latent class model for stochastic frontiers' (Cullmann 2009). A tribunal might then seek its own expert advice, but this may only serve to broaden the contest rather than resolve it
- the re-admission of detailed data as the corroborating evidence on which to base the determination. The bottom-up approach might then simply be deferred to the

¹⁰ With the inherent problems spelt out in detail by Rubinfeld (1985).

‘courtroom’. It is notable that in an appeal brought by EnergyAustralia, the Tribunal emphasised the relevance of the business’s detailed information:

EnergyAustralia is correct to submit that it is not the AER’s role to simply make a decision it considers best. It is also correct for it to say that the AER should be very slow to reject a DNSP’s proposal backed by detailed, relevant independent expert advice because the AER, on an uninformed basis, takes a different view. Nor, as EA submits, may the AER reject such a proposal merely because it has an expert opinion. The AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by this Tribunal. (Australian Competition Tribunal 2009, p. 56)

Currently, the arguments for the AER to use benchmarking to set allowances mechanistically are not compelling. The AER, the network businesses and some other stakeholders share this view (box 8.2). Responses on the Commission’s draft report did not repudiate this perspective.

8.2 Benchmarking the effectiveness of the regulatory regime

The AER and various stakeholders have claimed that regulatory arrangements have reduced efficiency in electricity networks. They cited several issues that are discussed in various areas of this report, including deficiencies in incentive regulations (chapters 1 and 5), prescriptive reliability settings (chapters 14 to 16), policy obstacles to demand management (chapters 9 to 12) and problems in the efficient utilisation of interconnectors (chapters 18 and 19). As shown in each of those chapters, the Commission agrees that there is a lot of room for improvement in the overall regulatory environment. The case for policy reform is much increased if analysis can reasonably demonstrate that a deficiency in a regulation has material consequences and that a specific change is likely to improve outcomes.

Benchmarking can play a useful role in these areas.

First, as emphasised in chapters 1 and 4, rigorous benchmarking analysis intended to measure business performance can incidentally highlight the efficiency impacts of the regulatory and policy environments facing network businesses. While most of the regulator’s interest in benchmarking is on the *residuals* from a model (the proxies for the inefficiency levels of businesses), policymakers should concentrate on the estimated *parameters* regarding policy variables in any model. In the current imperfect policy environment, those parameters may reveal the most lucrative direction for reform. These policy opportunities are the principal subjects of chapters 9 to 16.

Box 8.2 Participants said benchmarking should not be used deterministically

The AER highlighted concerns about using benchmarking in a determinative fashion:

Benchmarking is not a substitute for rigorous analysis and the exercise of judgement to determine expenditure allowances for a network business and cannot be used in a mechanistic fashion to directly determine expenditure allowances. However, when benchmarking is used prudently and carefully, and based on a robust specification that incorporates good quality data, it can be a very useful tool in the overall assessment of an expenditure proposal. (AER, sub. 13, p. 13)

The AER considers that at the current time it cannot establish revenue allowances based primarily on the outcome of comparative benchmarking against other firms. When more standardised and appropriate data becomes available as a result of the application of the AER's new framework, noted above, and benchmarking models give more consistent results, the weighting given to top down benchmarking as a part of the AER's comparative analysis will likely increase. (AER 2010b, Appendices, p. 99)

A review of the international use of benchmarking in regulatory agencies worldwide indicated the dangers of using benchmarking to punish/reward businesses:

The significant uncertainties in efficiency estimates could have important undesired consequences especially because in many cases the estimated efficiency scores are directly used to reward/punish individual companies through regulation schemes such as price-cap formulas. (Farsi et al. 2007, p. 13)

Network businesses were (unsurprisingly) hostile to deterministic benchmarking:

The ENA considers that it is not yet possible to set efficient costs using pure statistical benchmarking at high levels of aggregation without regard to expert interpretation. Doing so would impose material regulatory risk on the businesses and deter much needed investment in the regulated network sector (ENA, sub. 17, p. 5)

The Businesses are not aware of any country that uses benchmarking exclusively to regulate DNSPs' revenues and prices. (ETSA Utilities et al., sub. 6, p. 30)

Perhaps more importantly, high level aggregate benchmarking with the use of a few high level causal factors makes it impossible to 'sanity check' the results that come out of a statistical model with the real world engineering constraints facing a business. If the regulator determines that expenditure on zone substation is not efficient because less costly alternatives exist, then this is a finding that can be contested on the available facts. By contrast, consider an example where a regulator decides that five per cent of total expenditure is not efficient purely on the basis of a high level statistical comparison to other businesses. This reasoning provides no indication of what aspects of the expenditure proposal are imprudent. Consequently, the business has no recourse to defend its proposed asset investment program on the engineering needs of the business because this was not the basis of the regulator's finding. (ENA, sub. 17, p. 27)

Others have been similarly cautious:

The CEC agrees with the Commission that benchmarking will be unable to supersede the current 'building block' approach taken by the AER. Rather, benchmarking methods should be able to be applied by the AER in order to provide supporting information to its determinations. Indeed, benchmarking should be another tool from the AER's toolbox of revenue assessment tools at its disposal. Given the broad use of benchmarking in regulated markets globally the CEC sees no reason why this could not be the case. (Clean Energy Council, sub. 38, p. 3)

Second, benchmarking can be aimed directly at measuring regulatory efficiency and effectiveness. Some examples could include:

- whether changes in the Rules or guidelines by the AER lead to cost-reflective network and retail prices for each distribution business. As chapter 11 notes, if they do not, then the efficiency benefits from demand management would be reduced, and it would be important to find out why the predicted outcomes were not eventuating. It would be relatively straightforward to collect data on the actual pricing behaviour of the various distribution businesses and assess whether it accorded with the objectives of the regulations
- the degree to which retail price regulation frustrated cost-reflective pricing across the NEM
- examining any gap between the value of customer reliability and the costs of investment intended to achieve given reliability improvements
- the links between various safety regulations and safety outcomes (an issue discussed in relation to fire risk in chapter 7)
- the costs borne by the AER, the businesses, the merit review body and other stakeholders associated with regulatory determinations, and the regulatory processes that most increase those costs. While any regulatory process must involve transactions costs for the contesting parties, benchmarking might be able to assess whether process reform could economise on these.

It appears likely that many of the greatest inefficiencies in networks lie outside the control of the businesses, but reflect the unintended consequences of a parochial and flawed set of regulations across the NEM. Regulatory benchmarking may be able to identify and quantify these inefficiencies, prompting reform. The AER, the AEMC and AEMO can all perform useful roles in these areas.

In the past, some claims about deficiencies in the Rules — such as those that led to the major changes in the Rules in late 2012 (AEMC 2012r) — were not strongly empirically based at the time. A proactive approach to regulatory benchmarking might help bolster cases for Rule changes (or cut them off early).

An overall test of the effectiveness of the regulatory regime

While much regulatory benchmarking would target specific areas, an advantage of upper-level benchmarking of business's performance would be to provide a bird's eye view of the overall effectiveness of the regulatory regime. As well as cross-sectional benchmarking (described in chapter 4), the AER should also model growth rates of total factor productivity (and their constituent partial productivity

rates) — for each business and for the industry as a whole. This would highlight how any business is performing compared with the entire electricity network industry, and with other industries in the Australian economy. This would also test the degree to which revenue determinations reflected ongoing negative (or low) TFP growth (and would assist in any progression to CPI-x benchmarking later).¹¹

These forms of benchmarking should be included in the AER's regular benchmarking publications. And as discussed in chapter 4, any such indicative aggregated benchmarking analysis should control for the most important differences in the operating environments of businesses — such as customer density, line type and length, reliability requirements, and the capital vintage of relevant assets.

RECOMMENDATION 8.1

The Australian Energy Regulator's regular aggregate benchmarking of the performance of network businesses should include comparisons of:

- *multifactor productivity — the output of services for given inputs*
- *separate productivity of capital, labour and intermediate inputs.*

The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the age of relevant capital assets.

8.3 Could more targeted analysis act as a filter?

Benchmarking could be used as a diagnostic tool to identify areas of a proposal that may require greater scrutiny, but without it assuming a determinative role. Many participants supported the use of benchmarking as an input into the regulatory process, rather than as a replacement for the building blocks framework (box 8.3).

From aggregate benchmarking to detailed analysis

The use of aggregate benchmarking as a filter would have advantages over detailed bottom-up approaches in that it could first identify those businesses that were more likely to be inefficient in their expenditure. The analysis could then bore down into

¹¹ The AEMC (2011b) proposed a similar approach to pre-testing of TFP methods. In its review of TFP benchmarking, it recommended 'paper trials' of benchmarking before considering further Rule changes in the area.

the more disaggregated detail, but only down the branch where benchmarking revealed that costs were sufficiently distant from the efficiency frontier (figure 8.1).

Box 8.3 Benchmarking is a useful adjunct to other modelling

Many participants accepted the value of benchmarking as one input into the regulator's determination of the appropriate aggregate or disaggregated costs of the regulated business:

The Businesses support the Rules' requirement for the AER to use benchmarking as part of the building block approach to test the efficiency of DNSPs' expenditure — and to choose which types of benchmarking techniques it will use — although this should recognise the inherent limitations of different benchmarking techniques and of the comparability of data. (ETSA Utilities et al., sub. 6, p. 15)

Overall, benchmarking of certain performance outcomes is useful only as an adjunct to the establishment of revenues using the existing cost build-up approach. The fundamental objective enshrined in the National Electricity Law will not be achieved with regulatory uncertainty, which will ultimately deter investment. (APA Group, sub. 2, p. 2)

Ergon Energy believes that benchmarking techniques are not robust enough to replace a detailed investigation of costs and should not be relied on entirely to set revenue allowances. Instead, benchmarking should be one of many assessment techniques adopted by the AER to determine efficient and prudent expenditure. (Ergon Energy, sub. 8, p. 9)

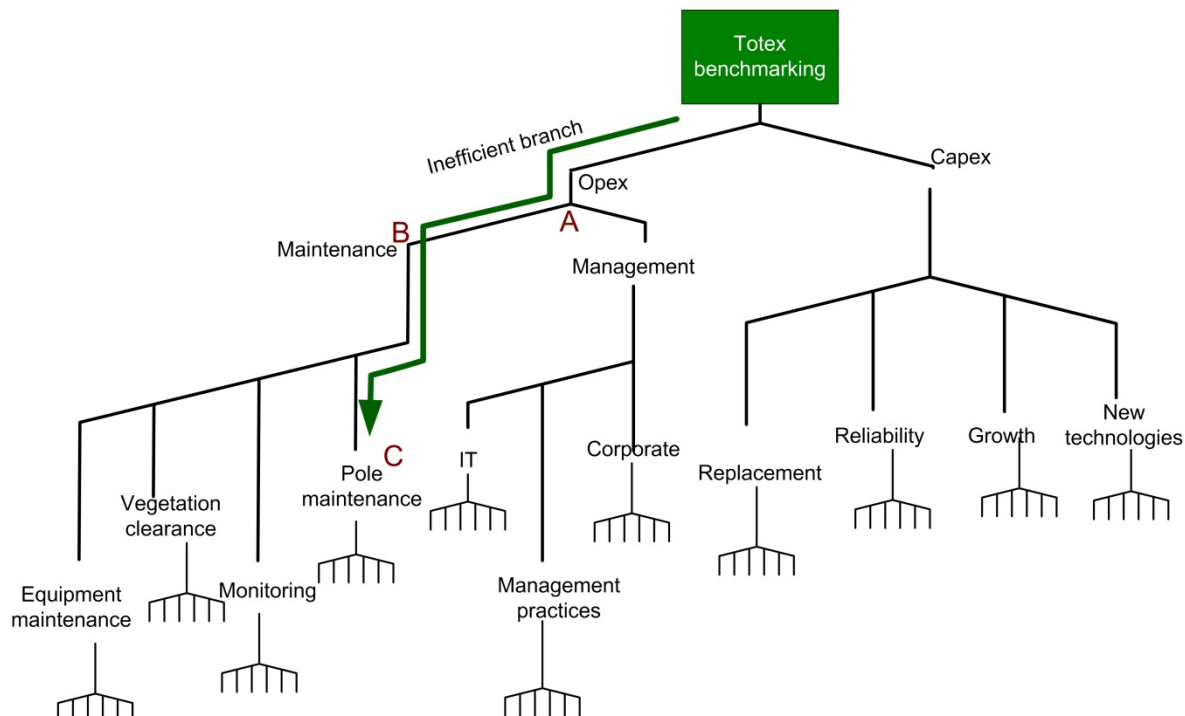
In the ENA's view, pure statistical analysis is most likely to be useful: as a means of identifying anomalies in an expenditure proposal that require closer more detailed examination; or when applied at low levels of expenditure aggregation. (ENA, sub. 17, p. 5)

... benchmarking results can also be used to allow the regulator to request further information. Consumer Action believes an appropriate first step to sophisticated benchmarking approaches should be to ensure that the regulator has more information combined with the ability to request further information/evidence from network businesses that under-perform. The onus should then be on the network businesses to justify and prove their case (in relation to revenue proposals). (Consumer Action Law Centre, sub. 5, p. 2)

Some leading researchers are pessimistic about the usefulness of benchmarking in economic regulation. For instance, in looking at arrangements for Swiss distribution businesses Farsi and Filippini (2005, p. 1) concluded that benchmarking analysis should be used to support rather than to determine regulatory decisions. Similarly, Shuttleworth concluded that:

In practice, benchmarking has proven either troublesome or irrelevant to the regulatory process, but proponents continue to search for 'better' models that will be more useful. ... I conclude that, at best, benchmarking can help to focus regulatory enquiries, but that it shows no prospect of becoming a substitute for detailed evaluation of each regulated utility's own costs. (Shuttleworth 2005)

Figure 8.1 Boring down through successive layers of network costs^a



^a The chart is illustrative of the process, but not intended to depict the cost structures of distribution network businesses.

Where an expenditure class appeared close to best practice, further investigation of its constituent elements — of the forensic kind currently undertaken — would be avoided (box 8.4). The AER’s repex model for modelling replacement expenditure by distribution businesses exemplifies this approach:

The calibrated repex model, among other things (e.g. significance of expenditure), was used as a guide to whether or not we considered a detailed review of a specific asset category should be undertaken. (Nuttall Consulting 2010a, p. 31)

Any such analysis would have to consider substitution possibilities between certain classes of spending, particularly opex and capex.¹²

¹² For example, Aurora Energy (2012, p. 73) has indicated that it will increasingly decide whether to replace an asset when it has actually deteriorated (rather than basing replacement on asset ages, which was its past practice). This approach will reduce replacement investment, but would be likely to increase monitoring costs.

Box 8.4 The bottom-up approach — getting into the detail

Locks and keys

In its regulatory proposal to the AER, Ergon Energy proposed an allowance for expenditure on 300 000 locks and keys. The AER asked its consultants, PB Associates to assess this claim. As a result of this, Ergon revised its budget for locks and keys and provided 'a business case' for this expenditure including an 'options analysis'. PB Associates then assessed this claim by examining the number of locks per kilometre of track, and the number of keys to be provided. At the end of its review, PB Associates concluded that the scope of works was transparent and the cost estimate was well supported and so it decided that the revised budget for locks and keys was prudent and efficient. The AER then concluded that Ergon Energy provided a 'well substantiated' forecast for its revised keys and locks program in its revised regulatory proposal and so it accepted Ergon's revised proposal. The lock and key budget was less than 0.2 per cent of the total allowed expenditure by Ergon during its regulatory period. (Mountain 2011, p. 55)

Detailed information on the average span lengths of insulated conductors

The [blacked out writing] also assumes an average span length of 50m for an insulated conductor. This assumed span length is actually 25 per cent greater than the actual average span length. The [blacked out] identifies that CitiPower has 191km of ABC [aerial bundled cable] and 4,703 spans. This works out as an average of 40.6m per span. The reason why the longer span assumption was used when actual span length information was available is not clear. (Nuttall Consulting 2010a, p. 296)

Special trees

As a result of discussions with the ESV, United Energy has revised down its resource requirement to one full time equivalent (FTE) to establish the 'habitat' tree register in the first year (2011), followed by 0.4 FTE in subsequent years to monitor and update the register, process questions and information requests, and provide on-going training to employees and vegetation contractors. (Nuttall Consulting 2010a, p. 357)

Pole treatment processes

Aurora submitted that the AER erred in comparing Aurora's historical pole lives to pole lives achieved by mainland distribution network service providers (DNSPs) because Aurora uses a different type of timber pole to mainland DNSPs. In its draft determination the AER considered that the treatment of Aurora's timber poles should result in similar lives to the untreated mainland timber poles despite Aurora using a different timber class to mainland DNSPs. Aurora submitted that the treatment process typically only impregnates the sapwood (outer layers) whilst the heartwood (inner core) remains untreated. Aurora submitted that although treatment may extend pole life, there is no engineering reason to expect that it would result in a pole with the same life as the poles used on the mainland. (AER 2012f, p. 60)

Regardless of whether the regulator used a formal hierarchical modelling approach, aggregate opex/capex benchmarking could test the overall reasonableness of any

bottom-up approach. If the two are sufficiently discordant, the regulator could ask the business to investigate the likely source of the difference, such as important omitted control variables that affect the benchmarking model. This would again focus attention on major rather than minor cost drivers, and improve the quality of the benchmarking models.

Moreover, if two similar network businesses have very different unit costs, then they should be able to explain the probable reasons and to quantify them. Some networks have already used this approach in the determination process:

Country Energy provided us with a comparison that had been undertaken with Ergon Energy's vegetation management expenditure. The comparison showed that Ergon Energy had a similar profile of vegetation density and that after allowing for differences in cycles and size, Country Energy's proposed expenditure was comparable to that incurred by Ergon Energy. (Wilson Cook and Co. 2008, p. 41)

Requesting feedback from businesses about why results might diverge would not require the business to *demonstrate* how the benchmark result was wrong (notwithstanding the views of one key participant — box 8.2). Until the methods and the data underpinning benchmarking are significantly improved, reversing the existing onus of proof in the Rules would increase business risk significantly (Lowry and Getachew 2009, p. 1325).

Benchmarking at a disaggregated level

In general, disaggregated benchmarking could be used to judge detailed bottom-up aspects of a business's proposal (an approach supported by the ENA, sub. 17, p. 5). This would be possible under the current regulatory framework, as well as under the framework described in figure 8.1. Disaggregated benchmarking might relate to:

- vegetation management
- the linkages between asset vintages and replacement rates by major class of assets (such as poles and distribution substations)
- maintenance efficiency, such as time and resources to correct certain faults
- the efficient monitoring of assets.

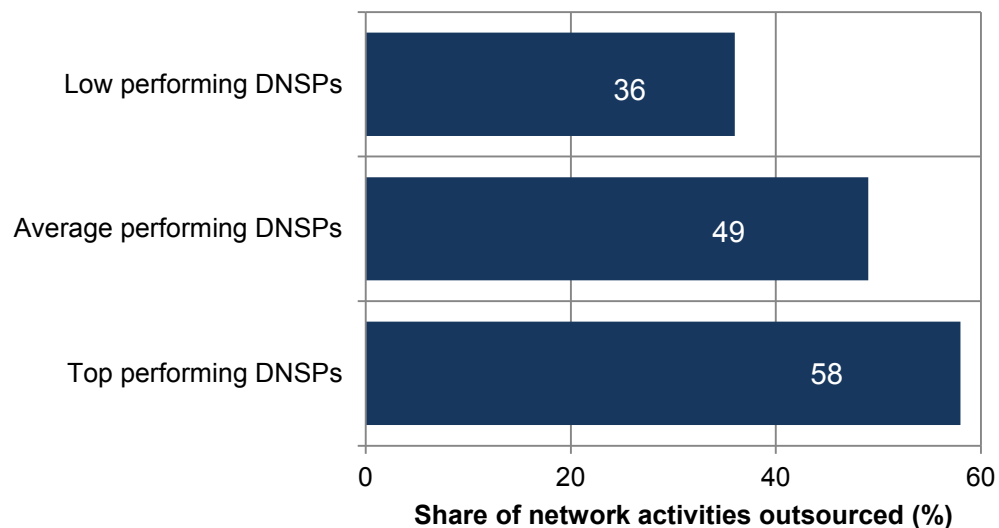
Such specific benchmarking may be reasonably reliable because there are fewer confounding variables.

Management performance measures should not be overlooked. For example, benchmarking of distribution businesses in Europe suggested that higher performing businesses were more likely to outsource their network functions (figure 8.2).

Among other factors, management performance could be measured as the adoption rates of best-practice commercial processes and equipment, including:

- the use of customer panels and surveys (as these can be important elements of customer engagement)
- employment and procurement practices
 - outsourcing (a way in which the business itself can exploit competitive processes)
 - work processes and occupational safety
- demand management (as a network alternative)
- information technologies (increasingly important as networks become ‘smarter’, and given the need to serve millions of customers and control complex networks efficiently)
- innovation
- financial controls
- project management.

Figure 8.2 Do not overlook management processes
Outsourcing and high performing firms in European distribution network businesses^a



^a Outsourced network activities related mainly to preventative maintenance, and assembly and construction.
Data source: Chanel (2008).

Following Turvey's advice (discussed in chapter 4 and 11), regulators need an 'understanding of what an enterprise does and how it does it' before collecting information. Consequently, in determining relevant benchmarking performance and control variables, the AER should consult directly with network businesses, as well as with others in the supply chain (including generators, retailers and network equipment suppliers).¹³

It is equally critical to test whether the performance measures are relevant to customers (by the type of customer). For example, customers may give different weights to connection costs, fault rectification times, reliability, and call centre performance, and may sometimes directly observe practices they regard as inefficient. Finally, and as emphasised later, electrical engineers and other experts may provide strong guidance on the most appropriate measures and controls, including the pitfalls in their measurement and interpretation.

As much as possible, the AER's annual benchmarking reports (box 8.1) and their regulatory determinations should include such disaggregated measures. Moreover, while there is a requirement under the Rules for the reports to use 'reasonably plain language', this should not preclude the use of, and full documentation of elaborate benchmarking analysis (which is reflected in recommendation 8.11).

However, it is unlikely, given the limited time available, that the first report due in September 2014 could cover all of the above matters.

RECOMMENDATION 8.2

Subject to compliance and other costs (recommendation 8.12), the Australian Energy Regulator should accompany aggregate analysis with detailed benchmarking of particular aspects of the performance of the businesses, including:

- ***the rate of investment relative to the age-weighted capital stock by asset class***
- ***the efficiency of major maintenance activities***
- ***the adoption rate of best-practice commercial processes and equipment, including the use of customer panels and surveys, outsourcing, demand management, information technologies, financial controls, procurement practices, occupational safety, and project management.***

In determining relevant benchmarking performance and control variables, the Australian Energy Regulator should consult with:

¹³ This was recognised by the ACCC/AER (2012a, p. 166) and several participants in the inquiry, such as Ergon Energy (sub. 8, p. 10).

-
- *network businesses, generators, retailers and network equipment suppliers*
 - *customer representatives*
 - *relevant experts within Australia and internationally.*

As discussed in chapter 4, the small number of network businesses in Australia poses an obstacle to authoritative benchmarking. This is because it limits the possibilities of making ‘like with like’ comparisons between networks, especially when there are significant differences in operating environments. There are several strategies for addressing this:

- use combined time-series, cross-sectional (or panel) data
- collect data about different businesses’ performances by feeder type, so that comparisons are more robust. For example, the AER (2008a, pp. 160ff) examined reliability by four feeder types — central business district, urban, short rural and long rural feeder
- collect data about the performance of different business units within businesses (for example, comparing in-house with contracted services, or monitoring activities in different areas).

Given that most people served by distribution networks are in Australia’s major cities, comparisons between business performances within metropolitan areas are likely to be the most useful.

RECOMMENDATION 8.3

The Australian Energy Regulator should periodically assess the comparative performance of network business units within particular sub-regions of the National Electricity Market, where:

- *those sub-regions share similar physical operating environments*
- *the costs and informational requirements of doing this are not too great (recommendation 8.12).*

The comparisons should relate to units within a particular business, as well as comparable units in different businesses.

The Australian Energy Regulator should place most emphasis on comparisons of the efficiency of distribution networks in metropolitan areas.

Potential challenges of the targeted approach

This targeted approach may result in excessive rents for some businesses. Any benchmarking model will involve:

-
- (i) false positives (firms that appear inefficient, but are not)
 - (ii) false negatives (firms that appear efficient, but are not).

Under the targeted approach, firms in (i) would be subject to more detailed scrutiny, which should correct the false positive error. However, businesses in (ii) would not be subject to such scrutiny, and so the false negative error would not be corrected. Overall, this would create an upward bias in revenue allowances.

This issue may not matter greatly over successive determinations as the regulator continues to learn. Moreover, if incentive regulation is functioning properly, businesses in (ii) have strong incentives to improve their performance. In that respect, the asymmetric treatment of false positives and negatives may be appropriate.

Alternatively, were the negotiated approach outlined in section 8.4 to be used, it would also help to reduce the incidence (or severity) of false positives, as customers would have some bargaining power to reduce rents.

A further challenge is that, notwithstanding its greater likely reliability and accuracy, the passage of disaggregated benchmarking through the limited merit review process still suggests that it can be problematic to control for the relevant differences in the operating environments of the businesses (box 8.5).

8.4 Benchmarking could be a trigger for negotiated settlements

As the analytical rigour of aggregate benchmarking develops, it could also encourage early settlement in determinations, short-circuiting the protracted, uncertain and costly processes currently applying under the Rules (figure 8.3). The current costs of participating in the determination process are up to \$15 million for each network firm and up to \$6 million for the AER (AEMC 2009a, p. 9). In considering the advantages of CPI-x as a simpler approach to determinations, the AEMC (2011b, p. iii) estimated that the approximate cost of one complete cycle of revenue determinations using the current building blocks method was \$330 million (of which the component paid by the businesses would mainly be passed onto consumers).

Box 8.5 The fiery hoop of merits review

CitiPower and Powercor each challenged the AER's expenditure allowances for vegetation clearance (with the Tribunal considering their concerns in a single review). The AER's ruling relied heavily on benchmarking the costs of Powercor and CitiPower against those of other distribution networks. The challenge provides a useful case study of how the limited merits review has applied to benchmarking.

The network's proposal lacked explanatory evidence. The Tribunal agreed that it should not have been accepted. However, the AER also had to prove that its judgment was reasonable under the Rules. Similar boundaries are likely to apply to benchmarking in the future.

The Tribunal had agreed in principle with the AER's treatment of the proposal, given the lack of explanatory information.

The AER was entitled to be suspicious of the quantum of the step change amounts claimed by each of CitiPower and Powercor given the shortcomings in the information provided and the significant increase over the 2009 base year. Furthermore, it was entitled to benchmark those rates against information provided by the other DNSPs.

In our view, CitiPower and Powercor had ample opportunity to provide greater assurance to the AER concerning the step change amounts which they had claimed. They must be taken to have understood that the AER would wish to look at the rates which underpinned those amounts carefully, would wish to benchmark them against the other DNSPs' rates and would wish to cross-check them as against expenditure in prior periods. (Application by United Energy Distribution Pty Limited [2012] ACompT 1).

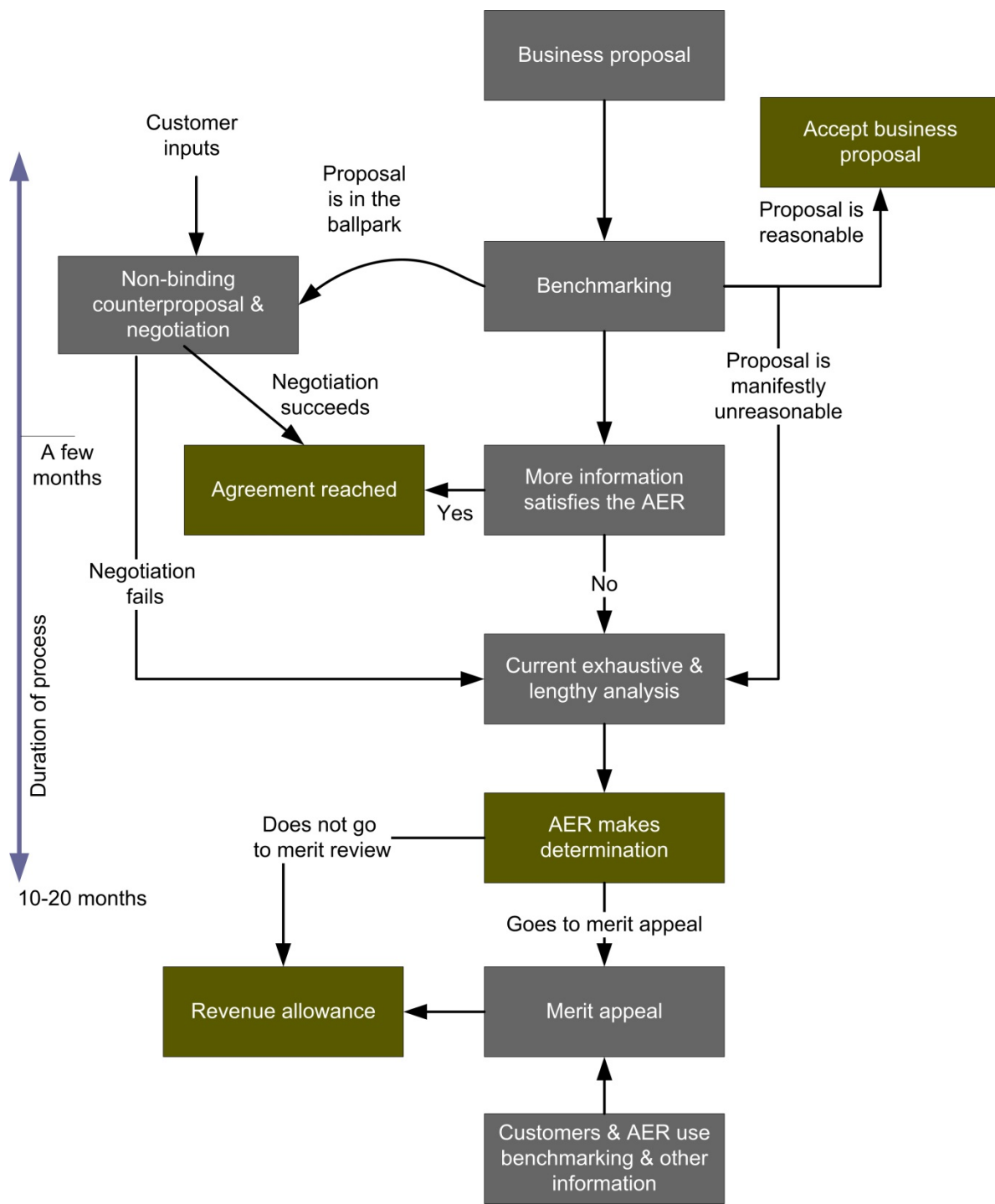
On the other hand, the Tribunal also considered the benchmarking undertaken by the AER, and found that it had not considered factors that were likely to be significant.

... the assessment made by Nuttall Consulting failed to pay proper regard to the differences between Powercor's network and those of the other DNSPs and failed to take proper account of the differences between the work programs which had been put in place by Powercor, in particular, and those which the other DNSPs proposed to undertake. After all, the work programs which Powercor had put in place had been assessed as reasonable by ESV, at the behest of the AER. ESV had concluded that the Powercor work programs constituted a reasonable response to the new regulatory environment created by the Victorian Government as a result of the Black Saturday bushfires.

The AER was justified in not being satisfied with the VEMCO costings [Vemco Pty Ltd is an independent, third party vegetation management contractor]. However, its assessment of the costs of Powercor's work programs was unreasonable. (ibid)

The Tribunal's decision was to remit the matter back to the AER.

Figure 8.3 **Benchmarking as a short circuit**



Under a 'short circuit' approach, depending on the divergence between benchmarking and the business proposal, the AER could immediately accept a proposal as reasonable, or if the proposal was in the 'ballpark', commence negotiations with the network business, with the involvement of customers. These would be better informed because of published benchmarking analyses, and could

act better on this information given the reforms to their resourcing set out in chapter 21.

The AER could also request further information (a ‘please explain’ notice) to assist the early resolution of an agreement. Failing a quick resolution, the AER would adopt the current forensic and protracted processes, with the risks and costs that this would involve for all parties.

There are precedents for benchmarking to assist consumer advocacy

In California, benchmarking analysis is used in the settlement process between the business and a consumer advocate (the Division of Ratepayer Advocates). For example, the DRA has assessed total factor productivity measures to examine the performance of utilities (DRA 2010) and to assess the reasonableness of a given utility’s calculations.

As noted by the ACCC/AER, the role of the DRA is

... to advocate on behalf of the customers of regulated public utilities. It represents consumers in the CPUC [California Public Utilities Commission] proceedings, including rate settings, investigations, and rule makings. The DRA also participates in CPUC-sponsored working groups, advisory boards, workshops, and other forums. The DRA also evaluates utility proposals, investigates issues, presents findings and formal testimony, litigates complaints, and makes recommendations to the CPUC and to other forums. The DRA must ‘represent and advocate on behalf of the interests of public utility customers and subscribers...to obtain the lowest possible rate for service consistent with reliable and safe service levels’. The DRA also has statutory rights to obtain information from utilities through discovery and other means. The CPUC is required to provide sufficient legal support for the DRA, and provide the DRA with its own lead counsel. (ACCC/AER 2012b, p. 176)

Ofgem has proposed the implementation of a similar approach for the regulation of electricity networks in the United Kingdom. In the Ofgem Information Quality Incentive framework, firms are initially judged on the quality of their proposals; their past performance; and benchmarking exercises. Firms are then categorised accordingly as:

- requiring a low level of scrutiny — business plans would typically be given a shorter assessment, and final determinations would be relatively early
- requiring a moderate level of scrutiny — assessments would focus on the deficiencies of the proposal, as well as past performance. Capital projects may be subject to random inspections. Determinations would likely run their normal duration

-
- requiring a high level of scrutiny — business plans would be subject to a full engineering and economic analysis, as well as follow up analysis. Firms may be required to supplement their business plans with further explanatory data. Determinations would likely run their normal duration (Ofgem 2010, p. 58).

Regulation of water in Italy has used a similar approach. The business proposes a tariff in the first step. The regulator estimates a price cap using benchmarking analysis, and approves the business's proposal if it lies within an acceptable range around the estimated price cap. If it does not, then the tariff is renegotiated with the business required to justify its excessive tariff before any revision (Farsi et al. 2005, p. 25).

In Florida, the Florida Public Services Commission has encouraged negotiated settlements in telecommunications and energy utilities. A statutory consumer advocate, the Office of Public Counsel, has been at the forefront of negotiating settlements, replacing formal regulatory processes (Cunningham sub. DR84, p. 9; and the Consumer Action Law Centre, sub. DR79, p. 38). Cunningham noted:

Over the seven years to 2002, approximately 30 % of telecommunications and energy utility price reviews were settled, growing further since then. The available evidence suggests that the elements of settlements have been innovative and customers have tended to obtain better outcomes when compared with formal rate cases.

More broadly, Cunningham provides a comprehensive examination of settlement arrangements in a range of other utility and non-utility contexts, commenting on their (significant) advantages, but observing that all such models have limitations.

Further work on negotiated settlements

The short-circuit process outlined by the Commission in its draft report had in-principle support from many stakeholders.¹⁴ However, participants (and indeed the Commission itself in its draft report) recognised that some pre-conditions would need to be met.

- A consumer body would need to have a statutory right to participate in such negotiations.
- Benchmarking would have to be sufficiently reliable and informative to underpin such settlements.

¹⁴ These included the Total Environment Centre (sub. DR50, p. 2, p. 4); National Seniors Australia (DR62, p. 10), the ENA (sub. DR71, attachment A, p. 4), the AEMC (sub. DR89, p. 19) and CitiPower et al. (sub. DR90, p. 16).

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- A customer group (or groups) would need to be formed and have sufficient expertise before it could occur. For example, the Public Interest Advocacy Centre (sub. DR65, p. 18) and the Total Environment Centre (sub. DR50) considered that consumer stakeholders did not yet have the experience and resources to effectively represent the interest of all consumers in a three-way negotiation process. While these stakeholders recognised the future value of incorporating negotiated settlement processes, the Major Energy Users questioned whether any single consumer body could act as a representative negotiator (sub. DR66, p. 29). However, the experiences in other jurisdictions described above appear to belie that contention. The formation of effective advocacy is discussed further in chapter 21.
 - Some of the potential deficiencies of the approach would need to be resolved, or at least examined more closely. For example, as observed by Cunningham (sub. DR84, p. 16), once a consensus is achieved in a negotiated settlement between the nominated parties, the process stops (that being one of its intentions), which narrows consultation about the outcome, and potentially procedural fairness. This raises issues about the transparency of the settlement process — a point also made by the AER (sub. DR92, p. 3). If nothing else, this reinforces the need for a consumer negotiating body to have credibility with its constituencies.

Among participants to this inquiry, the AER expressed the greatest misgivings about the general viability of negotiated settlements. Not only was it concerned about the transparency of the arrangements, but it suggested that:

The PC has also overestimated the potential role of expenditure benchmarking in terms of being able to ‘fast track’ an entire regulatory proposal, which includes a considerable amount of material non-expenditure items. (AER sub. DR92, p. 3)

It supported a more selective use of a negotiated settlement approach.

Overall, the Commission still considers that a negotiated settlement arrangement should be introduced — subject to the formation of a credible, well-resourced consumer body and sufficiently reliable benchmarking information. The AER itself would have to develop a capability to assist in such a process. As discussed above, years of experience of similar arrangements in the United States and other jurisdictions shows that they are workable and produce good outcomes.

When benchmarking is sufficiently reliable, the National Electricity Rules should be changed to allow the Australian Energy Regulator (AER) to have the discretion to initiate a three-way negotiation of a mutually acceptable settlement. This should involve itself, the network business and the representative and qualified customer body identified in recommendation 21.5:

- *Negotiation would only be triggered if the AER judged that the divergence between aggregate benchmarking estimates of forecast spending and the business's proposal were sufficiently narrow.*
- *Where an agreement was successfully negotiated using this process, the AER should not be obliged to go through the current formal draft/final determination processes.*

8.5 Information and 'moral suasion'

Benchmarking at any level of aggregation could be used to inform customers (and the media) about the relative performance of businesses, which provides indirect pressures on inefficient businesses and their shareholders (including state governments). In this respect, the Consumer Action Law Centre pointed out:

Enhanced information and transparency about regulated network businesses can benefit the regulatory process as well as improving the behaviour of network businesses. A better-informed regulator will produce more efficient price setting, while comparative analysis and reporting on the network businesses' performance by the regulator can create an incentive for the network businesses to 'self-discipline' as a result of competition-by-comparison and brand protection. (sub. 5, p. 1)

Benchmarking would also facilitate the participation of consumer groups in the determination process (beyond the negotiated settlement arrangement discussed above). For instance, the EUAA cited an example where the availability of benchmarking might have assisted in the merit review process:

The [Australian Competition Tribunal] refused the EUAA leave to appeal on the basis that the EUAA could not demonstrate that the AER's failure to have regard to benchmarks satisfied the financial threshold for appeals under the National Electricity Law. The Tribunal required the EUAA to have benchmarked the distributors' expenditure and to show that, had the AER also done this, the expenditure allowance would have been significantly lower than the allowance determined by the AER. Obviously, the EUAA was not in a position to undertake extensive regulatory benchmarking itself and so could not satisfy the Tribunal's criterion for leave to appeal the AER's determination. (EUAA, sub. 24, p. 4).

Aside from contributing to determinations, the advantage of systematic benchmarking comparisons between network businesses at the micro and macro level is that it could identify groups of firms that are consistently more efficient, and highlight some of the potential causes of the efficiency gaps (an issue raised in chapter 4).

The requirement that the AER produce annual benchmarking reports in ‘reasonably plain language’ will achieve many of the above objectives, as will the formation of an effective consumer advocacy body (chapter 21).

8.6 The long-run application of benchmarking

As discussed in section 8.1, even though benchmarking may contribute to regulatory determinations, there is little immediate scope for benchmarking to play a decisive role. Nevertheless, as data and modelling improve, and with better-designed incentives arrangements, there may be greater scope to give more weight to aggregated benchmarking. As Jemena observed:

The AER now has extensive information gathering powers under the NEL and it is exercising those powers. Over time, that should produce a data-set that could support more extensive use of benchmarking and the use of more sophisticated benchmarking techniques; however that is some way off. (sub. 21, p. 10)

While the risk of regulatory error would still persist, the protection against regulatory error would be to set the benchmark at a level close to the competitive market standard — such as the 75th percentile — rather than at the frontier (Lowry and Getachew 2009, p. 1329). The Major Energy Users also recognised the need for the long-run viability of the network businesses when setting the benchmark:

If it is awarded too little revenue which is based on the efficient frontier, then the firm could be in financial trouble which would be a worse outcome for consumers. (MEU, sub. 11, p. 26)

As Jemena (sub. DR77) point out, any new benchmarking-based framework should be considered in light of both the Revenue and Pricing Principles in the NEL, and the National Electricity Objective.

Participants also noted that moving to a regime where the AER uses benchmarking as the primary basis for setting revenue determinations would be a significant change, and that the processes to reach that goal would require consultation and stakeholder confidence (SP AusNet, sub. DR69). The Commission recommends a consultative and rigorous process to achieve this goal, particularly in regard to data, model outcomes and methodologies (section 8.7).

RECOMMENDATION 8.5

In any of the next rounds of regulatory determinations, the Australian Energy Regulator should not use aggregate benchmarking as the exclusive basis for making a determination. Instead, it should use aggregate benchmarking as a diagnostic tool in responding to business cost forecasts.

CPI-x may have some advantages when linked with privatisation

The evidence suggests that state-owned networks are less efficient than their private sector counterparts (chapters 6 and 7) and, without reform, would continue to face muted incentives to reach the efficiency frontier over time. Privatisation can be expected to significantly increase efficiency and strengthen the responsiveness of the businesses to incentive regulation. This could open the door to the use of the TFP methodology described in section 8.1 and chapter 4 (and strongly advocated by the Victorian Government in the Rule change it proposed in 2008).

This could best be achieved by:

- privatising the state-owned enterprises following the orderly approach described in chapter 7
- refining the methodology for deriving x from TFP, and the commencement of data collection. Much of the work for specifying the appropriate methodologies for TFP indexes has already been completed (AEMC 2011b and Pacific Economics Group, subs. 35 and DR48) and some data are already available
- examining the revealed costs of the privatised businesses after completion of the forthcoming round of building-block determinations. The AER would use these costs as the *partial* basis for setting the base year revenue amount, when the TFP approach commenced. (It would be important to set a base at a higher level than the actual revealed efficient costs because otherwise the private business would have an incentive to cost pad during the forthcoming determination period)
- ensuring that the TFP measure was reasonably reflective of likely future productivity trends. DPI (2009, p. 9) recommended that x should be calculated some years after privatisation, reflecting the short-term, positive impacts of privatisation on productivity. However, it may be possible to use the TFP estimates of the long-privatised Victorian and South Australian distribution businesses as a proxy for x across the NEM, noting that TFP *growth* rates are less likely to be affected by the environmental factors affecting efficiency *levels*.

The businesses might still charge higher than desirable prices under such a regulatory regime, but would have incentives to set these in a way that reduced their

allocative inefficiencies. Moreover, subject to an effective privatisation process (chapter 7), the sale price would capitalise at least a part of the businesses' future stream of rents.

Given the sequenced nature of the reforms required, the realisation of this option would be some way away. The Commission has not recommended the long-run adoption of a CPI-x approach based on TFP, since that decision does not need to be made now, and its desirability would depend on what actually transpires in the market and in the Rules. However, this option should be regarded seriously, and the preliminary analysis and data collection to realise it should be undertaken, a view echoed by the Victorian DPI (sub. DR94, p. 5).

8.7 The regulator's benchmarking practices

The path to more sophisticated benchmarking requires supportive actions by the regulator.

Acquiring, sharing and using data

Due to the rulings in AEMC (2012a), network operators are already collecting greater amounts of data specifically for benchmarking purposes, while the AER is standardising its data collection and benchmarking processes (box 8.6).

There remains a further question over the extent to which data should be made publicly available. Several commentators have emphasised the importance of putting data in the public domain in order to allow greater transparency, and to allow stakeholders to undertake their own analysis (Lawrence 2009). Information and data on network characteristics are often only publicly available in high-level aggregates, whereas detailed data is often subject to confidentiality concerns.¹⁵ However, network businesses are natural monopolies, where confidentiality is not as justified as it is for businesses operating in the competitive market. Accordingly:

- most data required to assess business performance should be made publicly available. This would allow rigorous analysis of network performance by customer groups and researchers. This would increase the capacity for customers to act in the negotiating role set out in section 8.4 and in creating public pressures for improved efficiency (section 8.5)

¹⁵ All data collected by the AER through Regulatory Information Notices (or other compulsory processes) are confidential. In the Commission's own experience, the sourcing of detailed data for the purposes of this inquiry has been met with various responses from networks, ranging from free unfettered use to complete anonymity.

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- even where data are genuinely commercial-in-confidence, consumer groups involved in negotiations under recommendation 8.4 and independent researchers should be able to access the data. This access should be subject to requirements that they do not divulge publicly the information either directly, or in a way that identifies specific businesses. Such arrangements are routine for other sensitive information (for example, survey data sets collected by the ABS and administrative records from major government agencies).

To give effect to the better dissemination and use of these data, the AER needs to develop systematic and easily used databases, and publish more information on how businesses are performing. The annual ‘State of Energy’ reports are useful, but the information provided has reduced over time. The 2008 report provided more than 320 pages of information, while the 2011 report was 120 pages in length. (This is in contrast to the exponential growth in the length of regulatory proposals and determinations.)

Box 8.6 The AER’s information strategy

The AER’s information strategy includes reviewing the data definitions of key information required to undertake economic regulation, and developing:

- benchmarking measures for electricity network capex, operating expenditure and, if appropriate, total expenditure
- benchmarking measures to compare the relative efficiency of regulated energy businesses, with an initial focus on electricity distribution

Having expanded the electricity distribution performance report to include network businesses from the Australian Capital Territory, New South Wales, Queensland and South Australia for the 2010-11 report, and Victorian businesses for the 2011-12 report, it will look to include Tasmanian businesses in the 2012-13 report.

In 2013, while the AER will continue the development of analytical tools and data requirements, it will also consult with stakeholders regarding a stable set of reporting requirements for the following regulatory period.

Source: AER (sub. 13, p. 18; 2012, AER Information Framework, Information Paper, June).

In-house expertise

While raw data is valuable, a major role for benchmarking is to transform complex data into meaningful performance measures. As discussed in chapter 4, this often entails high-level technical expertise. While the AER should continue to engage

external consultants,¹⁶ an in-house capacity to undertake sophisticated analysis would have significant benefits. It would:

- better inform the collection of data relevant to best practice analysis
- improve the AER's capacity for intelligent and demanding outsourcing. Outsourcing requires sufficient in-house capability to discriminate among the various consultants. Moreover, there are likely to be greater benefits from outsourcing if the AER can absorb the research results it receives¹⁷
- allow the AER to interpret and communicate any technical results in a way that is accessible to non-experts.

Maximising the AER's capacity to learn

One particularly important aspect of acquiring and retaining internal expertise is a greater capacity for learning within the AER, and a more general capacity to interpret the revenue proposals of businesses.

A major problem besetting any method for determining the benchmark efficient costs of a business is that there is no recognised standard against which to test the accuracy and reliability of the estimates of efficient costs.¹⁸ In effect, there is no agreed benchmark for verifying *either* bottom-up or benchmarking models against the 'true' cost.¹⁹

Given that businesses have strategic interests, it seems likely that, after considering the businesses' processes and the detailed consultations that follow, the AER is in the best position to determine the best, unbiased estimate of their true costs. For the reasons outlined in chapter 5, that may be different from the AER's actual determination reached under the Rules. However, recommendation 5.2 proposes

¹⁶ The AER already routinely uses external consultants for economic and engineering advice, such as Nuttall Consulting (2010a) in the Victorian distribution network determinations, and Schweinsberg et al. (2011) on European benchmarking practices. But currently, it has limited current in-house capabilities in this area.

¹⁷ In the business world, an internal research capability is not only valuable in its own right, but because it raises the absorptive capacity of the business to others' ideas (PC 2007).

¹⁸ The situation is different from many other tests — such as the accuracy of medical diagnostics (confirmed through assays) and clocks (confirmed by reference to the US National Institute of Standards and Technology's highly accurate clock).

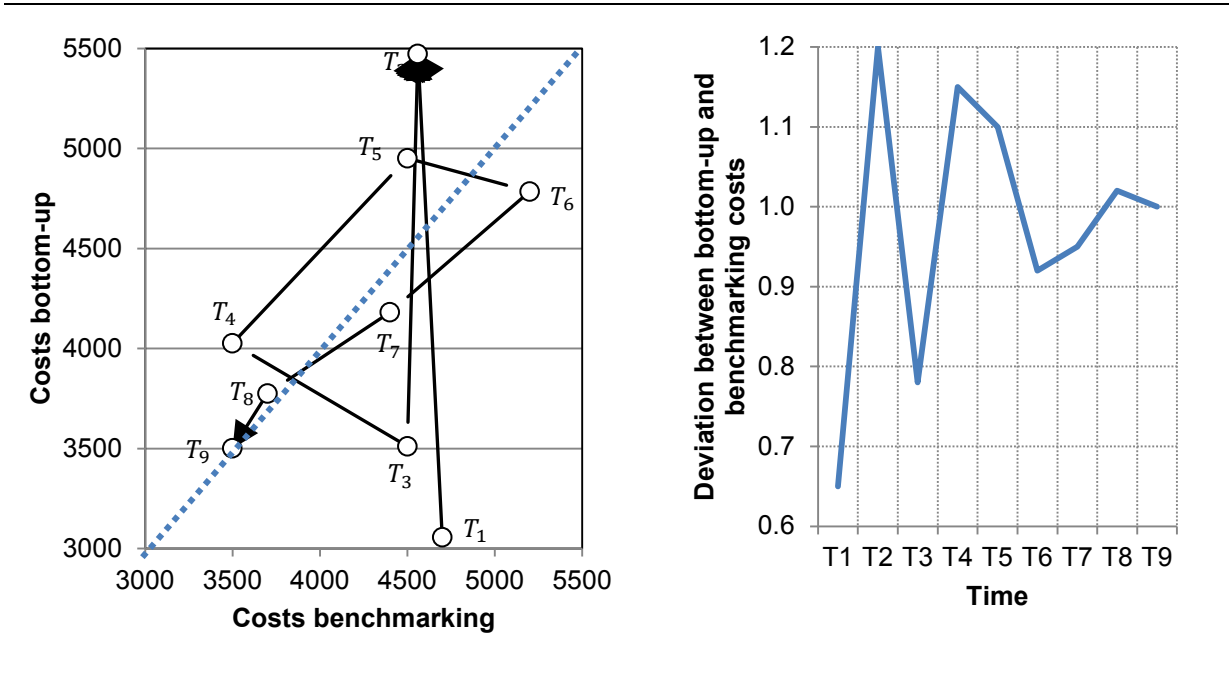
¹⁹ In theory, under a high-powered incentive regime (chapter 5), profit-motivated businesses will progressively reveal efficient costs, which could be an alternative estimate of 'true' costs. However, that process may be quite slow if lower-powered incentives apply or state-owned businesses (which may be constrained by a variety of non-commercial objectives imposed by their shareholders) continue their dominant role.

that if there is any divergence between the two estimates, the AER would also publish its preferred estimate. Over time, the AER can compare the estimate derived from a more bottom-up approach with the simpler estimates derived from aggregate benchmarking analysis. If benchmarking models improve, the model results should converge on the true estimate (in the fashion depicted in figure 8.4), improving their wider use and displacing the need for as much bottom-up testing.

One immediately useful exercise in this vein would be for the AER to reveal its preferred estimate of capex and opex arising from *past* determinations and examine how these estimates compare with the predictions of simple benchmarking models. That would provide an early test of the value of ‘primitive’ benchmarking.

Figure 8.4 **Convergence between benchmarking models and bottom-up cost estimates**

A speculative illustration for a single business



a The graph on the left hand side shows the relationship between the bottom-up and benchmark estimate of costs from T1 to T8. Full convergence occurs if the two estimates are the same, which means they would lie on the 45 degree line. At T9, the two estimates have converged. The right hand chart shows the *ratio* of bottom-up cost to the benchmarking costs over time, showing how they move closer together over time (shown as reduced variance).

Similarly, given the importance of demand forecast errors for both transmission planning and for the outcomes of regulatory determinations, there would be benefits in examining the reasons for variations in demand forecasts produced by AEMO and distribution businesses. The two most important aspects of demand are total energy and maximum energy because these drive the requirements for network

capacity.²⁰ Currently, AEMO (2012a) produces top-down forecasts of demand at the regional level, using regression models that include such factors as temperature and gross state product. It also produces demand forecasts based on information provided by distribution businesses and direct customers of transmission businesses, which differ from the top down estimates. Given its responsibility for demand forecasting, AEMO is in the best position to undertake the technical analysis to understand why the two sets of forecasts diverge. However, given that the AER makes regulatory determinations that provide considerable weight to demand forecasts, and as that it will be expected to do so in a more sophisticated way in the future (as discussed in chapter 11), it should:

- act as an informed consumer of AEMO's technical modelling, as this will assist the AER in its broader benchmarking analysis, and, through feedback and challenge, should assist AEMO to improve its own modelling
- take into account AEMO's modelling in making its regulatory determinations.

The AER pointed out that such exercises are not without costs — particularly when comparing past and present estimates and results (sub. DR92, p. 6). The Commission considers that comparing benchmarking results with actual outcomes is a part of the process for improving and refining models. Of course, the realistic goal is not to have an ex-ante model to perfectly predict the future — rather, it is to be able to identify the specific causes of the discrepancies, and hence understand the limits of the model.

RECOMMENDATION 8.6

The Australian Energy Regulator should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.

RECOMMENDATION 8.7

The Australian Energy Regulator should make all benchmarking input data publicly available (recognising that the businesses being benchmarked are regulated monopolies) except where the data can be demonstrated to be genuinely commercial-in-confidence.

Where the latter holds, the Australian Energy Regulator should still make the full datasets available to:

²⁰ Defined by AEMO as the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.

-
- *independent researchers who are using the results for non-commercial purposes*
 - *the consumer body involved in any negotiations described under recommendation 8.4.*

Provision of data should be subject to statutory requirements for non-disclosure of information predetermined as commercial-in-confidence, drawing on existing models for data protection.

RECOMMENDATION 8.8

When making its revenue allowance determinations, the Australian Energy Regulator should make judgments about capital expenditure forecasts that take account of:

- *any discrepancy between the Australian Energy Market Operator's top-down demand forecasts and the aggregate of network businesses' bottom-up demand forecasts*
- *any discrepancy between previous expenditure forecasts and actual outcomes by different parties.*

Collaboration

While there are several obstacles to international benchmarking, it may still provide useful information (chapter 4), and network businesses and governments already undertake such analysis. International collaboration between regulators, academic experts and global benchmarking specialists may improve the validity of international benchmarking. This has been long-recognised (Jamasb and Pollitt 2001, and Farrier Swier Consulting 2002), but the mechanisms for achieving it are still incomplete.

International collaboration would involve the consistent collection, auditing and reporting of data, and shared approaches to reporting results and the statistical testing of models.²¹ This would facilitate meta-studies, which help identify common variables that lead to robust benchmarking results. For example, if many

²¹ There appears to be greater efforts for international collaboration in water utility benchmarking than in electricity, with benchmarking consortia established for the Americas, Africa, and internationally (Berg 2010, p. 62). In utility regulation generally, the Public-Private Infrastructure Advisory Facility, the World Bank, and the Public Utility Research Center of the University of Florida have created a collaborative online repository of material on infrastructure regulation (<http://www.regulationbodyofknowledge.org>). However, this is more a collection of references and training tools, than a resource for benchmarking and data collection.

(rigorous) individual country studies find that a limited set of consistently defined explanatory variables perform well in measuring industry costs — across diverse regulatory and operational environments — it suggests that such methods may be reasonably robust in any country.

Collaboration could also have other benefits, such as:

- increasing diffusion of best practice benchmarking techniques and data construction (such as meaningful measures of capital), which would build expertise and knowledge
- facilitating contacts between experts for solving technical and practical problems in benchmarking
- providing lessons and case studies on the pitfalls and unexpected benefits of benchmarking. For instance, the Commission's own inquiry report has benefited from the experiences of Ofgem in the United Kingdom and FERC in the United States
- making it easier for secondments between agencies
- supporting external peer review of specific regulator's benchmarking analysis.

Transparency, consultation and communication

Section 8.3 has already spelt out the need for stakeholder involvement in developing benchmarking models. But, equally, they (and experts) should have a role in commenting on results (which should all be public). They should also be encouraged to undertake their own analysis, and have the information required that would allow them to replicate any models.

From a scientific perspective, the AER should adopt processes that will increase the quality of its analysis. This would involve independent expert peer review of benchmark models to:

- establish their ongoing relevance, sensitivity to assumptions, and scientific validity (including the performance of any statistical models against accepted standards — including confidence intervals, parameter stability, and specification testing, as set out in chapter 4)
- assess the modelling strategy used to produce the results
- consider the policy implications of model and parameter misspecification
- assess whether the AER has adopted best practice models
- ensure that methodologies and results are presented and reported according to widely accepted standards.

Most stakeholders agreed that peer review was appropriate.²² Nevertheless, the Victorian Department of Primary Industries (sub. DR94, p. 8) expressed concern that external peer review processes may be unnecessarily expensive. However, the Commission considers that peer review is generally not a costly exercise, particularly in relation to the costs associated with the overall revenue determination process. It would not involve long-winded inquiries, but rather it would resemble the processes routinely practiced by research agencies and academics, including the Productivity Commission itself.

The benefits of peer review would be particularly strong given that the vast majority of benchmarking research on Australian electricity networks is prepared for industry participants (including regulators), and may not necessarily be scrutinised to the extent typical of academic research.

It is also important for the AER to disclose the impacts of factors outside the control of businesses, but that may be controllable by governments (since, as noted above, these are important for policy and regulatory development).

While the key role of benchmarking is the determination of efficient revenue allowances, the AER would also need to communicate the results to their disparate stakeholders in an accessible way. As Berg (2010, p. 56) has colourfully noted: avoid ‘sensational factoids’, but use clear presentation methods for experts and lay audiences.

RECOMMENDATION 8.9

The Australian Energy Regulator should collaborate with other leading regulators, academic experts and global commercial benchmarking specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies. The collaboration should include cooperation in developing:

- ***the most meaningful measures of performance***
- ***consistent data collection***
- ***consistent reporting of results***
- ***best-practice analytic frameworks.***

²² These included the Public Interest Advocacy Centre (sub. DR65, p. 24), Major Energy Users (sub. DR66, p. 33), the Energy Supply Association of Australia (sub. DR70, p. 5), and the Energy Networks Association (attachment A of sub. DR71, p. 6).

RECOMMENDATION 8.10

The Australian Energy Regulator should submit its major benchmarking analyses of electricity networks for independent expert peer review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to gauge the degree of uncertainty in the results.

RECOMMENDATION 8.11

The benchmarking analysis produced by the Australian Energy Regulator should include:

- *accessible reporting of the results to inform consumer groups, network businesses, and others*
- *disclosure of the importance of factors outside the control of businesses, but that may be controllable by governments*
- *publication of the modelling strategy used to produce the results*
- *the sensitivity of the results to changes in key assumptions*
- *the performance of any statistical models against accepted scientific standards, including confidence intervals, parameter stability, and specification testing.*

Practicality and compliance costs

Data collection, consultation and modelling impose costs on the regulator and network businesses. Accordingly, the principle should be to only collect information or use processes likely to produce net benefits.

The AER considered that benchmarking methods might reduce compliance costs for businesses:

Unlike the current building-block approach, benchmarking does not unrealistically, burdensomely and intrusively aspire to duplicate or exceed the knowledge of business operation possessed by decentralised decision-makers in regulated entities. Rather, the informational and regulatory burden of a benchmarking program is limited to relative knowledge – a knowledge that only need pertain to relative performance. (ACCC/AER 2012a, p. 168)

This seems overly sanguine, since detailed bottom-up assessment is unlikely to be displaced over the medium term. Moreover, testing the validity of benchmarking models (using the learning process set out earlier) will still require bottom-up information. Consequently, the informational burdens are likely to rise, not fall (and this is one of the reasons why the Australian Government's decision to allocate additional resources to the AER is justified, as discussed in chapter 21). That should

change as the AER (and its international collaborators) develop better models and identify the most important data items.

In the meantime, the AER should routinely re-assess:

- its benchmarking approaches
- the resources it uses in benchmarking
- the compliance burdens on businesses.

These assessments should be publicly available and subject to independent refereeing.

RECOMMENDATION 8.12

The Australian Energy Regulator (AER) should periodically examine its benchmarking methodologies and processes — with input from an independent expert referee — to assess their usefulness in the determination process and the costs they impose on stakeholders. It should compare these costs with the likely benefits when determining the appropriate frequency and type of detailed benchmarking. In undertaking such assessments, the AER should consult closely with network businesses.

The AER should make all such assessments publicly available.

8.8 Conclusion

Although Australia has been relatively ‘unsophisticated’ in its use and application of regulatory benchmarking in the electricity sector, this is likely to change in coming years with improvement in the AER’s data collection and modelling capabilities. An increase in benchmarking for diagnostic and informational purposes is likely in the near term, given recent AEMC Rule changes. Over time, repeated use of benchmarking models (as well as ex-post analysis) will improve the reliability of the models’ estimation of network efficiencies, and increase the potential for them to have greater weight in regulatory decisions. Whilst there may be some shorter-term burdens for network businesses in providing additional data to the AER, improved confidence in benchmarking has the potential to simplify determinations and lower overall costs, leading to benefits for network businesses and consumers.