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PREFACE

Following a request from the South Australian Government, on 22 December 1995 the Assistant Treasurer requested that the Industry Commission review the structure of the South Australian (SA) electricity industry. Originally the Commission was asked to report within 75 days.

On 20 February 1996, the SA Minister for Infrastructure wrote to the Commission stating that he would be overseas until 16 March 1996. He requested that the Commission deliver the final version of its report on his return, on either 15 March or 18 March 1996.

Following presentation of the report, the SA Government wrote to the Commission on 19 March 1996, seeking clarification on three matters. The Government’s questions and the Commission’s response are reproduced in Appendix C.

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AECA	Australian Electricity Code Administrator
CEO	Chief Executive Officer
COAG	Council of Australian Governments
CP Agreement	Competition Principles Agreement
CPR Act	*Competition Policy Reform Act 1995*
CSO	community service obligation
CUBE	Canadian Utilities–Boral Energy joint venture
EBIT	earnings before interest and taxation
ESAA	Electricity Supply Association of Australia
ESI	electricity supply industry
ETSA	Electricity Trust of South Australia
GBE	government business enterprise
GTE	government trading enterprise
GWh	gigawatt-hour
IOA	Interconnection Operating Agreement
IPP	independent power producer
kWh	kilowatt-hour
MNC	Multiple Network Corporation
MW	megawatt
MWh	megawatt-hour
NCC	National Competition Council
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NGMC	National Grid Management Council
NSW	New South Wales

PSA	Prices Surveillance Authority
PS Act	*Prices Surveillance Act 1983*
SA	South Australia
SMP	system marginal price
STFM	short term forward market
TFP	total factor productivity
TP Act	*Trade Practices Act 1974*
TPC	Trade Practices Commission

GLOSSARY

augmentation	Additional capital works undertaken to increase capacity.
availability	The proportion of time for which a generating unit is available to produce electricity at its **rated capacity**.
base load	The minimum electrical **power** demanded over the year. A generating unit servicing the base load is run continuously at or near its **rated capacity**. Base load generating units normally operate with an annual **capacity factor** in excess of 60 per cent.
capacity factor	The measure of the **energy** production of a generating plant during a period compared to the total **energy** production if the plant had operated continuously at full output during the period. Usually expressed as a percentage.
cogeneration	The generation of electricity as a by-product of another process in industry. It involves the recovery of heat or **primary energy** that would otherwise be wasted.
combined cycle	A two-stage electrical generation process. In the first stage electricity is generated by gas turbine. The waste heat is then used to generate more power by steam turbine.
commercialisation	Applying commercial principles to a GBE as far as possible.
corporatisation	Subjecting GBEs to the principles of the corporations law. Often accompanied by a range of other initiatives, including providing greater management autonomy and clear commercial objectives, performance monitoring and competitive neutrality.
demand management	The modification of electricity demand (by spreading or reducing the **peak load**) to reduce the cost of generation. Also referred to as demand-side or load management.
dispatch	The process of bringing individual generators into production.

distribution — The process of transferring electricity from the **transmission** system to final users. Electricity is distributed along local networks of overhead and/or underground power lines.

energy — A measure of the amount of electricity (or gas) used over a period of time. Units commonly used for electricity are gigawatt hours (GWh), megawatt hours (MWh) or kilowatt hours (kWh), depending on the power and time scale involved.

forced outage — The unscheduled stoppage of an electricity generating unit.

generation — The process of converting **primary energy** (mostly coal, gas, oil or stored water) into electricity.

gigawatt — A measure of **power** equivalent to 10^9 **watts.**

gigawatt-hour — A unit of electrical **energy**. 1 GWh = 1,000,000 kWh.

horizontal separation — The separation of one organisation into several firms that each performs the same function. In the case of electricity utilities this involves separating one multi-plant generation business, for example, into several generation businesses.

Interconnection Operating Agreement — An agreement between utilities in New South Wales, Victoria and South Australia which specifies the terms and conditions under which electricity is exchanged between them.

interconnection — High voltage transmission line linking States.

intermediate load — The power demand which falls between the **peak load** and the **base load**. Intermediate load generating units typically operate on weekdays; they are shut down or off loaded overnight and on weekends.

interruptibility — An arrangement by which a large user’s load may be reduced to meet the operational requirements of the electricity utility in return for a price discount.

joule — The basic international unit of **energy**. Commonly used to measure the volume of **energy** for gas.

load — The instantaneous rate of electrical power demanded of or supplied by the electrical supply system.

load factor	The ratio of the average load to the peak load during a given period, usually expressed as a percentage.
loss of supply factor	The number of minutes per customer per year when electricity supply is disrupted.
kilowatt-hour	The basic unit of electrical **energy** in common use.
megawatt	A measure of **power** equivalent to 10^6 **watts.**
merit order	The ranking of generating units in order of their (increasing) costs of generating electricity. Used to schedule generating capacity over time so as to minimise system costs.
national electricity market	A competitive market for electricity between all the Australian regional electricity systems that could be interconnected by about the year 2000.
natural monopoly	Arises where the entire output of a market can be supplied at a lower cost by one supplier than by any combination of two or more firms. Reflects the presence of economies of scale and/or scope.
off-peak	The time of lowest electrical demand. Normally weekends, public holidays and week nights.
peak load	The maximum power demand placed upon the generating system for relatively short periods of time. Dedicated peak load generating units normally average a **capacity factor** of only 10 to 30 per cent over the year.
power	A measure of the rate at which **energy** can be generated. Generally measured in **watts** (W), **megawatt**s (MW) or **gigawatts** (GW).
power pool	A group of electricity utilities that co-ordinates planning and/or operation of generating capacity to achieve better reliability and lower costs of production for the group as a whole.
primary energy	Those natural resources from which **energy** can be extracted directly. Includes crude oil, black and brown coal, natural gas, uranium as well as renewables such as hydro-electricity, solar energy and wood.

rated capacity	The stated maximum power that a generating unit can produce continuously, normally measured in **megawatts (MW)**.
reliability	The ability of the electrical supply system to meet demand taking into account operational uncertainties.
reserve plant margin	The uncommitted generating capacity in a system, normally expressed as a percentage of the maximum demand over the year.
ring-fencing	The internal separation of business functions within an enterprise for management and accounting purposes.
scheduled outage	The planned removal of a generating unit from service for routine or preventative maintenance.
secondary energy	Sources of **energy** derived by processing or converting **primary energy** into other forms. Includes coke, electricity, petroleum products, town gas and briquettes.
spinning reserve	The on-line generating capacity held in reserve against any unexpected loss of capacity in or increased demand upon the system.
standby	Those off-line generating units held in reserve against any unexpected loss of capacity in or increased demand upon the system.
third party access	The use by third parties of essential facilities, such as the natural monopoly elements of a vertically integrated utility.
transmission	The process of transferring high voltage electricity from generating stations to **distribution** networks.
value of lost load	An estimate of the value of load involuntarily shed due to supply constraints.
vertical separation	The division of a vertically integrated enterprise into commercially autonomous operations. In the case of electricity utilities this involves separating generation, transmission, distribution and retail supply.
watt	The basic unit of electrical **power**.

TERMS OF REFERENCE

The Industry Commission is requested to review the structural arrangements for the electricity industry to determine the structure that will best suit South Australia taking into account;

- obligations made through National Competition Policy Agreements; and
- potential market power to be exerted by the generation entity or entities.

In taking into account past agreements at COAG, the review is to consider the extent of vertical separation required to achieve the outcomes of the Multiple Network Corporation (MNC) structural model. In the context of recent developments made by the National Grid Management Council towards an effective National Electricity Market, it should examine implications for competition and economic benefits of alternative structural arrangements, (a) consistent with the MNC structure, and (b) consistent with structures contemporaneously evolving in the Australian electricity industry.

In undertaking the review the Commission should have regard to:

- the principles for structural reform of public monopolies contained in the Competition Principles Agreement;
- the obligations for structural change in electricity utilities agreed by COAG meetings and subsequently incorporated into the April 1995 Inter-Government Agreement; and
- the operation of a competitive national electricity market.

Without limiting the scope of the study, the Commission should also have regard to:

- the appropriateness of the present structure of ETSA Corporation in relation to the requirements of national competition and related reforms;
- whether the separation of the ETSA Generation subsidiary from the network/retail subsidiaries or the introduction of some other structure is in the best interests of South Australia for its participation in the national electricity market;
- the extent of competition in the South Australian region with current interconnector capacity;
- the impact of alternative structural proposals on new investment and the capacity for new generation to enter the South Australian electricity industry;
- the potential for market power to be exercised taking into account capacity constraints on interconnectors and alternative generators; and
- the implications for the development of the nature and form of the South Australian energy market.

The review should also consider the implications of the alternative structures on the trade-off between benefits from structural reform and the costs associated with possible loss of economies of scale and scope.

The Industry Commission is requested to report within 75 days of receiving these terms of reference.

George Gear
22 December 1995

EXECUTIVE SUMMARY

This report reviews the structure of the South Australian electricity industry. It was undertaken to assist the South Australian Government to determine the structure that will best suit South Australia in preparing for the interim national electricity market which is scheduled to commence in September 1996.

The review was initiated by the Assistant Treasurer on 22 December 1995, following a request from the South Australian Government. The Commission was asked to report to the two Governments within 75 days. Subsequently the South Australian Government asked that the Commission's report be presented to it by 18 March 1996.

Electricity industry in South Australia

For many decades, electricity supply in South Australia has been organised around a monopoly Government Business Enterprise (GBE) protected by statutory barriers to prevent others entering the industry or trading electricity. Originally established as the Electricity Trust of South Australia, the Trust was recently corporatised and is now known simply as ETSA Corporation.

Until the 1990s, most electricity GBEs in the States and Territories were vertically integrated, that is they controlled several links in the supply chain from generation, through transmission and distribution, to retailing. ETSA is one of the most vertically integrated of the electricity GBEs in Australia. It generates 99 per cent of the electricity produced in South Australia, some of it with coal from its Leigh Creek mine. Although up to 35 per cent of South Australian demand can be supplied from interstate through the transmission interconnection with Victoria, ETSA controls all imports. Finally, ETSA transmits, distributes and retails effectively all electricity sold in South Australia.

In the past, government policy towards the electricity industry, in South Australia and elsewhere in Australia, sought to promote self-sufficiency in electricity. Unfortunately it provided weak disciplines on decisions by the electricity GBEs on their operating costs, tariffs to users and investment in new capacity. Partly as a consequence, efficiency in the Australian industry remains below that of leading comparable utilities overseas. In ETSA's case, the gap in efficiency at the beginning of the 1990s was around the average for all Australian electricity GBEs, but it appeared to perform worst in generation — to some degree this may reflect its smaller scale of operation and poorer quality coal. While ETSA has improved its performance significantly in recent years, it is not clear that it has narrowed the gap between it and international best practice.

Recent policy developments

Given the strategic importance of energy to industry, inefficiencies in electricity supply are a burden on industrial competitiveness and economic performance. In recognition of these cost burdens, there has been a significant reappraisal of policy towards the electricity industry throughout Australia and in many other industrialised countries. At the heart of this reappraisal is a recognition of the need to remove barriers to entry and to restructure the electricity utilities so as to encourage the competitive discipline needed to improve economic outcomes.

Although policy prescriptions have varied, structural reform has usually involved separating vertically integrated utilities to create autonomous organisations to manage each of the following activities:

- natural monopolies (transmission and distribution networks);
- potentially competitive activities (generation and retail); and
- market regulation (system control and planning).

Structural reform has also involved *horizontal separation* — dividing the potentially competitive activities into multiple, independent businesses.

Vertical separation promotes competition in several ways. It decreases the scope for the networks or the market regulator to be used to protect the potentially competitive activities. Separation focuses the efforts of the managers of each business on their own objectives, not those of the rest of the organisation. By doing so, vertical separation not only promotes competition, but also facilitates more efficient regulation of the networks.

It is for these reasons that structural reform of electricity supply has become a key requirement of the Council of Australian Governments (COAG) for national competition policy and the creation of a national electricity market.

Towards a national electricity market

In Australia, the policy reappraisal of the role of structure and competition in utility markets has affected the electricity industry in three major ways. The first is the decision by COAG to create a competitive national electricity market

— initially consisting of New South Wales, Victoria, South Australia and the Australian Capital Territory. The second is the sectoral reforms by the States and Territories of their electricity industries to underpin the national electricity market. The third is the national competition policy agreed by COAG. This policy incorporates provisions for the structural reform of GBEs and the payment of Commonwealth assistance to compensate the States and Territories for specific reforms agreed by COAG, including those for the national electricity market.

Jurisdictions participating in the national electricity market are undertaking major structural reforms. In New South Wales, Victoria and Queensland, the grid, generation and most industry regulation have been placed in separate organisations independent of each other. New South Wales and Victoria have each created an independent transmission business, multiple independent generation businesses and announced plans for the progressive deregulation of electricity retailing. Victoria has also removed system control and planning from transmission to create a new independent agency, created several independent distribution businesses and embarked on extensive privatisation of its generation and distribution businesses.

In South Australia, ETSA has been corporatised and organised around a holding corporation with four subsidiary corporations — ETSA Generation (electricity generation), ETSA Transmission (transmission, system control and system planning), ETSA Power (distribution and retail), and ETSA Energy (gas trading). Each subsidiary has its own board and chief executive officer (CEO). The directors of ETSA Corporation are prominent on the boards of the subsidiaries, and the CEO of the holding corporation is represented on all five boards. Each of the subsidiaries is 'ring-fenced' — with its own administration and audited financial accounts.

Competition in the South Australian electricity market

At the present time, ETSA has scope to influence prices in the South Australian electricity market. Its market power is considerable. ETSA's only real competition comes from gas — but only in about half of its electricity market.

In its present form, ETSA will possess the power to influence prices in the South Australian region of the national electricity market. Its market power in the rest of the national market will be insignificant.

There are several reasons to expect ETSA's regional market power to continue in the national electricity market, once it is operational. First, ETSA's transmission and distribution networks are likely to be able to be used to protect its generation and retail businesses, notwithstanding any regulation of these networks. This protection could manifest itself in delays and difficulties for new or potential entrants in obtaining access to the networks, or in cross-subsidisation of generation and retail. Second, in its role as system controller and planner, ETSA can disadvantage its competition in generation and retail. Third, at present ETSA has 99 per cent of the generation capacity in the South Australian market.

To the extent its regional market power were not constrained, ETSA would be able to raise electricity tariffs above efficient levels. Use of this ability would have a direct impact on living standards in South Australia. Furthermore, as electricity is an important operating cost for much of industry, its use would also impair the competitiveness of other industries — affecting their employment and putting further downward pressure on living standards in the State.

Once it enters the national market, ETSA's regional market power would be most effectively constrained by competition — or the credible threat of it — in generation and retailing in South Australia. Maximising the potential for competition in these two areas, in part, depends upon:

- the repeal of barriers to entry and constraints on trading in the South Australian *Electricity Corporations Act 1994*;
- arrangements to ensure that the Interconnection Operating Agreement between ETSA, the State Electricity Commission of Victoria and the Electricity Commission of New South Wales, governing use of the interstate interconnections, does not inhibit competition in the South Australian regional market;
- introduction of a regime for non-discriminatory access to ETSA's transmission and distribution networks by other parties; and
- completion of the structural, regulatory and access reforms under way for a competitive national gas market.

Although these reforms are essential for competition in the South Australian regional market, they are unlikely to be sufficient if ETSA were retained in its existing state. ETSA's present structure would continue to provide it with the opportunity to exploit market power through its control of the grid and its role as system controller and planner.

Even with 'ring-fencing', the ETSA holding corporation necessarily retains ultimate control of each subsidiary and remains responsible for the overall conduct of the four businesses. Accordingly, it is not clear how much operational and financial independence each subsidiary can expect or sustain.

For these reasons, the present structure of ETSA is likely to discourage new generators and new retailers from entering the South Australian regional market. Retention would be unlikely to meet the spirit of the COAG agreements on the national electricity market and prospects for a competitive regional market would, at best, be uncertain.

ETSA's market power could be addressed by regulation — but it could not be eliminated as regulation only treats the symptoms of market power. Moreover, vertical integration exacerbates the asymmetry of information between the regulator and the regulated utility, as well as providing both the opportunity and the incentive to exploit that asymmetry.

A more competitive structure

After carefully weighing up the costs and benefits involved, the Commission considers that there is a case for further structural reform of ETSA.

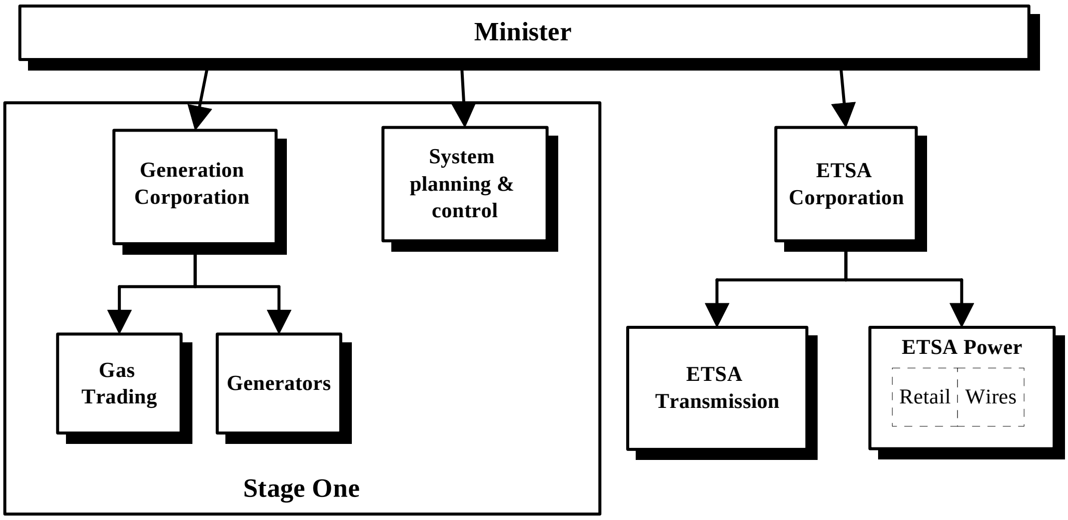
The case rests upon the scope for competition in generation and retail and the benefits in economic efficiency in South Australia that competition can be expected to bring. On the other hand, structural reform is likely to involve some costs. The Commission has examined the potential for losses to the South Australian community in terms of economies of scale, economies of scope and additional transactions costs. It has concluded that any losses are likely to be modest in relation to the efficiency gains from competition.

The Commission's assessment of the potential costs has convinced it that structural reform is best undertaken in two stages: the first to promote competition *between* generators; and the second to promote competition *for* the output of the generators. A subsidiary objective in the second stage is to promote competition *between* those who provide retail services in electricity. Although complementary, the two stages can be implemented independently.

Stage 1 consists of transferring ETSA Generation and ETSA Energy, together with system planning and control from ETSA Corporation. ETSA Generation and ETSA Energy would form two business units in an independent GBE. System planning and control would be set up as an independent organisation (this would also help it to function as the South Australian agent of the National Electricity Market Management Company). These changes have the highest priority and should be implemented as soon as practicable. In the Commission's view, Stage 1 would meet the spirit of the COAG agreements on the national electricity market.

Stage 2 involves dividing ETSA Power into two or three independent distributor–retail GBEs. Such a division is needed to ensure there is sufficient competition among buyers in the wholesale market in South Australia. Stage 2 would take longer to implement than Stage 1 — time is needed to determine the most cost-effective way of dividing the distribution network. Creation of multiple distributor–retailers would require the transmission and distribution networks to be separated from each other and from both distributor–retailers.

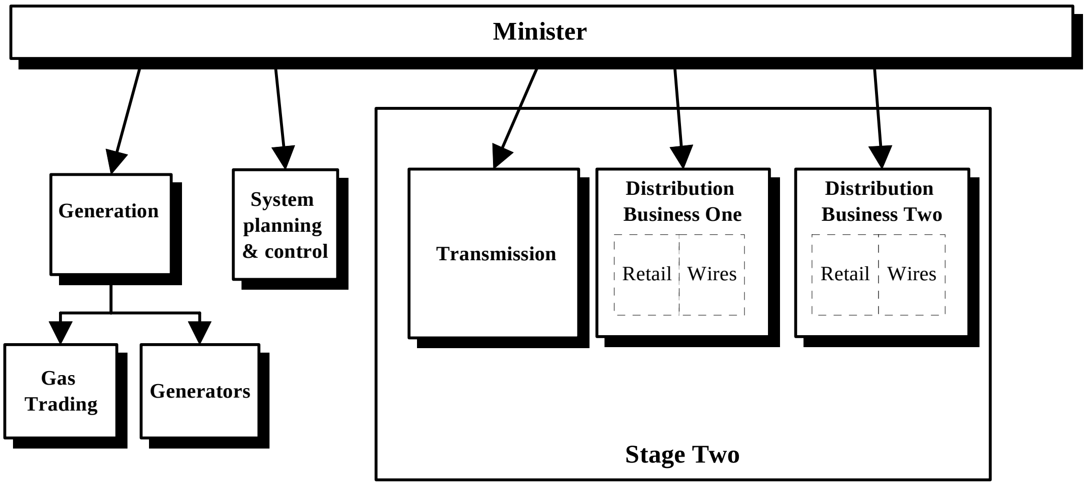
Figure 1: Structural reform of ETSA — Stage One



To promote buyer competition, the in-principle case favours separating ETSA Power into a distribution GBE and two or three retailers. This option is fully consistent with the principle of separating the natural monopoly (distribution) from the potentially competitive sector (retail). In addition, it avoids the costs of splitting the distribution network and allows distribution and transmission to co-exist in one enterprise.

Information given to the Commission suggested, however, there may be significant practical difficulties in creating viable, stand-alone retailers, at least in the early stages of the national market. Moreover New South Wales, Victoria and Queensland have recently restructured their distribution businesses so as to combine distribution and retail. On balance, the Commission considers that it would be in South Australia's best interest to follow their example, given the state of development of the national market.

Figure 2: Structural reform of ETSA — Stage Two



The cost of dividing the distribution network may be significant. An evaluation needs to be undertaken to determine the most cost-effective way of doing so. If the evaluation were to find that there was no cost-effective way of dividing distribution, a reassessment would be in order.

In that event, the Commission's preference is to separate ETSA's retail activities from ETSA Power and divide them between two or three retailers. Distribution and transmission could then be left together under the holding corporation.

All these GBEs and the system control and planning organisation should be operationally and financially independent of each other. Each should be the responsibility of a board which reports directly to the Government. Except where specifically indicated, none should be under a holding corporation.

The Commission's proposals would be consistent with the Multiple Network Corporations model of the National Grid Management Council and with the organisational structures emerging in other States.

Most of those who participated in the review supported structural reform of ETSA for its competitive benefits. Some also favoured privatisation of some of ETSA's businesses to lock in those gains. Others opposed structural reform because it might lead to such privatisation.

For its part, the Commission was not asked to look at privatisation of ETSA. Competition in electricity supply is needed for economic efficiency. The need does not depend on who owns the resources in the industry. The community's interest is in greater efficiency in *all* enterprises. The Commission sees no reason why all parts of ETSA could not be retained in the public sector following separation, if that is in the community's interest. Indeed, this is precisely the situation in New South Wales — the Electricity Commission of New South Wales has been broken up to create a transmission agency and multiple generating businesses but the New South Wales Government has indicated that they will not be privatised.

Containing market power in generation

The existing transmission interconnector cannot supply much more than 35 per cent of South Australia's needs. For the moment, the remaining demand can only be met by ETSA. For this reason ETSA Generation will possess significant scope to influence prices in the South Australian regional market over the short to medium run. If exploited, South Australian end-users would face tariffs higher than would exist in a fully competitive market.

This risk raises the issue of whether ETSA Generation should be divided into multiple independent generators. The Commission's analysis led it to conclude that division was unlikely to reduce market power to any practical degree. Division could result in losses of economies of scale and scope. Such losses would disadvantage South Australian generators in the national market, compared to the much larger generators in New South Wales and Victoria.

ETSA Generation's market power would be eroded by the entry of independent generators or expansion of interconnection capacity with the eastern States. Such developments would be deferred by any expansion of ETSA Generation's own capacity.

In addition to restructuring ETSA Corporation, a combination of measures may be needed to constrain the scope for ETSA Generation to influence prices in the South Australian regional market. This may be necessary until substantial generating capacity in that market was held by others, or the transmission interconnection had been expanded substantially. The combination could be selected from the following:

- a limit on ETSA Generation's generating capacity;
- an evaluation of options to increase transmission interconnection capacity;
- prices oversight of ETSA Generation by an independent competition regulator; and

- limiting the scope for ETSA Generation to use its market power by vesting it with contracts.

The Commission favours a limit on ETSA's generating capacity for a specified period. This approach has been used overseas, notably in New Zealand and the United Kingdom. If it were adopted, all proposals to refurbish ETSA Generation plant would need to be reviewed to ensure that they did not increase generating capacity during the period in question. Alternatively, a limit on capacity could apply until substantial capacity in the regional market was held by independent generators or the transmission interconnection was augmented.

Costs and benefits of reform

The Commission's proposed structure involves some start up costs and it may result in the loss of some economies of scale and scope. Although the Commission believes they should be modest, any costs of structural separation need to be minimised as far as practicable.

With greater competition in generation in South Australia, the substantial investment by South Australia in ETSA Generation will be at greater risk. If the value of this investment is eroded by competition, the Government could see a reduction in the stream of dividends and tax revenues it currently receives from ETSA.

The cost, pricing and investment efficiencies from competition in generation and retail are likely to be significantly greater to the South Australian economy than the costs to the community or the South Australian Government. This provides an opportunity for electricity tariffs to households and businesses to be lower than they would otherwise have been with ETSA's current structure. Furthermore, Commonwealth financial assistance for the States under the Agreement to Implement the National Competition Policy and Related Reforms is partly to compensate for any costs to State Governments.

Implemented as a package, the Commission's recommendations will promote competition and greater economic efficiency in the South Australian electricity and energy markets. They will maximise the benefits to South Australia of participating in the national electricity market. Partial implementation is likely to reduce significantly the extent of the benefits to South Australia.

CONCLUSIONS

1. With its present structure, ETSA Corporation will have significant market power in the South Australian region of the national electricity market. Its market power in the rest of the national electricity market will be insignificant.
2. ETSA's market power can be most effectively constrained by maximising the potential for competition in the South Australian regional electricity market.
3. Vertical separation facilitates competition where it is feasible. It also facilitates the more efficient regulation of transmission and distribution, the natural monopoly components of the industry.
4. The present structure of ETSA is likely to discourage other generators and electricity retailers from entering the South Australian regional market.
5. The achievement of a competitive market for electricity in South Australia will require the following changes:
   (a) the repeal of barriers to entry and constraints on trading in the *Electricity Corporations Act 1994,* with the changes to be commenced as soon as possible;
   (b) the negotiation of arrangements to ensure that the Interconnection Operating Agreement does not inhibit competition in the South Australian regional market; and
   (c) the restructuring of ETSA Corporation.
6. The restructuring of ETSA Corporation is most efficiently achieved in two stages:
   (a) **Stage 1**: As soon as it can be arranged, ETSA Generation and ETSA Energy together with system planning and control, should be transferred from ETSA Corporation to form:
      (i) a generation and energy enterprise; and
      (ii) a system planning and control organisation.
   (b) **Stage 2**: ETSA Power should be divided into two or three distributor-retail GBEs, subject to an examination of the most cost-effective way of dividing the distribution network. ETSA Transmission should be established as a separate business.

(c) In the event the examination in (b) does not identify a cost--effective way to divide the distribution network, ETSA Power's retail activities should be transferred to two or three independent retail businesses.

7. The various electricity businesses together with the system planning and control organisation should be operationally and financially independent of each other. They should report directly to the Government. There should be no holding corporation linking any of them.

8. In addition to restructuring ETSA Corporation, a combination of other measures may be needed to constrain the use of market power by ETSA Generation. The combination could include the following options:

(a) a limit on ETSA Generation's generating capacity in the South Australian regional market for a specified period;

(b) a limit on ETSA Generation's generating capacity in the South Australian regional market until substantial capacity in that market was held by independent generators or the transmission interconnection was augmented;

(c) an evaluation of options to increase transmission interconnection capacity;

(d) prices oversight of ETSA Generation by an independent competition regulator; and

(e) limiting the scope for ETSA Generation to use its market power by vesting it with contracts.

9. The Commission favours option (a). If it were adopted, all proposals to refurbish ETSA Generation plant would need to be reviewed to ensure that they did not increase generating capacity during the period in question.

1 INTRODUCTION

Following a request from the South Australian Government, on 22 December 1995 the Assistant Treasurer requested that the Industry Commission review the structure of the South Australian electricity industry to determine the structure that would best suit South Australia.

In undertaking the review, the Commission was asked to have regard to:

- obligations made through National Competition Policy Agreements;
- potential market power to be exerted by the generation entity or entities;
- the principles for structural reform of public monopolies contained in the Competition Principles Agreement between the Commonwealth, the States and the Territories;
- the obligations for structural change in electricity utilities agreed by the Council of Australian Governments (COAG) and incorporated in the April 1995 Inter-Governmental Agreement; and
- the operation of a competitive national electricity market.

In taking account of COAG commitments, the terms of reference request the Commission to consider the extent of vertical separation required to achieve the outcomes of the Multiple Network Corporation structural model recommended by the National Grid Management Council (NGMC) (see Chapter 3).

The full terms of reference are set out on page 15. The correspondence between the South Australian Minister for Infrastructure and the Assistant Treasurer is reproduced in Appendix A. Originally the Commission was asked to report within 75 days. Subsequently the South Australian Government wrote to the Assistant Treasurer to ask that the report be delayed until 15 or 18 March 1996.

1.1 Background to the review

The Commission's analysis is intended to assist the South Australian Government in deciding on a structure for its electricity supply industry that would provide the optimum economic benefits to the South Australian community.

The project is not an inquiry under section 7 of the *Industry Commission Act 1990*. Nevertheless, consistent with its statute and general approach, the Commission has evaluated the implications of the structure of South Australia's electricity market taking into account the interests of the community as a whole, both in South Australia and the rest of Australia.

To this end, the Commission has encouraged the participation of all relevant parties, both in South Australia and all jurisdictions that will form part of the national electricity market. However, given the regional nature of the study, most participants have been from South Australia. The Commission has also undertaken some modelling of the South Australian regional electricity market, which it intends to document and publish later (see Chapter 7).

Recent developments in the electricity industry in South Australia, moves to set up a national electricity market and competition policy reforms are all inter-related.

Electricity supply in South Australia

In Australia, electricity supply has traditionally been provided by public sector monopolies in each State and Territory and this is the case in South Australia. Until 1995 the Electricity Trust of South Australia (ETSA) was responsible for the generation, transmission, distribution and retailing of electricity.

The Trust was corporatised in 1995 and its activities divided into subsidiaries in preparation for South Australia’s entry into the national electricity market. The new corporation — ETSA Corporation — remains the sole provider of electricity in South Australia. It also has a contracted capacity right to the transmission interconnection between the Victorian and South Australian grids.

A national electricity market

In the early 1990s, Australian Governments commenced a coordinated national effort to increase the efficiency of electricity supply. The major focus of the reform was the proposal to develop a national electricity market.

The concept of a national electricity market arose out of recommendations by the Industry Commission (1991) report on *Energy Generation and Distribution*. The aim is to promote efficiency by increasing competitive pressures within and between State grids.

The July 1991 Special Premiers Conference established the NGMC to coordinate the development of an electricity market covering eastern and southern Australia, with a view to allowing a competitive market in electricity. The interim national market is now expected to commence in September 1996 and eventually to encompass all States and Territories for which interconnection of grids is economic.[1]

Competition policy reform

Electricity sector reforms have simultaneously occurred in the context of an examination by governments of the broader policies and principles underlying the conduct of government and monopoly businesses. This national approach to competition policy culminated in the national competition policy package.

The cornerstone of the package is three inter-governmental agreements formally agreed to at the April 1995 meeting of COAG. The agreements provide for:

- the extension of the *Trade Practices Act,* including to government business enterprises;
- structural reform of public monopolies;
- regulation of monopoly pricing by government business enterprises;
- competitive neutrality policy and principles;
- open access to essential facilities such as electricity networks; and
- payments by the Commonwealth to the States and Territories.

The Commonwealth has agreed to make a series of special payments to the States and Territories to compensate jurisdictions for meeting agreed obligations set out in the Competition Principles Agreement and related reform commitments in electricity, gas, water and road transport. Payments to each jurisdiction are conditional upon each jurisdiction making satisfactory progress with implementation of the specified reforms (see Chapter 3).

1.2 Public participation in this project

The Commission invited contributions from all interested individuals and organisations. It supplemented this information and its own research with visits to various parties, including ETSA Corporation, some interstate generators and distributors, large industrial users and government bodies. A list of all participants, visits and meetings is provided in Appendix B.

The Commission wishes to thank all those who participated.

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1 Western Australia and the Northern Territory will not be involved due to the transmission distances involved. The inclusion of Tasmania and Queensland depends on decisions to construct transmission interconnections with the grids in Victoria and New South Wales respectively.

1.3 Report structure

The next Chapter provides a background to electricity supply and demand in South Australia, recent structural changes in the sector and ETSA's past performance.

Chapter 3 discusses recent national competition policy reforms and sectoral reforms in the electricity and gas industries. Chapter 4 describes the arrangements and institutions for the proposed national electricity market and how the market might impact on South Australia.

Chapter 5 discusses problems with ETSA's current structure and Chapter 6 presents the Commission's preferred structure. Chapter 7 discusses the issue of market power in generation in the South Australian electricity market.

2 THE SOUTH AUSTRALIAN ELECTRICITY MARKET

Electricity has several distinctive characteristics that affect the way in which it is produced, distributed and used. It is a fungible commodity, which means that once supplied into the grid it is impossible to tell its origin. Consequently, where there are several producers (generators), there needs to be individual meters at supply points and at delivery points (houses and business premises), and some form of market settlement process is required to ensure each producer is paid and customers are billed appropriately.

Electricity can not be economically stored in large quantities. Consequently, the electricity system must constantly balance the demands of many customers and the output of a small number of generators. If this balancing is not achieved, the system collapses and blackouts occur. Therefore, a central control mechanism is needed to ensure that the system remains in balance.

Finally, the electricity supply system needs a high degree of reliability because supply failures can impose high costs on consumers.

This Chapter describes the current structure of the South Australian (SA) electricity market outlining the nature of demand and supply, the structure of ETSA and the industry's regulatory structure. It then compares the performance of the SA electricity industry over time, with other States and with leading utilities overseas. The Chapter concludes by outlining the importance of electricity to the SA economy.

2.1 Demand for electricity in SA

The quantity of electricity consumed in SA in 1994–95 was 9245 GWh, valued at $883 million.[1] Sales of electricity to residential and industrial customers each make up over one-third of total sales and commercial customers represent about one-quarter of total sales.

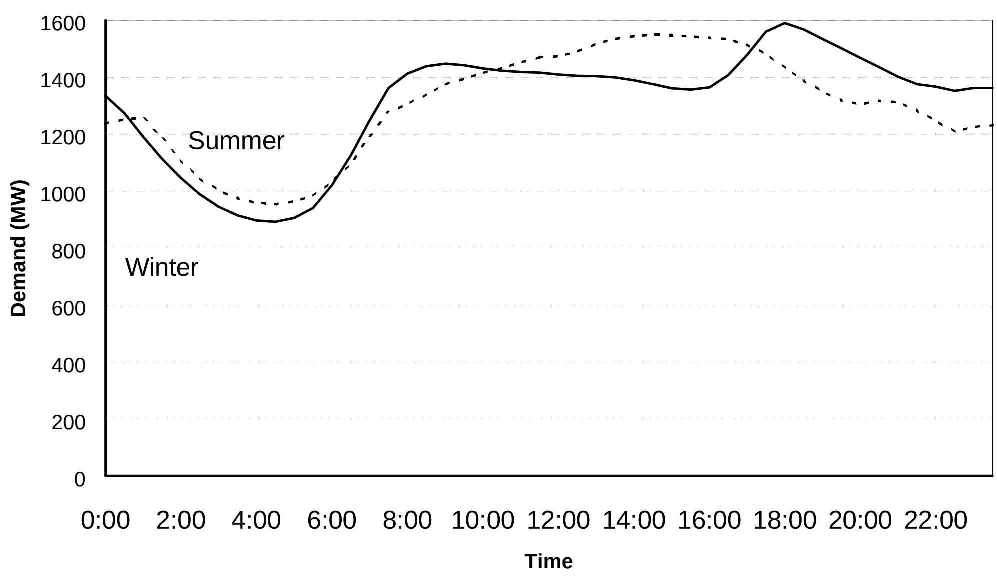
Although SA has proportionally fewer industrial users than other States, a small number of customers account for a significant share of demand. Some 2 per cent of customers account for 37 per cent of all electricity sales within SA.

1 This figure excludes consumption by private producers of electricity.

Demand for electricity in SA varies according to the time of the day, the day of the week and the season of the year. For example, demand almost doubles between 4 am and 5 pm on an average weekday and, while the load peaks at about 1600 MW on an average summer weekday (see Figure 2.1), it can exceed 2130 MW on extremely hot days.

Over the period 1989–93, the SA winter peak demand has been growing at an average annual rate of 0.6 per cent but summer peak demand has been rising at an average annual rate of 3.1 per cent (NGMC 1994, p. 4). Over the period 1994–2006, SA's winter peak demand is forecast to grow at about 1.5 per cent, and summer peak demand is forecast to grow at about 1.9 per cent.

Figure 2.1: Electricity demand in SA, average summer and winter weekdays, 1994–95



Source: ETSA Corporation.

Interstate comparisons

Compared with the other States proposing to join the national electricity market, SA has:

- a low level of consumption;
- the smallest share of industrial sales in total demand;
- the highest share of domestic sales in total demand;

- the smallest number of large load customers;
- the greatest variability of demand; and
- the lowest rate of demand growth.

Annual electricity consumption in SA is a little over one-quarter the level in Victoria, and less than one-fifth that in New South Wales (NSW) (see Figure 2.2). Consumption in SA represents approximately 10 per cent of the national electricity market comprising the interconnected networks of NSW, ACT, Victoria and SA.[2]

Industrial sales represent only 38 per cent of total demand in SA, in contrast to NSW and Victoria, where they are almost 50 per cent of the total. Reflecting this, SA has a smaller number of large load customers (see Table 2.1). The small share of industrial sales is one factor making SA demand more 'peaky' than demand in other States. This is reflected in the fact that the SA generation sector has the lowest load factor of all States.

SA has the lowest projected demand growth of the States in the national electricity market. Annual demand in SA is forecast to grow by less than 2 per cent between 1994 and 2006. In contrast, annual demand in Queensland is expected to grow by over 4 per cent per annum, over the same period.

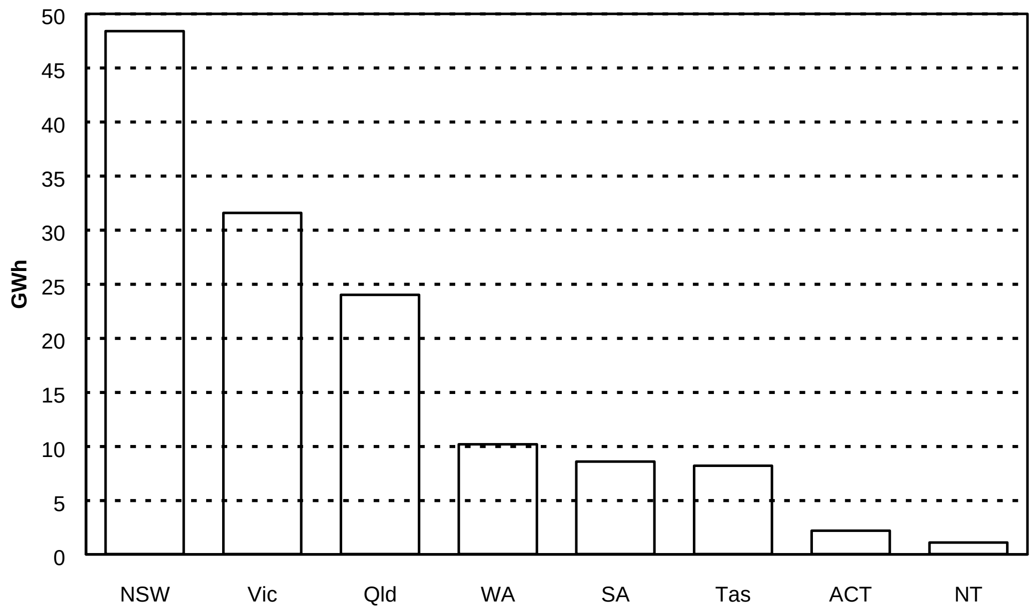
Table 2.1: Share of demand by customer class, by State 1993–94

		Customer class				*Customers*	*Customers*
State	*Total demand*	*Residential*	*Commercial*	*Industrial*	*Other[a]*	*greater than 1 MW*	*greater than 5 MW*
	(GWh)	(per cent)				(number)	
NSW	48 423	32	16	49	3	659	108
Vic	31 640	27	23	48	2	630	47
Qld	24 001	31	24	42	3	na	na
SA	8 603	37	24	38	0	150	25

a Includes traction, public lighting and unclassified customers.
na Not available.
Source: ESAA 1995, p. 46, and information supplied by the SA, Victorian and NSW Governments.

[2] Queensland is also expected to be part of the national electricity market, but at this stage is not interconnected to the other States. Including Queensland, SA represents 7.5 per cent of electricity demand in the national electricity market.

Figure 2.2: Demand for electricity by State, 1993–94



Source: ESAA 1995, p. 46–47.

Substitutability between electricity and other energy sources

Demand for electricity is also influenced by substitution with other energy sources, most notably gas. Gas is substitutable for electricity in water heating, cooking, space heating and temperature control for commercial and industrial applications. However, only electricity can be used in lighting, many domestic appliances (such as dishwashers, washing machines and clothes dryers), water pumping and a range of commercial and industrial equipment (for example, electronic equipment and refrigeration).

Although gas can be switched for electricity in some uses, this substitution usually takes time. This is because substitution often does not just involve a change in energy source — it frequently also requires changes to, or the replacement of, the appliance using the energy source. For example, switching to gas for hot water heating requires the purchase of a new hot water system. In the case of some industrial plants, conversion may only be possible when old plant is being replaced. Thus, in some circumstances, a change in the price of electricity relative to other energy sources could result in substitution in a relatively short time frame, while in other instances there could be a lag of many years.

Reflecting the linkages between the gas and electricity markets, some firms are now developing gas and electricity businesses to meet the total energy needs of their customers. For example, ETSA has recently established an energy subsidiary to trade in gas, and gas companies like AGL and Boral have moved into the electricity market.

Participants were divided about the extent of competition between electricity and gas, and whether electricity suppliers compete in an electricity or an energy market. ETSA considers that electricity faces competition from gas in many uses, and therefore that it is mainly competing in an energy market. Boral Energy, on the other hand, contends that ETSA operates in the SA electricity market, not the energy market. Boral notes that the Trade Practices Commission contested Santos' proposed takeover of SAGASCO Holdings Ltd in 1992 on the basis that the markets for electricity and gas in SA were separate.

A study on the Victorian market (Grimwade et al 1993) found that 56 per cent of electricity sales are open to competition from gas. In other words, in 44 per cent of its market, electricity faces no competition from gas. Data provided by ETSA indicated that a similar share of SA electricity sales were subject to competition from gas.[3]

In conclusion, there are some applications where electricity is substitutable with gas, and demand for electricity is relatively price responsive, particularly over the longer term. In these applications, electricity suppliers face competition from gas producers, and risk losing market share if they raise prices. However, in other applications, there are no other economic alternatives to electricity, and electricity producers do not face competition from gas.

2.2 Supply of electricity in SA

There are three sources of electricity supply in SA:

- electricity generated by ETSA;
- imports of electricity from the Eastern States; and
- private producers.

In 1994–95, electricity generated by ETSA represented 75 per cent of total supply, imports made up 24 per cent and private producers supplied about 1 per cent of total supply. As ETSA currently controls imports from the eastern States, in effect it controls 99 per cent of SA's electricity supply. It will also

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3 This data was derived from a 1992 study by SRC Australia and the SA Department of Mines and Energy.

control disposal of the output from the Canadian Utilities Power and Boral Energy (CUBE) cogeneration project.

Electricity generated by ETSA

ETSA has eight power stations. Two stations — Northern and Torrens Island — account for 99 per cent of electricity generated by ETSA (see Table 2.2).

ETSA's power stations have been designed to complement, not compete with each other. Each station has a distinct role in meeting electricity demand. Northern provides base load power throughout the day, the six small stations only generate in the peak, and Torrens Island handles the intermediate load and most of the peak.

The fuel for Northern is brown coal from ETSA's Leigh Creek coal field. The Torrens Island, Dry Creek and Mintaro power stations run on gas. Reflecting the requirements of these stations, ETSA consumes around 45–50 PJ of natural gas per annum, equivalent to 55 per cent of total gas used in SA.

Table 2.2: ETSA's power stations, 1994–95[a]

Name	*Capacity*	*Output*	*Plant type*	*Role*	*Age*	*Value*[b]
	(MW)	(GWh)			(years)	($ million)
Northern	500	3 555	steam, brown coal	base load	11	307
Torrens Island A	480	4 566[c]	steam, gas	peaking	19	288[d]
Torrens Island B	800	b	steam, gas	intermediate	19	c
Dry Creek	156	4	gas turbine	peaking	23	8
Playford	120	10	steam, brown coal	peaking	32	0
Mintaro	90	0	gas turbine	peaking	12	24
Snuggery	63	3	gas turbine	peaking	18	12

a Osborne and Port Lincoln power stations have been excluded. In recent years, these power stations have produced negligible output.
b Value is after revaluation and depreciation.
c Combined annual output of Torrens Island A and B stations.
d Combined value of Torrens Island A and B stations.
Source: sub. 5, p. 16, ETSA 1995 p. 52, 74, NGMC 1994 p. 29.

Interstate trade

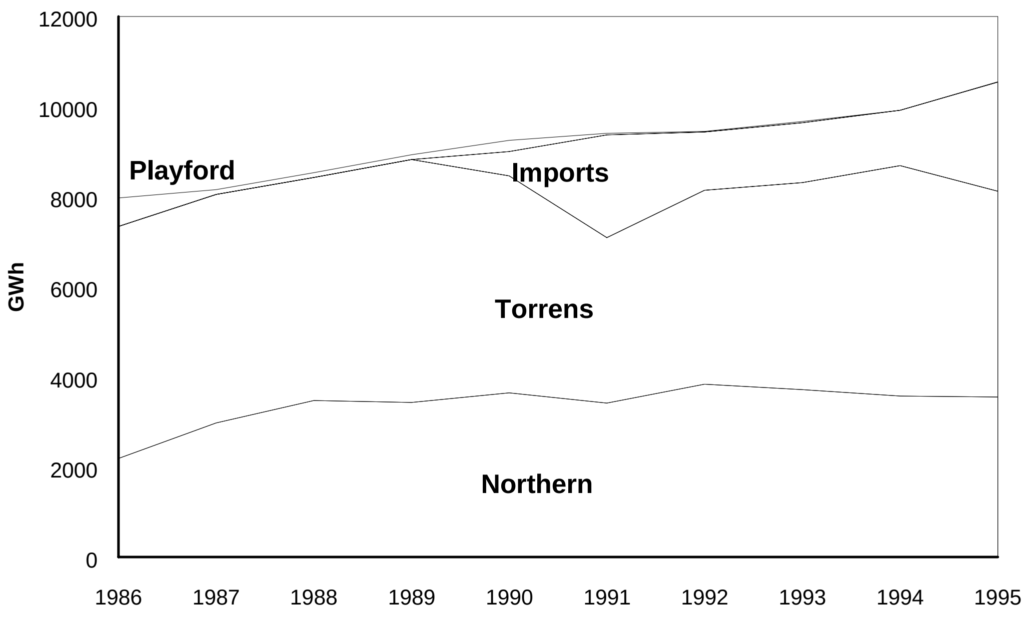
In 1990, the transmission interconnection between SA and Victoria was completed, enabling interstate trade in electricity between SA and the eastern States. The interconnection has a capacity of 500 MW for imports into SA, and a capacity of 250 MW for exports from SA.

Interstate trade is currently governed by the Interconnection Operating Agreement (IOA) between ETSA, the State Electricity Commission of Victoria and the Electricity Commission of NSW. It is discussed further in Chapter 4.

Since 1990, ETSA has imported between 12 and 24 per cent of SA's electricity needs from the eastern States. Over this period, the level of exports has been negligible. In 1994–95, ETSA's imports were equivalent to about two-thirds of Northern Power Station's output (see Figure 2.3).

ETSA considers that imports could provide up to 35 per cent of SA demand, given the existing interconnection capacity. It expects to increase imports to this level in 1995–96. The decision to do so reflects the recognition that, at present prices, power is cheaper from Victoria than from new capacity in SA.

Figure 2.3: Imports by SA and output of main SA power stations, 1985–86 to 1994–95



Source: ETSA 1995, p. 74.

Electricity produced by private producers

Currently, ETSA sources a negligible amount of its power from private producers.

There are many small independent power producers in SA, but all of them essentially produce for their own use. The data on the output and capacity of these producers is limited. Information collected by the National Grid Management Council (NGMC) indicates that BHP Whyalla has 63 MW of generating capacity, and information collected by the Australian Cogeneration Association indicates that there are a further 23 cogeneration projects with a combined capacity of about 30 MW.

In 1995 ETSA entered into a memorandum of understanding with Canadian Utilities Power and Boral Energy to buy electricity from the CUBE joint venture and to sell gas to it. The CUBE project is for a 180 MW cogeneration plant supplying steam to Penrice Soda Products and an average of 1075 GWh of electricity to ETSA beginning in 1998. The expected electricity output is equivalent to about 10 per cent of SA's current electricity demand.

ETSA is reported to have contracted to purchase electricity from the joint venturers over 20 years. Under these arrangements, ETSA will be the sole seller of electricity generated by this project.

Meeting future demand

Current demand forecasts indicate that SA will need to augment capacity or increase imports shortly after the year 2000. This is in addition to the extra capacity provided by the proposed CUBE project.

Whether future electricity requirements are met through new generation capacity installed in SA or through higher imports, will depend on the cost of new SA capacity and gas prices, compared to the cost of importing power and expanding the transmission link to the eastern States. New gas-fired generators can be competitive at prices of around $40 to $45 per MWh (Industry Commission 1995a, p. 68).[4] ETSA's estimates of the capital cost of new or additional interconnection capacity are in Table 2.3. The Victorian Power Exchange's estimates of the cost of expanding the interconnection are considerably lower than ETSA's estimates.

4 This price would cover the average costs of new generators, including capital costs. It is considerably higher than the costs of power stations shown in Figure 2.4, which only cover fuel costs.

Table 2.3: Estimated capital cost of transmission links from South Australia to Victoria and NSW

Option	*Capacity*	*Capital cost*
	(MW)	($ million)
Victoria to South Australia augmentation	150	30
Darlington Point (NSW) to Berri (SA)	125	75
Darlington Point (NSW) to Tungkillo (SA)	250	150
Sydenham (Victoria) to Tungkillo (SA)	500	400

Source: sub. 5, p. 35.

Transmission, distribution and retail

SA has a long, thin transmission system stretching from the south east of the State, where there is the interconnection with Victoria, to the northern mining centres of Leigh Creek and Olympic Dam, and to the south west at Port Lincoln. It also has a low density of users over its distribution network, as a result of its small population spread over a large area. These factors increase the cost of transmitting and distributing electricity in SA.

ETSA owns and operates the State’s electricity transmission and distribution networks, and is effectively the only retailer in SA.[5] ETSA estimates that distribution will represent between 85–90 per cent of the earning capacity of its distribution–retail subsidiary once the national market commences (ETSA 1995, p. 23).

Losses in transmitting electricity over large distances affect the competitiveness of generating electricity locally versus sourcing it from afar. The NGMC has estimated that the losses of transmitting electricity within SA are less than 5 per cent. However, the transmission losses associated with importing electricity from Victoria are significant and rise with the rate of transmission — at 300 MW the losses are 10 per cent, and at 500 MW about 18 per cent.

5 The District Council of Hawker distributes electricity in the far north of SA. The Council’s responsibilities include construction and maintenance of the Hawker Grid, and the billing of all consumers in its jurisdiction.

Interstate comparisons

Key differences between the SA industry, and that in NSW and Victoria are:

- the smaller size of the SA industry: SA has one-third the generating capacity of Victoria, and less than one-fifth that of NSW. SA represents only 7 per cent of the total capacity of the four States of the proposed national market;[6]
- the smaller number of power stations in SA: SA has only one base load and one intermediate power station. Victoria and NSW have many base load power stations;
- the smaller size of SA power stations (see Table 2.4);
- the larger share of SA electricity generated from gas: 57 per cent of the energy used in SA power stations is gas, compared to 6 per cent in Victoria and less than one per cent in NSW;
- the larger amount of electricity imported to SA: in 1993–94, SA imported 14 per cent of its requirements, whereas NSW and Victoria only imported 10 and 5 per cent respectively. Since then, SA imports have risen sharply;
- the marginal costs of SA generators are generally higher than generators in Victoria and NSW. However, transmission losses and the limited capacity of the interconnection between Victoria and SA, partly insulate SA generators from import competition. Fuel costs are the largest component of marginal costs. The fuel costs of SA, Victoria and NSW generators are compared in Figure 2.4;
- SA has effectively one distributor and retailer. Each of the other States has at least five distributors. ETSA has more customers and higher sales than the average of the Victorian distribution businesses (see Table 2.5); and
- SA has a higher cost distribution network: SA has a low ratio of customers and sales to kilometres of electricity line, which raise distribution costs.

6 SA represents only 9 per cent of the generating capacity of the four interconnected States (Queensland is not connected).

Table 2.4: Distribution of power stations by capacity, by State[a]

Capacity	*NSW*[b]	*Victoria*[b]	*Queensland*	*SA*
0 to 100 MW	7	3	5	2
100 to 250 MW	1	3	2	2
greater than 250 MW	7	6	5	2[c]
All capacity	15	12	12	6

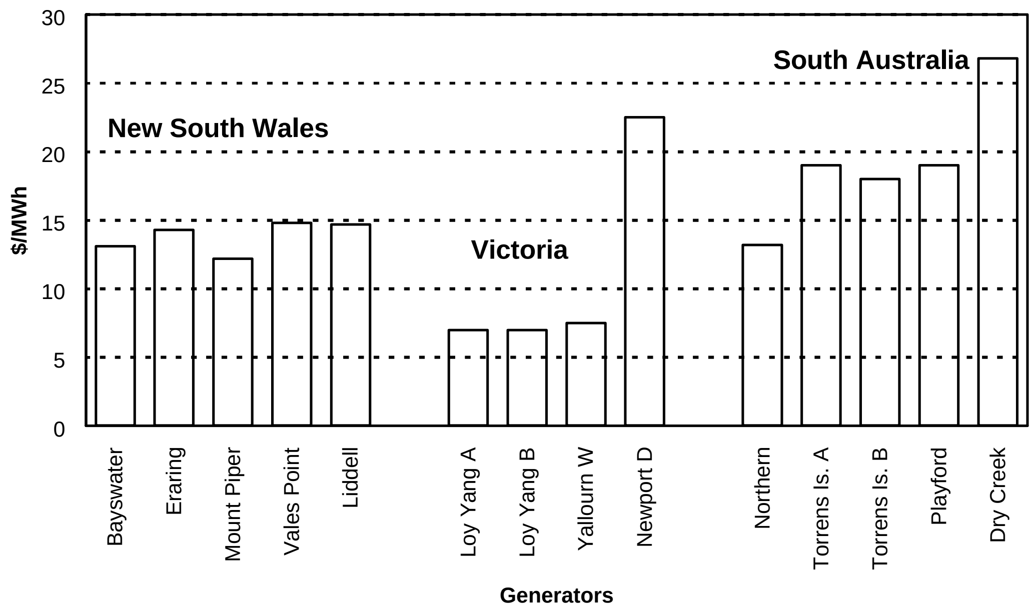
a Excludes private power stations which generate for own-company use.
b In addition, Victoria and New South Wales have access to the capacity of the Snowy Mountains Scheme.
c Torrens Island A and B power stations are counted as one.
Source: NGMC 1994, p. 23–29.

Table 2.5: Comparison of electricity distributors, by State

State	*Number of distributors*	*Average number of customers per distributor*	*Average annual sales per distributor*	*Customers per distribution circuit kilometre*	*Sales per circuit kilometre*
		('000)	('000 GWh)	(customers/km)	(MWh/km)
New South Wales					
– metropolitan	1	1 583	25	32	488
– rural[a]	5	208	5	12	182
Victoria	5	397	6	14	170
Queensland					
– metropolitan	1	874	12	22	288
– rural[b]	6	80	1	3	88
South Australia	1	693	9	8	101

a Estimates of customers and sales per distribution circuit kilometre for NSW rural, are based on data for Orion Energy and Illawarra Electricity only.
b Estimates of customers and sales per distribution circuit kilometre for Queensland rural are based on data for the Capricornia Electricity Board only.
Source: sub. 7, p. 10 and Steering Committee on National Performance Monitoring of Government Trading Enterprises, 1995.

Figure 2.4: Estimated fuel costs of SA power stations and selected Victorian and NSW power stations



Source: London Economics et al 1995, p. 33.

2.3 Legislation covering the SA electricity industry

The main legislation regulating the SA electricity industry is the South Australian *Electricity Corporations Act 1994*. The Act seeks to improve ETSA's performance and to meet possible requirements under national competition policy and the proposed national electricity market (Olsen 1994, p. 982).

The Act:

- provides for the possibility of dividing ETSA into three corporations responsible for generation, transmission (and system control) and distribution;
- converts the Electricity Trust of South Australia into a statutory corporation and subjects it to the South Australian *Public Corporations Act 1993*; and
- allows ETSA Corporation to trade in fuels, including gas.

The implications of making ETSA subject to the *Public Corporations Act* are:

- ETSA is required to act commercially and to perform non-commercial operations efficiently;
- the Minister can direct the Board of ETSA, but directions must be in writing and be publicly reported;
- ETSA must have a public charter which details its commercial and non-commercial operations, and the arrangements for the funding of its non-commercial operations; and
- ETSA must have a performance statement that stipulates performance targets against which the Board's performance can be assessed. The Act does not require that the performance statement be made public.

Structure of ETSA

In 1995 ETSA was established as a holding corporation with four wholly owned subsidiary corporations: ETSA Generation; ETSA Transmission; ETSA Power; and ETSA Energy. Key financial data on the subsidiaries are in Table 2.6.

Each subsidiary is to have its own board, charter and performance statement. The structure and functions of ETSA and its subsidiaries are shown in Figure 2.5.

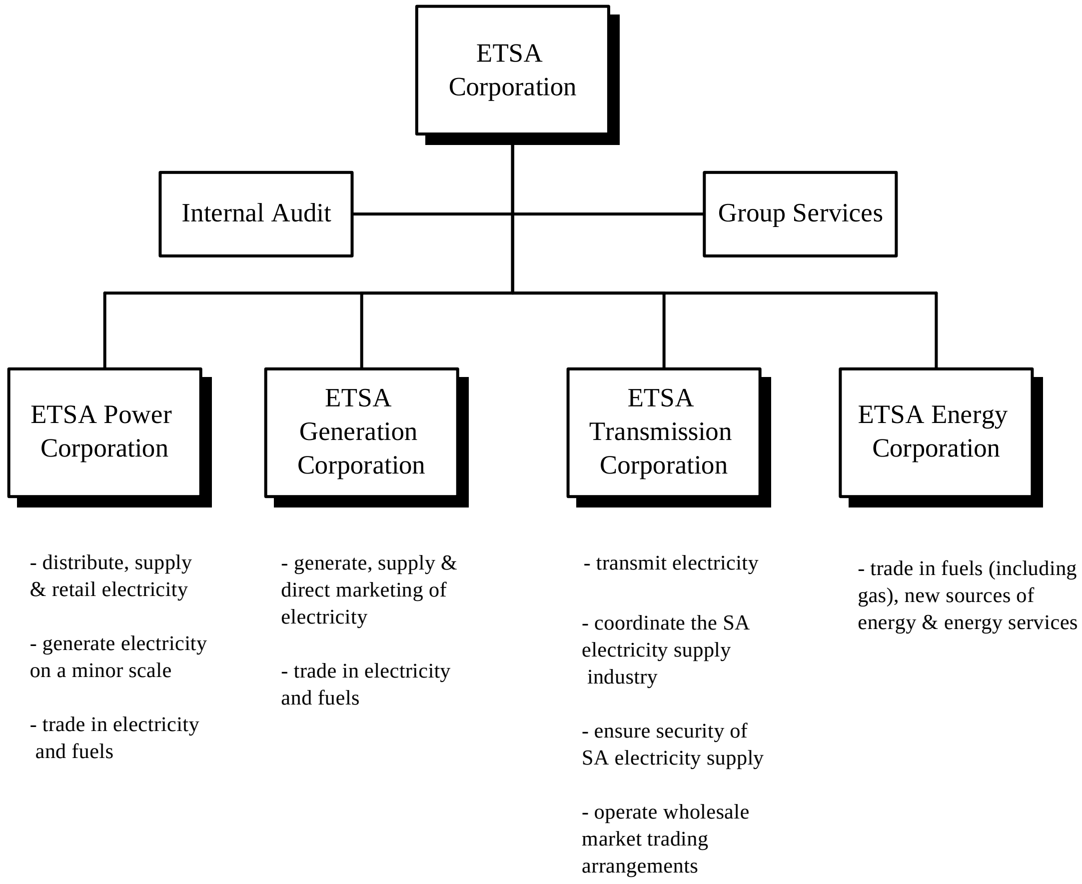
The composition of each of ETSA's five boards is shown in Figure 2.6. The Chief Executive Officer (CEO) of ETSA Corporation and at least one Director of ETSA Corporation sit on all five Boards. The Boards of ETSA Transmission and ETSA Energy are the same as that of ETSA Corporation, except for the inclusion of the CEO of the relevant subsidiary.

Table 2.6: Key financial data for ETSA subsidiaries, 1995–96 ($ million)

Indicator	*Generation*	*Transmission*	*Power*	*Energy*
Revenue	333	115	905	107
Operating expenditure	252	22	663	108
Financing charges	53	46	146	0
Total assets	722	708	2253	1
Number of employees[a]	930	106	1727	5

a As at December 1995.
Source: sub. 5, p. 27.

Figure 2.5: Structure and functions of ETSA Corporation and subsidiaries



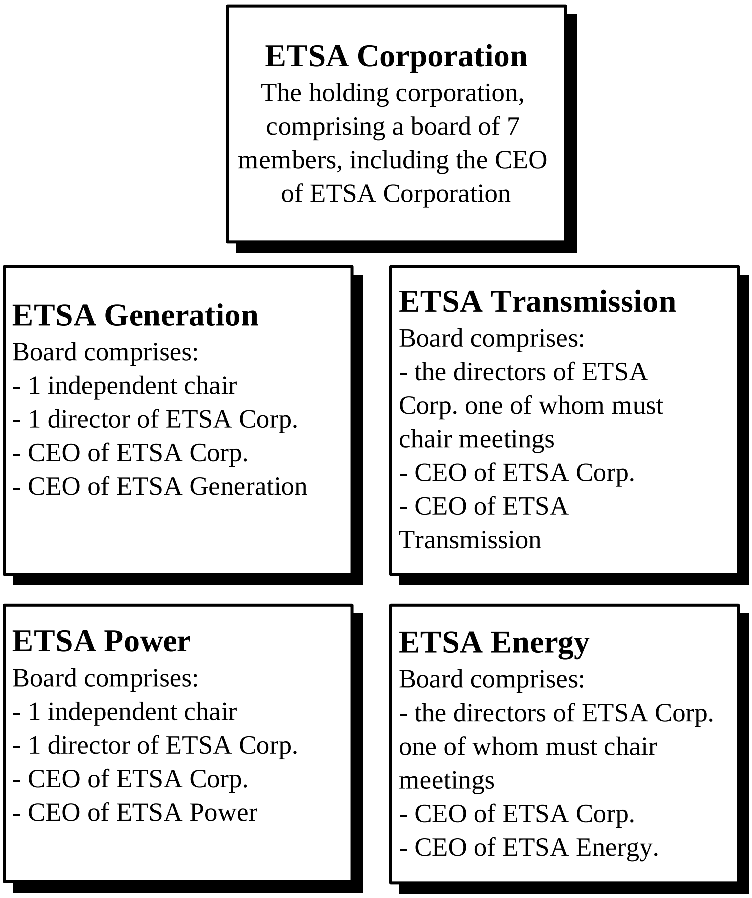
Source: sub. 5, p. 15 and SA Government Gazette 1995, p. 3113–3130.

Regulation of the SA electricity industry

The South Australian *Electricity Corporations Act 1994* protects ETSA from competition in generation and retailing by making it an offence to contribute electricity to any part of the grid, or to charge others a premium for the cost of electricity supplied by ETSA, without the approval of the Minister.

When ETSA was corporatised, responsibility for administering regulations relating to safety was transferred to the SA Department of Mines and Energy. Responsibility for the licensing of trades persons was transferred to the Office of Consumer and Business Affairs. The SA Government has announced that it intends to incorporate provisions relating to the regulation of the electricity supply industry in proposed legislation applying to electricity suppliers generally (Olsen 1994, p. 983).

Figure 2.6: Composition of boards of ETSA Corporation and subsidiaries



Source: sub. no. 15, p. 6.

The SA Government has not finalised its approach to economic regulation. Currently, maximum prices for ETSA’s regulated activities are determined by the Minister for Infrastructure, and are subject to the Government’s policy of uniform state-wide tariffs. As a result, not all consumers face cost-reflective prices. The Government has said that it is examining ways of maintaining assistance to rural and remote areas consistent with the National Competition Policy principles (see Chapter 3).

ETSA is now subject to the new provisions of the Commonwealth *Trade Practices Act 1974* (TP Act) providing for access to essential infrastructure, under which it will be required to give competitors access to its transmission and distribution networks. From July 1996 it will also become subject to

Part IV of the TP Act.[7] This means that it will be illegal for ETSA to act in anti-competitive ways, such as taking advantage of market power to damage a competitor. Given the way in which the ETSA subsidiaries have been established, each will be subject to the TP Act in its own right.

2.4 Performance of the SA electricity industry

In this section, three approaches are used to assess the performance of the SA electricity industry. The first measures changes in the industry's performance over time. The second uses a range of indicators to compare SA's performance to the performance of other States in the national electricity market. The third approach, which is the most comprehensive but most dated, compares the total factor productivity of the SA industry against other Australian utilities and selected best practice utilities overseas.

Performance of the SA industry over time

The performance of the SA electricity industry has improved significantly over the last five years, as measured by a range of indicators (see Table 2.7).

Average real electricity prices in SA have fallen by 13 per cent in real terms between 1989–90 and 1994–95, and there has been a significant realignment in prices between customer classes. Over the same period, ETSA has more than doubled its operating surplus, and cut employee numbers by 44 per cent.[8]

SA's performance compared to other States

It is difficult to compare the performance of the electricity industry in different States for a number of reasons. Differences in performance may reflect natural or geographic constraints, such as the availability of fuel or the dispersion of the population. Such differences may make it optimal for States to configure their industries differently, leading to differences in partial performance indicators that reflect these factors. Differences in how the States collect data can also reduce comparability. Despite these qualifications, interstate comparisons are useful because they give an indication of what is possible, and are therefore more outward looking than comparisons of a State's performance over time.

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7 There has been some uncertainty about whether the shield of the crown exempted State government business enterprises from the *Trade Practices Act 1974*. Recent amendments will remove this uncertainty from July 1996.

8 Operating surplus is measured after interest, depreciation and abnormal items, but before contributions to the State Government.

The performance of the SA electricity industry is compared with other States in Table 2.8. In a capital intensive industry like electricity, capital productivity is vital to overall performance. SA's low reserve plant margin indicates that it has successfully avoided over-investing in generating capital. In terms of labour productivity, SA performs well in the distribution sector, but poorly in the transmission sector.

Table 2.7: Indicators of performance, SA electricity industry, 1989–90 to 1994–95

		Financial year						*Average*
Indicator	*Unit*	*1989-90*	*1990-91*	*1991-92*	*1992-93*	*1993-94*	*1994-95*	*change 1989-95*[a]
								(per cent)
Average real price	\$/MWh (\$1989-90)	97	92	96	96	91	84	- 4
Return on assets[b]	per cent	9	8	8	11	6	12	- 5
Labour productivity								
– generation	GWh/emp	6	6	8	9	14	13	+ 47
– transmission	GWh/emp	26	26	30	34	40	48	+ 32
– distribution	cust/emp	211	217	246	277	340	393	+ 33
Reserve plant margin[c]	per cent	32	22	22	12	20	5	- 41
Loss of supply factor	minutes/ customer	253	263	106	171	120	116	- 32

a The average change identifies consistent improvements in performance, and is less sensitive to the choice of the end point for comparisons. It is calculated by averaging the results from 1989–90 to 1994–95, and determining the percentage change from the base year, 1989–90.

b The definition of return on assets changed in 1992–93, reducing comparability between years. Prior to 1992–93, the return on assets was calculated in terms of earnings before interest and taxation (EBIT) and excluded abnormal items. From 1992–93 EBIT included abnormal items.

c ETSA's reserve plant margin does not include contracted capacity from the interconnection or arrangements for reserve sharing with the eastern States. ETSA estimates that if these sources of capacity are included, its reserve plant margin rises to 25.7 per cent. The fall in the reserve plant margin between 1993–94 and 1994–95 reflects the mothballing of 120 MW at the Playford power station.

Source: Steering Committee on National Performance Monitoring of Government Trading Enterprises 1995, p. 30-33, and material supplied by the SA Department of Treasury.

Total factor productivity

The two above approaches to measuring performance suffer from the weakness of being based on partial indicators of performance. Total factor productivity (TFP) is a comprehensive measure of productivity which takes account of all outputs produced and all inputs used. Comparing the TFP of the SA electricity industry with leading utilities overseas provides a measure of how SA compares with international best practice.

The Bureau of Industry Economics (BIE 1994) and the Electricity Supply Association of Australia (ESAA 1994) have undertaken studies of the TFP of the Australian electricity supply industry. Although these studies are the latest available, they are based on old data. The BIE study used 1991–92 data, and the ESAA study used 1989–91 data. As discussed above, there have been significant improvements in the performance of the SA industry since then.

The BIE study found that the Australian electricity industry was achieving TFP levels around 73 per cent of the average US investor-owned utility (BIE 1994, p. 40). The worst performing State was Victoria, with a TFP level of 67 per cent. The best was Queensland with a TFP level of 83 per cent. SA's TFP was about 75 per cent of the average US investor-owned utility.

These results were confirmed by the ESAA study. This work separately considered the TFP of the generation, transmission and distribution sectors (ESAA 1994).

The ESAA study found that the SA Generation sector was the least efficient of Australian generation sectors, and was only 67 per cent as efficient as overseas best practice generators. This was mainly because of its less efficient input mix, which reduced its allocative efficiency. In part, SA's poor performance reflected a high level of electricity imports from the eastern States, which had reduced capital utilisation and increased unit capital costs.

ESAA found that the ETSA Transmission system was 92 per cent as efficient as the best in the world, and was the second most efficient in Australia after Queensland. However, ESAA noted that this result may have reflected its methodology, which favoured lower voltage systems.

The ESAA study found that ETSA Distribution was 75 per cent as efficient as the best in the world, and about the average of the Australian States. In part, this low efficiency reflected low density of users and sales in SA. However, when compared against other low density distribution systems, SA was still only 87 per cent as efficient as best practice utilities operating low density distribution systems.

Table 2.8: Indicators of performance, by State[a]

Indicator	*Unit*	*NSW*[b]	*Victoria*[c]	*Queensland*[d]	*SA*
Return on assets	per cent	12	9[e]	np	12
Labour productivity					
- generation[f]	GWh/employee	13	11	19	13
- transmission	GWh/employee	38	77	52[g]	48
- distribution	customer/employee	272	387	318	393
Reserve plant margin	per cent	22[h]	2[i]	19	5
Loss of supply factor	minutes/customer	76	np	124[g]	116

a Data for SA, Victoria and Queensland are for 1994 95. Data for NSW are for 1993–94.
b Data on the labour productivity of distribution and the loss of supply factor are for Sydney Electricity. All other indicators are for Pacific Power.
c The data on labour productivity in transmission are for Power Net Victoria. The labour productivity of distribution was aggregated over all Victorian distributors. The labour productivity of generation, the reserve plant margin and the loss of supply factor were aggregated over all Victorian generators, other than Mission Energy. The aggregated data were for five months (1 February to 30 June 1995) and were extrapolated out to provide a 12 month estimate.
d Labour productivity of generation and reserve plant margin are for Austa Electric. Labour productivity of transmission is for the Queensland Transmission and Supply Corporation. The labour productivity of distribution and the loss of supply factor are for the South East Queensland Electricity Corporation.
e This is the return on generation, transmission and distribution assets, and was calculated by the Industry Commission.
f Excludes construction and mining personnel.
g Data were provided for the six month period 1 January to 30 June 1995. To facilitate comparisons, this figure was doubled to provide an annual estimate. However, this adjustment does not take account of any seasonality.
h Excludes Snowy Mountains entitlements. If these are included, the reserve plant margin rises to 48.2 per cent.
i Excludes Loy Yang B and Snowy Mountains entitlements.
np Not provided.
Source: Data released by members of the Steering Committee on National Performance Monitoring of Government Trading Enterprises, and Annual Reports.

Overall conclusions on SA's performance

Data limitations make it difficult to draw precise conclusions about the performance of the SA electricity supply industry. However, the three broad approaches outlined above indicate that the industry's performance has improved substantially over the last five years, but there remains considerable scope for further improvement.

2.5 Importance of electricity to the SA economy

Electricity prices impact on the living standards of households and the competitiveness of business in SA. Although items like housing, food and transport are more important in the family budget than electricity, the cost of electricity is incorporated into all of these. Consequently, electricity prices directly and indirectly affect the price of most other goods and services.

Electricity prices also affect household living standards through their impact on employment, and therefore household income. As a key business input, electricity prices affect the competitiveness of SA industry, and therefore its ability to expand and employ. For example, electricity constitutes 8 per cent of the total value of goods and services purchased in the health industry, and 2 per cent of the total value of output of the health industry — the State's largest employer with over 59 000 people. In some manufacturing industry electricity makes up in excess of 20 per cent of operating costs.

The South Australian industry with the second largest employment is business services. Electricity accounts for 6 per cent of the value of goods and services purchased in the business services industry, and 2 per cent of the total value of all outputs. These figures *underestimate* the importance of electricity in production costs, because they do not include electricity costs which have already been incorporated into the cost of other production inputs.

In its work for COAG on *The Growth and Revenue Implications of Hilmer and Related Reforms*, the Commission estimated that reform of the electricity and gas industries would increase national income (GDP) by 1.4 per cent — about one-quarter of the potential benefits from the Hilmer reforms (IC 1995a, p. 20 and Chapter B5). While SA is already enjoying some of these benefits as a result of its reforms over the last five years, the Commission's estimates reveal that far-reaching benefits would flow from increasing the efficiency of the electricity industry.

3 NATIONAL COMPETITION POLICY AND THE ELECTRICITY INDUSTRY

This chapter contains two parts. First, it briefly outlines the features of the national competition policy, paying particular attention to the Competition Principles Agreement (CP Agreement). This agreement forms part of the competition policy package which sets out the principles and processes for the reform of government business enterprises (GBEs). The second part describes events leading to the establishment of the national electricity market, including specific structural reform requirements relating to the electricity industry and reforms already implemented in southern and eastern Australia. A brief discussion of the establishment of the natural gas market is also provided.

3.1 Competition policy reform

In 1991, the Commonwealth, State and Territory governments agreed to examine a national approach to competition policy. The impetus for a more coordinated approach reflected views that greater gains could be achieved through a collective effort. To this end, the Independent Committee of Inquiry into National Competition Policy was established in October 1992. Its report into national competition policy, known as the Hilmer Report, was released in August 1993.

The Hilmer Report made a number of recommendations on the nature of competition policy, as well as the processes and principles that should guide its implementation. These findings were subsequently considered by Commonwealth, State and Territory Governments. The competition policy reform package, which emerged out of this consultation process, was approved by all Governments in April 1995.

The reform package contains legislative and non-legislative elements. In essence, it has been designed to extend both the coverage and depth of the *Trade Practices Act 1974* (TP Act) and establish a process to identify and remove impediments to competition throughout the economy.

As part of this process, the Commonwealth, States and Territories developed several agreements that aimed primarily at establishing the institutions, guiding principles and incentives to promote the development of a nationally consistent approach to competition policy. These inter-governmental agreements underpin the cooperative approach to national competition policy (see Box 3.1).

The CP Agreement is a key element of the competition policy package. The CP Agreement seeks to remove impediments to competition that would not be removed by simply extending the coverage of the TP Act. These impediments include:

- legislation that restricts competition in particular markets;
- special advantages and disadvantages imposed on some GBEs;
- restrictions on potential competitors obtaining access to the services of certain facilities (such as power transmission grids and gas pipelines);
- monopoly pricing where competition is not effective; and
- the structure of some public monopolies.

Accordingly, the CP Agreement sets out a number of principles and processes to address these concerns. For example, it lists reforms required to achieve competitive neutrality — that is, putting GBEs on equal terms with private businesses. These require governments: to corporatise[1] GBEs 'where appropriate'; apply tax equivalent systems and debt guarantee fees; and the same environmental, planning and approval regulations to GBEs and core business activities of government agencies as those which apply to private enterprises. There are also principles requiring governments to review legislation that restricts competition. Structural reform and prices oversight of GBEs, and the non-discriminatory access to essential infrastructure facilities are also features of the CP Agreement. Because these latter elements are particularly important for this review, they are discussed in greater detail below. Additionally, reforms implemented by the States and Territories are compensatable under the terms of one of the three inter-governmental agreements and this is also discussed below.

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1 In its most basic form corporatisation involves subjecting GBEs to the corporations law. However, in practice it is usually accompanied by a range of initiatives such as providing management with greater autonomy, clear commercial objectives, and performance monitoring.

Box 3.1: Elements of the national competition policy package

The competition policy package contains three inter-governmental agreements:

- The *Competition Principles Agreement* (CP Agreement) establishes agreed principles on structural reform of public monopolies comprising: competitive neutrality between the public and private sectors; prices oversight of government enterprises; a regime to provide access to essential facilities; a program of review of legislation restricting competition; and consultative processes for appointments to the National Competition Council (NCC).
- The *Conduct Code Agreement* sets out the basis for extending the application of the TP Act — including to government business enterprises. It sets out the consultative processes for making modifications to competition law and appointments to the Australian Competition and Consumer Commission (ACCC). It also commits each State and Territory to pass the required application legislation to enable the Commonwealth's new legislation to take effect.
- The *Agreement to Implement the National Competition Policy and Related Reforms* provides for payments by the Commonwealth to States and Territories. These are in return for them meeting agreed obligations set out in the Agreement, the Conduct Code Agreement plus reform commitments in electricity, gas, water and road transport.

The *Competition Policy Reform Act 1995* is the Commonwealth's legislative element of the package which:

- amends the competitive conduct rules of part IV of the TP Act and the provisions that exempt specific forms of conduct from these rules;
- inserts provisions into the TP Act extending the coverage of the competitive conduct rules to the unincorporated sector and to State and Territory GBEs;
- creates a new section of the TP Act (part IIIA) establishing a new national regime for access to services provided by means of 'nationally significant' infrastructure facilities;
- amends the *Prices Surveillance Act 1983* (PS Act) to extend prices oversight to State and Territory owned business enterprises; and
- creates two new institutions responsible for overseeing and providing advice on the implementation of the policy package. The ACCC — formed from the merger of the Trade Practices Commission and the Prices Surveillance Authority (PSA) — is primarily responsible for administering the PS Act and the TP Act. The NCC has been formed to provide advice on access declarations and on prices oversight of State or Territory Government businesses and undertake reviews under the CP Agreement.

Structural reform of GBEs

Structural reform of GBEs has long been recognised as a necessary precursor to the introduction of competition in some sectors of the economy, for example, electricity, gas, rail and water.

Structural reform seeks to create an environment where GBEs — especially vertically integrated enterprises with contestable elements — are exposed to competition (or at least the threat of competition), thereby creating pressures for adjustment and continuous improvement. The Hilmer Report stated that:

> The introduction of effective competition into markets traditionally supplied by public monopolies will often require more than the removal of regulatory restrictions on competition. Where the incumbent firm has developed into an integrated monopoly during its period of protection from competition, structural reforms may be required to dismantle excessive market power and increase the contestability of the market (1993 p. 215).

The Hilmer Report centred on three structural reforms to promote competition in markets traditionally supplied by public monopolies. They were to separate:

- regulatory and commercial functions;
- natural monopoly and potentially competitive activities; and
- potentially competitive activities.

Accordingly, the structural reform element of the CP Agreement obliges governments to examine the appropriate structure of public monopolies before introducing competition (see Box 3.2). Each party to the CP Agreement is free to set its own agenda for reform, although where other agreements have been made to introduce competition — such as the national electricity market — the structural reform commitment contained in the CP Agreement becomes binding.

Prices oversight of GBEs

GBEs that have activities with natural monopoly characteristics and those that operate in markets where competition is weak have the capacity to limit supply and to charge prices above those that would prevail in a competitive market. This is detrimental to economic efficiency and to the interests of users. The national competition policy recognises that prices oversight may be necessary under these circumstances.

Box 3.2: Structural reform elements of the Competition Principles Agreement

Before any government introduces competition to a market traditionally supplied by a public monopoly or privatises a public monopoly, it must first undertake a review into the appropriate structure for the enterprise. In undertaking such reviews, governments must examine a number of issues, including:

- the appropriate commercial objectives for the enterprise;
- the merits of separating any natural monopoly elements from potentially competitive elements of the public monopoly;
- the merits of separating potentially competitive elements of the public monopoly;
- the most effective means of separating regulatory and commercial functions of the enterprise;
- the most effective means of implementing competitive neutrality principles;
- the merits and most appropriate means of funding and delivering any mandated community service obligations (CSOs);
- the price and service regulations to be applied to the industry; and
- the appropriate financial relationships between the owner of the public monopoly and the public monopoly, including the rate of return targets, dividends and capital structure.

Source: Inter-governmental Agreement on Competition Principles, April 1995.

Prices oversight of major Commonwealth owned GBEs and declared privately owned corporations[2] was previously undertaken by the PSA. Under the new arrangements, this has now become the responsibility of the ACCC.

State and Territory Government GBEs, with the exception of New South Wales (through the Government Pricing Tribunal) and Victoria (through the Office of the Regulator-General), have previously not been subject to independent prices surveillance or prices oversight.

The CP Agreement, in conjunction with the *Competition Policy Reform Act 1995*, sets out new arrangements for national prices surveillance and, importantly, principles to guide State and Territory prices oversight arrangements. Under the CP Agreement, State and Territory Governments have agreed to *consider* establishing bodies to undertake prices oversight of their

[2] A declared privately owned corporation is one which has been assessed as having market power and therefore becomes subject to prices oversight mechanisms.

GBEs. Additionally, the ACCC can also undertake prices oversight of State or Territory owned GBEs if the relevant government has agreed or where the NCC has, on request of another government, recommended declaration of an enterprise for prices oversight.

A number of Governments have recently established or indicated their intention to establish an independent agency for prices oversight. For example, the Tasmanian Government has announced the establishment of the Tasmanian Government Prices Oversight Commission. South Australia has yet to indicate the outcome of their consideration of whether to establish an independent agency for prices oversight.

Access to essential infrastructure facilities

Effective competition in some markets requires that competitors have access to the services of certain ‘essential facilities’ — that is, facilities which have natural monopoly characteristics. For example, the creation of a competitive electricity supply market requires that generators have access to the electricity transmission and distribution networks. Such access can improve economic efficiency by increasing competition in downstream and upstream markets.

The CP Agreement requires the Commonwealth Government to put forward legislation to establish a regime for third-party access to essential infrastructure facilities. The Commonwealth’s coverage is, however, limited where existing State or Territory access regimes are in place, unless the influence of the facility extends beyond the boundaries of the State or Territory or the existing access regime is deemed to be ‘ineffective’ by the NCC.

Under the new arrangements, access regimes can be established in three ways. First, the *Competition Policy Reform Act 1995* (CPR Act) requires the NCC to consider applications from any person for a right of access to be declared to the services of certain essential facilities of national significance. Second, the CPR Act, in conjunction with the CP Agreement, also makes provision for the endorsement of State and Territory access regimes. Third, the ACCC can accept ‘undertakings’ from providers of access services on the terms and conditions under which they will provide access to third parties.

Commonwealth financial payments

The Agreement to Implement the National Competition Policy and Related Reforms makes provision for financial assistance to be paid by the Commonwealth to the States and Territories. The assistance is to compensate jurisdictions for meeting agreed obligations set out in the CP Agreement, the

Conduct Code Agreement plus the related reform commitments in electricity, gas, water and road transport. With regard to electricity, the reform measures require each participating jurisdiction to implement a competitive national electricity market as agreed through the COAG process.

Total payments to the States and Territories are about $4.2 billion (in 1994–95 dollars) over nine years, commencing in 1997–98. Payments made to a jurisdiction are conditional upon it making satisfactory progress with implementation of the reforms. The payments are staged over three phases. South Australia's share of the compensation payments is estimated to total about $350 million, in 1994–95 dollars (see Box 3.3).

Box 3.3: National competition policy and compensation payments

Commonwealth financial payments will be made to the States and Territories for implementing reforms under the competition Agreements. The payments will be made over three stages, commencing in the following financial years: 1997–98 (for two years); 1999–2000 (for two years); and 2001–2002 (until 2005–2006). All payments are conditional on the relevant jurisdiction having made specific progress on competition reforms. This is divided between the three stages in the following manner:

The first payments

The agreed payment for this first stage is $400 million in 1994–95 prices — $200 million for each year. This is divided amongst the jurisdictions on a per capita basis. South Australia's share would be over $16 million per year based on existing populations.

The second payments

The total payment over the two years of stage two is $800 million in 1994–95 prices — $400 million per year, divided on a per capita basis. South Australia's share would be about $33 million each year.

The third payments

The total payment over this stage, from 2001–2002 to 2005–2006, is equivalent to $3 billion in 1994–95 prices — or $600 million a year over 5 years. Once again this will be divided amongst the jurisdictions on a per capita basis. South Australia's share would be almost $50 million per year.

Note: Commission estimates.
Source: Agreement to Implement the National Competition Policy and Related Reforms, Attachment (Conditions of Payments to the States), pp. 7-9.

3.2 Development of national energy markets

A commitment to national reforms in both the electricity and natural gas industries began early this decade. This section outlines the process that has led to reforms in the electricity industry, with particular emphasis on the South Australian situation. A list of reforms in participating jurisdictions is provided in Table 3.1. A brief discussion of the natural gas industry and associated reform commitments is also provided.

COAG agreements on electricity industry reform

The concept of a national electricity market arose out of recommendations by the Industry Commission (1991) report *Energy Generation and Distribution*. The aim was to promote efficiency by increasing competitive pressures within and between state grids.

At the July 1991 Special Premiers Conference, Heads of Government agreed to establish the National Grid Management Council (NGMC). The NGMC comprises representatives of the Commonwealth, New South Wales, Victoria, Queensland, South Australia, Tasmania and the Australian Capital Territory, plus an independent arbitrator. Under its charter, the NGMC is required to encourage open access and free trade in bulk electricity, and to coordinate the most efficient, economical and environmentally sound development of the interstate electricity supply industry in eastern and southern Australia.

In December 1992, relevant Heads of Government 'reaffirmed their commitment to the principle of separate generation and transmission elements in the electricity sector' (COAG 1992, p. 7).

In 1993, Heads of Government 'confirmed their commitment to the establishment of an interstate transmission network, separate from generation and distribution interests' and to the form of the transmission network. The Communique stated that:

> [Relevant Heads of Government] agreed that establishment of the interstate transmission network be through adoption of the Multiple Network Corporation model outlined in the NGMC report (COAG 1993, p. A1).

It was also agreed by Governments in southern and eastern Australia that the Multiple Network Corporation structure would be in place by 1 July 1995. The model requires each jurisdiction to separate the network (transmission and distribution) businesses from the other elements — generation and retail supply (where applicable) — and subsequently corporatise the new business (see Box 3.4).

Box 3.4: The multiple network corporations (MNC) model

The MNC model developed by the NGMC has the following characteristics:

- network service businesses would be separated from their respective utilities and corporatised;
- the separate corporations would have responsibility for all the network assets used by participants for trading under the Protocol;
- a number of options exist regarding ownership of the network corporations — including private equity;
- each network corporation would have a board of directors and a management structure independent of generation and retail supply interests;
- the business would be responsible for the detailed day-to-day switching operation, maintenance and augmentation of the network assets;
- responsibility for directing the non-discriminatory commitment and dispatch of generating capacity and managing coordinated maintenance of generation and the network could be performed by the business or a separate System Operation Group;
- the corporation may also carry out certain pool functions, including merit order determination and provision of information essential for settlement of customer market trading;
- the new corporations would pay dividends and income and sales tax equivalents to Governments where applicable;
- CSOs would be at the discretion of each Government, but would be explicit and by formal direction; and
- MNCs would be bound by their charter or articles of association and the Protocol to provide network services to all market participants in a non-discriminatory and transparent manner, including: pricing on consistent principles for network service; non-discriminatory access; and provision of information.

Source: NGMC 1993a.

At this meeting, the SA Government indicated that it had a number of issues to resolve before progressing further. The COAG Communique stated:

> South Australia indicated it is considering the use of a subsidiary structure pending the resolution of cost issues associated with separating transmission from its vertically integrated authority. Resolution of those issues would enable the adoption of the Multiple Network Corporation model (1993, p. A1-2).

Similarly, Tasmania indicated that it was reviewing the appropriate structure of its electricity supply industry.

At the August 1994 COAG meeting in Darwin, the South Australian and Tasmanian Governments indicated that reviews of their respective electricity industries were under way 'with a view to structural reform consistent with the national model' (1994, p. 4). At that time, structural reforms in Queensland, New South Wales and Victoria were already under way.

The outcome of the (confidential) review into the South Australian electricity industry resulted in the recent changes to the structure of ETSA outlined in the previous chapter — the creation of ETSA Corporation and four subsidiary corporations.

There is debate about whether the new structure of ETSA conforms with the structure for transmission agreed by COAG. For example, the Victorian Government argued that:

> ... the status quo of ETSA trading as four ring-fenced entities (distribution, transmission, generation and energy trading) does not satisfy the objective of structural reform (sub. 7, p. 1).

Similarly, the Business Council of Australia stated that:

> ... it would appear to the Business Council that this [present] structure does not comply with the requirements of the Council, nor of the stated intentions of the COAG (sub. 18, p. 17).

However, ETSA believes that its present structure complies with South Australia's commitment to the June 1993 COAG meeting. It contended that:

> ETSA's structure satisfies all the requirements for the fully competitive national electricity market and has the degree of separation to overcome the concerns that caused the Multiple Network Corporation structure to be recommended (sub. 5, p. 3).

In its submission to this review, ETSA stated that the South Australian Government had given other jurisdictions the opportunity to outline their concerns with the structure of ETSA. At a meeting of relevant Ministers in late 1995, the South Australian Minister invited each jurisdiction to identify in writing the nature of their concerns. However, ETSA claims that to date, the only response received is from the Chairman of the NGMC. The NGMC's main concern appears to be the maintenance of the systems control functions in the ETSA structure. In its submission, ETSA acknowledged that it may be inappropriate for the transmission subsidiary to have responsibility for system control, market management and transmission planning. As such, ETSA agreed:

> ... to consider the removal of both the System Control and the Investment Planning function from the rest of ETSA as the market is implemented (sub. 5, p. 47).

To the extent that there is some debate about the suitability of the existing SA structure, there could be implications for South Australia joining the national electricity market, and the payments by the Commonwealth under the Implementation Agreement. In this context, the SA Government commented that:

> Advice is sought from the Commission on the consistency of this [present] corporate structure and governance arrangements with NCP and COAG Agreements (sub. 15, p. 5).

On the basis of the information provided to the Commission, there appears to be some grounds for ETSA's claim that:

> ... the unclear nature of the commitment made here has led different parties to different interpretations (sub. 5, p. 42).

However, the Commission considers that it is not the appropriate body to interpret and adjudicate on any Agreements made through the COAG process. In accordance with the terms of reference for this review, the Commission's approach has been to identify the most efficient structure for South Australia to adopt, independent of the nature of any previous undertakings or of COAG or NGMC requirements. However, as is discussed in Chapters 5, 6 and 7, the Commission believes ETSA's present structure has limitations in terms of achieving the intentions of the COAG commitments.

The interim national electricity market is due to start operation in September 1996. The national market will become fully operational after a transition period of about four years.

Implementation of electricity reforms

Before the agreement to specific COAG commitments, a number of jurisdictions had already commenced electricity sector reforms. However, the type of reforms and the speed of progress has differed substantially between jurisdictions. The key structural reforms that have been implemented in jurisdictions other than South Australia include:

- generation has been established on an entirely independent basis in Victoria, New South Wales and Queensland, albeit in different ways;
- separate independent transmission corporations have been established in Victoria and New South Wales. In Queensland, transmission and distribution businesses have been established as subsidiaries of a holding corporation;

- in Victoria, system control and planning functions has been separated from transmission operations. In Queensland and New South Wales, these functions have been maintained within the transmission business;
- in New South Wales and Victoria, the number of distributors was dramatically reduced with retail functions maintained within each business. Victorian distributors have recently been privatised; and
- Victoria and New South Wales have announced a phased deregulation of their retail markets.

Further recent reforms across the jurisdictions involved in the national electricity market are briefly outlined in Table 3.1 below.

Table 3.1: Recent electricity reforms in the States involved in the national electricity market

Jurisdiction	*Date*	*Nature of reform*
New South Wales	Aug 1991	Electricity Commission of NSW was renamed Pacific Power and internally restructured into 6 commercially oriented business units — 3 generating groups, a pool trading unit, a network business and a services unit. The 25 distribution businesses remained separate.
	May 1994	Pacific Power’s network business unit established as a separate legal entity.
	Feb 1995	High voltage transmission and system control activities removed to become the responsibility of the Electricity Transmission Authority — trading as TransGrid. TransGrid given authority to develop and operate the state wholesale electricity market.
	May 1995	Government endorsement for restructuring of the generation and distribution sectors, introduction of interim State wholesale market and the development of policy for retail competition.
	June 1995	Announcement that the number of distribution companies be reduced from 25 to 6, through mergers: 4 rural and 2 metropolitan distributors. Each distributor will have a ‘wires’ and retail supply business.
	Nov 1995	Announcement that Pacific Power will be split into two competing generation companies.

Table 3.1: Recent electricity reforms in the States involved in the national electricity market (continued)

Jurisdiction	*Date*	*Nature of reform*
New South Wales (continued)	Dec 1995	Bills passed to: . formally split Pacific Power into two State-owned generation companies — First State Power and Macquarie Generation. . establish six energy services (distribution) corporations: Energy South, FarWest Energy, MetNorth Energy, MetSouth Energy, MidState Energy and NorthPower Energy. . establish an interim State wholesale market from the first quarter of 1996, and allow for the transition to full wholesale and retail competition. . allow for generation corporations to participate in the wholesale market, the distributor corporations to compete in the wholesale and retail markets, and other forms of energy and services.
	Mar 1996	New generation and energy service corporations commenced operation. TransGrid commences interim State wholesale market.
Victoria	Nov 1992	Majority interest in Loy Yang B power station sold.
	Oct 1993	The vertically integrated State Electricity Commission is separated into three businesses — Generation Victoria, National Electricity (transmission) and Electricity Services Victoria (distribution) — and corporatised.
	Oct 1994	National Electricity split into two businesses: . Victorian Power Exchange (VPX) established to develop and administer the wholesale electricity market (VicPool). System control and planning functions are the responsibility of VPX; and . Power Net Victoria established as a separate statutory corporation responsible for high voltage transmission functions.
	"	Five regulated regionally based distribution businesses were established, comprising the 18 business units of the former Electricity Services Victoria and the 11 Municipal Electricity Undertakings. Each comprises a competitive retail arm. The retail and distribution functions are ring-fenced within each business.

Table 3.1: Recent electricity reforms in the States involved in the national electricity market (continued)

Jurisdiction	*Date*	*Nature of reform*
Victoria (continued)	July 1994	The Office of Regulator-General (ORG) was established. With regard to electricity, the key tasks of the ORG are to oversee franchise customer tariffs, service standards, pool rules and operating procedures, transmission and distribution access and pricing, and market conduct.
	Sep 1994	Government tariff policy announced: . residential customer tariffs frozen until June 1996, followed by a 2% real price fall in July 1996, and a 1% real price fall each year thereafter to the year 2000; . small business tariffs to be reduced by 20% over three years; . large industrial (tariff H) customers offered a safety net; and . vesting contracts to be phased out as the retail sector is opened to competition.
	Jan 1995	Generation Victoria disaggregated into 5 corporatised regionally based companies.
	July 1995	Privatisation of the five distribution companies commences.
	"	Customers with load in excess of 1 MW are removed from the franchise market.
	"	Cross-ownership controls apply, such that parties will be allowed to own or control 100 per cent of one licensed Victorian electricity company, 20 per cent of another, and 5 per cent thereafter.
	Mar 1996	Sale of Yallourn Energy to a consortium headed by PowerGen International.
Queensland	Mar 1994	Gladstone Power Station sold to a consortium headed by Comalco.
	Jan 1995	The vertically integrated Queensland Electricity Commission was divided into two corporations — Queensland Generation (trading as AUSTA Electric) and Queensland Transmission and Supply Corporation (QTSC).

Table 3.1: Recent electricity reforms in the States involved in the national electricity market (continued)

Jurisdiction	*Date*	*Nature of reform*
Queensland (continued)	Jan 1995	QTSC is a holding company for 8 subsidiary corporations — 7 regional distribution corporations and the Queensland Electricity Transmission Corporation, trading as Powerlink Queensland.
		QTSC has responsibility for planning, coordinating and supplying electricity.
South Australia	July 1995	Electricity Trust (ETSA) corporatised and a new Board appointed. Separate business units were established through vertical ring-fencing arrangements — ETSA Generation, ETSA Transmission, ETSA Power (distribution and retail), and ETSA Power (trading in fuels, new sources of energy and energy services).
	"	Agreement reached for the construction of a co-generation plant at the Penrice Soda ash plant, supplying 180 MW to the State grid. Built and operated by joint venture partners Canadian Utilities and Boral Energy (CUBE), it is scheduled to commence operation in 1998.
Australian Capital Territory	1995	ACT Electricity and Water Authority is corporatised.
Snowy Mountains Hydro Electric Scheme	July 1994	Snowy Mountains Hydro-Electric Authority is commercialised.
	July 1995	Commitment to corporatise the scheme has been agreed by the three Governments involved (set to occur in 1996). They will retain equity in the new corporation in return for giving up present entitlements for electricity at cost.

Natural gas industry reform

Notwithstanding the importance of the above reforms in electricity, some of the gains will not be realised without pro-competitive reforms simultaneously taking place in other industries, particularly the natural gas industry.

Gas is an important energy form in Australia. It competes with electricity as an end-use source of energy in some applications, as well as being a fuel used in electricity generation. However, to date, there is little interstate trade in natural gas[3] and virtually no competition between producers in the south eastern States. This has major implications for the future efficiency of the national electricity market (the South Australian electricity industry's use of natural gas is discussed in Chapter 2).

The benefits of pro-competitive reform in both the gas and electricity markets are twofold. Firstly, it will provide the potential for greater end-use competition between the two forms of energy, thereby promoting more efficient outcomes. Secondly, gas required for electricity generation will be sourced from a potentially more competitive market, providing scope for lower electricity prices. Both factors will have major consequences for future electricity generation investment decisions.

The need for reforms to the natural gas industry in Australia has been recognised by all Governments.[4] Consequently, a package of pro-competitive reforms has been agreed through the COAG process with the aim of establishing a competitive national market in natural gas (see Box 3.5). Additionally, the Gas Industry Taskforce has recently been established to coordinate the implementation and further develop the COAG Agreements relating to gas reform.

3 An exception is the long standing contractual arrangement for the sale of gas from the Cooper Basin in South Australia to New South Wales.

4 In its recent study of the Australian gas industry, the Commission examined the benefits of allowing interstate trade in both electricity and gas. Using the MENSA Model of the Australian energy system, the net present value of benefits was estimated to be about $1.5 billion over 35 years (see IC 1995b, p. XLV). A significant finding of the MENSA simulations is that it is generally less expensive to transport gas to the point of electricity demand and generate electricity locally, than to transport electricity over long distances via the network.

Box 3.5: The establishment of a national market for gas

Governments are heavily involved in the gas industry. All stages of the gas supply chain are regulated, and governments own several key natural monopoly transmission and distribution assets (although this varies across jurisdictions). Regulatory controls in the gas industry are shared between the Commonwealth and the States, with the States regulating the production, transmission, and distribution of gas, and onshore exploration. The Commonwealth regulates, among other things, interstate trade, and offshore exploration and production (beyond the three mile limit).

Like electricity reforms, the greatest impetus for regulatory and structural changes in the natural gas industry has been provided by the recent focus on competition issues, including the national focus offered through COAG processes. Through COAG, all jurisdictions have agreed to implement free and fair trade in natural gas by 1 July 1996. Agreed features of the COAG decision include:

- the removal of barriers to trade within and between the states;
- a uniform national framework to provide for third party access rights to gas transmission pipelines;
- no new exclusive franchises to be issued, and the development of a plan to implement more competitive franchise arrangements;
- the corporatisation of publicly-owned gas utilities; and
- vertical separation of transmission and distribution activities (COAG 1994).

Commitment to gas reforms by individual governments is also linked to the competition payments agreed to under the Agreement to Implement the National Competition Policy and Related Reforms.

4 OPERATIONS OF THE NATIONAL MARKET

The National Grid Management Council (NGMC) was established in 1991. It has developed a set of proposed arrangements to create the national electricity market. The specific form and mode of operation of the proposed national electricity market will have implications for ETSA and all South Australian electricity users.

This chapter describes the proposed arrangements for the national market. It focuses on the form of the market and raises transitional issues where relevant. Some areas are yet to be agreed by all jurisdictions in the NGMC and are subject to change. This discussion is based on the current draft proposals, dated September 1995.

4.1 Market institutions

The proposed arrangements for the national electricity market will incorporate various trading markets, participants and institutions. The arrangements are illustrated in Figure 4.1 and described below.

Generators, retailers, distributors, large users and energy traders will all be able to participate in the national electricity market. They will become members of the Australian Electricity Code Administrator (AECA) and be bound by its Code of Conduct (the Code). The participating jurisdictions will pursue legislative changes to establish the AECA and agree to develop effective governance and accountability arrangements for its administration and operation. The AECA will monitor compliance with the Code, enforce the Code and manage changes to the Code. The existing draft Code (the proposed Code of Conduct) incorporates rules for electricity trade; for the connection of generators and users to the transmission grid; for security; and administrative rules.

To comply with the *Trade Practices Act 1974* (TP Act), the Code will need to be authorised, and a series of undertakings given to cover access to the transmission and distribution networks. Authorisation is required because the code might be deemed to be contrary to section 45 of the TP Act which deals with restrictive trade practices. An authorisation can be granted by the ACCC if it believes the public benefits outweigh the anti-competitive detriment.

The Code provides a uniform means for third parties to gain access to the networks of the participants. This also requires endorsement under the TP Act, through the participants providing undertakings to the ACCC. Once these are accepted by the ACCC, the services of the networks cannot be separately declared under Part IIIA of the TP Act.

The national electricity market will incorporate all states and territories that are interconnected. The four regions that are currently interconnected comprise: South Australia; Snowy (incorporating surrounding parts of Victoria and New South Wales (NSW) and the Australian Capital Territory); the rest of NSW; and the rest of Victoria. An interconnector between NSW and Queensland would add several regions.

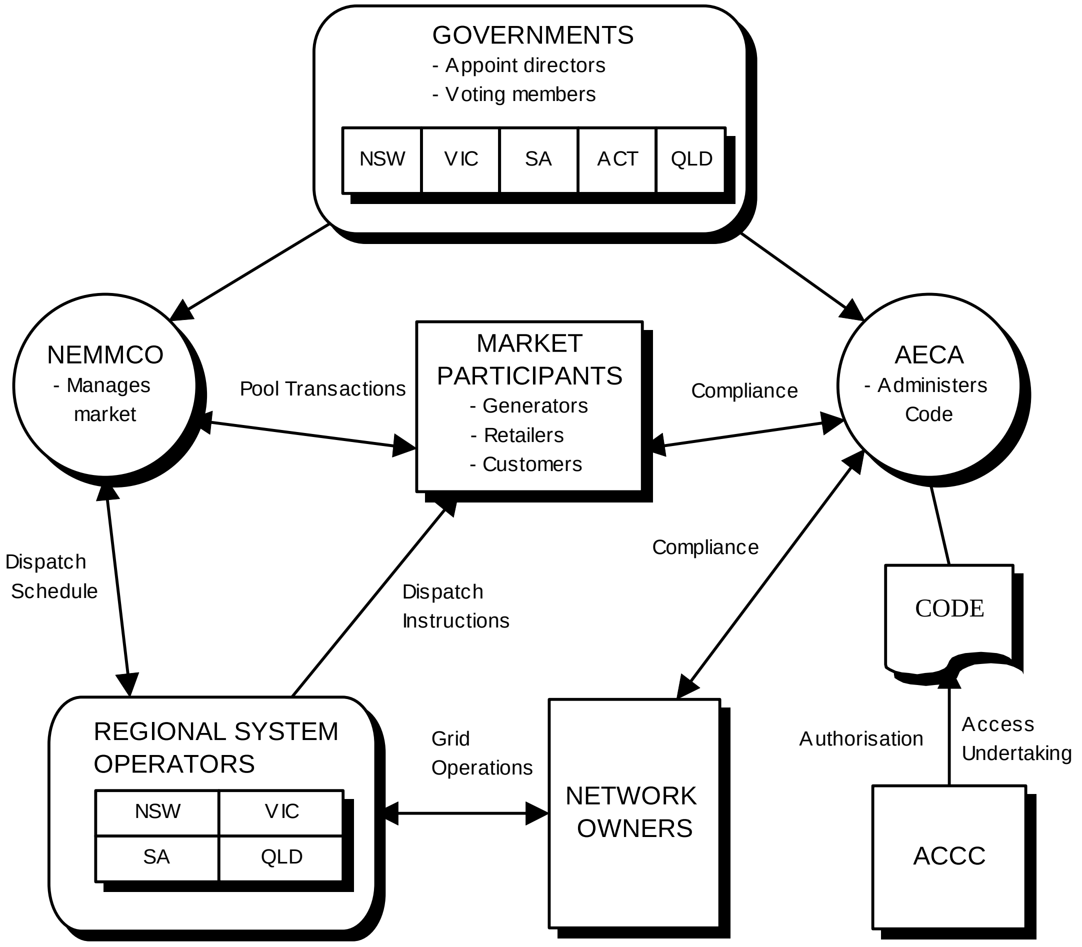
For the purposes of managing the operation of the market and the power system, Heads of Government will establish a company, currently referred to as the National Electricity Market Management Company (NEMMCO). NEMMCO will manage and administer the national market across participating jurisdictions, establish and develop market management infrastructure on a commercial basis and arrange financial settlement of transactions. A Regional System Operator will act as an agent for NEMMCO in each region and issue instructions for electricity generation and supply (called dispatch). Each region will have a Network Service Provider to manage the transmission and distribution network in that region. NEMMCO will incorporate some separate commercial functions:

- an Inter-regional Trader to facilitate management of the risk arising from price differences between regions (see later discussion);
- a Reserve Trader will operate, at least initially, to handle emergencies and over-ride the market in exceptional circumstances; and
- an Ancillary Services Trader to ensure the quality of electricity supplied to customers in terms of frequency and voltage, and provide the capability to restore system operation after a black-out.

4.2 Market mechanisms

The market trading arrangements are intended to allow participants the possibility of managing their plants and loads. This section briefly outlines key features of the proposed market arrangements including the spot market, the impact of transmission losses and constraints, the short term forward trading market and long term contracting.

Figure 4.1: The structure of the national market



Source: NGMC presentation to the Commission.

Spot market

The spot market will underpin the national electricity market in that all electricity volumes will be bought and sold through this market. All generators over 30 MW will have to participate in this market. It will be essentially a wholesale market with fees to participate.

- Suppliers of electricity (generators) will *offer* their output.
- Purchasers of electricity (called loads) will *bid* for electricity.
- Purchasers could also *offer* to reduce their load.

NEMMCO will dispatch loads and generators according to the *marginal generator principle*. That is, the next plant dispatched will be the one with the lowest bid of those plants not yet dispatched. If an offer of load reduction were cheaper than the next cheapest bid to supply electricity, that reduction will be accepted instead of additional generation. Every generator already dispatched will earn the price of the last plant dispatched (called the system marginal price or spot price).

The spot price will also take into account transmission losses from the generator or load to the regional reference node.[1] These losses are discussed below. Under this approach, spot prices reflect the marginal cost of electricity at the regional reference node.

Offers to supply electricity or to reduce demand will be submitted to NEMMCO for a whole day. NEMMCO will then match supply and demand according to price and plant availability and the spot price will be finalised each half hour. Generators that take longer than half an hour to be ready to supply electricity will be required to submit their intentions in advance. This will include most coal-fired power stations.

In extreme conditions (when there is insufficient supply to meet demand), the spot price will rise in predefined steps towards a preset Value of Lost Load (VOLL). If involuntary load shedding is occurring the price will equal the VOLL. Technically, the VOLL is the amount of money purchasers of electricity would be prepared to pay to avoid a disruption to their power supply. It could vary from a nominal level to as much as $50,000 per MWh. The NGMC has proposed that the VOLL initially be set at $1000 per MWh, gradually moving to $10,000 per MWh by 2002 as market participants gain experience in the national market. This is designed to provide very clear signals to market participants about the capacity constraints within the network and to encourage offers of further capacity or load reduction. NEMMCO will monitor reserve capacity and, if necessary, the Reserve Trader could take bids (in advance) for reserve capacity of a defined type for specified periods of time.

Spot prices will vary considerably as demand fluctuates, for example, Victorian pool prices have ranged from zero to $290 per megawatt hour since July 1994. However, market participants could reduce the risks of price variability using hedging (or financial contract) markets (these are discussed later). However, generators will still face the risk of an unplanned limitation on supply; purchasers will face the risk of their actual load differing from the amount contracted; and both generators and loads will face the risk of spot prices in

1 Each region will have one reference point (or node) at which the spot price is calculated.

their region differing from the spot price in the region in which they have contracted with a generator or load.

Transmission losses and constraints

On average, about 10 per cent of electricity sent out from power stations is lost in transmission and distribution networks. As mentioned in Chapter 2, when 500 MW of power is imported into South Australia from Victoria, transmission losses are about 18 per cent (NGMC, 1995a).

Under the proposed Code of Conduct, network losses will be taken into account when determining the dispatch price at the Regional Reference Node. Each region will have a reference node. This will be the Murray switching station in the Snowy region and the main demand centres in the other regions. Each generator and load point will be assigned a fixed loss factor at each time of day. The price received by each generator will be discounted by its loss factor and each participant would pay a premium equal to its loss factor.

Loss factors will be based on historical network losses at various time of the day. For losses on the distribution network, the loss factor will be based on average losses. For the transmission network, losses will be based on the average of the marginal losses expected over the year. The publication of loss factors will help participants formulate their bids and offers.

The Australian market arrangements must deal with a ‘long and skinny’ transmission system, unlike the highly meshed networks often encountered in other countries. It is important for an efficient market that participants take account of the costs of transmission between regions in their decision-making.

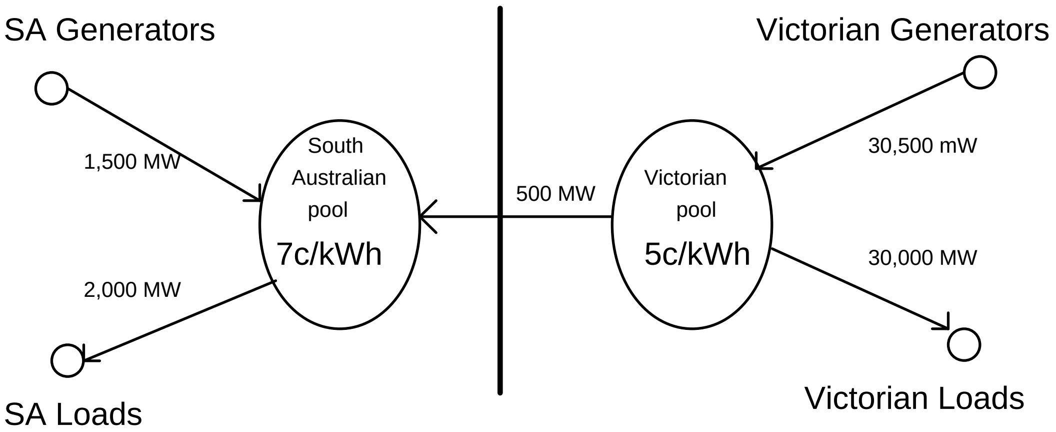
The spot price will differ between regions due to transmission losses. With no capacity constraints, the spot price at two reference nodes would be based on the same dispatch offer or bid but the prices would differ because of adjustments for inter-regional transmission losses. It is proposed that transmission costs across the interconnector between regions vary with the flow across the interconnector to reflect dynamic transmission losses, and be shared equally between the buyer and seller.

Inter-regional trade is inhibited whenever an interconnector is at capacity, when transmission costs are sufficiently large or whenever a regional generator can influence the flow over an interconnector to its commercial advantage. For example, if the South Australian regional generator strategically bids to constrain the interconnector at given times, the South Australian generator will then monopolise the residual demand in the South Australian market.

When trade between regions is inhibited, all further demand has to be satisfied by plant located in the isolated region. To the extent that regional plant faces less competition than when competing with all the plants operating in the national market, there is a likelihood that spot prices in the isolated region will be higher than prices elsewhere in the national market (see Box 4.1).

Box 4.1: Illustration of inter-regional pricing for network losses and constraints

For illustrative purposes, it is assumed that all Victorian generation costs 5 cents per kWh and all South Australian generation costs 7 cents per kWh. South Australia would import electricity from Victoria for 5 cents plus an amount for losses across the interconnector. The premium for losses would depend on the amount of electricity flowing, but might add 0.5 cents per kWh, for example. Once the interconnector is at capacity, further South Australian demand must be met by South Australian generation, costing 7 cents per kWh. Thus, if that plant priced according to cost, South Australians would pay 1.5 cents more for electricity when the interconnector is constrained.



Thus, the constraint in the link provides the opportunity for South Australian generators to raise prices for the residual demand for electricity in South Australia. The price differential also provides an incentive to augment the interconnector or to install additional generation capacity in South Australia. In practice, cost structures vary between generators and with transmission capacity, making the analysis of the costs imposed by interconnector constraints more complex. Chapter 7 discusses this issue in more detail.

A generator in another region that sells electricity directly to a customer in South Australia will face the risk of the interconnector becoming constrained and prices in South Australia rising to very high levels. The proposed market arrangements will provide opportunities for managing the risk arising from these price differences through the use of hedging contracts — a form of insurance. The hedging contracts will apply to the difference in spot prices at different regional reference nodes and, in principle, would usually 'insure' participants against potential losses that could arise if pool prices differed between regions. The Inter-regional Trader will supply hedges against inter-regional price differences. Participants will be able to purchase hedges from the Inter-regional Trader or, once a secondary market develops, from existing holders of hedging instruments.

Short term forward market

The proposed national market includes a Short Term Forward Market (STFM) that will be operated by NEMMCO. The STFM is being designed to provide a method for generators and energy purchasers to fine-tune their financial exposure under their long term contracts. For example, with extreme spot prices, generators and purchasers could be exposed to large losses if they operate in the spot market.

The forward price will be determined by buyers and sellers continually adjusting their overall contract positions. This will facilitate risk management as long as the market is liquid. This refers to the ease with which trades can be made and not necessarily the number of participants.

The STFM will trade in contracts which are referenced to the spot price. The contracts may be used by market participants to hedge the price of energy purchases and sales each half hour. Under the current draft Code, NEMMCO will be a party to all the STFM contracts, but will maintain a balanced position by the matching of bids and offers.

Long term contracts

Long term contracts are seen as fundamental to the stability of the electricity market and the achievement of effective forward planning in the industry. Many electricity users can anticipate their needs for electricity and prefer to engage in a contract for the bulk of these supplies to minimise the risk of price variability. Some may also wish to contract to avoid the costs of being an active trader in the spot market. Generators may engage in contracts to manage risks in order to attract finance. Producers of electricity are willing to sell such contracts in order to lock in their revenues over the same period. For example, in England many contracts are struck on an annual basis.

Although NEMMCO will not be directly involved with long term contracts, all market participants will buy and sell in the spot market. NEMMCO can offer to settle the differences between contracted prices and spot prices, although it will not be required to. A participant who has a contract with a participant in another region can buy a separate hedging contract to remove the risks associated with price differences between the regions.

Long term contracts may affect the behaviour of market participants but there is no link between long term contracts and other electricity market trading forms. Specifically, long term contracts will not affect the dispatch process or the spot trading settlements process.

The use of long term contracts, coupled with the other arrangements outlined above, will have significant implications for ETSA and its customers. Some of these implications are outlined in Box 4.2.

Box 4.2: Changes for ETSA and its customers that might arise from the commencement of the national electricity market

Currently, ETSA Generation determines which of its plants will run. However, with the commencement of the national market, ETSA generators will bid to supply electricity in a financial electricity market (the spot market) in competition with generators in other regions and with offers by electricity purchasers to reduce their demand.

Currently, most of ETSA's customers pay set rates for electricity. Residential customers will most likely continue to pay set rates for electricity under the proposed national market — a retailer will pay for electricity in the spot market on their behalf.

Large customers that currently purchase their electricity from ETSA will have more options under the new arrangements. For instance, a large customer may choose to continue with a fixed tariff from their choice of retailer. Alternatively, such a customer might enter into a financial contract for electricity at a fixed price with a retailer, distributor or generator in another region. This does not mean that their electricity would be produced by that generator, as the source of its power is unable to be determined.

Large customers will also have the opportunity to enter the wholesale spot market, buy electricity at variable prices and adapt electricity usage to take advantage of this. Large customers might choose a fixed-price contract to cover most of their expected needs and use the spot market to manage the remainder.

4.3 Augmentation of generation and transmission

South Australian generation capacity, supplemented by the Canadian Utilities Boral Energy (CUBE) cogeneration project, should be sufficient to maintain reliable supplies until at least the year 2000, after which new generation or transmission interconnector capacity will be required. The South Australian Government questions whether price effects will provide sufficient signals for investment (sub. 15, p. 9). The resolution of augmentation issues is a priority for South Australia. This is discussed further in Chapter 6.

Transmission

There are three proposed mechanisms for signalling a need for transmission augmentation between regions.

First, cost-reflective network pricing of transmission aims to provide incentives for economically efficient investment in transmission assets. The determination by NEMMCO of regulated network prices for individual users of electricity involves three steps:

- the Aggregate Annual Revenue Requirement is determined by each network owner (based on a risk-adjusted commercial rate of return on capital invested in the network);
- this total cost is allocated to individual locations of customer categories using cost-reflective approaches; and
- the allocated costs are translated into network prices based on the use of the system.

Entrepreneurial investment in transmission would be outside this regulated regime. Such investment is expected to be induced if, after transmission costs (losses), electricity prices differed between regions on a sustained basis. The behaviour of investors is expected to be constrained by the potential of further interconnection or new generation seeking to exploit price differences. It would also be subject to the TP Act.

Second, the price of long term inter-regional hedges (against price variability between regions) could signal the desirability of increased interconnector capacity. However, by manipulating flows across the interconnector, a South Australian regional generator with market power could conceivably raise the costs incurred in inter-regional trading by rival generators. The price differentials between constrained regions would then become a strategic tool. This would threaten the operation of the inter-regional hedging market.

Third, the proposed Code also requires NEMMCO to provide an annual Statement of Opportunities detailing performance of the existing grid and interconnector capabilities and the adequacy of the network to meet forecast requirements. The provision of this information would encourage current and potential transmission and generation providers to anticipate network constraints before they resulted in significant price differentials and potentially large financial impacts on the contracting parties.

Generation

The current draft Code appears to rely on the long term contract market and information provision by NEMMCO to generate economically efficient investment in new plant. For investment to occur at the appropriate time without intervention, future demand and supply balances must be signalled through contract prices. In addition, contracts would have to be of a sufficiently long duration for potential new generators to ensure revenue security. For instance, a new generator might not enter unless it had a significant proportion of its output covered by a 20 year contract with a distributor. NEMMCO would assist in the coordination of investment by encouraging the development of a secondary trading market in long term contracts as soon as practicable after the commencement of the national market.

It is uncertain whether the proposed market arrangements would encourage sufficient reserve generation capacity. An electricity system requires some capacity above expected peak demand to cater for planned and unplanned plant outages. Plant would earn the spot price when it is operating and zero otherwise, as there are no scheduled payments for reserve capacity under the proposed Code. The spot price would rise to the VOLL when supply is insufficient to meet demand and this is relied upon to provide the incentive to invest. However, this would at best induce generation capacity up to the level of expected demand and would appear unlikely to encourage investment in sufficient reserve capacity. The proposed Code allows for the Reserve Trader to call for offers of reserve capacity in times of market failure and also to enter into medium term contracts for reserve capacity. The existence of such ‘emergency’ arrangements indicates uncertainty about the success of the proposed market signals for investment.

Victoria and NSW have excess generation capacity which is expected to persist well into the next decade. However in the very near term, decisions will need to be made about investment in transmission interconnection or generation capacity to satisfy the South Australian regional market. It is important that augmentation of generation and transmission issues are resolved quickly by the NGMC.

4.4 Interconnection Operating Agreement

Interstate trade between NSW, Victoria and South Australia is currently governed by the Interconnection Operating Agreement (IOA), which expires in 2010. The IOA is between ETSA, the State Electricity Commission of Victoria (SECV) and the Electricity Commission of NSW. The IOA provides for three types of exchange:

- opportunity interchange: this exploits opportunities for reducing the cost of power generation by swapping cheaper sources of power generation for more expensive sources, with the cost savings split between the parties;
- emergency assistance: this covers capacity support if any party has insufficient capacity available to meet demand; and
- contract energy transfers: these contracts are priced on whatever basis the parties agree (sub. 7, p. 24).

ETSA has a contract, concluded under the IOA with the SECV to purchase electricity. This contract expires in April 1997. The relatively low contract price for electricity reflects ETSA's bargaining power as a large buyer and the excess capacity available in NSW and Victoria. As the proportion of excess capacity in the eastern states declines with increasing demand in those states, the price of electricity negotiated in the future should rise. The establishment of the national electricity market will not alter the fundamental forces which will shape prices of electricity delivered to South Australia.

In the longer term, as generation becomes more competitive and participants in the national electricity market gain experience, contract prices should reflect the spot price for electricity. The entry of new retailers into the South Australian market would erode ETSA's position as the sole buyer from Victoria, and possibly increase the price of electricity negotiated through Victorian suppliers.

While ETSA currently reaps substantial benefits from the contract negotiated under the IOA, it is expected that the negotiated price will rise naturally over time — independently of the nature of the contractual arrangements. If ETSA remained a monopsony buyer in the South Australian market in the future, its bargaining strength would result in a larger proportion of the benefits of trade going to ETSA, but the benefits available to all parties from further interstate trade will decline as the supply and demand balance in the eastern states tightens.

Several participants argued that the IOA is not compatible with the national market and should be discontinued. The Victorian Government (sub. 7) argued that the IOA was inconsistent with the proposals for a competitive national electricity market because:

- it is an exclusive arrangement, which does not allow competing generators or customers open access to the interconnector; and
- it does not allow for the unbundling of functions and the establishment of regulated charges for monopoly services (such as transmission and system control) or competitive pricing for non-monopoly services (energy, retail supply).

The South Australian Government said:

> The IOA is currently the subject of negotiations by the parties to the Agreement with the objective of ensuring that the rights and benefits of the parties are retained in a form of contract that is compatible with the national electricity market trading arrangements. Whilst the outcome of those negotiations relies on commercial considerations, the principal competitive issue relates to the exclusivity provisions of the IOA (sub. 15, p. 9).

Many of the purposes for which the IOA was put in place should now be achieved through the national electricity market. In the longer term, the existence of the IOA should not result in substantially different contract outcomes from the national electricity market so long as participants are free to choose with whom they contract. In this sense the IOA is redundant. However, should ETSA retain any exclusive rights to capacity on the interconnector, its contract with Victoria would not be compatible with an open access regime and would need to be formally discontinued.

The significance of this is that the price of electricity imported by South Australia from the eastern states is likely to increase over time irrespective of the national electricity market, although the advent of the national market may speed up the process.

4.5 Transition to the national market

The proposed national market is scheduled to commence in September 1996. However, it is not expected (or planned) that all the mechanisms outlined above be fully operational at that date.

Jurisdictions participating in the national market have adopted transitional measures to ease the commencement of the full national market in 2001. For example, Victoria has introduced contracts, expiring in 2000, between generators and existing clients (called vesting contracts). These limit the amount of electricity traded that is subject to the proposed market rules. This offers a degree of stability for incumbent generators and distributors during the transition period.

South Australia could also develop transitional arrangements to ease its entry into the national market.

5 THE EXISTING STRUCTURE OF ETSA

In some industries, the successive stages of production of a good or service are controlled by the one firm. This is commonly referred to as vertical integration. Until recently, the Australian electricity industry was characterised by a high degree of vertical integration. For example, in South Australia (SA), ETSA mines the coal to generate the electricity which it transports over its transmission and distribution networks, before retailing it to customers.

Where firms are subject to effective competition, vertical integration is beneficial in some circumstances. The benefits arise from economies of scale and scope, and the savings in transactions costs achieved by internalising contractual arrangements between business units. However, Australian electricity utilities became vertically integrated through policy choices, not through market forces, hence it does not necessarily follow that these savings are significant.

In Australia and overseas, the separation of vertically integrated utilities has been seen as a means of introducing competition in the potentially contestable elements of generation and retail. It does this by enhancing the prospects for access to the natural monopoly elements of transmission and distribution to be provided on a non-discriminatory basis. It also has important implications for the effectiveness of regulation of transmission and distribution.

This chapter considers whether there are shortcomings with ETSA's existing structure in terms of its effects on competition and efficiency in the electricity industry. The rationale for vertical separation is examined, in particular how different forms of vertical separation affect the intensity of competition in the generation and retailing of electricity. The implications for regulatory effectiveness are then discussed. The chapter concludes by examining the current structure of ETSA. Since the current structure incorporates a degree of vertical separation the key question then becomes whether this is sufficient, or whether some other structure would be more conducive to economic efficiency.

5.1 Structural reform and competition

If a firm has significant and sustainable market power and commercial objectives, it is likely to increase prices and profitability. This is not to deny the possibility that certain factors — such as a threat of regulation or political pressure — can moderate a firm's market power. However, to the extent that market power is exercised, considerable costs are imposed on the community. These costs reflect:

- *allocative inefficiencies* that arise because prices do not reflect supply costs, causing customers to forego consumption;
- *productive inefficiencies* that occur because costs are likely to be higher than they would be in a competitive market; and
- *dynamic inefficiencies* that arise because of reduced incentives to respond to changes in market conditions, and to make sound and timely investment decisions.

Chapter 2 showed that there was considerable scope for improving the economic efficiency of the electricity supply industry (ESI) in SA. These inefficiencies are partly due to the existence of legislative barriers to entry and restrictions on trade in electricity. Removal of these restrictions is a necessary step in introducing competition into the contestable elements of generation and retail. However, after their removal, vertical integration could still act as a disincentive to the entry of new participants. This is because market power derived from the natural monopoly elements of transmission and distribution could be used to protect the potentially competitive areas of generation and retail and thereby improve the value of the integrated business.

Creating contestable markets in generation and retail

The economic benefits of structural reform in the electricity industry are expected to flow principally from opening retail and generation to competition. If an incumbent generator or retailer in a contestable market attempted to sustain prices at levels markedly above costs, or did not minimise costs, there is scope for others to take market share from the incumbent.

Where it is credible, the threat of entry by a potential generator or retailer is sufficient to achieve a similar result. For instance, the sunk costs of an incumbent generator may enable it to price at below full (replacement) cost in the short term. The risk that an incumbent would adopt such a pricing strategy would discourage entry, but an incumbent cannot sustain it indefinitely if it intends to stay in the market. Consequently such a strategy would defer rather than prevent entry. In addition, new lower cost technology (such as combined cycle gas generation relative to gas fired thermal generation), and growth in demand will assist the process of new entry.

The importance of access

Once statutory barriers to entry are repealed, the key to competition lies in the third party access arrangements. Since distribution and transmission are widely held to be natural monopolies,[1] competition in generation and retail is unlikely to occur without third parties having access to the services of these facilities. Access would make it possible, for instance, for another power producer to enter the market (by purchasing transmission and distribution services), and compete against ETSA Generation for sales to customers. These customers could include ETSA retail, independent retailers or individual end users.

Vertical structure becomes important if the integrated incumbent firm can set access fees above the minimum necessary to ensure supply of network services, or otherwise act in an anti-competitive manner. For instance, if a vertically integrated electricity utility were required to provide access, it would have an incentive to cross subsidise its contestable activities with earnings made in the natural monopoly elements of transmission and distribution.[2] By charging itself the same price for access as anyone else, the vertically integrated incumbent meets the requirement that it be non-discriminatory. However, the price level acts as a barrier to entry by other participants.

Generally, vertical integration enables the potentially competitive activities to act more aggressively — giving them an advantage over actual or potential competitors. Although this behaviour is anti-competitive, it is consistent with the incentives inherent in a vertically integrated enterprise that seeks to maximise the value of the business as a whole.

Ring-fencing is often promoted as a solution to this problem. By requiring separate accounts to be kept for each business activity, ring-fencing increases transparency and makes it more difficult to conceal anti-competitive conduct. Although ring-fencing reduces the scope for this behaviour, it treats the symptoms of the problems and does not change the incentives. In addition, a variety of other non-price ways are open for an integrated utility to frustrate entry. Ring-fencing is best used where complete separation is either not feasible or is uneconomic.

1 Natural monopoly implies that one firm can produce all of a market's requirements at a lower cost than two or more firms. Hence it would be uneconomical to duplicate the assets of the incumbent firm.

2 The ability to do this depends in part on the degree with which downstream users can substitute away from the intermediate good or service. In the case of electricity, this would not appear to be possible. Thus whatever market power the integrated monopolist has at the retail stage, can be mirrored almost perfectly in access prices for the intermediate services of transmission and distribution.

The inadequacy of ring-fencing was emphasised by the Victorian Government who argued that:

> ... ring-fencing arrangements within a single company will tend to maintain loosely defined, non transparent and informal arrangements (that are typical of a vertically integrated utility) rather than clearly defined and transparent rights and obligations that are legally enforceable contracts between legally separate parties and subject to clearly defined regulation. Moreover, a ring-fenced system places directors in an ambivalent situation since, under company law, they are obliged to maximise the wealth of the entity as a whole. This may entail offering advantages to a related subsidiary (sub. 7, p. 12).

By comparison, complete separation overcomes these problems by creating independent organisations to conduct each of the following activities:

- the natural monopolies (transmission and distribution);
- the contestable activities (generation and retail); and
- market regulation (system control and planning).

Each organisation needs to be financially and operationally independent from each of the others. This decreases the scope for the network or the market regulator businesses to discriminate between users, and focuses their efforts on their own objectives, not those of the other organisations.

Having said that, the natural monopoly networks would still need to be subject to some form of regulation to stop them restricting aggregate capacity and capturing monopoly rents by charging high access prices.

Regulation of the natural monopoly elements is required whatever structure is chosen. The crucial difference is that vertically integrated utilities have the incentive to manage their affairs as a whole to limit the extent of competition. For practical reasons regulators are unable to eliminate each and every opportunity to limit competition (see following section). Accordingly, vertically integrated utilities can expect to have some scope to exploit their market power. Whether a vertically integrated incumbent behaves this way or not, the *perception* that it could, may still be sufficient to deter entry.

The Commission accepts that there will be a limit to which a vertically integrated, profit maximising utility will find it profitable to effectively subsidise some parts of its business. In some circumstances, it could be more profitable for the utility to opt out of generation or retail altogether. Since retailers and generators cannot avoid using the transmission and distribution networks, whatever market power that is available to the integrated utility would remain available to it because of its control of those networks. However, it is unlikely that any government trading enterprise would be able to pursue profit maximisation without regard for the consequences for other social objectives, such as employment and regional development.

The benefits of competition

In practice, the benefits of competition arising from vertical separation are likely to be impossible to distinguish from those accompanying other concurrent reforms in the ESI (such as corporatisation and privatisation initiatives). However, there are likely to be significant short term and long term benefits.

In the short term, efficiency gains will result from the pressures on electricity enterprises to reduce costs, align tariffs with costs, and use their assets more efficiently. Chapter 2 has illustrated the substantial scope that exists for further improvements by ETSA. In Victoria, where significant structural reforms have occurred, extensive gains are attributed to the more competitive environment. For instance, the Victorian generation sector has achieved:

- increased supply reliability (total annual customer outage was reduced by 48 per cent between 1989–90 and 1993–94); and
- higher plant availability (the average for Loy Yang A, Yallourn 1 and 2, and Hazelwood increased from 67 per cent in 1991–92 to around 89 per cent in 1994–95) (sub. 7, pp. 3–4).

In the longer term, as new competitors emerge the efficiency gains are likely to be more substantial. There will be increased discipline on generators to ensure that new investment decisions are timely, and involve technologies and plant sizes that best match market needs. There will also be additional pressures on both generators and retailers to seek new and innovative ways to contain costs and improve services to users.

At a higher level, a competitive national electricity market has the potential to achieve the following additional benefits:

- reserve plant margins can be reduced by sharing plants between States;
- non-coincident peaks can be better managed and allow better capacity utilisation of generation assets;
- regions with access to low cost primary energy sources can provide cheaper energy to other regions;
- economies of scale in generation could be better utilised; and
- incentives for retailers to develop innovative means of meeting customers needs will help to increase competitive pressures on generators and improve overall economic efficiency. Retail innovations could affect the design of tariffs, the provision of demand management, and the provision

of overall energy packages covering electricity, gas and energy efficient appliances.

Many participants pointed to overseas experience to support their views on structural reform. The Commission has not had sufficient time to undertake a detailed analysis of the experiences of other countries. However, an increasing number of countries around the world have recently implemented, or are contemplating, structural reforms to their electricity industries to enhance efficiency by promoting competition (see Box 5.1).[3]

5.2 Effectiveness of regulation

Regulation is necessary to create a right of access by third parties to transmission and distribution networks. It is also needed to inhibit the market power that owner–operators of such networks could exert by restricting capacity and raising prices.

Since some regulation of these natural monopoly elements will be required, irrespective of vertical structure, it is appropriate to consider the implications of different vertical structures on the likely costs and effectiveness of regulation.[4] Considerations include the transparency of the relationships between the different parts of the ESI, the market power that each has, the ease with which the regulator can obtain information, and the incentives to withhold or distort information.

In supporting the separation of ETSA, the Australian Chamber of Manufactures stated that among other things it would:

> ... reduce the need for heavy Government regulation to ensure effective operation of the utility (sub. 3, p. 2).

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3 See for instance Navarro (1995) and Argyris (1993).

4 The form of price regulation also has implications for structural options. One of the recognised difficulties of regulating prices is in allowing for a reasonable rate of return on assets, but if prices are too closely linked to the rate of return, over investment can be encouraged (the so called Averch–Johnson, or gold plating effect). This problem has been addressed in Victoria by locating system planning in a separate organisation (Victorian Power Exchange) from transmission (PowerNet Victoria), and limiting the transmission owner to being a manager of those assets.

Box 5.1: Electricity industry restructuring in selected overseas countries

In the United Kingdom (UK), the ESI was vertically separated prior to privatisation. The national grid and the 12 regional electricity companies (RECs) were privatised in 1989, while generation was divided into three firms before two were privatised in 1990. Limits on any one entity owning more than a certain proportion of other entities have been instituted — for example, the RECs can only own up to 15 per cent of their generation requirements. Of the new structural arrangements, Vickers and Yarrow conclude that:

> The main argument *for* vertical separation is that it may promote horizontal competition. In respect of supply of electricity to the non-franchised market, the partial separation of supply and distribution has indeed led to a surge in competition for the accounts of large end users (1991, p. 225).

In 1995, the ESI in the UK has also seen some re-emergence of vertical integration albeit in a substantially different form to how it was originally configured. For example, seven of the 12 RECs have received takeover offers, predominantly from companies already involved in the industry, including overseas interests.

In New Zealand, generation and transmission were initially ring-fenced business units of the same corporation when reform began in 1987. However, in July 1994, the full separation of transmission from generation occurred. The Government considered it inappropriate for transmission to remain with generation as it facilitated the Corporation's dominance in generation (Media Statement, 1992). More recently, the break up of the single generator into two separate companies has been announced, and is set to occur in early 1996. The larger of the two generators will have capacity restraints imposed in order to encourage new generators to supply additional future capacity. All but two of the 44 energy distribution entities have been corporatised, with mixed ownership. Distribution entities must 'ring-fence' the wires from the retail business through separate accounting.

Norway's ESI is a mix of private and public (including municipal) ownership, with transmission predominantly publicly owned, although the government does lease privately owned sections. Deregulation of generation and retail supply, including third-party access provisions to the transmission network has been provided by the *Energy Act 1992*. Although regulation requires that vertically integrated companies apply separate accounting for each of their activities (ring-fencing), some problems have emerged regarding its effectiveness. The International Energy Agency argues that:

> The continued existence of vertically integrated companies has led to a situation in which the accounts for the distribution businesses are being padded to shelter supply and/or generation costs (OECD/IEA 1994, p. 262).

Getting access prices right is important for economic efficiency. Competition that reduces the costs of generation and retail would be of no benefit to consumers if transmission and distribution owners were able to capture the savings and maintain prices. If the terms and conditions of access are set too low, investment in the networks themselves will be affected, and if they are set too high, consumers lose welfare from reduced supply. Perhaps most importantly, an access price that is too high will allow a vertically integrated utility to cross subsidise generation or retail and deter potential competitors.

Regulation of the natural monopoly networks can limit the ability of the vertically integrated firm to raise prices above the efficient level. But this degree of restraint is difficult to achieve in practice without heavy handed regulation. There are considerable difficulties in precisely estimating and allocating costs between the natural monopoly and contestable sectors of the industry. The integrated entity can exploit this ambiguity to protect or otherwise support its contestable activities.

One of the central issues in structural reform is the difficulty regulators experience in being able to accurately cost each stage in the production chain. As in all regulation, there is an asymmetry of information between the regulator and the regulated entity. The regulator is dependent on the regulated firm for a substantial amount of information needed in setting access prices.[5] Regulators can turn to some third party sources to verify the information that they receive from the regulated firm (for instance transmission and distribution organisations in other States or overseas). However, such information will almost invariably need to be heavily qualified because of differences in the circumstances and characteristics of the benchmark firm.

Vertical integration of the regulated utility does not alter the asymmetry of information. But the capacity of an enterprise to exaggerate or disguise its true costs are greater if it encompasses activities not subject to regulation.

Even where ‘ring-fenced’ accounts are kept, there will inevitably be problems for the regulator in allocating costs and assets to one function or another. Even allocations which genuinely seek to accurately distribute costs between activities within the one business invariably involve a degree of subjectivity (especially in the allocation of overheads such as many management related costs).

Vertical separation of the utility reduces the incentives and the capacity to distort this information It also provides greater transparency in the accounting and other information needed by the regulator.

5 The NGMC’s draft Code of Conduct for the national electricity market attempts to overcome this problem for transmission and distribution by applying consistent valuation criteria and cost allocation methods.

These problems can be exacerbated if different parts of an integrated utility are regulated differently by different agents, as is likely under the draft Code of Conduct for the national market. Transmission regulation will be under the Australian Electricity Code Administrator (AECA) but distribution may be under State regulators. While the draft Code attempts to apply consistency to transmission and distribution pricing, the regulated utilities will have an incentive to load costs into the more tightly regulated regime (and thus justify a higher price) and to shift profit-making to the less tightly regulated one.

In summary, a vertically integrated utility can be expected to manage its subsidiaries as a group in order to maximise shareholder value, subject to compliance with competition law. For this reason the problems of regulating parts of such utilities are exacerbated. Regulation becomes simpler, less expensive, and more effective if there is complete separation of the different activities into independent businesses or corporations.

5.3 Costs of vertical separation

There may be costs involved in separating a vertically integrated utility. They include the following:[6]

- loss of any benefits from the combination of successive stages of production (*economies of scale and scope*); and
- changes in *transactions costs* that arise from new contractual and administrative arrangements between the separated entities.

The presence of *economies of scale and scope* between the various stages in the electricity supply chain can make a vertically integrated structure less costly than if generation, transmission, distribution and retail were all operated separately.

Economies of scope arise from sharing resources between the different stages of production. Many fixed assets in the electricity industry tend to have specific applications and can be readily identified as belonging solely to one stage of production or another. They will therefore tend not to give rise to significant economies of scope. Resources that can be shared include the head office (including executives, buildings and computer systems), and specialist staff involved in more than one stage of production (for instance, corporate support

6 In an unregulated environment vertical integration also eliminates concerns about the effects of so called ‘double marginalisation’, which refers to the undesirable tendency for sequential monopolies (transmission and distribution) to set prices that in aggregate lead to a worse result, in terms of social welfare, than if they behaved as an integrated monopoly. See for instance Vickers and Yarrow (1988).

functions such as information technology, and human resources management, where a common pool of resources could service all of the subsidiaries).

Economies of scale can also be an advantage of vertical integration. These arise where, through the sheer size of the integrated organisation, some service functions can be provided at a lower cost than they could be if the organisation was separated into its components. These can include economies in procurement, such as vehicle purchasing and insurance.

Transactions costs arise when there is a need to formally specify the economic and legal obligations of two parties to each other. Such costs are potentially important in vertical and horizontal separation. Not only must contracts be drawn up and monitored to cover what might otherwise be relatively informal arrangements between business units, but there are also costs in coping with unforseen circumstances. An example of the former would be the contractual terms and conditions for the supply of electricity by a generator to a distributor. The latter might include the financial losses incurred by a retailer from a supply outage that was not foreseen in its contractual arrangements with its generator.

It is important to recognise that even relatively informal arrangements will involve transactions costs. For instance, the development and maintenance of internal procedures for dealing with the interactions between transmission and generation subsidiaries, or between different generators within the one portfolio will not be costless. It is the additional cost arising from vertical separation that is important.

In practice, distinctions between *economies of scale and scope* and *transactions costs* in some of these areas can be blurred. What is important is whether or not the cost of operating one large integrated organisation is the same as, or less than, the cost of operating its constituent parts as independent organisations.

On a higher level, *network externality* effects may be important. Since investment in one part of a network can have implications for other parts, its separate management may result in a higher cost solution than if a system-wide approach was taken. In other words, optimising the whole may be easier in a vertically integrated utility than it would be for separate systems working through market mechanisms.[7]

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[7] One of the characteristics of the ESI is that even in a more decentralised state, pricing signals that participants face will be a hybrid of market determined prices (such as electricity prices at point of dispatch, and retail margins), and regulated prices (access charges). Transmission pricing mechanisms is one issue the NGMC is still grappling with. Problems in coping with new investment, and the externality effects it can have, may require some intervention.

The Commission has reviewed the available literature on these issues, and finds that the empirical evidence on the presence of *vertical economies* is inconclusive.

In their econometric study of 74 privately owned electricity utilities in the USA, Kaserman and Mayo (1991) demonstrated that costs would rise by almost 12 per cent if vertically integrated firms were to be separated into generation and networks enterprises. On the other hand, other research points to a range of outcomes from vertical economies being non-existent, to savings that are even greater than this figure.[8] However, Kaserman and Mayo have warned against the:

> ... use of these numbers to infer precise cost changes associated with vertical divestiture. In particular, competition at the generation stage may lead to efficiency gains that offset the efficiency gains from vertical divestiture (1991 p. 499).

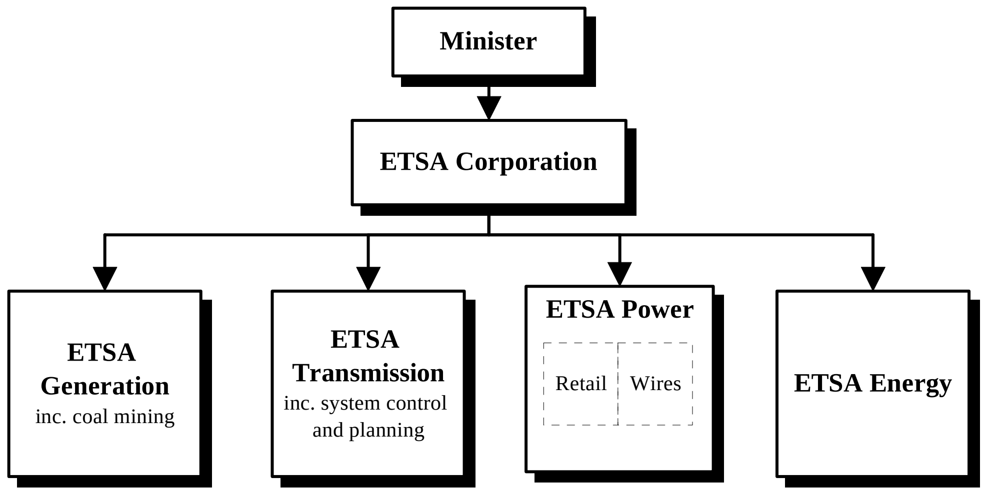
In summary, the Commission accepts that vertical separation in the ESI will mean some trade-off exists between integration economies, and the benefits of competition. Horizontal separation of generation has different implications for economies of scale and scope and these are discussed in Chapter 7.

5.4 ETSA's current structure

As explained in Chapter 2, ETSA Corporation is currently constituted as a public corporation under the SA *Electricity Corporations Act 1994*. It has four subsidiary corporations established by regulation under the *Public Corporations Act 1993* (see Figure 5.1). Each corporation is a legal entity in its own right.

8 The validity of Kaserman and Mayo's results has been questioned by Gilsdorf (1994), who has tested for subadditivity among 49 US electricity utilities and found: '...no evidence of subadditivity for vertically integrated electric utilities over the admissible region, implying that integrated utilities are not multistage monopolies' (p. 137). However, Byung-Joo Lee (1995) has also looked at the potential technological efficiency loss from disaggregating the electricity industry using US data. Lee's quantitative work suggests that technological efficiency losses would occur, and that these might be between 4.12% and 18.63% compared with the vertically integrated production function (p. 58).

Figure 5.1: ETSA's current structure



Each of the five corporations has a board of directors. There is a high degree of cross membership between the boards. This is most pronounced in the case of the boards of ETSA Transmission and ETSA Energy which contain all of the members of the Board of ETSA Corporation (the holding company), plus in each case the respective chief executive officers of those subsidiaries. The Boards of ETSA Power and ETSA Generation are constituted differently. Two of the four directors must be from the board of ETSA Corporation (one a Ministerial appointment, the second the CEO of ETSA Corporation). The other two directors are an independent chair person, and in each case the respective chief executive officer of that subsidiary (see Figure 2.6). In practice:

> The membership of these Boards have been constructed to ensure that members of the Generation and Power Subsidiary Board who are also Corporation Board members do not have a majority position on their Subsidiary Board (sub. 5, p. 14).

The current structure means that some ETSA directors also sit on more than one subsidiary board (since all are on the Board of ETSA Transmission, some must by definition be on at least two subsidiary boards). But the numbers of directors are such that ETSA directors who are also members of the board of ETSA Power, cannot have a majority on the ETSA Transmission subsidiary. The same applies for directors of ETSA Generation.

ETSA has argued that its:

> ... structure and the regulatory regime provide sufficient checks and balances on its subsidiaries to ensure open access and encourage competition while at the same time realising the benefits available through economies of scale and scope. The competitive

> pressures of the national electricity market on the subsidiary corporations will ensure that they are driven to perform at their most efficient level (sub. 5, p. 2).

Most participants were critical of ETSA's current structure. The Business Council of Australia believes that:

> ... the principle of the separation of the functions in the electricity industry should no longer be in doubt in Australia. When faced with competitive pressure at the generation and/or supply end of the supply (chain), a vertically integrated utility will always be sorely tempted to use the issues of access to and pricing of the network function as an anti competitive defence (sub. 18, p. 10).

In referring to the ability of other retailers to enter the South Australian market, the Victorian Government was concerned that:

> ... a subsidiary relationship of ETSA Power Corporation has the potential to raise barriers to these competitors in the form of: exposure to prices offered by the parent company; the financial interdependence of the parent and the subsidiary; and the overall investment policy of the parent in terms of generation, transmission and distribution (sub. 7, p. 9).

Similarly the South Australian Employers' Chamber of Commerce and Industry (SAECCI):

> ... sees merit in splitting the subsidiaries of ETSA into completely separate and independent corporations.
>
> Such action would ensure that the decisions of each entity were more independent and that prices reflect the cost of supply rather than some artificial price designed to support the whole group. SAECCI has no evidence that this occurs but is concerned that the risk of it occurring is there (sub. 20, p. 4).

These and other submissions reflect the concern that the current structure provides incentives and scope to insulate generation or retail from competitive pressure. Economic efficiency in South Australia would be harmed if this excluded alternative lower cost generators or retailers.

Not all participants favoured further separation. The Australian Services Union (ASU) opposed further separation of ETSA on two grounds: first, it could be a precursor to privatisation of the industry; and second it would adversely affect the competitiveness of the South Australian electricity supply industry in the national context:

> ... the size of the electricity industry in SA, in association with the size of the SA economy, is such that the automatic transference of national competition models (linked to a national market) will disadvantage the regional economy of SA (sub. 14, p. 2).

The ASU position was supported by the United Trades and Labor Council of South Australia.

With respect to these concerns, the Commission can only comment that it has been requested to examine structural options for ETSA that will best suit the South Australian community, not the electricity industry. The Commission was not asked to look at privatisation and the issues involved are independent of ownership issues. The quest is for greater efficiency in *all* enterprises in the electricity industry regardless of who owns them.

The Commission sees no reason why all the parts of ETSA could not be retained in the public sector following separation. Indeed, this is precisely the situation in New South Wales — the Electricity Commission of NSW has been broken up to create a transmission agency and multiple generating businesses but the NSW Government has indicated that they will not be privatised.

The case to retain ETSA’s current structure rests on several important presumptions:

- legal separation into subsidiary corporations is sufficient to ensure those subsidiaries are financially and operationally independent of each other;
- the costs of further separation are significant; and
- the effectiveness of access regulation will be unaffected.

The Commission believes that these presumptions are questionable. Moreover, it appears that the current structure is inconsistent with the spirit of the Competition Principles Agreement and related COAG agreements.

The problems of regulation where there are vertical links has already been discussed in the earlier parts of this chapter. Although ring-fencing goes part of the way to improving the ease of regulating, the Commission believes that formal separation into independent corporations will significantly improve regulatory effectiveness. The independence and cost issues are canvassed below.

Independence of the subsidiaries

The current subsidiary structure involves significant conflicts of interest.

ETSA’s claim that: ‘... sufficient checks and balances’ on anti-competitive conduct are in place, is based partly on the view that the individual subsidiaries are subject to the *Trade Practices Act 1974*.

> The companies within the ETSA Group will not ‘qualify’ as related bodies corporate or subsidiary companies for the purposes of the Corporations Law, and therefore will not enjoy the ‘exemption’ contained, for example, in s 47(12) of the Trade Practices Act. The Trade Practices Act defines related bodies corporate and subsidiaries in terms used by the Corporations Law. Those definitions are terms of art. Because the directors of

> the ETSA companies are not appointed by the ETSA Corporation, but by a Minister, that definition of subsidiary and related body corporate does not apply to them.
>
> The clear obligations on the directors and officers of the subsidiaries to ensure that they will comply with all requirements of the law and the market regulatory arrangements naturally demand a level of independence in decision making, particularly in market sensitive areas (sub. 5, p. 13).

Notwithstanding this, some participants were concerned about the ability for commercially confidential information to flow from one subsidiary to another. They argued that it is only by full formal separation that the different business units can be kept at arms length. For instance Boral Energy argued for the establishment of:

> ... Generation, Transmission, Distribution and Retailing in four separate corporations, with separate management and not under a holding company structure. Boral Energy expects that transactions between these corporations will be through arm's length commercial contracts. Legislation or regulation is required to prevent transfer of confidential information between the separate functions (sub. 4, p. 11).

However, ETSA has claimed that:

> ... the law insists that Directors of companies within a group are required to act for the company within the group to which they are appointed and must not disclose confidential information coming to them in that capacity to other companies within the group, in particular to the holding company. This would prevent transfer of confidential information from Transmission to the competitive businesses of the Group ie. Generation and Retail (sub. 5, p. 15).

The Commission has not sought legal advice on this aspect, and for the sake of argument has presumed ETSA's interpretation is correct.[9] Although this may mean that collusion between subsidiaries or the transfer of confidential information would be illegal, it does not alter the fact that the current structure creates stronger incentives and opportunities to share information than would exist between independent corporations.

As a holding company, by definition ETSA Corporation has some powers of direction over the subsidiaries and hence could influence their actions. The interaction between the ETSA boards is strengthened by the high degree of cross membership between them. The practical reality is that as long as ETSA Corporation has residual powers, including the ability to approve investment, the subsidiaries cannot be said to be independent. ETSA Corporation owns the

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9 The boards of ETSA Generation and ETSA Power have only one director that can be independently appointed by the Minister. All others are appointed either by virtue of their membership of the board of ETSA Corporation, or because they are either the CEO of ETSA Corporation or the CEO of the subsidiary.

subsidiaries, hence legal separation cannot mean operational and financial independence.

The cross membership between the ETSA Corporation board and the subsidiaries means a high degree of shared knowledge about each other's business plans and operations. For instance, the CEO of ETSA Corporation sits on all boards, and could be in the position of knowing beforehand about potentially competing investment proposals in generation or retail. This represents a possible conflict of interest.

The fact that the boards cannot be fully independent is acknowledged by ETSA, who stated that:

> Whilst the subsidiaries have a degree of autonomy, there are also requirements on Directors to build sustainable value for the owner. This means that where efficiencies or economies are to be made, the organisation as a whole will be bound to realise them (sub. 5, p. 13).

ETSA has indicated that it intends to: '... tighten commercial (arms length) trading arrangements between subsidiaries' (sub. 5, p. 12), but it is inconceivable that these could be as opaque or impervious as independent boards. Even with completely different boards, the residual powers of ETSA Corporation make full independence impossible.

The holding company structure also means that the accountability of some of the directors of the subsidiaries are blurred. For instance there is the potential for the Minister to appoint independent chairs to the boards, but in a practical sense these people are responsible to ETSA Corporation.

Costs of separation

ETSA has estimated the loss of economies of scale and scope that would result from the complete separation of ETSA's generation, transmission and distribution/retail businesses. ETSA Corporation suggested that these would not be less than $18 million per annum, made up as follows (sub. 5, pp. 26-8, 30):

- establishment of 'principal additional administrative functions' $8.1m;
- loss of 'value added commercial activities' in gas trading $6.7m;
- increase in the 'overall cost of debt' $3.2m.

The Commission has not been able to examine these claims in any detail, but is concerned that they are likely to exaggerate the true costs.

With respect to the first item, the Commission accepts the possibility of additional administrative costs. However, little background information has been supplied to verify the figures quoted by ETSA, hence it is unclear how justifiable they are. Some of the costs could be for services that could be contracted out. If so, then some of the scale and scope advantages might be able to be retained. For instance, part of the claimed $8.1 million in 'principal additional administrative functions' is $1.2 million for 12 additional taxation accountants and financial planners (sub. 5, Appendix B). If the magnitude of the task undertaken by the current team of ETSA taxation accountants and financial planners did not increase with the change to independent corporations, some savings could be achieved by contracting out.

ETSA has stated that the combination of ETSA Generation with ETSA Energy would result in lost commercial opportunities amounting to $6.7 million.

> If ETSA was disaggregated, it would not be possible to build such an active, competitive gas business in either the Power or Generation businesses. Naturally ETSA Generation would manage its gas supply contracts, but this would be done as a passive, gas supply management activity described in Appendix D rather than being developed as a commercial business which was profitable in its own right (sub. 5, p. 26).

It is quite unclear how the location of this function affects the potential to achieve these benefits. The Commission understands the need for ETSA to manage its take or pay obligations to minimise the risk of forfeiting gas at considerable cost to itself. Implementation of the national electricity market, and the loss of ETSA's exclusive rights to the transmission interconnection could result in the interconnection being operated more or less at full capacity most of the time. If a consequence of this was a reduction in output from the Torrens Island Power Station, ETSA Generation would have to reduce its gas consumption, and ETSA's gas inventory would increase.

The Commission accepts that this creates a challenge for ETSA, and that there may be opportunities for it to sell gas into the national gas market now emerging. However, the Commission does not accept that the mere transfer of this gas marketing activity to another entity should necessarily mean that contract management changes from being 'an active competitive business' to a 'passive' business under ETSA Generation, or under some other alternative such as with ETSA Power.

Furthermore, ETSA's main gas purchasing contract is on a ten year rolling basis and it has two other contracts for shorter terms.[10] This suggests that their exposure to high take or pay obligations is a medium term issue (that is, less than ten years).

Higher debt costs are claimed by ETSA to derive from the effect on the credit rating of the various organisations created by separation and the ability of each to deal directly with financial markets, absorb risks, bear debt, and enter into contracts. In particular ETSA claims that:

> ... ETSA Transmission would have a credit rating one to two steps worse than that of ETSA Corporation and ETSA Generation around four steps. This would increase the overall cost of debt to the group by $3.2 million (sub. 5, p. 28).

The Commission sees no reason to expect that the weighted average cost of debt to the individual businesses should be any different when separated than when integrated. This is because their riskiness has not changed. What is likely is that there will be some increases in transactions costs (for example, in loan establishment fees) as each new corporation takes on the role of managing their own debt.

In aggregate therefore, the Commission believes ETSA's estimate of the vertical economies of scope and scale forgone of over $18 million is an overestimate, perhaps by more than double. Even if, for the sake of argument it was around $10 million, this would be less than one per cent of ETSA's total operating and financing costs.

ETSA has not claimed an increase in transactions costs with complete vertical separation. Indeed, complete separation should not add greatly to transactions costs. This is because the current subsidiary board structure and the separate legal status of the subsidiaries requires that arrangements between them be formally specified in one form or another. For instance, ETSA Generation needs to contract with ETSA energy under the current structure to obtain its energy gas supplies.

10 The Natural Gas Authority of South Australia (NGASA) currently hold the contracts for the purchase of gas from the various gas producing joint ventures in the Cooper Basin, and pass these on to ETSA in back to back arrangements. This is a carryover from when the Government owned the Moomba-Adelaide pipeline through PASA which acted as a gas merchant. The Government has indicated its intention to ETSA that the existing gas contracts be transferred to ETSA under the same terms and conditions.

5.5 Adjustment issues

ETSA has argued that complete vertical separation of the Australian ESI will only yield an interim structure in the national electricity market as reintegration will subsequently occur. Furthermore, ETSA believes there will be a convergence between the electricity and gas markets, leading to an emergence of a few large players who straddle these two markets. Accordingly it believes that its current structure is the most appropriate for meeting these challenges.

There are two reasons implicit in this argument as to why ETSA should be retained in its current form. First, to some extent this may be what the market would ultimately reassemble from its component parts. Second, it would give ETSA greater market presence and commercial strength.

The current vertical structure of ETSA is a result of legislative protection, not commercial forces. Whatever reintegration is likely to occur may result in a vastly different structure — not least because the *Trade Practices Act 1974* requires that any subsequent mergers not substantially lessen competition. Provided the costs are acceptable, separation is important to kick-starting the competition which is needed to ensure that any re-integration will reflect the best balance of costs and benefits Finally, the commercial viability of the separated components is not the issue. Either as subsidiaries of ETSA Corporation or as separate corporations, they are but one part of the diversified portfolio of assets held by the crown.

ETSA has argued strongly that it should be given the chance to prove itself under its new corporate structure. Given that issues involving the national electricity market and the Code of Conduct to govern it are still being resolved, this view suggests that it would be premature to make judgements about how ETSA might or might not behave under the framework.

The Commission understands this view. Nevertheless the over-riding issue is what is in the best interests of the South Australian community, not what will enhance ETSA's commercial viability. The wider community interest would be served by ETSA entering the national electricity market with a structure that is clearly pro-competitive.

In the Commission's view, quite significant problems could arise at a later date if ETSA enters the national market with its existing structure. It needs to be recognised that the problems may not even relate to ETSA's market behaviour — they can arise because of the perceptions of other participants (and potential participants) that the structure of ETSA is an obstacle to competition. Such perceptions could be enough to deter potential competitors to ETSA from entering the South Australian regional market, and providing the commercial discipline needed to protect the interests of the rest of the South Australian community.

In these circumstances, the Commission considers that it is better to ensure that ETSA has the most appropriate structure from the outset so as to minimise the likelihood of problems emerging later, rather than trying to rectify problems after they have emerged.

5.6 Concluding comment

In conclusion, the Commission is not convinced that the current structure is sufficient to promote competition, or that regulation can be an effective alternative. The Commission believes it is not possible for ETSA's subsidiaries to act independently while at the same time availing themselves of the economies of scale and scope of a vertically integrated structure.

As long as the holding corporation is responsible for the whole business and conflicts of interest exist between the subsidiaries, the current structure contains the incentive and the scope for anti-competitive conduct while aggravating the problems of regulating transmission and distribution.

The costs from full separation into three independent corporations are likely to be less than one per cent of ETSA's combined operating and financial expenditure. The efficiency gains to the South Australian economy from implementing a pro-competitive structure are likely to be much larger than this.

In coming to this conclusion the Commission wishes to stress that it is not suggesting that ETSA has been, or is, conducting itself in an illegal manner under its current corporate structure. Rather that a structure should be chosen that minimises the incentives and scope for anti-competitive behaviour and provides greater transparency.

6 THE COMMISSION'S PREFERRED STRUCTURE

In Chapter 5, the Commission concluded that ETSA's current structure is likely to discourage competition in generation and retail in the South Australian region of the national electricity market. The Commission also concluded that the present structure is likely to impair the effectiveness and efficiency of regulation of transmission and distribution.

In this Chapter, the Commission proposes a structure that it considers will overcome these limitations. Its objective is to maximise the potential for competition in the generation and wholesale purchase of electricity from generators, as well as in retailing to end-users. The Commission's approach is tempered by the need to do so in a way that recognises the costs and benefits.

The benefits of the proposed structure arise from:

- reducing the incentive and the scope for transmission and distribution to be used to protect competition in generation and retail;
- easing the task of regulating transmission and distribution;
- increasing the confidence of potential generators and retailers in South Australia (SA) that the grid cannot be used to prevent or weaken competition; and
- improving the accountability of the various enterprises to the Government.

There are likely to be some costs with the proposed structure in the form of loss of economies of scale and scope; increased transaction costs; and some once only transition costs. These costs are considered small in relation to the benefits from a competitive regional electricity market in SA. If the current ETSA structure has been effective in making the subsidiaries of ETSA independent of each other, many of these costs would have already been built into the current arrangements. To be able to take advantage of many of the economies of scale and scope associated within vertical integration, ETSA would need to function in a completely integrated fashion.

6.1 Commission's proposals

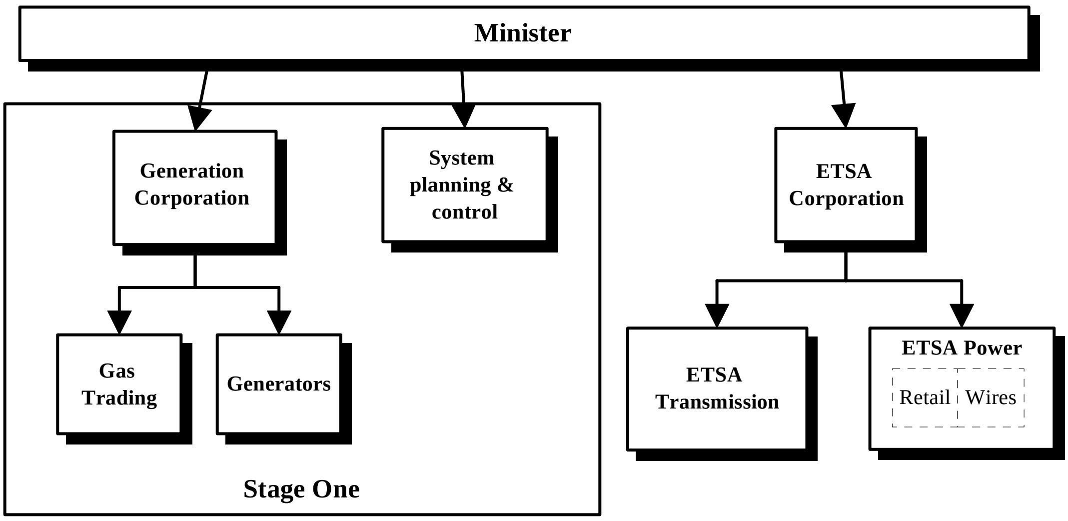
The Commission's proposals are designed to be implemented in two stages. Stage 1 aims to promote competition in generation. The main aim of Stage 2 is to promote competition between wholesale buyers of electricity. Its secondary objective is to promote competition between those who then retail electricity to small to medium sized end-users — particularly households and small business. Although each stage reinforces the other, they are considered to be separate for the purpose of implementation. This means that the design of Stage 2 does not interfere with the implementation of Stage 1.

Stage 1

The first stage consists of the separation of ETSA Generation, ETSA Energy, and system control and planning from ETSA Corporation. ETSA Generation and ETSA Energy form the basis of an independent enterprise. System control and planning form another independent organisation. ETSA Corporation would then consist of the holding corporation, ETSA Power and the rest of ETSA Transmission (see Figure 6.1). ETSA Corporation must be independent of the two new organisations. All three should report directly to the Minister.

Stage 1 should be given the highest priority and undertaken as soon as is practicable. This would facilitate SA joining the national electricity market in September 1996 with a structure which was in accordance with the spirit of the decisions by the Council of Australian Governments (COAG).

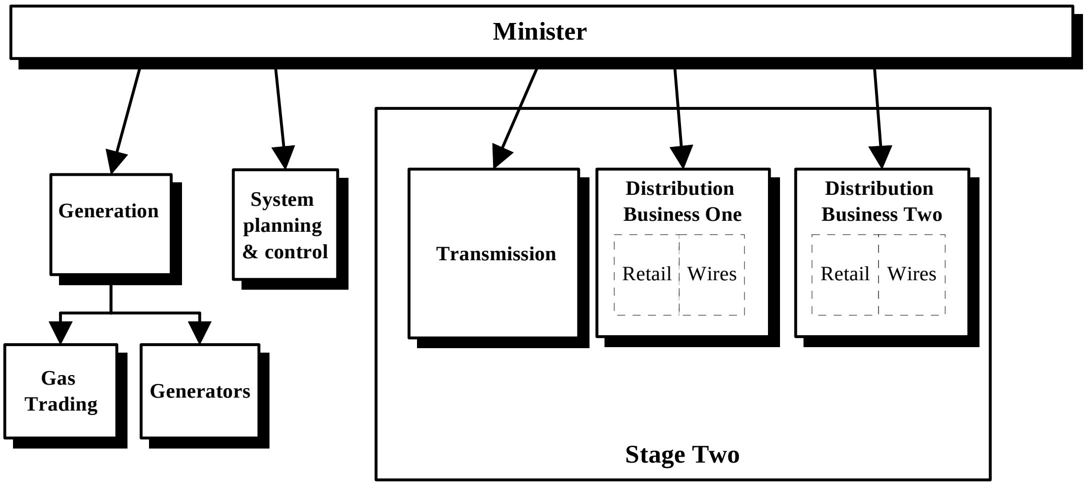
Figure 6.1: Structural reform — Stage One



Stage 2

Stage 2 involves dividing ETSA Power into two or three independent distribution–retail businesses and separation of ETSA Transmission as an independent network manager (see Figure 6.2). These three enterprises must be independent of each other and of those created in Stage 1. Each of the organisations created in Stage 2 should report directly to the Minister. Stage 2 necessarily has a longer lead time to its implementation than Stage 1, as time is needed to determine the most cost-effective way of dividing the existing distribution network.

Figure 6.2: Structural reform — Stage Two



Stage 2 will ensure that there are at least two or three large wholesale buyers in the SA regional market. There are grounds for believing that keeping ETSA's retail business intact, particularly in combination with its distribution business, would discourage entry by other wholesale buyers and other retailers.

Once the legislative restrictions on trading electricity are removed there will still be technical and economic limitations to small users changing suppliers. Under the COAG agreements on the national electricity market, users with an electricity load of less than 10 MW may be franchised to nominated retailers. Jurisdictions have until 1 July 2001 to deregulate retail customers below this level.

This limit means that retail franchises are likely to be a relatively larger share of the market in SA. Moreover, there are likely to be relatively few users in SA big enough to participate in the national market (the wholesale market) in their own right. For these reasons, competition in the SA regional market would be unlikely to be vigorous if all the retail franchises were held by the one retailer.

In principle, there is a superior alternative to the restructuring proposed for Stage 2. This option is to separate the retail business from ETSA Power and to divide it to create two or three independent retailers. ETSA's distribution and transmission networks could then remain under ETSA Corporation which would become an independent network manager. This option would be fully consistent with the principle of separating the natural monopoly (distribution and transmission) from the competitive activities of retail.

The evidence provided to the Commission suggested that there are likely to be some practical difficulties in separating distribution and retail, at least in the early stages of the national electricity market. If the examination proposed for Stage 2 does not identify a cost-effective way of dividing the distribution network, then the Commission recommends the adoption of this alternative.

Benefits and costs of proposed restructuring

Stage 1 will promote competitive conditions for the entry of independent generators into SA. The generation sector is the one where the gains from competition are likely to be the greatest.

Stage 2 will encourage competition in wholesale buying, especially over the short to medium term when the national electricity market is establishing itself. It will also encourage competition in the retail sector, particularly for residential and small business customers.

After the proposed restructuring there is a risk that ETSA Generation may possess some market power over the short to medium term. The issues of what market power ETSA generation currently has and is likely to have in the future and its implications for structure are taken up in Chapter 7. For the purposes of this chapter, the generation business is treated as if it is retained as a portfolio generator.

The preferred structure eases the task of regulating the transmission and distribution networks. The potential for cost shifting between them is significantly reduced. Furthermore, clear and transparent accounting information would be available.

The proposals improve the accountability of government business enterprises (GBE) in the electricity industry. They facilitate the setting of unambiguous goals for each business. The independence of the various businesses, and the system control and planing organisation would be enhanced by their having separate and independent boards with no holding corporations linking any of them. This structure would create less incentive and opportunity for information to be shared between the different organisations.

The recommended structure will involve some start up costs and it may result in some loss of economies of scale and scope. Any costs should be modest but they need to be minimised as far as practicable. The Commission expects that the efficiency benefits from competition in generation and retail will be significantly greater — thereby providing an opportunity for electricity tariffs to households and businesses to be lower than they would have been under the current structure.

In any event, the compensation payments provided by the Commonwealth under the Agreement to Implement the National Competition Policy and Related Reforms, are in part to cover some of the costs to the SA Government of introducing competition into its regional electricity industry.

The remainder of this chapter is devoted to examining some of the specific issues associated with this structure.

6.2 Generation and energy supply

The Commission's proposal would see ETSA Generation and ETSA Energy form an independent GBE. It envisages the new enterprise being assigned all ETSA's generating assets, the Leigh Creek coal mine and its existing take-or-pay gas contracts. From a competition policy perspective, there is no reason why it should be prevented from trading in gas, entering the retail electricity and gas sectors or investing in generation in other states. It should, however, be prevented from owning existing distribution or transmission assets.

The greatest benefits of competition in the electricity supply industry will be felt primarily through competition between generators because they represent the greatest share of costs in supplying customers. Establishing generation as a stand-alone corporation is of the highest priority.

Like many other participants, the BCA saw this as the most important structural change:

> We believe that the separation of ETSA Generation from the remainder of the organisation is the first priority (sub. 18, p. 18).

Separation will increase the exposure of ETSA Generation to competitive forces, the more so once the national market pricing mechanisms for new transmission interconnections are finalised. This is important because in the SA regional market, supply and demand are fairly well balanced and transmission links to other states provide competitive pressure through imports. Competition also arises because interstate generators and potential generators in SA can have more confidence that ETSA is unable to use network access to limit competition.

The new enterprise should have direct responsibility for its gas purchases. This will give it the ability to negotiate gas purchases commensurate with planned generation commitments. In order to be able to dispose of any surplus gas under the existing take-or-pay arrangements the new enterprise may need to trade in gas.

Originally ETSA's gas contracts were negotiated through the then Pipeline Authority of South Australia (PASA). ETSA had, until recently, little direct experience in gas trading and has consciously been developing this expertise in ETSA Energy. There is no reason why these skills could not reside in the new enterprise and be just as effective. It may, in fact, assist in diversifying the business and even lead to opportunities to contract to supply generators in other regions.

The Commission sees no significant competitive issues in the new enterprise owning and operating the Leigh Creek coal fields. The only possible problem relates to competitive neutrality and coal royalties. Santos did consider these were issues:

> In the case of electricity produced from Leigh Creek coal in the Northern power station, Santos is concerned that as a result of subsidisation of coal production by other activities of ETSA and royalty exemptions, etc. and the use of short-run marginal costs for economic decision making, the levels of coal production and electricity generation have been higher than those which could be justified if the the mine and power station were stand–alone entities, subject to the same royalty and tax regimes and required to provide the same returns on debt and equity components of the capital bases as equivalent private sector entities (sub. 13, p. 4).

The fact that royalties are not paid is consistent with the very low opportunity cost of the coal (it has virtually no alternative use).

As discussed in detail in Chapter 7, the new generation business would have market power for some time but dividing it up would not reduce its market power to any practical degree. Therefore, the Commission prefers alternative measures to discipline market power in generation over the short to medium term.

The Commission recognises that there is a concern that SA could somehow lose from entering the national electricity market, and that separating out generation will exacerbate this risk. This concern is based on the fact that Victoria and New South Wales (NSW) have lower generation costs than those in SA. However, this risk is borne by the shareholder (the SA Government) and is independent of ETSA's structure — unless ETSA's distribution and transmission are able to be used to exert market power, prevent competition and maintain the overall value of the business.

The Commission has undertaken some modelling of the SA regional market, which it intends to document and publish later. The results indicate that it is uncertain at this stage whether present or future generation assets located in SA will be at risk in the national electricity market. In the short run, there is protection in the form of the limited capacity to import electricity and the absence of independent generators connected to the grid in SA.

In the longer run, there is protection in the form of transmission costs (the cost of lines plus energy losses), which help to reduce the cost advantage of base load electricity in NSW and Victoria. Further, in time excess capacity in NSW and Victoria is expected to decline, and any new capacity in those States to supply SA will be based on their *expected total costs* not current marginal costs. Another important factor is the price of gas in SA. If gas prices do not significantly rise, then SA is likely to retain a competitive advantage in intermediate and peak period generation. There are uncertainties surrounding the changes created by the emerging competitive national markets in both electricity and gas.

Broadening the perspective from ETSA to the SA economy, competition in generation will be beneficial because it produces lower electricity costs than would otherwise prevail. Therefore, to the extent that existing SA generators are uncompetitive, there will be some trade offs in terms of lower employment and investment in electricity production, but higher employment and investment in other sectors of the SA economy, as well as higher consumer welfare.

The importance of standing back and taking in the broader benefits was emphasised by the NSW Government who commented that:

> ... the effects on producers have a higher profile than the effects on consumers due to the diffuse nature of the consumer benefits. In articulating their shared interests, producers also have the advantage over consumers. Producers form a more compact and thus more readily mobilised interest group. Moreover, the greater the degree of vertical integration within the industry the more polarised towards producer interests the efforts to influence the reform path will be. Vertical integration narrows the scope for the formation and expression of alternative points of view on the balance of interests involved in reform (sub. 21, p. 6).

In relation to any loss of value in ETSA's generation assets, one of the reasons underlying the Commonwealth provision of funds to introduce competition reform was to compensate for any loss in the value of assets that may result. The Commission believes that this is the appropriate way to deal with this issue, rather than limit the gains from competition. To the extent that the national energy markets impose such transition costs on SA, they are best addressed by appropriate compensation payments. Resolution of the competitive inhibitions in the Interstate Operating Agreement is another issue that should be approached in this way.

6.3 System control and planning

The Commission recommends the creation of a separate system control and planning organisation to ensure that its influence over generation and transmission investment should be restricted to advice over system needs and bottlenecks, not about the type and location of generation investment.

Under the arrangements for the national electricity market proposed by the NGMC, there is some flexibility in how system control and planning may be managed, but they must be separated from generation. The market manager (NEMMCO) will appoint Regional Systems Operators in each region to act as its agents (see Chapter 4). Their primary responsibility will be to maintain system security and dispatch generators in accordance with the merit order determined by NEMMCO.

The NGMC proposals intend system planning to be coordinated under NEMMCO, but this may be largely restricted to investments that affect interconnection capabilities (these could be investments within a jurisdiction). Under the NGMC's proposed Code of Conduct, endorsement by NEMMCO would be required before the new assets could be rolled into the asset base for determination of transmission prices.[1] However, it is likely that the jurisdictions will still have significant responsibility for system planning.

Different structural approaches to accommodating these responsibilities at the state level have emerged. In Victoria they reside with an independent organisation — the Victorian Power Exchange (VPX) — whereas in New South Wales they have been placed with the transmission manager, Transgrid. Under the Victorian arrangements, VPX leases the transmission network from the

1 A higher risk and hence less likely approach is that investors would rely on capturing differences in pool prices by building new interconnectors. But this may necessitate offsetting investments elsewhere in the network, and hence may still require NEMMCO endorsement of some kind.

transmission manager (PowerNet). VPX currently undertakes the planning process, and should a system augmentation be required, calls for tenders for its construction.[2]

The advantage of the Victorian approach over the NSW one is that potential conflicts of interest between the system operator and the transmission owner are reduced. The system operator's main tasks are to ensure system security and the efficient dispatch and delivery of electricity. The transmission owner is more concerned with increasing revenue and, if subject to rate of return regulation, has a vested interest in expanding the asset base. Since the system operator will have the best information on system loads and where bottlenecks are developing, placing system control and planning in a separate organisation gives the regulator a more independent source of information and advice. This would also improve access by market participants to this important body of information.

The Commission believes that an approach similar to VPX should be adopted for the SA industry, but that this should be consistent with the plans for operation of the national electricity market. ETSA has indicated a willingness to divest themselves of system control and planning and outlined a strategy for separation:

> The network service provider would be responsible for the transmission system planning. Therefore, it will decide what assets should be acquired and allowed to earn a commercial return. This role would also include dealing with any possible independent generators and planning for any potential expansions, including being part of bipartisan or national planning of further interconnection capacity (sub. 5, p. 14).

However, ETSA considers that the best structural solution:

> ... can not be determined until the NEM design is finalised (sub. 5, p. 1).

Given that some participants have a perception that ETSA Transmission is not impartial, this is an important step. For instance, with posted access tariffs, an independent generator would be able to avoid any contact with ETSA until well into the planning stage. ETSA Transmission's interest would be reduced to the transmission system's ability to cope with the power that the independent generator would put on the system, and on any concomitant costs that they would be obliged to meet. Most of the commercially sensitive negotiation by the independent generator would be with the new VPX type organisation.

2 Note that this has not happened to date.

6.4 Multiple distribution–retail businesses

The Commission is concerned that a single distribution–retail business, such as ETSA Power, would have such significant advantages over new retailers that they could restrict entry. This problem would be compounded by the small size of the non-franchise market in SA, and the fact that retailers in SA would have to source the bulk of their electricity from ETSA Generation for some years.

In the longer term, new retailers can be expected to enter the SA regional market. Several participants indicated they were looking to expand their energy businesses to cover the national electricity market and would be exploring opportunities in the SA market. Over time, the number of non-franchise customers will increase as SA complies with the COAG requirement to deregulate retail franchises progressively. It is likely therefore that additional competition will eventually develop in the retail sector, and to the extent that it does, it would complement the Commission's proposal.

In principle, the Commission prefers to divide ETSA Power into a separate distributor and two or three separate retailers. This would be consistent with the competition framework outlined in Chapter 3, where the competitive elements of retail would be separated from the natural monopoly elements of distribution.

Through the course of the Commission's review, various views were put to the Commission opposing the separation of distribution and retail, including:

- the ability of the retail staff to offer 'effective' innovative solutions to demand side management would be impaired (sub. 5, p. 22);
- both businesses essentially deal with the same customers;
- the asset backing of the network business, and its regulated cash flow provides diversification against the riskier, low asset retail business;
- the combined organisation would be better able to develop pricing packages to address capacity constraints and smooth load;
- the small margins in retail, the low volume of sales to individual households and small business, and the cost of enticing customers to switch retailers; and
- the uncertainty about future pool prices in the national market.

In NSW and Victoria, combined distribution–retail business have been created. On balance, the Commission believes that it would be in SA's best interest to follow their example than divide ETSA Power another way. It should also make easier the task of achieving the SA Government's objective of having uniform urban and rural tariffs for each class of franchised customers — the means of doing so may, however, have to be changed to an explicit community service obligation financed from the State budget.

The Commission therefore proposes the division of ETSA Power into two or three distribution–retail businesses but has no *a priori* preference for how it should be done. For benchmarking purposes there would be some advantages if each had urban and rural customers in more or less equal proportions. Strict ring-fencing of the retail and distribution components would be required because the distribution system will operate under an open access regime, administered by a competition regulator.

The main purpose of dividing distribution is to facilitate wholesale buyer competition. The creation of multiple retailers would be an important investment in creating large buyer competition each with enough counterweight to deal with ETSA Generation. By virtue of their captive retail franchises, each would start with a significant and stable customer base.

A secondary purpose is to create competition between retailers. By creating incentives to enter into each other's territory and compete for non-franchise customers, it should encourage the development of an effective access regime. However, a potential problem with integrating distribution and retail is that it creates some incentives to operate in an anti-competitive manner. For instance, there would be the scope and incentive to use the network side of the business to protect its retail business.

Retention of retail with network activities will therefore require a significant regulatory effort on the part of the proposed regulator. It will be important that regulation of distribution access be rigorous and that ring-fencing of retail and distribution have a high degree of transparency.

There is a possibility that significant costs would be involved in dividing the distribution network. Accordingly, the Commission recommends that the SA Government needs to investigate the most cost effective way of dividing the network before implementation of Stage 2 could commence. If division proved not to be cost-effective, then the Commission prefers retail to be separated from distribution and divided into two or three independent businesses. In that event, distribution and transmission could be managed within the one network management business.

6.5 Transmission

In Stage 1, system control and planning functions are to be transferred from ETSA Transmission to an independent body.

If Stage 2 proceeds as expected, the rest of ETSA Transmission would be established as an independent corporation to own and manage the transmission assets.

Looked at in isolation, there are reasons for having transmission and distribution managed by the one enterprise as many aspects of the two ‘wires’ businesses are similar. Both are network businesses which involve progressive steps down in voltage. In terms of employment, ETSA Transmission is small relative both to the other ETSA corporations, and to transmission managers in other States. Thus it could conceivably benefit from some economies of scale and scope from being combined with distribution. An alternative might be to contract out the management of its operations, for example, to PowerNet in Victoria.

The BCA reflected on this question. Although its first best option for the restructure of ETSA is to have independent corporations for generation, transmission and distribution–retail, the BCA:

> ... acknowledge that the transmission system in South Australia is far less extensive than that in the eastern states, and the full separation into a separate corporation may introduce unacceptable additional establishment and overhead costs. The Business Council does not have access to sufficient information to make this judgement (sub. 18, p. 19).

Separation of transmission from distribution becomes essential to create multiple distribution–retailers in SA. There may also be regulatory problems in keeping them together if, as expected, regulation of transmission and distribution were to be undertaken by different regulators (State and Commonwealth). This could create an incentive for the integrated wires business to shift costs and manipulate asset values accordingly. The NGMC’s draft Code of Conduct is an important mechanism for adopting consistent guidelines and the allocation of assets between the two, reducing these incentives. Nevertheless, formal separation reduces the scope to react to such incentives.

In summary, the Commission believes that the separation of transmission from distribution is necessary to create multiple distribution–retail businesses. However, if only retailers are to be formed and they are independent of distribution, then combining transmission and distribution would be appropriate if a consistent approach to regulation is adopted.

6.6 State regulatory body

Technical regulation in the electricity industry in SA has been transferred to the South Australian Department of Mines and Energy. The licensing of trades persons has been transferred to the South Australian Office of Consumer and

Business Affairs. These moves are consistent with the Competition Principles Agreement (CP Agreement).

Under the CP Agreement, the task of regulating the distribution of electricity in SA can be given to a State competition regulator, rather than the ACCC.

The Commission believes that any State regulator needs to be independent of the State Government, to address the potentially conflicting roles of ownership and regulation. For instance the Victorian Government maintained that:

> As part of the consideration of industry structure, decisions need to be taken in respect of an independent regulatory agency in relation to retail supply, franchise customer pricing and distribution pricing so as to facilitate new entrants to enter the retail market supply market. This regulatory agency should be fully at arms length from Government (sub. 7, p. 1).

The Victorian Government also stated that:

> The need for this regulator arises from: the sovereign risk created when Government is both owner of major market participants and also the regulator; and from the likely dominance of the retail, distribution and generation sectors by the Government participants (sub. 7, p. 19).

During the transition to the national electricity market, the regulator may also have a role in oversighting prices. This may also be required for a period of time to control market power by the proposed generating and energy supply corporation. This is discussed in the next chapter.

7 PROMOTING COMPETITION IN GENERATION

The vertical separation of ETSA Corporation, as proposed in Chapter 6, would facilitate greater competition in the generation sector in South Australia (SA) by reducing the potential for ETSA to use its transmission system to protect generation. However, vertical separation does not reduce the concentration of generation capacity in SA. ETSA Generation operates two major power stations, Northern (NPS) and Torrens Island (TIPS), and several smaller stations. These two stations accounted for over 99 per cent of South Australian based generation in 1994–95 (see Table 2.2).

Electricity imported from generators located in Victoria made up 24 per cent of energy sent out in SA in 1994–95.[1] The current interconnector could physically supply a larger percentage of the demand for electricity in SA than it currently does, although this will not necessarily be the case once the national electricity market commences. Imports and exports under the national electricity market should reflect the relative costs of generation in different regions plus the costs of transporting electricity to remote loads, up to the capacity of the various interconnectors.

Irrespective of the eventual level of imports and exports, the interconnector between SA and the eastern states is small relative to peak demand in SA and an aggregated ETSA Generation would have a dominant position in its regional market. This could represent a major obstacle to the development of competition in the South Australian electricity market. In the absence of effective competition, it is possible that ETSA Generation would be in a position to exploit market power to the detriment of the South Australian community as a whole.

The problem of market power in the generation sector has been addressed in Victoria and New South Wales (NSW) through the horizontal separation of generation into multiple firms. In SA, the only practical alternative for introducing structural change is to create a duopoly, based on the two major power stations.

1 Imports are currently subject to a contract between ETSA and SECV, negotiated under the IOA (see Chapter 4). The contract price is lower than the average price for base load in the Victorian spot market in 1994–95. The current level of imports into SA is not necessarily indicative of the level of imports likely under the national electricity market. This is discussed in more detail below.

The key issues for this chapter are:

- whether ETSA Generation is likely to possess market power in the short term when there is no new generation capacity and the capacity of the interconnector with the eastern states is unchanged;
- whether new entrants to generation in SA or an expansion of the interconnector would reduce any market power, and the period of time this is likely to take; and
- whether a duopoly structure based on NPS and TIPS is an effective structural solution, or, if an alternative contractual or regulatory solution exists to overcome problems caused by the presence of market power.

The following section briefly outlines the notion of market power and its implications. Section 7.2 discusses how market power could be used in the SA region of the national electricity market, and the constraints on this. Section 7.3 discusses market power in the SA generation sector utilising the results of two studies. Section 7.4 evaluates the options to deal with this market power, and Section 7.5 outlines the Commission's recommendations.

7.1 Nature of market power

A firm is said to have market power if it has the capacity to significantly influence price. In these circumstances, the firm can restrict output and raise prices for consumers. The extra revenue can be captured by the firm in terms of higher than normal profits or higher production costs (wages, employment levels, fuel prices and over capitalisation) than would exist in a competitive market.

It is not unusual for a firm to have a degree of market power from time to time. Indeed, even firms operating in markets that are regarded as highly competitive may at times have market power. For example, stock shortages or the introduction of a new product may provide a firm with a commercial advantage and permit the firm — or even a group of firms — to raise prices and earn high profits for a period of time. However, higher prices will normally attract rivals or new entrants. Alternatively, sales may be lost to substitute products. These developments usually place downward pressure on prices. As a result, market power is frequently only a short term phenomenon and is not a cause for undue concern.

There is cause for concern, however, if market power can be sustained for a period of time. This can occur if:

- there are no existing rivals, including suppliers of substitute products, that can mount an effective competitive response;
- there are rivals having the capacity to respond, but all firms act, explicitly or tacitly, in a collusive manner to restrict competition and raise prices;
- barriers to entry — factors that give incumbent firms an advantage over new or potential entrants — impede (or even prohibit) the entry of competitors to the market;[2] and
- there is little or no prospect of competition from imports.

If a firm has significant and sustainable market power and commercial objectives, it is likely to exploit its market power to increase prices and profitability. This is not to deny the possibility that certain factors — such as a threat of regulation or political pressure — can moderate a firm's use of market power. However, to the extent that market power is exercised, considerable costs are imposed on the community. These costs reflect the types of inefficiencies discussed in Chapter 5. The longer the market power is likely to persist, the higher will be the social costs and the more likely it is that government action to reduce the costs is warranted.

7.2 Market power in generation

Market power in the generation sector is a potential problem during the transition to a competitive market.[3] In part it reflects the change in the objectives given by the shareholder (government) to Directors appointed to manage generation assets. In the past, managers of public generation assets were mainly charged with minimising the cost of supplying a particular grade of service, whereas they are now being instructed to maximise shareholder value. The national electricity market is designed to promote competition between generators and between retailers and generators. Providing competition develops, it will keep profits to competitive levels and encourage generators to be as efficient as possible. Without effective competition, actions taken to maximise shareholder value will not result in efficient market outcomes.

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2 Factors which can act as barriers to entry include regulation, sunk costs, economies of scale and access to scarce resources or cost advantages enjoyed by incumbent firms.

3 Clearly, the design (size, location and technology) of the existing assets was chosen to fit the previous objectives of the generators. It is likely to take some years before the generation sector fully reflects market outcomes.

If the opening of regional markets to competition is accompanied by the entry of new suppliers, market power in the generation sector could be a relatively short term problem. On the other hand, some characteristics of electricity generation (for example, large sunk costs) suggest that the problem could be of a longer term nature. For instance, in its recent study of Pacific Power, the Industry Commission (1995c) concluded that Pacific Power, operating as a single generation business, would have substantial market power until well into the next century. However, the length of time that market power persists in any region is influenced by: the expected rate of growth of demand; whether existing power stations are due to be retired or are obsolete due to changes in technology; the level of excess capacity in the regional system; and, whether there are ready substitutes for electricity.

In Chapter 2 of this report, the role of gas as a substitute for electricity is discussed. In particular, it is noted that in 44 per cent of its market, electricity faces no competition from gas. The markets in which gas represents the strongest competition for electricity are in some industrial applications, space heating and water heating. These sectors have quite long appliance cycles and it is expected that, in the short run, consumers have little incentive to substitute between the two energy sources. If electricity prices are increased relative to gas prices for sustained periods of time, consumers would be expected to substitute gas appliances for electrical appliances. However, this is likely to manifest itself over a period of years.

These issues are relevant to the assessment of the SA case. However, the issues are not independent of the operations of the national electricity market and, in particular, the spot market. Hence, before discussing the SA market, the way in which generators can assert market power in the process of bidding for dispatch in the national electricity market spot pool is reviewed.

Market bidding processes

Broadly speaking, the marginal generator principle, outlined in Chapter 4, sets the half hour spot price for electricity at the bid of the highest cost generator dispatched in the period.[4] This price is termed the system marginal price (SMP) for the period.

Box 7.1 illustrates a stylised example of bidding behaviour in a spot market for electricity. The SMP is usually determined by the highest cost generator dispatched in the period. All generators dispatched in the period receive the

4 This is a simplification of the process outlined in Chapter 4.

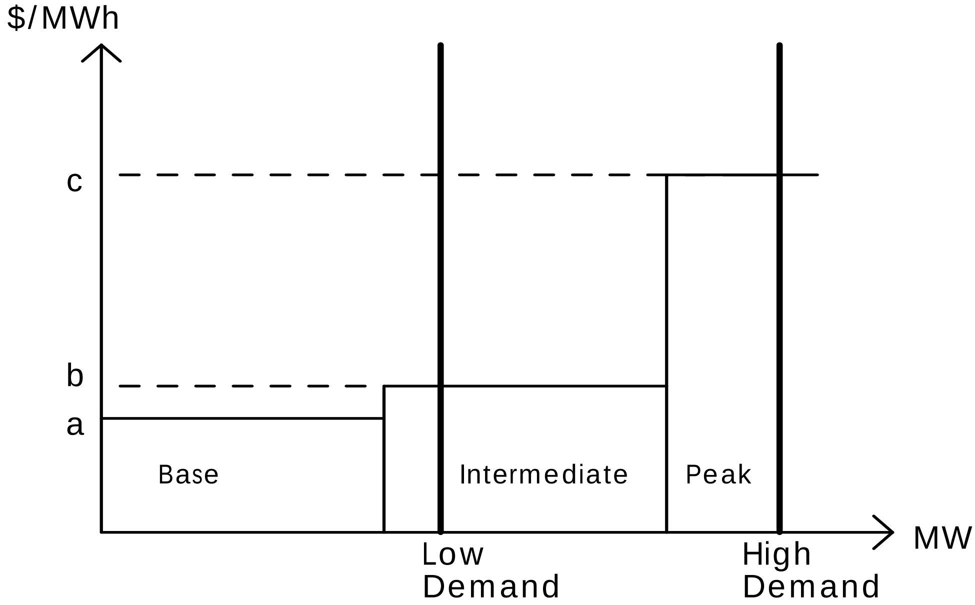
SMP, which is not necessarily the price they bid. In the example in Box 7.1, base load generators need never set the SMP because base load demand is greater than base load capacity. However, base load generators could bid up to the incremental costs of intermediate plant in case demand was unexpectedly low. In the example, intermediate generators are likely to set the SMP in low demand periods and peaking generators will determine the SMP in high demand periods.

Intermediate generators could bid up to the incremental costs of the peaking generators without causing peak plant to be dispatched. The base load and intermediate load generators will receive payments above the marginal cost of generation for production in these periods enabling them to recover their fixed costs.

An efficient spot pool will exist if there is competition to be dispatched in each demand segment. If there were several intermediate generators bidding into the pool illustrated by Box 7.1, there would be competition to ensure that they were dispatched during low demand periods. This should drive the price in that half hour down toward marginal costs. However, the level of competition does not necessarily increase with the number of competing generators in the industry. Increasing the number of generators only increases competition to the extent that it increases competition at the margin — that is, if it increases competition between generators to be dispatched in any given market period.

Box 7.1 is a very simple and restricted view of the sorts of strategic behaviour that can occur in the pool. The technologies used in generation can lead to large discrete jumps in the marginal cost of generation when an additional generator is dispatched. This can give lower cost generators a large margin in which to raise prices. At other times, the difference in the marginal costs between generators may be quite small. In addition, different generation technologies have different operating characteristics. Base load generators are not usually flexible in the sense that they have long start-up times and they operate most efficiently when producing near capacity. The operator of, for example, a large coal-fired generator would prefer to operate the plant for 24 hours a day. Hence, the technical characteristics of generation plant will influence bidding behaviour. The shape of the load curve is also significant. If the load curve is in a steep region, that is, demand is increasing rapidly, generators could simply bid up prices in the knowledge that any reduction in the time they are dispatched will be small relative to the increase they obtain in the pool price.

Box 7.1: Strategic bidding in the spot pool



Demand in the spot pool for wholesale electricity changes continuously. Let there be two levels of demand only: low demand and high demand. The amount of electricity available to supply the market is represented in the schedule of merit order in the above diagram. This schedule of supply is made up of the marginal costs of several generators designed to supply base, intermediate and peak loads respectively. In the spot market, generators can bid a price above their marginal cost and may do so if it is profitable.

Low demand period

The base load generators will be assured of being dispatched provided that they bid below the cost of the intermediate generators, because demand is always higher than the total base load capacity. The base load generators could bid above their marginal costs (point a) up to the marginal costs of intermediate generators (point b). If there were only one intermediate generator, it could bid into the pool up to the marginal cost of the peaking generators (point c) without losing market share. If the intermediate block represents three or four generators, they would need to compete in order to ensure that they are dispatched during the low demand period, thereby lowering prices.

High demand period

During high demand periods, the pool price is set by the peaking generators as there is no alternative supply. If there were only one peaking generator, it could set the pool price to the highest allowable price. The base load and intermediate generators receive the price bid by the highest bidding generator in the period.

These represent very simple strategies on the part of generators. However, they illustrate the importance of introducing competition into the process of setting the system marginal price at all times. Newbery notes that ‘...the crucial point...is that pool prices are set by mid-merit and peaking plant, and the number of base load generators is irrelevant...’ (1995, p. 60).

South Australian regional market

Transmission losses and transmission capacity constraints create a set of spatial markets linked by the Australian transmission network. Generators' bids for dispatch do not include inter-regional transmission losses, and the bid for a generator dispatched in one region to meet a load in another region must be adjusted to account for them. It is this adjusted bid that determines the merit order. The combination of transmission losses and strict capacity constraints on transmission led Hinchy and Low (1993) to argue that the competitive structure of the industry within each state would influence the performance of the overall national electricity market. However, a set of spatially linked markets is not inconsistent with economic efficiency — the costs of transporting electricity from one region to another should be reflected in regional prices. Nonetheless, it suggests that it is appropriate to consider the analysis of market power in both the regional and national contexts.

The most distinctive features of the SA market are:

- an import capability of up to 35 per cent of current system maximum demand under normal conditions[5];
- a low projected rate of demand growth of 2 per cent per annum;
- supply and demand balance in SA is tight compared to NSW and Victoria, and an expansion of capacity is expected to be required in SA over the next few years[6];
- a small number of power stations with a high proportion of base and intermediate capacity; and
- the dominance of two main generation plants, NPS and TIPS. The former is relatively inflexible and the gas fired thermal plant at TIPS B was commissioned in 1977 and TIPS A in 1967.

Victoria has sufficient excess base load capacity to potentially supply up to the current capacity of the SA–Victoria interconnector during off-peak periods. A 50 per cent increase in the capacity of the interconnector would see base load generation in SA competing with interstate base load generators across the full base load demand in SA. Increasing the size of the interconnector to SA

5 The capacity of the interconnect is nominally 500 MW. However, this is dependent on system stability and the flows between NSW and Victoria. At full Victorian export capacity to NSW, the SA interconnect has a maximum capacity of 300 MW. The firm rating of the interconnect is 250 MW (NGMC 1993b).

6 It is estimated that SA has sufficient existing capacity to provide supply reliability until 1998. An additional 50 MW per annum is required after 1998 on current growth projections. The new CUBE plant is expected to provide sufficient capacity through to the year 2000.

together with independent entry of generators into SA would reduce the residual demand available to ETSA Generation. The plausible behaviour of ETSA Generation is therefore dependent on the interconnector, through the behaviour of interstate generators, and the likelihood of entry of new generation capacity into the SA region.

The Snowy Mountains Hydro-Electric Authority said that:

> ... the expected prolonged over-capacity of generation in New South Wales and Victoria will encourage the development of greater interconnection capacity to South Australia... (sub. 1, p. 2).

In addition, they suggested that '....ETSA Generation will face a price cap set by the cost of new generation' (sub. 1, p. 2). Assuming relative fuel prices remain the same, technological advances in gas turbines are expected to result in the costs of new generation falling below the costs of existing generation. These developments would encourage entry, possibly replacing some existing capacity in SA, or ETSA could undertake conversions of some of its gas generators to update its technology.

The uncertainty attached to these factors explains the divergence of views expressed to the Commission regarding potential market power in SA. A more detailed examination of the state of the interconnector between SA and Victoria and the likelihood of new entry is required.

Trade with the other States

The interconnector has a maximum capacity of 500 MW and base load demand in SA rarely falls below 800 MW. Therefore, at the current size of the interconnector, irrespective of the pricing of local generation or imports, some ETSA Generation capacity will always need to be dispatched during off-peak and it will set the SA regional price. Given merit order dispatch based on current operating and transmission costs, the interconnector would probably not be at capacity during off-peak periods. However, if ETSA generation raises its prices sufficiently, the interconnector will be at full capacity and the SA marginal generator will face a residual demand of over 300 MW.[7] ETSA Generation could then set the SA price in off-peak periods to maximise profits across this residual demand. If ETSA bid low to maximise its dispatched capacity, the level of imports will then be determined by the relative prices bid by generators in the eastern states.

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[7] A merit order based on current Victorian pool prices rather than the operating costs of Victorian generators may result in different flows across the interconnector.

As demand increases over a day, the flow over the interconnect will vary as new generators are dispatched in merit order. For example, an ETSA generator could be dispatched in SA, lowering the flow across the interconnector. The price in Victoria and SA would then be determined by the marginal generator that may have been dispatched in either SA or Victoria.[8] This is determined in turn by the bidding behaviour of the participants.

The merit order for inter-regional dispatch incorporates marginal transmission losses, pre-determined by NEMMCO and applied dynamically to transfers of electricity between regional nodes. The NGMC has published estimates of the marginal transmission losses across the SA–Victoria interconnector, although the actual losses at any time are determined by the state of the national grid. Under normal conditions, the NGMC estimates that losses over the SA–Victoria interconnector rise to 18 per cent at full capacity (NGMC 1995a).

Accounting for transmission losses places a wedge between the price of electricity at the SA regional node and other regions. This component of the regional price differential reflects the marginal costs of generating electricity in one region and delivering it to another. This creates a price advantage for ETSA Generation within the SA region over generators exporting via the interconnector. Should this price differential become large enough, it will result in high levels of imports and frequent transmission capacity constraints. This should provide the signal for new investments in generation and or transmission. To the extent that a regional monopolist raised prices above competitive levels, this signal would be distorted.

Participants in the national electricity market contracting for electricity across regions will need to hedge against these regional price differences to defray the risk of large inter-regional price differentials developing. CitiPower expressed a concern that:

> The knowledge that ETSA can ... determine the flows across the interconnector will dramatically increase ... the risk premium associated with these instruments and thereby discourage contracting across interstate boundaries (sub. 6, p. 5).

This represents a barrier to competition from existing rivals.

A monopolist generator in SA could raise the price of electricity in SA at all times by bidding high into the pool. This will cause imports to increase, reducing the residual demand available to a SA monopolist up to the capacity of the interconnector. If the monopolist only raised prices at some times, the flows

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8 An exception to this rule is when the marginal generator is running at minimum stable generation (MSG). The NGMC rules do not permit a generator running at MSG to set the system marginal price (SMP).

across the interconnector would depend on the relative prices bid by the marginal generators in SA and the eastern States during these periods. If eastern State prices were high enough, the SA generator could export, although this is generally not expected to be the case.

There is clearly a trade-off between high prices and residual demand, but bidding behaviour determines the merit order of dispatch of generation plant and this will also influence a generator's bidding strategy. For example, attempts to raise prices in off peak periods may result in some base load units not being dispatched for some half hours during a market period. Coal-fired thermal plant is slow and expensive to start-up and a generation firm will have to trade-off increasing prices against reducing demand and increasing its costs of generation.

The commercial behaviour of generators in the SA regional market will be influenced by a number of additional factors that involve a significant degree of uncertainty. They include:

- the pool price in the eastern States;
- the relative prices of fuel;
- the extent to which consumers substitute to alternative energy sources;
- the likelihood of accelerating entry into the industry by raising prices; and
- the reaction of regulators to rising prices.

In what follows, the results of two studies of market power in the SA region are discussed. These models are used to underpin a general discussion of market power in the SA market. When modelling the likely behaviour of generators it is not possible to accommodate all of these elements directly. However, the sensitivity of the results to changes in fuel prices and the national pool price are considered.

7.3 Economic analysis of market power

The results of a confidential independent study of market power in the SA region, commissioned by ETSA Corporation, were supplied to the Commission (sub. 5). The Commission undertook complementary modelling work as part of this review. Both studies investigate the short run outcome when ETSA Generation remains aggregated and when it is separated into multiple firms, as well as the long run implications for the SA market. The Commission's model identifies the cost minimising dispatch program given the bids of the participants. In the long run, this can result in new generation plant being introduced in response to demand growth and the costs of new generation plant relative to the costs of existing generation plant based on their bidding behaviour.

Short run results

ETSA's analysis found that an aggregated ETSA Corporation would possess a significant degree of market power in the short run. The Commission's modelling confirms this view.[9] ETSA can set prices in the SA regional market for significant periods of time across all expected demand conditions, based on demand forecasts for 1997.

The Commission estimates the price of wholesale electricity in SA, under competitive behaviour in the SA region with import prices based on current prices in the Victorian pool and current fuel costs, ranging from 1.9 cents per kWh in off-peak up to 9.3 cents per kWh in the highest demand periods. An assumption that ETSA Generation acts as a short run profit maximising monopolist, all other things being equal, produces extremely high prices in the SA regional pool. This is a function of the nature of the short run demand for electricity.

Figures 7.1a and 7.1b illustrate plant dispatch in the Commission's model for SA generation and imports in 1996 when ETSA Generation bids at competitive and non-competitive levels respectively. The low level of imports when prices are competitive, compared to current imports into SA, reflects the higher costs of electricity sourced from the Victorian pool relative to the current price paid

9 The Commission's results were calculated using an annual load duration curve. Hence the impacts of peaks and troughs in demand are included. It may be that the highest peaks in demand are more difficult to predict and, therefore, the expected returns from behaviour designed to take advantage of shortages are lower than might otherwise be the case. The use of average demand in calculating the effects of strategic behaviour may then be preferred. However, in order to develop estimates of prices across a wide range of demand levels, a load duration curve was employed.

by ETSA for imports. When ETSA Generation acts as a monopolist in the SA market, consumption and output in SA fall dramatically with 500 MW being sourced from imports at all times. TIPS B supplies most of the electricity generated within SA and the output of NPS falls dramatically. The Commission's monopoly scenario has ETSA Generation setting prices at extremely high levels. ETSA's model assumes that bids are three times marginal cost. This is an arbitrary figure but it is a suitably high margin to represent an abuse of market power.

Figure 7.1a: Imports into and plant dispatch in South Australia in the short run — ETSA behaves competitively

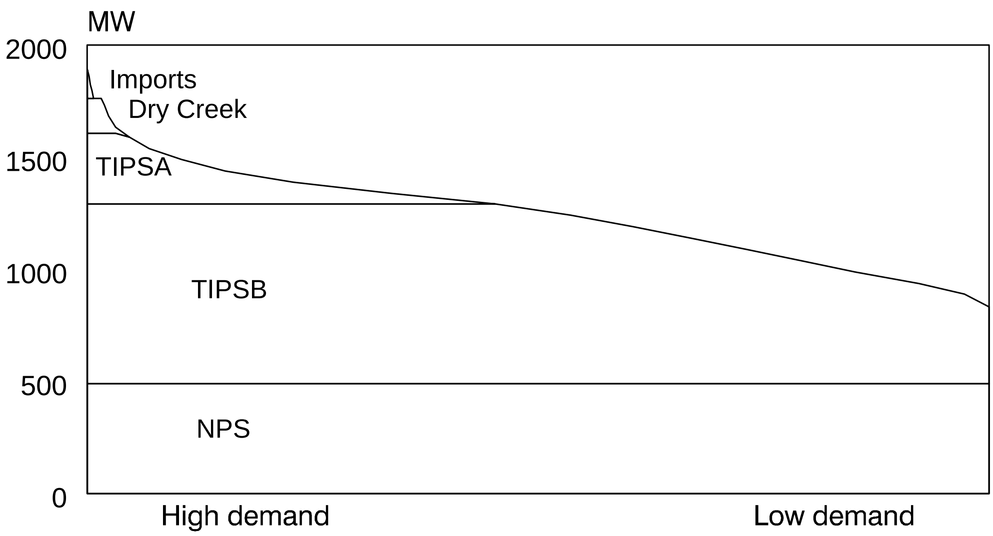
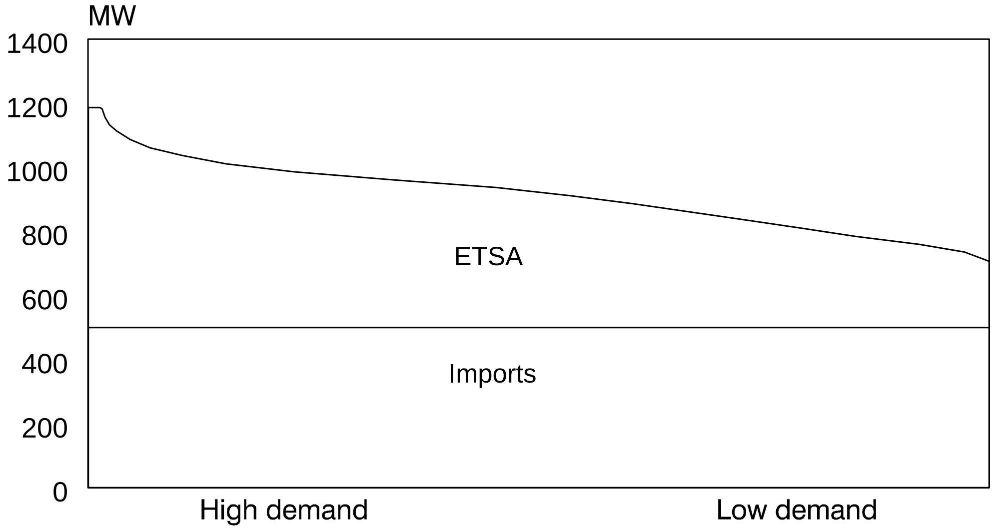


Figure 7.1b: Imports into and plant dispatch in South Australia in the short run — ETSA exerts market power



The above simply demonstrates a potential to exercise market power. The degree to which ETSA exerted this potential would depend upon strategic objectives, including the expected impact on entry of pricing behaviour and the likely reactions of the state authorities to increases in prices. The modelling shows that a regional monopoly would have an incentive and some scope to dramatically raise prices in SA. The future role of NPS and the impact that raising prices has on substitution to alternative power sources in the short term are additional considerations.[10]

Long run results

ETSA concludes that its market power would rapidly erode because high prices would depress demand, accelerate entry or prompt governments to augment transmission capacity (sub. 5, p. 38). This implies that the market power available to ETSA Generation is not robust with respect to entry. It implies that the transition period may be as short as four to five years. This conclusion is premised on the assumption that sufficient entry into the SA market occurs through independent generators and an expansion of the interconnector.

[10] The Commission’s model did allow some short run demand response, although demand was assumed to be highly inelastic, in the range of -0.1.

In ETSA's model, Playford is phased out of operation over the period and the proposed Canadian Utilities and Boral Energy (CUBE) plant is treated as bidding independently from ETSA Generation. The Commission's model also phases Playford out of operation but CUBE is bid in the pool as part of ETSA's portfolio because this more accurately reflects the status of CUBE under the existing contractual arrangements. ETSA's model finds that competitive outcomes result with an aggregated ETSA Generation in the year 2000 under several scenarios. All these scenarios assume as a base case that there is 820 MW of independent generation with a cumulative reduction in ETSA's capacity of 227 MW. Given current projections of demand growth this represents substantial, although not unrealistic, entry into the SA market.

In ETSA's base case model, the total capacity available for dispatch in SA is increased to 2.7 GW by the year 2000. When ETSA Generation remains aggregated, this base case does not discipline market power. However, an expansion of the interconnector by between 150 MW and 500 MW does have a significant impact on ETSA Generation's market power.[11] This result should be tempered by the fact that transmission losses will be determined at the margin in the national electricity market and, consequently, the price differential when the interconnector is running near capacity will be higher than is assumed in ETSA's model.

Figures 7.2a and 7.2b illustrate the plant dispatched in the Commission's model in the year 2000, given competitive and non-competitive behaviour respectively on the part of ETSA Generation. ETSA increasing prices results in the entry of gas fired generation when it is assumed that the interconnector capacity is 500 MW and real fuel prices remain at 1996 levels. This entry has the effect of displacing ETSA's plant and the output of NPS falls. As ETSA Generation is assumed to exert more market power, the output of NPS falls to zero.

11 This requires that a new interconnector be built. Expansion of the current interconnector by 150 MW is not sufficient to contain ETSA Generation's market power.

Figure 7.2a: Imports into and plant dispatch in South Australia in the long run — ETSA behaves competitively

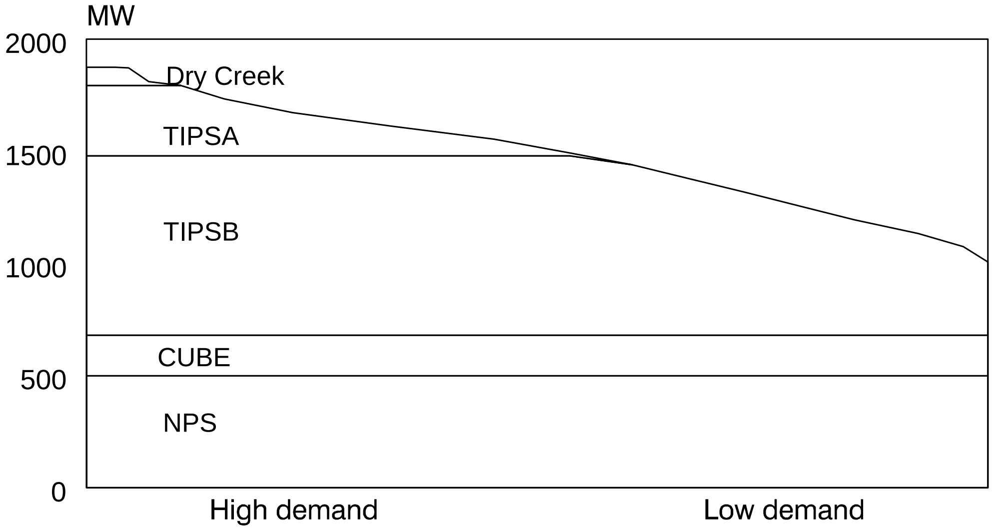
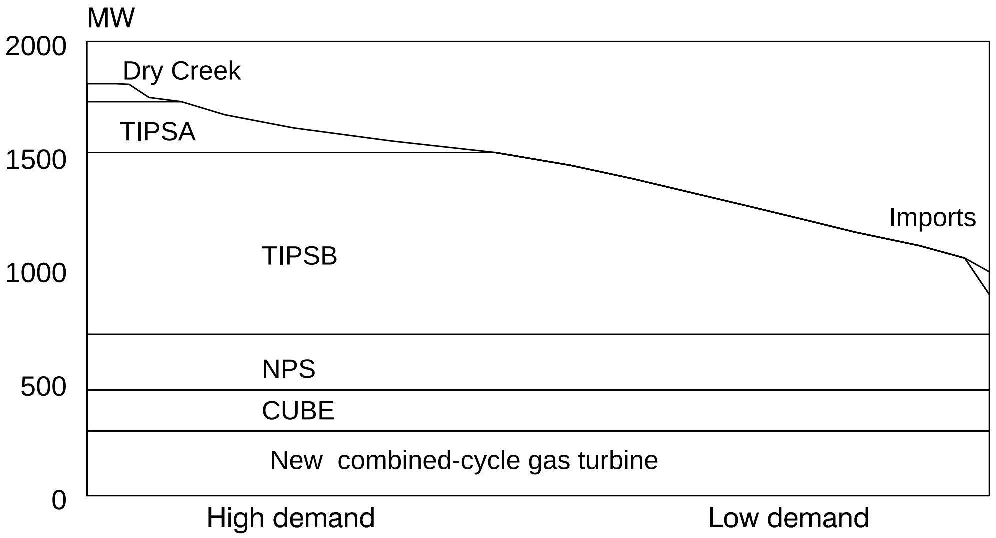


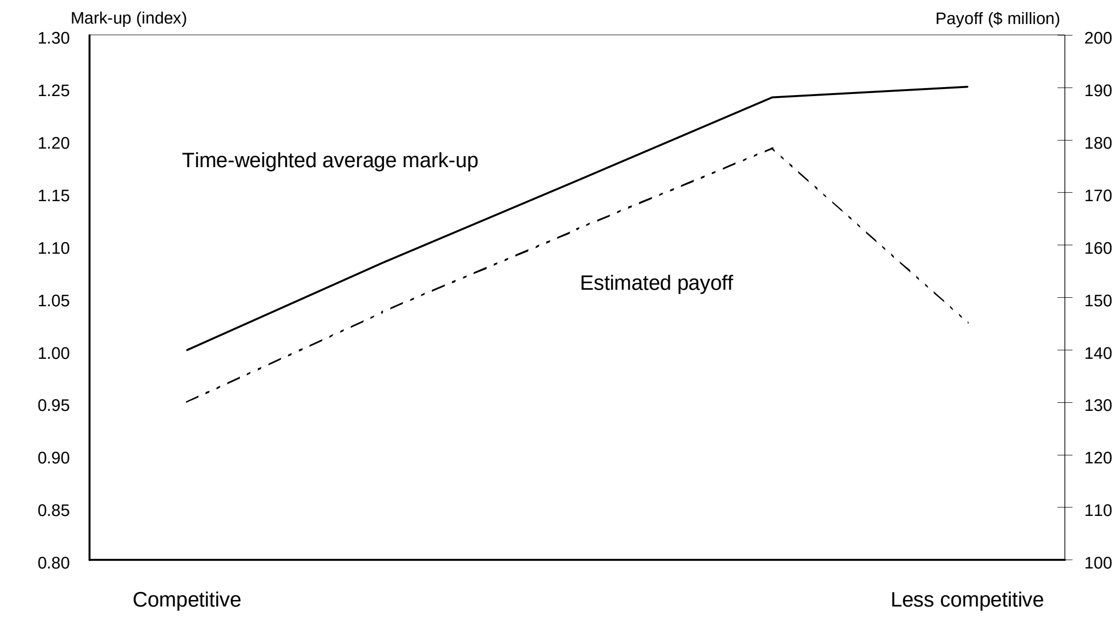
Figure 7.2b: Imports into and plant dispatch in South Australia in the long run — ETSA exerts some market power



Testing for the sensitivity of new generation entry in the SA market, it was found that an increase in price of around 20 per cent above incremental costs induced significant levels of entry. However, if ETSA priced at incremental cost, it would not induce any entry. Figure 7.3 illustrates the impact on ETSA's pay-offs through raising the time weighted average price. The pay-offs fall rapidly after the entry of new gas-fired generators.

ETSA Corporation argues that it is vulnerable to the entry of new gas generation, which the Commission (1995b) suggests would be competitive at prices of around $40–$45 per MWh.[12] However, entry into the SA region can also come through the expansion of transmission capacity. ETSA Corporation and the Victorian government provided estimates of the costs per kW of several transmission options (see Chapter 2). This new transmission capacity has a similar per unit capacity cost to new open cycle gas plant.

Figure 7.3: Pay-offs in the long run as market power is exercised



[12] As a point of reference, this is slightly higher than the current average price in the Victorian pool.

The Commission's modelling supports the conclusion that ETSA Generation is vulnerable to entry, should it raise prices too far above incremental cost. The Commission does not believe that it has the information required to undertake a comprehensive analysis of the generation and transmission alternatives in this report.

One of the determinants of entry will be the future regional price of gas.[13] Assuming that relative fuel prices remain unchanged, the Commission's modelling indicates that entry of combined cycle gas turbines in SA is plausible *even if ETSA Generation priced at incremental cost.* This could occur because more efficient gas production would displace NPS, given its current costs. ETSA Generation's response to this type of entry may be to bid NPS at below incremental cost, once entry occurs. It follows that, at the current relative costs of fuel, a plant like NPS would not be built again in the future. This conclusion is robust whether ETSA attempts to use its market power or not, and would only be revised if coal prices fell relative to gas prices.

The likelihood of an augmentation of the transmission link between SA and the eastern States is more difficult to determine, mainly because of the uncertainty attached to the planning process for the augmentation of interstate transmission capacity (see Chapter 4).

The Commission's modelling suggests that SA generation capacity would be displaced up the merit order by new entrants. This effect will be more pronounced if the transmission links to the eastern States are expanded. NPS is an inflexible base load plant which runs most efficiently when it is run 24 hours a day. There is limited scope, as it is currently configured, to use it to provide intermediate generation capacity at a price that would be competitive with more flexible intermediate plant and yet still provide some return on the assets employed. The future of NPS will be determined by ETSA Generation's pricing decisions and its ability to lower its relative costs of production.

The results of the analysis suggest that ETSA Generation is vulnerable to new entry, through new gas-fired plant situated in SA or through an expansion of transmission capacity. However, the Commission is concerned that the transition to more competitive outcomes could take several years longer than is suggested by ETSA's analysis. The Commission is also concerned that ETSA Generation can pre-empt entry by independent generators through building new

[13] The price of gas in SA relative to the eastern States will also influence where generators choose to build plant. In the Commission's model, entry takes place in SA. In reality, the locational decision will be determined by the relative costs in different regions and the possible need to augment inter-regional transmission capacity.

capacity or through converting and or augmenting existing gas plant. Hence, the options for controlling short run market power need to be considered.

Controlling short run market power

Two options for dealing with short run market power were modelled:

- ETSA Generation is split into multiple firms; and
- ETSA Generation is vested with 500 MW of contracts.

ETSA models a duopoly with portfolios of generation capacity based on NPS and TIPS, with peaking plant distributed between the two on a geographical basis. It finds that this structure does not reduce market power significantly in the short run.

An intuitive explanation of the failure of the duopoly structure to induce a high level of competition can be provided with reference to Box 7.1. The wholesale electricity market would be competitive if any one generator could supply a substantial portion of demand at any time, while facing competition from a similar sized generator or a number of alternative suppliers in each demand segment. In this scenario, each generator has a strong incentive to compete for dispatch. In Box 7.1, assume that one firm owns all the base load capacity while the other owns all the intermediate capacity. Although both firms own peaking plant, neither firm can meet all demand in the market at any given time. The incentive to compete for dispatch is low and, consequently, there will tend to be non-competitive outcomes.

This simplified explanation may be misleading because the market power result does not rest on the two rival firms owning different types of plant. Even if each of the two firms owned a range of base, intermediate and peak plant, high levels of competition could not be expected in the SA spot market in the short run. Market power will continue to exist so long as there is limited competition for dispatch in each market segment. The evidence available from the England and Wales market strongly suggests that two dominant generators who can not independently meet total demand will not compete vigorously (Newbery 1995).

The level of competition between three identical firms would be more significant, but the small number of generation sites in SA restricts the number of realistic configurations of portfolios that can be considered.[14] An option to separate the peaking plants into an additional firm did not alter these conclusions.

[14] Green and Newbery (1992) argue that outcomes in the England and Wales market do not become competitive until there are five identical portfolios of competing generation plant.

However, ETSA finds that the duopoly structure loses its market power in a relatively shorter time than does the aggregated structure (sub. 5, p. 38). The transition time to more competitive outcomes is shortened because, with new independent entry, each of the duopolists loses relatively more market share by bidding high. Hence, ETSA's modelling suggests that the duopoly would become competitive by the year 2000 on the base case assumption that 820 MW of capacity in SA was produced by independent generators.

An alternative to horizontal separation to address short run market power is to vest ETSA Generation with contracts to supply some part of its capacity for several years. ETSA models the SA market with 521 MW of vesting contracts, made up of one unit of NPS, one unit of TIPS B and Mintaro.

Vesting contracts lock in the price to be received by the generator irrespective of the pool price. The generator receives revenue from the pool based on the pool price and the quantity it supplies to the pool. However, it is also responsible for the consumers' pool payments in the sense that it must compensate the consumer when pool prices rise above the contract price. The vesting contract thereby reduces the financial incentive for the generator to withhold capacity and raise pool prices.

The Commission's model confirmed ETSA's contention that vesting contracts would reduce the prices a regional monopolist, unconstrained by the threat of regulation or new entry, would charge. Vesting contracts do not eliminate market power. Indeed, given that the monopoly (no vesting) prices are extremely high, it is not clear that vesting at 500 MW would impact as heavily on pricing as would other considerations, such as the threat of regulatory intervention. That is, 500 MW of vesting contracts may have a limited impact on pricing strategies.

Conclusions from analysis

The modelling undertaken by ETSA and the Commission produced the following conclusions:

- an aggregated ETSA Generation possesses short run market power;
- a duopoly, formed by splitting NPS and TIPS into separate businesses, is unlikely to result in a significantly greater level of competition in the short run. However new entry would impose competitive pressures at a faster rate on a duopoly than a monopoly; and
- in the long run, NPS is vulnerable to being displaced by entrants utilising newer gas technologies. That is, some incentive for entry through

generation currently exists irrespective of ETSA Generation's pricing policies.

The impact of low demand growth in SA is reflected in the Commission's modelling when there is no entry in the year 2000 if ETSA Generation bid at incremental cost. The net expansion of capacity that occurs when CUBE replaces Playford is sufficient to meet SA's needs.[15]

Another feature of the Commission's modelling is that imports from Victoria displace base load generation in SA *at the current import price* when ETSA is bidding at incremental cost. However imports, at the existing price in the Victorian market, fall to insignificant levels when ETSA bids at incremental cost.

7.4 Assessing the options for ETSA Generation

The benefits of the national electricity market partially depend on the availability of a structural solution to the problem of market power in generation. The three interconnected states have, at different times, considered this issue (see Culy and Read 1994, on Victoria and Industry Commission 1995c, on NSW.) In NSW and Victoria, generation assets have been horizontally separated.

Several submissions expressed the view that ETSA Generation should be separated. For example, United Energy argued that:

> ... the generation sector needs to be made competitive. This can be achieved by splitting ETSA generation into at least two separate corporations ... to ... give potential new entrants the confidence that a competitive market exists where no one player dominates the market (sub. 17, p. 2).

The main costs arising from horizontal separation are due to the loss of any firm economies of scale. For horizontal separation to yield net benefits, the gains from increased competition must outweigh any increase in unit costs.

A consideration of the options for horizontally separating ETSA Generation is limited to the costs and benefits of dividing the two principal generation sites at NPS and TIPS into a duopoly. While any immediate benefits of horizontal separation through increased competition are likely to be small, the analyses undertaken by the Commission and ETSA suggest that the duopoly structure reduces the transition time to achieve more competitive outcomes, compared to

15 The need for additional reserve plant in SA has not been incorporated into the analysis.

the aggregated firm. Consequently, the likely costs of separation are now considered.

Regulatory options, including vesting contracts, restrictions on new generation capacity and price regulation also need to be considered in more detail. There will be a need for measures to constrain ETSA's market power for some time irrespective of the structural option chosen for generation, because both the aggregated and duopoly structures exhibit market power in the short run. In addition, these types of arrangements have been adopted in Victoria and NSW to provide an orderly transition to a competitive market.

Horizontal separation

Economies of scale arise when an increase in the volume of outputs results in a fall in average unit costs. 'Plant' economies of scale refer to the change in unit costs as individual plant size is varied. 'Firm' economies of scale refer to the average unit costs of a firm which is made up of several individual plants. Firm economies can arise as a result of lower operating and maintenance costs, financing costs, costs of corporate governance and risk management costs. The latter refers to managing the risks associated with unplanned outages and exposure to pool prices.

ETSA Corporation estimates the costs of horizontal separation of generation plants into a duopoly due to losses of economies of scale as being between $9 million and $40 million per annum (sub. 5, p. 30). The wide range of these estimates is a function of the two techniques used to value the losses. ETSA argues that the higher estimate is more reliable. ETSA's estimates represent between 2 per cent and 11 per cent of the total operating and maintenance costs for generation reported by ETSA for 1993–94.

ETSA also states that:

> ... if the power stations were to operate in the market as independent businesses there would be a need to replicate most of the ... corporate functions for each individual business (sub. 5, p. 17).

Although it is accepted that separation does lead to the duplication of some corporate governance functions, these costs have already been captured by the measure of costs due to the loss of firm economies of scale.

London Economics (1994) argues that the minimum economic size of a generation business is between 1500 MW and 4000 MW. In its report into Pacific Power, the Commission discounted the importance of firm economies of scale (IC 1995c, p. 145). However, three individual stations in NSW have capacities of 2000 MW or more. In fact, Bayswater and Eraring individually have more capacity than the total fleet of generators in SA. In contrast, the duopoly firms proposed for SA would have capacities of 1499 MW and 710 MW respectively. Therefore, the losses due to horizontal separation are expected to be proportionally higher in SA than in NSW.

A potential cost of having smaller generation firms is a reduced capacity to self-insure against outages. Several submissions commented on the ability of generators in Victoria to co-insure against exposure to pool prices during outages of generation plant. For example, CitiPower states that:

> In fact the solutions devised [in Victoria] tend to be better arrangements than might occur if a portfolio generator were to self insure against [the risks occasioned by plant outage] because they pass appropriate signals to the customer side of the market (sub. 6, p. 5).

However, increases in the costs of managing risk are considered to be firm diseconomies of scale and, as such, will raise average prices. It is not clear that this will impact on any demand management initiatives.

Perhaps of more significance is the argument that ETSA Generation's self insurance through portfolio holdings will impede a co-insurance market from developing in SA amongst (future) independent generators. Given that the existing co-insurance market in Victoria is an artefact of the structure chosen by policy makers and not a function of market mechanisms, the case for a co-insurance scheme as a driver of horizontal separation is not convincing.

The costs of horizontally separating ETSA Generation into a duopoly are likely to be significant, but they can easily be overstated if separation leads to the more effective management of major assets. These efficiencies are more likely to be achieved in a competitive market. However, there are doubts as to whether the duopoly structure does result in competitive outcomes in the short run. Hence, the benefits to be had from separation arise over time as a response to independent entry. The difference between the aggregated structure and the duopoly is the expected length of the transition period.

Vesting and regulation

It is clear that some regulation of generation in SA will be required in the early stages of the national electricity market to facilitate the orderly transition to a competitive market. This should reduce the scope ETSA Generation has to exert market power over the period in which it has the most to gain from exercising it.

Although vesting contracts have been widely used as part of the transition process from a centrally planned system to a market based system, they are instruments of regulation, not pro-competitive mechanisms. In order that market power be controlled, it would be necessary to vest a larger proportion of ETSA Generation's output than is proposed by ETSA in its submission.

In the England and Wales market, the two newly privatised generators, National Power and PowerGen, were initially vested with contracts supervised by the Department of Energy. In 1991, vesting contracts represented 84 per cent of National Power's total capacity and 89 per cent of PowerGen's total capacity (Helm and Powell 1992).[16] ETSA's proposal represents less than 25 per cent of its total capacity.

However, high levels of vesting limit ETSA Generation's ability to make day to day operational decisions and this is not consistent with the objective of achieving efficiency in generation. There is some trade-off in vesting ETSA Generation, either as a monopoly or a duopoly. Hence, work needs to be undertaken to determine the optimal level of vesting under the structural option chosen by the SA government.

Under either structural option, independent entry into the SA market is required for competitive outcomes to result. This will be delayed if ETSA Generation builds new capacity or if a large proportion of its existing gas-fired plant were to be refurbished and augmented. When the new capacity from the CUBE plant is treated as being under the control of ETSA Generation, allowing for the decommissioning of Playford, the need to constrain ETSA Generation from increasing its capacity is important to encouraging new entry.

7.5 Recommended approach

An aggregated ETSA Generation does possess market power in the short to medium run. The Commission accepts that ETSA Generation's market power is constrained to some degree. This is a function of the size of ETSA Generation relative to the interconnector, the mix of plant, the low expected growth in the SA market and the impact that raising prices is likely to have through the response of regulators and entry.

The structural separation of ETSA Generation into two firms is unlikely to result in sufficient competition on its own to deliver large benefits in the short to medium run. The gain from an improvement in short run competition arising from the horizontal separation of ETSA Generation is not expected to be

[16] In the United Kingdom, vesting was a result of the Government's concerns about the impact of the privatisation of generation on the coal industry, as much as it was with limiting price rises.

sufficiently high so as to outweigh the costs incurred through separation. Separating ETSA Generation into three firms, based on NPS, TIPS and the peaking plant would not alter this conclusion.

The option of placing NPS in a separate corporation should also be viewed in the context of the trends in generation. Raschke said that:

> ... in markets where gas is available and both the gas and the electricity industries have been liberalised, there is a growing tendency for independent power producers to choose gas over coal (1996, p. 392).

He also notes that a trend has emerged whereby both new entrants and established utilities prefer natural gas as a fuel for *base load* generation. Whether this develops into a trend in Australia or not will depend on the relative cost of fuels. The Commission's modelling indicates that, at current prices, new gas-fired base load plant would enter before new coal fired plant in SA. As was noted above, NPS would not be built in the current environment and, all things being equal, would not be replaced in the future.

In the absence of a clear structural solution to the problem of market power, alternatives will need to be considered. Vesting contracts will constrain ETSA Generation's behaviour, but at the cost of imposing non-competitive instruments on the market. In addition, it is clear that vesting at the levels suggested by ETSA Corporation will not fully constrain its market power while vesting at higher levels may not be practicable. Prices have been regulated in other states during the transition period and this also presents an opportunity to contain market power and to provide an orderly transition to a competitive market.

A package of instruments should be considered, but these can be costly and each component of the package should be prepared so as to complement the others.

As part of this package, the Commission favours limiting any expansion in ETSA Generation's capacity in SA for some time into the future. The SA government may wish to consider options to:

- tie ETSA Generation's involvement in new generation to developments in the national electricity market, for example, the augmentation of transmission capacity or the entry of independent generation; or
- determine a specific timetable.

The latter would give ETSA Generation and potential entrants a certain planning horizon and should be preferred. Any plans for the refurbishment of existing plant by ETSA Generation should be subject to the scrutiny of the SA government. For ETSA Generation to remain viable into the future, some conversion of older plant may be required, but care must be exercised that this does not impede the entry of independent generators.

The over-riding consideration is the timing and size of independent entry and augmentation of transmission links. Given that the relative costs of fuel remain similar, the analysis undertaken by the Commission indicates that some opportunities for entry of lower cost gas generation into the SA market exist. This must be balanced against the fact that the decommissioning of Playford and the commissioning of CUBE will give ETSA Generation sufficient capacity to meet expected demand growth in SA until the year 2000.

This places the role of transmission in perspective. The SA government should investigate the feasibility of augmentations to transmission capacity as part of the structural reform process. It is clear that competitive outcomes will be realised quicker if the interconnector is increased in size. *The Commission does not suggest that the SA government undertake the augmentation or actively encourage it, but rather it needs to be investigated as a matter of urgency*.

Limiting the impact that ETSA Generation can have on the inter-regional hedging market should be a priority of the SA government and NEMMCO. Further, it is recognised that inter-regional hedging is a problem *even if ETSA Generation is horizontally separated into two firms*. This issue must be resolved to the satisfaction of participants in the national electricity market. Until then, the costs of inter-regional hedging will be inflated and it will impede the ability of wholesale customers to source generation from other regions.

To counter the possible effects on the potential for ETSA to expand, it should be allowed to compete to supply generation in other States.

A MINISTERIAL CORRESPONDENCE ESTABLISHING THE REVIEW

This appendix consists of the text of:

- a letter from the South Australian Minister for Infrastructure to the Commonwealth Assistant Treasurer proposing that the Commission review the structure of the South Australian electricity industry;
- a reply from the Commonwealth Assistant Treasurer to the Minister for Infrastructure, regarding the above letter; and
- a letter from the Commonwealth Assistant Treasurer to the Chairman of the Industry Commission which accompanied the terms of reference for this study.

Minister for Industry, Manufacturing, Small Business and Regional Development. Minister for Infrastructure. South Australia

21 December 1995

The Hon George Gear MP
Assistant Treasurer
Parliament House
CANBERRA ACT 2600

Dear Minister

As you would be aware, the South Australian Government is a signatory to the three Intergovernmental Agreements on competition policy signed at the April 1995 meeting of the Council of Australian Governments (COAG). It is committed to introducing competition in the South Australian economy to improve the competitiveness of South Australian industry and to provide economic benefits to the State.

A key component of the competition policy reforms is the introduction of a national competitive electricity market. South Australia is actively participating in the development of the national market through the National Grid Management Council and its various working groups. The Government has established the Electricity Sector Reform Unit to coordinate electricity reform in the State, and to oversee all aspects of the implementation of the national market in South Australia.

For the past 49 years ETSA has been responsible for electricity supply in South Australia. Currently 99% of South Australia's needs is provided by ETSA of which up to 30% is sourced under the Interconnection Operating Agreement with the Eastern States.

In June 1993, COAG agreed that the Australian electricity industry should be restructured to create multiple network corporations (as proposed by the NGMC) to facilitate the operation of a national electricity market. South Australia indicated at the time that it was considering the use of a subsidiary structure pending resolution of the cost issues associated with separating transmission from its vertically integrated authority.

Since that time and in preparing for the national electricity market, South Australia has introduced a new structure for ETSA. The old Electricity Trust of South Australia was corporatised on the 1 July this year as ETSA Corporation with a holding company and four subsidiaries.

These subsidiaries, ETSA Generation, ETSA Transmission, ETSA Power and ETSA Energy are ring-fenced and arrangements are in place for separate boards to be appointed to them. This more contemporary but vertically integrated enterprise remains responsible for coal mining, electricity generation, transmission, distribution, retailing and gas marketing.

South Australia is keen to ensure that its electricity supply industry provides the optimum economic benefits to the State. For this reason, the Government requires the assistance of the Industry Commission to provide it with an assessment of the appropriate structural arrangements for the industry in South Australia, including the implications of the current structure for competition in both the national and the regional South Australian electricity markets. The Commission could also provide advice on any alternative structures that it believes might be implemented in South Australia to enhance the economic benefit to the State from implementation of the competitive electricity market.

I understand that the Industry Commission, as an independent agency, will conduct this research study consistent with its statutory guidelines. We concur with the Commission's wish to publish its report within a reasonable period after delivery to the Commonwealth and South Australian Governments. I understand that the details of its release will be negotiated between the Commission and the South Australian Government taking into account sensitive commercial negotiation and arbitration matters currently pending with ETSA Corporation at this time.

In undertaking this study, the Commission will wish, time permitting, to consult with key interested parties and to receive public submissions to it. I ask that as a minimum, the IC consult with the following:

A Department of Premier and Cabinet (SA)
B Department of Treasury and Finance (SA)
C Department of Mines and Energy (SA)
D ETSA Corporation
E Electricity Sector Reform Unit (SA)
F National Grid Management Council
G Department of Primary Industry and Energy (Federal)
H Electricity Supply Industry Reform Unit (Vic)
I Taskforce on Electricity Reform (NSW Treasury)
J Department for Family and Community Services (SA)
K South Australian Council on Social Services
L Office of Consumer and Business Affairs (SA)
M Australian Chamber of Commerce
N South Australian Chamber of Commerce and Industry
O United Trades and Labour Council (SA)
P Leader of the Opposition (SA)
Q Leader of the Australian Democrats (SA)

South Australian Government agencies and Corporations will, of course, cooperate fully with the IC's requests for information relevant to the study. It is understood that the IC has agreed that it will take all appropriate steps to protect fully the commercial-in-confidence material that it gathers for the Study.

I attach a draft terms of reference that the Government considers would provide a suitable basis for this assessment. In order to provide the Government with the adequate time to consider and implement any recommendations made by the Commission, prior to the commencement of the national market, it would be necessary to receive a report by no later than 27 February 1996.

The Government understands that the IC will absorb all salary costs of the study, and that expenses incurred as a result of travel to undertake consultation will be charged to the Electricity Sector Reform Unit up to a maximum of $10,000. Any consultancy commissioned by the IC in response to the Terms of Reference will be the subject of agreement and approval by the ESRU.

I look forward to your agreement to this proposal and request that you refer such a study to the Industry Commission as a matter of urgency.

Yours sincerely

JOHN OLSEN FNIA MP
Minister for Industry, Manufacturing,
Small Business & Regional Development
Minister for Infrastructure

ASSISTANT TREASURER
PARLIAMENT HOUSE
CANBERRA ACT 2600

The Hon John Olsen FNIA, MP
Minister for Infrastructure
GPO Box 1067
ADELAIDE SA 5001

Dear Minister

Thank you for your letter of 21 December 1995 in which you seek agreement for the Industry Commission to undertake a review of the structure of the electricity supply industry in South Australia. Subject to satisfactorily settling the interpretation of the terms of reference, I concur in your proposal for such a review. In doing so I would like to comment on several issues that were raised in your letter.

As you are aware, all governments have committed to:

- working towards implementation of the Multiple Network Corporation structural option, in which the activities of generation and transmission are separated into distinct corporations (at the June 1993 COAG meeting); and

- implementing competition policy and related reforms, in which each jurisdiction will receive competition payments in three tranches subject to meeting particular conditions (at the April 1995 COAG meeting).

As drafted, the terms of reference could be taken to imply that there is some scope for the Industry Commission to consider alternative structures outside of the approved Multiple Network Corporation model outlined in the National Grid Management Council's report. In my view, however, any Industry Commission study of alternative structural options for the South Australian electricity industry should confine itself to options that are broadly consistent with commitments already made by governments.

I also note that emphasis has been placed on the structure that would be in the best interests of South Australia. I have no difficulty with this provided the best interests of South Australia are assessed in an appropriately broad, national context that takes account of COAG commitments and the wider economic benefits of a fair and efficiently functioning national electricity market. Since the thrust of the competitive national market is to generate benefits to consumers, I would expect the Industry Commission to give considerable weight to the interests of South Australian consumers in conducting the review.

The terms of reference request the Industry Commission to complete the review within 75 days while your letter calls for a report by 27 February 1996. I agree that, if it is at all possible, the Industry Commission should complete its report by 27 February 1996, so as to ensure that there is no further delay in the commencement of the national electricity market. If this is not possible, the Commission should provide our governments with a preliminary report by that date.

On the understanding that the terms of reference will be interpreted along the lines I have outlined above, I have directed the Industry Commission to undertake the proposed review. I have copied this letter to the Chairman of the Industry Commission, Mr Bill Scales, for the Commission’s guidance.

Yours sincerely

GEORGE GEAR

ASSISTANT TREASURER
PARLIAMENT HOUSE
CANBERRA ACT 2600

Mr Bill Scales
Chairman
Industry Commission
Nature and Conservation House
Emu Bank
Belconnen ACT 2617

Dear Mr Scales

I have received a letter of 21 December 1995 and proposed terms of reference from the South Australian Minister for Infrastructure, the Hon John Olsen, MP asking that the Industry Commission undertake a review of the structure of the electricity supply industry in South Australia. A copy of Mr Olsen's correspondence is attached.

I welcome the South Australian proposal which, I understand, has been the subject of informal consultations between Commission officials and State Government officers.

Attached is a copy of my reply to Mr Olsen. I would be pleased if the Commission would proceed with the review as soon as possible. You will note that I have made some observations to the State Minister about the interpretation of the terms of reference and I ask the Commission to bear these in mind in undertaking the review.

Yours sincerely

GEORGE GEAR

B PARTICIPATION IN THE INQUIRY

The Commission received the terms of reference for this review on 22 December 1995. It sent copies to a range of interested parties, inviting them to submit their views. Section B.1 provides a list of the organisations which responded. The Commission met with the organisations listed in Section B.2.

B.1 Submissions received

During the course of the review, the Commission received the written views of those organisations listed below.

Organisation	Sub. No.
Australian Capital Territory Government	19
Australian Chamber of Manufactures	3
Australian Gas Association	10
Australian Services Union	14
Boral Energy Limited	4, 22
Business Council of Australia	18
CitiPower Ltd	6
District Council of Hawker	11
ETSA Corporation	5, 23
Federal Bureau of Consumer Affairs	9
Fletcher Challenge	8
New South Wales Electricity Reform Taskforce	21
Penrice Soda Products Pty Ltd	2
Santos Limited	13
Snowy Mountains Hydro-Electric Authority	1

Organisation	Sub. No.
South Australian Employers' Chamber of Commerce and Industry	20
South Australian Government	15
Tenneco Energy SA Pty Ltd	12
United Energy Ltd	17
United Trades and Labor Council of South Australia	16
Victorian Government	7

B.2 Visits and meetings

The Commission held discussions with the following organisations during the course of the study.

Australian Capital Territory

ACTEW Corporation

Australian Chamber of Commerce and Industry

Australian Competition and Consumer Commission

Australian Gas Association

Commonwealth Department of Primary Industries and Energy

Department of Urban Services

New South Wales

New South Wales Government Pricing Tribunal

Taskforce on Electricity Reform (Department of Treasury)

South Australia

Adelaide Brighton Cement

Boral Energy Limited

Centre for Economic Studies, Adelaide and Flinders Universities

Cowell Electric Supply Co Ltd

Department for Family and Community Services

Department of Mines and Energy

Department of Premier and Cabinet

Department of Treasury and Finance

Economic Development Authority

Electricity Sector Coordinating Committee

Electricity Supply Reform Unit

Elliott, M. (Leader of the Australian Democrats)

ETSA Corporation

Foley, K. (Shadow Minister for Infrastructure)

Office of Consumer and Business Affairs

Olsen, The Hon. J. MP (SA Minister for Infrastructure)

Penrice Soda Products Pty Ltd

SA Council on Social Services

South Australian Employers' Chamber of Commerce and Industry

Santos Limited

Tenneco Energy SA Pty Ltd

United Trades and Labor Council

Western Mining Corporation

Victoria

Australian Cogeneration Association

Business Council of Australia

CitiPower Limited

Electricity Supply Industry Reform Unit

Energy and Minerals Victoria

Fletcher Challenge

London Economics

Mobil Oil Australia Limited

National Grid Management Council

PowerNet Victoria

United Energy

Victorian Power Exchange

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