# TOWARDS A TRULY NATIONAL AND EFFICIENT ENERGY MARKET

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# Council of Australian Governments
# Energy Market Review
## CHAIR

The Hon Ian Macfarlane MP
Minister for Industry, Tourism and Resources
Parliament House
CANBERRA ACT 2600

Dear Minister

It is with much pleasure that I present to you as the Chair of the Ministerial Council on Energy the final report of the Council of Australian Governments' Independent Review of Energy Market Directions.

Since releasing the draft report on 15 November, we have received over 100 submissions. My Panel colleagues, Paul Breslin, Rod Sims and David Agostini, and I have considered the submissions and have made some adjustments as a result.

We were pleased to note that the vast majority of the respondents endorsed the broad policy directions and recommendations contained in the draft report.

We believe that Australia now stands at a very important decision point on energy market development. Tremendous opportunities are available for Governments to take Australia the next important steps along the road to achieving a national and efficient energy market. We believe that adoption of our recommendations will lead to this outcome and we commend the report to you and your colleague jurisdictional Ministers.

We wish to take this opportunity to acknowledge the time and effort devoted by many stakeholders in making submissions to the Review. Many of these stakeholders also gave freely of their time to meet with the Panel to further discuss their views and in some cases provided us with additional material.

My colleague Panel members and I also wish to record our appreciation of the dedication and professionalism of the Secretariat which supported the Review. Completion of this review in less than the 12 months originally envisaged for it by COAG is due in no small part to the Secretariat's efforts.

Yours sincerely

Warwick R Parer
Chair

20 December 2002

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# CONTENTS

**Executive summary** .......... **7**

**List of recommendations** .......... **47**

**Chapter 1: Introduction and context** .......... **59**
- Energy in the Australian context .......... 59
- Creation of competitive markets .......... 62
- Framework for future energy market reform .......... 64
- Context for the future directions .......... 65
- Deficiencies in Australia's energy markets .......... 67

**Chapter 2: Governance and regulatory arrangements** .......... **69**
- Context .......... 69
- Key findings .......... 74
- Proposed solutions .......... 83
- Recommendations .......... 96

**Chapter 3: Electricity market mechanism and structure** .......... **99**
- Context .......... 99
- Key findings .......... 102
- Proposed solutions .......... 117
- Recommendations .......... 119

**Chapter 4: Electricity transmission** .......... **121**
- Context .......... 121
- Key findings .......... 124
- Proposed solutions .......... 133
- Other comments .......... 150
- Recommendations .......... 151

**Chapter 5: Electricity financial market development** .......... **155**
- Context .......... 155
- Key findings .......... 163
- Proposed solutions .......... 168
- Recommendations .......... 171

**Chapter 6: Demand side participation and full retail contestability in electricity ...... 173**
Context ........ 173
Key findings ........ 174
Proposed solutions ........ 178
Recommendations ........ 183

**Chapter 7: Increasing the wider penetration of gas ........ 185**
Context ........ 185
Key findings ........ 189
Proposed solutions ........ 209
Recommendations ........ 220

**Chapter 8: Options to reduce greenhouse gas emissions ........ 223**
Context ........ 223
Key findings ........ 229
Proposed solutions ........ 233
Recommendations ........ 242

**Chapter 9: Rural and regional issues ........ 243**
Context ........ 243
Key findings ........ 245
Proposed solutions ........ 248

**Chapter 10: Estimating the benefits ........ 251**

**Attachment A Energy technologies ........ 257**
**Appendix 1 Panel members ........ 263**
**Appendix 2 Secretariat ........ 265**
**Appendix 3 Terms of reference ........ 267**
**Appendix 4 Responses to Issues Paper ........ 269**
**Appendix 5 Responses to Draft Report ........ 275**
**Appendix 6 References and consultancies ........ 281**
**Appendix 7 Acronyms and abbreviations ........ 287**

# EXECUTIVE SUMMARY

## Assessing the energy industry's 'report card'

### The importance of the energy sector

Australia is endowed with significant, diverse and high quality energy resources. Australia has approximately 800 years supply of easily accessible brown coal and 290 years supply of black coal. It has large natural gas resources in the North West, in Bass Strait and in the Cooper-Eromanga Basin, new fields coming on stream in the Otway Basin, and promising coal bed methane deposits. Australia also has good wind, hydro and solar resources, and the potential for geothermal energy.

Not surprisingly, Australia's electricity and gas prices are close to the lowest in the developed world. International studies show this to be the case for both major industrial and residential users.

Energy is, therefore, a very significant strategic policy matter for the Australian economy. It underpins the competitiveness of our exported goods sector, is a vital ingredient for domestic industry, and it is a very important item in the monthly household expenditure budget.

### The need for review

The competition reforms of the 1990s transformed Australia's electricity and gas sectors. They included the separation of the previously vertically integrated supply chain, introduced competition between generators and between retailers, brought the network element under access and price regulation and saw the creation of a National Electricity Market. In gas, laws limiting interstate trade were repealed and third party access to pipelines was mandated.

These reforms have, however, been subject to criticism. In part this is due to the far reaching nature of the changes. In part it is due to the fact that some areas (such as South Australia) saw the reforms lead to what were considered to be unwarranted energy price rises because of generator market power, and because of the large increase that occurred in many network asset values which significantly increased network prices.

At its meeting of 8 June 2001 the Council of Australian Governments (COAG) endorsed the need for a national energy policy and agreed to commission an independent review of the strategic direction for stationary energy market reform in Australia. The Review has received over 250 submissions, met interested groups and people in all states and mainland territories, gained first hand knowledge of energy reform in key overseas markets, initiated targeted analysis, and reviewed the available research both here and overseas. In conducting the Review the Panel was very much aware of community and hence government sensitivity to issues of supply reliability and the competitive price of energy.

## Energy reform has brought benefits

Much has been achieved since COAG agreed to establish a national energy market. Competitive pressures have seen increased generator efficiency and availability, additional generation investment has occurred that seems market related (that is, new efficient base load plants in South Australia and Queensland, and new peaking plant in Victoria), there have been new gas fields discovered and utilised, and new pipelines have been constructed to transport gas interstate.

Indeed, Australia can be proud of its reforms so far. Energy reform is new all around the world and, while there have been problems, Australia has not experienced them on the scale that has occurred in many other places. Further, the reforms have a clear and appropriate bias to efficient outcomes, which reflects the importance of energy to Australia's welfare.

In fact, Australia's energy reforms seem to have a larger market orientated dimension than many of the reforms overseas. This can and should lead to better outcomes. It does, however, require care in terms of ensuring that the conditions for success are in place on a continuing basis.



## Key report finding – serious deficiencies remain

Just as the energy reforms have brought benefits, it seems clear that there are serious deficiencies in some of the reform areas. These deficiencies are either areas that still need to be addressed or they have emerged as unintended consequences of the recent reforms. It is clear that important steps need to be taken to achieve a truly national and efficient energy market.

These deficiencies are summarised in Exhibit 1.

Exhibit 1

## SERIOUS ENERGY MARKET DEFICIENCIES

| Key findings | Example implications |
|---|---|
| – The energy sector governance arrangements are confused, there is excessive regulation, and perceptions of conflict of interest. | – Poor market development mechanisms, overlapping responsibilities, unnecessary costs, distorted signals for behaviour. |
| – There is insufficient generator competition to allow Australia's gross pool system to work as intended. | – Too many periods of excessive generator market power and pool price volatility. |
| – Electricity transmission investment and operation is flawed, and the current regions do not reflect the needs of the market. | – A 'regionalised' NEM, with five markets rather than one, and a severe limitation on trading interstate and market liquidity in general. |
| – The financial contracts market is extremely illiquid, in part reflecting large regulatory uncertainty. | – No effective short term contract market, large users cannot obtain long term contracts, market overall less efficient. |
| – There are many impediments to the demand side playing its true role in the market. | – Pool prices are more volatile than they need to be, the system requires more generation capacity than it should. |
| – There is insufficient competition in the east coast gas market, and too much uncertainty surrounding new pipeline development. | – Some prices to consumers are (or will soon become) higher than necessary, the gas market is not flexible. |
| – Greenhouse responses so far are ad hoc, and poorly targeted. | – A given greenhouse benefit is costing the community much more than it needs to. |
| – The NEM is currently disadvantaging some regional areas. | – Some regional areas are not attracting the investment that their resource endowment would suggest. |

The Review sought only to focus on the strategic deficiencies. It did not seek to comment on all issues, or to systematically address every issue raised in the submissions received.

The deficiencies are quite wide ranging, and have serious consequences. They need to be quickly addressed if we are to achieve a genuinely national and efficient market. They range from issues of governance and regulation, in the case of electricity to such key issues as transmission and financial market development, and in the case of gas to concerns about upstream competition and barriers to the construction of new pipelines.

Given the short history of energy market reform worldwide, all countries are facing problems. Some of the problems in Australia are the same as those overseas (for example, in transmission). And it is very clear that for some of the deficiencies there are no perfect solutions. This fact, however, must not prevent us from moving forward.

This Report elaborates on these deficiencies, and proposes clear solutions.

## Addressing governance and regulatory arrangements

### Governance and regulatory problems

A striking feature of Australia's energy sector is its confused governance arrangements and excessive regulation. Seven problems can be identified.

First, the electricity and gas Code change processes are deficient. Code changes take too long, and they sometimes do not reflect sufficient market knowledge and input.

Second, the responsibilities of the key electricity governing bodies — the National Electricity Market Management Company (NEMMCO), the National Electricity Code Administrator (NECA) and the Australian Competition and Consumer Commission (ACCC) — overlap in important areas, which adds to the sense of confusion.

Third, there are too many regulators, which leads to costly inconsistency. The differing rules between states, and between gas and electricity, can boost the cost of new market entry by retailers by up to one third through the need for additional IT system capital and operating costs, and the inability to take advantage of back office scale economies that should otherwise be available.



Fourth, there are concerns about perceptions of conflict of interest when some governments are energy asset owners, regulators and also determine energy policy. The concerns centre on the problems that are caused when such perceptions seem widely held.

Fifth, is the uncertain role for Ministerial decision-making. Views amongst the market participants varied widely, from those wanting more Ministerial involvement, to those wanting less. What all agreed on, however, is that current Ministerial interventions did not always take into account the full effects they can have on the energy market.

Sixth, the nature of network regulation can send distorting signals that have the potential for perverse results. With most networks needing to be regulated given their monopoly power, it is extremely important for that regulation to be well focussed.

Finally, there are some barriers to embedded generation, which limit the benefits that could be gained in this area.

These problems have a large cost. The confusion and excessive regulation increases uncertainty and may see participants decline to invest or apply a larger discount rate to their investments and decisions than otherwise. This results in higher costs to the community.

## Proposed governance and regulatory changes

To address these problems a number of changes are proposed. These are summarised in Exhibit 2, and are as follows:

- the creation of a National Energy Regulator to encompass the energy specific roles of the ACCC, all the state and territory regulatory bodies, and some of the roles of NECA
- an enhanced role for NEMMCO in terms of proactive market development, within a clear framework set by Ministers
- a statutory end user and industry committee to drive a streamlined process for changes to the National Electricity Code
- the creation of a Gas Advisory and Code Change Committee to improve the Gas Code change process
- a clarification and enhancement of the role of Ministers that mirrors their role in other industries of significance
- a range of changes to the way network assets are regulated
- the establishment of a mandatory code of practice for arrangements between distribution companies and prospective embedded generators.

Exhibit 2

# GOVERNANCE AND REGULATION ISSUES

**Key findings**

- Too many regulators
- Deficient electricity and gas Code change processes
- Overlapping responsibilities of the key electricity governing bodies
- Perceptions of conflict of interest when governments are owners, regulators and policy makers
- Uncertain role for Ministerial decision–making
- Distorted and inappropriate signals from current network regulation
- Barriers to embedded generation

**Proposed solutions**

- Create a National Energy Regulator to encompass ACCC, state and territory regulators and NECA under a legislative approach agreed by COAG.
- Enhance NEMMCO's role to facilitate a National Electricity Code change process managed by a statutory end user and industry committee and with streamlined processes.
- Create a Gas Advisory and Code Change Committee.
- Have the MCE as the Ministerial decision-making body.
- Make important changes to the way network assets are regulated.
- Have the NER establish a mandatory code of practice for dealing with embedded generation.

## The creation of a National Energy Regulator

There are three sound reasons for a National Energy Regulator (NER):

- As already mentioned, the current excessive number of regulators leads to costly overlap and inconsistency. Creating a national energy regulator is the only way to remove this problem.
- Particularly given the history of the industry, the regulator must be seen to be a national body. This is crucial to the stability and overall performance of the national energy market.
- Such a move will help create a truly national market.

The NER will be an authority established under a legislative approach agreed by COAG and will assume the energy specific roles of the ACCC and all the relevant state/territory regulators. In particular it will:

- approve electricity and gas Code changes. The NER will not be able to initiate changes, only approve or disallow them.
- regulate as required the gas and electricity sectors in the non-NEM states and territories. This is aimed at achieving a common regulatory system throughout Australia.
- administer transmission and distribution regulation in the electricity and gas sectors
- provide a wide range of licensing and other approvals currently provided by various state/territory agencies
- be responsible for the various (currently) state and territory marketing and retail codes
- monitor and assess compliance with the National Electricity Code.

The Panel's view is that the most appropriate approach is for the NER to be a separate energy sector-specific agency. Others have advocated a single energy regulator located as a specialised arm of a generalist economic regulator. This is an issue to be resolved by COAG in the implementation of the proposal. The key elements of the Panel's proposal should be preserved regardless of the eventual decision.

In any case, the ACCC would, of course, remain responsible for administering the Trade Practices Act (TPA) as it does for other industries.

The NER would have three commissioners, who would be appointed on merit by the Ministerial Council on Energy (MCE).

## Improving the National Electricity Code change process

A new statutory Code change committee would be formed to progress changes to the National Electricity Code. It would be appointed by the MCE and comprise both end users and industry representatives. NECA and the Code Change Panel would cease to exist.

The Committee would receive administrative and analytical support from NEMMCO. NEMMCO, while providing comments on proposed Code changes, would have no veto power over the submission of the changes to the NER.

## An enhanced role for NEMMCO

To perform its role in terms of proactive market development and in providing analytical and administrative support to the National Electricity Code Change Committee, NEMMCO will need to grow its market research capacity and it will need to establish formal arrangements for stakeholder consultation.

It is also envisaged that NEMMCO, like the NER, will provide whatever services are appropriate in the non-NEM markets. The aim is to have as national a market as is possible.

NEMMCO should continue to be funded by participants and it should continue as a company owned by governments. NEMMCO Board members will be appointed by the MCE on merit.

## Improving the Gas Code change process

A new advisory and code change committee would be formed to replace both the Gas Policy Forum and the National Gas Pipelines Advisory Committee. It would be appointed by the MCE on merit.



Its key role will be to propose and analyse changes to the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code). It would also provide advice to the MCE on gas policy matters and be supported by ad hoc specialist committees as needed.

The Committee would also be supported in terms of administration and research by a Secretariat comprising Commonwealth and state officials. This would enable it to draw on the resources and skills it requires to ensure the Gas Code remains relevant to the needs of the market.

As with electricity, any market player could initiate a Gas Code change. The aim is, however, to ensure a rigorous assessment of the proposal prior to the change being considered by the NER.

## The role of the Ministerial Council on Energy

There is a need to have a common Ministerial approach on all electricity and gas issues within Australia. The objective is to have one policy on key issues, such as greenhouse, not several policies whose objectives can conflict.

It is proposed that the MCE subsume the role of the NEM Ministers Forum. This will allow a more national, gas and electricity, perspective.

A key and immediate role for the MCE, of course, will be to assess the proposals in this report. To implement the proposals in this report, legislation will need to be changed and the electricity and gas Code changes will need to be referred to the relevant Committee. These steps could be taken as part of a co-ordinated implementation plan.

Once implementation is complete, the continuing role of the MCE will be clear. It will be to:

- agree the laws that will govern the energy sector across Australia
- appoint the NER Commissioners
- appoint the NEMMCO Directors
- appoint the members of the Gas Advisory and Code Change Committee and the National Electricity Code Change Committee.

The MCE should be formally briefed at least once a quarter by both NEMMCO and the Gas Advisory and Code Change Committee. This will facilitate a continuing understanding of the effect of laws and policies on the energy market, and the need for any new legislation.

While we do not know how technology will affect future developments we must, in our regulatory and policy evaluation, allow for the fact that a future pipeline could connect the west and east of Australia, and that one day electricity transmission lines could do the same. We should therefore be pursuing national approaches wherever possible.

## Improving network regulation

There is currently a fierce debate on the regulation of both electricity and gas network assets. Vigorous debate is to be expected given the importance of network costs in final electricity and gas prices, and given the different interests of the parties involved.

Debate focuses on some very narrow issues. These centre on the level of the regulated asset base and the appropriate return on capital, and should be left to the parties involved to resolve.

Debate also centres on the type of regulation, and the regulatory philosophy which should underpin it. While this debate is important, the alternative regulatory philosophies are not yet fully worked out so as to make a valid comparison of them. The debate has further to run.

This debate would be most effective if it focussed on moving regulation to a less intrusive form. This may best be brought about by giving further consideration to regulators relying more on industry wide rather than detailed company specific information.

It is important, however, not to let any such debate impede immediate changes that are needed to address some obvious shortcomings within the current regulatory framework. Since most energy networks will continue to be regulated, and the nature of this regulation has an important effect on the industry, it is important that some immediate changes be made. Chapter 7 deals with the key changes required in relation to gas network issues. The following changes should be made in relation to electricity network regulation:

- Electricity distribution owners should have price, not revenue, caps. With the latter, demand can exceed forecasts and lead to prices too low to build and maintain the network.
- There should be bonuses and penalties for meeting defined service standards. These should help signal how the network is performing. With the current regulation there is an incentive only to cut costs, which can work to the detriment of the network.
- Uncertainty must be reduced. There needs to be greater clarity on how the gains from cost reductions will be shared over time, and greater certainty on how particular investments will be treated in the cost base.



## Facilitating embedded generation

The various constraints on embedded generation are well known and relate, for example, to the nature of the charges imposed by distributors and the risk of having the investment optimised out of the regulated asset base.

Various state regulators have sought to address these issues, but none has done so comprehensively. The formation of the NER would provide a good opportunity to do so, and on a national basis.

It is proposed that the newly formed NER establish a mandatory code of practice for arrangements between distribution companies and prospective embedded generators. This would cover, among other things, issues to do with information disclosure on network capacity, the timeliness of responses to queries, and a methodology for calculating the contribution of embedded generation to network reliability.

It is worth noting that the introduction of price caps rather than revenue caps, and improved certainty in the treatment of investment in the asset base, will also assist embedded generation.

## Deciding on the most appropriate electricity market structure

### The 'gross pool' versus 'net pool' debate

The debate over Australia's electricity pool structure has been vigorous. This issue has been the key concern, for example, of large energy users who are less affected by network charges.

After careful analysis, however, there seems little value in the debate about a 'gross' versus 'net' pool. In a gross pool all energy must be bid into a central point of dispatch, whereas with a net pool only the non-contracted amounts are bid in. If the financial contracts market was allowed to work as intended, Australia's gross pool would deliver similar outcomes to that of a net pool.

What is at issue, however, is whether Australia should stay with its current pool, or should move to an arrangement that introduces mechanisms that effectively lessen the importance of the pool, such as has recently occurred in the UK.

### Advantages of and concerns with Australia's gross pool system

A gross pool is, in concept, a very efficient market arrangement. It usually provides for generators dispatching according to the level of their marginal costs. It reduces entry barriers to generation, in that there are no wider obligations that favour portfolio or vertically integrated generators. Finally, it has the simplicity of an energy-only market, in that there is only one energy price setting mechanism.

Two main concerns are mentioned in relation to a gross pool.

The first relates to generator market power. With pool prices set by the highest bid unit required to meet demand, with generators able to rebid continually as they assess the level of demand and plant failure, and with pool prices set every five minutes, there can be too many periods when one or two generators know they can effectively set the price at a level they choose.

While generators may only be able to exercise their market power for short periods, when they do it can send power prices close to $10,000 per MWh and cause extreme pool price volatility. Even five hours a year at $10,000 can increase annual pool prices by over 15 per cent. This volatility is also factored into financial contract prices in terms of higher risk premiums, and it contributes to the difficulties that large users have in obtaining long-term energy contracts.

Some pool price volatility is, of course, appropriate as it sends signals for new investment. As the supply/demand balance tightens, for example, generators can increasingly exercise market power in more five minute intervals, thus gradually raising average price levels. This increase in average price levels may provide a smoother investment signal than in, say, less flexible markets where prices often need to reach many times new entrant levels to attract the necessary investment.

The second concern with the gross pool relates to supply capacity. Without an explicit mechanism to signal the need for new generation capacity to be built there is a concern that energy shortages could occur.

The evidence so far supports the first concern, but not the second. There have been many periods where generator market power has clearly been exercised, for example in NSW in May and June 2002. During this time there were not high levels of demand or plant failure, simply the financial incentive to exercise market power provided by the NSW Electricity Tariff Equalisation Fund mechanism.

In contrast, and indeed consistent with the findings on the first concern, considerable new generation has been built recently. South Australia and Queensland have seen new base load construction, for example, and Victoria has seen peaking capacity built. This was probably what was needed.



The key issue becomes how best to respond to these concerns.

## Possible responses to current gross pool concerns

In essence, it appears that the mechanisms used overseas to address these two concerns would, in the Australian context, create their own problems and also remove some of the important gains of the current system. Some examples illustrate the point.

The NETA system in the UK has introduced penalties such that participants are forced to heavily contract bilaterally and not rely on the pool. This system, however, sees generators carrying their own reserve, which increases system costs, and it favours large portfolio and vertically integrated generators, which raises the entry barriers to new entrants. This latter issue, in particular, is significant. While periods of generator market power are of concern, this concern is reduced if new entrants are able to enter the market easily. If a market is difficult to enter, the incumbents will extract price premiums whatever the system.

Some overseas systems impose capacity obligations, but these also impose costs. The PJM system in the USA, for example, requires retailers to reach agreements with generators to ensure sufficient capacity is available, with penalties applying if they do not. This requirement introduces the complexity of another element (that is, capacity payments) in energy prices, and it creates a separate market where capacity can be purchased to avoid the penalties that is in itself very volatile. The largest problem, however, is that it requires capacity to be constructed which, while matching the capacity obligations, does not necessarily meet the eventual needs of the market.

## Improving the operation of the gross pool

The preferred course is to seek to improve the operation of the current gross pool to keep its advantages and to lessen the potential for generator market power and excessive pool price volatility. While an examination of overseas markets confirms there is no perfect market design, the Australian design has important advantages that should be kept.

The market has already responded in beneficial ways to the likelihood of many periods of generator market power and pool price volatility. Retailers have seen the need to activate demand side management (DSM) measures, and they have built (or caused to be built) peaking capacity so that they can reduce the risks they face. These developments are welcome and to be encouraged.

The following proposals will improve the operation of the current market design, including the financial market. These are summarised in Exhibit 3.

Exhibit 3

## MARKET STRUCTURE ISSUES

**Key findings**

- Australia's gross pool is very similar to a net pool system.
- Many overseas markets have introduced measures that seek to lessen the influence of the pool, but they have imposed large costs in doing so.
- The best approach is to make the current market structure perform as intended.

**Proposed solutions**

- Make the current pool system perform as intended:
  - End ETEF and BPA (which can be a separate step to removing price controls).
  - Increase transmission, make FTRs available (see Chapter 4).
  - Introduce a demand side 'pay as bid' mechanism (see Chapter 6).
  - Further disaggregate the NSW generators.
  - Tighten the ACCC Merger Guidelines.

First, the arrangements under the Electricity Tariff Equalisation Fund (ETEF) in NSW, and under the Benchmark Pricing Agreement (BPA) in Queensland, should cease. These arrangements affect contracting, reduce liquidity in the financial market and increase pool price volatility (see Chapter 5).

Second, transmission capacity needs to be enhanced, and firm financial transmission rights (FTRs) made available, to enable a truly national market. This will facilitate contracts across state borders and so increase competition (see Chapter 4).

Third, the introduction of a 'pay as bid' demand reduction mechanism will encourage more market participation by energy users which, at times, will reduce market power (see Chapter 6).

Fourth, the NSW generators should be further disaggregated to provide more competition. NSW needs more competing generators, and more dispersed generator ownership. Waiting for further new entrants to achieve the same end will impose unnecessary costs on users and on the economy.

Finally, the ACCC needs to include in its Merger Guidelines specific criteria relating to mergers between generators. The ability of generators to exercise market power in a costly way at particular times should be explicitly recognised. More competition is needed than would be normally required in other industries to address this concern.

A range of other measures to address the concern of generator market power are explicitly rejected. There seem no practical rule changes that can assist. Bidding rule changes to address the 'economic withdrawal' of capacity, for example, will likely impose more costs than benefits. Rebidding allows the optimisation of dispatch, and may see pool prices go lower as often as it pushes them higher.

## The proposed market structure in Western Australia

In light of the above there are potentially some serious issues in relation to generation in Western Australia. The Electricity Reform Task Force in that state has recently reported and made recommendations which the Panel finds of concern.

The Task Force has recommended that in the South Western Interconnected System, Western Power be split into single companies responsible for, respectively, generation, network and retail. It is the first that is of concern.

The Panel believes that it would be an error to create an active energy market, but then establish a dominant generator. Its market power would lead to higher electricity prices unless fettered in some way. It would be preferable to disaggregate Western Power's generation into as many separate units as is practical.

# Solving electricity transmission problems

## Transmission is the largest NEM problem

The current state of transmission is one of the most significant problems facing the NEM. This was confirmed through the submissions received, and by observing the many current problems that were caused by inadequate transmission. Transmission is also one of the major problem areas faced by overseas electricity markets.

Inadequate transmission links, and the poor transmission arrangements, effectively 'regionalise' the NEM and remove most of the benefits that were envisaged with a national market. The NEM is largely five trading markets, not one. This is seen in the price separation that occurs between markets. This separation occurs sufficiently often to limit significant interstate financial contracting.

A regionalised NEM causes many problems:

- It means that generators within some states have excessive market power.
- It severely decreases liquidity in the financial market.
- It also means that when a state needs new generation it is more likely to look for a state-based, rather than NEM-wide, solution.

## The five main transmission problems

In relation to electricity transmission there are five highly visible problems.



First, transmission planning is currently fragmented. With so many entities involved the transmission system lacks a national focus. Key interconnectors are built, only to find that the within state linkages are inadequate to support them when they are most needed. This fragmentation would not be so important in a deep and integrated transmission system, but it is a major current problem for the NEM.

Second, it is not possible to buy 'firm' financial transmission rights. Interstate contract parties cannot ensure that their arrangement is valid in all circumstances. This lack of 'firmness' significantly impedes the development of the financial market which is necessary to support the current market design.

Third, the system for augmenting transmission investment is flawed, which sees inadequate links being built:

- There is confusion in having both regulated and unregulated interconnectors, and they have crowded each other out.
- In the case of regulated interconnectors, the currently applied regulatory 'benefits' test is inappropriate. This is because the test is not a commercial one as it ignores the market power that can be exercised when transmission lines bind.
- For unregulated interconnectors, the key problem is that they cannot address intra-regional constraints.

Fourth, the regulated interconnectors do not face any market incentives. Their behaviour often conflicts with that required, and increases market costs significantly.

Finally, the current regions are state-based and do not reflect the needs of the market. This means that significant transmission problems, such as the Tarong constraint in Queensland, are inside a region. Pool prices in that region, therefore, will not just reflect supply and demand across the region, but will on occasion only reflect supply and demand within a small part of the region. That is, pool prices will be higher than they need to be, as they will include a premium that simply reflects inadequate transmission.

An important problem is a lack of cost reflective network pricing which means that locational decisions are distorted. For example, it may make sense for energy intensive new load to locate within an area with surplus generation but the signals do not currently exist to drive this outcome. This issue cannot be addressed properly while the current regional boundaries remain.

This report addresses all of these issues. Exhibit 4 summarises the key problems, and the proposed solutions.

## Exhibit 4

## TRANSMISSION ISSUES

| Key findings | | Proposed solutions |
|---|---|---|
| – Transmission planning is fragmented. | ▶ | – Give NEMMCO responsibility for transmission planning. |
| – It is not possible to obtain 'firm' financial transmission rights to underpin interstate contracting. | ▶ | – Have NEMMCO auction 'firm' financial transmission rights (FTRs). |
| – The transmission augmentation process is flawed. | ▶ | – Use the price of FTRs as the key indicator of the need for transmission augmentation |
| – Regulated transmission entities face poor incentives that can conflict with the needs of the market. | ▶ | – Introduce explicit incentives that penalise/reward transmission entities according to the availability of lines during times of most pressing market need |
| – The current regions do not suit the needs of the NEM. | ▶ | – Allow the number and location of regions to be set by the needs of the NEM |

### Giving NEMMCO responsibility for transmission planning

It is proposed that NEMMCO be responsible for all transmission planning but that it delegate some areas of responsibility back to the transmission network service providers (TNSPs). These delegated areas should be the non 'backbone' (particularly the metropolitan) transmission network.

There are many benefits in NEMMCO playing this role:

- As it is also the system operator it can minimise congestion with both its roles as transmission planner and system operator (see discussion of FTRs below).

- It is best placed given its in-depth market knowledge, and its experience with auctioning the settlement residues.
- NEMMCO can bring a national approach, and no existing TNSP can do this.

A new body could have been formed to be the transmission planner, but this option was explicitly rejected. Such an option would break the beneficial link between system operator and transmission planning. In addition, a new entity might simply be an entity representing the current TNSPs, which would bring governance problems and many of the same difficulties we face today.

It is envisaged that the asset ownership role will stay with the current TNSPs. When the need for new regulated transmission is determined, the construction shall be put to tender, with the tender price forming part of the regulated asset base. NEMMCO should also nominate a binding period during which the new transmission cannot be optimised out of the asset base to provide the necessary certainty. The role of the current unregulated interconnectors should not be affected, but they will not be accorded any priority in future investment.

## Providing 'firm' financial transmission rights

It is proposed that each year NEMMCO shall auction firm financial transmission rights (FTRs). This auction will replace the current settlement residue auction. Settlement residues are the difference between the pool prices between two interconnected regions multiplied by the flow over the line during the relevant period. These residues are not firm because their value is zero if there is no flow over the interconnector.

NEMMCO shall, therefore, auction rights that give the owner the difference between the pool prices between two regions to the extent of the MW of capacity sold. NEMMCO will receive the auction proceeds and the settlement residues to meet its commitments.

NEMMCO will not face any financial risk in selling the firm FTRs. It can sell FTRs equal to less than the full interconnector capacity and use the surplus residues to meet its commitments. Any residual risk can be met by a transparent levy on the entire NEM, but this would be a last resort and should never be needed. Any surplus shall be rolled forward to underpin more FTRs in future years.

NEMMCO shall be given the dual objectives of avoiding any deficit, and maximising the FTRs it is able to offer.

It is envisaged that NEMMCO would sell FTRs each year, over five years, subject to the setting of a reserve price. Buyers will be able to trade them in a secondary market on an exchange facilitated by NEMMCO. The nature of the FTRs will reflect, and therefore support, the over-the-counter contracts currently available.

It can be seen with this proposal that NEMMCO is the obvious entity to be both the transmission planner, and the seller of FTRs. The current TNSPs can never be certain of gaining access to the settlement residues if they offered the FTRs because they can never be certain of the flows through their network. In addition, there are too many other factors beyond their control. Having the transmission planner and the market operator offer the FTRs most aligns responsibilities with accountabilities.

## Improving transmission augmentation

It is proposed that inter-regional transmission will be triggered by the traded price of the FTRs. The need for more transmission will be signalled when the traded price of an FTR between two regions is sustainably above the cost of transmission augmentation. That is, when the price of the FTR is greater than the annual equivalent of the net present value of the augmentation, divided by the extra energy flow over that augmentation.

It will be up to generators, or other solution providers such as unregulated interconnectors, to react before the cost of FTRs gets above the cost of new transmission. Just as with the current Statement of Opportunities, NEMMCO would disclose the comparison between the FTR cost and the cost of a range of augmentations, based in part on information provided by the TNSPs.



It is envisaged that the National Energy Regulator will approve all such augmentations. Note that the effect of this augmentation mechanism is to change the benefits test to take account of price (and not just cost) differentials that arise due to line congestion.

It is proposed that intra-regional transmission investment approvals will be determined by the regulator on application from NEMMCO. With no FTRs to guide the decision, the NER will have to continue to rely on a 'benefits' test. This test should, however, be changed to a commercial one, that takes into account the price rather than the cost differentials caused by congestion. While this may require some forward modelling to judge the extent of price difference, it should be influenced largely by past price differentials. Once they become large enough then, subject to allowance for any non-recurring factors, the need for additional transmission would be triggered.

The test for assessing reliability investment should be unchanged for both inter and intra-regional transmission investments. However, NEMMCO should be responsible for managing the process and submitting proposals to the NER for approval.

## Changing TNSP incentives

It is proposed that TNSPs receive bonuses and penalties according to the times when the line is operating below capacity *and* a significant price separation occurs. The addition or subtraction from the allowed rate of return would be set at a rate that provides a clear incentive for behaviour without being so large as to do serious financial harm if the penalty is invoked. It would be paid according to whether line operation was above or below a target level, set by the NER. This target level would account for the likelihood of circumstances beyond the TNSP's control. There will be imperfections in this scheme but it can be made to work, and it provides a useful incentive where none currently exists.

This arrangement should also be duplicated within regions. A number of mechanisms can be used to determine the sensitive time of line operation, from simply using peak periods, to looking at the number of times there is a within-state bid stack separation.

This mechanism would be in addition to the general service standards outlined in Chapter 2.

## Increasing the number of regions

The number of regions needs to be increased to account for where significant constraints exist and to provide improved locational signals for investment. This will require more regions particularly in NSW and Queensland, and it will mean that the shape of regions will cross state borders.

Additional regions will allow the FTRs to provide a market signal for the need for augmentation, rather than relying only on regulatory discretion. The existence of more regions in this context will reinforce the sense and reality of a national market.

Clear criteria have been provided in the body of the Report as to how the NEM regions should be determined in future.

### Full nodal pricing as the longer term goal

The long run solution to the various transmission inadequacies, particularly the issue of providing clear locational signals for investment, lies with full nodal pricing. This sees each node as a price point and allows new loads, new generators and new transmission providers to respond to the price disparities. The market rather than regulators will then be the driving force.

While this is the preferred option ultimately, for two reasons it is not recommended now:

- First, because the other steps proposed in this report (for example, FTRs) are a big enough first step.
- Second, because there needs to be significant additional transmission augmentation before taking this step.

## Driving financial market developments

### The fundamental importance of the financial market

The financial contracts market is integral to the gross pool market. Indeed, with all electricity required to be offered into the pool every five minutes and settled at half hourly intervals, the financial contract market is the only way for sellers or buyers of electricity to agree on the price to be paid for the product. It was always intended that the overwhelming majority of electricity would effectively be sold via the financial contract market, rather than the pool.

A liquid and deep financial contracts market allows market participants to continually adjust their positions. This reduces risk, delivers more efficient outcomes, and provides a smoother path to new circumstances. For example, a liquid and deep financial market would see lower, less volatile price rises to encourage new generation. An illiquid market would likely see prices rise higher and more sharply to achieve the same result.



### An illiquid market

The energy related financial contracts market is, unfortunately, quite illiquid. It is characterised by activity restricted to certain sections of the forward curve, there are very few intermediaries as participation is dominated by retailers and generators, there is limited pricing transparency, and there are often wide bid-offer spreads.

The key problems are a lack of a short term market to adjust positions as circumstances change, and an inability of large users in particular to gain long term price certainty. The lack of a short term market has led, for example, to the need for retailers to build or control the dispatch of peaking capacity to manage their risks.

## Causes of an illiquid market

These problems are caused by a number of factors.

First, some arrangements (e.g. ETEF in NSW) which have been set in place by governments which own both generators and retailers see huge liquidity taken from the market. Such arrangements are akin to vertical re-integration. They raise entry barriers to new generation and retail entrants and they cause pool price volatility.

Second, there is the lack of transmission capacity and a lack of firm financial transmission rights (FTRs). This makes it difficult to contract large capacity across state borders.

Third, is the existence of generator market power, which sees more price spikes than otherwise, and so increases contract risk. This discourages intermediaries.

Fourth, is serious concerns over regulatory uncertainty. Uncertain retail price caps and ad hoc responses to greenhouse issues are two prominent examples. This uncertainty makes it difficult for all parties to enter long term contracts.

Finally, there are strong credit quality concerns. It is difficult for market participants and intermediaries to become too exposed to some privately owned generators and retailers.

Exhibit 5

## FINANCIAL CONTRACT MARKET ISSUES

| Key findings | Proposed solutions |
|---|---|
| – Some government arrangements remove market liquidity. | – Abolish ETEF and BPA (which can be a separate step to removing price controls). |
| – Transmission problems prevent large interstate contracting. | – Improve transmission augmentation mechanism, introduce FTRs (see Chapter 4). |
| – Regulatory uncertainty limits long term contracts in particular. | – Disaggregate NSW generators, raise merger hurdles (see Chapter 3). |
| – Regulatory uncertainty limits long term contracts in particular. | – Ensure all Code changes take explicit account of financial market effects.<br>– Review in 1-2 years the need for NEMMCO to facilitate the introduction of a voluntary clearing service. |

### Creating a liquid financial contracts market

There are some crucial steps that must be taken to address this fundamental problem of a lack of liquidity. These are summarised in Exhibit 5, and are as follows:

- Abolish ETEF and the BPA. These are fundamental steps, and ones that can be taken quickly. They can be taken irrespective of whether price caps are removed.

- Second, address the need for transmission augmentation and the need for FTRs (see Chapter 4).
- Third, further disaggregate the NSW generators and have the ACCC consider any proposed generator mergers very carefully (see Chapter 3).
- Fourth, ensure all Code changes take explicit account of financial market effects.
- Finally, assess and if necessary address the credit risk issue.

## Taking account of effects on the financial market

There was considerable comment in submissions about the links between the physical and the financial electricity markets. Many felt these links were not widely appreciated by policy makers, particularly in the Code change process. One example was the move to a $10,000 MWh level of VoLL, where it was stated that the credit implications for retailers and generators were not well understood. Another example was the consideration of changes to the transmission benefits test, which did not seem to account for the effects of transmission constraints on 'regionalising' the NEM in terms of the difficulty created in contracting across regions.

It is proposed that explicit account should be taken of the effects of any Code changes on the financial market. This would in itself require a Code change to make such consideration mandatory in all Code change processes. In particular, future reviews of the appropriate level of VoLL should take full account of the impact on contract premiums, contract availability and access to prudential cover.

## Addressing the credit issue

Credit risk is a problem because in some regions it limits the number of counterparties that can be dealt with at any one time.

The Review considered having NEMMCO clear financial contracts as well as the spot market. Retailers currently have to lodge around $1.6 billion in bank guarantees to back their pool settlements. These guarantees take no account of any financial contracts that significantly reduce their pool exposure. They are, therefore, larger than are necessary, and then in addition the retailers must allow for the capital to back the risk associated with their financial contracts.

The Review, however, decided against such a recommendation. The proposal raised difficulties, and there was a danger that it could damage rather than assist financial market development.

It is also possible that as the NEM becomes more 'national' that some companies may themselves see the need to address this issue to be competitive in the wholesale market.

It is proposed that, in 1-2 years, NEMMCO review the need to take an active role to facilitate the introduction of a voluntary clearing service. This period will allow judgements to be made as to whether recent initiatives by the Sydney Futures Exchange and the changes discussed above will address the issue.

## Increasing demand side participation

### Current demand side measures

A range of energy efficiency, building code and other demand reduction measures have been introduced or are being contemplated.

There are, however, few effective measures for stimulating the demand side to influence pool prices, or the need for generation, in the NEM. This is where the immediate policy focus needs to be.

There is some demand side management (DSM) occurring currently. It is arranged through retailers who enter agreements with users to curtail their load when pool prices reach high levels.

### Some causes of low demand side involvement in the NEM

The low demand side involvement is attributable to three factors.

First, in the short term the demand for electricity is inelastic. There are natural limits to the DSM capability likely to be available.



Second, those with the most 'peaky' demand, residential consumers, face no price signals regarding their use of electricity. These consumers account for around half the load in many markets.

Third, those offering to curtail demand cannot gain the full value of what they bring to the NEM. This is due to the current market mechanism.

It is in relation to the second and third issues where action is needed. Exhibit 6 summarises the key findings and proposed solutions.

### Exhibit 6

## DEMAND SIDE PARTICIPATION ISSUES

| Key findings | Proposed solutions |
| --- | --- |
| – Low demand side involvement in the NEM due to: | |
| – Residential consumers do not face price signals. | – Mandate roll–out of interval meters for all NEM households as soon as possible.<br>– Remove retail price caps and introduce FRC into all markets as soon as practicable, but in any event within the next three years. |
| – The demand side cannot gain the full value of what it brings to the market. | – Introduce 'pay–as–bid' mechanism into NEMMCO dispatch and market systems for demand reduction. |





### Sending price signals to residential users

Some important steps are needed to send effective electricity price signals to residential users. These are an accelerated replacement roll-out of interval meters, the introduction of full retail competition (FRC) in all markets and the removal of retail price caps as soon as practicable, but in any event within the next three years.

It is proposed that there be an accelerated roll-out of interval meters over the next 5-10 years. These meters should meet minimum standards (consumers can pay for higher standards if they want them) and the cost should be included in the regulated distribution use of system (DUOS) cost base. This proposal is based on detailed cost benefit analysis that is included in Chapter 6 of the Report.

Distribution companies must be obliged to pass the load use information to anyone chosen by the customer, such as a competing retailer bidding for their business, and retailers should explicitly be allowed to price by time of day and to move away from deemed load profiling.

Interval meters can play a very useful role even while retail price caps exist, but this is not optimum. It is possible, however, to set the price caps by time of day and season.

It is preferable, of course, to allow the full range of price signals to be sent as would occur under FRC and with price caps removed. The Panel recognises, however, the political sensitivity of such moves.

The Panel accepts that jurisdictions will want to pick an appropriate time to introduce FRC and remove all price caps. In the immediate short term these are politically sensitive issues. Nonetheless, the Panel sees their removal as inevitable.

Until their removal, jurisdictions should adopt an approach to setting the price caps based on the bilaterally negotiated contract rates secured by each affected retailer and the other costs reasonably associated with retailing electricity.

This approach makes the existing arrangements that protect incumbent retailers from price risks (e.g. ETEF and BPA) redundant. Retailers will not be exposed to unmanageable risks under this approach as the price cap determination has proper regard to the bilateral contract position of each retailer. ETEF and BPA should therefore be removed as soon as possible.

## Introducing a ‘pay-as-bid’ demand side mechanism

The current Code provisions for demand side participation are unworkable and recently proposed Code changes are unlikely to change this. A new approach is needed.

The key problem is that the demand side cannot capture the value it brings to the market.

Currently, consumers almost always reach arrangements with retailers to curtail their load and so must share the benefits with them. More important, if the load curtailment deflates the pool price consumers then get rewarded for the curtailment at this lower price, not the price the market would have been at without that curtailment.

It is proposed that NEMMCO should introduce a new demand reduction module into its market systems. It should activate any demand reduction bid just as it does with generation bids, but these demand bids should be 'paid-as-bid', and not receive the system marginal price. This brings equality of treatment with generators, who know when they bid that, if their bid is called upon, they will generally receive their bid or more than their bid, but not less. To meet the 'pay-as-bid' requirement an appropriate amount would be added to pool prices. Even with this addition, however, pool prices should be lower than they would have been without accepting the demand reduction bid.

## Promoting a more competitive gas market

### Gas reform success but still an emerging market

The recent gas reforms have been effective. By facilitating access to pipelines, and removing the previous restrictions on interstate trade in gas, new pipelines have and are being built, new fields have been discovered, and some initial upstream gas competition has been introduced.

Australia's gas market, however, is still immature. It remains an emerging market. There is insufficient upstream competition, and it is characterised by long term bilateral contracts with virtually no ability to adjust positions as circumstances change.

There is clear benefit in facilitating the move to a more mature gas commodity market with many players and an active short term market. This will promote the more widespread use of gas, and more efficiency, through the opportunity for participants to involve themselves in the market in a wider variety of ways.

### Barriers to moving to an active gas commodity market

There are barriers to moving to an active gas commodity market. Four in particular have been highlighted in this Review.

The first is a lack of upstream gas competition. Until recently each state market effectively had one gas supplier and one gas buyer, through long term bilateral supply contracts. While downstream competition has been introduced, upstream competition is less common. This reflects the limited number of basins, the fact that suppliers from each basin in eastern Australia have traditionally marketed jointly, and insufficient pipeline interconnection between markets. There are strong fears that this current lack of upstream competition will lead to much higher gas prices once current contracts expire over the next few years.

The second is uncertainty over the regulatory treatment of new pipelines. On the one hand, project proponents are currently unable to gain a binding decision on whether a new pipeline will be covered by the Gas Code during the life of the project. On the other hand, there is uncertainty as to how regulators will interpret critical Gas Code components such as future access pricing if the project is covered. This all adds to risk which, at the margin, could reduce the number of pipelines built.

The third is that there is currently no effective mechanism to ensure that significant pipelines not covered by the Gas Code are operated in a way that will facilitate effective competition by, for example, having appropriate ring fencing and offering tradeable capacity.

The fourth is the relatively small size of the Australian gas market compared with those overseas where commodity markets in gas developed spontaneously.

## Proposals to create an active gas commodity market

There are a range of proposals that will help create an active gas commodity market. Exhibit 7 summarises these.

One proposal is for exploration licence issuers to have the 'promotion of competition' as one of their criteria for assessing applications for acreage. In essence, Australia needs a wider range of upstream producers, rather than having virtually all fields dominated by a few companies.

Even more important is the need to address joint marketing. Each East Coast producing area has many producers, but they market jointly. While it may have been appropriate to exempt such marketing from the Trade Practices Act to encourage the original field development, this may no longer be the case.



It is proposed that the Trade Practices Act be strengthened through legislative change to remove the ability of states to exempt joint marketing from the anti-competitive provisions of the Trade Practices Act, and through compulsory notification of arrangements, to allow closer regulatory examination of new proposals for joint marketing, and of existing arrangements as the current contracts expire. The objective should be to have producers separately market as much as possible, subject particularly to practical considerations.

To encourage basin-on-basin competition it is proposed that additional certainty be provided to new pipeline developments. First, the Gas Code should be changed to allow for up front binding rulings on coverage.

## Exhibit 7

# GAS INDUSTRY ISSUES

| Key findings | Proposed solutions |
|---|---|
| – There is insufficient upstream gas competition on the East Coast to promote a healthy market. | – The separate marketing of gas should be actively facilitated as current contracts expire.<br>– Governments should give more consideration to promoting competition in gas markets when awarding exploration leases. |
| – Too much regulatory uncertainty exists around new pipeline development. | – Allow project developers to seek an up-front binding ruling on coverage, and the choice of either an up-front and longer term binding ruling on the regulatory conditions that will apply or, for a new transmission pipeline, a 15 year economic regulation holiday. |
| – There is a lack of tradeable capacity on some pipelines, and other market supporting mechanisms. | – Introduce tradeable capacity and other mechanisms on new and unregulated pipelines. |
| – Both industry and users have concerns with the Gas Code. | – Review the Gas Code to judge its effectiveness from both a gas industry and user perspective. |
| – Access by independent producers to upstream facilities will become more important. | – Review the industry's principles for access to upstream facilities. |

Second, it is proposed that project developers be given a choice, to be exercised before financial closure. For all new pipelines, project developers could approach the regulator to seek a longer term binding ruling on the regulatory conditions that will apply. Alternatively, for new transmission pipelines, project developers could opt for a 15 year economic regulation free period. The 15 year economic regulation free 'holiday' would be automatic if the developer opted for this route. Clearly, the availability of the 15 year economic regulation free 'holiday' will put pressure on the regulator for appropriate binding rulings. The 'holiday' will only be available to pipelines with sufficient vertical separation of control so that the pipeline owners do not have an incentive to reduce competition in upstream or downstream markets.

There is considerable logic behind the 15 year economic regulation free 'holiday' for new transmission pipelines. When transmission pipelines are built they are on the basis of agreements between upstream and downstream 'consenting adults'. There is no issue of pipeline market power because without both the supplier and the user the pipeline will not be built. Fifteen years balances the need for certainty with the need eventually to give potential new pipeline users some rights of regulatory assistance in gaining later access.

Two changes are proposed to move to tradeable capacity on pipelines. First, if the 15 year economic regulation free 'holiday' is chosen then the relevant pipeline would be required to allow users to trade their capacity, and it must post its prices for any remaining capacity.

Second, it is proposed that an enforceable minimum requirement be developed to ensure that pipelines not covered by the Gas Code introduce a range of market supporting mechanisms such as tradeable capacity, ring fencing and the requirement to post prices.

The proposed review of the Gas Code should proceed to consider the experience of regulatory outcomes against which it could test both industry and end user concerns. The review should ensure that the tentative steps being taken towards a more competitive and dynamic industry are encouraged and the momentum and direction of reform is maintained.

Governments should adhere to their earlier agreement that a review be conducted after the industry's upstream facility access principles have been in operation for two years. The review should seek to establish whether the operation of the principles has been effective in facilitating commercially negotiated third party access to upstream gas facilities and in achieving greater competition in the upstream gas sector. It should also examine whether anything more needs to be done to ensure that separate marketing of natural gas will not be hindered by a lack of reasonable access to upstream facilities.

The above proposals should, over time, greatly assist Australia's move to having an active gas commodity market.

# Directing policies to abate greenhouse gas emissions

## Importance of the greenhouse issue

The greenhouse issue is extremely important for the energy sector. Evidence of this came from the many references to it in the submissions received by the Review and from the constant references to this issue by representatives from the electricity and gas industries.

There is a vibrant public policy debate on greenhouse issues. The Review was *not* invited to enter that debate, but rather to comment on the least cost ways to abate greenhouse emissions.

Greenhouse abatement measures have an immediate economic cost to the community. It is simply not possible to mandate less carbon emissions without having this effect. This emphasises the importance of using the least cost measures to achieve the community's environmental objectives.

## Major problems with the current greenhouse measures

There are some major problems with the current greenhouse measures that impose significant and unnecessary costs on the Australian community.

First, many of the schemes are very poorly targeted in that they favour particular technologies or solutions rather than focus on greenhouse abatement. For example, the Commonwealth's Mandatory Renewable Energy Target (MRET) scheme focuses exclusively on renewable energy, not carbon abatement. The Queensland Gas Electricity Certificates (GECs), of course, favour gas. The NSW Benchmarking scheme is a less distorting scheme to these others as it is more broadly based, but remains unsatisfactory in that it only focuses on the electricity sector, and only recognises particular measures.

The rationale for a scheme which focuses only on renewable rather than on greenhouse benefits is the perception of the need for the conservation of non-renewable resources. This is, however, not an issue for Australia. Consequently, any arbitrary diversion of investment away from more efficient carbon reducing options and towards renewables will burden the economy with unnecessary costs.

Clearly, the solutions that represent least cost to the community will be those focussed on greenhouse abatement, and that apply to the broadest part of the economy.

Equally clearly, the solutions that represent least cost will be those that can choose between all technologies. Currently there is considerable focus on biomass, ceramic fuel cells, coal seam methane gas, 'hot rocks' geothermal energy, wind and solar power, and clean coal technology, to name a few. Some of these technologies are already proven, but will more than double the cost of energy. Some have reliability problems as they are dependent on the wind blowing or the sun shining. Governments should not, however, be picking technologies, as they are doing now. They will invariably get the choice wrong, to the cost of the wider community.

Second, the Commonwealth and the states/territories have competing greenhouse schemes. This has created the potential for gaming and the distortion of economic behaviour. In some jurisdictions for some measures, companies can claim under both Commonwealth and jurisdictional schemes, whereas in others this is disallowed. Some measures are seen as greenhouse friendly in one state, but not in another.

The third problem is the cost imposed on the energy industry because of the uncertainty. Industry can see the public concern over this issue and they recognise that the current responses are not the final ones. Industry responds to this uncertainty by factoring in higher project discount rates which are then reflected in a requirement for higher wholesale electricity prices than should be necessary to justify new investment.

This cost can also be seen in the lack of longer term financial contracts. In essence there is too much uncertainty over future greenhouse responses to allow parties to fix the cost of energy over any more than, say, five years. This is not satisfactory for large users.

These pressing problems require solutions. Exhibit 8 summarises these.



## Addressing greenhouse emissions in the most effective way

The key way to address these problems is to introduce an economy wide emissions trading system. It can apply to all sectors, and it allows the full range of market responses to deliver a given level of emissions reduction at the lowest cost to the economy.

There is clear benefit in abolishing a range of current schemes and substituting emissions trading as soon as possible to achieve the same effect. Of course, investments entered into under the schemes to be abolished would need to have their current effective subsidy protected into the future.

## Exhibit 8

# GREENHOUSE ISSUES

**Key findings**

- The major greenhouse measures are poorly targeted, and they seek to pick technology 'winners'.
- A wide variety of new technologies are under active consideration.
- The Commonwealth and the states have each introduced schemes that create gaming and distortion.
- The energy industry faces large costs because of the greenhouse uncertainty.

**Proposed solutions**

- Introduce an economy wide emissions trading system.
- Once an announcement has been made on an agreement to implement an emissions trading system the poorly targeted schemes i.e. MRET, GEC, GES, GGAP-stationary energy projects and NSW benchmarking, are to cease operating.
- Energy intensive users in the traded goods sector are to be excluded from the emissions trading system until Australia's international competitors introduce similar schemes.

There are, of course, a number of important issues to address before emissions trading can be implemented. These go to the best way to issue the initial permits, issues of transition and the extent of emissions to be initially included. Given the work already done it need only take up to a year to do the analysis and consultation necessary to deal with these issues and to design the system. A further 1-2 years should be allowed to both secure the necessary legislation and to develop the monitoring and reporting systems that will be needed. An economy wide emissions trading scheme should be operating well within three years of the initial announcement.

Given Australia's strong reliance on energy intensive industries, governments have made it clear that they will not place Australia at a large competitive disadvantage. It is proposed therefore, that until Australia's international competitors introduce similar schemes energy intensive users in the traded goods sector are to be excluded from the emissions trading system. This exemption should, however, be subject to any exempted business being able to demonstrate that it meets world's best practice in relation to energy use. This will ensure that the exemption is not contributing to higher world emissions overall.

Proposals referred to elsewhere in the Report will have a beneficial effect on greenhouse emissions.

## Identifying regional issues

Some regions will benefit significantly from particular proposals in this Report. The main recommendations of relevance are shown in Exhibit 9.

### Exhibit 9

### REGIONAL ISSUES

| Key findings | | Proposed solutions |
| --- | --- | --- |
| – Poor locational pricing signals disadvantage some regions significantly. | ▶ | – Increase the number of NEM regions, and eventually move to full nodal pricing (see Chapter 4). |
| – Some regions can benefit from increased renewable energy generation and sequestration. | ▶ | – Introduce emissions trading (see Chapter 8). |
| – Additional gas pipeline development can benefit parts of Australia. | ▶ | – Promote the wider penetration of gas (see Chapter 7). |

The proposal that will have most effect is to increase the number of NEM regions, and eventually move to full nodal pricing. This will allow those regional areas well endowed with energy resources to benefit in ways that are currently denied them.

Electricity generation from alternative energy sources will often occur in remote regions. The introduction of an emissions trading scheme to replace a range of other current greenhouse schemes will benefit regions which have the ability to assist the abatement of greenhouse gases in least cost ways.

Finally, the promotion of a wider penetration of gas by reducing the current regulatory uncertainty and the promotion of greater upstream competition can assist regions. This is because new pipelines have often brought increased economic development to the regions they pass through.

## Counting the benefits

The Panel commissioned ACIL Tasman to estimate the impacts on the Australian economy of the recommendations contained in the Draft Report. ACIL Tasman modelled the impacts of the proposed reforms for the period 2005 to 2010, assuming the full implementation of all measures by 2005. This short benefit period (5 years) was chosen because the necessary assumptions become less accurate over time. This means that the estimated benefits of the recommendations are conservative.

The projected impact of the recommendations is to increase real Australian Gross Domestic Product (GDP) by just under $2 billion per annum at 2010. On a 5 year net present value basis, the increase in GDP is worth approximately $7 billion. The estimated benefits are broken down by area in the table below. In addition, the estimated benefits from implementing the recommendations on greenhouse gas emission reduction are approximately $1.3 billion.

**Table 1 Projected impact of the proposed reforms on economic growth at 2010**[1]

| | Australian GDP *a* % | Australian GDP *b* $m | Aggregate GSP of NEM States *c* % | Net present value of gains *d* $m |
|---|---|---|---|---|
| (i) Productivity growth from proposed reforms | 0.12 | 477 | 0.14 | 1,767 |
| (ii) Electricity transmission reform | 0.08 | 303 | 0.09 | 1,112 |
| (iii) Demand side management initiatives | 0.16 | 630 | 0.18 | 2,310 |
| (iv) Regulatory certainty | 0.03 | 109 | 0.03 | 673 |
| (v) More financial certainty | 0.03 | 126 | 0.04 | 779 |
| (vi) Gas market reform | 0.08 | 330 | 0.09 | 296 |
| **Total** *e* | **0.49** | **1,975** | **0.56** | **6,936** |
| (vii) Benefits from the climate change recommendation | 0.09 | 391 | 0.09 | 1,267 |

*a Percentage deviation from the reference case*

*b Present value of the change in GDP at 2010 using a 7 per cent discount rate, presented in 2002 dollars*

*c Percentage deviation from the reference case for New South Wales, Victoria, Queensland, South Australia and Tasmania*

*d Discounted using a 7 per cent rate over the period 2002 to 2010, presented in 2002 dollars*

*e Totals may not add due to rounding.*





[1] ACIL Tasman (2002), p.2

**Australia has made a good start to its energy reforms, but has now reached an important decision point.**

**The Panel sees a future where Australia's energy market is characterised by strong national competition, clear and well accepted governance and regulation, supply coming from least cost sources and with the ability of all players to optimise their positions regularly in a deep and liquid market.**

**Much more must now be done to reach this future position and, indeed, to avoid losing the gains already made. We should now choose to move to a truly national and efficient energy market. This will bring significant benefits to the energy sector and to the environment, and it will provide the foundation for the strong economic growth necessary to underpin Australia's broader objectives.**

# LIST OF RECOMMENDATIONS

## Governance and regulatory arrangements (Chapter 2)

2.1 A statutory National Energy Regulator (NER) should be established under a legislative approach agreed by COAG to be the independent energy regulator in all jurisdictions, interconnected or otherwise, and to encompass the energy-related regulatory roles of the ACCC, NECA and state and territory regulators.

2.2 The three Commissioners of the NER are to be appointed by the Ministerial Council on Energy (MCE).

2.3 The NER is to have the following principal roles:

(a) approval of changes under the National Electricity Code, the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code), and other energy market codes

(b) decisions on pipeline coverage under the Gas Code

(c) administration of electricity and natural gas transmission access regulation currently dealt with by the ACCC and the Western Australian regulator

(d) administration of electricity and gas distribution access regulation

(e) provision of other licensing and approvals currently provided by jurisdictional regulators including licences to operate as a retailer or generator, and utility marketing and consumer protection codes

(f) responsibility for setting technical standards for the planning, design and operation of critical elements of the power system which are material to the security of the system including the functions of the present NEM Reliability Panel

(g) NEM monitoring and assessment of compliance with the National Electricity Code

(h) briefing and formal reporting to the MCE.

2.4 The role of NEMMCO will encompass:

(a) responsibility for NEM development

(b) facilitation of the National Electricity Code change process.

2.5 NEMMCO to have the following ownership arrangement:

(a) NEMMCO to remain a government-owned company

(b) the Commonwealth to be a member of NEMMCO

(c) Western Australia and the Northern Territory to be invited to consider becoming members of NEMMCO.

2.6 The National Electricity Code and Gas Code change processes to be changed to:

(a) provide greater end user and industry involvement in and ownership of the Code change processes

(b) provide no provision for regulator-initiated Code changes

(c) provide for the acceptance or rejection, but not variation, of all Code changes by the NER

(d) eliminate successive consultation processes, with the NER conducting a merits-based review of proposed changes if the required consultation processes have been observed or to send the proposal back to the Code change proponent otherwise.



2.7 A statutory end user and industry based National Electricity Code Change Committee will be created to progress amendments to the National Electricity Code with the following features:

(a) the MCE to appoint the members following end user and industry consultation

(b) creation of ad hoc end user and industry committees to advance specific Code changes

(c) NEMMCO to provide analytical and administrative support for the new structure

(d) NEMMCO to have no veto power over Committee recommendations other than a power to refer back recommendations if consultation is assessed as inadequate but to advise the NER of its position on each proposed change.

2.8 A statutory Gas Advisory and Code Change Committee (GACCC) will be created to subsume the operation of the National Gas Pipelines Advisory Committee and the Gas Policy Forum, with the following functions:

(a) proposing and progressing amendments to the Gas Code

(b) providing strategic briefing to the MCE on natural gas market issues.

2.9 The members of the GACCC are:

(a) to be appointed on merit by the MCE

(b) not to exceed six in number.

2.10 The GACCC is to be supported by a full-time Commonwealth/state/territory funded and staffed secretariat.

2.11 Decisions by the NER and NEMMCO are to be reviewable by the Australian Competition Tribunal.

2.12 The MCE should be the single ministerial forum for all gas and electricity market issues in Australia including the National Electricity Market (NEM).

2.13 The MCE, in relation to its energy policy oversight role, should:

(a) provide policy direction by way of developing and facilitating amendment of electricity and natural gas legislation

(b) have no power of direction over NEMMCO or the NER and no role in Code change processes.

2.14 The following changes should be made to electricity network regulation:

(a) provide certainty on how the gains from cost reductions will be shared over time and on how particular investments will be treated in the regulated asset base

(b) electricity distribution to be price, not revenue capped

(c) institute a nationally consistent bonuses and penalties regime for meeting defined network service provider service standards.

2.15 The NER should establish a mandatory code of practice governing arrangements between distribution companies and prospective embedded generators.

# Electricity market mechanism and structure (Chapter 3)

3.1 The New South Wales Government should further disaggregate its generation assets.

3.2 The Western Australian Government should disaggregate Western Power's existing generation portfolio in the South West Interconnected System into as many separate units as is practical.

3.3 Once appropriate generation structures are in place, governments that currently own generation assets should pursue a program of divestment, with a view to completely exiting the market, or at least reducing ownership to a single generator.

3.4 Governments should pursue initiatives to address transmission problems (see Chapter 4).

3.5 The NSW Government should abolish the Electricity Tariff Equalisation Fund and the Queensland Government should abolish the Benchmark Pricing Agreement as soon as possible and irrespective of whether retail price caps are removed.

3.6 The Australian Competition and Consumer Commission should include specific criteria in its Merger Guidelines that explicitly address the potential for generators to exercise market power.

# Electricity transmission (Chapter 4)



## NEMMCO be given responsibility for transmission planning

4.1 Establish an independent, NEM-wide planning function within the National Electricity Market Management Company (NEMMCO).

(a) NEMMCO's responsibilities would extend to planning for the inter-regional and intra-regional transmission network. The scope of its responsibilities would be consistent with its system operation responsibilities under the National Electricity Code.

(b) Particular planning responsibilities would include:

   i. providing independent and accurate information to inform augmentation processes

   ii. highlighting potential augmentation opportunities, similar to the function it currently performs through the annual Statement of Opportunities

   iii. managing a regulated transmission augmentation process through a competitive tendering process.

(c) NEMMCO would be able to initiate a competitive tender process for regulated transmission augmentation to relieve network constraints identified through the transmission planning process.

### NEMMCO to auction firm financial transmission rights

4.2 NEMMCO is to assume the responsibility for offering and underwriting firm financial transmission rights (FTRs) for regulated NEM interconnectors.

(a) NEMMCO would auction firm FTRs each year, covering a period five years in advance:

   i. NEMMCO FTRs would apply to existing regulated interconnects.

   ii. The firm FTRs would expose NEMMCO to the spot price divergence between interconnected regions.

   iii. When spot prices diverge, NEMMCO would be liable to pay FTR holders the difference between spot prices multiplied by the volume of FTRs sold.

   iv. NEMMCO would retain the settlement residues associated with regulated interconnects and auction proceeds to fund firm FTRs.

   v. NEMMCO would be able to set a reserve price for FTRs.

   vi. NEMMCO would be able to determine the volume of FTRs to sell, subject to feasibility requirements.

(b) NEMMCO to minimise the cost to the market of providing FTRs:

   i. NEMMCO is to be given the dual objectives of avoiding any deficit and maximising the FTRs it is able to offer.

ii. Any residual costs would be covered by market participants through a separate and transparent levy as a last resort.

4.3 NEMMCO is to facilitate the operation of a secondary market for the transparent trading of FTRs.

### Using the price of FTRs to signal new investment in inter-regional transmission

4.4 Create a transparent and market based investment trigger for interconnect augmentations based on the cost of FTRs.

(a) The regulated interconnect investment trigger would compare the annualised unit cost of new investment with the price of firm FTRs.

(b) The trigger methodology would be approved by the National Energy Regulator (NER) and would require a sustained signal before activating a regulated response.

(c) When the unit price of firm FTRs exceeds the unit value of a potential regulated transmission augmentation, NEMMCO would pursue new regulated network investment through a competitive tender process subject to the approval of the NER.

(d) The successful tender price for new regulated investment or augmentation, resulting from the NEMMCO competitive tender process, would establish the asset value for regulatory purposes.

(e) NEMMCO would determine the potential regulated transmission augmentation possibilities and related costs and publish this information well in advance of the triggered need, providing regular updates to give the market opportunity to react prior to initiating a regulated transmission response.



(f) The NER would approve regulated transmission interconnect augmentations or investments on the basis of the FTR investment trigger information published by NEMMCO.

### Using a 'commercial' regulated benefits test for intra-regional transmission augmentation

4.5 The NER should assess and approve new regulated intra-regional transmission proposals on application from NEMMCO, subject to a 'commercial' benefits test that takes account of spot price separation between trading regions as well as efficiency implications.

### Transmission reliability investments

4.6 The test for assessing reliability investment should remain unchanged for both inter and intra-regional transmission investments.

### Incentives and rewards for regulated TNSPs

4.7 Transmission network service providers (TNSPs) should receive bonuses and penalties according to the times when their inter-regional transmission lines are operating below capacity and a significant price separation occurs.

(a) The bonuses and penalties would be set as an addition or subtraction from the allowed rate of return at a rate that provides a clear incentive for behaviour without being so large as to inflict serious financial harm if the penalty is invoked.

(b) The bonuses and penalties would be paid according to whether line operation is above or below a target level which accounts for the likelihood of circumstances beyond the TNSP's control.

4.8 The arrangement described for inter-regional transmission lines should be replicated for transmission lines within a region as far as practicable.

### Allow the number and location of regions to be set by the needs of the NEM

4.9 An increased number of regions in the NEM should be implemented.

(a) Objectives and criteria for increasing the number of regions should achieve the following outcomes:

i. Maximise regional boundary stability over the medium to long term (7 to 10 years).

ii. Regional boundaries should be located at natural 'pinch points' in the network. Compromise boundaries that attempt to encompass multiple network limits should be avoided in favour of multiple boundaries.

iii. Regional boundaries should minimise the risk of participants being required to trade across significant intra-regional constraints.

4.10 Implement full nodal pricing in 7 to 10 years.

## Electricity financial market development (Chapter 5)

5.1 The NSW Electricity Tariff Equalisation Fund and the Queensland Benchmark Pricing Agreement should be abolished as soon as possible and irrespective of whether retail price caps are removed.

5.2 The National Electricity Code should reflect the principle that the impact of any changes to the Code must assess and take into account the likely impact on financial market activity.

5.3 Future reviews of the level of VoLL should take full account of the impact on contract premiums, contract availability and access to prudential cover.

5.4 NEMMCO should review in 1 to 2 years the need to take an active role to facilitate the introduction of a voluntary clearing service for bilateral contracts.

## Demand side participation and full retail contestability in electricity (Chapter 6)

6.1 The NEM mechanism should be amended to include a demand reduction bidding option that would enable load reduction to be bid into the NEM for dispatch and payment in competition with generation offered into the market to meet demand. This would involve:

(a) users (including retailers and aggregators) bidding price and volume into the NEM to *reduce* load on a similar basis to generators

(b) the NEM systems 'stacking' the demand reduction bids and the generator offers

(c) the price of the demand bids being compared with the price of the generation offers, and the best combination selected to meet the demand

(d) accepted demand reduction bids being paid for their dispatch on an 'as bid' basis while generators would continue to be paid according to the system marginal price.

6.2 Installation of interval meters should be mandated for all consumers with the installation program to be achieved over the next 5 to 10 years.

6.3 Full retail contestability should be adopted and implemented by all jurisdictions including the removal of price capping arrangements and other measures that impede the entry of new retail competitors as soon as practicable, but in any event within the next three years.

# Increasing the wider penetration of gas (Chapter 7)

## Pipeline regulation

7.1 The Gas Code should be amended to enable proponents of new pipelines to seek a binding ruling from the National Energy Regulator on coverage under the Code prior to construction. In making an application for a binding ruling, companies can propose the period of the binding ruling — with the obligation upon the applicant to provide arguments in support of the period sought. Any binding ruling granted would not be subject to potential revocation due to material changes in circumstances for the period granted unless the regulator relied on information that is proved to be false or intentionally misleading. A decision to grant a binding ruling of no coverage for a defined period should be subject to merits and judicial appeal.

7.2 If a proposed transmission pipeline is likely to be covered, the proponent can commit to a 15 year economic regulation free period. To qualify, the pipeline company must commit to providing access, publishing tariffs, making all capacity it contracts tradeable and have sufficient vertical separation of ownership (i.e. no upstream or downstream firm has sufficient ownership to exert control over the pipeline in a way that might lessen competition in upstream or downstream markets). At the end of the 15 year period, an assessment will be made as to whether the pipeline company is exercising market power. If it is, the pipeline will be deemed to be covered. If it is not, the pipeline will not be covered.

7.3 Alternatively, the proponent of a prospective pipeline can enter into an up-front agreement with the National Energy Regulator prior to construction, locking in a number of key regulatory parameters for extended periods of time. This can provide regulatory certainty for the period agreed with the NER.

7.4 The proposed review of the Gas Code should proceed, to consider experience of regulatory outcomes against which it could test both industry and user concerns. The review should ensure that the tentative steps being taken towards a more competitive and dynamic industry are encouraged and the momentum and direction of reform is maintained.

7.5 An enforceable minimum requirement be developed to ensure that pipelines not covered by the Gas Code introduce a range of market supporting mechanisms such as tradeable capacity, ring fencing and the requirement to post prices.

### Encourage greater competition through separate marketing

7.6 Mandatory notification by joint venturers to the Australian Competition and Consumer Commission of all future joint marketing arrangements.

7.7 The ACCC conduct case-by-case assessments of the feasibility of separate marketing and any authorisation granted must contain a review date.

7.8 The Trade Practices Act be amended to preclude jurisdictions from exempting the application of section 45 to joint marketing of natural gas.

7.9 Existing state exemptions and Commonwealth authorisations continue to apply to the existing contracts but all new contracts, or renewals, be subject to the nationally consistent regime as currently applied through the Trade Practices Act section 45 test of substantially lessening competition and the section 90 authorisation public benefit test.

### Include criteria to promote competition in acreage management regimes

7.10 Acreage management regimes in relevant jurisdictions be amended to include 'promotion of competition' as one of the criteria for awarding exploration acreage.

### Review the industry's principles for access to upstream facilities

7.11 Governments adhere to their earlier agreement that a review be conducted after the industry's upstream facility access principles have been in operation for two years. The review should seek to establish whether the operation of the principles have been effective in facilitating commercially negotiated third party access to upstream gas facilities and in achieving greater competition in the upstream gas sector. It should also examine whether anything more needs to be done to ensure that separate marketing of natural gas will not be hindered by a lack of reasonable access to upstream facilities.

# Options to reduce greenhouse gas emissions (Chapter 8)

8.1 A cross sectoral greenhouse gas emissions trading system should be introduced to reduce greenhouse gas emissions in the electricity and gas sectors. Once an announcement has been made on an agreement to implement an emissions trading system the following measures should immediately cease to operate:

(a) Commonwealth stationary energy measures:

Mandatory Renewable Energy Target

Generator Efficiency Standards

Greenhouse Gas Abatement Program: stationary energy projects.

(b) State based stationary energy measures:

NSW Electricity Retailer Greenhouse Benchmarks

Queensland 13 per cent Gas Scheme.

8.2 Energy intensive users in the traded goods sector are to be excluded from the scheme referred to in Recommendation 8.1 until Australia's international competitors introduce similar schemes. Excluded entities are required to meet world's best practice in relation to their energy use.

8.3 Investments entered into in response to existing schemes, identified in Recommendation 8.1, will continue to receive an equivalent subsidy. The final details of such a payment will need to be developed in parallel with the development of the emissions trading system so as to minimise overlap.

8.4 The introduction of interval meters should be mandated in order to increase opportunities for demand-side participation in the electricity sector (see Chapter 6).

# 1 INTRODUCTION AND CONTEXT

The Council of Australian Governments (COAG) at its 8 June 2001 meeting endorsed a national energy policy framework that acknowledged the strategic importance to the economy and national prosperity of reliable, competitively priced energy. At this same meeting, COAG agreed to commission an independent review of the strategic directions for energy market reform in Australia – the Energy Market Review.

This report details the findings and recommendations of the Review. It builds on the draft report released on 15 November 2002 and has been informed by the submissions received in response to that document. Many of these submissions were, however, received after the due date of 6 December 2002. In view of the short time available to finalise this report, the Panel has not been able to assess in substantial depth all of the submissions received after the due date.

## ENERGY IN THE AUSTRALIAN CONTEXT

Australia is endowed with significant, accessible and high quality energy resources.

The natural gas resources to the north-west of the country are substantial and support an increasing export trade of liquefied natural gas and the WA domestic market. Reserves in the Bass Strait and Cooper-Eromanga basin serve a growing domestic market in the south and east of the country. These resources will soon be bolstered by the development of a number of fields in the Otway Basin and promising coal bed methane deposits, especially in Queensland and New South Wales.

Natural gas networks have been steadily developing across Australia. Victoria has the most developed network with much of the state serviced by reticulated natural gas. The remaining states, while not as well serviced by gas networks, do have good natural gas availability in their capital cities and surrounding areas. Tasmania was the exception to this, though a pipeline from Victoria has recently been constructed. Much of rural Australia is yet to have access to reticulated natural gas.

Grid-based electricity is well established in all of the populated areas of Australia. The networks in the ACT, New South Wales, Queensland, South Australia and Victoria are inter-connected and Tasmania should join these states in being inter-connected by 2005. Smaller, stand-alone grid systems have also existed for some time in Western Australia and the Northern Territory. These latter two jurisdictions are not connected to the more easterly networks due to the significant distances between them.

Coal is the dominant fuel for electricity generation in Australia, accounting for 84 per cent of all electricity generated in 2000-01.[1] Australia has abundant supplies of price competitive coal; estimates of brown coal deposits are that around 800 years' supply at current usage rates is available, while black coal resources are sufficient for about 290 years.[2] These coal resources are also low in cost at around $6 per tonne for brown coal.

The price of electricity and gas in Australia has provided a competitive advantage and supported a shift towards energy intensive production. For example, in 1999 the cost of natural gas for industrial purposes was reported to be the third lowest in the major OECD economies and second lowest for residential purposes.[3] Electricity prices for residential and industrial consumers are also low by world standards. The IEA Review of Australia reports an ESAA survey of electricity prices across selected developed nations at January 2000 which shows Australia as having the lowest residential and industrial prices.[4] A significant omission from this analysis is the USA.

Electricity generation is forecast by ABARE to grow at an average annual rate of 2.3 per cent between 1998-99 and 2019-20. This would see Australia's electricity production grow from 202 tWh in 1998-99 to 325 tWh by 2019-20.[5] Forecasts by some other bodies anticipate a more substantial growth rate for electricity. Natural gas production over the same period is anticipated to experience growth averaging 4.4 per cent per annum over the 20 years from 1297 PJ in 1998-99 to 3188 PJ in 2019-20.[6] This reflects both the growth in LNG exports and the progressive further uptake domestically of natural gas, including for electricity generation.



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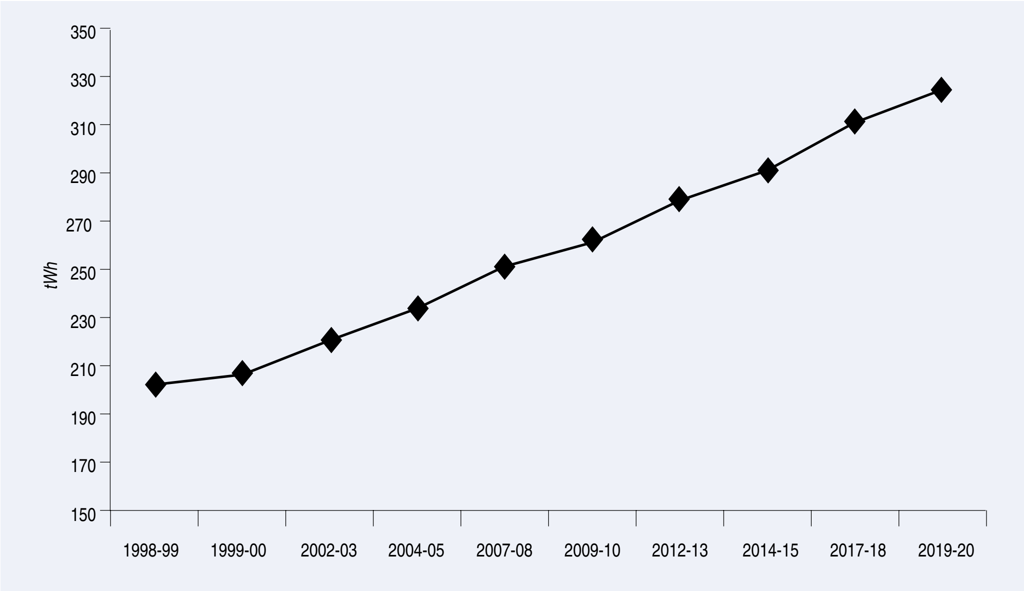
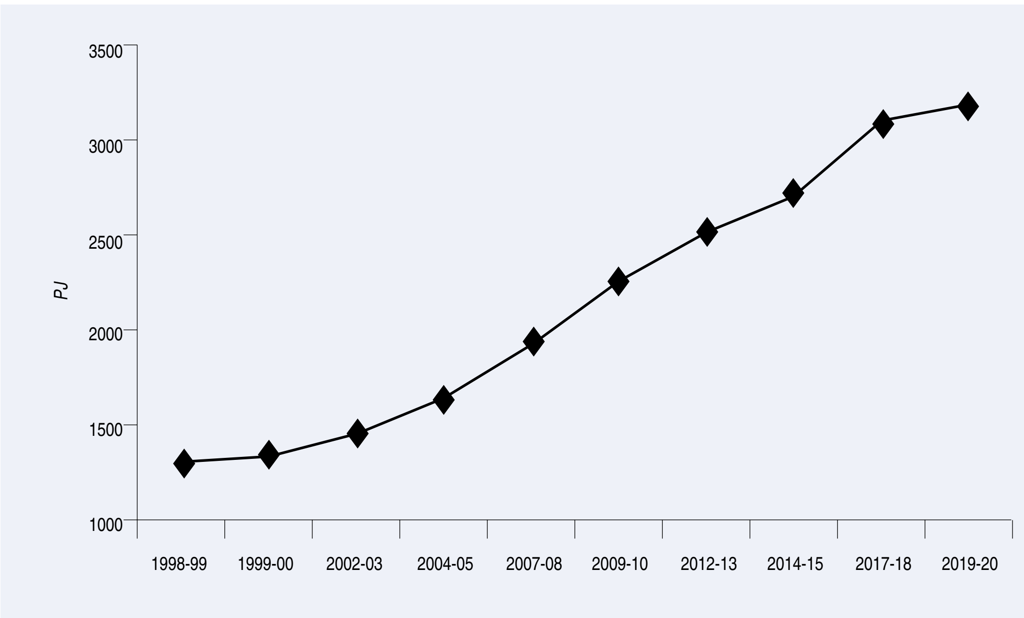
[1] ESAA 2002, chart 2.5, p. 33
[2] IEA (2001), p. 7
[3] AGA (2001), p. 23
[4] IEA (2001), p. 129
[5] ABARE (2002), p. 201
[6] ABARE (2002), p. 204

**Figure 1.1: Forecast growth in electricity generation to 2020**




*Source: ABARE (2001)*

**Figure 1.2: Forecast growth in natural gas production to 2020**




*Source: ABARE (2001)*

As these figures show, significant growth is forecast for both electricity generation and natural gas production in the period up to 2020.

This growth will require substantial investments in generation and production plant. It will also require major expansions of, and extensions to, existing energy transportation infrastructure.

Dynamic and competitive energy markets are essential to signal the appropriate amount and timing of investment that will be required.

Australia's use of fossil fuel resources in the stationary energy sector is a significant contributor to the nation's greenhouse gas emissions. In 2000 almost half of Australia's national greenhouse gas emissions were produced in the stationary energy sector. Greenhouse gas emissions from this sector have grown strongly as a result of the increased demand for energy, particularly demand for electricity, and the increased use of brown coal fired capacity to meet electricity demand. It is likely, given estimates of energy demand growth, that emissions from this sector will continue to rise unless a significant shift to less greenhouse gas intense sources of capacity occurs.

## CREATION OF COMPETITIVE MARKETS

Reviews by the Industry Commission and the Independent Committee of Inquiry into a National Competition Policy for Australia (the Hilmer Inquiry) in the early 1990's identified the significant benefits that were potentially available from introducing competitive market arrangements for the trading of electricity and enabling free and fair trade of natural gas. These findings led to Australian Governments committing to the development of a National Electricity Market and implementation of reforms to the electricity and natural gas industries under the National Competition Policy and the related Competition Principles Agreement.



Electricity had until this time been a state or territory government provided service. The systems were jurisdictionally focussed and consequently there was limited physical inter-connection between the state grids. Individual state agencies were responsible for planning, developing, commissioning and operating these systems. But with no competitive market for electricity, economic considerations tended to be secondary to achieving robust engineering outcomes.

Though government ownership of natural gas sector assets was less than for electricity, the development of the industry had still been substantially on a state-by-state basis. Laws existed in some jurisdictions to prevent the inter-state sale of natural gas, while the level of pipeline inter-connection between the jurisdictions was weaker than for electricity. The gas 'networks' were typified by a few transmission pipelines from basin to population centre (usually the capital city) with a distribution network at the end. Little 'off-take' from the transmission pipeline occurred before it reached the population centre. Much of the gas network constituted a natural monopoly. Access to the network by 'third parties' on fair and just terms was not guaranteed and served to limit new entrants both upstream and downstream.

The competition reforms of the 1990s transformed these two industries.

The creation of the National Electricity Market (NEM) in Queensland, New South Wales, the ACT, Victoria and South Australia involved the separation of the previously vertically integrated supply chain and introduced competition between the generators and, on a phased basis, between the retailers. It also brought the monopoly network elements under economic and access regulation to ensure open access at fair and reasonable tariffs. This was a revolutionary step for the industry, placing economic and market considerations on an equal footing with engineering excellence, supply availability and reliability — the traditional drivers for the government-owned electricity sector.

The natural gas sector in Australia is much newer than the electricity sector. Where grid based electricity dates back to the early part of the 20th century, with the growth in grids concentrated in the immediate period post World War 2, significant local use of reticulated natural gas started in 1969 with Bass Strait production feeding into Victoria. Production from Moomba followed later with connecting pipelines to Adelaide and Sydney servicing those cities. With such a short history in Australia, the natural gas sector presents as an emerging rather than mature market.

To achieve free and fair trade in natural gas, governments established an industry specific arrangement to ensure third party access to monopoly pipelines (both transmission and distribution) and associated provisions to encourage the emergence of a vibrant market in natural gas. Jurisdictional laws limiting the inter-state trade in natural gas were repealed. Progressive customer choice of their natural gas retailer was also enabled. These reforms were aimed at increasing competition in natural gas marketing and at enabling the entry of new market participants through easing barriers to accessing pipeline services (and therefore gas).

The reform of Australia's energy markets has brought significant benefits to date. Australia can point to:

- electricity and gas prices that are now competitive with other OECD member countries
- market signals working effectively to induce appropriate new generation investment

- new gas resources being discovered and exploited
- significant additional pipelines constructed between and within jurisdictions (both regulated and not)
- substantial improvement in the participation of consumers in the energy market through choice of retailer.

However, the reform of Australia's energy markets is far from complete and significant deficiencies remain that require attention. Without these deficiencies being addressed, Australia's energy market will not only fall short of reaching its full potential, but it risks losing the valuable benefits gained over the past 10 years.

## FRAMEWORK FOR FUTURE ENERGY MARKET REFORM

The Review has been informed by COAG's national energy policy objectives. Key among these is 'encouraging efficient provision of reliable, competitively priced energy services to Australians, underpinning wealth and job creation and improved quality of life, taking into account the needs of regional, rural and remote areas'.

COAG detailed the following principles to support the energy policy objectives:

- recognise the importance of competitive and sustainable energy markets
- continually improve Australia's national energy markets
- enhance the security and reliability of energy supply
- stimulate sustained energy efficiency improvements
- encourage the development of less carbon-intensive sources and technologies
- recognise and enhance Australia's competitiveness in world energy markets
- provide transparency and clarity in government decision making to achieve confidence in current and future investment decisions
- consider the social and economic impacts on regional and remote areas
- facilitate effective inter-jurisdictional cooperation and productive international collaboration on energy matters.

These principles have guided the work of the Review. The findings and recommendations in the following chapters detail the steps needed to complete the achievement of sustainable, competitive markets that deliver effective, reliable and efficient energy supply at least cost.

## CONTEXT FOR THE FUTURE DIRECTIONS

In considering the future directions for Australia's energy markets, several matters are clear.

Firstly, energy is a very significant strategic policy matter for the Australian economy. Australia draws considerable comparative advantage from its competitively priced, reliable stationary energy resources. The continuing recent interest by energy intensive industries in locating and expanding production facilities in Australia is testament to this. Independent analysis also finds that the energy market reforms implemented to date have contributed an additional $1.5 billion per annum to the wider economy with the potential for this to rise to $2.4 billion by 2010.[7] Remaining vigilant to secure the benefits gained to date and building on them is vitally important to Australia's economic health. The following table demonstrates the significance of electricity prices in the cost structures of major Australian industries and the impact a 10 per cent reduction in price can have on profitability.

**Table 1.1**

**EFFECT OF ELECTRICITY PRICE REDUCTIONS ON PROFITABILITY**

| Industry | Energy Costs as a proportion of production costs | EBIT margin | Effect of 10 per cent reduction in energy prices on EBIT margin |
|---|---|---|---|
| Aluminium Smelting | 20% | 14% | + 12% |
| Paper Manufacturing | 20% | 9% | + 20% |
| Chlor/Alkali Production | 20% | 15% | + 11% |
| Brick Manufacturing | 18% | 10% | + 16% |
| Steel Production | 11% | 14% | + 7% |
| Nickel Production | 10% | 17% | + 5% |
| Copper / Uranium Production | 10% | 8% | + 12% |
| Gold Production | 8% | 7% | + 11% |
| Cement Production | 7% | 8% | + 8% |

*Source: Business Council of Australia (2000)*

[7] Short et al (2001)

Secondly, Australia has no real stationary energy fuel supply availability or security challenge. Though some stakeholders observe that Australia's oil resources are dwindling and are a cause for concern, this is not the case for the sectors covered by the Review. Fuels for the generation of electricity, whether from traditional sources or renewables, are assured for many years to come. Australia has very substantial deposits of coal, vast reserves of natural gas and valuable hydro facilities as well as high quality renewable energy sources (solar, wind and geothermal). Natural gas resources are known to be extensive, with more being discovered and developed. Increasingly, these gas resources are being pursued for their own value instead of being a by-product of oil exploration and development.

Thirdly, a range of technologies that are emerging in the electricity generation and natural gas end-use sectors are potentially valuable and could result in a reduction in the greenhouse gas intensity of energy supplied. In particular, pursuit of new renewable generation forms such as geothermal capacity offer potentially significant value and diversity to the electricity sector. Of similar interest and importance are efforts to capture and sequester greenhouse gases from the coal and gas fired electricity generation sector. Still further market benefit is likely from the adoption of new embedded generation technologies such as micro-turbines and fuel cells, each of which are likely to be largely dependent on natural gas as their fuel source. Adoption of other natural gas end-use technologies such as air-conditioning and chilling have the potential to make a strong contribution to energy diversification, especially as they will be used most at times when the electricity system is at peak demand.

Fourthly, effective energy markets must be technology neutral. With a range of potentially valuable new technologies becoming available over the next 10 to 20 years, the energy market must not entrench the incumbent technologies. Energy markets rely on rules for their operation which can easily, and perhaps unwittingly, amount to barriers to entry for new technologies. This needs to be avoided.



Fifthly, the rates of growth projected for electricity and gas use in Australia over the next 20 years imply the need for significant capital investment in both sectors. Market and regulatory arrangements, including policies on abating greenhouse gas emissions, will play a significant role in determining the attractiveness of these sectors to investors.

Finally, there are no simple solutions. Around the world different approaches have been employed to achieve the efficient, reliable and effective supply of energy at a competitive price. All models have their strengths and weaknesses. What is most important is to select and deploy the appropriate market mechanisms that are sympathetic to and complement the physical, financial and social structures of the country.

## DEFICIENCIES IN AUSTRALIA'S ENERGY MARKETS

The Review has found that significant action is needed to resolve a number of serious deficiencies in Australia's energy market. The over-riding issue that must be resolved is to create a truly national energy market that is efficient and transcends jurisdictional boundaries.

The Review has identified serious deficiencies in the following areas:

- governance and regulatory arrangements
- electricity market mechanism and structure
- electricity transmission reform
- financial market development
- demand side participation and full retail contestability
- natural gas initiatives
- options to abate greenhouse gas emissions.

A chapter dealing with regional Australia issues is also included.

The Review's terms of reference also included an examination of energy market reform benefits for the small business sector. The Review actively sought submissions from the small business sector, but few were forthcoming. Small businesses are generally defined by the number of employees they have. The definition is blind to the volume of energy used by these businesses. Indeed, small business will have a very wide range of energy requirements. For example, small foundries will be much more energy intensive than will a sole accounting practitioner. Yet both may be small businesses. The small business sector is therefore difficult to address separately from other energy use classes. This may provide an insight into why few submissions were received from the small business sector. Consequently, the Review has not reported separately on small business and energy market reform, but is confident that the significant energy market issues confronting users at all levels have been taken into account, and by definition, small business issues are also covered.

In considering the Review's findings and recommendations, caution needs to be exercised in assessing the issues in isolation of each other. It is clear to the Panel that the individual elements of energy markets often have complex relationships with each other. The recommendations from this Review have been framed to take account of their likely impacts in other areas of the market or the physical system. To proceed with some but not all recommendations in each chapter risks leading to dysfunctional or unintended outcomes.

The recommendations in this report address deficiencies which are currently imposing an unnecessary burden on the economy. It is important that these are addressed by COAG in the shortest possible time frame.

# 2 GOVERNANCE AND REGULATORY ARRANGEMENTS

## CONTEXT

Australian energy markets have been created by governments through legislation and various codes. Effective governance of these arrangements is exceptionally important to ensuring efficient market operation.

Regulatory arrangements cannot be seen in isolation from general governance questions. The operation and effectiveness of market regulators is as central to the question of governance as the operation and effectiveness of bodies such as NEMMCO and NECA.

Energy market governance and regulatory arrangements are of considerable concern to key stakeholders. A consistent view in submissions to the Review is that regulatory arrangements, for both natural gas and electricity, are not optimal and are impeding market development. Many submissions also commented more broadly on the difficulties and uncertainties surrounding electricity market governance arrangements.

The NSW Government, for example, argued that 'good governance and market rules are the most appropriate methods of restricting anti-competitive behaviour'.[1]

The following comment from the Tasmanian Government's submission echoes the sentiments of many other stakeholders:

**It is clear that energy market reform is far more complex than was initially anticipated. It is also acknowledged that there are a number of major deficiencies in the present market arrangements. It appears to be widely accepted that the governance arrangements for energy, and electricity in particular, are confused and the regulatory arrangements more complex and intrusive than necessary.**[2]

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1 NSW Government, submission 147, p. 10

2 Tasmanian Government, submission 140, p. 17

Concerns are evident in submissions from most if not all stakeholder sectors, including governments, regulators, industry associations, individual businesses and customer advocacy groups.

Despite the immaturity of Australia's natural gas and electricity markets, there is little sense from submissions that the problems involved are transitional in nature. Indeed, it is clear that many concerns have been current from the commencement of competitive markets and certain stakeholders are of the view that problems are increasing rather than decreasing.

There can be no suggestion of unanimity among stakeholders as to the detailed deficiencies of the present system or the preferred way forward. Despite this, certain key themes have emerged in many submissions.

Many stakeholders have highlighted the negative effect on energy markets of uncertainty as to future directions. The Electricity Supply Association of Australia (ESAA), for example, states that for the electricity industry:

**The biggest single issue that must be addressed is uncertainty, stemming from sovereign and regulatory risks that are increasingly a characteristic of the current market environment.**[3]

A frequently expressed view is that lack of governance and regulatory certainty will have consequences for future investment. Origin Energy, for example, argues that:

**The overriding deficiency with current arrangements is the lack of a national energy policy to provide strategic direction, regulatory stability and ultimately investment certainty …** [4]

A perceived lack of national focus was another major theme. The Australian Financial Markets Association (AFMA), for example, commented that:



**Jurisdictional or sovereign risk is a further related concern to participants, jurisdictions having implemented parochial policies that lead to specific price outcomes. Such policies often impact on liquidity in the market and require participants to manage additional risks. As such, they can have an impact beyond state borders.**[5]

[3] ESAA, submission 4, p. 2

[4] Origin Energy, submission 71, p. 18

[5] AFMA, submission 84, p. 4

The possibility of a move to an industry-specific energy regulator was raised in many submissions to the Review. Stakeholder views were divided as to whether a move to such an arrangement was desirable and as to the scope and powers of any national regulator. The decision of the NEM Ministers Forum to pursue further investigation of a national regulator has also focussed strong interest on the proposal.

The Australian Consumers' Association (ACA) expressed concern about the consequences of state-based approaches:

**The drive to expose domestic energy consumers to full retail competition is currently a messy experiment, unfolding in an uneven state-by-state process. Consumer protection measures vary, and will deliver a patchy result.**[6]

A related theme, reflected in many submissions, was the need to accommodate regional differences. Energex, for example, argued for maintaining 'jurisdictional regulators for distribution given these are local markets and given geographic differences in consumer preferences.'[7]

The role of governments in markets was another major theme, which again attracted widely divergent views. It was evident that the view of the Tasmanian Government[8], that no 'appropriate role for governments' had been established in the process was one shared by the majority of those making submissions.

Submissions provide evidence of a fierce debate on the regulation of both electricity and gas network assets. That stakeholders have widely separated views as to the adequacy of the present arrangements and possible ways forward is to be expected given the importance of network costs in final electricity and gas prices, and given the different interests of the parties involved.

Submissions to the Review indicate serious concerns on the part of large customers. Amcor and Paperlinx state that:

**Power transmission and distribution companies are able to hide behind codes that protect them from their customers who suffer from such power interruptions. These regulated monopoly businesses need to be given incentives to improve their system reliability and be penalised when they do not perform up to expectations.**[9]

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[6] ACA, submission 14, p. 7

[7] Energex, submission 15, p. 6

[8] Tasmanian Government, submission 140, p. 17

[9] Amcor and Paperlinx, submission 54, p. 16

The appropriateness of current approaches for adequate system investment was also raised, for example by the Energy Planning and Policy Group, University of Technology Sydney:

**Considerable weight is placed on delivering lower prices to end-use customers by containing costs, rather than on providing revenue streams to ensure ongoing improvement in the network. The emphasis on costs is short-term. Experience, however, suggests customer costs today are a function of yesterday's investment. If customers are to benefit from lower prices in the future, consideration today must equally be given to investment for longer term performance.**[10]

The regulatory treatment of embedded generation was an issue raised in many submissions. Embedded generation is connected to the distribution network as opposed to those generators connected to the transmission network.

Continuing technological progress, for example in the development of high efficiency small scale fuel cells that may be suitable for location in individual business premises or houses, makes it likely that the range and importance of embedded generation will grow in the coming years.

The potential benefits that embedded generation can offer include:

- alternatives to network augmentation and a range of network support services in relation to reliability and ancillary services
- empowerment of end users through providing an economic means of partial network bypass
- greenhouse gas abatement benefits through the avoidance of network losses, the generation of electricity as a by-product of another industrial process and the use of renewables and natural gas in embedded generation technologies
- more efficient supply options in remote areas.

Many stakeholders[11] claim that the potential of embedded generation has been impeded by a number of barriers. The claims include:

- difficulties in negotiating network connection agreements and costs, including availability of network operation information to assist embedded generation proponents
- lack of requirements for embedded generation to be explicitly considered where augmentation of distribution networks are being contemplated

[10] Energy Planning and Policy Group, submission 52, p. 8

[11] See, for example AEA, submission 86, for a fuller list of alleged barriers.

- demand charges, including minimum chargeable demand, which do not penalise customers that self-generate
- fair 'buy back' rates for electricity to be exported to the network
- common ownership of retailer and distributor businesses resulting in conflicts of interest in enabling third party proposed embedded generation projects
- network pricing structures.

The claims are not new. There have been several substantive investigations into the barriers to the entry of embedded generation and demand side facilities in general by a number of regulators and authorities. These include the NSW Independent Pricing and Regulatory Tribunal (IPART), the Victorian Essential Services Commission (ESC) and VENCorp.

To obtain a stocktake of progress and remaining barriers, the Review engaged Charles River Associates (CRA). CRA canvassed the views of a number of regulators, embedded generation proponents and distribution network owners across the NEM. CRA found common ground with many of the previous reviews, stating that, while positive change was occurring, many of the claims are, or have been, valid. These reflect a range of factors, including conflicting demands on distributors. CRA found that certain material barriers, such as difficulties in negotiating network connection agreements and costs, could be addressed relatively quickly by development of regulatory instruments and industry standards. In the longer term, there was value in pursuing methodologies on more complex issues, such as assessing the contribution to reliability of supply from different technologies, including embedded generation. Policy reviews into matters such as resolving potential conflicts caused by common ownership of distribution and retail activities were also supported.

CRA highlighted the importance of a shift of focus to rapid and efficient implementation, commenting that 'Although there appears to be a broad consensus from previous reviews about changes that should be made, implementation is slow'.[12]

The different treatment accorded to natural gas and electricity in submissions was of some interest. The vast majority of discussion on governance issues reflected the National Electricity Market arrangements; the same was true of discussion on code change arrangements. On natural gas there was much comment on the working of the access regulation framework. This is addressed together with other natural gas issues in Chapter 7.

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[12] CRA (2002), p. 7

There was little comment on proposed arrangements for the Western Australian electricity market, perhaps reflecting that the reform process is still in train in that state. Notwithstanding the ongoing reform process, the report makes a number of findings that are relevant to the future direction of reform in Western Australia and the Northern Territory.

This is consistent with the Panel's over riding concern to move forward to a truly national energy market that is efficient and transcends jurisdictional boundaries. Core energy market principles can and should be aligned and consistent, even when there is variation in the detail.

## KEY FINDINGS

The widespread unease surrounding present governance and regulatory arrangements is justified. The governance arrangements are confused and there is excessive regulation.

The key findings are:

- there are too many regulators
- the electricity and gas code change processes are deficient
- the key electricity governing bodies have overlapping responsibilities
- there are perceptions of conflicts of interest where governments are owners, regulators and policy makers
- the role for ministerial decision making is uncertain
- there are distorted and inappropriate signals from the current network regulation framework
- there are barriers to the uptake of embedded generation.



### There are too many regulators

The multiplicity of regulators creates a barrier to competitive interstate trade and adds costs to the energy sector. The present arrangements are inappropriate for a situation in which cross-border energy flows are now a reality.

Submissions to the Review indicated significant industry disquiet about the present regulatory burden on energy businesses from national and local regulators, in particular different compliance requirements and the need to develop separate customer management systems for each state and territory to address different regulatory requirements. The National Retailers Forum (NRF), for example, has stated:

**A retailer wishing to compete in those markets open to competition is … required to obtain a separate retail licence in each state, with different licence conditions attaching to each of these licences. Moreover, the codes and guidelines (which include billing, reporting and marketing requirements) that sit under these licences differ in their requirements. The result is that business processes and systems must be tailored for each jurisdiction. The inefficiencies that result from this inhibit a retailer's ability to compete effectively. Energy specific codes duplicating general competition regulations exacerbate this problem.**[13]

The NRF has also provided[14] in its submission a listing of the national and jurisdictional regulatory instruments relevant to Australian retailers. The length of the list gives only a partial impression of the potential complexity of compliance. It is noted, for example, that the Victorian Retail Code contains 46 obligations with a further 12 contained in guidelines. The South Australian Retail Code contains 46 obligations plus 64 in guidelines, together with a further 9 obligations relating to the compliance system and another 10 relating to green power. Consistent industry advice is that the extent of the differences in operational rules is such that back office processes are too expensive to integrate and it is more efficient to operate separate state systems.

Additional costs associated with compliance with a variety of regimes and even with monitoring continual changes to the various regimes to avoid regulatory risk are costs that ultimately will flow through to customers.

Separate requirements eliminate most of the economies of scale or scope for operators across both states and sectors. They also introduce serious licence compliance risks. The present arrangements constitute a clear entry barrier to energy businesses thus working against competition.

It is, understandably, difficult to assess the precise additional costs involved and the extent to which these costs are material in a business's decision to extend or not to extend its activities into a new jurisdiction. The Panel's view, however, is that these costs are substantial:

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[13] NRF, submission 42, Part B, p. 5

[14] NRF, submission 42, Part C, Appendix A

- The Panel received information from credible sources that the varying regulatory requirements add up to $10m per annum in operating costs and depreciation of establishment costs when a retailer enters a new state market.
- Apart from these costs, the ongoing management distraction associated with compliance with so many regulatory requirements may be difficult to quantify but is nevertheless real.

The present number of regulators and regulatory instruments has grown over time. This situation is sub-optimal and can no longer be justified.

## The electricity and gas code change processes are deficient

### National Electricity Code

The model adopted for changes to the National Electricity Code is complex, both in its conception and the way in which the system has worked in practice.

The checks and balances added to the process by what is effectively a dual assessment of proposed Code changes by NECA's Code Change Panel and the ACCC may well have been considered appropriate when the process was designed given the revolutionary change to electricity markets. They have not worked well in practice.

Not only is the process time consuming, but the process under which the ACCC is obliged to carry out a separate public consultation process and the possibility of substantive changes being introduced or required at a late stage in the process engenders uncertainty and works against the effectiveness of the first consultation process.

The problem has been recognised from the NEM start onwards. Limbers[15], reporting on the outcome of an investigation that began shortly after NEM start, stated that 'It was widely accepted by all NEM Stakeholders (including NECA and the ACCC) that there is a large degree of regulatory overlap between NECA and the ACCC in respect of Code change and that the process needs to be streamlined'.



### Gas Code

The change processes for the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), and the associated National Gas Pipelines Advisory Committee (NGPAC), have not demonstrated the ability to cope with a significant number of changes.

[15] Limbers (1999)

Despite the continuing criticism on the part of the gas industry of the operation of the Gas Code, the number of Code changes processed since commencement of the access framework is low, with almost all being the product of regulator suggestions. Many proposed changes have never moved forward.

The evident lack of industry ownership of the process may be linked with present NGPAC arrangements under which only jurisdictional representatives are entitled to vote on whether proposed changes can go forward.

The process under which Ministers must agree all Gas Code changes also has consequences for the responsiveness of the process for the industry and for timeliness. The Panel does not support continuation of this arrangement.

The proposed review of the Gas Code is not, in itself, sufficient to drive action on measures to address the present situation.

## The key electricity governing bodies have overlapping responsibilities

The responsibilities of the key electricity market and regulatory institutions, NEMMCO, NECA, the state regulators and the ACCC are overlapping at times and confused. There is also overlap between the responsibilities of these organisations and relevant arms of government.

The overlapping roles of NECA and the ACCC in the Code change process is discussed above.

It has also been recognised for several years that there is some duplication in the allocation of responsibility for 'market development' under the Code. As spelt out in the 1999 Limbers Report[16] there is tension between NEMMCO's stated objectives, which include promoting the ongoing development of the NEM, and NECA's clear allocation of Code change responsibilities.

It is evident that there is a decided lack of agreement between key stakeholders on the responsibilities of market institutions, reflected in the following commentary from the Queensland Treasury submission: '... the evolution of the NEM has been frustrated by NEM institutions and the ACCC overlaying their own views on the market framework agreed by governments and industry at the commencement of the NEM'.[17]

Where the inadequacies of the present process show themselves most clearly is the difficulty with which the NEM has handled certain key market development issues. The fact that several market development issues, critical to future NEM development, remain unresolved is a strong argument for change.

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[16] Limbers (1999)

[17] Queensland Treasury, submission 129, p. 29

A major example is the slow progress with achieving a sustainable framework for electricity transmission and distribution pricing. As is outlined in Chapter 4, NECA and the ACCC have been developing and advancing a framework for transmission and distribution network pricing, under the auspices of the Code change arrangements, since prior to NEM start. Another example is progress with NECA's review of the integration of energy markets and network services.

Such slow progress is indicative of:

- the difficulties of progressing large scale consultation exercises under NECA auspices with the full involvement of all relevant stakeholders, including governments, in circumstances where there are clearly economic 'winners' and 'losers' in alternative approaches
- the changes of direction associated with the ACCC's second consultation process and the ability of the ACCC to impose conditions on Code change authorisation
- the consequences of such division of responsibility for establishing and keeping to realistic timeframes for closure of the exercise in order to provide certainty to the industry.

Whatever the details of the difficulties involved, and acknowledging that the two issues instanced here are most complex, the upshot has been that two market development issues crucial to investor certainty and to the future shape of the NEM remain unresolved, with no timeframe for their conclusion.

The Panel therefore sees it as a priority to define the market development function more clearly and allocate unequivocal responsibility for it in a revised structure.

The Panel does not support the suggestion made in many submissions, including that of NECA, that there would be value in splitting the National Electricity Code into 'rules' and 'policy'. The Panel is doubtful as to whether such a split could be made in a way that would receive broad acceptance, and it could become a major distraction.



## There are perceptions of conflicts of interest where governments are owners, regulators and policy makers

Many submissions referred to the conflict of interest that can exist when government bodies determine the rules and administer regulations affecting markets in which their own businesses operate. The risk of inappropriate control being exercised by governments is magnified when they own a high proportion of both the generators and retailers operating within a particular regional market, as is the present case in jurisdictions other than Victoria and South Australia.

Structures that create potential conflicts of interest can lead to inappropriate influence. Whether or not this is actually occurring, it is an unhealthy arrangement and deters investment.

Ultimately the Panel's concerns centre on the problems that are caused for the development of energy markets when perceptions of a possible conflict of interest appear to be widely held.

## The role for ministerial decision making is uncertain

The role of governments in energy market governance is a serious unresolved issue. It is relevant for both natural gas and electricity.

Submissions indicate that many stakeholders have a perception that governments' actions in the past have worked against confidence in the reform process and in energy markets more generally, creating uncertainty, instability and magnifying potential sovereign risk. This issue, like those discussed above, is long standing.

Views among market participants vary widely, from those who want more ministerial involvement in market processes to those who argue for less. Despite the differences in opinion, it is clear that:

- industry and communities have an expectation that governments will have a continuing role in energy market reform
- there are high expectations for actions on the part of governments to resolve issues including the current uncertainties about greenhouse gas abatement.

Uncertainty as to the role of governments has worked against the timely resolution of the ongoing NEM market development issues referred to above and, through the possibility of sovereign risk to industry participants, has consequences for ongoing investment decisions and market viability.

A clearly articulated understanding of governments' ongoing role is a prerequisite for sustainable energy market reform. As the NSW Government submission argued, a stable investment environment relies upon 'the Government [having] clear rules of engagement with the market'.[18]

Submissions to the Review provide a wide range of views as to the possible roles for ministerial oversight, particularly on the degree to which Ministers should intervene or influence the day to day operation of the NEM. The position put forward in the South Australian Government submission appears to be broadly accepted by a wide range of stakeholders:

[18] NSW Government, submission 147, p. 8

**It is important for Governments to provide a policy oversight role, while refraining from having any involvement at the operational level.**[19]

This is consistent with the statement in the communiqué issued by the NEM Ministers Forum following the July 2002 meeting that jurisdictions do not see their role as regulating or operating energy markets, this being the task of independent regulators and the market operator. The Panel endorses such views.

Lack of precision in the definition and separation of the role of government has serious implications. As is indicated in the South Australian Government submission:

**Whilst it is important for the National Electricity Market (NEM) that appropriate policy leadership is provided by the participating jurisdictions, this must be done in a manner that minimises any sovereign risk issues.**[20]

The Panel's position is that Commonwealth involvement in NEM market oversight is vital. This accords with the majority of stakeholders.

The following view from the Energy Users Association of Australia (EUAA) appears representative of the majority of those who expressed a view on Commonwealth involvement in energy reform:

**The Commonwealth, which is responsible for the ongoing health of national economy, needs to 'lead' energy reform if it is to be successful, sound and nationally based.**[21]

Commonwealth involvement is important in providing a national focus.

The Panel also finds that separation of Ministerial oversight mechanisms for the NEM from that for energy markets generally works against the development of efficient, national markets. There are no sound reasons for continuing with both a NEM Ministers Forum and the Ministerial Council on Energy.



Against this background, a clear statement of roles and responsibilities of the MCE is a necessity. The Victorian Department of Natural Resources and Environment (DNRE), in its submission, sets out a framework that the Panel has found useful in addressing the issue:

**Governments should oversight policy through review and amendment of legislation and protected Code provisions.**[22]

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[19] SA Government, submission 146, p. 9

[20] SA Government, submission 146, p. 9

[21] EUAA, submission 88, p. 1

[22] DNRE, submission 126, p. 8

## There are distorted and inappropriate signals from the current network regulation framework

In relation to energy network regulation the Panel observed widely conflicting views on the type of regulation that should apply, and the desired outcomes from it. As already stated this is not surprising given the range of interests involved.

The debate reflects many factors. It reflects on some occasions self-interest by network owners, and on apparently arbitrary interpretation of rules and intrusive information collection processes by regulators. The debate also reflects varying philosophies on such issues as the objectives of regulation and whether regulation should be aiming to replicate perfect or imperfect markets.

The Panel makes four key findings in relation to energy network regulation.

First, while there is value in the wider debate, it is unclear at this stage whether it will yield a fundamental change in regulatory approach.

There are some suggestions for significant change. A move to 'price monitoring' or 'negotiate and arbitrate' has been suggested. At this stage, however, such a change could lead to more complicated regulatory procedures as regulators make judgements about how closely to 'monitor' and what details they will need to successfully 'arbitrate'.

Second, the Panel found that some of the debate revolves around quite narrow issues. These centre on the level of the regulated asset base, and the appropriate return on capital. The Panel notes that the level of the regulated asset base cannot be set with regard to the price paid by any purchaser of these assets as this could lead to an ever escalating asset base. Otherwise, these narrow issues are found to be ones that are best left to the parties included in each regulatory determination.

Third, the future debate would be most effective if it focussed on moving regulation to a less intrusive form. This may best be brought about by giving further consideration to regulators relying more on industry wide rather than detailed company specific information.

Fourth, there is a need for immediate changes to address some obvious deficiencies. It is important that the wider debate does not distract from the need to make changes that would bring immediate benefits.

The necessary gas network regulatory changes are described in Chapter 7. In this chapter we deal with the desired immediate changes to electricity network regulation.

Priority action is necessary to address the following electricity network regulation issues:

- increasing certainty as to how the gains from cost reductions will be shared over time and on how particular investments will be treated in the cost base
- moving away from revenue caps which can cause unintended consequences when demand forecasts are inaccurate
- including incentives for meeting defined service standards. Without such a regime, there is an incentive only to cut costs, which can work to the detriment of the network.

## There are barriers to the uptake of embedded generation

Barriers remain to the equitable treatment of embedded generation. The various constraints are well known and appear to be symptomatic of a number of issues including:

- inexperience, lack of expertise and resource limitations on the part of distributors and embedded generation proponents, particularly in the face of an increasing number of projects and developments in technology
- a range of incentives created by the economic regulatory framework that encourages distributors to grow network businesses in order to maximise revenue and to maintain and enhance network reliability
- limitations, some of which are significant, in the still-evolving regulatory arrangements. These include the lack of resolution of distribution network pricing policy, the absence of a means of valuation of embedded generators' positive and negative contributions to network reliability and the risk of having network investment optimised out of the regulated asset base as a result of embedded generation.



The issues involved are complex. Until they are worked through, it will be hard to facilitate negotiations satisfactory to both parties and avoid allegations of unreasonableness and conflict of interest.

Various state regulators have sought to address these issues, but none has done so comprehensively. Even where worthwhile solutions have been agreed, much action is required to translate the solution into action, and then this would only occur in the jurisdiction involved. No national solution to these matters has emerged.

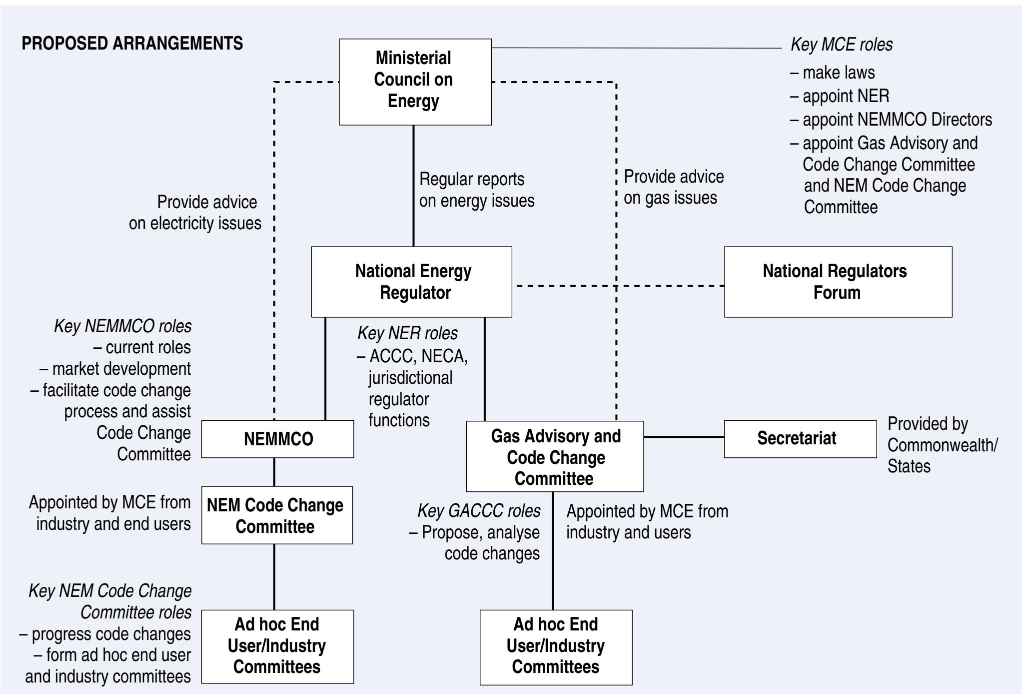
## PROPOSED SOLUTIONS

The Panel recommends a suite of changes to governance and regulatory arrangements to address the findings. These are:

- creation of a national energy regulator to assume roles currently performed by the ACCC, state regulators and NECA
- an enhanced role for NEMMCO in pro-active NEM development including facilitating a streamlined electricity code change process with a clear end user and industry focus
- formation of a Gas Advisory and Code Change Committee
- an enhanced role for the Ministerial Council on Energy as the Ministerial decision-making body for all Australian energy policy
- changes to network regulation
- establishment by the national energy regulator of a mandatory code of practice for dealing with embedded generation.

The key changes are represented diagrammatically below.

**Table 1: Proposed governance and regulatory arrangements**



The proposed changes will:

- strengthen both the definition of governments' policy oversight role and the resources available to governments for strategic policy advice
- encourage transparency in governments' interactions with market institutions and avoid any perception of conflict of interest
- facilitate a regulatory structure that is strong, consistent and nationally focussed
- facilitate industry ownership of a streamlined and more effective code change process.

## Creation of a National Energy Regulator

The Panel recommends that a new statutory body be formed, called the National Energy Regulator (NER) in this report, to be the independent energy regulator in all jurisdictions, interconnected or otherwise. The NER would encompass the current roles of NECA and the energy-specific roles of the ACCC and state regulators.

The aim is to create a regulator accountable under legislation to all Australian governments, with strongly defined independence and a national focus.

The NER proposal set out in this report brings with it:

- an independent regulator that is accountable to all jurisdictions, not simply the Commonwealth
- a drastic reduction in the number of regulators with which energy business have to do business
- a consistent source of focussed regulatory advice to inform government policy making
- greater regulatory consistency to assist in the development of national energy markets
- significant reductions in energy businesses' regulatory compliance costs and greater incentives for the growth of national energy businesses
- more streamlined code change processes (as set out in this Chapter).



The NER should be set up under a legislative scheme agreed by all governments. There are a number of legislative options available. These range from uniform legislation enacted by each jurisdiction, through enactment of lead legislation in one jurisdiction together with 'application of laws' legislation in the other jurisdictions along the line of the National Electricity Law, through to the possibility of referral of state/territory powers to the Commonwealth. The preferred legislative approach should be a matter for governments' decision. The objective, however, should be an efficient and responsive national regulatory regime that ensures appropriate accountability to ministers.

Under this proposal, the ACCC would remain responsible for administering the Trade Practices Act as it does for other industries (mergers, misuse of market power and so on).

The Panel's view is that the proposed NER is the only viable solution to address its findings as set out in this Chapter.

### Cooperative approaches are not an alternative to a national regulator

Cooperative approaches, under which existing regulators would work together to achieve consistency in regulation and avoidance of duplication, would not achieve a satisfactory outcome.

There was some support for such a solution in submissions. For example, the Public Interest Advocacy Centre (PIAC) argues that such an approach would address key customer issues:

**The need is not so much for a national regulator as for a consistent framework providing a right to supply; a right to fair treatment in the market; the right to complain and have disputes resolved; and the management of customer debt.**[23]

The Panel's assessment, however, is that such cooperative approaches are a suboptimal solution. It is in effect a status quo solution, with no drivers for national solutions. As Delta Electricity states:

**Although the various state and federal regulators meet at regulators forums to share views, this does not ensure a consistent national approach to the regulation of the network businesses in the NEM.**[24]

There is little evidence that work on the harmonisation of regulatory requirements would progress as expeditiously as if under the leadership of one agency. Differences, or perceived differences, in the actual application of any 'template' arrangements would remain, and there would be no clear way forward for rectifying that concern.

[23] PIAC, submission 111, p. 4

[24] Delta Electricity, submission 134, p. 17

### A transitional process is not the right way forward

The Panel's view is that the viability of a national energy regulator is dependent on all jurisdictional and national regulatory functions being combined in one agency. To do less than this, for example by having distribution network service regulation or retail licensing remain with jurisdictional regulators, would not address any of the problems raised above.

The argument that Australia's energy regulators need to 'walk before they run' is not compelling. The present divided arrangements have been reasonably well tested. Cross-border energy flows are a reality. Ownership and operation of assets in multiple jurisdictions are now a reality. An increasing number of retailers are now nationally based. There is now sufficient experience on which to move to a national energy regulator.

### The location of the NER is not the key issue

The Panel's view is that the most appropriate approach is for the NER to be a separate energy sector-specific agency. Others have advocated a single energy regulator be located as a specialised arm of a generalist economic regulator. This is an issue to be resolved by COAG in the implementation of the NER proposal.

While the debate is important, the key elements of the Panel's proposal should be preserved regardless of the eventual decision: a single Australia-wide electricity and natural gas regulator, with national focus, established under a legislative approach agreed by all jurisdictions, accountable to these jurisdictions, with Commissioners appointed by the Ministerial Council on Energy and a charter that extends to the distribution and retail functions currently carried out by state and territory based regulators.



### NER to have decision making role for National Electricity Code and Gas Code

Changes to both the National Electricity Code and the Gas Code would proceed to the NER for approval. For gas, this replaces the present arrangement under which Ministers agree proposed Code changes. The present approach sits uneasily with the framework of independent regulation, the Ministers' policy oversight role as formalised in the recommended changes to the MCE, and the desirability of Code changes reflecting industry rather than regulator concerns.

### NER role in technical regulation

It is appropriate that the NER assume responsibility for the setting of technical standards for the planning, design and operation of critical elements of the power system which are material to the security of the system. Central to this are the functions of the present Reliability Panel. The Reliability Panel determines and monitors the standards that guarantee the continued reliability and security of the NEM, including roles in relation to frequency control and plant technical standards. It is appropriate that such technical standards be set independently of NEMMCO, although the close involvement of NEMMCO in the process remains vital.

As noted above, the NER would assume distribution regulation and licensing functions. Certain of these functions include technical considerations, for example distribution connection standards and generator licensing. In carrying out these functions, links with appropriate jurisdictional technical regulators are important. Other than this, the NER would not cover technical and safety issues such as energy worker licensing or safety incidents involving electricity and gas infrastructure.

### Roles of the NER

Against this background, the key roles of the NER would be to:

- approve code changes under the National Electricity Code, the Gas Code, and other energy market codes such as the future Western Australian electricity market rules
- decide on pipeline coverage under the Gas Code (as opposed to the National Competition Council and the Commonwealth Minister as is presently the case)
- administer the transmission access regulation that is currently dealt with by the ACCC (for the NEM and natural gas pipelines other than Western Australia) and the Western Australian regulator
- administer distribution access regulation that is currently dealt with by state/territory based regulators
- provide other licensing and approvals currently provided by the various jurisdictional agencies. This includes entry and exit conditions such as licences to operate as a retailer or generator, and utility marketing and consumer protection codes.
- have jurisdiction on National Electricity Code compliance and breach, including adjudicating disputes on implementation of Code changes

- assume responsibility for the setting of technical standards for the planning, design and operation of critical elements of the power system which are material to the security of the system
- provide the MCE with expert briefing or formal reports on matters formally referred to the NER by the Ministerial Council for inquiry or other issues requested by the Ministerial Council or provided by the NER as part of a formal quarterly reporting arrangement.

The NER would be expected to be a permanent and active member of the Regulators Forum as its administration of access regulation should at least be informed by the regulatory approaches applying in other industries in relation to access.

The NER would not have the power to propose Code changes. It would be inconsistent with its power to approve Code changes and would work against approaches under which Code changes would increasingly be driven by the needs of market participants and end users.

Decisions of the NER would be appealable, either on merits review by the Australian Competition Tribunal or on judicial review grounds by the relevant court of appeal.

Formation of the NER raises the question of the future of the National Electricity Tribunal (NET) which, at present, has the power to review 'reviewable decisions' of NEMMCO and NECA. The NET can also issue orders and civil penalties against NEMMCO for Code breach. Certain decisions at present subject to NET review would pass to NEMMCO and some to the NER.

The preferred option is to pass all review functions to the Australian Competition Tribunal. The alternative approach, maintaining two review bodies, one for NEMMCO decisions and one for the NER, would add needless complication.



## An enhanced role for NEMMCO in pro-active NEM development including facilitating the Code change process

To provide a clear and unambiguous focus for electricity market development and to streamline the Code change process, it is proposed that the roles and responsibilities of NEMMCO be broadened to include, among other things:

- a pro-active market development role for the NEM and for other Australian electricity markets
- facilitating the Code change function.

Code change processes for electricity should be overhauled, with the NER having a Code change decision making role.

NECA functions would be subsumed into the expanded NEMMCO and the NER.

The present confusion over NEM development responsibility will be resolved by explicitly locating this activity within NEMMCO.

The Panel's view is that market development will almost always involve policy issues in terms of making sure that markets and their rules continue to develop in a way that maximises competitive outcomes and consumer benefits. Governments have a legitimate interest in the outcome of this process. That said, those most directly affected by the proposed development are perhaps the best placed to determine the effect of market rule changes on market operations.

The Panel's view is that the tension between these two interests can be managed by according the MCE a clearly defined policy role as is set out in this Chapter. In simple terms, if jurisdictions believe that a particular policy direction is sufficiently strategic to justify the development and passage of legislation, then such development would be a role for the MCE. If it does not justify the passage of legislation, then NEM development is a role for NEMMCO.

By taking a pro-active market development leadership role NEMMCO will be a source of advice to both the NER and to Ministers.

The original decision to separate functions between NEMMCO and NECA appears to have been based on a perceived conflict of interest between NEMMCO's market operation role and the market development function. The Panel believes that in hindsight the (not for profit) market operation role and the market development function sit comfortably together.

As a consequence of the new direction on market development, NEMMCO should also facilitate a revised NEM Code change process as is set out later in this Chapter. Code change is the key facet of the market development process.

These changes are in addition to additional functions accorded to NEMMCO elsewhere in this report, principally those relating to transmission planning.

It is proposed that NEMMCO will continue to be funded by market participants and be a 'not for profit' Corporations Act company owned by the various governments. Given the proposed enhanced roles of NEMMCO, a move to industry and user ownership of the company is not appropriate. To recognise the national importance of the energy market, the Commonwealth should become an owner of NEMMCO with voting rights equal to the other parties. Each owner government will be able to nominate one director.

Western Australia and the Northern Territory should be invited to consider the advantages accruing from NEMMCO ownership. There may be advantages, in terms of perceived independence from incumbents, efficiency and development of nationally consistent approaches, if NEMMCO performed the following roles for the Western Australian electricity market and, where appropriate, the Northern Territory:

- network planning
- balancing market operation
- Code maintenance.

NEMMCO will also brief the MCE on its work program and the results of work performed at the request of the MCE.

The accountability and performance incentive regime for NEMMCO would be similar to that existing at present:

- formal reporting to the MCE
- MCE agreement of annual Statements of Corporate Intent following a consultation process with industry and industry stakeholders
- MCE agreement of budgets following a similar consultation process.

NEMMCO accountability to market participants must be a vital consideration in finalising arrangements for the expanded organisation. The National Electricity Code sets out a framework for consultation on key initiatives that has worked reasonably well in practice and which remains robust. It is noted that since NEM commencement there has been substantive progress in the development of effective consultation processes on the part of NEMMCO and NECA. The formation of NEMMCO's Participant Advisory Committee is one case in point. Against this background, it is recommended that NEMMCO, in mapping out its new roles, seek to involve, to the greatest extent possible, key stakeholders in its market development exercise. This is especially true in the new Code change processes.

## Amended National Electricity Code change process

The changes to energy market governance and regulatory arrangements require significant changes to the present processes for changes to the National Electricity Code.

While NEMMCO would facilitate and manage the overall process, responsibility for the development of Code changes and the decision to advance such proposals would be with a reconstituted statutory end user and industry based Code Change Committee.

The Code Change Committee, supported by ad hoc end user and industry committees depending on the matter under review, would take responsibility for the development of proposed changes. This would promote a stronger focus on the needs of stakeholders, and is an arrangement that worked well in the former Victorian Electricity Market.

The MCE would appoint the members of the Code Change Committee on merit. NEMMCO would provide administrative and analytical support for the Committee and would have the ability to submit its own proposed Code changes to the Committee.

NEMMCO would forward all Code change proposals to the NER for approval. NEMMCO should provide comment to the NER on the proposals but may not prevent them going forward.

The revised process would reflect the importance of industry and end users driving the Code change process and the Code, as it develops, reflecting the needs of industry and users. The focus, however, should be on enhancing market efficiency and effectiveness, not advancing sectoral interests.

Revised Code change arrangements for electricity, as with natural gas, should incorporate arrangements to minimise the successive, partly-duplicated consultation exercises that have been a concern with the present electricity Code change arrangement. The following approach is recommended, to be supported as necessary by statutory codes or legislation:

- End user and industry based committees, in developing a fully-rounded proposal, will be required to consult as thoroughly as is at present required.
- NEMMCO will have the power to send the proposal back to the Code Change Committee if consultation is not adequate, against the background of Code requirements. Alternatively, NEMMCO could choose to work cooperatively with the committee to address its concerns.
- The NER would only have the power to accept or reject a proposal, not to amend it.

- The NER will have the right to send proposals back to proponents where there is evidence that the required consultative processes have not been observed.
- Otherwise it should make a 'merits based' decision without further consultation.
- Ministers will not have the power to veto Code changes. As discussed below, the present arrangements for 'protected' Code changes should be removed and incorporated into the National Electricity Law.

The NER would not be able to initiate Code changes. The reformed Code change process must be focussed on the needs of the industry and end users. Other changes to the regulatory or governance framework should be by way of legislation.

## Create a Gas Advisory and Code Change Committee

The Panel recommends formation of a Gas Advisory and Code Change Committee (GACCC) with two major functions:

- proposing and progressing amendments to the Gas Code and
- providing strategic briefing to the MCE on natural gas market issues.

The GACCC would be a committee consisting of no more than six members. Its members would be appointed on merit by the MCE and supported by a full time Commonwealth/state/territory funded and staffed Secretariat. The appointees would not be advocates for their particular industry sectors or organisations. The GACCC would appoint ad hoc Committees to assist in the development of Code change proposals or briefing assignments.



The recommended Code change process would be broadly similar to that proposed for electricity, with the aim of avoiding unnecessary duplication of process. The Gas Code Change Secretariat would work with the GACCC to provide appropriate analytical support and assessment of proposals and forward them to the NER once the consultative process has been completed.

As a consequence of the formation of the GACCC and the move of the decision making function on Code changes to the NER, the National Gas Pipelines Advisory Committee, the Code Registrar and the Gas Policy Forum would be abolished.

Amendment of the Gas Pipelines Access Law (and the related WA legislation) would be necessary for the new Code change process.

## An enhanced role for the Ministerial Council on Energy as the Ministerial decision-making body for all Australian energy policy

Governments have an important responsibility in the establishment of competitive energy markets. They establish market structures, regulatory arrangements and rules governing the nature and scope of such markets and are responsible for maintenance of the frameworks.

The Ministerial Council on Energy (MCE) should be the single Ministerial forum for all gas and electricity market issues in Australia. This recognises that energy market policy and operation is a matter of national importance; that the Commonwealth has a role in national electricity policy as well as natural gas policy; and that electricity market development issues encompass both the NEM and market arrangements in other jurisdictions.

The MCE should also provide a coordinating forum for Ministerial actions on any issue that has implications for the energy market.

The NEM Ministers' Forum would have no continuing role under this recommendation. The NEMMF is not an optimal solution because:

- it separates Ministerial consideration of NEM issues from natural gas issues
- it separates Ministerial consideration of NEM issues from electricity markets outside the NEM in Western Australia and the Northern Territory
- under its present constitution, it excludes the Commonwealth as a full participant.

### Defining governments' policy oversight role

The MCE's policy oversight role should be by way of developing and facilitating changes to statutory provisions, for example the National Electricity Law and the National Gas Pipelines Access Law.

The NEM Ministers' Forum, in its July 2002 communiqué, proposed that the National Electricity Law be amended to provide for the power of Ministers to gazette binding NEM policy directions on NEM institutions. The Panel does not support this proposal and does not recommend that any similar policy direction power should be accorded to the MCE.

The jurisdictions' public policy interest in energy markets will be sufficiently catered for through the jurisdictions' responsibility for the governing legislation and through the role of the independent regulator. In addition, there are major advantages in terms of transparency and rigour in any policy directions being communicated to the market by way of legislative change. If a policy direction is sufficiently substantive to warrant the decisions of Ministers, then it warrants the proper parliamentary and community scrutiny of the legislative process.

The proposed reforms allow Ministers every opportunity to review the policy framework in the light of market experience and to commission inquiries on matters that impact on market objectives.

This approach to the definition of policy responsibility recognises the importance of Ministerial involvement to the future success of markets. It also provides opportunities and mechanisms for NEMMCO and the NER to communicate effectively with the MCE so that Ministers can take decisions concerning legislation with all the relevant knowledge available.

The Panel does not recommend any power for the MCE to intervene in the gas or electricity Code change process.

The existing arrangement under which certain provisions of the National Electricity Code are classified as 'protected' should not continue. These provisions cannot be changed without changing fundamental policy settings and so require Ministerial agreement in addition to the agreement of the regulator. They do not sit well with the principle enunciated above that policy positions should be established by way of legislative change. As part of the transition to the new governance and regulatory structure, these provisions should be incorporated into the National Electricity Law.

A decision would also be required as to which, if any, provisions in the Gas Code should be transferred to the National Gas Pipelines Access Law as part of implementation of the new Code change process.



### Responsibilities of the MCE

Ministers will be responsible for appointing the Commissioners of the NER, the directors of NEMMCO and the members of the National Electricity Code Change Committee and the Gas Advisory and Code Change Committee.

The MCE would be able to request NEMMCO, as the market operation and market development agency, to undertake particular work of a market analysis nature. It would also be able to refer matters to the NER for investigation and report back.

The recommendations in this report provide the MCE with a vital and complex agenda. The starting point would be the considerable legislative change required to implement the reforms recommended in this report and the major policy issues that will need to be shepherded over the next few years.

Important to the ongoing success of the MCE in policy leadership is the interaction with NEMMCO and the NER. These bodies will have invaluable knowledge that will contribute to sound policy decisions in matters as crucial to the public interest as assurance that the electricity system's security and reliability is being adequately protected.

Against this background, the MCE should receive regular briefings and reports from these bodies and should also be able to request specialised briefing as required.

## Improving network regulation

The following solutions are proposed in relation to electricity network regulation issues. They are separate from the discussion of electricity transmission issues in Chapter 4 and the key changes required in relation to gas network issues in Chapter 7.

Regulatory uncertainty must be reduced. There needs to be greater certainty on how the gains from cost reductions will be shared over time and greater certainty on how particular investments will be treated in the regulatory asset base.

Electricity distribution owners should have price, not revenue, caps. Revenue caps bring to distribution networks potential dangers. If demand exceeds forecasts, a revenue capping regime has the potential to lead to tariffs too low to augment distribution networks and too low to maintain the overall networks.

There should be a bonus and penalties regime for meeting defined service standards. Such a regime would provide powerful signals about how the network was performing and would address comments from many stakeholders about the potential for network unresponsiveness. A bonuses and penalties regime would also provide a counterbalance to incentives in the current regulation regime only to cut costs, which can work to the detriment of the network.

## A mandatory code of practice for embedded generation

The formation of the NER provides an opportunity to address the barriers to embedded generation on a national basis. The limited progress to date through present regulatory arrangements constitutes a strong argument for why distribution regulation must be addressed nationally.

It will be a matter for the NER to determine a work program and to establish arrangements that provide timely reporting of progress.

It is proposed, however, that the newly formed NER establish a mandatory code of practice governing arrangements between distribution companies and prospective embedded generators. This would cover, among other things, information disclosure on network capacity, the timeliness of responses to queries, and a methodology for calculating the contribution of embedded generation to network reliability.

It is worth noting that the introduction of price caps rather than revenue caps, and improved certainty in the treatment of investment in the asset base, will also assist embedded generation.

## RECOMMENDATIONS

2.1 A statutory National Energy Regulator (NER) should be established under a legislative approach agreed by COAG to be the independent energy regulator in all jurisdictions, interconnected or otherwise, and to encompass the energy-related regulatory roles of the ACCC, NECA and state and territory regulators.

2.2 The three Commissioners of the NER are to be appointed by the Ministerial Council on Energy (MCE).

2.3 The NER is to have the following principal roles:

(a) approval of changes under the National Electricity Code, the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code), and other energy market codes

(b) decisions on pipeline coverage under the Gas Code

(c) administration of electricity and natural gas transmission access regulation currently dealt with by the ACCC and the Western Australian regulator

(d) administration of electricity and gas distribution access regulation

(e) provision of other licensing and approvals currently provided by jurisdictional regulators including licences to operate as a retailer or generator, and utility marketing and consumer protection codes

(f) responsibility for setting technical standards for the planning, design and operation of critical elements of the power system which are material to the security of the system including the functions of the present NEM Reliability Panel

(g) NEM monitoring and assessment of compliance with the National Electricity Code

(h) briefing and formal reporting to the MCE.

2.4 The role of NEMMCO will encompass:

(a) responsibility for NEM development

(b) facilitation of the National Electricity Code change process.

2.5 NEMMCO to have the following ownership arrangement:

(a) NEMMCO to remain a government-owned company

(b) the Commonwealth to be a member of NEMMCO

(c) Western Australia and the Northern Territory to be invited to consider becoming members of NEMMCO.

2.6 The National Electricity Code and Gas Code change processes to be changed to:

(a) provide greater end user and industry involvement in and ownership of the Code change processes

(b) provide no provision for regulator-initiated Code changes

(c) provide for the acceptance or rejection, but not variation, of all Code changes by the NER

(d) eliminate successive consultation processes, with the NER conducting a merits-based review of proposed changes if the required consultation processes have been observed or to send the proposal back to the Code change proponent otherwise.

2.7 A statutory end user and industry based National Electricity Code Change Committee will be created to progress amendments to the National Electricity Code with the following features:

(a) the MCE to appoint the members following end user and industry consultation

(b) creation of ad hoc end user and industry committees to advance specific Code changes

(c) NEMMCO to provide analytical and administrative support for the new structure

(d) NEMMCO to have no veto power over Committee recommendations other than a power to refer back recommendations if consultation is assessed as inadequate but to advise the NER of its position on each proposed change.

2.8 A statutory Gas Advisory and Code Change Committee (GACCC) will be created to subsume the operation of the National Gas Pipelines Advisory Committee and the Gas Policy Forum, with the following functions:

(a) proposing and progressing amendments to the Gas Code

(b) providing strategic briefing to the MCE on natural gas market issues.

2.9 The members of the GACCC are:

(a) to be appointed on merit by the MCE

(b) not to exceed six in number.

2.10 The GACCC is to be supported by a full-time Commonwealth/state/territory funded and staffed secretariat.

2.11 Decisions by the NER and NEMMCO are to be reviewable by the Australian Competition Tribunal.

2.12 The MCE should be the single ministerial forum for all gas and electricity market issues in Australia including the National Electricity Market (NEM).

2.13 The MCE, in relation to its energy policy oversight role, should:

(a) provide policy direction by way of developing and facilitating amendment of electricity and natural gas legislation

(b) have no power of direction over NEMMCO or the NER and no role in Code change processes.

2.14 The following changes should be made to electricity network regulation:

(a) provide certainty on how the gains from cost reductions will be shared over time and on how particular investments will be treated in the regulated asset base

(b) electricity distribution to be price, not revenue capped

(c) institute a nationally consistent bonuses and penalties regime for meeting defined network service provider service standards.

2.15 The NER should establish a mandatory code of practice governing arrangements between distribution companies and prospective embedded generators.

# 3 ELECTRICITY MARKET MECHANISM AND STRUCTURE

## CONTEXT

Structural reform of public electricity utilities was largely implemented during the 1990s. Key achievements included breaking up functions into separate generation, transmission and distribution/retail business units, and further horizontal disaggregation of generation and retail functions into separate and competing business units within each jurisdiction. Victoria and South Australia took an additional step and sold or leased their restructured businesses to the private sector.

These reforms were complemented in the interconnected jurisdictions by the introduction of a compulsory, competitive wholesale market for the trading and dispatch of electricity — the National Electricity Market (NEM).

For electricity markets to work effectively and deliver least cost outcomes, their design must support and facilitate competitive behaviour by the participants. This must be complemented by a competitive market structure that does not limit the number of sellers and buyers involved, nor impede their entry or exit. Competitive market structures need to be supported by effective and transparent price signals, to ensure efficient market responses including new investment.

The appropriateness or otherwise of the NEM market mechanism is the subject of vigorous debate among stakeholders.

The NEM is a compulsory gross pool mechanism where generators are required to offer volume and price to the market on a 5 minute by 5 minute basis. These offers are accumulated and 'stacked' with physical dispatch occurring according to lowest cost generation required to meet the instantaneous demand, subject to network constraints. The price in the pool for the 5 minutes is set by the last generator dispatched to meet the load, while the market settles on a 30 minute time weighted average price basis. The registered market customers (the demand side) are not required to bid into the NEM for supply, but are able to take energy from the system at the prevailing pool price (and are charged accordingly).

Much of the debate on the market mechanism is driven by the price volatility of the NEM, and especially at times when the spot market price 'spikes' even though adequate, low marginal cost generation capacity appears available to meet demand. Some, mainly larger electricity users, claim that this is evidence of the market power held by generators and that the demand side is in a weak position to respond. They claim that the gross pool mechanism delivers this market power to the generators.

For example, the Energy Market Reform Forum, representing several large industrial consumers of energy contends:

**There has been widespread opposition by major electricity users to the NEM trading system since its inception. Criticisms of the compulsory, energy-only wholesale pool include:**

- **there is limited demand-side participation**
- **consumers are in general unable to influence wholesale price outcomes**
- **withholding of economic capacity and rebidding strategies have allowed the exercise of market power by generators**
- **there have been massive transfers of income from consumers to generators**
- **frequency of price spikes and excessive price volatility.**

**The consequences of these are that market risks in the NEM are seen as excessively high. As a result, there is an inability to write long-term electricity contracts, which are necessary to underpin long-term investments in major energy-using down-stream and up-stream industries.**[1]



Like-minded stakeholders strongly advocate that the current NEM mechanism be replaced with a so-called net pool arrangement. This market design predominates overseas and has as its key features a dependency on bilateral contracting between generators and consumers (including retailers), 'self dispatch' by generators and smaller centrally co-ordinated real time markets to enable instantaneous 'balancing' of the physical power system.

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[1] Energy Market Reform Forum, submission 33, p. 3

Conversely, many market participants (generators and retailers alike) and jurisdictions, contend that the current market mechanism is working well and is appropriate for Australia. They acknowledge the opportunity to make improvements, but advocate the retention of the selected market mechanism. It is of concern that the industry and users have such differing views on this key issue.

Market mechanisms in a selection of other countries were examined by the Panel, with some of the market operators, regulators and policy agencies visited to explore the features, successes and weaknesses of the alternative approaches. What is abundantly clear from examining the alternative mechanisms is that none are perfect. They all have their strengths and weaknesses.

Western Australia is currently in the process of deciding on the market mechanism and structural changes appropriate to enable competitive electricity trading at the wholesale level. Observations in this report will be of relevance to the Western Australian Government.

The structure of the generation sector, particularly in New South Wales and Queensland, has attracted comment that some generators have positions of market power at critical times leading to price outcomes that are higher than would have otherwise been the case.

Concern has also been expressed by some (see for example the Victorian Department of Natural Resources and Environment (DNRE) submission[2]) that the NEM mechanism does not or may not lead to appropriately timed and sized investments, especially in new generation.

The National Electricity Market Management Company (NEMMCO) foreshadows new investments of between 2,500 MW and 6,200 MW (between $1.25 billion and $7.4 billion) by 2009-10.[3]

The Electricity Supply Association of Australia (ESAA) estimates demand growth in the order of 2.8 per cent per annum, necessitating new generation investment of around 7,000 MW ($10 billion) during this decade.[4]

It is vital that electricity markets provide an efficient and appropriate response to meet future electricity needs.

2 DNRE, submission 126

3 NEMMCO, submission 57, pp 13-14

4 ESAA, submission 4, p. 1

## KEY FINDINGS

The Panel found that:

- An effective pooling arrangement is necessary for efficient market operation.
- Gross and net pools can provide essentially similar outcomes.
- Generators sometimes exert market power.
- The NEM provides a sound mechanism to signal new investment requirements.
- The structure of the generation sector in NSW does not support competitive outcomes.
- The proposed structure for the Western Australian generation sector under new market arrangements will not deliver competitive outcomes.

### An effective pooling arrangement is necessary for efficient market operation

The Panel examined the operation of Nord Pool and the Pennsylvania, New Jersey, Maryland (PJM) markets, which are successfully operating 'net pool' arrangements. Additionally, the New Electricity Trading Arrangements (NETA) of England and Wales were examined.

Though none of these three markets employ precisely the same market mechanisms, they share common features, including:

- relying on generators and users (including retailers) to enter into bilateral contracts for the physical supply of electricity
- a central, independent system operator responsible for matching supply with demand in real time
- bilaterally contracted loads must be advised to the system operator
- variations between bilaterally contracted positions and the actual demand and supply is reconciled through a balancing market mechanism used to select and dispatch the most cost effective bid to keep the physical system in balance.

This balancing market represents the 'net pool'. In essence, it enables surplus energy and uncontracted demand to be matched.

Beyond these features, the three markets examined differ markedly. They each also have a number of 'add-on' features to address specific perceived market shortcomings.

In Nord Pool, the financial market is compulsory. This ensures that contracting parties transact their business through Nord Pool. They can also access its standard contract and derivative products and avail themselves of the Nord Pool clearing house services. This arrangement ensures the capture of all contract data, enabling the publishing of reliable price information. Of course, individual contract details are not disclosed.

The NETA regulator (Ofgem) does not regard the market as a 'net pool' but rather as having no pool. In this system, penalties are imposed on generators and users alike if they need to access the balancing and settlement arrangement. The Panel understands that this approach was adopted to encourage to the maximum extent possible a reliance on bilateral contracts and to discourage resorting to the balancing arrangement. In practice this has meant that most generators maintain significant spinning reserve to ensure that if their contracted position is 'short' they can quickly 'self dispatch' the shortfall and avoid the penalty cost of the balancing arrangement. However, this appears to the Panel to be a significant inefficiency that adds cost to the system.

An effectively functioning pool minimises the barriers to entry to both generators and retailers. The key problem with effectively lessening the function of the pool in playing its appropriate balancing role is that, because a large degree of self balancing is required, it provides an incentive for large generation portfolios and the vertical integration between generators and retailers.

## Gross and net pools can provide essentially similar outcomes

If the financial contracts market was allowed to work as intended, Australia's gross pool would deliver similar outcomes to that of a net pool.

The Panel found that in principle the gross pool model possesses some advantages over net pool arrangements in that it:

- encourages generators to supply according to their marginal cost
- reduces barriers to entry for new generators
- has the simplicity of an energy-only design with a single spot price for energy being set
- provides transparent, widely available price and volume data to the market and stakeholders enabling more informed investment and usage decisions.

The Panel agrees with the assessment of the Australian Competition and Consumer Commission (ACCC) in its submission:

**… market power will not change or be addressed by a move to a net pool design. In fact, such a move would require fundamental changes to the market's operation for uncertain benefits. The current market arrangements are relatively new and have not been fully tested. Reforms in other parts of the market, such as structure and demand side participation, can be made within the current framework and are more likely to address issues of market power. Indeed, it could be argued that a move to a net pool would also require further structural separation of the generation sector to ensure that competitive outcomes were achieved in the bilateral dealings between market participants.** [5]

Nonetheless, the NEM mechanism is operating with insufficient competition between generators in some regions. To fulfill its potential, this issue needs to be addressed and the gross pool must be complemented by a vibrant, effective and liquid financial market supporting efficient financial risk management for all market participants. Opportunities for improvement in this latter area are examined in Chapter 5.

## Generators sometimes exert market power

A significant matter for concern is the ability of generators to exert market power at certain key times. In examining this issue, it is important to contemplate some of the relevant features and benefits of the gross pool mechanism.

The gross pool relies on effective competition among generators to supply the market. This implies an expectation that this sector will have a fundamentally competitive structure (covered later in this chapter). As the market settles by dispatching the least expensive, next available generator needed to satisfy instantaneous demand it will always solve for the least cost to the market, based on offers by generators. As available supply and demand converge, prices will rise in the immediate term and if sustained, average prices will also rise. At times of inadequate supply prices will spike, indicating the scarcity value of electricity at that time.

Price spikes generally reflect tight supply-demand situations which can confer temporary market power onto some generators. However, as dispatch occurs on a five minute basis and prices in the market are known very close to real time, the duration of this market power is likely to be limited.



[5] ACCC, submission 136, p. 78

Nonetheless, with a maximum pool price allowed of $10,000 per MWh even short periods of market power can have a significant impact on the average pool price. These high priced events do impact on the cost of bilateral 'hedging' contracts due to the price volatility premium that must be added to cover risk and can limit the length of contracts.

But spikes also play a valuable role in the market. Firstly, spikes can send a strong demand side signal. When supply is scarce and demand is strong high prices may encourage a reduction in demand. The gross pool arrangement provides a 'real-time' indication of scarcity enabling users in a position to reduce consumption to do so. That many consumers do not reduce demand during periods of high wholesale prices suggests opportunities for improvement in wider market arrangements. These are covered at Chapter 6.

Secondly, spikes provide necessary signals for new investment. Where a consistent pattern of spikes during high demand times of day are apparent, investment in peaking plant will be encouraged. There is evidence of this occurring in the NEM already. Additionally over time the consistent occurrence of price spikes will lead to a change in the average price of electricity traded in the market. These average price movements tend to be gradual and reflect the slowly moving balance between demand and supply. It tends to be a gradual movement that does not 'shock' the market, but provides growing evidence for potential investors of the value of investing in new capacity, especially baseload generation.

Some significant instances occurred in May and June 2002 where generators strategically bid large amounts of capacity into high price bands during the evening peak even though adequate, low marginal cost baseload capacity was available to meet the demand.

These are examples of market power being held by generators. But these patterns are not confined to generators operating in a gross pool. In PJM, following instances of generators bidding high prices to provide capacity needed by the system to meet demand, a new requirement was instituted for generators bidding into the net pool to provide *both price and cost bids*. This requirement was included to provide some data against which PJM could assess whether or not the generators had been seeking to achieve 'economic withdrawal' (as opposed to physical withdrawal) to cause prices in the net pool to spike. The Panel understands that this mechanism has not led to any significant changes in bidding behaviour nor any adverse findings against generators.

In the Australian context, NECA has proposed Code changes to the ACCC on several occasions relating to generator re-bidding in the NEM. These proposals variously sought to place a ban on re-bidding within 3 hours of market operation, required bids and re-bids to be made in good faith and a proposed ban on bids or re-bids that would materially prejudice the market. Only the requirement for bids to be in good faith has been accepted by the ACCC.

A range of other measures to address the concern of market power are available, but rejected. There seems no practical rule changes that can assist. Bidding rule changes to address the 'economic withdrawal' of capacity, for example, will likely impose more costs than benefits. Rebidding allows the optimisation of dispatch, and may see pool prices go lower as often as it pushes them higher.

In examining the opportunity for generators to exert market power, the Panel has concluded that the structure of the generation sector, combined with transmission issues (Chapter 4) and measures which encourage market distorting activities such as ETEF (Chapter 5) play a far more significant role in enabling this to occur than does the NEM market mechanism and the re-bidding provisions of the Code.

## The NEM provides a sound mechanism to signal new investment requirements

The likely adequacy of investment responses to a tightening of the supply and demand position in the NEM has also been raised by some as a concern with the NEM market mechanism. In this regard, the Department of Natural Resources and Environment, Victoria (DNRE) observed:



**The Victorian electricity market is characterised by large increases in demand for electricity in summer, driven mainly by the increasing penetration of air conditioning. As a result, the top 15 per cent of peak electricity demand in Victoria occurs for less than 1 per cent of the time.**

**Investment in new generation has come forward in response to Victoria's tightening supply-demand balance, following substantial price excursions in spot prices in early 2001, which flowed through to wholesale contract prices for 2002. However, the capacity was not in place in time to meet peak demand in the summer of 2001, which was unusually hot. Further, the new generators were planned to be commissioned prior to the 2001/2 summer peak period, but will not be fully operational until June 2002. This, together with a protracted failure of a major generating unit, would have left Victoria with low reserves had a one in ten year heat wave occurred, raising questions as the adequacy of capacity signalling in the National Electricity Market, and the adequacy of generator maintenance.**

**The Pennsylvania New Jersey Maryland (PJM) market uses capacity payment mechanisms to provide incentives on retailers to maintain an adequate reserve margin. The use of capacity mechanisms in the NEM has been examined previously to some extent for the Australian market. NECA published a major paper on this issue in 1999. In the NEM, the energy-only spot market provides capacity signals. These were in evidence over the 2001 summer when pool prices rose substantially in Victoria. The contract market also appears to be providing signals for new capacity, as evidenced by increases in prices for standard contracts (peak and flat swaps and $300/MWh caps) for 2002, in mid-2001. There is anecdotal evidence of longer-term non-standard contracts between generators and retailers underpinning new supplies.**

and

**The fundamental question is whether the signals provided by the market, while large, were too late, and whether a capacity payment mechanism such as that used in the PJM market could produce smoothed and timely price signals for new generation.**[6]

NECA has recently released a discussion paper examining the replacement of the 'reserve trader' Code provision with NEMMCO being empowered to purchase cap contracts to ensure adequate generation reserve. This approach seems to the Panel to have two significant drawbacks. Firstly, it potentially reduces the availability of cap contracts for market participants to manage their commercial risks. Secondly, it places NEMMCO as the independent market and system operator in a position of competing with the market participants for whom it facilitates a market.

The Panel is of the view that the market mechanism with its energy-only design provides appropriate price signals for new investment. The high South Australian pool prices, despite the interconnection capacity with Victoria, led to the commissioning of Pelican Point. Queensland may be another example where pool prices rose well above those of other regions until new baseload plant was commissioned.

Notwithstanding the comments by the Victorian DNRE, investment in plant to accommodate seasonal peaks has been significant. The investment in new Victorian peaking plant has not been as high as first announced or as substantial as the high prices of some recent summers may have suggested was required. Peaking plant investment appears to have been based, quite rationally, on longer term analysis of weather and price outcomes.

[6] DNRE, submission 126, pp 19-20

Regardless of market design, the timely construction of new capacity appears to be an issue. The original UK market had a capacity payment mechanism, and as observed by the DNRE submission the PJM Market in the USA has a capacity obligation on suppliers. The Panel examined these examples closely.

In the case of the UK, the original capacity payment mechanism to generators did not lead to any new generation capacity being constructed by the incumbents (to whom the payments were made). New capacity investments were made, in fact, by new entrants associated with the well documented 'dash-for-gas'. This capacity payment mechanism resulted solely in added costs to the market for no benefit. Interestingly, NETA in the UK does not have any capacity mechanisms.

The PJM capacity requirement operates differently. It places an obligation on electricity suppliers to purchase capacity from generators in addition to energy. They must purchase 'capacity tickets' equivalent to 120% of the load to be supplied. Failure to acquire the required amount results in a penalty of $US 177 per MW. The Panel was advised in private discussions with some regulatory officials in the USA that it is debatable whether this requirement has been responsible for the new generation built in the PJM area. They also noted that, in any case, it provides no signal about where new generation is needed. Instead, they contended that the locational marginal prices delivered through the nodal pricing arrangement of the PJM market send stronger investment signals and are more likely responsible for the generation investment response. Additionally, a very significant 'gaming' of the capacity market occurred in January 2001 which is currently under investigation under Federal anti-trust laws.



The Panel does not believe that additional mechanisms are required to ensure sufficient future generation capacity. The Panel has also concluded that capacity mechanisms designed to bring timely generation investments on line have not generally met with success.

## The structure of the generation sector in NSW does not support competitive outcomes

The competitiveness of the NEM's current market structure has been called into question. In particular, stakeholders point to the generator bidding activity in New South Wales during May and June 2002, which it has been claimed led to price spikes that bore little relationship to underlying movements in supply and demand. NECA noted in a recent Statistical Digest that:

**The bidding activity seen in New South Wales and to a lesser extent elsewhere, throughout May and June added almost a third to the overall average prices for 2001-02 in both New South Wales and Queensland. The average price for the financial year in those regions was $38 /MWh, compared to average prices for the year up to mid May of $28/MWh and $31/MWh respectively. Spot price exceeded $2,500/MWh in New South Wales on 21 occasions throughout the quarter, representing more than half of all prices above that level since market launch. The highest spot price ever of $8,049/MWh occurred on Sunday 30 June in New South Wales.**[7]

Such outcomes reflect a weakness in the market structure in New South Wales where ownership of generating capacity is concentrated among a few large companies which have the potential to exercise market power at critical times.

However, the ability to exercise market power in the NEM is not simply a function of concentration of ownership within a region. It critically depends on the potential for competition between regions and the level of demand relative to capacity.[8] Recent work undertaken by ABARE suggests that considerable potential exists for generators to exercise market power in the NEM.[9]

The current structure and ownership of generation in each NEM jurisdiction and Tasmania is summarised in Table 3.1.[10]

Observations in relation to generation structure and ownership include:

- the largest three generators control 95.4 per cent of New South Wales capacity
- the three largest Queensland generators control 69.9 per cent of total Queensland capacity
- 81.8 per cent of South Australian generation is controlled by three companies
- nearly 100 per cent of generation in Tasmania is controlled by Hydro Tasmania





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7 NECA (2002), p 1

8 Levels of residual demand (i.e. defined for each generator as the demand remaining after subtracting all other potential generation capacity, including through interconnects) is an important factor in determining a generator's potential to exercise market power. Where the level of residual demand is relatively high, a generator has greater capacity to exercise market power when supply-demand balances are tight.

9 See Short (2002) and Melanie and Brennan (1997).

10 ESAA (2002), Appendix 1

**Table 3.1:**

**Generation market structure and ownership in NEM jurisdictions and Tasmania**

| Jurisdiction | Owner | Nature of Ownership | Capacity (MW) | Share of Total Capacity (%) | Cumulative Total (%) |
|---|---|---|---|---|---|
| NSW | Macquarie Generation | Public | 4690 | 37.1 | 37.1 |
| | Delta Electricity | Public | 4240 | 33.5 | 70.6 |
| | Eraring Energy | Public | 3132 | 24.8 | 95.4 |
| | Sithe Energies | Private | 162 | 1.3 | 96.7 |
| | National Power (US) | Private | 150 | 1.2 | 97.9 |
| | Other Embedded Generation | Mix | 270 | 2.1 | 100.0 |
| Victoria | Loy Yang Power | Private | 2000 | 23.6 | 23.6 |
| | Hazelwood Power | Private | 1600 | 18.8 | 42.4 |
| | Yallourn Energy | Private | 1450 | 17.1 | 59.5 |
| | Mission Energy | Private | 1300 | 15.3 | 74.8 |
| | AES Transpower | Private | 966 | 11.4 | 86.1 |
| | Southern Hydro | Private | 473 | 5.6 | 91.7 |
| | Energy Brix | Private | 170 | 2.0 | 93.7 |
| | AGL | Private | 150 | 1.8 | 95.5 |
| | Alcoa | Private | 150 | 1.8 | 97.3 |
| | Duke Energy | Private | 80 | 0.9 | 98.2 |
| | Other Embedded Generation | Private | 153 | 1.8 | 100.0 |
| Queensland | CS Energy | Public | 2974 | 27.3 | 27.3 |
| | Enertrade | Public ([1]) | 2657 | 24.4 | 51.6 |
| | Tarong Energy | Public | 1915 | 17.6 | 69.2 |
| | Stanwell Corporation | Public | 1622 | 14.9 | 84.0 |
| | Intergen | Private | 852 | 7.8 | 91.9 |
| | Callide Power Trading | Private | 420 | 3.9 | 95.7 |
| | Origin Energy | Private | 108 | 1.0 | 96.7 |
| | Other Embedded Generation | Private | 360 | 3.3 | 100.0 |
| South Australia | TXU Torrens Island | Private | 1280 | 36.6 | 36.6 |
| | Australian National Power | Private | 877 | 25.1 | 61.7 |
| | NRG Flinders | Private | 700 | 20.0 | 81.8 |
| | Origin Energy (& CU Power) | Private | 260 | 7.4 | 89.2 |
| | AGL | Private | 220 | 6.3 | 95.5 |
| | Other Embedded Generation | Private | 158 | 4.5 | 100.0 |
| Snowy Region | Snowy Hydro | Public | 3756 | 100.0 | 100.0 |
| Tasmania | Hydro Tasmania | Public | 2509 | 99.0 | 99.0 |
| | Amcor Paper | Private | 16 | 0.6 | 99.6 |
| | BHP | Private | 10 | 0.4 | 100.0 |

*([1]) Enertrade manages the output from a series of privately owned power stations (Gladstone, Oakey, Mt Stuart, Collinsville, Yabulu and Barcaldine) through a series of power purchase agreements. These agreements give Enertrade complete control over bidding and trading this output into the NEM. Enertrade is wholly-owned by the Queensland Government and is a registered market generator and customer. Further information on Enertrade's functions and activities is provided at <www.enertrade.com.au>.*

- there is substantial public control of total generation capacity in New South Wales (over 95 per cent), Queensland (over 85 per cent including Enertrade's interests) and Tasmania (nearly 100 per cent)
- three substantial generation projects are being developed, or have recently been completed, in Queensland including two public-private joint ventures. Together, these projects have total planned capacity of nearly 1700 MW, 450 MW of which is still under construction. Other projects currently under construction in the NEM are relatively small peaking or renewable projects. Several significant projects are in the planning or evaluation stage
- five or more substantial and independent generators operate in Victoria.

Further evidence of unhealthy levels of market concentration in the NEM has been provided by the ACCC. This analysis uses a Herfindahl-Hershman Index (HHI)[11] to identify market concentration and market power. A HHI score over 1800 is indicative of levels of concentration consistent with the presence of market power. Results of this analysis are contained in Table 3.2 below.[12]

**Table 3.2:**
**HHI index for NEM jurisdictions**

| | NSW | Vic | Qld | SA | NEM |
|---|---|---|---|---|---|
| Based on registered capacity as at July 2002 | | | | | |
| • no interconnection | 3290 | 1646 | 2108 | 2823 | - |
| • with interconnection | 2547 | 1425 | 1899 | 2222 | 706 |
| Based on output for 2001 | 3364 | 2274 | 2500 | 3568 | 824 |

The results in South Australia are high. However, the South Australian generation sector has been disaggregated as far as is practical.

Importantly, the figures demonstrate that interconnection has the capacity to strengthen competition throughout the NEM, with the HHI index numbers based on registered capacity dropping considerably when the potential for competition through interconnection is introduced.

11 A definition and derivation of the HHI is provided in ACCC, submission 136, p. 66, footnote 93.

12 ACCC, unpublished figures, calculated on the basis of registered capacity as at July 2002, or on the basis of actual output for 2001. The NEM-wide figures show a theoretical minimum concentration assuming no network constraints and no line losses.

Stronger interconnection of the NEM has the potential to yield a highly competitive generation sector, which is reflected in the HHI index numbers falling below 1000 in the theoretical best case of no network constraints and no network losses (ie. the NEM column in Table 3.2).

However, even with current levels of interconnection included, the HHI index numbers based on capacity suggest that all jurisdictions except Victoria possess a degree of market concentration that is consistent with the presence of market power.

HHI index numbers calculated on the basis of actual output in 2001 indicate a worse problem with all jurisdictions recording results consistent with the presence of market power. The ACCC concluded in its submission that:

**The result is particularly disappointing in NSW and Queensland where there is scope to break up the generation companies in a similar way to Victoria. In both states the generation companies operate as 'portfolio' generators, each owning a number of generating units. Having only three generating companies is not enough to address generator market power, especially when state interconnection is limited.**[13]

The nature of generating units controlled by portfolio generators may strengthen the potential for them to exercise market power. For example, a portfolio generator that owns peaking and base-load generation would have greater potential to implement a bidding strategy (eg. possibly including economic withdrawal of capacity) to drive spot prices higher during periods when the supply and demand balance tightens.

Concerns have been raised about the impact of schemes such as the Electricity Tariff Equalisation Fund (ETEF) in New South Wales and the Benchmark Pricing Agreement (BPA) in Queensland.[14] In particular, ETEF has the potential to create barriers to new investment and entry by generators seeking to compete with government-owned generators. ETEF is discussed further in Box 3.1 below. BPA effectively discourages government-owned retailers from trading the financial contracts underpinning their franchise load commitments within each year, reducing financial market liquidity.



13 ACCC, submission 136, p. 67

14 Queensland's Benchmark Pricing Agreement (BPA) commenced in June 1999. BPA is a commercial negotiation between the Queensland Government and the Government owned retailers over funding for the energy purchase costs for franchise customers. Under the BPA, Queensland Treasury negotiates a fee (or receipt) with the retailers for servicing their franchise load for the next financial year. The subsequent community service obligation (CSO) payment (or receipt) for each retailer would be based on actual revenue received from non-contestable customers less: an allowance for energy purchases at a set rate of $/MWh; a fixed margin; and actual costs incurred in respect of certain charges (eg transmission use of system charges). Where total revenue exceeds expenses, the retailer will be obliged to pay Treasury a franchise surplus (or negative CSO).

## Box 3.1: Electricity Tariff Equalisation Fund (ETEF)

### Main features

ETEF commenced on 1 January 2001. It requires standard retail suppliers in NSW to pay money into a fund when the NSW pool price is below the regulated energy component (REC) recovered from regulated tariffs and receive money from the fund when the pool price is above the REC. ETEF allows the retail suppliers to purchase wholesale energy and earn a regulated margin. NSW state-owned generators would be required to make payments to top up any shortfall in the fund. ETEF would repay generator contributions over time as pool prices rise and the fund balance recovers.

From a retailer's perspective, ETEF operates like a contract for difference (CFD).

However, the same is not true from a generator perspective. If the pool price tends to be below the REC (equivalent to a strike price in a CFD) for long enough the balance of the fund grows due to payments from retailers. However, the generators do not receive the difference payment. If prices tend to be above the REC for long enough then the generators are required to contribute to ETEF, which may have the effect of restricting the capacity they are willing to offer under contract, compared to previous vesting arrangements, due to the potential liability under ETEF.

### Operational performance & market implications

From July 2001 to May 2002, ETEF fund balances grew steadily, reflecting a mild 2001-02 summer, to peak at around $310 million by May 2002.

Between mid May 2002 and the end of June 2002, extreme spot price events occurred on a regular basis in the NSW region. ETEF rapidly diminished toward a nil balance as average prices moved well above the REC, leading to substantial payments to retailers, which were passed through to generators via high spot prices. As noted by NECA in its National Electricity Market Statistical Digest for April to June 2002, this bidding activity added almost a third to overall average prices for 2001-02 in New South Wales, and included more than half of all spot prices exceeding $2,500 MWh in the New South Wales region since market launch.

In effect, the state-owned generators converted the balance of ETEF into pool revenue by departing from their typical offer strategies. The fact that this occurred in the last two months of the 2001-02 financial year may not be a coincidence. If ETEF (and regulated tariffs) did not exist then most likely the retailers and generators would have agreed to some form of CFD, and given the mild spot prices over the 2001-02 financial year, the generators would have received a difference payment.

However, under ETEF, the generators do not receive a difference payment. Generators may have viewed the $300m plus ETEF balance as essentially belonging to their end of year revenue statements. Importantly, all three state-owned generators appeared to take this view and their change in offer strategy resulted in extreme price events. Given the reduced contract position of the generators (a result of ETEF), their uncontracted pool revenues benefited considerably from the resultant price spikes.

What is of greatest concern is that the three generators in NSW could exercise such effective market power at will. This was a period when demand was not high and no major plants failed. The ability of the NSW generators to do this raises serious risk issues for those wishing to enter the NSW market, and illustrates the concerns raised in this chapter.

The range of concerns raised about these type of arrangements in submissions is summarised by the Institute of Public Affairs, which notes that:

**ETEF suppresses market signals for when new generation capacity, especially peak capacity, might be required. Over the longer term it will bring mismatches in energy requirements and availabilities as retailers have a much reduced incentive to signal needs by contracting forward for new supplies.**

**A manifestation of the effect of ETEF can be seen in contract transactions. In relation to the energy market, the turnover of contracts in NSW declined last year while that of Victoria increased fivefold. Victorian retailers and generators were seeking out ways of defraying their risks but in NSW there was far less need to do so because of the Government mandated form of insurance.**

and

**The effect of ETEF also impacts on the operations of private firms that compete with them. New South Wales government retail businesses are shielded in much of their market from competition by other firms.**

**Not only might such shielding of government firms from competition bring risks and stunted market development in the 'home' market, but the government firms' relative immunity from competition may allow them to compete unfairly in other, more open markets.**[15]

The New South Wales Government has noted in its submission to the Review that its electricity businesses operate at arm's-length from the policy and regulatory arms of government, and that they do not benefit from their status as government owned businesses.[16]

However, the perception that governments intervene to protect their commercial interests, or at least to shield themselves from full exposure to commercial risk, remains. Such perceptions have the potential to compromise the integrity of the NEM in the minds of market participants. They have the potential to be extremely damaging to market credibility, promoting uncertainty and sovereign risk that has the potential to undermine investor confidence.

Structural weaknesses, including poorly integrated regional markets combined with sovereign risk resulting from the inappropriate mechanisms adopted by governments to address public policy issues, have the potential to distort efficient NEM operation and development.

## Western Australian electricity market developments

Western Australia has considerable concentration of generator ownership in the South West Interconnected System (SWIS), with the government-owned generator Western Power controlling over 80 per cent of total generation capacity. Ownership is far less concentrated in the North West Interconnected System and among remote generators, which together account for around 20 per cent of total Western Australian capacity. This reflects the impact of the Western Australian Government's competitive tendering policies, which have resulted in considerable diversification of ownership. The current generation market structure and ownership in the SWIS is provided in Table 3.3 below.[17]





15 Institute of Public Affairs, submission 30, pp 32-33

16 NSW Government, submission 147, pp 9-10

17 ESAA (2002), Appendix 1

**Table 3.3: Generation market structure and ownership in Western Australia**

| SouthWest Interconnected System | Owner | Nature of ownership | Capacity (MW) | Share of total capacity (%) | Cumulative total (%) |
|---|---|---|---|---|---|
| | Western Power Corp. | Public | 3210 | 82.3 | 82.3 |
| | Alcoa | Private | 268 | 6.9 | 89.2 |
| | Worsley Alumina | Private | 117 | 3.0 | 92.2 |
| | Edison Mission Energy | Private | 116 | 3.0 | 95.2 |
| | Goldfields Power | Private | 105 | 2.7 | 97.9 |
| | Southern Cross Energy | Private | 84 | 2.1 | 100.0 |

The Electricity Reform Task Force delivered its final report, *Electricity reform in Western Australia - a framework for the future*, to the Western Australian Government on 15 October 2002.[18]

The Task Force has proposed introducing a net pool trading mechanism and changes to the structure of the electricity supply chain. The key features include:

- users and generators to bilaterally contract for supply and advise the system operator of their contractual commitments
- a residual trading market to operate for short term, spot trades
- the system operator to provide an energy imbalance service, and manage transmission congestion using mandatory incremental and decremental price bids
- loads or load serving entities, such as retailers, to contract generation capacity of a set amount above their forecast peak monthly demand
- Western Power's activities in the SWIS to be vertically disaggregated into three independent entities, State Generation, State Networks and State Retail
- Western Power to not be further disaggregated.

The Panel endorses the proposed vertical disaggregation of Western Power to facilitate the entry of new market participants by establishing independent transmission and retail bodies in the SWIS, and providing open access to networks for new entrants. However, it considers that many of the benefits that should be derived from the reforms are unlikely to be achieved unless further changes are made.



[18] Electricity Reform Task Force (2002b)

The Panel is concerned about the Electricity Reform Task Force recommendations in relation to electricity market mechanisms and structural issues, particularly the proposal to maintain the dominance of Western Power in the SWIS.

The Panel believes that it would be an error to create an active energy market but then establish a dominant generator. Its market power would lead to higher electricity prices unless fettered in some way, which is likely to distort the efficient operation and development of the proposed wholesale market.

## PROPOSED SOLUTIONS

A robust market mechanism and structure that will support sustainable competition is necessary to promote efficient operation and development of the NEM, so that it can meet growing demand for reliable and affordable electricity services at least cost to the community.

In the Panel's view, the energy only design of the NEM can provide as strong a set of investment signals as is possible, provided that measures that serve to distort the operation of the market are removed and the demand side is enabled to respond more adequately at times of high prices and system stress.

In the current NEM mechanism, Australia has an appropriately robust mechanism, provided it is enabled to operate to its potential. To achieve this, the Panel proposes that:

- the generation sector structure be made substantially more competitive
- inter-regional electricity trade be facilitated
- market distorting mechanisms be removed
- the ACCC Merger Guidelines for the electricity industry be tightened.

### The generation sector structure to be made more competitive

Sustainably robust market structures are unlikely to emerge while ownership of generation remains concentrated and other barriers to entry persist.

The Panel considers that jurisdictions which currently own generation assets have an opportunity to rectify undue regional concentration of ownership by pursuing appropriate disaggregation of their portfolio generation businesses to create more sustainably competitive regional markets.

Further divestment is required to reduce concentration of ownership and control within some NEM regions. This would minimise the risk of any generator, whether private or publicly owned, being able to exercise market power to the detriment of efficient NEM operational and developmental outcomes.

Divestment of the remaining government owned electricity assets may also yield other benefits. It would help clarify the role of government by removing any perception of conflict of interest, ensuring that the rule maker and regulator is no longer a market participant. It would also reduce potential competitive neutrality concerns by ensuring that no market participant unduly benefits from government ownership. Such divestment would reinforce the integrity of the market and participant confidence, providing greater certainty for new investment in the NEM.

However, divestment of government-owned generation is less important provided the full package of proposed measures are implemented, given their potential to address stakeholder concerns by substantially improving governance arrangements, strengthening generator competition, increasing inter-regional trade and underpinning efficient financial risk management.

## Facilitate inter-region trade

Enabling effective trade in electricity between the NEM regions is a pressing matter for market development and efficiency. This matter is dealt with extensively in Chapter 4. Governments should pursue the initiatives outlined there to encourage more efficient levels of inter-regional trade and transmission development, which have the potential to promote more sustainable competition between generators across the NEM and reduce potential for any one generator to exercise market power.



## Market distorting mechanisms to be removed

Interventionist policies which have the potential to undermine the development of genuine and sustainable competition, create sovereign risk, erode investor confidence and distort efficient NEM operation and development should be removed. ETEF in New South Wales and BPA in Queensland are particular examples retarding efficient NEM development.

## The ACCC merger guidelines to be tightened for the electricity sector

Specific criteria need to be included in the ACCC's Merger Guidelines to guide decisions in relation to mergers between generators. The ability of generators to exercise market power in a costly way at particular times should be explicitly recognised.

## Western Australian reforms

To achieve a competitive outcome, Western Power's generation assets need to be disaggregated into as many separate competing units as is practical, rather than seek to address structural weaknesses through complex regulatory arrangements.

As identified elsewhere in this Chapter, establishing and maintaining a competitive generation sector is vital to achieving sound electricity market outcomes. The Panel considers this to be true regardless of the market mechanism used.

# RECOMMENDATIONS

3.1 The New South Wales Government should further disaggregate its generation assets.

3.2 The Western Australian Government should disaggregate Western Power's existing generation portfolio in the South West Interconnected System into as many separate units as is practical.

3.3 Once appropriate generation structures are in place, governments that currently own generation assets should pursue a program of divestment, with a view to completely exiting the market, or at least reducing ownership to a single generator.

3.4 Governments should pursue initiatives to address transmission problems (see Chapter 4).

3.5 The NSW Government should abolish the Electricity Tariff Equalisation Fund and the Queensland Government should abolish the Benchmark Pricing Agreement as soon as possible and irrespective of whether retail price caps are removed.

3.6 The Australian Competition and Consumer Commission should include specific criteria in its Merger Guidelines that explicitly address the potential for generators to exercise market power.

# 4 ELECTRICITY TRANSMISSION

## CONTEXT

### Transmission networks are critical for the NEM

This area was identified by many submissions as one of the most important in the Review. The Panel considers that transmission network services are critical to the development of a competitive National Electricity Market (NEM).

Transmission is also one of the major problem areas faced by overseas electricity markets. Considerable focus on this overseas has not resulted in a perfect or simple solution.

Transmission networks enable inter-regional trade, which allows competition between generators and retailers in different regions. The increased competition reduces the ability for market participants to exercise market power. Transmission also provides an efficient means of sharing reserve capacity between regions within the NEM, enabling reliable electricity services to be delivered throughout the NEM at least cost.

Key issues raised in submissions included:

- improving network pricing arrangements, including the potential for transmission property rights
- transmission planning arrangements
- incentives for more market responsive network operation
- the investment signals and processes, particularly for new regulated transmission augmentations
- the role of transmission network services and potential for coexistence of market and regulated transmission network services

- the need for reform of transmission network services regulation, particularly the regulatory benefits test
- the need for more transmission capacity, particularly interconnects
- the level of inter-regional contracting is very low because of transmission constraints
- transmission constraints allow the exercise of market power in regional markets.

## Transmission network policy developments

Governments recognised the importance of transmission network services from the outset, and have given considerable attention to developing market and regulatory arrangements that will encourage the efficient operation and development of these services.

The Council of Australian Governments (COAG) objectives for a fully competitive NEM recognised the importance of inter-regional trade for efficient market development and the emergence of effective customer choice, and identified non-discriminatory access to the interconnected network as a principal objective in this context.[1] COAG reaffirmed its commitment to this and other key electricity reform principles at its June 2001 meeting.[2]

Consistent with these objectives, COAG also agreed a set of high-level principles for pricing transmission network fixed costs.[3] Unresolved transmission network pricing issues were referred to the National Grid Management Council for further consideration.[4] However, governments were unable to satisfactorily resolve many of the complex details and agreed an interim set of arrangements for transmission and distribution pricing to facilitate NEM commencement. Key features of the transmission pricing arrangements include:



- entry and exit charges recovered through a fixed annual charge on users at each connection point
- net transmission use of system charges (TUOS)[5] recovered through a combination of cost-reflective network pricing (50 per cent of net TUOS charges), and postage stamp pricing
- common service charges recovered through a postage stamp charge on each connection point, with individual users at each connection point paying an energy-based variable charge.[6]

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[1] COAG (1994), Attachments 2(a) and 2(b)
[2] COAG (2001)
[3] COAG (1994), Attachment 3(a)(i)-(ii)
[4] COAG (1994), Attachment 3(a)(iv)-(v)
[5] Net of revenues derived from settlement residue auctions, which are applied to reduce TUOS charges.
[6] Details are contained in the National Electricity Code, Chapter 6, Part C

These interim transmission pricing arrangements are not particularly cost-reflective and provide ineffective signals for efficient use of transmission networks, particularly when they physically constrain. The considerable reliance on averaging and postage stamping also mutes locational pricing signals for new investment, both in transmission and generation.

Governments recognised these shortcomings and referred transmission pricing arrangements to the National Electricity Code Administrator (NECA) for review. Key Electricity Code[7] provisions NECA was required to review included:

- the merits of arrangements specified in Part C (transmission pricing) and Part E (distribution pricing) of Chapter 6 of the Code including:
  - efficacy of price signals in promoting economically efficient outcomes
  - equity and access considerations
  - the locational signals resulting from the transmission and distribution pricing regimes, including the appropriate balance between cost-reflective and postage stamp elements of charges and the incidence and treatment of cross-subsidies
  - whether there is a need for a framework for firm access and, if so, appropriate arrangements
  - appropriate incidence of TUOS charges, and the pros and cons of unbundling TUOS charges
- review of the adequacy and appropriateness of the existing criteria for the determination of regions (Clause 3.5.1(e) of the Code)[8]
- the financial impact of distribution loss factors on market participants (Clause 3.6.3(h) of the Code).

Several proposals have been advanced by NECA and the Australian Competition and Consumer Commission (ACCC) in the context of the Transmission and Distribution Pricing Review and NECA's Scope for Integrating the Energy Market and Network Services to improve efficient operation and development of transmission networks, and to strengthen cost-reflective transmission pricing. Proposals have included application of a more refined beneficiary/causer pays model through to a congestion management regime, and proposals to improve locational pricing signals through a refined regional structure. Work is continuing to develop the beneficiary pays model, with some more technical modifications being implemented, including pass-through of TUOS savings resulting from the operation of embedded generators.

[7] NECA (2001)

[8] NECA (1999), p. 3. Criteria for regional boundaries and loss factors were considered in the same study.

Proposals have received a mixed reception. Concerns have been raised about the practicality and complexity of the proposed changes; their implications for price stability and cost of network services, particularly during extreme events or peak periods when networks are likely to physically constrain; and implications for managing exposure to risk.

At its July 2002 meeting, the NEM Ministers Forum agreed to initiate a process to review the framework for transmission development and pricing. This review will include a study of options to undertake transmission planning and the setting of regional boundaries. It is anticipated that NEM Ministers will consider the findings of this review around June 2003.[9]

In the interim, NEM Ministers have written to the National Electricity Market Management Company (NEMMCO), NECA and the ACCC requesting that they consider the outcomes of this process in the context of resolving transmission development and pricing issues.

Although nearly five years have elapsed since NECA commenced work to address the interim arrangements, a sustainable resolution to promote efficient operation and development of transmission networks, and strengthen cost-reflective transmission pricing is yet to emerge.

## KEY FINDINGS

Competition reform of the electricity supply industry has fundamentally changed the environment in which transmission networks operate and consequently the nature of the transmission network business. Central planning and operation of electricity infrastructure on a regional basis by an integrated utility has been replaced with decentralised decision making by separate generators and retailers responding to commercial incentives.



Accordingly, regional transmission network service providers (TNSPs) have far less certainty about the demands that will be placed on their networks. They also have less capacity to undertake integrated planning and development of the transmission network as a whole. The network extends beyond single regions, has multiple owners and individual TNSPs have little capacity to manage the challenges resulting from new generator investments and evolving load patterns.

This new commercial reality has fundamentally changed the way that the transmission system is operated. It cannot be ignored, nor can it simply be managed by quarantining TNSPs from the consequences of their operations on contestable electricity markets.

[9] NEM Ministers Forum (2002)

Problems are apparent including continuing underdevelopment of inter-regional trade, regionalisation of the NEM, and inefficient bidding and dispatch practices to address intra-regional constraints.[10]

These weaknesses may magnify potential abuse of market power, hinder efficient market development and undermine cost-effective outcomes for users.

The Panel has identified four critical problems with current transmission network arrangements:

- absence of nationally focused and coordinated transmission network planning
- failure to facilitate sufficient inter-regional trade and competition
- poor incentives for transmission investment, particularly uncertainty over approval processes governing regulated transmission investment
- poor responsiveness of transmission network services to contestable electricity market requirements.

## Absence of nationally focused transmission planning arrangements

Concerns have been raised about existing regulated network planning arrangements including:

- that current transmission planning is undertaken on a regional rather than NEM-wide basis, with unclear responsibilities for interconnect planning
- a real or perceived lack of independence in planning processes dominated by incumbent TNSPs
- a lack of available detailed and accurate information on network performance.

The nature of electricity networks requires integrated and independent planning across the entire NEM to ensure efficient network development.[11] Regional planning in isolation of its NEM-wide implications can create unanticipated operating constraints.

The Inter-regional Planning Committee (IRPC) planning process for interconnector augmentation has proven less than effective, as its responsibility extends only to interconnect

10 The potential substantial costs associated with managing intra-regional constraints are discussed in Intelligent Energy Systems (2002a), Appendix 3, pp 89-92

11 The physics of electricity networks means that physical changes within any part of an interconnected network can have significant implications for the operation of any other part of the network, particularly changes to transmission networks.

planning and excludes intra-regional transmission planning. Concerns have also been raised about its composition, particularly the inclusion of incumbent TNSPs, which may have competing commercial priorities that could undermine the IRPC's effectiveness as a NEM-wide planning body.[12]

Integrated, centralised planning may be less important for market network services, where investment is driven by decentralised decision making in response to price signals. However, access to accurate, timely, and detailed information on the nature and physical performance of the interconnected network would be critical to the successful participation of market network service providers, as it would facilitate more timely and appropriate investment responses. Given that incumbent TNSPs are likely to have little incentive to provide such information to potential competitors, it is unlikely that sustainable competitive network services would be able to emerge unless this information asymmetry is addressed.

The Panel notes that the Network and Distributed Resources package of Code changes approved by the ACCC earlier this year attempts to address some of these concerns. However, the package does not fulfil the objectives the Panel has identified for transmission to play its market–supporting role. For example, it does not address the need for independent system-wide planning. Current planning arrangements have contributed to:

- a lack of integration in transmission network planning throughout the NEM
- continuing doubts over the credibility of planning processes among stakeholders, hindering competitive delivery of investment responses, both generation and network responses
- delays in resolving network constraints, both inter and intra-regional constraints.



## Poor signals and certainty for network investment

Concerns have been expressed about the lack of new regulated interconnects that have been proposed and approved. Since NEM commencement in December 1998, only two regulated proposals have been advanced and approved — the South Australia to New South Wales Interconnect (SNI) and the Snowy to Victoria Interconnect Upgrade (SNOVIC) — with the SNI approval only recently confirmed following an appeal. The National Competition Council has stated that:

**… the delays experienced by the SNI application indicate possible problems with the process for evaluating regulated interconnectors. Further, the delays suggest that the NEM**

[12] NEMMCO (2001), pp 21-22

**objective of no discriminatory legislative or regulatory barriers to interstate and/or intrastate trade is not being met.**[13]

Weaknesses in the rules and approval processes applying to regulated interconnectors have been identified including:

- the nature and application of the regulatory test for new regulated interconnectors
- potential for conflict of interest within the IRPC (which assesses and advises NEMMCO on aspects of new proposals)
- unduly long administrative processes
- potential for competitors to game the process.[14]

Concerns have also been raised about the inability to access the information required to develop new network augmentation proposals.

At the heart of these concerns is the problematic regulatory benefits test. The Panel considers that the key problem with the benefits test is that it does not fully recognise the commercial benefits associated with alleviating network constraints between regions. Many of the concerns raised in submissions about the test and more broadly about the approval process are well summarised by Intelligent Energy Systems in its report to the NEM Ministers Forum, which states that:

**The test, as interpreted by the IRPC, does not attempt to assess or include the benefits that would arise through increased competition or the spillover effects that could potentially be captured by a coalition of investors. The result can be to undervalue interconnector augmentation.**

**There is an anomaly between the market-driven and least-cost planning scenarios required under the test, in that they are not symmetrically defined.**

**The NEMMCO reserve criterion as used in the test and as implemented does not give sufficient regard to the potential variability of the firmness of interconnector capacity. The result of this can be to overestimate the reliability of interconnector support and consequently underestimate the need for additional interconnection.**[15]

The result has been uncertainty, protracted regulated investment processes and delayed (and possibly inappropriate) investment responses.

13 NCC (2001), p. 6.11

14 NEMMCO (2001), pp 2-5

15 IES (2002a), p. 7

### Failure to facilitate sufficient inter-regional trade and competition

Concerns have been raised about the lack of physical interconnection between regions within the NEM and its negative implications for the development of inter-regional trade and competition.

A key finding of the International Energy Agency's (IEA) in-depth review of Australian energy policy related to the lack of interconnection between NEM regions. The IEA stated that:

**The NEM is not yet strongly integrated; the amount of electricity traded is comparatively low and prices can differ across NEM regions, particularly when transmission constraints emerge. During periods of peak demand, the network can become congested and the NEM separates into its regions, potentially exacerbating reliability problems and market power of regional utilities. Solutions comprise more transmission interconnection, new generation and demand-side measures. In the IEA's view, transmission augmentation is essential for better integration. Several private, unregulated (entrepreneurial) interconnectors are under construction, but better signals for investment are needed.**

**The main challenge in the Australian power market is to complete the highly successful electricity reforms by reviewing transmission pricing with a view to strengthening interconnection …**[16]

These sentiments have been echoed by the National Competition Council (NCC) in its third tranche assessment for competition policy payments[17], and in several submissions[18] to the Review.

However, work undertaken for the NEM Ministers Forum suggests that physical congestion of interconnectors is a relatively minor problem in the NEM. According to this analysis, NEM interconnectors constrained for a total of 25 hours during 2001, with a maximum total constraint of 7 hours from Queensland to NSW on QNI. The report concluded that with the construction of SNOVIC, Basslink and SNI there would be sufficient physical interconnect capacity to capture the majority of the potential competition benefits, including moderating market power abuse, and to provide efficient reserve and capacity sharing for the next five to six years.[19]

Although physical constraint of NEM interconnectors may be a relatively minor problem from a short term reliability perspective, it is a substantial impediment to inter-regional trade.

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16 IEA (2001), p. 7

17 For example, NCC (2001), pp 6.10-6.13

18 For example, the Energy Users Association of Australia, submission 88; Business Council of Australia, submission 62 and Amcor & Paperlinx, submission 54

19 IES (2002), p. 29

**Table 4.1: Incidence and cost of price separation in the NEM during 2001-02**[20]

| Month | Number of events | Cost of events ($m)(*) |
|---|---|---|
| July 2001 | 0 | - |
| August 2001 | 3 | 29.0 |
| September 2001 | 0 | - |
| October 2001 | 15 | 28.1 |
| November 2001 | 1 | 4.3 |
| December 2001 | 4 | 34.8 |
| January 2002 | 1 | 0.5 |
| February 2002 | 14 | 18.5 |
| March 2002 | 1 | 0.1 |
| April 2002 | 3 | 0.7 |
| May 2002 | 26 | 308.6 |
| June 2002 | 20 | 216.9 |
| Total 2001-02 | 88 | 651.5 |

*Notes:*

*A 'price separation event' is defined as any half hour where the price in any region is >$300/MWh higher than any other region.*

*Cost of price separation is calculated as (eg. if Queensland is separated = (Queensland Pool Price - min NEM Pool Price - 300) x Queensland load). That is, the cost is the additional cost of energy incurred because prices weren't constant (within $300/MWh) across the NEM.*

* *This may overstate the cost as with full interconnection the cost could have risen in the low price NEM region by >$300/MWh.*

Table 4.1 indicates that although price separation events were relatively uncommon (0.5 per cent of trading periods during 2001-02), this separation may have increased the cost of electricity in NEM by up to 11 per cent during 2001-02. Had the NEM been better interconnected, and had no significant price separation occurred, up to $650 million could have been saved.

Irrespective of the level of interconnection, physical constraints between regions are of critical concern where they undermine the development of efficient levels of contracted interstate trade

[20] Port Jackson Partners Ltd, unpublished, October 2002

and efficient integration of the NEM at a wholesale and retail level. The key issue is the ability of market participants to manage the financial risks that result from the potential for interconnects to physically constrain or fail.

The Settlement Residue Auction (SRA) process was established to provide a means for market participants to manage the risks associated with inter-state trade. It enables market participants to purchase a share of any settlement residues that accrue as a result of spot price separation between two interconnected regions. In this way, market participants trading between regions have the ability to manage their exposure to price separation.

However, this instrument does not provide access to settlement residues when interconnects fail or are taken from service for maintenance. In these circumstances, no settlement residues accrue, and market participants are completely exposed to spot price divergence between regions. In effect, the settlement residue instrument does not provide firm financial access to the interconnected network when interconnects fail. As NEMMCO states:

**The potential inter-regional trading risks faced by participants in the NEM are illustrated by an event that occurred on 15 January 2001. On that occasion the physical interconnection between New South Wales and Victoria was severed in the Snowy region. The interconnection had a nominal capacity of 1500 MW from Snowy to Victoria and 1000 MW in the reverse direction. If 500 MW of firm inter-regional hedges had existed then hedge holders would have received compensation of up to $180,000 for a single half-hour. If those same participants had held SRA units they would have received no compensation.**[21]

The present simplified regional structure of the NEM[22] can serve to exacerbate these problems by masking ongoing constraints in the intra-regional transmission network, which have the potential to severely reduce interconnect capability. As noted above, the inefficient, non-market fixes currently employed to address intra-regional constraints are likely to be expensive, inefficient and fundamentally unsustainable.



A combination of a lack of access to firm financial instruments to manage inter-regional trading risk across interconnects and an inappropriately defined regional market structure has produced:

- inefficiently low levels of contracted inter-regional trade, with the potential to restrict the development of related financial markets

[21] NEMMCO, submission 57, p. 36

[22] The NEM is built around a simplified regional model consisting of five regions, with a sixth (Tasmania) expected to be added in 2005. These regions essentially mirror jurisdictional boundaries.

- a consequent reduction in effective wholesale and retail competition throughout the NEM
- delayed development of an integrated NEM.

## Poor transmission network responsiveness to markets

At present the vast majority of transmission network services are provided by regulated entities. Many submissions to the Review have identified the relative unresponsiveness of regulated transmission services to market requirements as a substantial impediment to efficient market operation and development.[23]

The principal reason for this unresponsiveness is that regulated TNSPs are not directly exposed to the market consequences of their operational and maintenance activities. They have no incentive to respond to high priced events in the spot market, as their regulated revenues are determined in isolation of the market price impacts of network operation.

Regulatory performance requirements can exacerbate this problem by focusing on minimising cost of service rather than maximising market responsive network capability. These requirements can encourage regulated TNSPs to adopt asset management practices that could lead to the perverse outcome of scheduling routine maintenance during a peak period, rather than during an off peak period, because it would minimise labour costs (i.e. reducing marginal operating costs).

The financial consequences for the market can be devastating. NEMMCO notes that:

**… in late October 2001 a network outage in New South Wales affecting the transfer capability between New South Wales and Queensland, contributed to an increase in ancillary service costs of more than $50M over 5 weeks.**[24]

Even if regulated TNSP revenues were exposed to the market consequences of network operation, for example through some form of congestion pricing, questions have been raised about TNSPs' capacity to effectively manage this exposure within a competitive market structure and under current regulatory arrangements.

[23] For example: ESAA, submission 4; NECA, submission 81; NEMMCO, submission 57; Hydro Tasmania, submission 21; Southern Hydro, submission 13; Ergon Energy, submission 17; Holden, WMC, Visy Paper, OneSteel & BHP Billiton, submission 46; ElectraNet SA, submission 65; SPI PowerNet, submission 75; Stanwell Corporation, submission 107; and DNRE, submission 126.

[24] NEMMCO, submission 57, p. 41

Network performance is influenced by several factors, some of which are outside TNSPs' direct control within a competitive market structure. TransGrid has identified several factors, which are either under the control of other market participants or market institutions.[25]

SPI PowerNet suggests that the limited capacity of TNSPs to manage commercial risks is the principal factor that may limit the potential to expose them to more commercial incentives.[26]

Regulatory arrangements would need to provide TNSPs with the necessary flexibility to efficiently manage the commercial risks resulting from greater exposure to the financial consequences of their operational performance.

Exposing market participants to cost-reflective network prices is also important to create appropriate commercial incentives to encourage the efficient use and development of networks. Its importance is magnified in remote areas and within embedded networks where total network charges can represent a substantial proportion of delivered electricity costs.[27]

Cost-reflective network pricing (CRNP) is a principle in the National Electricity Code. However, it has not been fully applied in the NEM due to existing derogations, which are due to expire at the end of 2002.[28]

Although generators are directly exposed to the cost of network losses and indirectly exposed to the cost of network constraints (through volume risk) under present arrangements, they do not typically pay TUOS, and are therefore not directly exposed to the full cost of network use. It has been suggested that incumbent generators' lack of exposure to TUOS may distort efficient investment decisions between remote and embedded generation, undermining the competitiveness of embedded generation.[29]



User exposure to CRNP is valuable under a competitive network model, where transparent prices would reinforce the commercial incentives for user responses to network prices.[30]

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25 TransGrid, submission 41, pp 3-4

26 SPI PowerNet, submission 75, pp 8-12

27 Queensland Treasury analysis suggests that network charges can represent between 60 per cent and 80 per cent of total delivered electricity costs for most rural and regional users in Queensland, and represent over 80 per cent of total charges for regional users in far North Queensland. See Queensland Treasury, submission 129, Table 1, p. 17.

28 ACCC, submission 136, p. 61

29 Australian EcoGeneration Association, submission 86, pp 13-18

30 Such as forming coalitions of beneficiaries to fund network investment, and stimulating demand for financial property rights to manage risk exposures.

The current practice of averaging of losses within regions also provides a cross-subsidy between different users on the network, significantly masking the real cost of network services. For example, within the existing Queensland region, losses can vary from around 1 per cent to 10 per cent, yet these costs are averaged across the region.[31] Continuation of such cross-subsidies will likely undermine incentives for efficient use and development of transmission networks, and possibly preclude otherwise efficient alternatives, such as remote area power systems and embedded generation.

The Panel acknowledges that transmission network pricing raises a number of complex issues which are yet to be resolved. However, it is unlikely that a sustainable solution to these issues can be achieved in the absence of more fundamental structural and regulatory reform. Accordingly, the Panel has sought to address those more fundamental priorities, which are a prerequisite to resolving the network pricing issues.

A combination of poor regulatory incentives and excessively averaged network pricing has led to:

- transmission network services that are unresponsive to market requirements
- the undermining of price signals for efficient network use and development.

## PROPOSED SOLUTIONS

The Panel considers that there is considerable scope for improving the transmission arrangements in the NEM. The Panel proposes that:

- NEMMCO be given responsibility for transmission planning
- NEMMCO auction firm financial transmission rights (FTRs)
- the price of FTRs to be used as the key indicator of the need for transmission augmentations
- explicit incentives be introduced to financially reward or penalise regulated TNSPs according to the availability of transmission lines during peak price periods
- the number and location of regions be set by the needs of the NEM.

[31] Queensland Treasury, submission 129, Table 1 & Table 2, pp 17-18

## NEMMCO be given responsibility for transmission planning

A NEM-wide and independent planning process is required to ensure that appropriate network development opportunities are efficiently developed.

The Panel considers that NEMMCO is uniquely placed to undertake this function:

- As market and system operator NEMMCO has considerable understanding of the whole transmission network to undertake efficient and timely NEM-wide planning. It would be able to build on synergies derived from its system operating functions and its current involvement in the IRPC process for interconnector development.
- NEMMCO is a not-for-profit body charged with undertaking its functions in a manner that will promote efficient market development, adding credibility to the process among market participants.
- NEMMCO has access to accurate and detailed information about transmission network performance and constraints.

NEMMCO's responsibilities should extend to planning for the inter-regional and intra-regional transmission network. NEMMCO may delegate to individual TNSPs responsibility for some aspects of the planning function, but this shall not extend to the 'transmission backbone'. For these purposes, the transmission backbone is represented by those elements of the network for which NEMMCO has system operation responsibilities under the Code.

NEMMCO's accountability would be achieved through Code requirements that establish its planning objectives, consistent with its existing Code objectives of promoting efficient and sustainable market development.



The Panel considers that the proposed planning function needs to be complemented with a competitive tender process operated by NEMMCO for new regulated transmission investments. A tendering process would provide a competitively neutral mechanism for achieving the most cost effective response.

The Panel considers that this planning function would not crowd out private investment responses, whether from generation, market network service providers or demand-side participants, as the trigger for such processes would be linked to the value of FTRs and based on transparent planning and investment information provided to the market by NEMMCO well in advance. This is discussed further in the investment section below.

Accordingly, the Panel considers that NEMMCO's key planning functions should include:

- provision of independent and accurate information to inform augmentation processes
- highlighting potential augmentation opportunities, similar to the function it currently performs through the annual Statement of Opportunities
- managing a regulated transmission augmentation process through a competitive tendering process.

## NEMMCO to auction firm financial transmission rights

FTRs are the key to unlocking efficient inter-regional trade and strengthening competition within an integrated NEM.

Physical rights are impractical, given the difficulties of matching actual physical flows of electricity to contractual property rights within an electricity network.[32] However, the same financial outcome can be achieved through a firm FTR, which confers a financial property right equivalent to a physical right.[33]

Firm FTR instruments:

- are superior to settlement residue surpluses in that they confer financial rights irrespective of the physical condition of the network, thereby providing purchasers with a certain cash flow and robust means of managing financial risks associated with inter-regional trade
- enable transparent pricing and management of risk, allowing risk to be defrayed at least cost by parties best able to manage it, creating appropriate incentives for efficient risk management behaviour
- provide the means to achieve the greatest value from having more regions or nodal pricing (see below).

It is appropriate to incorporate network losses into the FTR instrument, reflecting the considerable losses that can accrue over the large distances covered by the NEM. Pricing both constraints and losses could improve the viability of FTRs, by enhancing the revenue stream, and strengthening the value of the property right to users.[34]

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32 Electricity flows follow the path of least resistance within a free-flowing network. These flows can, and do, change frequently according to system conditions and usage patterns, making it practically impossible to align flows to a contract path, which is a prerequisite for creating a physical property right.

33 A more detailed explanation is provided in Hogan (1999), pp 14-16

34 ACCC, submission 136, p. 60

The Panel considers that, in principle, the most effective way to create a sustainable financial incentive to influence regulated TNSP behavior would be to expose them to the risks and returns associated with underwriting firm service contracts over interconnects. This implies that TNSPs should be directly exposed to the financial consequences of providing firm FTRs, and have sufficient flexibility and commercial incentive to efficiently manage the associated risks.

However, in practice, this may prove to be problematic for a variety of reasons including:

- A single TNSP cannot be held accountable for the servicing of FTRs between points in a free-flowing network which includes a number of different owners.
- As the TNSPs indicated to the Panel, they would be unable to manage all the risks associated with underwriting a firm FTR product because important factors affecting network capability are outside their individual control.[35]
- For-profit TNSPs are natural monopolists and may seek to use FTRs as a means of creating and exercising market power, to the detriment of inter-regional trade and the development of efficient and sustainable competition within the NEM.
- Poor incentives may exist for market participants to purchase FTRs, reflecting potential to catch a 'free ride' on the spill-over benefits which can result from the operation of individual network assets within a larger open access, free-flowing network.

A combination of these factors may result in regulated TNSPs making an inefficiently small volume of firm FTRs available to market participants. Such an outcome would have the potential to undermine the development of efficient levels of inter-regional trade and threaten the development of sustainable competition within an integrated NEM.



A more appropriate and sustainable response would involve a central entity offering and underwriting firm FTRs for regulated interconnects. The Panel considers that NEMMCO is ideally suited to perform this function:

[35] TransGrid, submission 41, p. 3

- NEMMCO as the market and system operator can draw on its unique expertise regarding the physical operation of the interconnected transmission network to ensure that firm FTRs offered for each interconnect confer a feasible and sustainable financial property right.[36]
- NEMMCO is able to pool risks across regions, helping to minimise the risk and cost of providing firm FTRs.
- NEMMCO is a not-for-profit body that will undertake its FTR functions subject to Code objectives and requirements. Its activities would be monitored by the NER to ensure Code compliance.

NEMMCO would auction firm FTRs each year, covering a period five years in advance:

- NEMMCO FTRs would apply to existing regulated interconnects.
- The firm FTRs would expose NEMMCO to the spot price divergence between interconnected regions.
- When spot prices diverge, NEMMCO would be liable to pay FTR holders the difference between spot prices multiplied by the volume of FTRs sold.
- NEMMCO would retain the settlement residues associated with regulated interconnects and auction proceeds to fund firm FTRs.
- NEMMCO would be able to set a reserve price, reflecting the Panel's concern that the market for FTRs may be too thin to ensure fair auction prices years in advance.

Box 4.1 presents a simplified example to illustrate the cashflow implications of implementing the Panel's firm FTR proposal.





[36] Network externalities refer to the derived impact a new network investment can have on the physical capacity/operation of other elements of the network. Such externalities have the potential to erode or eliminate financial property rights on existing interconnects, undermining the value of related firm FTRs and their effectiveness in supporting inter-regional trade and strengthening competition. As a result, it would be necessary for an independent entity spanning the entire interconnected network to undertake a feasibility assessment to ensure that FTRs issued for any network augmentations or new investments do not erode existing financial property rights. This issue is discussed in Hogan (1999), pp 27-28.

## Box 4.1:
## Cashflows under 'firm' financial transmission rights — a simplified example

### Assumptions:

- A single 100 MW transmission line connects two regions (Region A and Region B).
- Supply, demand and bidding characteristics in Region A and Region B for a given trading period are as follows:

### Region A

**Generator X**

- 300 MW @ $25 MWh
- 50 MW @ $40 MWh
- 50 MW @ $45 MWh

**Aggregate Demand (Retailer K)**

400 MW

### Region B

**Generator Y**

- 300 MW @ $10 MWh
- 200 MW @ $20 MWh
- 100 MW @ $30 MWh

**Aggregate Demand (Retailer L)**

500 MW

- Losses are excluded.
- A generator in Region B (Generator Y) enters into a financial contract with a retailer in Region A (Retailer K) to supply 10 MW of electricity each period at $35 MWh in Region A.
- NEMMCO auctions off 100, one megawatt, firm FTRs for the 100 MW interconnect from Region B to Region A. Generator Y purchases 10 MW of FTRs.
- NEMMCO as the underwriter of the firm FTRs receives the auction proceeds and any settlement residues to fund its FTR obligations.



### Example A: Base case with no constraints

- Spot price = $30 MWh in both regions.
- No settlement residues accrue.
- FTR holders receive no payments from NEMMCO in relation to their FTRs, as prices between regions are identical.
- Generator Y receives a $50 payment from Retailer K to settle its contracted position (i.e. the contract strike price less the spot price in Region A [$35 MWh - $30 MWh = $5 MWh] multiplied by the contracted volume [10 MW]).

### Example B: Interconnector derated to 50 MW

- Spot price in Region A = $40 MWh, while spot price in Region B = $30 MWh
- Total settlement residues of $500 accrue (i.e. the spot price difference between Region A and Region B [$40 MWh - $30 MWh = $10 MWh] multiplied by the volume of the interconnector flow that was available [50 MW])
- FTR holders would receive an aggregate payment from NEMMCO of $1000 (i.e. spot price differential [$40 MWh - $30 MWh = $10 MWh] multiplied by the volume of the FTRs sold [100 MW]). Individual FTR holders would receive a share of this total in proportion to the volume of their FTR holdings. For example, Generator Y would receive $100 (i.e. the share (10 FTRs) divided by the total number of FTRs auctioned (100 FTRs) multiplied by the total payment from NEMMCO ($1000)).
- Generator Y needs $100 to cover its contract position: comprising a $50 payment to Retailer K (i.e. the spot price in Region A less the contract strike price [$40 MWh - $35 MWh = $5 MWh] multiplied by the contracted volume [10 MW]); and the $50 cashflow shortfall resulting from the difference between the contract strike price and the spot price in Region B (i.e. the contract strike price less the spot price in Region B [$35 MWh - $30 MWh = $5 MWh] multiplied by the contracted volume [10 MW]). However, it receives $100 for its FTRs, enabling it to exactly cover its contract exposures and meet its revenue requirements.

### Example C: Complete interconnector failure

- Spot price in Region A = $45 MWh, while spot price in Region B = $20 MWh
- No settlement residue would accrue as the line is not available and each region is independently settled.
- FTR holders would receive an aggregate payment from NEMMCO of $2500 (i.e. spot price differential [$45 MWh - $20 MWh = $25 MWh] multiplied by the volume of the FTRs sold [100 MW]). Individual FTR holders would receive a share of this total in proportion to the volume of their FTR holdings. For example, Generator A would receive $250 (i.e. the share [10 FTRs] divided by the total number of FTRs auctioned [100 FTRs] multiplied by the total payment from NEMMCO [$2500]).

- Generator Y needs $250 to cover its contract position: comprising a $100 payment to Retailer K (i.e. the spot price in Region A less the contract strike price [$45 MWh - $35 MWh = $10 MWh] multiplied by the contracted volume [10 MW]); and the $150 cashflow shortfall resulting from the difference between the contract strike price and the spot price in Region B (i.e. the contract strike price less the spot price in Region B [$35 MWh - $20 MWh = $15 MWh] multiplied by the contracted volume [10 MW]). However, it receives $250 for its FTRs, enabling it to exactly cover its contract exposures and meet its revenue requirements.

### Example D: Peak demand in Region A

- Aggregate demand in Region A increases from 400 MW to 500 MW for the trading period.
- Spot price in Region A = $45 MWh, while spot price in Region B = $30 MWh.
- Total settlement residues of $1500 accrue (i.e. the spot price difference between Region A and Region B [$45 MWh - $30 MWh = $15 MWh] multiplied by the volume of the interconnector flow [100 MW]).
- FTR holders would receive an aggregate payment from NEMMCO of $1500 (i.e. spot price differential [$45 MWh - $30 MWh = $15 MWh] multiplied by the volume of the FTRs sold [100 MW]). Individual FTR holders would receive a share of this total in proportion to the volume of their FTR holdings. For example, Generator Y would receive $150 (i.e. the share [10 FTRs] divided by the total number of FTRs auctioned [100 FTRs] multiplied by the total payment from NEMMCO [$1500]).
- Generator Y needs $150 to cover its contract position: comprising a $100 payment to Retailer K (i.e. the spot price in Region A less the contract strike price [$45 MWh - $35 MWh = $10 MWh] multiplied by the contracted volume [10 MW]); and the $50 cashflow shortfall resulting from the difference between the contract strike price and the spot price in Region B (i.e. the contract strike price less the spot price in Region B [$35 MWh - $30 MWh = $5 MWh] multiplied by the contracted volume [10 MW]). However, it receives $150 for its FTRs, enabling it to exactly cover its contract exposures and meet its revenue requirements.

NEMMCO would have flexibility to manage the risks resulting from underwriting firm FTRs on the basis of settlement residue cash flows and auction proceeds. NEMMCO would also be able to determine the volume of FTRs to sell, subject to feasibility requirements.

NEMMCO would be required to minimise the cost to the market of providing FTRs:

- NEMMCO would be required to minimise any deficits or surpluses of FTR proceeds over settlement residues (including all risk management costs).
- It would also be required to maximise the volume of FTRs for sale.
- Any residual costs would be covered by market participants through a separate and transparent levy as a last resort, while operating surpluses can be rolled-over to facilitate offering a greater volume of FTRs in future years, subject to feasibility requirements.

However, NEMMCO should never need to resort to the levy given that it can sell less than the maximum capacity of the line, would have access to the FTR auction proceeds and would have access to the settlement residues to fund payments to FTR holders. Conservative network reliability standards and the Panel's proposed incentives for regulated TNSPs to maximise network capability during peak or extreme events, will ensure that complete line failures are kept to a minimum, further reducing the likelihood that payments to FTR holders would exceed total proceeds from the auction and settlement residues. As a result, the Panel proposes the levy solely as a last resort.

FTR trading needs to be transparent to facilitate appropriate network operation, usage and investment responses. Transparent pricing of FTRs across a forward yield curve will also support the operation of the investment trigger proposal described in the next section. To assist, NEMMCO should establish and run a secondary market to facilitate FTR trading. An exchange has the potential to add depth and liquidity to financial markets. NEMMCO could outsource this function to a financial intermediary. Wider issues about developing efficient and sustainable financial markets to support network and market development are discussed in Chapter 5.

## Using the price of FTRs to signal new investment in transmission

Clear investment signals are required that more accurately reflect the value of new transmission investment to the market and the community, along with greater consistency in decision making relating to new regulated investment.

There are some attractions to relying on merchant network services. However, they currently face several fundamental challenges. These include:

- the impact of economies of scale and high fixed costs, which for transmission networks imply that the most efficient investment response to alleviate a network constraint may completely eliminate the constraint and related price differences between regions/nodes, thus removing the underlying cashflows needed to fund the investment[37]
- uncertainty regarding the strength of incentives for coalitions of beneficiaries to emerge to fund new transmission investments, reflecting an individual beneficiary's potential to 'free ride' as a consequence of network externalities[38] and the high costs of forming coalitions of beneficiaries[39]
- the public good characteristics of transmission networks which may lead to pressure to bring forward transmission investments that may undermine efficient price signals for new market-based investment[40]
- the current lack of access to accurate and detailed information about the physical nature and capacity of networks, from a whole of network perspective, which will be a critical pre-condition for efficient competitive network investment responses.[41]

In view of these unresolved issues, the Panel considers that the most practical way forward will involve a combination of market and regulated network services into the medium term.

The Panel notes the tensions which have emerged between regulated and market interconnects, particularly in relation to the development of new interconnect proposals into South Australia. However, the Panel does not accept that these tensions imply that market and regulated interconnectors cannot coexist under any circumstances. As noted in a recent report prepared for the ACCC:



37 For example, Cameron (2001) discusses the potential implications of economies of scale and high fixed costs for market-based transmission investment.

38 Network externalities in this context refer to the range of positive spillover benefits that result from a transmission investment and which cannot be fully reflected in a charge on incremental users.

39 Hogan (1999), pp 22-34

40 Fraser (2002)

41 NEMMCO (2002). The 2002-03 Statement of Opportunities published, for the first time, the results of an annual interconnector review conducted by the Inter-regional Planning Committee. Costs and capabilities of potential interconnection augmentations are provided together with information on the need for further interconnections. This represents a useful overview, but more detailed information may be required to address information asymmetry and facilitate new network entrants.

**Non-regulated and regulated interconnectors can coexist provided that arrangements present a clear priority for development, and that sufficient time is given to regulated options if non-regulated proposals for an identified need do not eventuate.**[42]

The Panel considers that its suite of initiatives to address the transmission network priority issues would address these structural and regulatory deficiencies, enabling sustainable coexistence of market and regulated interconnectors in the NEM.

Arrangements relating to new regulated investments need to be rationalised, with regulatory assessment linked to measurable and transparent commercial benefits, as signalled through movements in firm FTR prices, rather than continuing to rely on the narrow approach enshrined in the current regulatory benefits test.

Creation of an investment trigger for new regulated interconnect investments that is based on a transparent market signal, such as the traded price of firm FTRs compared to the unit cost of new transmission augmentation, would help reduce the scope for arbitrary decision making and provide a clearer signal of the need for new transmission investment, well in advance of actual requirements.

This regulated transmission investment trigger would compare the unit cost derived from the net present value of new investment with the traded price of firm FTRs:

- NEMMCO would determine the potential regulated transmission augmentation possibilities and related costs on the basis of data supplied by TNSPs, supplemented with independent analysis.
- NEMMCO would publish this information well in advance of a triggered need and provide regular updates to give the market an opportunity to react prior to initiating a regulated transmission response. It is envisaged that NEMMCO would inform the market through a regular publication like its Statement of Opportunities.
- The trigger methodology would be approved by the National Energy Regulator (NER) on the basis of the traded price of FTRs and would require a sustained signal before activating a regulated response. Once activated and approved, however, the new transmission would proceed regardless of the later emergence of any other proposal.

[42] IES (2002b), summary, p. VI

- Emergence of more transparent pricing, through trading of FTRs on the proposed secondary market, would help refine signals for new investment and ensure more accurately timed regulated investment responses.

Where the unit price of firm FTRs exceeds the unit value of a potential regulated transmission augmentation, NEMMCO would pursue new regulated network investment through a competitive tender process:

- The successful tender price for new regulated investment/augmentation, resulting from the NEMMCO competitive tender process, would establish the asset value for regulatory purposes.
- The NER would approve regulated transmission interconnect augmentations or investments on the basis of the FTR investment trigger information published by NEMMCO.

The trigger proposal would replace the regulatory benefits test for regulated interconnects, and transform the assessment process from a pure 'economic' test to a 'commercial' test that would more adequately capture the wider benefits resulting from alleviating inter-regional constraints, particularly in terms of improving inter-regional trade and strengthening competition throughout the NEM.

Improved transparency and certainty resulting from the trigger proposal could facilitate competitive market responses from generators or merchant operators in advance of the need for an FTR triggered solution. Where the market response is slow, however, the trigger mechanism would be activated.



Complementary approaches should be developed for regulated transmission investments at an intra-regional level to minimise the risk of inconsistent regulatory outcomes that could undermine the effectiveness of the proposed investment trigger. Key features should include:

- The NER would assess and approve new regulated intra-regional transmission proposals on application from NEMMCO, subject to a 'commercial' benefits test that takes account of price separation as well as efficiency implications.
- Where NEMMCO has delegated the planning role to the relevant TNSP, the case for new regulated investment must first be passed to NEMMCO for consideration and endorsement or otherwise before submission to the NER for decision.
- NEMMCO would be required to advise the NER about the potential implications of any intra-regional proposal for the performance of the inter-regional network.

Exclusive reliance on FTR price signals or the commercial regulatory test may not deliver sufficient investment from a reliability or system security perspective, given the public good characteristics of networks. The test for assessing reliability investment should, therefore, remain unchanged for both inter and intra-regional transmission investments. However, NEMMCO would be responsible for managing the process and submitting proposals to the NER for approval.

## Incentives and rewards for regulated TNSPs

Financial incentives should be introduced to encourage more responsive network performance outcomes from regulated TNSPs, particularly in relation to maximising network capability during peak periods or extreme events. These incentives will involve exposing regulated TNSPs to the financial consequences of their operational and maintenance decisions to some degree.

Other options for creating performance incentives include:

- contractual arrangements between regulated TNSPs and NEMMCO as the central provider of FTRs
- regulatory incentives prescribed and enforced by the NER.

The Panel's preference would be for the NER to establish a range of regulatory incentives, rather than rely on contractual arrangements between NEMMCO and regulated TNSPs. Contractual arrangements would place NEMMCO at a negotiating disadvantage compared to the regulated TNSPs.

By comparison, regulatory incentives developed and implemented by the NER would provide a framework for achieving responsive network performance. The NER will be in the best position to ensure that an appropriate balance is maintained between the risk and returns available to regulated TNSPs.

It is important to maintain as close a link as possible between regulatory incentives on the TNSPs and the market incentives reflected in movements in the price of FTRs.

It is proposed that TNSPs receive bonuses and penalties according to the times when the line is operating below capacity *and* a significant price separation occurs. The addition or subtraction from the allowed rate of return would be set at a rate that provides a clear incentive for behaviour without being so large as to do serious financial harm if the penalty is invoked. It would be paid according to whether line operation was above or below a target level, set by the NER. This target level would account for the likelihood of circumstances beyond the TNSPs' control. There will be imperfections in this scheme but it can be made to work, and it sees a useful incentive provided where none exists now.

Complementary financial incentives, for instance to encourage the minimisation of outages during peak periods, should be developed for regulated transmission at an intra-regional level to help align incentives throughout the regulated transmission network. This will improve intra-regional network capability when it is of greatest value to the contestable market.

A challenge for the NER will be to adjust the approach to network regulation to balance the current predominant focus on cost minimisation to also include the need to ensure network capability, especially at peak times.

## Allow the number and location of regions to be set by the needs of the NEM

Increasing the number of regions would help maximise the inter-regional trade and competition gains from implementing FTRs. More regions would improve locational pricing in the NEM, improving signals for more efficiently timed, sized and located new investment, and facilitating the development of commercial incentives that may deliver more market-responsive transmission network services.

The Panel's preference would be to implement locational marginal pricing on a nodal basis — commonly referred to as full nodal pricing (FNP).

FNP would involve establishing a price at each node throughout the interconnected transmission network[43], providing clear price signals for the value of congestion and dynamic accounting of losses throughout the NEM transmission network.

FNP offers the best basis on which to decide the location of new load, new generation or new transmission. Other advantages include, when compared to existing state-based market arrangements:



- conceptual simplicity
- more market-based transmission pricing
- reduced regulatory risk
- better facilities for participants to manage network-related risks
- better management of local market power
- reconciliation of economic and social objectives.[44]

[43] Approximately 340 nodes exist within the NEM transmission network.
[44] Outhred (2002), reproduced in ACCC submission 136, Appendix C, pp 126-127

The Panel does not advocate moving immediately to FNP for two reasons.

Firstly, it is concerned about the practicality of implementing an FNP regime at the same time as introducing firm FTRs. While firm FTRs are the key policy initiative required to improve transmission network performance, they may pose some transitional challenges for NEMMCO and market participants, such as developing efficient risk management strategies to accommodate the initial possibility of many pricing combinations. The Panel considers it would be inappropriate to introduce these two levels of complexity at once, and proposes a staged implementation with the FTR regime — which represents the most important adjustment — implemented prior to introducing FNP for the transmission network. This would provide an opportunity for market participants to adjust to the new arrangements.

Secondly, staged implementation would also provide an opportunity for transmission infrastructure to be strengthened, particularly at existing regional extremities, prior to the introduction of FNP.

As more regions would maximise the benefits from introducing firm FTRs, the Panel considers that these two initiatives should be implemented concurrently.

NECA's Review of the Scope for Integrating the Energy Market and Network Services (RIEMNS Review) concluded that there is scope to improve the productive efficiency of the market by adopting a more accurate representation of loss factors within a refined regional structure.

The RIEMNS Review analysis suggests that a regional structure of between 12 and 15 regions would have potential productive and allocative efficiency gains in the order of $150 million over a ten-year period. Dynamic efficiency gains were estimated to be in the order of $500 million to $1 billion over the same period.[45]

Potential objectives for refining the regional structure of the NEM and related criteria for determining a refined regional structure are summarised in the Box 4.2 below.

[45] NECA (2000), pp 2-4

### Box 4.2: Principles and criteria for defining NEM regional boundaries

**Proposed objectives** for defining the NEM regional structure include:

- Participants who wish to trade between two locations can reasonably expect the region boundaries to remain stable over the medium to long term (5 to 10 years).
- Region boundaries should be located at the location of natural 'pinch points' of the network. Compromise boundaries that attempt to encompass multiple network limits should be avoided in favour of multiple boundaries.
- Region boundaries are selected to minimise the risk of participants being required to trade across significant intra-regional constraints (which are not priced).
- Inter-regional loss models should reasonably reflect the actual marginal losses that occur for transfers between regions.

Regional boundary criteria consistent with these objectives include the following:

- **Minimising changes.** The regional structure, reference node locations, and allocation of connection points to regions should be selected so as to minimise the number of anticipated changes to these market structures through the foreseeable future. For the avoidance of doubt, this principle requires the adoption of additional regions rather than fewer regions in marginal cases.
- **Topology.** Each region should be closed and enclose at least one significant load and/or generation centre (this is consistent with the principle currently in the Code).
- Each region must have a single regional reference node.
- **Network constraints.** A region boundary should to be at the location of significant network constraints, including:
  - historical points of congestion that have bound for a set number of hours a year or more, including the effects of forced and planned network outages, unless there are committed network developments which can reasonably be demonstrated to address the network limit for a period of at least 5 years
  - congestion points that are expected to emerge within a 5 to 10 year outlook period, based on assessments conducted by NEMMCO.
- **Network losses.** Regional boundaries should be located to minimise the difference between dynamic and static marginal loss factors.

- Regional boundaries should be established such that the variation between the central dispatch of generation and scheduled loads using pre-determined static intra-regional loss factors and dynamic inter-regional loss factors is not materially different from the dispatch that would occur under an optimal dispatch occurring under full nodal pricing.

The Panel is aware of concerns that have been expressed about moving to a more refined regional structure, particularly the key concerns that:

- a more refined regional structure would create pricing differentials between consumers, possibly disadvantaging regional users compared to urban users
- refined regions will facilitate abuse of market power when interconnects constrain.

Losses currently create considerable price differentials within regions. However, costs are currently smeared across all users within each region. This averaging simply entrenches substantial cross-subsidies into network charges and undermines their potential to signal an efficient locational market response to minimise their impact, with substantial efficiency costs borne by all affected users. The related efficiency losses and community costs are magnified where intra-regional constraints exist.

NECA's RIEMNS analysis suggests that a move to more regions will actually benefit users in most new regions, by reducing the amount of cross subsidies and need for inefficient and expensive internal 'fixes' to resolve intra-regional constraints.

Governments are rightly concerned about managing the potential distributional consequences of energy market reform. The critical problem is that the reform benefits are typically diffuse and the beneficiaries dispersed, while the losses can be concentrated and the losers prominent. Governments have a clear role in helping to manage these distributional effects. However, it is important that they do so in a manner that does not undermine efficient market operation and performance, or jeopardise the benefits.

The public interest would be best served by governments adopting off-market mechanisms, such as transparent community service obligations, rather than seeking to distort network pricing. An example meriting further consideration is the Special Power Payment adopted by the Victorian government to ease the adjustment to electricity full retail contestability in regional Victoria.[46]

[46] DNRE, submission 126, pp 23-24

As for the claims about facilitating abuse of market power, more regions would support a market-based response to alleviate the problem by clearly exposing any such behavior through more efficient locational prices. These prices would encourage a market response that could weaken or possibly eliminate the potential to abuse market power.[47]

Where market power exists within an existing region, continuation of present arrangements means that the cost is smeared across all users in that region, which increases prices to many more users than is necessary. This is a particular problem where chronic intra-regional constraints exist and is magnified under the current regional structure with its small number of large regions.

## OTHER COMMENTS

In view of the transitional challenges inherent in the various initiatives proposed above, the Panel suggests that an implementation strategy should possess the key elements outlined in Box 4.3.

### Box 4.3:
### Key components of an implementation strategy

**Phase one (1-2 years)**

- establish an independent planning function within NEMMCO, with responsibilities including network information dissemination, NEM-wide planning and undertaking competitive tendering for new regulated transmission augmentations or investments
- implement the firm FTR proposal
- implement more regions in the NEM.

**Phase two (7-10 years)**

- implement full nodal pricing throughout the NEM transmission network
- to ease the transition, run the full nodal pricing system in demonstration mode in parallel to the existing system for a year prior to implementation.



[47] Outhred (2002) reproduced in ACCC submission 136, Appendix C, p. 132

## RECOMMENDATIONS

### NEMMCO be given responsibility for transmission planning

4.1 Establish an independent, NEM-wide planning function within the National Electricity Market Management Company (NEMMCO).

(a) NEMMCO's responsibilities would extend to planning for the inter-regional and intra-regional transmission network. The scope of its responsibilities would be consistent with its system operation responsibilities under the National Electricity Code.

(b) Particular planning responsibilities would include:

i. providing independent and accurate information to inform augmentation processes

ii. highlighting potential augmentation opportunities, similar to the function it currently performs through the annual Statement of Opportunities

iii. managing a regulated transmission augmentation process through a competitive tendering process.

(c) NEMMCO would be able to initiate a competitive tender process for regulated transmission augmentation to relieve network constraints identified through the transmission planning process.

### NEMMCO to auction firm financial transmission rights



4.2 NEMMCO is to assume the responsibility for offering and underwriting firm financial transmission rights (FTRs) for regulated NEM interconnectors.

(a) NEMMCO would auction firm FTRs each year, covering a period five years in advance:

i. NEMMCO FTRs would apply to existing regulated interconnects.

ii. The firm FTRs would expose NEMMCO to the spot price divergence between interconnected regions.

iii. When spot prices diverge, NEMMCO would be liable to pay FTR holders the difference between spot prices multiplied by the volume of FTRs sold.

iv. NEMMCO would retain the settlement residues associated with regulated interconnects and auction proceeds to fund firm FTRs.

v. NEMMCO would be able to set a reserve price for FTRs.

vi. NEMMCO would be able to determine the volume of FTRs to sell, subject to feasibility requirements.

(b) NEMMCO to minimise the cost to the market of providing FTRs:

i. NEMMCO is to be given the dual objectives of avoiding any deficit and maximising the FTRs it is able to offer.

ii. Any residual costs would be covered by market participants through a separate and transparent levy as a last resort.

4.3 NEMMCO is to facilitate the operation of a secondary market for the transparent trading of FTRs.

## Using the price of FTRs to signal new investment in inter-regional transmission

4.4 Create a transparent and market based investment trigger for interconnect augmentations based on the cost of FTRs.

(a) The regulated interconnect investment trigger would compare the annualised unit cost of new investment with the price of firm FTRs.

(b) The trigger methodology would be approved by the National Energy Regulator (NER) and would require a sustained signal before activating a regulated response.

(c) When the unit price of firm FTRs exceeds the unit value of a potential regulated transmission augmentation, NEMMCO would pursue new regulated network investment through a competitive tender process subject to the approval of the NER.

(d) The successful tender price for new regulated investment or augmentation, resulting from the NEMMCO competitive tender process, would establish the asset value for regulatory purposes.

(e) NEMMCO would determine the potential regulated transmission augmentation possibilities and related costs and publish this information well in advance of the triggered need, providing regular updates to give the market opportunity to react prior to initiating a regulated transmission response.

(f) The NER would approve regulated transmission interconnect augmentations or investments on the basis of the FTR investment trigger information published by NEMMCO.

## Using a 'commercial' regulated benefits test for intra-regional transmission augmentation

4.5 The NER should assess and approve new regulated intra-regional transmission proposals on application from NEMMCO, subject to a 'commercial' benefits test that takes account of spot price separation between trading regions as well as efficiency implications.

## Transmission reliability investments

4.6 The test for assessing reliability investment should remain unchanged for both inter and intra-regional transmission investments.

## Incentives and rewards for regulated TNSPs

4.7 Transmission network service providers (TNSPs) should receive bonuses and penalties according to the times when their inter-regional transmission lines are operating below capacity and a significant price separation occurs.

(a) The bonuses and penalties would be set as an addition or subtraction from the allowed rate of return at a rate that provides a clear incentive for behaviour without being so large as to inflict serious financial harm if the penalty is invoked.

(b) The bonuses and penalties would be paid according to whether line operation is above or below a target level which accounts for the likelihood of circumstances beyond the TNSP's control.

4.8 The arrangement described for inter-regional transmission lines should be replicated for transmission lines within a region as far as practicable.

## Allow the number and location of regions to be set by the needs of the NEM

4.9 An increased number of regions in the NEM should be implemented.

(a) Objectives and criteria for increasing the number of regions should achieve the following outcomes:

i. Maximise regional boundary stability over the medium to long term (7 to 10 years).

ii. Regional boundaries should be located at natural 'pinch points' in the network. Compromise boundaries that attempt to encompass multiple network limits should be avoided in favour of multiple boundaries.

iii. Regional boundaries should minimise the risk of participants being required to trade across significant intra-regional constraints.

4.10 Implement full nodal pricing in 7 to 10 years.

# 5 ELECTRICITY FINANCIAL MARKET DEVELOPMENT

## CONTEXT

### Importance of electricity financial markets

Active financial markets are crucial to the development of Australia's electricity market and to energy markets generally. They enhance market participants' capacity to manage commercial risks resulting from exposure to volatile wholesale markets.

This chapter is restricted to discussion of issues relating to the NEM.

The only gas spot market in Australia operates in Victoria. The associated financial market is illiquid, primarily due to a small number of market participants, particularly upstream, and a lack of price volatility. Gas issues are discussed separately in this report.

Reform of the Western Australian electricity sector will have implications for the development of electricity-related financial markets in that state. At this stage, with final decisions on market structure yet to be made, there is little value in discussing possible financial market directions specific to that state. The principles discussed in this chapter are relevant to the further development of the Western Australian market.

An electricity-related financial market, comprising an over-the-counter and futures market, has emerged as a means of hedging exposure to the volatility that is inherent in the NEM. Generators, retailers and financial intermediaries are now utilising financial contracts to minimise their exposure to significant risks in the spot market.

Financial markets are integral to the ongoing viability of the gross pool model adopted for the NEM and to the overall success of the electricity reform program. NECA comments that:

**… a properly functional overall market relies on a deep and active contract market alongside the spot market, and on a close and dynamic relationship between spot and contract prices.** [1]

## Other risk management strategies

Other arrangements, facilitated by jurisdictions to manage price risks during the implementation of competitive electricity markets and to facilitate the transition from the old to the new supply arrangements, compete with commercial financial market products.

Most NEM jurisdictions put into place vesting contract arrangements between retailers and generators, with the aim of shielding retailers from variations in wholesale prices at a time when retailers were obliged to supply non-contestable franchise customers at regulated prices. Such vesting contracts phased out over time with the opening up of additional customer classes to contestability.

The Electricity Tariff Equalisation Fund (ETEF) was introduced by the NSW Treasury for managing the risks of retailers supplying electricity to small retail customers who elected to take electricity under regulated tariffs when vesting contracts expired. It was facilitated by government for the exclusive use of government-owned generators and 'standard' retail suppliers, in effect the government owned retailers.

The NSW Government's stated objective in establishing ETEF is to allow the government to offer regulatory price protection to retail customers in a way that does not undermine competition in the market and does not expose retailers to unacceptable financial risk.[2]

The Queensland Benchmark Pricing Agreement (BPA) was developed to address the situation of retailers facing a fixed revenue stream but variable energy purchase costs. Its objective is broadly similar to that of ETEF but its operation is quite different, including a regime of community service obligations.

More detail on the operation of ETEF and BPA is set out in Chapter 3.



[1] NECA, submission 81, p. 2

[2] Information on ETEF from NSW Treasury (2000)

## Comments in submissions

Submissions indicate that there are a wide range of views from market participants on factors that should be considered in a review of the development of NEM-related financial markets and the seriousness attached to present difficulties with the operation and pace of development of financial markets.

Many submissions support the proposition that, despite a range of problems and opportunities for improvement, there has been credible development in energy-related financial markets since NEM start.

The Australian Financial Markets Association (AFMA), for example, argues that 'an innovative and sophisticated electricity financial market already exists in the NEM'[3] while AGL states that:

**Australia's electricity hedge markets have undergone a remarkable growth since the opening of the NEM. While there have been complaints about lack of depth or liquidity AGL has generally found (there have been exceptions) that contracts have been available to fill our needs. Indeed the resilience of the secondary markets over the past six months or so can be seen as testimony to its success.**[4]

Edison Mission Energy (EME) argues that the financial market 'is still developing and has achieved a workable level of sophistication and innovation given the relative short time'.[5]

Such comments, however, are typically offered against the background of a range of potentially serious problems with electricity-related financial markets. While emphases varied according to market sector, there was a high degree of commonality as to the issues identified.

Generators in their submissions have cited factors including the level of regulatory risk, uncertainty over transmission and interconnection planning and risks involved with trading between regions.

EME, for example, comments on the threat of government regulatory intervention, failure to develop 'an efficient set of defined regional boundaries' and the absence of a 'firm access/property right regime for networks to encourage inter-regional trade'.[6]

[3] AFMA, submission 84, p. 3
[4] AGL, submission 48, p. 22
[5] EME, submission 118, p. 7
[6] EME, submission 118, p. 8

CS Energy also sees inter-regional risk and regulatory uncertainty relating to the creation of new regions as barriers to the development of sophisticated financial markets, also adding the importance of the level of VoLL.[7]

Retailers have generally cited factors that include a perceived lack of market liquidity and suitable counterparties for over-the-counter hedging transactions, the level of regulatory risk, the impact of lack of firmness across interconnectors and generators' market power.

Ergon Energy, for example, has argued that factors working against the creation of liquidity in financial derivative markets include:

- generators' market power, in particular what is perceived to be their ability to pick up the maximum value of the unhedged position when high pool prices arise
- unequal pressure to trade in forward contracts for generators and retailers
- arrangements such as the NSW ETEF representing a disincentive for generators to offer cover to retailers
- lack of firmness across interconnectors introducing physical risks to inter-regional trade
- various generator contractual policies that work against secondary markets such as transfer of physical generation plant risk to retailers.[8]

Financial institutions that made submissions to the Review cite factors including regulatory uncertainty, the requirement to consider interactions between the physical wholesale and financial markets and existing inter-regional risk issues.

AFMA argues that several 'externalities' are working against financial market liquidity and the value of financial contracts. Externalities cited include:



- changes to the Code not taking due account of the impacts on financial markets of the changes
- regulatory uncertainty and sovereign risk, including 'parochial' jurisdictional policies which AFMA considers 'can have an impact beyond state borders'.[9]
- non-market financial arrangements, such as the NSW ETEF and the Queensland BPA, which the AFMA recommends be abolished.[10]

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[7] CS Energy, submission 47, p. 10
[8] Ergon, submission 17, p. 65
[9] AFMA, submission 84, p. 4
[10] AFMA, submission 84, p. 3

AFMA also stated that:

**ETEF serves to remove around 40% of market liquidity from the financial market in NSW by providing the incumbent players with a state-based financial arrangement. The Benchmark Pricing Agreement in Queensland has a similar impact to ETEF and the cancellation of the South Australian Vesting Contracts has had the contrary, positive effect on contract liquidity.**[11]

Westpac Institutional Bank, which operates as an electricity trader, recommends the following steps to increase financial market liquidity and also aid wholesale market maturity:

- **transitional arrangements [being] swiftly extinguished, including vesting contracts and subsequent similar artifices**
- **there [being] greater certainty over transmission and interconnection planning and approval regimes**
- **incentives [being] given to Network Service Providers to ensure that they are correctly motivated to provide high service levels to under pin the firmness of the physical and financial markets**
- **less intervention in the market by regulators and government.**[12]

Major customers cite factors such as the lack of market liquidity and the volatility of the wholesale market. It is noted, however, that many other major customers are silent on this issue.

In their submission, Holden, WMC Limited, Visy Paper, OneSteel and BHP Billiton comment on the withdrawal of financial intermediaries from the market and argue that:

**The result of this has been that liquidity is in short supply in the contract market and hedge quantities and prices are effectively set by the generators. This provides another avenue for the generators to use the market power that they undoubtedly possess.**[13]

Market institutions have also reported concerns with the development of financial markets. NEMMCO, for example, comments that:

[11] AFMA, submission 84, p. 3

[12] Westpac Institutional Bank, submission 76, p. 2

[13] Holden et al, submission 46, p. 15

**NEMMCO is aware of concerns being expressed about a lack of liquidity in financial arrangements between retailers and generators, and also the difficulties experienced by third parties when attempting to facilitate exchange based trading arrangements. Low levels of transparency in financial activities make it difficult to assess whether or not these problems are systemic, but some issues such as physical risk due to network limitations do appear to be contributing to difficulties.**[14]

NECA comments that:

**Key to further development of the contract market … is to retain the national integrity and further improve the broader efficiency of the overall market arrangements. The closer integration of networks, and especially managing their effects on the market, is also crucial to that further development.** [15]

## Market facilitation activities

A frequent theme in submissions was the desirability of market based solutions to problems with financial markets as opposed to the imposition of regulatory solutions.

ESAA argues for retention of present arrangements under which financial markets are regulated by the Corporations Act and Trade Practices Act but are otherwise free to develop according to the needs of participants, commenting that:

**New products have been introduced progressively in response to market needs and market liquidity has gradually improved. Electricity generators and retailers are generally satisfied with the current rate of progress towards market maturity and are confident that this will continue if the existing market is allowed to mature fully.**[16]



Ergon Energy argues that participant risk issues be 'addressed through the market reform process rather than through adopting an interventionist approach to the contract market' which it believes would impede market development, restrict development of market based solutions and ultimately reduce confidence in energy markets.[17]

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[14] NEMMCO, submission 57, p. 12
[15] NECA, submission 81, p. 2
[16] ESAA, submission 4, p. 8
[17] Ergon, submission 17, p. 65

One recent development that is an example of the derivative markets responding to market forces is the futures contracts that were introduced in 2002 by both the Sydney Futures Exchange (SFE) and the Australian Stock Exchange. The SFE is also offering a clearing house service for its members to include swaps, swap options and other instruments traded in the over-the-counter market.

A number of submissions, however, queried whether effective financial markets could benefit from facilitation activity. NECA, for example, commented that:

**A fully fledged contract market also needs to be able to integrate off-market, and most importantly ancillary services, arrangements. The market rules also provide for off-market, bilateral contracts between generators and end-use customers, or so-called settlement reallocation. There is valuable scope for much wider use of that facility, including to net-off exposure in the settlement process.**[18]

Comments on the potential value of NEMMCO's settlement reallocation arrangement are echoed by several other submissions including those from AGL[19] and Energy Australia.[20] AGL, while recommending that, as a general rule, 'continuing evolution be encouraged through removal of any impediments rather than through imposition of regulatory solutions'[21], has commented on additional work that may be required to make the reallocation process attractive to participants.

AGL also queried, given the limited volume of short-term trading in electricity-related financial markets, whether it was now appropriate to review the ACCC's decision that the Short Term Forward Market proposed in the Code put forward by the proponents not proceed.[22]

## Consultancy work on financial markets

In advancing its consideration of this issue, in particular the strength of the serious claims that have been made in submissions and elsewhere as to the barriers to financial market development, the Panel commissioned consultancy work from KPMG.

KPMG's reports[23] were informed by a major quantitative survey on the current state of energy-related financial markets in Australia to which the majority of stakeholders responded. The

[18] NECA, submission 81, p. 2
[19] AGL, submission 48, p. 23
[20] Energy Australia, submission 94, p. 11
[21] AGL, submission 48, p. 22
[22] AGL, submission 48, p. 23
[23] KPMG (2002a) and (2002b)

information provided as a result of the survey is the most comprehensive and up-to-date available on market activity. KPMG also conducted a series of one-to-one interviews with key stakeholders.

KPMG confirms that, while financial markets that have developed for electricity and natural gas in Australia are in their infancy, such markets exhibit fewer attributes of market liquidity than other well developed financial markets.

The contracts market is an over-the-counter market largely dominated by bilateral trading between generators and retailers and, to a lesser extent, financial intermediaries. The futures or exchange-traded market has had a minimal role in financial market development to date. The withdrawal of Edgecap and Enron Australia has compounded the illiquid nature of electricity futures contracts traded on the SFE. In general, financial institutions have been reluctant to commit risk capital to energy traded financial markets.

In electricity markets, the lack of depth and liquidity exhibits itself in:

- wide bid-offer spreads
- limited pricing transparency
- activity restricted to certain sections of the forward curve: in particular, there is limited short-term trading (less than 30 days) by participants
- participation dominated by retailers and generators.

The report commissioned by NEMMCO from Bach Consulting and Sirca in early 2002 *Management of financial risk in the wholesale electricity market* [24] is also of relevance in setting a context.



The purpose of the study was to determine the health of financial markets and the implications this has on NEMMCO's obligation of surety of electricity supply. The objectives included identifying issues in spot trading arrangements that may be working against financial market trading.

In general, the study's finding were in alignment with those of the KPMG study. Despite the high degree of risk in electricity markets, liquidity was assessed as low and there was also a lack of transparent price signals.

[24] Bach Consulting (2002)

## KEY FINDINGS

The Panel's findings are that:

- government off-market arrangements are a significant impediment to achieving adequate market liquidity
- transmission problems prevent large-scale interstate contracting
- generator market power increases contract risk
- regulatory uncertainty limits long term contracts in particular
- strong credit quality concerns exist.

Until these concerns are addressed, financial markets will be restricted in scope and participation and it is unlikely that full transparency in the forward electricity price will develop.

### Government off-market arrangements are a significant impediment to achieving adequate market liquidity

Financial market liquidity has been adversely affected by government policy decisions and off-market risk management and pricing arrangements including:

- the NSW ETEF and the Queensland BPA
- state-based retail price caps and delays in the implementation of full retail contestability.

The ETEF arrangement in NSW and other non-market arrangements which achieve similar outcomes to over-the-counter products remove both the ability and the incentive to participate in financial markets. It is clear that implementation of such arrangements has reduced liquidity in the forward contract market and so works against a fundamental feature of NEM design.

The Queensland BPA does not discourage the government-owned retailers from entering into bilateral financial contracts. It does, however, effectively discourage the retailers from trading the financial contracts underpinning their franchise load commitments within the year, thus reducing financial market liquidity.

## Transmission problems prevent large-scale interstate contracting

Physical transmission constraints across the interconnected market represent a risk to market participants and affect secondary market activity. There is no effective or convenient hedging mechanism available to eliminate the risk from disparities in pricing between regional pools. This increases the risk associated with transacting financial contracts based on different regional pool prices. The inability to manage such risk contributes to the regionalisation of financial markets and reduces overall market depth.

It is noted that the Bach/SIRCA review for NEMMCO saw the moderate depth of transmission and the unclear motivation of transmission owners to build or maintain capacity as the most important issue in its study of management of financial risk. Addressing it was seen as leading to a national market with national regulatory scope and a precondition for the development of a vibrant short to medium term exchange traded product.[25]

## Generator market power increases contract risk

The potential for market power to be exercised by generators, by concentration of ownership in particular regions, or simply as a result of the lack of an effective demand response, is inhibiting the participation of financial intermediaries.

Generator bidding behaviour, combined with restrictions in inter-regional transmission capacity, can accentuate volatility in wholesale electricity prices in the spot market and in financial markets. In such circumstances, retailers will have difficulty in achieving hedge cover at efficient prices while intermediaries face the prospect of unexpected financial losses during volatile periods.



## Regulatory uncertainty limits long term contracts in particular

Uncertainty over regulatory responsibilities and government policies is limiting participation by intermediaries in financial markets with a consequent negative impact on liquidity, financial product development and innovation.

The lack of uniformity in regulation in the wholesale electricity market creates uncertainty both in terms of the market's future direction and competitive neutrality between regions.

[25] Bach Consulting (2002)

The findings of Chapter 2 on the deficient electricity Code change process, overlapping responsibilities and the uncertainties arising from ministerial decision making are directly relevant for the future of electricity-related financial markets.

An additional concern is the absence of any explicit requirement in the National Electricity Code or elsewhere to consider the financial market impacts of Code changes.

As an illustration, the decisions on the level of VoLL in the NEM made in 2000 had implications for financial market liquidity and depth. Changes in the level of VoLL have the potential to affect activity in financial markets by altering the hedging strategies and contracting decisions of participants. As VoLL increases, generators have a greater incentive to accept spot price risk. In the absence of other factors, this will reduce the expected volume of hedge contracts that would otherwise have the effect of fixing prices for future load.

A further impact of the increase in VoLL was to effectively double the prudential requirements on all retailers participating in the NEM. It also increased the risk capital required by financial market participants.

In the event, the ACCC took considerable evidence on this matter and factored into its decision its assessment that, while there may be an increase in demand for risk management products as a result of a change in the level of VoLL, there may not be a corresponding increase in supply.[26] This points to the importance of a broad assessment of financial market implications in all such decisions.

Failure to resolve key policy issues such as greenhouse gas abatement and the present range of basically ad hoc approaches to address the issue, as discussed in Chapter 8, also work against longer term contracting.

That there is a degree of regulatory risk for financial institutions has clear implications to the preparedness of such institutions to commit resources and capital to market operations.

## Strong credit quality concerns exist

Credit risk is a serious issue. Financial market transactions are being prevented because counterparty credit limits are not available or existing limits have been fully utilised. Availability of credit is especially an issue in the case of intermediaries and publicly owned retailers and generators dealing with poorly capitalised private sector participants due to concerns over the risk of default.

[26] ACCC (2000) p. 4

Hedge contracts are only effective provided the counterparty is able to settle all financial obligations as and when they fall due. The cost of replacing hedge cover can be substantial, particularly in volatile markets such as the NEM.

The Panel has investigated whether market facilitation and/or regulatory action could have value in relation to the following financial market issues:

- the limited short term trading (less than 30 days) at present taking place
- credit risk issues.

### Short term hedging

As noted above, there is limited short-term trading (less than 30 days) by participants. The KPMG study indicates that the short term trading that does take place is restricted to managing variations in load that occur primarily on the retailer front. The prices that a counterparty will ask for any short term cover will generally be high as the expectation is of increased spot price volatility.

No support has been provided for the view that a compulsory market would advance a deep and liquid market and there is the danger that an enforced short term market could stifle market-based innovation, particularly the increased participation of financial intermediaries, and could encourage undesirable behaviour in the physical markets such as retailer load shedding and restriction of generator supply.

In addition, it would appear that high spot price volatility and the potential market power of generators are driving the hedging strategies of participants. Addressing these issues would facilitate commerically driven moves towards enhanced short term hedging.



### Addressing credit risk concerns

The Panel investigated whether participant credit exposures and NEM prudential exposures could be more effectively managed.

At present, NEM participants must provide NEMMCO with credit support in the form of bank guarantees to ensure participants meet their financial obligations on purchases from the pool and avoid credit risk being factored into wholesale spot prices. NEMMCO is obliged to call upon the guarantees in the event of default by a NEM participant on their physical settlement obligations.

As the major domestic banks in Australia provide most of the guarantees to NEMMCO, the issue of concentration of risk within their lending portfolios is placing a constraint on the further extension of credit support.

NEMMCO provides a mechanism for settlements reallocation that gives participants the ability to net their cash flows in the central pool through bilateral agreements.[27] The reason for the small use of the facility is unclear. It is possible that the prudential costs remain smaller than the transactional overheads of 'netting'.

The Panel investigated an arrangement under which counterparties to bilateral contracts would be required to register their bilateral contracts with NEMMCO. NEMMCO would determine the netted obligations and the net payment would occur as advised by NEMMCO. In effect, NEMMCO would become a clearing house.

Such a compulsory arrangement would appear to have value in reducing settlement exposures for NEM participants. It could potentially lead to a reduction in maximum credit limits and therefore bank guarantees.

For such benefits to occur, however, the timing of cash flows under the contract for difference would need to coincide with the cash flows for the spot market commitments. This is unlikely, particularly where more sophisticated contract arrangements are established.

The benefits of the proposed change would also only apply to matched cash flows between retailers and generators with bilateral contracts in place. It would not appear to promote trading with other participants and, as such, may even work to deter other participants (such as financial institutions) from entering the market.

The proposal also does not appear effective in reducing credit risk exposures prior to settlement. At the beginning of a financial contract, where credit risk issues are most evident, it would be difficult to align the financial contract with known physical commitments which cannot be certain and which may be up to two years forward. As such, no credit relief would be obtained by those institutions that at present are undergoing difficulties in arranging appropriate credit support.

In summary, compulsory reallocation of financial contracts is not supported.

The most promising way forward is the registration of participants' over-the-counter financial contracts with a central counterparty exchange to be provided by a third party financial markets entity. The exchange would assume the central counterparty to all transactions registered with it. The Sydney Futures Exchange has recently established such a facility.

[27] Authorised under section 3.3.19 of the National Electricity Code

This option would have no direct impact for NEMMCO's prudential requirements; NEMMCO would retain responsibility for physical market settlements. It is possible, however, that promotion of a central clearing house service would present an opportunity to:

- alleviate pressure on NEMMCO-required credit support arrangements by releasing credit support provided by banks in the form of over-the-counter contracts
- reduce counterparty credit exposures by clearing financial contracts through a designated exchange and implementing margining requirements in place of the bank guarantees that are commonly provided in the bilateral contract market
- offset obligations under energy related financial transactions with exchange traded contracts in electricity or any other contract traded on the exchange.

Development of such a voluntary clearing mechanism, therefore, would appear to offer potential value to NEM participants.

The decision on whether to proceed, as with any other financial market initiative, should be the market's assessment of its worth and the ability of an appropriate provider to institute such a service.

## PROPOSED SOLUTIONS

The Panel's solutions are grounded in its vision of what the NEM should and can look like once the changes recommended in the Report are implemented.

The Panel expects the NEM to be characterised by a much larger number of generators competing aggressively, intense cross-region trading, and a group of retailers offering diverse products and services. Such a market will also have a deep and liquid financial market in which intermediaries, generators, retailers and many users will be active.



The proposed solutions outlined below relate directly to the identified key findings:

- abolish ETEF and BPA
- improve transmission regulation, including the transmission augmentation mechanism and introduce FTRs
- address generator market power issues by disaggregating NSW generators and raising merger hurdles

- ensure all Code changes take explicit account of financial market effects
- review in 1-2 years the need for NEMMCO to facilitate the introduction of a voluntary clearing service.

## Abolish ETEF and BPA

Removal of these arrangements is a priority action to address problems with market liquidity and depth. They are incompatible with the development of sustainable financial markets. Since they preclude market-based solutions they are not effective transitional measures. A rapid program for the removal of such arrangements should be pursued.

Abolition of these arrangements can be taken irrespective of whether price caps are removed. Such a step would redress the financial market liquidity issue. It will also provide clearer signals as to when retail price caps are so low as to be a disincentive to new generation investment.

## Improve transmission regulation

The Panel has recommended major changes to the present arrangements for transmission planning and augmentation, including NEMMCO assuming responsibility for 'backbone' transmission planning and the auctioning of firm transmission rights to replace the current settlement residue auction. By addressing the present 'regionalisation' of the NEM, these initiatives will also address the difficulties associated with contracting between regions.

## Address generator market power issues

The potential for generator market power abuse to work against appropriate secondary market development is addressed by two recommended solutions in Chapter 3 of the report:

- addressing the issue of generator concentration, in particular within New South Wales to help to reduce generator market power
- moving towards a stricter test, under the Trade Practices Act, for mergers in the electricity industry.

## Reform governance and regulatory arrangements

The report sets out proposals for restructuring regulatory and governance responsibilities in the NEM. The reform will serve, among other things, to promote greater certainty, reduce complexity, shorten regulatory timeframes, and diminish the potential for sovereign risk.

The approach recommended on greenhouse gas abatement in Chapter 8, combined with recommendations on the enhanced role of the MCE in Chapter 2, have the objective of developing a single, national approach on this key issue. Implementation of these approaches will improve regulatory certainty and remove a major barrier to longer term financial contracting.

## Ensure all Code changes take explicit account of financial market effects

There would be value in making explicit, in relevant statutory material such as the Code, the principle that changes to physical market structure should involve an examination of the impact of such changes on financial market activity.

The National Electricity Code provides for periodic reviews of the level of VoLL to assess whether it should be increased or decreased. The Panel considers that these reviews should take full account of the impact on contract premiums, contract availability and access to prudential cover.

## Monitor financial market development

As noted under Findings, the Panel has investigated possible solutions to address its key findings on credit risk and the absence of short term hedging opportunities and has decided that no action is appropriate at this stage. The way forward to address these topics is implementation of the overall reform package.



It is also to be expected that as the NEM becomes more 'national' that interested companies will themselves see the need to address these issues.

It is proposed, however, that in 1 to 2 years, as implementation of the reform agenda outlined in this Report gains momentum, NEMMCO review the need to take an active role to facilitate the introduction of a voluntary clearing service for bilateral contracts. This will focus on the extent of the credit risk problem at that later stage, and the likelihood of there being beneficial change through any action proposed to be taken.

## RECOMMENDATIONS

5.1 The NSW Electricity Tariff Equalisation Fund and the Queensland Benchmark Pricing Agreement should be abolished as soon as possible and irrespective of whether retail price caps are removed.

5.2 The National Electricity Code should reflect the principle that the impact of any changes to the Code must assess and take into account the likely impact on financial market activity.

5.3 Future reviews of the level of VoLL should take full account of the impact on contract premiums, contract availability and access to prudential cover.

5.4 NEMMCO should review in 1 to 2 years the need to take an active role to facilitate the introduction of a voluntary clearing service for bilateral contracts.

# 6 DEMAND SIDE PARTICIPATION AND FULL RETAIL CONTESTABILITY IN ELECTRICITY

## CONTEXT

A key feature of competitive markets is the active participation of both the supply and demand sides. Without this, competition is blunted and the potential for the exercise of market power is enhanced.

Many submissions to the Review contended that demand side involvement in the NEM is under-developed. For example, NRG Flinders states:

**Demand side bidding is still not efficient and effective in the NEM.**[1]

The ESAA submission acknowledges that demand side response is inhibited, stating:

**Retail price regulation — and the hedging arrangements, such as vesting contracts, that have and may continue to support this regulation — inhibits demand-side response by discouraging or preventing retailers from passing price signals to customers.**[2]

The Victorian Department of Natural Resources and Environment claims:

**It is generally accepted that demand management in the NEM is under-developed and has the potential to contribute to the security of electricity supply, particularly during periods of tight supply-demand balance.**[3]

This is not to say, however, that there is no demand side activity in the wider market context. Off-peak hot water tariffs are a long-standing example of a demand side activity. The Panel is also aware that many retailers offer and enter into curtailable and interruptible load contracts with major electricity users. These contracts represent demand side involvement under the management of the various retailers and are generally activated during high-priced wholesale market events. However, the extent of these arrangements and the frequency and effect of their use is difficult to assess.

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[1] NRG Flinders, submission 87, p. 1

[2] ESAA, submission 4, p. 11

[3] DNRE, submission 126, p. 22

Actions by the demand side of the electricity market also have scope for contributing to the reduction in greenhouse gas emissions. The adoption of energy efficiency technologies and practices by consumers has the potential to both save on energy costs and to reduce greenhouse gas emissions. In a wider market sense, they can also lead to a deferral of new capital investment to meet growing demand.

The extent and effectiveness of demand side involvement in the electricity market will likely be affected by the availability to consumers of information regarding the costs of consumption at various times of the day and their ability to then respond. Consumers' ability to select from differing products and services, resulting in a reduction or shift in consumption, will assist competing electricity retailers to manage wholesale market price risks.

Current policies on the implementation of full retail contestability across the jurisdictions vary with no jurisdiction to date enabling the market to operate fully without some form of price control mechanism being used.

## KEY FINDINGS

The Panel found that there is a relatively low demand side involvement in the NEM because:

- the NEM systems are supply side focussed
- the demand side cannot gain the full value of what it brings to the market
- residential consumers do not face price signals.

### The NEM systems are supply side focussed



In the NEM, the wholesale market mechanism is supply side focussed. It has been designed to accommodate the needs of generators in recognition that it manages both the market bidding and system dispatch processes. Generators are the key system clients by necessity as they are compelled to use the NEM. Consequently, the information technology architecture has been constructed to ensure effective interfacing with the physical requirements of the generation sector more than for the retail or demand side of the market.

Bidding by NEM customers (the retailers and any others purchasing direct from the wholesale market) for supply is not mandatory. They can either simply take energy from the market at the prevailing pool price (known as market load) or lodge bids for supply (known as scheduled loads) in a manner very similar to that used by generators wishing to offer supply.

However, very little use is made of the scheduled load option and consequently, NEMMCO employs advanced load forecasting models to inform the market of expected demand. To the extent that scheduled load is notified, NEMMCO takes this into account in its load forecasting.

Demand has consistently shown that it is relatively price inelastic in the immediate to short term. Large electricity users are generally not easily able to reduce consumption at very short notice, due to the impact on their production processes, and are limited in how long they can remain operating with reduced supply. Many users are not able to quickly 'switch on and off' at short notice. This is a very different position to that of most generators which are able to move their output relative to market movements.

The demand side has not been bidding for supply in the NEM. This is despite efforts via Code and administrative changes introduced by NECA and NEMMCO to encourage explicit involvement.

The Panel is of the view, however, that the explicit involvement of the demand side in the wholesale market offers potential advantages worthy of further pursuit. These include:

- moderation of the extent of price spikes by enabling consumption to be more reactive to price movements during extreme events or peak demand periods
- reduced electricity costs and improved system reliability by shifting some consumption away from peak demand periods and so averting the need to call on relatively more expensive peaking generation and stressing the networks.

## The demand side cannot capture the full benefit of its involvement

Charles River Associates, in their report for VENCorp, indicated that relatively moderate levels of demand response could be expected to reduce pool price. The study found that Victoria has some 250 MW of load reduction practically available and that use of this at times of tightening supply and demand would see Victorian pool price reductions of between 15 per cent to as much as 79 per cent in certain half hour periods.[4]

The findings in the VENCorp commissioned report are not surprising. At times of high demand and limited supply, relatively small demand reductions will move the point of supply and demand intersection down the price curve significantly, resulting in substantial savings across the market.

[4] Charles River Associates (Asia Pacific) and Gallaugher and Associates (2001), p. 3

In the Panel's view, the most significant reason for the demand side not actively participating in the wholesale market is that the capture of the financial benefits of reducing demand on a firm basis are compromised.

Demand reductions by individual participants and retailers during high priced events may lead to two financial outcomes. Firstly, the party that reduced demand will not face the cost of the energy they would have otherwise consumed. This financial benefit is fully captured by the entity reducing demand (but offset by the loss of amenity it suffers from lack of energy). Secondly, to the extent that the load reduction reduces the pool price over what it otherwise would have been, this benefit is smeared across all those parties that continued to consume energy in the form of lower energy prices. The load reducing party, however, receives none of this benefit yet is the cause of its occurrence.

Load reductions are analogous to the dispatch of the next unit of generation to meet the load that otherwise would exist. Such generation would be bid into the NEM and paid the system marginal price. Yet if load reduction occurs, no such payment is made, the price in the pool is reduced and all customers pay less.

In the Panel's view, a greater explicit demand side response from a wider range of participants including individual consumers, retailers and load aggregators is likely if the ability to more fully capture the economic benefits of load reduction were possible.

## Residential consumers do not see price signals

Demand side responses are reliant on consumers having some visibility of the price of energy and being able to determine their response to changes in price. This does not automatically mean that this must be in real time, but instead would most likely be in concert with an intermediary such as a retailer or aggregator who offered a product that valued interruptibility in return for a benefit of some type.



Of course, such arrangements are already possible (and used) for much of the contestable sections of the NEM.

However, time-of-use meters are not generally used for users of less than 160 MWh per annum, even in those jurisdictions which have made full retail contestability (FRC) available. This effectively excludes these consumers, representing between 40 per cent and 50 per cent of load in the NEM, from access to innovative products that could encourage load reduction at peak times.

A further impediment to demand side involvement based on price signals is the existence across most of Australia of caps on the price of energy. Even jurisdictions that have proceeded to enable FRC have nonetheless imposed price cap arrangements, while those yet to move to FRC continue to set uniform tariffs.

With around 50 per cent of load subject to price control, the opportunity for an active demand side involvement by smaller consumers is significantly reduced, aside from traditional offerings such as off-peak hot water rates. Without the ability to differentiate products and prices in an openly competitive market, retailers are not able to offer these consumers products that will encourage appropriate demand curtailment at times of higher wholesale prices.

Regulating retail prices in an unregulated wholesale price environment inevitably means that retailers are exposed to substantial risk in the marketplace. Retailers must manage this risk as best they can, in an environment where pass through of additional costs to consumers may not be possible. This has very substantial risks for electricity supply.

Experiences with rent control are instructive in this area. Governments have on occasions in the past moved to cap the rent that landlords may charge tenants in seeking to ensure private rented housing remains affordable during times of shortage of stock, high inflation, rising interest rates or a combination of all of these. In the short run the tenants benefit from the capped prices. The landlords, however, are left with rising costs but fixed income. In the short run they have to internalise these losses to the extent they can and suffer a reduced return. However, in the medium term the investors (landlords) will be motivated to move their capital to assets that provide both a sound return and limited sovereign risk. This usually results in a reduction of housing stock for rental as those that buy the properties sold by the investors often do so to occupy them. The tenants are ultimately the losers. This scenario is equally applicable to capping electricity prices.

Fully competitive markets will deliver competitive prices. Price movements reflect the changing balance between supply and demand and enable appropriate responses. For example, inadequate price signals discourage demand side participation, as they dull the information required to adequately respond. Also, investors are unlikely to be attracted to invest in capital-intensive infrastructure when prices are not free to find their appropriate level, or are muted.

While the current approaches to FRC implementation are unlikely to encourage consumers to actively pursue energy efficiency measures, it is clear that governments at all levels have extensive energy efficiency promotion programs which are well funded and active. In the Panel's view, the success of these programs would be significantly enhanced by fully implementing FRC, thereby enabling proper market signals to provide incentives for consumers to change their behaviour.

## PROPOSED SOLUTIONS

The Panel proposes the following solutions to address the findings:

- Introduce a demand reduction bidding system into the NEM.
- Mandate the roll-out of interval meters for all consumers.
- As soon as practical, but in any event within the next three years, remove retail price caps and introduce FRC into all markets.

### Demand reduction bidding proposal

As noted earlier, one of the assessed impediments to achieving a more active demand side involvement in the wholesale market is the inability of demand side participants/consumers to capture all of the economic benefits of reducing load during higher priced events.

To redress this, an enhancement to the existing NEM mechanism to encourage greater explicit participation by the demand side is proposed. The basic elements of this proposal are:

- Users (including retailers and aggregators) would be able to bid price and volume into the NEM to *reduce* load.
- These bids would be lodged on a similar basis as for generation offers, including the ability to re-bid, but they should allow for flexibility in the notice period and the duration of the bid.
- The NEM systems would then 'stack' the demand reduction bids and the generator offers.
- The price of the demand bids would be compared with the price of the generation offers, and the best combination selected to meet the demand.
- Accepted demand reduction bids would be paid for their dispatch on an 'as bid' basis. Generators would continue to be paid according to the system marginal price.

Pay as bid rather than payment of the system marginal price has been decided for the demand side because the marginal demand side bidder may cause pool prices to fall, potentially to a level below their own bid. Conversely, when generators are dispatched into the NEM, they will always get *at least* the amount they bid but may get a higher price.[5]

Revenue to fund payments for the accepted demand reduction payments would be sourced from the market by adjusting the half hour system marginal price to account for generation and demand reduction bids and offers dispatched to meet demand.

Users must be able to be responsive to last minute market changes in the same way as generators. However, it is recognised that demand is inherently different in nature to supply, with limitations on flexibility and variability.

As a result, it is unlikely that all users will be able to reduce capacity at short notice. A range of demand reduction bids, incorporating a range of response times, will thus need to be available to the market operator. NEMMCO will need to have a 'notice period' to facilitate advising consumers that they are to be dispatched. Demand reduction bids will need to be able to specify the amount of notice required prior to dispatch.

Due to the nature of some of the larger users, it is essential that demand reductions be biddable for a specified amount of time. That is, given x amount of notice, the demand reduction bidder can switch off y capacity (as bid into the market), for a maximum of z hours. This algorithm may also need to specify a period before which a demand bidder can be dispatched again.

Provision may need to be made for a 'standing bid' for demand side participants. This situation reflects the fact that the primary focus of energy consumers is unlikely to be watching pool prices in the NEM. A standing bid will assist these organisations in managing their participation in the NEM.

Management of failure of an accepted demand reduction bid to 'dispatch' could be along similar lines to the provisions for generator failure i.e. utilisation of the ancillary services market. In this situation, the causer of the problem is responsible for the cost of not meeting the demand reduction.

It is essential that consumers in demand reduction bidding have accurate metering infrastructure installed, so that their usage can be accurately monitored.

[5] On occasions, generators may be dispatched for less than the full half hour period. If the five minute prices during that half hour period fluctuate substantially, then the time weighted average price for the full half hour may be less than the generator's 'bid' price. In these circumstances the generator may be paid less than the price they bid.

## Mandate the roll-out of interval meters

The Panel believes that a mandatory roll-out of interval meters to all consumers is necessary to achieve the full benefits of electricity market reform. Table 6.1 below reflects analysis undertaken by the Victorian Essential Service Commission (ESC), which indicates that the cost of introducing manually read interval meters is likely to be modest.

**Table 6.1: Cost of a 5-year roll-out of manually read interval meters in Victoria**[6]

| **Expenditure item** | **Single-phase non-off peak** | **Single-phase off peak** | **3 phase direct connect** |
|---|---|---|---|
| Capital cost ($)(*a*) | 75.00 | 133.00 | 318.00 |
| Installation ($)(*b*) | 40.00 | 73.00 | 143.00 |
| Maintenance ($ p.a.)(*c*) | 1.88 | 3.33 | 7.95 |
| Data reading & management ($ p.a.)(*d*) | 20.00 | 20.00 | 20.00 |
| Average total cost ($ pa.)(*e*) | 29.55 | 37.07 | 58.68 |

*Notes:*

a. *Average capital cost varies depending on the number of units purchased. Figures assume around 276,000 single-phase non-off peak meters (approximately 1.3 million over 5 years), 118,000 single phase off peak meters (nearly 600,000 over 5 years), and 42,000 three-phase direct connect meters per annum (around 200,000 over 5 years), consistent with a 5-year accelerated rollout policy. Costs based on data provided by meter manufacturers to KPMG/ESC.*

b. *Average installation costs for accumulation meters are based on costs allowed in the recent ESC excluded service charge decision. Average installation costs will vary according to the number of meters installed. Figures presented assume installation of around 276,000 single phase non-off peak meters, 118,000 single phase off peak meters , and 42,000 three-phase direct connect meters per annum, consistent with a 5 year accelerated rollout policy.*

c. *Maintenance costs are assumed to be 2.5 per cent per annum of the meter capital cost, based on the average of allowed maintenance costs in the ESC approved excluded service charges for meters.*

d. *Meter data service costs are based on the average approved excluded service charges for accumulation meters in Victoria for 2002, assuming quarterly meter reads. The figure has been increased for interval meters to reflect the small incremental time to download data from an interval meter compared to reading an accumulation meter, and the additional data storage capacity required for information systems.*

e. *Average costs presented assume that capital and installation costs are recovered over a 15-year period on a 'straight line' basis.*

[6] ESC (2002), Appendix F, Table 14, pp. 74-75

Table 6.1 suggests that the average cost of introducing manually read interval meters for the majority of consumers would be in the order of $30 per annum. Analysis undertaken by the ESC indicates that the incremental cost over current activity associated with implementing a 5-year rollout of single phase interval meters would be less than $5 per annum.[7] Once full roll-out had been achieved, users with single phase meters would only need a saving of less than 4 per cent on an average annual electricity bill of $1000 to begin reaping the benefits.

ESC analysis shows that a full roll-out of manually read interval meters for all residential consumers would deliver net benefits in Victoria. Under the scenario involving a 5-year replacement of single-phase meters, the net present value of the benefits are calculated to be around $270 million, representing a benefit cost ratio of nearly 3 to 1. The net present value of these benefits is somewhat less under a new and replacement scenario, with the net present value falling to around $50 million and a benefit cost ratio of around 2 to 1.[8] The Panel considers that these results are likely to be indicative of the outcomes achievable in other states and territories.

Benefits result from retailers being able to more accurately charge consumers according to their time-of-day usage. Consumers would then potentially have the price signals available to them to engage more actively in load reduction, perhaps through energy efficiency measures and load shifting into cheaper periods for discretionary power uses.

The benefits to retailers from aggregating these reductions in demand are likely to be significant. The roll-out of interval meters on a large scale will enable retailers to better share price risks with consumers interested in doing so. It will also result in better outcomes for consumers, with greater incentives for price responsiveness more innovative products and greater equity among electricity consumers. Interval meters also have the potential to increase price efficiency, bring operational network management improvements and increase the accuracy of settlement.[9]

The roll-out of interval meters should be on the following basis:

- an accelerated roll-out of interval meters to all contestable consumers. It is proposed that the roll-out take place in the shortest possible time, estimated to be between 5 and 10 years.



[7] ESC (2002), Appendix F, Tables 12-14, pp. 68-75
[8] ESC (2002), Table 1, p. 17
[9] ESC (2002), p. 12

- distributors to own the meters and be allowed to include the cost in their regulated asset base, which can then be charged to consumers in distribution charges. Access to meter data must be available to retailers as requested by the user.
- a minimum standard for interval meters for consumers to be established. This will also provide an opportunity for standards to maintain pace with metering technology development. Consumers should be able to opt for a more advanced meter should they require it.

## Introduce full retail contestability into all markets and remove price caps

Enabling active competition between retailers for the energy business of all users, including those at the residential level is imperative if products are to be developed that can support an active demand side in electricity markets. All jurisdictions should move as soon as practical, but within the next three years, to remove price caps and enable all consumers to select their supplier of choice.

The Panel accepts that jurisdictions will want to pick an appropriate time to introduce FRC and remove all price caps. In the immediate short term these are politically sensitive issues. Nonetheless, the Panel sees their removal as inevitable.

Until their removal, jurisdictions should adopt an approach to setting the price caps based on the bilaterally negotiated contract rates secured by each affected retailer and the other costs reasonably associated with retailing electricity. These bilateral contract prices must under-pin the prices established and should also provide sufficient flexibility for the retailers to develop time-of-use tariffs for customers.



This approach makes the existing arrangements that protect incumbent retailers from price risks (e.g. ETEF and BPA) redundant. Retailers will not be exposed to unmanageable risks under this approach as the price cap determination has proper regard to the bilateral contract position of each retailer. ETEF and BPA should therefore be removed.

## RECOMMENDATIONS

6.1 The NEM mechanism should be amended to include a demand reduction bidding option that would enable load reduction to be bid into the NEM for dispatch and payment in competition with generation offered into the market to meet demand. This would involve:

(a) users (including retailers and aggregators) bidding price and volume into the NEM to *reduce* load on a similar basis to generators

(b) the NEM systems 'stacking' the demand reduction bids and the generator offers

(c) the price of the demand bids being compared with the price of the generation offers, and the best combination selected to meet the demand

(d) accepted demand reduction bids being paid for their dispatch on an 'as bid' basis while generators would continue to be paid according to the system marginal price.

6.2 Installation of interval meters should be mandated for all consumers with the installation program to be achieved over the next 5 to 10 years.

6.3 Full retail contestability should be adopted and implemented by all jurisdictions including the removal of price capping arrangements and other measures that impede the entry of new retail competitors as soon as practicable, but in any event within the next three years.

# 7 INCREASING THE WIDER PENETRATION OF GAS

## CONTEXT

Australia has very considerable natural gas resources, the majority of which are remote from major demand centres.

As Woodside Energy observes:

**Australia has abundant reserves of natural gas. Proven and probable reserves as at January 2000 amounted to around 110 trillion cubic feet (tcf) which is equal to more than 100 years supply at current production levels. With the exception of the Cooper Basin, most major accumulations are offshore and some distance from the major markets. In recent years there have been a number of significant finds and potential developments in the Timor Sea, Otway and Bass Basins. Major new pipelines affecting virtually all markets, including historic linkages to the mainland gas system to PNG and Tasmania, have been developed or are being planned.**[1]

Concerns regarding security of supply of gas or adequacy of reserves into the future appear to be unfounded. In addition to these vast conventional gas reserves, ongoing research and development into extraction techniques continues to lower the cost of coal seam methane, making it a more viable option. Indeed the Queensland Government recently selected a coal seam methane producer as the preferred long term supplier of gas to a power generation facility in Townsville.

Australia provides some of the cheapest gas in the world to industry and residential customers. These low (by international standards) gas prices are generally the result of mature long term contracts out of the Cooper and Gippsland basins and the North West Shelf fields. However, natural gas remains at a price disadvantage to black and brown coal for electricity generation purposes and for some industrial uses.

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[1] Woodside Energy, submission 50, p. 5

The existing major long-term contracts in the South East markets are due to expire this decade and there is concern amongst retailers and major users that new contracts will not be offered at current price levels, especially by the existing producers in the South East Australian market. Santos has publicly indicated a likely price of around $4.50 per GJ (up from around $3).

Significant reforms in the gas industry have been pursued over the past decade, focussed predominantly on ensuring free and fair trade in natural gas. At the heart of this was the creation and implementation of the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), an industry specific set of access arrangements and regulated tariffs for pipelines that could exert monopoly power. Governments also committed to enabling consumers to choose their supplier.

Australia's pipeline infrastructure of over 90,000 km provides substantial benefits to the economy by linking about 3.5 million customers, including value adding industries and residential consumers in cities and in regional areas, to gas supplies. Over 13,000 km of natural gas reticulation and transmission pipelines were laid in the five years up to June 2000.[2]

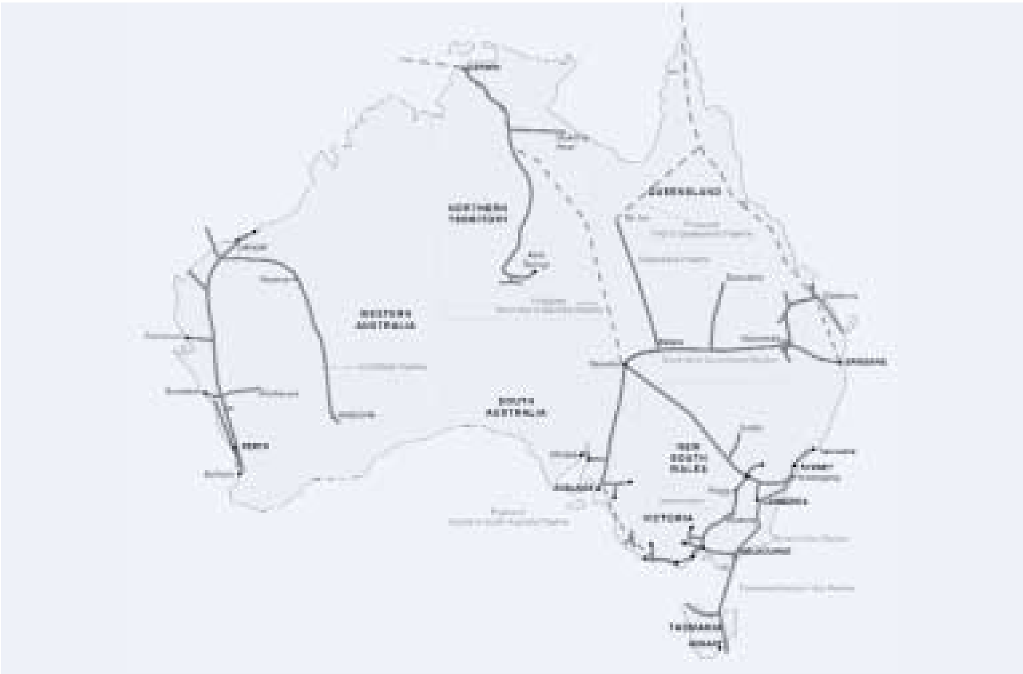
**Over the last decade the length of Australia's transmission pipeline system has nearly doubled — from 9,000 km in 1989 to over 17,000 km in 2001.[3]**

**Figure 7.1: Major Natural Gas Pipelines 1995**

[2] AGA, Gas Statistics 2001, p. 70

[3] APIA Business Plan 2002-2005 (October 2001), p. 4

**Figure 7.2: Major Natural Gas Pipelines 2002 and proposed**



Significant new pipelines have dramatically enhanced gas supply flexibility and therefore promoted the development of a more competitive market. Figures 7.1 and 7.2 show the growth in major pipelines from 1995 to 2002 (and indicate potential new significant supply sources from the north and the proposed Victoria to South Australia pipeline). Key among these developments (and potential developments) include:

- The Goldfields Gas Pipeline, which became operational in 1996, delivers gas from WA's North West to Kalgoorlie and various mining operations throughout central WA.
- The Culcairn 'interconnect' which became operational in September 1998 allowed gas to flow between Victoria and NSW for the first time by connecting the Victorian Principal Transmission system with the Moomba to Sydney Pipeline (MSP).
- The South West Pipeline completed in May 1999 which connects the Western Underground Gas Storage System at the Iona field to the Victorian Principal Transmission system.
- The Eastern Gas Pipeline (EGP) which became operational in early 2001 and provides for gas transfers between Longford, Victoria and Horsley Park, west of Sydney.

- The Tasmanian natural gas pipeline completed in September 2002 which will provide natural gas to Tasmania (from Victoria) for the first time.
- The SEAGas transmission pipeline, due for completion in early 2004 which will connect Victoria to Adelaide. This pipeline has the potential to link recent significant gas discoveries in the Otway Basin to Victoria and other States.
- Duke Energy International (DEI) has announced the development of a natural gas trading hub 'VicHub' at Longford in Victoria to connect the NSW, Victorian and Tasmanian gas markets for the first time. DEI claim that VicHub will enable trading in physical and financial gas markets.

Comparatively, the upstream sector has not been significantly affected by the reforms pursued over the past decade. Many stakeholders believe that attention needs to be paid to a number of upstream issues. The Australian Gas Association (AGA), for example, submitted that:

**One of the key tasks of the Energy Market Review team should be to identify and recommend an active upstream reform agenda. In the first instance, the previously identified upstream reform agenda needs to be re-activated to ensure access to upstream facilities is available on competitive terms. This would involve ensuring the joint marketing of gas is constrained especially for gas coming from mature gas fields; and that exploration and production acreage management is further tightened to ensure prospective territory is available for exploration and development by new players if incumbents are less interested in bringing forward new supplies.**[4]



Despite the significant progress of the natural gas sector in Australia over the past decade, key industry groups are warning of a rapidly changing investment climate for the sector. They contend that the pipeline regulatory arrangements are excessively restrictive and are impeding investment. They observe that greenhouse mitigation measures discriminate against natural gas, despite its relatively more greenhouse-friendly attributes when compared to other fossil fuels. And finally, many call for attention to be paid to the upstream sector to improve competition among the producers.

[4] AGA, submission 73, p. 74

## KEY FINDINGS

Our key findings are that:

- while previous gas reform has been successful, Australia's gas markets can at best be described as emerging
- there are conflicting views regarding the impacts of gas regulation
- significant additions to the nation's pipeline infrastructure over the last decade have enhanced the competitiveness of the natural gas market considerably
- current approaches to economic regulation are creating a perception of uncertainty for investment in new pipelines
- there are currently no effective market supporting mechanisms to ensure that significant pipelines not covered by the Gas Code are operated in a way that will facilitate effective competition
- there is limited upstream competition, particularly in the South East market, and steps should be taken to encourage greater competition through separate marketing and acreage management practices
- where governments observe a public benefit in facilitating gas developments, competitive processes which do not distort the natural gas market should be used to achieve least-cost outcomes
- further penetration of natural gas can be achieved by making all greenhouse abatement measures technology neutral.





### Australia's gas markets are best described as emerging

Australia's gas markets have continued to develop over time, particularly in the last decade — moving away from the previously common scenario of monopoly supply, single pipeline, single distributor/retailer in each capital city.

COAG's implementation of the free and fair trade in gas principles has been a significant factor in the industry's development. Removal of restrictions on interstate trade in gas and provision of access to pipelines (transmission and distribution) and to customers (removal of exclusive franchises) has encouraged new pipelines to be built.

Similarly, exploration for and development of new gas reserves has been encouraged.

The combination of new pipelines and new suppliers is bringing greater competition to most gas markets. The creation of a spot market in Victoria and the introduction of an underground gas storage facility are also significant developments. Further, Duke Energy has recently announced the creation of a gas hub in Victoria — based around the Longford gas processing plant. Duke intends to publish daily spot prices for gas at Sydney, Longford and Tasmania. It will also offer a number of financial products that enable market participants to hedge against risk, including price volatility.

These are all encouraging signs of a market that is developing. In this context, the Panel believes that while there have been strong concerns raised regarding the current arrangements in gas, the market is developing and becoming more competitive, dynamic and efficient.

Nevertheless, Australia's eastern gas markets can still at best be described as emerging. While these recent developments are encouraging, Australia's gas markets remain immature — particularly when compared with the gas markets in the United Kingdom or United States of America. The degree of supply competition in Australia's eastern markets is still weak — particularly compared to Western Australia. This is reflected in lower gas prices in WA.

Some significant barriers to a truly competitive natural gas market remain. The limited competition arising from the small number of basins supplying eastern gas markets is further restricted by joint marketing of gas from within those basins. In addition, the high level of upstream ownership concentration across basins is a concern. Another barrier to a competitive market is the relatively small size of the Australian economy.



Regulatory regimes implemented in the gas transportation sector, while freeing up access to existing pipelines, are claimed to be impacting adversely on investment. New pipelines will be needed if new basins are to be able to supply markets.

There are limited secondary markets associated with natural gas in Australia and at the same time, a strong dependence on very long-term (by international standards) take or pay contracts within the gas sector remains.

The challenge for the natural gas industry is to meet the needs of a growing energy intensive economy which is demanding a lower carbon intensive energy mix by becoming more dynamic and flexible including contracting on a shorter term basis.

## Conflicting views on the impact of regulation

The pipeline industry raised significant concerns regarding the negative impact of the Gas Code. The Australian Pipeline Industry Association (APIA), for example, submitted that:

**The current situation is highly destabilising to our industry. The intrusive and illdirected application of an inappropriate code by a purely end-consumer focussed regulator has resulted in serious and unintended consequences, whose impacts are beginning to be seen beyond the industry itself.** [5]

The pipeline industry has expressed concerns that regulation has resulted in reductions of asset value and shareholder returns with the potential to limit investment in new projects and potential undersizing of new pipelines to avoid third party access regulation. The industry also claims that regulators' actions are not consistent with government policy, creating mistrust and litigation.

The Panel wrote to the APIA, asking for evidence of prospective pipelines not proceeding solely because of the operation and application of the Gas Code. In reply, the APIA did not identify any such pipelines and acknowledged that there are a suite of barriers to new transmission pipeline development, including:

- the distance between major uncommitted gas resources and major markets
- competitiveness of natural gas as a fuel alternative/market development
- the new effective life tax depreciation regime (largely addressed through the new capping mechanism)
- delays/uncertainties caused by inefficient and time consuming land and technical/licensing approvals in a number of jurisdictions
- adverse implications of the Code for investment.[6]

Similarly, the Australian Gas Association (AGA) submitted that:

**Significant changes to the third party access regulation of gas distribution networks is required to provide the necessary incentives to maintain the currently high levels of gas network reliability, and continue to allow for the expansion and enhancement of gas distribution networks.**

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[5] APIA, submission 128, p. 5

[6] APIA, submission 128.2, p. 1

**… The significant problems with access regulation of gas distribution networks must be addressed separately to the important greenfields and coverage issues. If they are not, measures encouraging new supplies of gas, improving transmission pipeline regulation, or facilitating customer choice will be critically undermined as the delivery of gas to new consumers will be discouraged, and existing consumers will face declines in service reliability and quality.**[7]

In contrast, the Energy Users Association of Australia submitted that:

**The application of genuinely independent regulation, both here and overseas, has helped reduce network prices to more competitive levels through lower rates of return and incentive-based approaches, although asset values remain excessive. It has not, as claimed by regulated industries, produced very low rates of (risk adjusted) returns and is not threatening investment, especially in mature networks.**

**The regime is not perfect and needs to be improved, but to throw out this regime now would be detrimental to all energy using businesses. It would mean a return to the monopoly rents and poor performance of the past.**[8]

The Australian Petroleum Production and Exploration Association (APPEA), while supporting a review of the Gas Code noted that:

**… the Gas Code has been instrumental in gas accessing markets and [APPEA] does not believe that any wholesale changes to the Code are justified.**[9]

Clearly there are conflicting views regarding the impacts the Gas Code is having. While strong statements have been made by a range of participants regarding the necessity of the Gas Code, the Panel considers that economic regulation will continue to be required for some key infrastructure in the Australian gas market. However, the form of that regulation should remain consistent with the needs of the market as it develops.

## Growth in pipeline infrastructure

Significant additions to the nation's pipeline infrastructure over the last ten years have enhanced the competitiveness of the natural gas market considerably. A number of proposed pipeline developments, should they go ahead, have the potential to provide for even greater competition in the South East natural gas market in the future.

[7] AGA, submission 73.1, p. 2
[8] EUAA, submission 88, p. 6
[9] APPEA, submission 16.1, p. 2

The APIA believes this significant new investment in pipelines is not because of the Code:

**Undoubtedly the relatively recent investment in some 7000 km of new pipelines has stimulated the gas market. However there can be no doubt that this investment has been the result of commercial arrangements and contracts with major gas users and cannot be attributed to the Gas Code.[10]**

It is worth noting, however, that this investment has been made with the Gas Code in operation. The APPEA '… believes that pipeline access regulation has not been hindering investment in economic pipelines, which has been significant in recent years.'[11]

The preceding discussion deals primarily with existing pipelines. What is important for the future development of competitive markets, however, is whether the current regulatory arrangements have the potential to adversely impact on future investments.

## Perception of regulatory uncertainty

Many submissions from the gas industry expressed the view that aspects of the current regulatory frameworks and/or the interpretation of them by regulators are having the effect of discouraging investment in new infrastructure.

For example, Duke Energy noted:

**The actions of regulators strongly influence investor assessment of risk and the returns which might be expected from investment, and are significant when decisions are being made on the placement of global capital. Hence the approach adopted by regulators strongly impacts upon Australia's international competitiveness. In addition, investors and gas pipeline owners have found that the National Third Party Access Code for Natural Gas Pipeline Systems (the Code), as it has been interpreted and applied by regulators, acts as a substantial disincentive to investment in gas pipelines. Until the current regulatory arrangements for natural gas pipelines are brought back in line with the original light-handed Hilmer Report ideals, they will continue to be an impediment to efficient investment in pipelines. As such, regulatory arrangements will act to the detriment of continued and desirable development of gas markets in Australia.[12]**

[10] APIA, supplementary submission 128.1, p. 2

[11] APPEA, submission 16.1, p. 2

[12] Duke Energy International, submission 80, covering letter

The AGA submitted:

**The National Gas Code currently exposes regulated businesses to a number of significant forms of regulatory risk. These risks have the effect of deterring investment in new and existing assets and raising the cost of capital to regulated businesses above the levels used by regulatory authorities in reaching access pricing decisions.**[13]

Similarly, the APIA noted:

**The overt, narrow consumer bias, as reflected in the populist decisions made by regulators over recent years, is having a deeply negative and destabilising effect on investment sentiment.**[14]

A number of specific concerns have been raised with respect to regulatory uncertainty facing companies considering constructing new pipelines. These include:

- an inability to have a binding determination made prior to investment as to whether a proposed pipeline meets the coverage criteria or not
- uncertainty regarding what the key regulatory parameters will be prior to construction
- risk arising from the potential for key regulatory parameters to change significantly over the life of the project.

The Panel recognises the interests of the parties involved in this debate. Nonetheless, the Panel considers that the above concerns are causing regulatory uncertainty that creates risk and costs that impact on the viability of new pipelines. For an otherwise marginal proposed pipeline, significant regulatory uncertainty may be sufficient to make the project unviable.

## A lack of market supporting mechanisms for non-covered pipelines



The Australian Competition Tribunal recently ruled that the Eastern Gas Pipeline (EGP) should not be regulated under the Gas Code. The Tribunal found that the EGP faced enough competitive pressure to prevent it from having sufficient market power to hinder competition in a dependent market. Competition from the Moomba to Sydney Pipeline (MSP) to deliver gas into Sydney was a significant factor in this assessment. The owners of the MSP have since applied to have its coverage revoked — for parallel reasons. The panel notes the National Competition Council's recommendation on 14 November 2002 that coverage be retained on the MSP. The Minister is yet to make a decision.

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[13] AGA, submission 73, p. 4

[14] APIA, submission 128, p. 12

Users, however, have expressed concern that removal of regulation on the MSP will take away a significant price discipline on the EGP. They mention concerns about an unregulated duopoly emerging.

The Tribunal's decision on the EGP may set a significant precedent for other pipelines and may lead to other major existing transmission pipelines having coverage revoked — particularly as new pipelines are constructed.

Interestingly, the proposed new pipeline from Victoria to Adelaide appears to be proceeding, which will compete with the Moomba to Adelaide Pipeline to supply gas to Adelaide. Arguably, this will result in a similar competition/market power dynamic to the situation created by the EGP in the NSW gas market.

This new pipeline will complete a loop of pipelines connecting markets in South Australia, NSW, Tasmania and Victoria. Queensland is also connected, albeit with a production pipeline linking gas processing plants in South West Queensland with Moomba in South Australia.

An interconnected gas pipeline loop in the South East of Australia can facilitate trading and swapping between markets and provide greater diversity in supply options.

The Panel is concerned that significant pipelines may not be covered by the Gas Code. Currently no effective mechanisms exist to ensure that pipelines not subject to the Code are operated in a way that will facilitate effective competition — for example maintaining appropriate ring fencing of pipeline operations from upstream or downstream interests, provision of relevant information to the market and offering tradeable capacity. Without these mechanisms the benefits to the wider market and especially users of greater flexibility of supply and transportation options, may not be fully realised.

In the Panel's view, the ring fencing provisions in the Gas Code are critical to ensure that companies do not have commercial incentives to operate pipelines in a way that distorts competition in upstream or downstream markets.

For markets to function properly, participants need access to sufficient information. The Panel believes the provision of information to the market regarding the nature and pricing of pipeline services (similar to that required by the Gas Code) is an important mechanism to address the information asymmetry between pipeline companies and users and to enable the market to function properly.

### Tradeable pipeline capacity

Trading of pipeline capacity in secondary markets provides opportunities to increase the efficiency and flexibility of gas transportation. It also encourages greater competition in gas supply and carriage. In the United States gas market, the volume of capacity traded in secondary markets exceeds one third of the volume of total end use consumption of gas. Typically the price of capacity in the secondary market is significantly lower than the original price paid (discounts of up to 80 per cent are not uncommon). In peak periods, however, when there are capacity constraints, prices in the secondary market can spike.

Until recently, the US Federal Energy Regulatory Commission capped the price of capacity in the secondary market at the regulated price of the initial capacity. This cap has been removed in recognition that capacity owners were finding ways of getting around the cap to extract the market value of their scarce capacity. It was also removed to allow potentially valuable market signals regarding when capacity should be augmented.

In Australia, the Gas Code currently provides for capacity trading on all covered pipelines — albeit requiring the agreement of the pipeline company if the trade results in the original party no longer having a contractual obligation to the pipeline company. In such circumstances, the Code requires that permission cannot be unreasonably withheld. Pipelines not covered by the Code have no such requirements.

Even though it is provided for under the Code, Australian experience of capacity trading has been very limited. The Panel understands that Duke Energy operates a capacity trading mechanism for its pipelines on its web site — with some trading occurring on the Queensland Gas Pipeline.



No other pipelines appear to actively facilitate capacity trading. One possible reason for such limited capacity trading in Australia thus far may be inflexible upstream gas supply arrangements. There is little point in seeking to buy (potentially discounted) short term capacity if relevant quantities of short term gas are not available. Historically, there have been very few shippers on pipelines, which also reduces the possibility of capacity being offered and of interested buyers bidding.

As Australia's gas markets continue to develop, however, secondary markets in capacity should become more frequently used and play an important role in providing greater flexibility in gas transportation options. For this reason, the Panel believes it is important that significant pipelines not covered under the Gas Code offer (or continue to offer) capacity on a tradeable basis.

## Increasing upstream competition

Australia has abundant gas resources but limited competition in gas supply, particularly to Eastern Australian markets.

The lack of competition stems from the large distances between supply sources and demand centres, a high concentration in ownership of supply compounded by joint marketing by producers within basins, the prevalence of very long term take-or-pay contracts, competitive alternative fuels supplies, and a relatively small domestic market.

Compared to the eastern markets, Western Australia has a more diverse gas supply, with at least seven separate joint ventures marketing gas. This has arisen due to a number of factors, including the acreage management regime used to allocate the original exploration permits and is likely to have been influenced by the focus of the North West Shelf producers on export markets.

Sustainable competition between a large number of producers is critical if gas consumers are to realise the full benefits of the reforms undertaken in other sectors of the gas market.

**For a major industrial user located at the edge of a major city requiring gas transmission and distribution services and taking its gas through a retailer, the largest component of the gas price is the well-head [ex-plant] price at around 64% of the total price. Transmission would be around 21%, distribution 11% and retail 4 %.[15]**

Similar views about the impact upstream gas prices have on the delivered price are noted in the VENCorp submission and the importance of a viable competitive upstream market on the development of retail competition is discussed.

**… the principal determinant of retail prices, especially in gas, is often the underlying contracts for supply. Competition in the downstream sectors can encourage new sources of supply and storage in the long run, but in the short run can do little more than make marginal improvements in operational efficiency, improve customer service, and reduce the extent of price discrimination among end users. Access to cost-competitive supplies is, therefore, a prerequisite for the entry of new retailers and the enhancement of retail competition. Retail competition is more likely to be influenced by limited access to supplies than by any particular features of the market or transport management regimes. In gas, the issue of limited upstream competition has been widely acknowledged and been the subject of**

[15] AGA submission 73, p. 72

**much consideration by industry, regulators and Governments over a long period of time. It is not an issue that is caused by nor is it solvable solely by implementation of, or changes to, spot market or pipeline access arrangements.**[16]

There are a number of new gas fields mooted for development in the near future, some of which could have a competitive impact in the South East Australian market. There are also proposals to bring large quantities of gas down from the north (PNG and Timor), with prospective gas suppliers in the market place competing to sign up sufficient volumes of gas sales to underwrite the major investments required in production and processing and the pipelines required to bring the gas to market. Should these new supplies eventuate, the commercial pressures they could bring to the existing suppliers will act to keep prices competitive.

Open access to transmission and distribution infrastructure has played a significant role in increasing upstream competition particularly in the South East Australian markets.

To achieve increased inter-basin competition governments need to ensure that economic pipeline development is not impeded. The majority of submissions commented on the issues relating to investment in pipelines and these issues are addressed elsewhere in this chapter.

Increasing intra-basin competition can also contribute to a more efficient market.

Duke Energy submitted that:

**Additional penetration and uptake of natural gas is hindered by the limited number of producers with vested interests in multiple production areas. This means there is little incentive for producers to bring on new fields, especially if the additional capacity merely results in downward pressure on prices.**



**… In DEI's view, what is needed to increase the use and penetration of gas is an increase in the number of producers via separation of the current joint marketing arrangements. This would promote greater competition, and increase liquidity in the overall gas market.**[17]

In addition to separate marketing, a range of other factors can have a significant effect on increasing intra-basin competition. Acreage management policies, including greater and more active management of exploration permits and the manner of granting leases, are one example.

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[16] Vencorp, submission 122, p. 3

[17] Duke Energy International, submission 80, p. 10

Similarly, open access to upstream production facilities can encourage smaller explorer/developers into the market through the confidence that they will be able to negotiate access to existing facilities on a commercial basis.

### Separate marketing

The Panel considers that separate marketing, where appropriate, can significantly increase competition in the upstream sector, and particularly in the South East markets.

Almost all oil and gas exploration in Australia is undertaken by joint ventures — primarily as a risk and cost sharing mechanism. This arrangement has tended to flow to joint production arrangements whenever gas reserves are developed.

The arguments for joint marketing stem partly from joint production arrangements, and from claims that the downstream markets lack sufficient depth and liquidity to support separate marketing by the joint producers of the resource.

Indeed, the ACCC in its consideration of the North West Shelf Joint Venture application for authorisation of joint marketing in 1998 compiled a scenario of the necessary market preconditions to support separate marketing. The approach of considering the relative maturity of the market was also adopted by the majority of submissions received on this matter.

ExxonMobil's submission to the Panel on the question of separate marketing noted in the covering letter that:

**Globally, ExxonMobil's preference is for separate marketing of its equity production of natural gas. ExxonMobil generally only adopts joint marketing where the wholesale market is shallow and illiquid and/or the characteristics of the resource are not conducive to separate marketing. In the case of the south-eastern Australian gas market and the Gippsland Basin both of these preconditions are met.**[18]

The Panel has concluded that not all the features of a mature market need be present for separate marketing from joint facilities to be feasible. If they were, separate marketing itself would probably only be of academic interest, as a high degree of competition would already be achieved. The existence of secondary markets with associated financial products are outcomes of a mature market, rather than prerequisites for separate marketing. For each gas producing joint venture, some market features will be more important than others in considering the feasibility of separate marketing.

[18] ExxonMobil, supplementary submission 32.1, covering letter p. 1

Historically, governments have supported joint marketing of gas production in order to facilitate the development of the resources. These approvals were given in the context of a sector where traditionally monopoly producers dealt with monopoly buyers and vertically integrated businesses were the norm. Under these conditions the potential loss of competition through joint venture marketing was minimal.

Increasing competition through separate marketing has the potential to significantly add to competition already existing in the Australian natural gas market. Clearly, the vertical disaggregation of the industry and the implementation of non-discriminatory third party access to interconnected gas transmission and distribution networks has provided the greatest impetus to upstream and downstream competition.

Moving toward separate marketing should be considered as part of the overall package to improve the competitive nature of the natural gas market. Separate marketing itself should be regarded as one of the ingredients that in the appropriate circumstances helps to create competition and thereby a more mature market.

A potential window of opportunity for upstream market reform is evident due to the expiration of long term contracts for gas supply from the Cooper Basin and the Gippsland Basin around 2005-06 and 2009-10 respectively. The existing contracts for gas supply from both these basins have been made on a joint marketing basis.

The Panel considers that the market environment within which these supply basins operate has changed significantly. Gas reforms and new pipelines have significantly increased the potential customer base for these producers, reflecting the ability for these producers to now market into a number of jurisdictions. The 'project' based selling arrangements prevalent during the start up phase of these operations are well passed.



To gain a greater understanding of the complex legal, technical and competition issues involved in separate marketing of natural gas the Panel commissioned KPMG to assess whether separate marketing of gas is feasible in Australian energy markets.

The Panel's view is supported by the KPMG report to the Review which notes that:

**The origins of the Cooper Basin joint venture as 'project' development and operation are long past. The current environment is one of open access transmission and distribution, additional pipeline infrastructure and significant growth in the number, diversity and availability of downstream buyers. The original basis for reducing risk through joint**

**marketing and State exemptions/ACCC authorisations to underpin the construction of facilities at Moomba and the Eastern Australia pipeline to Sydney has been well and truly achieved.**[19]

Similarly in relation to the Bass Strait operations:

**The Esso / BHPBilliton joint venture could now be described as an established non 'project' operation with proximity to markets coupled with an open access transmission and distribution regime. The retail market position has gone from one retailer in a discrete Victorian market to multiple retailers and distributors in a contestable Victorian market with connection to contestable markets interstate. At the same time however, Esso / BHPBilliton has remained as the one major producer supplying the Victorian market region with increased access and supply to interstate markets.**

**A substantial competitive imbalance has opened up between the supply and demand sides, certainly in the Victorian part of the South East Australian market. The Santos / Delhi / Origin joint venture in the Cooper Basin has made little significant inroad into Victoria.**

**Individually, the joint venturers have an increasing ability to secure contracts for incremental supply or add on contracts. They do not depend upon a united joint marketing structure to reduce market risk to the extent that a remote greenfields project or large new development might require to meet a development threshold.**

**Apart from potential impediments or difficulties such as Significant Producer legislation and allocation/balancing which are addressed later, Esso and BHPBilliton, as separate marketing entities, would seem unlikely to suffer any significantly greater market risk in their respective ability to access markets for demand growth or to compete for supplying replacement volumes under expiring contracts. Of course, they would be exposed to the risk that is attendant with legitimate competition. Separate marketing, particularly in the context of the substantial market share of the joint venture in the Victorian geographic market, would provide the multiple buyers with additional competition in which to negotiate terms of supply.**[20]

With regard to the Significant Producer Legislation (SPL) in Victoria the KPMG report concluded that:

[19] KPMG (2002c), p. 34

[20] KPMG (2002c), pp 29 — 30

**Separate marketing for Esso and BHPBilliton could not realistically be achieved whilst sections 78 and 79 of SPL concerning discrimination remained. The protections afforded by the competition provisions of the Trade Practices Act should be regarded as adequate.**[21]

As noted above ExxonMobil indicated that for the Gippsland Basin, the '…characteristics of the resource are not conducive to separate marketing.'

**…there are also practical impediments to separate marketing of jointly produced gas arising from the depletion characteristics of the water driven fields of the Gippsland Basin. In contrast to the more common depletion drive fields (depletion drive fields typically demonstrate steady and predictable depletion over the life of the field), water driven fields are characterized by relatively rapid and less readily predictable timing of depletion.**

**Separate marketing of these types of resources can result in either sub-optimal technical depletion of the field or one or more co-producers being placed at considerable commercial disadvantage. In terms of stimulating competition between co-venturers, balancing agreements for this type of field are only effective for relatively small volumes over short periods in the life of a field.**[22]

The Panel considers that effective allocation and balancing arrangements may not be possible in some circumstances, particularly where the risk to producers of finding buyers at a competitive price is high because there are few buyers and/or the volumes individual producers would have to place into the market are disproportionately large.

The KPMG report briefly considers the problems associated with allocation and balancing to support separate marketing within joint production fields and found that:



**Gas balancing agreements would need to address issues such as when to balance, ways to balance, price for balancing, acquisition ownership issues, nominations and allocation procedures and what occurs in the event of insolvency.**

**We are aware that circumstances can be different in other markets, but we have not seen any evidence, beyond generalised comments of complexity and cost, that demonstrates that the Australian field production and processing practices are such as to effectively preclude allocation and balancing mechanisms.**[23]

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[21] KPMG (2002c), p. 47

[22] ExxonMobil, supplementary submission 32.1, covering letter p. 3

[23] KPMG (2002c), p. 45

The Panel, however, recognises that joint ventures face some challenges in dealing with production balancing issues and that these need to be addressed in the unique circumstances of each case in determining the applicability of individual competitive marketing. It is acknowledged that there are circumstances where separate marketing is not practical. Nevertheless, the points below suggest that there are circumstances where separate marketing is likely to be practical:

- the significant differences that can exist between 'greenfield' developments and additional/incremental contracts from existing reserves and facilities
- the recent public announcements by Woodside that suggest it will separately market gas from a new joint venture in the Otway Basin
- the stated preference by ExxonMobil to separately market gas but that it considers that technical complexities preclude it in the Gippsland Basin
- the fact that companies, some of which operate in Australia, manage to satisfactorily allocate and balance production for separate marketing in other counties, albeit in different circumstances.

There appears to be no single rule for all circumstances. Clearly there is a need for the ACCC to undertake a detailed analysis on a case-by-case basis for each operation seeking an authorisation to jointly market natural gas in the future.

In the Australian economy there is a general presumption that competition between firms achieves the most sustainably efficient market place. Section 45(2) of the Trade Practices Act (TPA) does not permit a corporation to make a contract or arrangement, or arrive at an understanding which has the purpose or is likely to have the purpose of substantially lessening competition.

An application may be made under section 88 of the TPA to the responsible regulator, the ACCC, for an authorisation. The TPA does not mandate that all joint marketing ventures be required to make an application to seek an authorisation. In the absence of a joint venture seeking an authorisation, the onus is upon the ACCC to instigate any review if it believes that the arrangement might be likely to result in a substantial lessening of competition. Otherwise, a joint venture may form its own opinion as to whether its joint marketing behaviour is or is not likely to substantially lessen competition.

Section 90 of the TPA directs the ACCC to an examination of the extent to which joint marketing may be likely to result in a net public benefit. Major joint venture gas marketing contracts authorised under section 90 include the supply of gas to AGL in NSW by the Cooper Basin producers and the supply of domestic gas in Western Australia by the North West Shelf producers. These authorisations illustrate the framework the ACCC has applied in considering joint marketing applications.

Section 51(1) of the TPA allows states to exempt certain agreements from the competition rules administered under the TPA, including section 45. Exemptions have been specifically legislated for in Victoria, South Australia and Western Australia in relation to the supply of gas from Bass Strait, under Part V of the *Gas Industry Act 2001*, in relation to the Cooper Basin under the *Cooper Basin (Ratification) Act 1975* and in relation to supply from the North West Shelf under the *North West Gas Development (Woodside) Agreement Act 1979*.

Overall, the Panel finds that separate marketing, where it can be practically implemented, will encourage a more competitive natural gas market. Given the significant evolution in the Australian gas market in the last decade, the first steps should now be taken toward encouraging greater competition through separate marketing where this can be achieved.

## Access to upstream facilities

The Panel considers that the question of whether access to processing facilities is hindering the development of a more competitive upstream sector is a perennial issue compounded by the problem that the evidence to support the need for action in this area is largely anecdotal.

Little evidence was given to the Review of problems currently faced in obtaining access to processing facilities, and the Review is mindful of previous work in this area carried out by the ANZMEC Upstream Issues Working Group (UIWG).

The UIWG recommended that commercial negotiation, supported by publicly available access principles, should be the preferred option to provide for access to upstream facilities. The industry, through the APPEA, developed principles for access to upstream facilities.

When ANZMEC Ministers noted the principles developed by APPEA they agreed that a review should be conducted in two years time (August 2001).

The Panel notes the ACCC submission that:

**It is unlikely that a third party could seek access to gas production facilities through the provisions of the Gas Code or Part IIIA of the TPA. It is unclear whether the definition of services as contained in these laws is broad enough to include gas production facility services. As a result, the current arrangements continue to rely upon commercial negotiations and the competition provisions of the TPA. To date the Commission is unaware of any complaints about a denial of access to upstream facilities.**[24]

Nevertheless, as the gas market matures and additional upstream producers appear, access to upstream facilities will become more important.

The review requested by ANZMEC Ministers has not taken place. The Panel considers that such a review should be undertaken.

### Acreage management

Competition in the upstream sector can also be enhanced by efficient and competitive acreage management regimes.

Few submissions to the Review provided strong evidence of the need for reform of, or the potential for improvements in, the allocation or management of exploration and development leases to encourage greater upstream competition in the natural gas market. The Panel notes that the NCC has recently assessed the majority of acreage management legislation and found their continued operation to be in the public interest.

However, the National Retailers Forum submission notes that a particular concern of the acreage management scheme is the potential for some firms to exert market power in the downstream natural gas market through the use of retention leases (on the grounds that the discovery is not commercial):

**A direct impact of ownership concentration is the failure to develop gas resources that would compete with the owner's existing production assets.**[25]

The Panel is mindful of the reported outcome of the review of the Petroleum (Submerged Lands) Act (PSLA) and its interaction with competition policy conducted by ANZMEC in 2000. The PSLA governs exploration and development of Australia's offshore petroleum resources.

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[24] ACCC, submission 136, p. 88

[25] NRF, submission 42, Part B, p. 12

The ANZMEC review's main conclusion is that:

**…the Petroleum (Submerged Lands) legislation is free of significant anti-competitive elements which would impose net costs on the community. To the extent that there are restrictions on competition (for example, in relation to safety, the environment, resource management or other issues) these are considered appropriate by ANZMEC given the net benefits they provide to the community as a whole.**[26]

The Panel notes that the PSLA contains a presumption that discoveries should be developed promptly, and that the lease-holders seeking retention leases need to be able to demonstrate that the resource is not commercial to develop but is expected to become commercial within the next 15 years. Within each five year retention lease period the government has the power to seek a re-evaluation of the commerciality of the discovery.

## Government facilitation of new gas projects

Development of Australia's gas resources is undertaken by private companies. It involves very substantial investments and adequate returns are required to ensure sufficient capital can be attracted. Remotely located resources tend to also attract a further risk premium when investment decisions are being made by companies. Likely price and volumes of resulting production are critical elements in whether or not projects proceed. Only the companies with the capital at risk can make these judgements on project viability.

However, the Panel recognises that there may be circumstances whereby it is appropriate for governments to provide incentives to encourage major projects to proceed — such as when the national benefits do not completely coincide with the project proponent's commercial benefits. Some of the significant benefits major energy projects can provide, such as employment, defence and strategic national interests may not be able to be 'captured' by the investors in the project. In such circumstances, socially desirable investment may not occur without government incentives.



Determining when to offer incentives and the nature and magnitude of those incentives is an appropriate role for government. In performing this role, however, governments should ensure that energy markets are not distorted as a result of their actions. This means that governments should avoid 'picking winners' (targeting specific projects for exclusive assistance). Rather, outcomes or objectives should be identified, and incentives offered to anyone that is able to achieve those outcomes or objectives.

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[26] Manzie (2001)

The Panel received a substantial submission from the Northern Territory Government strongly in support of bringing Timor Sea gas onshore, citing significant potential benefits to the Northern Territory and Australian economies. The alternative proposal is to construct a floating gas processing and liquefication plant, with the liquefied natural gas being exported.

The Panel understands the Northern Territory Government's preference to have the gas brought on shore to underpin significant energy related business development in the region and to provide security of supply as the Mereenie field depletes.

There are likely to be other instances over time where Governments observe a public benefit in making energy available in certain areas which project proponents will not provide for various reasons. In the Panel's view, any facilitation should be on the basis of governments seeking proposals from the market to achieve a certain outcome, rather than targeting one particular source or solution. Competitive processes to meet the identified need that do not distort the market are more likely to result in least-cost outcomes for the community and economy.

## Impact of greenhouse gas reduction measures

The Panel believes that the introduction of a greenhouse gas emission reduction measure such as an emissions trading regime may increase the penetration of natural gas — particularly as a fuel for electricity generation. This issue is addressed in detail in Chapter 8.

If gas is used more intensively as an electricity generation fuel, it will require expansions of existing pipelines and, importantly, new pipelines built to areas that currently do not have natural gas available.

The quantity of natural gas demanded by an electricity generator can be sufficient to underwrite a new pipeline to a region. Once gas is available at reasonable cost, additional users can benefit from gas supply — from domestic reticulation through to commercial/industrial use.

### Removal of market distortions in the retail sector

Residential consumers constitute the third largest demand sector for natural gas. The penetration rate however, is not uniform across all states. Victoria has nearly twice as many gas customers as NSW and consumes nearly twice as much per capita.

Opportunities exist to encourage the wider penetration of natural gas by increasing the number of households connected. Increasing natural gas use in the residential sector (where it replaces grid electricity use) can provide an additional energy market benefit by flattening both gas and electricity demand profiles, especially at times of peak electricity demand.

The implementation of full retail contestability is resulting in the creation of multi-utilities which have the potential to offer fuel and appliance choices to residential customers.

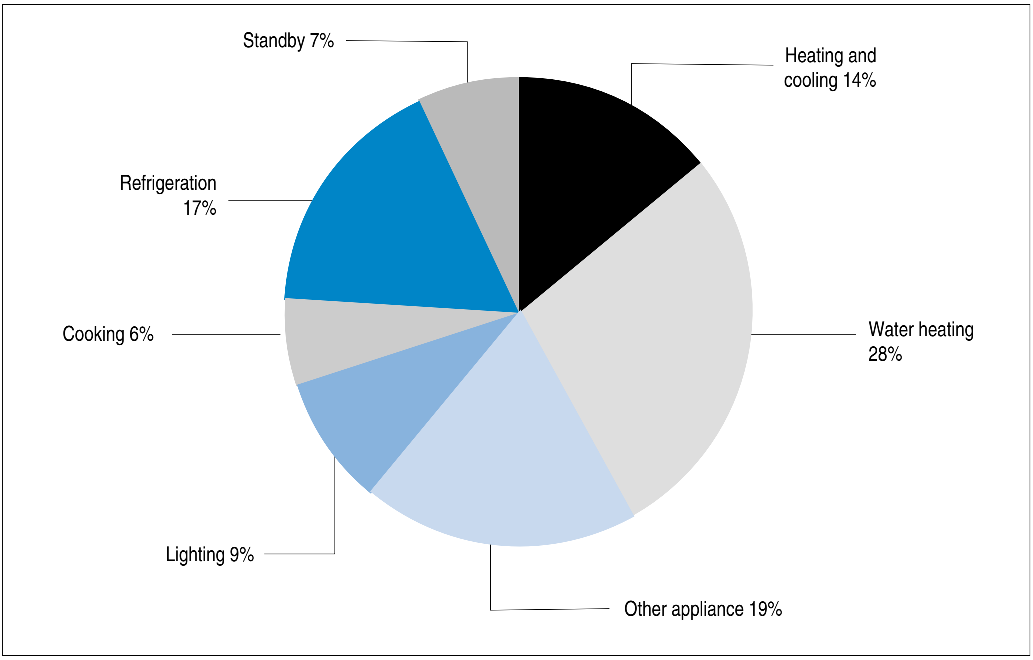
For customer choice to be effective markets need to be free of distortions.

Distortions can occur in a range of different ways including as a result of government programs that deliberately or inadvertently result in inefficient market outcomes and/or undesirable environmental outcomes.

A research paper *Reducing the emissions and costs of water heating in Australia* prepared by the AGA[27] noted that a significant distortion at the household and commercial levels occurs as a result of state and Commonwealth government programs and that these programs undermine the greenhouse abatement objectives they seek to achieve by discouraging gas water heater sales.

The research paper indicates that domestic water heating systems are the largest single load of an average Australian household's total energy use, accounting for about 30 per cent of total energy use, and about the same proportion of total greenhouse gas emissions. See Figure 7.3.

**Figure 7.3 : Energy use in the average Australian home**




*Source: AGA — Data from AGO Energy Use: Introduction 2002*

[27] AGA, supplementary submission 73.2

Most (59 per cent) of the estimated 7 million water heaters in Australia are electric. Of the remainder 35 per cent are gas, 4.8 per cent are solar and 1.2 per cent use some other form of energy (e.g. wood). In 2000 around a half a million new domestic hot water systems were sold in Australia — 61.5 per cent were electric, 32.9 per cent gas, and about 2.7 per cent solar.

The paper's four main conclusions are that:

- Governments' greenhouse abatement objectives could be more cost-effectively achieved by encouraging the increased use of natural gas.
- The existing solar hot water assistance measures discriminate against the use of natural gas and undermine the abatement objectives.
- Subsidies generally should be performance based and technology neutral.
- The preferred long-term sustainable solution is to bring about a competitive and efficient energy market.

The AGA paper finds that the current incentives result in greenhouse gas emission savings (over conventional systems) but that significant taxpayer savings could be made (potential saving of $5 million per year) if householders were encouraged to switch from electricity to natural gas water heating, rather than the solar heating systems that the current schemes target.

The Panel considers that a technology neutral, transparent and market based approach would remove the discrimination against gas (and any other emissions efficient water heating system) and enable all systems to be judged according to their greenhouse gas merit.

Effective, competitive markets should not contain distortions that result in inefficient and unintended outcomes.

## PROPOSED SOLUTIONS

The Panel proposes the following solutions to address the key findings:

- introduce binding up-front 'coverage' rulings
- offer 15 year economic regulation free periods for new transmission pipelines
- provide for up-front regulatory agreements for new pipelines
- change the governance and regulatory arrangements

- conduct an independent review of the Gas Code
- apply a code of conduct to non-covered pipelines to ensure a competitive market
- encourage greater competition through separate marketing
- include criteria to promote competition in acreage management regimes
- undertake a review of the industry's principles for access to upstream facilities.

## Introduce binding up-front coverage rulings

Under the current provisions of the Gas Code, parties can seek an 'opinion' from the National Competition Council (the Council) as to whether a proposed pipeline would meet the criteria for coverage. Any opinion the Council provides cannot bind the Council in relation to a subsequent application for coverage of that pipeline. This creates significant uncertainty for prospective pipeline companies regarding the potential for them to be covered (and hence regulated).

In its Review of the National Access Regime — Inquiry Report, the Productivity Commission (PC) concluded that the inability for prospective infrastructure builders to seek a binding ruling regarding declaration (equivalent to coverage) could create sufficient risk as to cause a marginal project to become uneconomic. The PC recommended that provision be made within Part IIIA of the Trade Practices Act (the National Access Regime) for the proponent of a proposed investment in essential infrastructure to seek a binding ruling on whether the services provided by that facility would meet the declaration criteria.

The PC recommended that any such binding ruling should apply in perpetuity, unless revoked by the Minister on advice from the Council on the grounds of a material change in circumstances and that such a revocation should be appellable.[28]



In its submission to this Review, the Council supported the concept of a binding ruling, proposing that:

**The Council's capacity to give a binding ruling would be affected by the information available to the Council, including information gathered through any public process. It would be appropriate for any binding ruling process to be conducted in a similar way to an application for coverage. It might include a process for the Council to recommend**

[28] PC (2001), p. XXXVII

**revocation of the binding ruling if there was a material change in circumstance or if the service provider purposively or negligently misled the Council in the information provided. Any such revocation should be subject to a merit review to the Tribunal.**[29]

The introduction of a power to revoke a binding ruling, should there be a material change in circumstances, will lessen the certainty sought to be provided by creation of the binding ruling in the first place. The revocation power is understandable given the perpetual nature of the proposed binding ruling. There is, however, a tradeoff here between wanting to provide the greatest possible certainty to prospective investors and wanting to be able to require access to a pipeline on reasonable terms and conditions if that proves to be in the public interest (and promotes competition) at some future time due to a material change in circumstances.

In the Panel's view, binding up-front coverage rulings are important in reducing regulatory uncertainty. The Gas Code should be amended to enable the granting of binding coverage rulings for fixed periods of time, but with no ability to revoke that ruling within the period unless information relied upon proves to be false or intentionally misleading. This would allow companies to make a case to the regulator prior to construction that a prospective pipeline would not be likely to meet the coverage criteria for a certain period. The longer this period, the more difficult it will be to convince the regulator that the coverage criteria would not be likely to be met. Conversely, as this period is reduced, the magnitude of the benefits (in terms of greater regulatory certainty) diminishes. The ideal period would be the minimum period regulatory certainty was required to deliver an expected return sufficient to make the investment profitable. A period of fifteen years should be sufficient in most situations.

If a prospective pipeline does not meet the coverage criteria when assessed, the likelihood of it subsequently meeting the criteria within ten or fifteen years is remote and should be foreseeable. In the Panel's view, the market is more likely to develop in a way that brings some degree of competition to a new pipeline (and hence lessens further the likelihood of it meeting the coverage criteria).

## Offer 15 year economic regulation free periods for new transmission pipelines

The arguments in support of economic regulation for new transmission pipelines may not be as strong as for established pipelines. Typically a proposed transmission pipeline is seeking to

[29] NCC, submission 96, p. 63

respond to a market demand. Either the developer of a new producing area intends to have its gas transported to a market or a customer (or group of customers) wish to have gas transported to them — or both. In such circumstances, the prospective initial users of the pipeline ('foundation users') have a significant degree of countervailing power — such that if a pipeline company seeks to charge them excessive tariffs, they can approach another pipeline company to build the pipeline for them. As such, any transportation agreement reached between the pipeline company and users prior to the construction of the pipeline should be reasonable for both parties — so long as there are no control issues arising from vertical ownership. This means that in the short term at least, there is little or no scope for benefit from imposing the burden of regulation upon the pipeline company. Indeed taking the costs into account, the short term impact of regulation in these circumstances is likely to be negative.

If an issue is to arise, it is likely to be some years after the pipeline is constructed. At that time, if a new prospective user seeks to negotiate terms to have its gas transported, the pipeline company can be in a position of market power which it can exploit to charge an excessive tariff since it can charge up to the next best alternative for the prospective user — which is usually to have a new pipeline built to service its needs. This will almost always be a significantly more expensive option. The more expensive the next best alternative, the greater the market power of the existing pipeline.

When a new transmission pipeline is first proposed, the prospective pipeline company will seek to identify and sign up all potential customers, since the per unit price of transportation falls markedly with increased volumes. This means that there is a low likelihood of additional users arising in the early years of a new pipeline's operation.



The risk of a new pipeline being regulated, however, can create significant uncertainty — potentially sufficient to make otherwise marginally profitable proposed pipelines unprofitable and hence not proceed.

In the Panel's view, the solution is that prospective transmission pipeline companies should have the ability to choose to not have any price regulation imposed upon the new pipeline for the first fifteen years of its operation. Pipeline companies choosing this option would be free to negotiate with customers and enter into transportation contracts.

At the end of the fifteen year period, an assessment would be made of whether the pipeline company is exercising market power in its negotiations with customers. If it were, then the pipeline could be covered and regulated under the Gas Code. If it is not, then it would continue to operate as a normal uncovered pipeline. It would then be exposed to the threat of an application for coverage should an access seeker believe a case could be made at any time in the future.

However, to qualify for the option of no price regulation, the relevant pipeline must satisfy the NER that the following conditions are met. The pipeline must:

- be a new transmission pipeline (i.e. not constructed yet)
- have sufficient vertical separation of ownership (i.e. no upstream or downstream firm has sufficient ownership to exert control over the pipeline in a way that might lessen competition in upstream or downstream markets)
- publish tariffs for access to the pipeline
- provide for all capacity to be fully tradeable.

The above measures are important to encourage the development of a more flexible and responsive gas market. However, the Panel is not convinced that this measure should be extended to distribution networks. There are difficulties in defining what is a greenfield distribution system (as opposed to an augmentation or extension of an existing system). Further, the 'consenting adult' principle may not hold for distribution systems to the same extent as for new transmission pipelines.

The optimal duration for the price regulation free period will vary according to the particular circumstances of each pipeline. The costs of determining the optimal period for each and every pipeline, however, would be significant. Further, such a process would be exposed to gaming opportunities for the pipeline companies, since there is a significant information asymmetry between the pipeline company and the regulator. On balance, it is likely to be more efficient to have a single period that applies to all pipelines.

The length of this period should be sufficient to allow a company to earn a reasonable return on its investment. Investors generally look for an early return on their investment — typically within a seven or eight year period. Gas pipelines are usually longer term investments, with slower pay back periods. However, as the length of time increases, so too does uncertainty about the economic potential of the project due to resource and market risk.

Recent consideration of the 'effective life' of gas pipelines for tax purposes indicate that primary economic factors, including variability in volumes contracted to the pipeline, the potential for new competing pipeline systems to be developed, the potential declines in the gas resource and even competition from other fuel sources can all dictate the potential effective life of gas pipelines.

The Panel believes a 15 year price regulation free period to be an appropriate balance between the competing objectives of providing greater certainty to pipeline companies and not excluding the possibility of regulation too far into the future should it prove to be warranted.

## Provide for up-front regulatory agreements

An alternative to the 15 year price regulation free period for prospective pipeline companies seeking long term regulatory certainty is to enter into an up-front agreement with the regulator.

Prior to construction, a pipeline company can approach the regulator with a detailed proposal of the services it intends to offer and reference tariffs for those services. It can seek to 'lock in' for extended periods of time the key regulatory parameters — such as weighted average cost of capital or return on equity, risk factors, depreciation schedules, financing structures or the operation of revenue sharing mechanisms.

Since the regulatory agreement needs to be reached prior to construction, some important parameters cannot be known — such as the pipeline's construction cost. For these, rather than agreeing on an estimate, principles can be agreed that define a process to calculate these parameters once the pipeline is constructed.

Other parameters could vary or be fixed, depending on the pipeline company's preferences and the overall regulatory package — for example volume projections or the impacts of exchange rate fluctuations on project costs.

An up-front agreement can potentially provide regulatory certainty for the life of a pipeline.

Regulators are understandably cautious in approving regulatory arrangements for extensive periods of time. Around the world, regulatory periods tend to be no more than three to five years. This is because the risk of not achieving an appropriate balance between providing a reasonable return to the pipeline company and a reasonable price to access seekers increases exponentially as the regulatory period increases.



The Gas Code currently provides for up-front regulatory agreements, and specifically provides for them to be of any duration. In seeking to address the risks of lengthy regulatory periods, however, the Gas Code requires that whenever a proposed access arrangement is for a period exceeding five years, the regulator is required to consider whether mechanisms should be included to address the risk of forecasts on which the terms of the access arrangement were based proving incorrect.

The Gas Code provides some examples of potential mechanisms, such as benefit sharing of revenues beyond a pre-agreed amount, or including a trigger for review of the access arrangement if certain events occur — such as profits falling outside of a specified range.

The ACCC provided a copy of its Draft Greenfields Guideline paper to the Review. This Guideline highlights the flexibility of the current Gas Code and provides an indication of the ACCC's interpretation of some of the key provisions of the Gas Code.

The Panel understands that no pipeline company has effectively submitted a proposal for an up-front regulatory agreement under the Gas Code — with the possible exception of the Central West Pipeline, which had a ten year access arrangement approved in recognition that it needed to have time to develop the natural gas market in the central west of NSW for the pipeline to be profitable. The riskiness of that project was also reflected in the approval of a mechanism to capitalise any losses in early years to enable them to be carried forward and recovered in subsequent years.

Another avenue currently available for prospective pipeline companies wishing to enter into an up-front regulatory agreement is to offer an access undertaking to the ACCC under Part IIIA of the Trade Practices Act.

In the Panel's view, there is considerable scope for pipeline companies to reduce regulatory uncertainty by taking advantage of the provision for up-front regulatory agreements in the Gas Code. The ACCC's Greenfields Guideline paper should assist companies in pursuing this option.

## Changed governance and regulatory arrangements

Chapter 2 of this report contains recommendations for changes to governance and regulatory arrangements. Of relevance, these include the creation of a single national energy regulator and reform of the Code change process.

All of these can have the effect of reducing regulatory uncertainty and lowering the cost of regulation on pipeline companies.

The creation of a single national energy regulator, by amalgamating all the current jurisdictional regulators, will significantly reduce regulatory costs — particularly for companies operating in more than one jurisdiction. It will also deliver greater uniformity in regulatory decision making and interpretation of Code provisions. This makes for more predictable regulatory outcomes and hence reduces risk.

Reforms to the Gas Code change process, particularly the greater involvement of industry and users, should ensure that the Gas Code is better able to adapt to changes in the industry environment and to be more responsive to issues or problems industry and users are experiencing due to aspects of the Gas Code.

## Conduct a review of the Gas Code

As described earlier, there are strong views regarding the impact regulation is having on the gas industry. The pipeline industry has complained that regulation has been applied in an overly restrictive and intrusive manner. Users, on the other hand, have expressed concern that regulatory outcomes have been overly generous, including through inflating asset valuations.

Many of these issues were discussed in the recently released Productivity Commission Report following its Inquiry into the National Access Regime. The Productivity Commission recommended a number of possible amendments to the national access regime. Of relevance are recommendations to make available up-front binding declaration (coverage) decisions; that the coverage criteria be strengthened; and that a mechanism be developed to address the truncation of returns that results from the current regulatory approach that caps blue sky upside but does not put a floor under potential downside. The PC report also recommended that a review of the Gas Code be undertaken. The Commonwealth Government's interim response to the PC Report includes a commitment to conducting a major review of the operation of the Gas Code.

The Panel supports a review of the Gas Code given it has been in operation since 1997 and a number of Access Arrangements have been approved. A review would now be able to consider experience of regulatory outcomes against which it could test both industry and user concerns.



In framing the terms of reference for a review of the Gas Code and in implementing any recommendations that arise from it, governments should ensure that an appropriate balance is achieved between the interests of pipeline companies and the users of those pipelines. It is in everyone's interest to have sufficient incentives for economically viable pipelines to be built. It is also critical that the tentative steps currently being taken towards a more competitive and dynamic industry are encouraged and the momentum and direction of reform is maintained.

## Introduce a code of conduct for non-covered pipelines

As part of a proposed alternative regulatory arrangement to apply to gas pipelines in Australia, Epic Energy in its submission recognises that there would be benefits in having 'minimum behavioural requirements' that apply to non-covered pipelines. Epic proposes that this be achieved by having these pipelines commit to an industry code of conduct containing the following features:

- a commitment to ring fencing requirements similar to those in the Gas Code
- a commitment for pipelines to be operated on an open access basis
- public disclosure of voluntary access principles in circumstances where a request has been made for access to a pipeline.[30]

Even if pipeline systems are not covered by the Gas Code, there are possible sanctions for anticompetitive behaviour by non-covered pipelines — such as the anticompetitive conduct provisions in Part IV of the Trade Practices Act and the threat of an application for coverage.

Nevertheless, some agreed minimum standards of operation would provide greater confidence to market participants. This could include development of standard contracts across the industry for common services — such as pipeline and network transportation of gas. Greater uniformity in contract terms and conditions will promote secondary markets and can significantly reduce negotiation costs for all participants.

The Panel believes that there is merit in having minimum market supporting requirements for non-covered pipelines and was informed by the Epic Energy submission in coming to this view. The Panel therefore proposes that enforceable minimum requirements be developed by the industry in conjunction with the NER. This should be enabled under the legislation establishing the NER.

## Encourage greater competition through separate marketing

As noted earlier, increasing intra-basin competition through separate marketing of natural gas from joint production operations can significantly add to the evolving natural gas markets, particularly in the south-east.

The Panel believes that it is now time to encourage greater competition in natural gas supply through separate marketing in the South East market and perhaps to a lesser extent in the Western Australian market.

In moving forward on separate marketing the Panel does not consider that a ‘blanket’ mandating of separate marketing is appropriate. A thorough case by case assessment of each individual situation is the most appropriate means to determine whether there is a net national public benefit in allowing joint marketing from a particular project and its feasibility in each case.

Assessments should continue to be carried out by the ACCC since it has responsibility for competition law including assessments of authorisation applications across all industries. Where appropriate the ACCC should liaise with the National Energy Regulator to ensure that the NER’s practical skills, experience and knowledge of the operation of the upstream and downstream gas industry and the circumstances of particular cases are taken into account.

The Panel considers that future assessments by the ACCC should move beyond the paradigm of whether the natural gas market is a mature market and therefore able to support separate marketing.

It has generally been considered that the lack of depth and liquidity in the Australian natural gas market precludes joint producers from separately marketing their resources.

As noted earlier, some jurisdictions have, in the past, enacted state-based exemptions to permit joint marketing. The Panel considers that as Australian gas markets continue to evolve, it is important for a transparent, nationally consistent approach to be adopted for the assessment of joint marketing arrangements.



With the current regulatory arrangements and the existing infrastructure it is now possible for producers in the South East to contract for supply in a number of different states. With the addition of the proposed pipeline between Victoria and South Australia and the proposed Duke Energy ‘VicHub’ the ability to contract in multiple states will be even further enhanced. In addition the potential for major gas supplies to enter the South East market from various northern or north western supply sources could substantially alter the competitive nature of the gas supply sector in the South East market.

Accordingly, in the Panel’s view there should be mandatory notification by joint venturers to the ACCC of all future joint marketing arrangements. This is merely to ensure that the ACCC is aware of all joint venture marketing conduct. It does not cause any formal process such as an investigation or authorisation to commence. As currently occurs, joint venturers are free to proceed with their marketing arrangements, while the ACCC considers whether any further action is needed.

Given the ongoing reforms and changes in the gas industry, the Panel believes that any authorisations granted should contain a review date.

The Panel also believes that to achieve a national approach, the Trade Practices Act should be amended so that jurisdictions are no longer able to exempt the application of section 45 to joint marketing of natural gas.

The Panel is concerned however, that existing contracts not be unduly affected. The Panel therefore proposes that the existing state exemptions continue to apply to the existing contracts but that all new contracts, or renewals should be subject to the nationally consistent regime as currently applied through the Trade Practices Act section 45 test of substantially lessening competition and the section 90 authorisation public benefit test.

The Panel considers that the test of ‘substantially lessening competition’ is an appropriately high hurdle to clear, and is consistent with recent findings by the PC that the test for the national access regime should also require the meeting of substantial improvements in competition.

The Panel notes KPMG’s concern that the Significant Producer Legislation in Victoria may have the effect of restricting significant producers’ ability to separately market. As such, if Esso and BHPBilliton are to be required to separately market in the future, the SPL should be repealed.

## Include criteria to promote competition in acreage management regimes

One of the key factors that led to the high levels of concentration of ownership in gas supply in certain jurisdictions was the previous practice of granting large exploration acreage to single firms or joint ventures without appropriate relinquishment requirements.

As current exploration acreage is relinquished and new acreage is released, jurisdictions have an opportunity to allow new explorers (potential new producers) into the market.

The incumbent or dominant producers should not be excluded from bidding for acreage. Often their experience of the region can increase the chance of discovery. Similarly, however, new explorers can bring new techniques and approaches that can lead to discoveries. In the Panel’s view, jurisdictions should take account of the likely impacts on competition in gas supply when granting exploration acreage.

The Panel considers that acreage management regimes should include 'promotion of competition' as one of the criteria for allocating acreage where there is a reasonable prospect of a commercial gas discovery. The Panel recognises the practical complexities of implementing this proposal and that consultation with industry is desirable to ensure that the principles of competitive work program bidding are preserved.

### Review the industry's principles for access to upstream facilities

As the market matures, access by independent producers to upstream facilities will become more important. The industry's principles for access to upstream facilities have been in operation for over two years. When the principles were developed, governments committed to reviewing the effectiveness of those principles after two years.

The Panel believes governments should now undertake the review as previously agreed. The review should seek to establish whether the operation of the principles has been effective in facilitating commercially negotiated third party access to upstream gas facilities and in achieving greater competition in the upstream gas sector. It should also examine whether anything more needs to be done to ensure that separate marketing of natural gas will not be hindered by a lack of reasonable access to upstream facilities.

## RECOMMENDATIONS

### Pipeline regulation

7.1 The Gas Code should be amended to enable proponents of new pipelines to seek a binding ruling from the National Energy Regulator on coverage under the Code prior to construction. In making an application for a binding ruling, companies can propose the period of the binding ruling — with the obligation upon the applicant to provide arguments in support of the period sought. Any binding ruling granted would not be subject to potential revocation due to material changes in circumstances for the period granted unless the regulator relied on information that is proved to be false or intentionally misleading. A decision to grant a binding ruling of no coverage for a defined period should be subject to merits and judicial appeal.

7.2 If a proposed transmission pipeline is likely to be covered, the proponent can commit to a 15 year economic regulation free period. To qualify, the pipeline company must commit to providing access, publishing tariffs, making all capacity it contracts tradeable and have sufficient vertical separation of ownership (i.e. no upstream or downstream firm has sufficient ownership to exert control over the pipeline in a way that might lessen competition in upstream or downstream markets). At the end of the 15 year period, an assessment will be made as to whether the pipeline company is exercising market power. If it is, the pipeline will be deemed to be covered. If it is not, the pipeline will not be covered.

7.3 Alternatively, the proponent of a prospective pipeline can enter into an up-front agreement with the National Energy Regulator prior to construction, locking in a number of key regulatory parameters for extended periods of time. This can provide regulatory certainty for the period agreed with the NER.

7.4 The proposed review of the Gas Code should proceed, to consider experience of regulatory outcomes against which it could test both industry and user concerns. The review should ensure that the tentative steps being taken towards a more competitive and dynamic industry are encouraged and the momentum and direction of reform is maintained.

7.5 An enforceable minimum requirement be developed to ensure that pipelines not covered by the Gas Code introduce a range of market supporting mechanisms such as tradeable capacity, ring fencing and the requirement to post prices.

## Encourage greater competition through separate marketing

7.6 Mandatory notification by joint venturers to the Australian Competition and Consumer Commission of all future joint marketing arrangements.

7.7 The ACCC conduct case-by-case assessments of the feasibility of separate marketing and any authorisation granted must contain a review date.

7.8 The Trade Practices Act be amended to preclude jurisdictions from exempting the application of section 45 to joint marketing of natural gas.

7.9 Existing state exemptions and Commonwealth authorisations continue to apply to the existing contracts but all new contracts, or renewals, be subject to the nationally consistent regime as currently applied through the Trade Practices Act section 45 test of substantially lessening competition and the section 90 authorisation public benefit test.

## Include criteria to promote competition in acreage management regimes

7.10 Acreage management regimes in relevant jurisdictions be amended to include 'promotion of competition' as one of the criteria for awarding exploration acreage.

## Review the industry's principles for access to upstream facilities

7.11 Governments adhere to their earlier agreement that a review be conducted after the industry's upstream facility access principles have been in operation for two years. The review should seek to establish whether the operation of the principles have been effective in facilitating commercially negotiated third party access to upstream gas facilities and in achieving greater competition in the upstream gas sector. It should also examine whether anything more needs to be done to ensure that separate marketing of natural gas will not be hindered by a lack of reasonable access to upstream facilities.

# 8 OPTIONS TO REDUCE GREENHOUSE GAS EMISSIONS

## CONTEXT

Australia's energy needs are predominantly met through the transformation of fossil fuels. This is a direct result of Australia having substantial reserves of black coal, brown coal and gas.

The benefits that have been derived from Australia's fossil fuel endowment are significant. These resources have shaped the development of Australia, its economic growth and living standards. However, Australia's stationary energy greenhouse gas emissions are directly linked to its fossil fuel use.

The stationary energy sector is a large and growing contributor to Australia's greenhouse gas emissions. Emissions from this sector accounted for 49.3 per cent of total emissions in 2000 and between 1990 and 2000 emissions increased by 46.0 Mt (35.6 per cent).[1]

The dominant source of emissions from the stationary energy sector is electricity generation, at 66.3 per cent of stationary energy emissions and 32.7 per cent of national greenhouse gas emissions.[2] This is a result of fossil fuels, particularly coal, being the dominant fuel source in the generation of electricity.

The Australian Greenhouse Office (AGO) submission to the Review estimated that greenhouse gas emissions from the stationary energy sector would rise by 50 per cent, inclusive of measures, by 2020 as indicated in Figure 8.1.

In August 2002 the Commonwealth Government, in the context of its 'Global Greenhouse Challenge' statement, announced that it would seek to develop a longer term greenhouse strategy aimed at reducing Australia's long term emissions signature.

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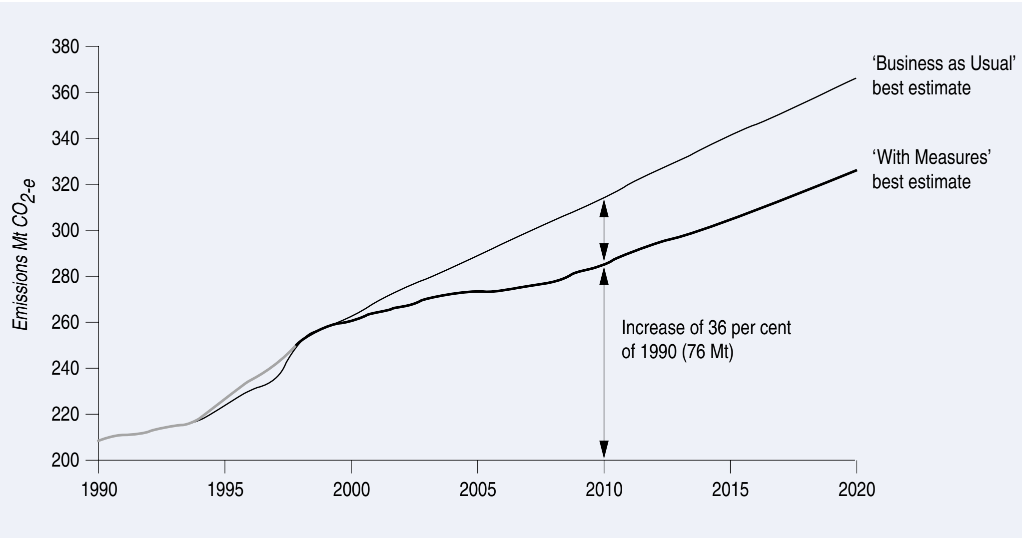
[1] Australian Greenhouse Office (2002b) p. A-17
[2] AGO (2002a) p. 25

Figure 8.1: Emissions Pathway in Australia's Stationary Energy Sector [3]




The Government also announced that:

- **it would not ratify the Kyoto Protocol in the current circumstances**
- **it remained committed to the emissions target it had accepted as part of the Kyoto Protocol negotiations — that is to restrict national emission levels to an annual average of 108 per cent of 1990 levels for the period 2008-12.**[4]

To develop elements of a long term greenhouse strategy for Australia the Government has invited industry input to this strategy process through the Climate Change Dialogue. This is expected to culminate in the communication of business advice on a long term national greenhouse strategy to Government in March 2003. The views of states and territories and non-government environmental organisations are also being sought.

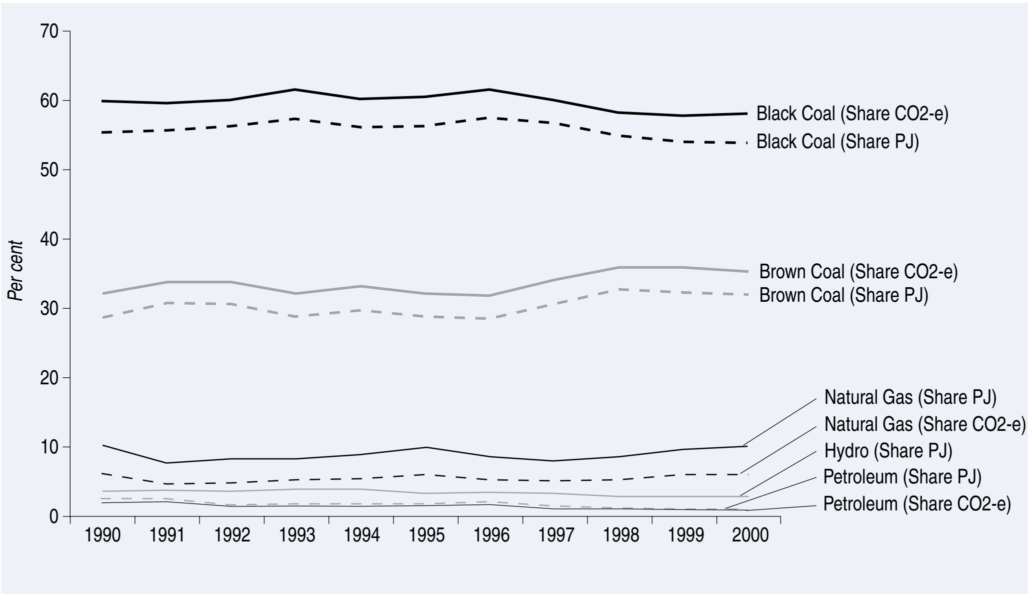
Government policy makers anticipated that energy market reform, and its acceleration, would lower the average greenhouse gas intensity of energy. Analysis now shows that far from achieving a 14 Mt reduction in 2010, as estimated in Australia's Second National Communication to the United Nations Framework Convention on Climate Change, energy market reform is now estimated to result in an increase of 0.1 Mt CO2-e by 2010.[5]

[3] AGO, submission 38, p. 7
[4] Kemp and Downer (2002)
[5] AGO, submission 38, p. 7

The growth in emissions from electricity supply since 1990 is attributed to an increase in the brown coal share of electricity generation and a corresponding reduction in the combined share of some of the less greenhouse-intensive energy forms.[6]

As Figure 8.2 shows the trend is most pronounced from the period associated with the implementation of competitive market arrangements for the production and supply of electricity ie 1996 onwards.

**Figure 8.2: Share of electricity generation primary energy and emissions by energy from 1990 - 2000[7]**

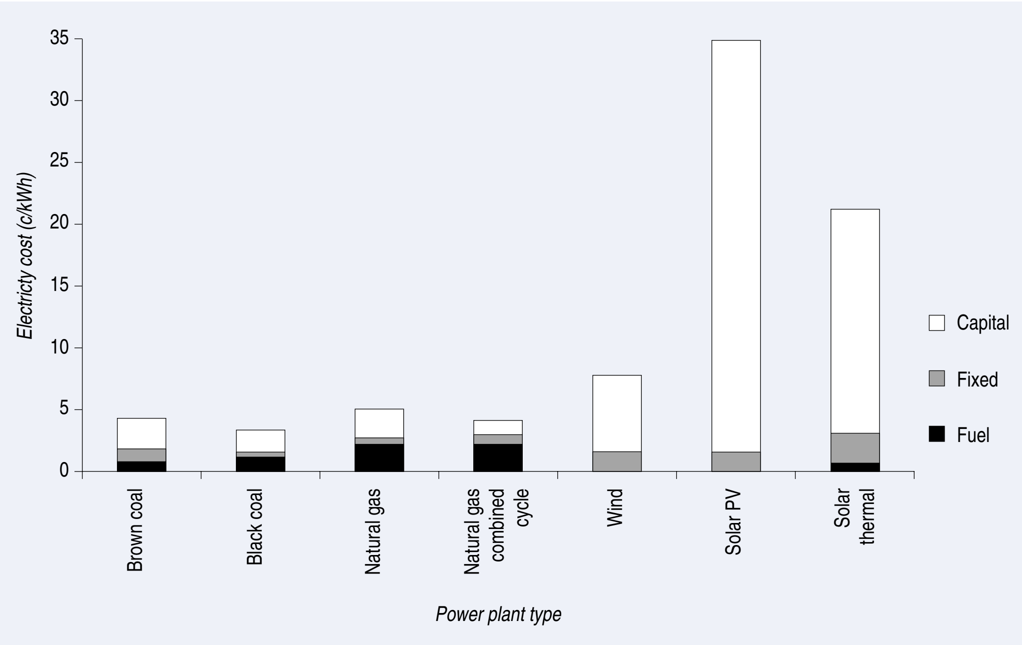



Less greenhouse gas intense capacity such as gas fired and renewable energy capacity provides an opportunity to reduce the greenhouse gas intensity of electricity supply. However, as indicated in Figure 8.3, there are significant cost differences between less greenhouse intense capacity and coal fired capacity which has meant that they have had difficulty penetrating the market.

[6] AGO (2002a) p. 26

[7] AGO (2002a) p. 26

Figure 8.3: Estimated Electricity Generation Costs - Inclusive of Capital Costs[8]




## Impacts of future demand growth

As stated above electricity generation is forecast by ABARE to grow at an average annual rate of 2.3 per cent between 1998-99 and 2019-20. This would see Australia's electricity production grow from 202 tWh in 1998-99 to 325 tWh by 2019-20.[9]

Given these projections greenhouse gas emissions will continue to increase unless:

- electricity demand substantially declines
- there are substantial efficiency improvements in energy transformation and use
- there is a significant shift to less greenhouse gas intense sources of capacity or
- carbon from fuels and combustion is captured and stored through geological and/or ecosystem sequestration.





[8] Bureau of Resource Sciences (1999) and Mclennan Magasanik and Associates, unpublished
[9] ABARE (2002), p. 201

## Measures addressing stationary energy greenhouse gas emissions

Commonwealth, state and territory governments have implemented a broad range of measures to reduce greenhouse gas emissions from the stationary energy sector. Key measures are listed in Table 8.1.

**Table 8.1: Key Commonwealth and state stationary energy greenhouse measures**

| | |
|---|---|
| Commonwealth Measures | • National Greenhouse Strategy (NGS) – Energy Use and Supply Measures, including:<br>- The acceleration of energy market reform<br>- The Mandatory Renewable Energy Target<br>- Strategies for energy retailers<br>- Generator Efficiency Standards.<br>• Greenhouse Challenge<br>• Greenhouse Gas Abatement Program – Stationary Energy Projects<br>• Support for renewable energy industry development – including:<br>- Renewable Energy Equity Fund<br>- Renewable Remote Power Generation Program<br>- Renewable Energy Industry Development<br>- Photovoltaic Rebate Program.<br>• Energy Efficiency and Performance Standards – including:<br>- Energy efficiency standards for residential and commercial buildings<br>- Energy performance standards for domestic appliances and commercial and industrial equipment<br>- Improving energy efficiency in government operations<br>- The energy efficiency best practice benchmarking program. |
| State Measures | • NSW Electricity Retailer Greenhouse Benchmarks<br>• Queensland 13 per cent Gas Scheme. |

The broad suite of measures to address stationary energy greenhouse gas emissions represent a mix of mandatory/regulatory measures, quasi market measures, voluntary measures and the provision of subsidies for emissions abatement.

The greenhouse issue is extremely important for both the energy sector and the Australian economy as a whole. A significant number of submissions to the Review raised greenhouse gas emissions as an issue. There was considerable divergence of opinion as to how stationary energy greenhouse gas emissions should be addressed.

For example, the Australian Conservation Foundation recommended a national energy policy with:

- **a key objective of reducing greenhouse pollution**
- **mandatory greenhouse reduction targets for retailers**
- **a key objective of demand management and energy efficiency**
- **emissions disclosure/labelling on consumer energy bills.**[10]

In their submission the Electricity Supply Association of Australia stated that:

**In recent years the electricity supply business has been subjected to a range of often-inconsistent measures related to greenhouse gas abatement. Most of these approaches are not market-based and are highly regulated; all amount essentially to additional taxation on electricity supply without having any significant impact on demand. None has been subjected to rigorous analysis of the trade-off between abatement likely to be achieved and its impact on market efficiency; and**

**Greenhouse gas policy between now and 2020 must move swiftly to an economy-wide approach in order to deliver cost-effective abatement. The temptation to target greenhouse gas emissions in the energy sector - and the stationary energy sector in particular — should be avoided.**[11]

The Climate Action Network Agenda (CANA) submitted that:



**CANA recommends that Federal and state governments need to develop as a matter of urgency a transition strategy to switch from fossil fuels to renewable energy and fuels so that it can occur in an orderly and manageable fashion, but within a timeframe necessary to prevent dangerous climate change. The current development of a national energy policy through the COAG process provides an ideal opportunity for this.**

**CANA recommends that COAG recognise that gas is not a long term solution to climate change, as it is a fossil fuel and does not have zero emissions.**

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[10] Australian Conservation Foundation, submission 9, p. 3

[11] ESAA, submission 4.2, p. 5

**CANA recommends that the COAG review incorporates a thorough assessment of the potential for implementing economic instruments such as carbon taxes or domestic emissions trading in Australia.**[12]

The Australian Industry Greenhouse Network stated:

**Australia's response to climate change needs to developed taking account of the following key policy considerations:**

- **sustainable development**
- **long term perspective**
- **competitiveness impacts**
- **effectiveness**
- **equity**
- **consistency across jurisdictions.**[13]

An overwhelming theme in submissions to the Review was the need for greater regulatory certainty, including greenhouse gas policy certainty.

There is vigorous debate on greenhouse gas emissions issues including policy on whether or not the Kyoto Protocol should be ratified. The Review was not invited to contribute to the debate. Instead, the Review was requested to examine and comment on the least cost options to reduce stationary energy sector greenhouse gas emissions.

Greenhouse abatement measures have an immediate economic cost to the community. It is simply not possible to mandate less carbon emissions without having this effect. This emphasises the importance of using least cost measures to achieve the community's environmental objectives.

## KEY FINDINGS

Particular measures being used to abate greenhouse gas emissions from the stationary energy sector are imposing major and unnecessary costs on the Australian community and economy. These measures are:

- poorly targeted

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[12] CANA submission 72

[13] Australian Industry Greenhouse Network, submission 68, p. 3

- uncoordinated and compete with each other
- creating uncertainty for the energy industry and the wider economy.

These issues are addressed further below.

## Measures are poorly targeted

Many of the current measures employed to reduce greenhouse gas emissions are poorly targeted. These measures target technologies or fuel types rather than greenhouse gas abatement. The use of policies and measures that mandate, or specify, the use of a particular fuel source, technology or production technique is problematic as it decreases the possibility of a liable party meeting the regulatory requirement at least cost.

The Commonwealth's Mandatory Renewable Energy Target (MRET), which is aimed at both developing the renewable energy industry and reducing greenhouse gas emissions, is a good example. The MRET is a more costly measure to reduce greenhouse gas emissions than it needs to be as it focuses exclusively on renewable energy sources rather than least cost greenhouse gas abatement, such as reducing energy consumption through improving energy efficiency.

The rationale for a scheme that focuses only on renewable energy, rather than on greenhouse benefits, is the perception of the need for the conservation of non-renewable resources. This is, however, not an issue for Australia. Consequently, any arbitrary diversion of investment away from more efficient carbon reducing options and towards renewables will burden the economy with unnecessary costs.



The Queensland Government's scheme to require 13 per cent of electricity generation to be sourced from additional, or new gas-fired generation, also fails to enable the least cost form of greenhouse gas abatement by specifying the fuel to meet the target. Liable parties, who are required to surrender gas electricity certificates (GECs) to the regulator in order to comply with the measure, are further hampered by the fact that accredited generators are eligible to create GECs only for electricity that is deemed to meet Queensland load.[14] Hence, liable parties are unable to source inter state gas-fired capacity to meet the requirement.

Mandating the use of a particular fuel, or technology, also requires a determination as to what fuel source, technology or production technique complies with the regulatory requirement. This can result in a diversion of investment away from more efficient options and can also result in the

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[14] Office of Energy (2002), p. 14

entrenchment of a particular fuel source, technology, or production technique. Attachment A details a range of technology options under development for the energy sector.

## Measures are uncoordinated and compete with each other

The number of measures to address stationary energy emissions at the federal, state and territory levels has increased regulatory complexity and, as a result, has increased the regulatory cost borne by liable parties.

Energy market participants are finding it increasingly difficult, and costly, to respond to the range of measures that are currently in place. For example, market participants at a national level are likely to be affected by at least some of the following:

- the MRET
- Generator Efficiency Standards
- the Queensland 13 per cent Gas Scheme
- NSW Electricity Retailer Greenhouse Benchmarks.

The Australian Gas Association in their submission to the Review raised the number of measures to address greenhouse gas emissions as an issue, stating that:

**Collectively [the] number and scope of these programs create a 'crowded field' in terms of programs businesses with limited resources can reasonably be expected to participate in.**[15]

The ESAA, in their submission to the Review, raised concerns in regard to the impact of numerous greenhouse gas abatement measures submitting that:

**The fact that numerous regulated greenhouse response measures are possible, both at Federal and State government levels, tends to provide opportunities for *ad hoc*, unilateral, inconsistent and market-distorting approaches as witnessed by current measures at the Federal level and in NSW and Queensland. Already electricity retailers are beginning to limit their activities to their base state as a result of action in NSW and elsewhere.**[16]

The cost of emissions abatement is also increased by measures competing with each other. For example, in NSW, liable parties will need to comply with both the MRET and the NSW greenhouse benchmark target. However, in complying with these measures NSW retailers will

[15] AGA, submission 73, p. 61
[16] ESAA, submission 2, p. 11

only be able to count a portion of the total quantity of Renewable Energy Certificates (RECs) they hold towards complying with the NSW benchmark. This is because the NSW Government intends to limit the amount to the number of RECs that the retailer is required to hold in relation to its NSW electricity sales.[17]

## Current measures have created uncertainty

The lack of a single, national, long term greenhouse policy has created significant uncertainty for the energy industry and wider economy. This uncertainty has negatively affected market outcomes as participants have factored in their own subjective view of likely future greenhouse costs in, for example, financial instruments (ie derivatives and hedges) and in the calculation of investment costs (ie discount rates).

Given the extended life span of energy assets and the magnitude of the investments, it is important to minimise uncertainty. The inclusion of a possible greenhouse cost in investment calculations is problematic as such estimations usually take a conservative approach and hence include a higher cost than that which may be incurred. It also effectively locks in an outcome that may make the cost of change, as a result of the introduction of a new policy or measure, unnecessarily expensive.

For example, an entity undertaking a cost benefit analysis of an investment will consider a number of issues including regulatory uncertainty. This can increase the threshold rate of return if the environment is considered to be relatively risky. This has two effects. Firstly, it means that in some instances investments that should go ahead will not go ahead because the entity will not expect to be able to earn a sufficient rate of return. Secondly, if the investment does go ahead, the price charged for output will reflect the risk premium that was factored in. Hence consumers will have to pay a higher price.



Certainty on greenhouse policy is therefore needed to ensure market participants are not factoring in unnecessary risk premiums.

[17] Ministry of Energy and Utilities (2002), p.2

## PROPOSED SOLUTIONS

The Panel proposes the following solutions to address the key findings:

- introduce an economy wide emissions trading system to replace, and so abate the same level of emissions as, the MRET, Greenhouse Gas Abatement Program: stationary Energy Measures, Generator Efficiency Standards, the Queensland 13 per cent Gas Scheme and the NSW Electricity Retailer Greenhouse Benchmarks
- energy intensive users in the traded goods sector are to be excluded from the emissions trading system until Australia's international competitors introduce similar schemes.

The Panel notes that other recommendations contained in the Report, particularly Chapters 2, 4, and 7 will also have a greenhouse benefit.

### Introduce a national economy wide emissions trading system

In the Panel's view the most efficient and cost effective mechanism to address greenhouse gas emissions in the electricity and gas sectors is an economy wide emissions trading system.

Once agreement to implement an emissions trading system is announced the following measures should immediately cease to operate:

- the MRET
- Generator Efficiency Standards (GES)
- the Greenhouse Gas Abatement Program – Stationary Energy Projects (GGAP)
- the NSW Electricity Retailer Greenhouse Benchmarks
- the Queensland 13 per cent Gas Scheme.

The Panel acknowledges that these changes could adversely affect return on investments entered into in response to the above measures. This would represent an unacceptable risk and would need to be addressed by providing some form of compensating subsidy. It is the Panel's view for example, that under an emissions trading system existing MRET renewable generation capacity, including those projects that have reached financial closure, would continue to receive a subsidy equivalent to that paid under MRET. The final details of such a payment will need to be developed in parallel with the emissions trading system so as to minimise overlap.

A number of submissions on the Draft Report raised their concern as to the apparent failure of the Panel to consider the industry development objectives of the MRET. The Panel has considered this matter and does not believe that the energy market should be distorted to effect the growth of the renewable energy industry. Should government wish to continue subsidising the development of the renewable energy industry, post the introduction of a nationwide emissions trading system, then this should be done outside the energy market.

An economy wide emissions trading system, if correctly designed, is capable of:

- achieving the same emissions abatement as the schemes it replaces
- reducing the cost of emissions abatement by allowing the widest possible coverage and greatest possible flexibility
- providing continual incentives to seek out least cost abatement opportunities
- minimising regulatory burden
- removing the need for a government agency, or regulator, to select specific technologies or mandate production techniques
- increasing policy certainty for greenhouse gas emitters
- providing options to minimise the impact on Australia's traded sector until similar measures are introduced by our competitors overseas.

### Independent assessment

The Panel commissioned ACIL Tasman to assess the impacts of the Draft Report recommendations. ACIL Tasman found that the existing stationary energy greenhouse gas abatement measures would reduce some 18.3 million tonnes of carbon dioxide in 2010. They will also reduce GDP in 2010 by 0.11 per cent relative to a baseline that included the energy market reforms recommended by the Panel in its Draft Report. [18]



Furthermore, the ACIL Tasman analysis indicates that the introduction of an emissions trading scheme would have a relatively small impact on Australia's economic performance resulting in a fall in Australian real GDP by 0.03 per cent at 2010 relative to the energy market reform scenario that includes all the other measures in the proposed reform package proposed in this Report.

The ACIL Tasman estimates of the impacts of the existing stationary energy measures are detailed at Table 8.2.

[18] ACIL Tasman (2002)

ACIL Tasman also estimate that the existing measures lead to an increase in the average wholesale electricity price of $2.82 per MWh in comparison to an increase under an emissions trading system of $2.41 per MWh or 6.9 per cent relative to the reference case.

The impact on the Australian economy from the shift to an economy wide emissions trading scheme and away from the current measures approach, equates to a benefit of just over $1.2 billion in 5 year net present value terms through 2010.

ACIL Tasman estimate that the projected permit price for emissions trading is $3.75 per tonne of carbon dioxide in 2002 dollars. At this price there are some renewable energy schemes which would be cheaper than the price of the permit (in addition to cost-effective energy efficiency measures). ACIL Tasman modelling suggests that the most likely would be biogas (sewage and landfill) schemes.

**Table 8.2: Estimates of emission abatement and electricity costs of existing schemes ($2002)[19]**

| | Year 2010 | | | Year 2020 | | |
|---|---|---|---|---|---|---|
| **Scheme** | **Abatement ($mtCO_2$-e)** | **Electricity cost per year ($ million)** | **Abatement cost per year ($\$/tCO_2$-e)** | **Abatement ($mtCO_2$-e)** | **Electricity cost per year ($ million)** | **Abatement cost per year ($\$/tCO_2$-e)** |
| MRET | 7.4 | 323 to 543 | 44 to 73 | 0 to 6.5 | 190 | 29 to ∞ |
| GES | 0 to 4.4 | 0 to 14.5 | 0 to 3.3 | 0 to 4.4 | 0 to 14.5 | 0 to 3.3 |
| GGAP* | 2 | 9.4 | 4.7 | 2 | 9.4 | 4.7 |
| NSW Benchmark | 4.3 | 75 to 150 | 17 to 35 | 4.3 | 75 to 150 | 17 to 35 |
| Queensland 13% Gas | 0.2 | 17 | 85 | 0 | 0 | 0 |
| Total/Average | 13.9 to 18.3 | 424 to 734 | 23 to 53 | 6.3 to 17.2 | 274 to 364 | 16 to 58 |
| Average increase in electricity cost $/MWh | | 1.72 to 2.97 | | | 0.92 to 1.23 | |

** Strictly speaking GGAP should not increase electricity costs. However, GGAP subsidies do incur other costs (increased taxation and opportunity costs) that have been presented in this table in the form of electricity costs for the purposes of comparison.*

[19] Source: ACIL Tasman 2002

### Resolving key design issues

The implementation of an economy wide emissions trading system is dependent on resolving key design issues including:

- permit allocation
- monitoring and verification
- acquittal
- compliance
- implementation.

In addressing these design issues the Panel requested the input of the AGO on how key outstanding issues could be resolved and the likely timeframe for their resolution.[20]

The Panel also sought input as to:

- What the likely price of emissions permits would be.
- How to best minimise impacts on the domestic traded sector in the event of Australia introducing a domestic emissions trading system prior to its introduction internationally.

In response, the AGO prepared a report titled 'Pathways and policies for the development of a national emissions trading system for Australia'.[21]

The AGO's Report provides a comprehensive analysis of design issues and approaches associated with the introduction of a nationwide emissions trading system. The Report found that:

**Combustion-related and other readily estimated and attributed emissions, covering around 65 to 70 per cent of Australia's emissions output, would represent the foundation for a simple, workable and efficient trading system.**

**Simple phasing options could be developed that promote flexibility and adjustment within the economy while delivering a modest and consistent emission price that contributed to national greenhouse objectives.**

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[20] The AGO is the lead Commonwealth agency on greenhouse matters and in 1999 it released a series of four discussion papers outlining issues and design approaches for a national greenhouse gas emissions trading system.

[21] AGO, submission 38.1

**In addition to a national emissions trading system, there is likely to be a need for supplementary measures that address market impediments and aim to promote consistent incentives for abatement and innovation in those areas of the economy that an emissions trading system would have trouble reaching.**

**Once accepted, an emissions trading system could be introduced within $2^1/_2$ to 3 years. This would allow for consultation processes to be completed, analysis and modelling undertaken and for legislation to be passed.**

The AGO Report stipulates that the overriding objective of the design process should be to:

**Develop a system that will consistently achieve its policy objectives and at the same time impose the lowest total cost on all those involved, taking explicit account of the cost of reducing emissions, the cost of demonstrating this outcome and the costs of participating in and administering the scheme.**

## Coverage of an emissions trading system

The AGO Report states that the coverage of an emissions trading system is a key determinant of the measures' effectiveness in facilitating least cost abatement. The AGO Report identifies combustion related emissions as a fairly straight forward target for an emissions trading system, which could form the core of an effective national system, as:

**Comprehensive coverage of fossil fuel use could establish a consistent price signal that would support least cost abatement in the areas of fuel switching, development and adoption of energy efficiency technologies, renewable energy, improved energy management and energy substitution across the power generation, industrial, transport, commercial and residential sectors.**

**Some non-combustion emissions such as gas leakage from monitored pipelines and emissions from chemically stable processes (eg conversion of limestone in cement production) could also readily lend themselves to inclusion in a simple, workable and efficient trading system. Further work would be needed to confidently identify other sources and activities that, at modest cost, could also be incorporated within a trading system.**

In regard to the inclusion of other sectors the Report argues that:

**In general the inclusion of emissions from fugitive, industrial, agricultural and waste activities would need to be considered on a case by case basis. However, a trading system**

**does offer scope for the voluntary participation of emitters engaged in these activities, and those seeking to earn 'credit' for sequestration activities (eg, through biological, chemical or geological means), who are prepared to absorb the [transaction] costs associated with participation in the system.**

The Report also posits that complementary measures for non-covered sectors could be introduced to establish a consistent set of economy-wide abatement incentives as:

**This would help guard against focusing the abatement burden on those that were easiest to target, rather than those with the greatest capacity to contribute to national greenhouse objectives.**

## Permit allocation

There are a number of alternative options available to allocate permits including auctioning, performance based allocation arrangements and/or a free once-and-for-all allocation. In addressing this issue the AGO Report states that:

**Given the diversity of interests and attributes represented within the economy, it is likely that a 'tailored' approach to permit allocation, possibly involving a process of intensive analysis and negotiation, could only be adopted for large individual players with a high greenhouse exposure and few opportunities to absorb or pass on costs. For less affected entities within the economy more generic allocation approaches could be considered, including the possibility of a permit auctioning arrangement with revenue recycled through adjustment assistance or tax relief packages.**



## Possible carbon prices

On a possible permit price the AGO Report states that economic modelling to date has focused on the costs to Australia of the Kyoto Protocol entering into force, with Australia linked into a global emissions trading system with permits traded at a world price determined by international factors. The AGO Report states further that:

**The most recent modelling analysis commissioned by the Commonwealth indicates an international carbon price in the range of $7-13 (US$4-7) per tonne of carbon dioxide for the 2008-12 period. At this price the models indicated that Australia would be a small importer of permits — suggesting that domestic permit prices, under a domestic system that was not integrated with international emissions trading, would be comparable to the world price.**

### Options to address traded sector effects

In analysing the possible impacts arising from the implementation of a nationwide emissions trading system the Panel recognised that energy intensive users in the traded goods sector could be adversely affected in the event of Australia introducing a domestic emissions trading system prior to its introduction by our competitors overseas.

In addressing this issue the AGO Report states that:

**One of the major rationales for implementing emissions trading as a greenhouse policy instrument is its capacity to minimise the cost of a national emissions target. In addition, design features that keep permit prices relatively low could be developed that would help put trade-exposed industries on a path toward lower greenhouse emissions without threatening their competitiveness.**

**However, for industries that operate in highly competitive markets or have few existing cost advantages over their international competitors, it is possible that even at a relatively low carbon price domestic production may be threatened.**

The Panel recognises that there is a risk of increasing the cost of emissions abatement if some greenhouse gas emitters are excluded from the operation of an abatement measure. However, the Panel considers that, in this case, the exclusion is necessary to avoid damage to the economy by the adverse effect on the traded goods sector.

The Panel proposes, therefore, that only those entities in the traded goods sector whose energy costs are a significant component of their total production costs should be excluded from the operation of the emissions trading system. Further modelling and analysis is required to determine the precise level of energy costs as a proportion of total costs that should act as a trigger to allow this exclusion.

In order to minimise the impact of the exclusion of energy intensive users in the traded goods sector the Panel proposes that excluded entities will be required to meet world's best practice in relation to their energy use.

### A nationwide emissions intensity requirement

The Terms of Reference for the Review required that the Panel consider the feasibility of a phased introduction of a national system of greenhouse emission reduction benchmarks.

The Panel concluded that an emissions trading system is preferable to an emissions intensity requirement because the latter is an electricity sector only measure. Emissions trading is an effective economy wide measure.

If, as the AGO Report to the Review indicates, an economy wide emissions trading system could be implemented within a relatively short time frame there would be little benefit to be gained from introducing a new 'interim' greenhouse gas mitigation measure or merely amending existing measures.

These factors cement the Panel's view that an economy wide emissions trading system is the most cost effective and efficient measure to reduce greenhouse gas emissions in the electricity and gas sectors.

### Relevant solutions in other chapters

Structural impediments, particularly transmission and distribution regulatory arrangements, have hampered participation of less greenhouse gas intense generation and hindered efficient locational investment decisions. Together these have minimised the reduction of the greenhouse gas intensity of electricity supply.

Recommendations in Chapter 4 will contribute to rectifying these problems through improving locational signals to users by providing appropriate signals for network augmentation and the entry of new capacity.

### Embedded generation

The greenhouse benefits of removing impediments to the entry of embedded generation include:



- Efficiency of energy transformation can be considerably greater than alternative forms of generation capacity.
- It can lead to a reduction in line losses.

In their submission to the Review the Australian Ecogeneration Association state that:

**Existing arrangements disadvantage embedded generators and hence, disadvantage low greenhouse emitters vis à vis high greenhouse gas emitters.**[22]

The recommendations contained within Chapter 2 will remove impediments to embedded generation capacity, which can also lead to a greenhouse benefit.

[22] Australian Ecogeneration Association, submission 86, p. 12

### Enhancing the demand side response

The Panel considers that the demand side response should be enhanced. An increased demand side response, as noted above, may provide considerable benefits including a reduction in greenhouse gas emissions.

The Panel has observed the lack of an explicit demand side involvement in the NEM at the wholesale level. Significant demand reductions at peak load times may serve to both lower pool prices and reduce greenhouse gas emissions. The Panel has advocated the development and implementation of a module in the NEM systems that enables users to bid into the market to reduce their demand and be paid according to their bid. This would reward participants directly for their action. Details of this proposal are at Chapter 6.

### Full retail competition

Full retail competition can contribute to an increase in demand side participation as it can increase competition amongst energy retailers encouraging them to offer services to consumers including measures to improve customer energy efficiency and fuel switching to lower a customer's total energy costs.

The AGO submission to the Review states that:

**Effective retail competition could allow retailers more scope to offer a range of alternate sources of energy (ie. electricity and gas), energy conservation and efficiency services to customers and thereby facilitate emission reductions.**[23]

In their submission to the Review the ESAA argue that demand management has been less successful as:

**Policies protecting smaller consumers from market prices prevent price signals from reaching many customers, removing the incentive for demand management. In turn, this has a negative impact on consumer interest in increasing energy efficiency.**[24]

The Panel considers that full retail competition should be implemented nationwide in order to facilitate an increase in the demand side response. There are considerable benefits to be gained from the implementation of greater competition in the retail sector including a reduction in greenhouse gas emissions.

[23] AGO, submission 38, p. 17
[24] ESAA, submission 4.2, p. 4

Further recommendations contained within Chapter 6 will also have a greenhouse benefit as a result of the fact that the recommendations will improve signals to electricity consumers.

### Interval meters

The Panel considers that the introduction of interval or time-of-use meters should be accelerated. Improving signals to energy consumers will increase opportunities for demand-side participation at both the industrial/commercial and household level with associated greenhouse benefits. Chapter 6 deals with this issue in greater detail.

## RECOMMENDATIONS

8.1 A cross sectoral greenhouse gas emissions trading system should be introduced to reduce greenhouse gas emissions in the electricity and gas sectors. Once an announcement has been made on an agreement to implement an emissions trading system the following measures should immediately cease to operate:

(a) Commonwealth stationary energy measures:

Mandatory Renewable Energy Target
Generator Efficiency Standards
Greenhouse Gas Abatement Program: stationary energy projects.

(b) state based stationary energy measures:

NSW Electricity Retailer Greenhouse Benchmarks
Queensland 13 per cent Gas Scheme.



8.2 Energy intensive users in the traded goods sector are to be excluded from the scheme referred to in Recommendation 8.1 until Australia's international competitors introduce similar schemes. Excluded entities are required to meet world's best practice in relation to their energy use.

8.3 Investments entered into in response to existing schemes, identified in Recommendation 8.1, will continue to receive an equivalent subsidy. The final details of such a payment will need to be developed in parallel with the development of the emissions trading system so as to minimise overlap.

8.4 The introduction of interval meters should be mandated in order to increase opportunities for demand-side participation in the electricity sector (see Chapter 6).

# 9 RURAL AND REGIONAL ISSUES

## CONTEXT

Regional Australia ranges from remote settlements to rural towns and regional cities — basically all locations outside of the major capital cities. Seven million people, representing some 36 per cent of the population live in regional Australia.

The implications of energy market reform for regional Australia are as diverse as the climates, landscapes, lifestyles and employment patterns throughout this vast geographic region. Energy usage ranges across energy intensive industries in medium sized regional centres, industrial plants in remote locations, residential and business usage in urban locations, the particular energy needs of farmers, through to the needs of isolated small settlements. While the vast majority of Australia's electricity generation capacity is located in regional areas, the more remote areas are not connected to electricity grids.

Submissions to the Review that touched on the implications of energy market reform to regional Australia have covered a wide range of topics. Most of the issues raised are not unique to regional areas but are relevant to energy reform generally and, as such, are discussed in other chapters of this report. For the most part, issues raised in the main report are relevant for this chapter.

It is evident that regional Australia has had an uneven experience of energy reform to date and, while some progress has been made, a significant number of issues remain to be resolved.

On the question of energy prices for regional consumers, the Issues Paper noted that two inquiries[1] in recent years had indicated that large users of electricity in regional Australia had benefited from significant reductions in usage charges. For natural gas, it was found that while there had been price reductions in urban areas, the main benefit in regional areas had been the additional incentives to extend gas networks and the new business opportunities that are created as a result.

[1] Productivity Commission (1998) and House of Representatives (2000)

The price implications of introducing full retail contestability (FRC) to rural/regional areas are still unclear given the limited experience with FRC generally.

In addition, there appears a general policy inclination to maintain a degree of price equalisation between rural and urban network tariffs in many parts of Australia. Examples include the Western Australian and Queensland governments' commitments to uniform tariff policies across their jurisdictions and retail price capping policies elsewhere.

Introduction of FRC in Victoria has coincided with new standing tariffs for smaller customers that represented significant price increases, even with the Victorian Government's Special Power Payment to limit the electricity price rises faced by households, small businesses and farmers in outer suburban, regional and urban areas. The package also included assistance for farm customers on higher consumption tariffs who have an unusually high level of off-peak use.

In Western Australia, introduction of FRC and the electricity reform process generally have needed to take into account the state's interconnected systems, the 29 separate regional systems and the various privately-owned non-interconnected systems usually associated with remote mining and processing activities.[2]

It would appear from submissions that pricing remains an issue for many customers in regional Australia.

Queensland Treasury reports that 'Regional customers in Queensland have not enjoyed the same level of price benefits from the deregulation of the electricity market as south-east Queensland customers.'[3]



The Australian Paper Industry Council, the majority of whose members' investments and employment is located in regional Australia, has stated in its submission that 'there is no effective retail competition for either gas or electricity in regional Australia.'[4]

The City of Greater Bendigo provided a report to the Review which indicated that 'energy intensive businesses experienced significant increases in power costs from 2000 to 2001 and pay amongst the highest charges within Australia.'[5] The report highlights the implications of such costs for business investment in Central Victoria.

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[2] Electricity Reform Task Force (2002), p. 138
[3] Queensland Treasury, submission 129, p. 16
[4] Australian Paper Industry Council, submission 84, p. 2
[5] City of Greater Bendigo, submission 141, covering Letter, p. 1

## KEY FINDINGS

The Panel's key findings are:

- Regional areas which have significant electricity generation located within them should enjoy a significant natural competitive advantage in energy costs, but do not.
- There is scope for regional Australia to benefit from growth in renewable energy generation, since such generation is primarily located in the regions.
- There is evidence of gas pipeline development bringing the benefits of an alternative fuel source to parts of regional Australia.

### Regional areas not benefiting from local generation

The majority of electricity generation occurs in regional Australia. Regional areas such as the Latrobe Valley, Hunter Valley and the Bowen Basin should enjoy a significant natural competitive advantage in energy costs. They stand to gain much from exploiting this competitive advantage via the development of locally based energy intensive industry. However, the current network pricing structure tends to detract from this natural competitive advantage, to the detriment of regional areas and, to the extent that the development of larger-scale generation capacity is impeded, to the possible detriment of the nation. Development of industry in such regions also has a role to play in reducing greenhouse gas emissions through the avoidance of transmission losses.

This issue was raised in submissions to the Review. Gippsland Development Limited, for example, submitted:

**… the current system creates the situation where industry consumers in the Latrobe Valley, situated in the shadow of 90% of the State's electricity generation, pay higher network charges than their counterparts in metropolitan Melbourne. For energy intensive industries this can be a major influence in choosing location. This is in spite of the fact that from an environmental and greenhouse gas perspective, at least, locating close to the generating source should be encouraged.**[6]

Present electricity network pricing arrangements, for both transmission and distribution, and the lack of progress towards a more sophisticated regional model for the NEM, work against those regional areas with a natural competitive advantage in energy production.

[6] Gippsland Development Limited, submission 29, pp 5-6

## Potential benefits from renewable energy generation

The Panel considers that regional Australia stands to benefit from a greater uptake of renewable generation technologies. This view is supported by a number of submissions. The Australian Biofuels Association, for example, comments that:

**Biofuels, for sound economic reasons, will also be predominantly produced in regional and rural areas. The evidence of the benefits of biofuels in stimulating economic and employment growth in rural communities is also expected to generate strong community support in rural Australia.**[7]

The Australian Ecogeneration Association (AEA), in its submission, notes the importance of alternative generation technologies for regional Australia:

**The AEA has analysed generation projects (cogeneration, renewables, waste-to-energy and distributed generation) presently under construction or in the development and evaluation stage. Three-quarters of committed and proposed projects totalling over 3000 MW are in rural and regional locations where renewable resources are abundant and where mineral and agricultural processing industries, that are large users of energy, are found.**[8]

The AEA concludes, however, that given this potential, progress has been disappointing:

**Regional and rural communities have borne the brunt of broader micro-economic reform as services have progressively been withdrawn. The potential gains from energy market reform, particularly the development of renewables and gas fired generation, which are predominantly located in regional and rural Australia have just not occurred.**



**Encouraging the switch to renewable and gas fired generation … delivers economic growth, lower greenhouse gas emissions, and more investment and employment in regional and rural communities.**[9]

Alternative and renewable generation technologies, subject to the viability of cost effective greenhouse gas reduction strategies, are likely to have a particular benefit for regional Australia. Resource and land availability considerations mean that many such technologies are likely to be regionally based and bring economic benefit to regional areas.

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[7] Australian Biofuels Association, submission 138, p. 3

[8] AEA, submission 86, p. 23

[9] AEA, submission 86, pp 22-23

Bioenergy Australia submitted that:

**Another feature of bioenergy is that it is highly applicable in rural and regional areas. It has been identified as having great potential in Australia for simultaneously addressing salinity and land degradation, and for providing permanent jobs through the provision of biomass supplies for power plants. For instance a 30 MW biomass plant would require approximately 300,000 tonnes per annum of biomass fuel (e.g. wood and agricultural residues) providing a valuable source of income in the local area.**[10]

Chapter 8 of this report examines options for the abatement of greenhouse gas emissions and discusses the implications for alternative generation technologies, including renewables.

## Benefits from gas pipeline development

Many rural and regional areas in Australia do not have access to reticulated natural gas. Some have access to deliveries of bottled gas (LPG), but this is typically significantly more expensive than natural gas — especially for large volume users.

The construction of additional natural gas pipelines has the potential to provide an alternative cost competitive energy source to parts of rural Australia and to further their economic development. Many localities have experienced industrial development following the introduction of gas supply. Additional processing of primary production can become economic, for example, such as canneries in a fruit growing region.

Regional areas will rarely have sufficient gas demand to make the construction of a pipeline to service that area economic. There are, however, some very large gas users located in remote areas, such as mines, which can underwrite investment in a pipeline. Once a pipeline is constructed to or through a regional area, it can make the provision of natural gas, via laterals off that pipeline, economic.

Similarly, major transmission pipelines from remote sources of gas to capital cities passing through rural and regional areas can make economic the supply of natural gas to communities or commercial operations along that route.

[10] Bioenergy Australia, submission 20, p.2

The Western Australian Government submission commented on the positive effects for regional industrial development of the expansion of the gas pipeline system and the implementation of retail contestability in natural gas supply. The submission argues that:

**The Goldfields Gas Pipeline from Karratha to Kambalda … resulted in competitively priced gas being delivered to iron ore, gold and nickel operations along its route, that until then were using diesel, as well as to the township of Kalgoorlie-Boulder. This has also contributed to the expansion of these industries.**[11]

There has been some comment to the Review on the difficulties of encouraging gas pipeline development for new industries, even within areas at present with reticulated natural gas. The Murray Shire Council, for example, has brought to the Review's attention the costs to the industries involved with achieving connection to several processing and manufacturing plants in the Shire, suggesting that there may be problems with the Gas Code.[12]

A number of submissions to the Review have raised concerns regarding the current regulatory approach acting as a disincentive to invest in new pipelines. These issues are discussed in Chapter 7 of this report.

## PROPOSED SOLUTIONS

The Panel proposes the following solutions to address the key findings:

- The regional structure of the NEM needs to better reflect the needs of the market and the physical constraints in the system. Locational decisions are distorted by the current inadequate definition of electricity regions. The recommendations set out in Chapter 4 will ensure that the investment signals are appropriate. Energy users adjacent to generation facilities will see the benefit of that proximity in terms of lower delivered electricity prices. This will provide the incentives for energy intensive manufacturing or processing facilities to be located in regional areas, nearby to generators.



[11] WA Government, submission 120, p. 15

[12] Correspondence, General Manager, Murray Shire Council to Energy Market Review, 5 September 2002

- Competitive alternative or renewable energy systems will assist regional development. Rural and regional Australia stands to benefit from any growth in alternative generation technologies. The Panel has, in Chapter 8 of this Report, recommended the introduction of an emissions trading system. This will also promote the many carbon sequestration opportunities that are available in regional Australia.
- Promote the wider penetration of gas (including into regional Australia) by lowering the current regulatory uncertainty that acts as a disincentive to invest in new pipelines. As new pipelines are constructed and current networks expanded, more regional areas will have access to natural gas. Chapter 7 of this report recommends a number of measures to address the current perception of regulatory uncertainty in the pipeline industry.

# 10 ESTIMATING THE BENEFITS

The Panel commissioned ACIL Tasman to estimate the impacts on the Australian economy of the recommendations contained in the Draft Report. ACIL Tasman modelled the impacts of the proposed reforms for the period 2005 to 2010, assuming the full implementation of all measures by 2005. This short benefit period (5 years) was chosen because the necessary assumptions become less accurate over time. This means that the estimated benefits of the recommendations are conservative.

The projected impact of the recommendations is to increase real Australian Gross Domestic Product (GDP) by approximately $2 billion per annum at 2010. On a 5 year net present value basis, the increase in GDP is worth approximately $7 billion. The estimated benefits are broken down by area in Table 1 below. In addition, the estimated benefits from implementing the recommendations on greenhouse gas emission reduction are approximately $1.3 billion.

The reforms are estimated to reduce wholesale electricity prices by between 11.4 per cent (Queensland) and 8.8 per cent (NSW), and retail electricity prices by between 14.4 per cent (South Australia) and 12.1 per cent (NSW). Gas prices in the eastern states are estimated to fall by 9 per cent.

As a result, the competitiveness of the energy-using sectors of the economy is improved. For example, the non-ferrous metals sector (including aluminium) is expected to increase output by between 17.5 per cent (Victoria) and 4.6 per cent (Tasmania) relative to the base case scenario. Other sectors of the economy also benefit from increased activity, for example construction, which increases by about 0.5 per cent in all states.

**Table 1 Projected impact of the proposed reforms on economic growth at 2010[1]**

| | Australian GDP [a] % | Australian GDP [b] $m | Aggregate GSP of NEM States [c] % | Net present value of gains [d] $m |
|---|---|---|---|---|
| (i) Productivity growth from proposed reforms | 0.12 | 477 | 0.14 | 1,767 |
| (ii) Electricity transmission reforms | 0.08 | 303 | 0.09 | 1,112 |
| (iii) Demand side management initiatives | 0.16 | 630 | 0.18 | 2,310 |
| (iv) Regulatory certainty | 0.03 | 109 | 0.03 | 673 |
| (v) More financial certainty | 0.03 | 126 | 0.04 | 779 |
| (vi) Gas market reform | 0.08 | 330 | 0.09 | 296 |
| **Total[e]** | **0.49** | **1,975** | **0.56** | **6,936** |
| (vii) Benefits from the climate change recommendation | 0.09 | 391 | 0.09 | 1,267 |

[a] Percentage deviation from the reference case [b] Present value of the change in GDP at 2010 using a 7 per cent discount rate, presented in 2002 dollars [c] Percentage deviation of Gross State Product (GSP) from the reference case for New South Wales, Victoria, Queensland, South Australia and Tasmania [d] Discounted using a 7 per cent rate over the period 2005 to 2010, presented in 2002 dollars [e] Totals may not add due to rounding.

## Scope of work

ACIL Tasman was commissioned to evaluate the impacts of the recommended reforms on the electricity and gas markets and in turn on the overall Australian economy. ACIL Tasman was not asked to consider alternative approaches to those recommended by the Panel.



ACIL Tasman have produced a detailed report estimating the impact of the reforms recommended by the Panel in terms of their impact on productivity and on GDP at the state and national level.

The impacts have been estimated using the ACIL Tasman models PowerMark, GasMark and Tasman Global, as well as a range of other data sources. The macroeconomic impact has been estimated assuming implementation by 2005, with effects from 2005 to 2010.

ACIL Tasman modelled the impacts of each of the groups of recommendations contained in the Draft Report. These are described below, under the chapter headings of this Report.

[1] ACIL Tasman (2002), p. 2

## Governance and regulatory arrangements

Governance and regulation of the electricity market is estimated to involve 17 different institutions while that of the gas market involves 14. Taken together, these are estimated to have cost some $112 million to administer in 2001-02, or around 1 per cent of the value-added of the two industries.

Moving to a National Energy Regulator delivers efficiency benefits through removal of a variety of different jurisdictional protocols and requirements. The United Kingdom's experience with a national regulatory approach was used as a proxy to estimate the potential benefits in Australia.

ACIL Tasman has modelled the impact of reforms on the overall economy by assuming that the recommended changes to regulatory arrangements, mainly through reducing regulatory risk, allow electricity and gas prices to fall by 1 per cent. This is a conservative assumption.

On the basis of this assumption, it is estimated that cost savings of around $673 million in 5 year net present value terms could be achieved by implementing the recommended governance and regulatory reforms. The reduction in electricity and gas prices would have important implications for the competitiveness of energy intensive industries.

## Electricity market structure

Two types of market structure changes were explored:

- the disaggregation of the NSW generation portfolios
- movement to a highly competitive market where generators offer marginal cost prices.

ACIL Tasman concluded that the disaggregation of generators is a necessary precursor to a more competitive market, along with many of the other recommended reforms, such as those relating to transmission.

ACIL Tasman determined that there are considerable benefits to electricity consumers from a more competitive market in the form of lower pool prices compared with the current situation. This is illustrated by comparing the base case results, which incorporate a tightening supply/demand balance in a non-competitive market, with the results under competitive market dispatch based on marginal cost. The 5 year net present value of the savings in electricity purchase costs is estimated to be $641 million or an average saving of $0.58 per MWh.

Analysis of the price spikes in the NEM in May and June 2002 suggests that ETEF has already had a significant distorting impact on the pool prices across the NEM. The large government-owned generators in NSW were able to force up the average NSW pool prices in 2001-02 to the pre-determined energy purchase price as determined under the ETEF arrangements. These activities are estimated to have contributed some $720 million to the cost of wholesale electricity across the NEM during 2001-02.

## Electricity transmission

The Panel's recommendations in this area aim to remove transmission constraints. To demonstrate the benefits of system wide planning, ACIL Tasman modelled the impacts on pool prices from a 20 per cent increase in interconnector capacities throughout the NEM. ACIL Tasman noted that expansion of capacity on one interconnector, for example, can be expected to result in changed flows, losses and constraints on other interconnectors and affect pool prices throughout the NEM.

The resultant impacts were estimated at $1.1 billion over the period from 2005 to 2010 which is equivalent to an average saving of $1.26 per MWh. This scenario suggests that there are substantial market benefits stemming from an enhanced transmission system.

To achieve these benefits, investment in the transmission system would be required. As an indication of the likely costs to achieve this outcome, ACIL Tasman examined what the effect would be of devoting the $1.26 per MWh saving to interconnector investment. In 2003-04, this would be sufficient to fund a 26 per cent increase in the transmission asset base — clearly exceeding the 20 per cent increase required to achieve the saving.

## Electricity financial market development



Many of the Panel's recommendations would also bring benefits to the financial market, particularly through reducing price volatility, increasing the amount of financial contracting and therefore lowering risk premiums. ACIL Tasman determined that this benefit would amount to a $1 per MWh reduction in the prices of wholesale contracts. This yields an economic benefit of just under $700 million in 5 year net present value terms.

## Demand side participation and full retail contestability in electricity

Improving demand side participation and management has significant potential to reduce prices and decrease peak pressures. The Panel's recommendations focus on demand reduction bidding, the installation of interval meters and the implementation of full retail contestability. All of these measures will increase incentives for domestic and commercial customers to tailor usage towards the least-cost.

While these measures, such as the installation of interval meters, have significant associated costs, the benefits from these measures should more than offset the costs. Overseas evidence collected by ACIL Tasman suggests that such measures can have significant effects on customer behaviour.

ACIL Tasman made estimates of the reduction in demand during particular peak periods due to the Panel's recommendations. They then used past market data to determine the price reductions that would result. The resultant benefit was modelled at $1, 982 million in 5 year net present value terms.

## Increasing the wider penetration of gas

The Panel's key recommendations include allowing greenfield transmission pipeline operators to either opt to be unregulated for the first 15 years of operation or seek a binding ruling prior to pipeline construction. The Panel also makes a number of recommendations aimed at increasing the level of competition in upstream gas markets.

ACIL has simulated the implications for eastern Australian gas markets with scenarios involving the expansion of the gas pipeline network as well as separate marketing of uncontracted gas.

The net present value of the cost savings to consumers is estimated to be around $400 million for the period 2005 to 2010. A large part of the cost savings to consumers is in the form of a transfer from producers who would now receive lower prices for their gas. However, part of the gain to consumers is also the result of an efficiency improvement. For the whole of eastern Australia, the modelling shows that delivered gas price reductions of around 9 per cent can be achieved by 2010.

The consequences of these recommendations include increased certainty for greenfield pipeline proponents over regulatory arrangements prior to construction of pipelines. This will eliminate any regulatory disincentives (perceived or otherwise) for new pipelines for the first 15 years of operation and should remove the potential incentive to 'undersize' pipelines to minimise regulatory risk.

Illustrative modelling has been undertaken to show that not only will larger pipelines deliver consumer benefits in the longer-term through cheaper tariffs, but also increased competition between fields due to pipelines having capacity available will reduce gas prices for consumers. Overall, gas market reform was projected to increase Australian real GDP at 2010 by $330 million in today's dollars.

## Options to reduce greenhouse gas emissions

The major recommendation of the Panel in this area is the replacement of existing state and Commonwealth measures aimed at reducing greenhouse gas emissions in the electricity sector with an economy-wide emissions trading scheme.

The existing 'measures' aimed at reducing emissions in the electricity sector (some 18.3 million tonnes of carbon dioxide at 2010) was estimated to reduce GDP at 2010 by 0.11 per cent relative to a baseline that included the energy market reforms recommended by the Panel in its Draft Report.

The recommended shift to an economy-wide emissions trading scheme and away from this current 'measures' approach, is projected to benefit the Australian economy by just over $1.2 billion dollars in 5 year net present value terms by 2010 through the implementation of a more efficient, market-based mechanism to facilitate emission reductions.

The projected permit price for emissions trading is $3.75 per tonne of carbon dioxide in 2002 dollars. At a price of $3.75 per tonne there are some renewable energy schemes which would be cheaper than the price of the permit (in addition to cost-effective energy efficiency measures). ACIL Tasman modelling suggests that the most likely would be biogas (sewage and landfill) schemes.

ACIL Tasman's best estimate of the impact of the existing measures on wholesale electricity prices is an increase of $2.82 per MWh, which translates into electricity costs per tonne of abatement of $37 per tonne of carbon dioxide equivalent.



The projected impact on average electricity prices under the emissions trading scheme would be 6.9 per cent or $2.41 per MWh. This represents a reduction of $0.41 per MWh from the impact of the current measures. It also represents a lower electricity cost per tonne of abatement of $31.60 per tonne of carbon dioxide.

The economic costs imposed by the existing 'measures' approach, measured by real GDP in net present value terms, equates to around $90 per tonne of carbon dioxide reduced in 2010 from reference case levels. In comparison, the emissions trading scheme is projected to cost around $20 per tonne of carbon dioxide reduced in 2010.

ACIL Tasman concluded the Panel's recommendation to exclude the trade exposed sector from an emissions trading scheme is soundly based. The modelling shows that, for example, the non-ferrous metals sector bears a greater impact from greenhouse measures than other sectors.

# ATTACHMENT A

## Energy Technologies

### Wind turbines

Wind power has been the world's fastest growing energy source over the last decade and is now considered to be one of the most cost-competitive renewable energy sources. Australia's installed wind capacity has been increasing at 35 per cent per annum over the last five years.[1]

Australia's first grid connected wind farm was built by Pacific Power near Crookwell, NSW. It consists of eight 600 kW wind turbines providing enough energy to meet the average demand of 3500 homes. Small scale turbines (generally rated less than 10 kW) can be used as remote area power systems.

Technological advances in materials used in modern wind turbines are helping to reduce costs and improve design and construction of large generators. The greatest challenge to the economic use of wind power is the need for significant further cost reduction, the variability of the wind resource and in some areas community acceptance. Very few areas have fairly constant wind throughout the day and throughout the year. Energy storage, or backup systems, are required for windless or extremely windy periods, and also to level the supply even when the wind is blowing. Environmental issues such as visual, noise and flora/fauna impacts are becoming an increasing concern for proponents of large scale wind farms.

### Microturbines

Microturbines are miniature versions of the conventional base load machines used to generate power from natural gas, and evolved from aircraft engines and automotive turbochargers.

CSIRO Energy Technology installed Australia's first commercial microturbine at their North Ryde Laboratory, Sydney. The turbine produces 30 kW of power, independent of the electricity grid. In the United States, microturbines are already being used as on site power generators in a number of industries.

[1] Australian Ecogeneration Association Submission 86, p. 9

Proponents claim that this technology can provide reliable, high quality power at the site of generation at a cost that is becoming comparable to the delivered price of peak electricity. As with other forms of distributed energy, microturbines have the potential to reduce loads on transmission and distribution networks and have the benefit that any waste heat produced can be used to provide heating or cooling, further reducing energy costs.

## Photovoltaics

Photovoltaic (PV) technology is a semiconductor-based technology in which light energy (photons) is converted into direct current (DC) electricity. PVs differ from solar collectors such as water heaters and some electricity generators which convert the light energy into heat. There are particular opportunities for this technology where the consumer has a need for DC power.

PVs include a range of different technologies and approaches including silicon wafer-based technology and more recent approaches such as 'thin film' technologies. PVs' first practical uses were in space applications, and where alternative (conventional) forms of generation are not viable such as in remote areas. However, increasingly PVs are being used in grid connected applications as the efficiency of the units are improving and construction costs are reducing.

A potential application is the integration of PV cells into rooftop material to generate electricity for household and commercial use. In May 2002, Professor Martin Green, Director of the University of New South Wales Photovoltaics Special Research Centre and Pacific Solar's Research Director, anticipated that Pacific Solar's manufacturing costs for its crystalline silicon on glass 'thin film' technology could be as low as US$1.25 per watt by 2005, below the cost at which PV starts to compete with the residential price of electricity in most developed countries.



## Biomass

Biomass energy is derived from plant and animal material, such as wood, residues from agricultural and forestry processes, and industrial, human or animal wastes.

Large-scale energy production from biomass which can substitute for conventional fossil fuel energy sources generally rely on fuels such as forest wood and agricultural residues; urban wastes; and biogas and energy crops.

A range of technologies exist to convert biomass into large-scale energy production which can substitute for conventional fossil fuel energy sources including:

- biogas technologies which rely on the decomposition of biomass through bacterial action producing methane and carbon dioxide (biogas). Landfill sites are a source of biogas with many operations extracting the methane to generate electricity resulting in a reduction in greenhouse gas emissions and electricity generation from other fuels.
- direct combustion technologies which use forestry residues, bagasse and municipal solid waste in furnaces and boilers to produce process heat, or steam to feed steam turbine generators. For example, the sugar cane industry produces large volumes of bagasse (sugar cane fibre) each year and most sugar cane mills utilise bagasse to produce electricity for their own needs, with some providing surplus electricity to the grid. Australian sugar mills have an installed generating capacity of over 250 MW, but the bagasse resource could supply a much greater capacity.

Biomass as an energy source benefits from the fact that the fuels are renewable and the use of some biomass energy sources can reduce greenhouse gas emission. However, biomass has relatively low energy density and the need to transport large volumes of the fuel can significantly reduce net energy production.

## Geothermal generation - hot dry rocks

Geothermal resources come in five forms: hydrothermal fluids, hot dry rock, geopressured brines, magma, and ambient ground heat. Of these resources, only hydrothermal fluids have been developed commercially for power generation with about 9000 MW installed capacity in place worldwide.

Hydrothermal electricity is generated from naturally occurring hot water and steam in rocks near volcanic centres providing steam for conventional steam turbines and generators. The geological conditions necessary for hydrothermal energy are relatively uncommon and only New Zealand, Indonesia, the Philippines, Iceland, Japan, northern Italy, western USA and Mexico have commercial scale hydrothermal systems. However, hot dry rock resources are generally more widespread.

Studies into the prospects for hot dry rock energy in Australia have established that a very significant resource exists with some estimates of the energy available for electricity generation at 7500 years of Australian energy consumption at current levels. This energy is stored in rock heated by the earth's core and close enough to the surface for conventional drilling to access. Much of the resource data information comes from oil and gas industry drilling.

Hot dry rock geothermal energy is converted into electricity by circulating water through the hot rock and using the heated water to generate steam for standard geothermal power stations. The extraction process relies on existing technologies and engineering processes such as drilling and hydraulic fracturing, techniques established by the oil and gas industry.

It has been estimated that hot dry rock geothermal energy is cost competitive with wind and hydro power generation. While recognising the difficulties of calculating total costs for energy systems it has been estimated that the total electricity costs from hot dry rock is about $40-$60 per MWh, compared to their estimates of coal at $35, natural gas at $40 and wind at $80.[2]

## Fuel cells

Fuel cells are a group of technologies that produce electricity from the chemical interaction between hydrogen and oxygen. Fuel cells can use pure hydrogen or if fitted with a fuel reforming device hydrocarbon fuels such as natural gas can be used. Various fuel cell technologies are under development and are generally classified by the type of electrolyte used in the cells, including:

- Alkaline Fuel Cells (AFC)
- Protein Exchange Membrane Fuel Cells (PEMFC)
- Phosphoric Acid Fuel Cells (PAFC)
- Molten Carbonate Fuel Cells (MCFC)
- Solid Oxide Fuel Cells (SOFC)
- Direct Methanol Fuel Cells (DMFC)



The operating environment is a critical factor in selecting an appropriate fuel cell technology as each technology has different characteristics and applications. Significant research and development is being directed toward PEMFC technology since it is most promising for mobile applications. PAFC is a first generation technology and has the largest commercial penetration in stationary power generation applications.

Many technological and commercial barriers remain for wide spread fuel cell applications including storage and transport of hydrogen and the high cost of materials used in construction of fuel cells. However, fuel cells have potentially many advantages over conventional energy sources including a lack of emissions, energy conversion efficiency and reliability. These factors provide significant advantages in applications such as transport and on-site electricity generation.

[2] Geodynamics Ltd., Economics of HDR geothermal energy at <http://www.geodynamics.com.au/02-5.htm>

## Carbon sequestration

Carbon sequestration includes capturing CO2 gas from combustion flue gas and other point sources and storing it, as well as reducing atmospheric concentrations by enhancing the uptake of CO2 through natural ecological systems generally referred to as sinks (e.g. forests, oceans, microorganisms).

Carbon dioxide capture is generally estimated to represent a significant proportion of the total cost of carbon capture, storage, transport, and sequestration systems. Options currently identified for CO2 separation and capture include the following:

- absorption (chemical and physical)
- adsorption (physical and chemical)
- low-temperature distillation
- gas separation membranes
- mineralization and biomineralization

Research is proceeding on CO2, once captured, being injected into geological structures or the deep oceans. The oil industry, in some situations, injects CO2 into the reservoir to maintain pressure and enhance the recovery of petroleum.

Carbon sequestration in terrestrial ecosystems includes the net removal of CO2 from the atmosphere or the prevention of CO2 net emissions from the terrestrial ecosystems into the atmosphere. It is estimated that the terrestrial biosphere sequesters approximately 2 billion tonnes of carbon per year. Two fundamental approaches to sequestering carbon in terrestrial ecosystems are:

- the protection of ecosystems that store carbon so that sequestration can be maintained or increased (reductions in land clearing, reforestation, crop choices etc)
- the manipulation of ecosystems to increase carbon sequestration beyond current conditions.

## Coal gasification

Coal gasification is one of a range of clean coal technologies and '… is the central element of the most efficient advanced cycle coal-fired generation technologies under consideration for coal'.[3]

[3] CRC for Clean Power from Lignite, Sub 135 p. 5

When coal is brought into contact with steam and oxygen, thermochemical reactions produce a fuel gas, mainly carbon monoxide and hydrogen, which, when combusted can be used to power gas turbines. Integrated Coal Gasification Combined Cycle (IGCC) power generating systems provide improved efficiency by using waste heat from the product gas to produce steam to drive a steam turbine, in addition to a gas turbine. The cost of CO2 capture is also reduced by the isolation of this gas during the gasification process.

The Australian Coal Association notes that '… advanced power generation systems based on gasification of coal have the potential to be both cheaper and cleaner than conventional technology'. And further that, '… gasification systems can achieve efficiencies of greater than 50 per cent, produce less solid waste, lower emissions of pollutants like sulphur dioxide and nitrous oxide and lower carbon dioxide emissions'.[4]



[4] Australian Coal Association at <http://www.australiancoal.com.au/>

# APPENDIX 1

## Panel members

| | |
|---|---|
| The Hon. Warwick Parer (Chair) | Former Senator for Queensland and former Federal Minister for Resources and Energy |
| Mr David Agostini | Senior Consultant, petroleum industry and Adjunct Professor, Oil and Gas Engineering, University of Western Australia |
| Mr Paul Breslin | Director, ACIL Consulting |
| Mr Rod Sims | Director, Port Jackson Partners Limited |

# APPENDIX 2

## Secretariat members

| | |
|---|---|
| Brad Page | General Manager |
| Trish Caldwell | |
| Simon Camroux | |
| Doug Cooke | |
| Emma Dowling | |
| David Hatfield | |
| Louise King | |
| Kylie Naveau | |
| Stephen Paterson | |
| Angela Schmidt | |
| Michael Sheldrick | |

# APPENDIX 3

## Terms of reference[1]

### COAG national energy policy

Energy is a shared responsibility in Australia among the Commonwealth, State and Territory governments. The Commonwealth has a national leadership role to ensure overall prosperity, and that Australia's international obligations are met. States and Territories have particular responsibilities within their jurisdictions, including in relation to provision of energy services to the communities they serve.

The Council of Australian Governments (COAG), at its 8 June 2001 meeting, considered a range of energy policy matters, including a national energy policy framework, establishment of the Ministerial Council on Energy (MCE), and identification of high priority National Electricity Market (NEM) issues for referral to the NEM Ministers' Forum and other parties. In addition, COAG commissioned an independent strategic review of medium to longer-term energy market directions.

COAG agreed to the following national energy policy objectives:

- encouraging efficient provision of reliable, competitively-priced energy services to Australians, underpinning wealth and job creation and improved quality of life, taking into account the needs of regional, rural and remote areas
- encouraging responsible development of Australia's energy resources, technology and expertise, their efficient use by industries and households and their exploitation in export markets
- mitigating local and global environmental impacts, notably greenhouse impacts, of energy production, transformation, supply and use.

Consistent with these objectives, COAG also agreed the following (paraphrased) principles to guide government energy policy development:

- recognise the importance of competitive and sustainable energy markets
- continuously improve Australia's national energy markets

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[1] Material from COAG 2001b.

- enhance the security and reliability of energy supply
- stimulate sustained energy efficiency improvements
- encourage the development and application of less carbon-intensive energy sources and technologies
- recognise and enhance Australia's competitiveness in the world energy markets
- provide transparency and clarity in government decision making to achieve confidence in current and future investment decisions
- consider the social and economic impacts on regional and remote areas
- facilitate effective inter-jurisdictional cooperation and productive international collaboration on energy matters.

## Terms of reference for Energy Market Review

COAG agreed that the independent Energy Market Review be a forward-looking, strategic study to facilitate decision-making by governments, focussing on those areas likely to generate the most significant benefits.

Without limiting the conduct or scope of the review, priority issues for consideration are:

1. identifying any impediments to the full realisation of the benefits of energy market reform
2. identifying strategic directions for further energy market reform
3. examining regulatory approaches that effectively balance incentives for new supply investment, demand responses and benefits to consumers
4. assessing the potential for regions and small business to benefit from energy market development
5. assessing the relative efficiency and cost effectiveness of options within the energy market to reduce greenhouse gas emissions from the electricity and gas sectors, including the feasibility of a phased introduction of a national system of greenhouse emission reduction benchmarks
6. identifying means of encouraging the wider penetration of natural gas including increased upstream gas competition, value adding processes for natural gas and potential other uses such as distributed generation, because it is an abundant, domestically available and clean energy resource.

# APPENDIX 4

## Responses to Issues Paper

| No. | Person/Organisation | Received |
|---|---|---|
| 1 | South Australian Independent Industry Regulator (SAIIR) | 26 March 2002 |
| 2 | Bill McDowall | 31 March 2002 |
| 3 | Craig Parsonage | 03 April 2002 |
| 3.1 | Further submission | 04 June 2002 |
| 4 | Electricity Supply Association of Australia (ESAA) | 04 April 2002 |
| 4.1 | Further submission | 08 May 2002 |
| 4.2 | Further submission | 24 July 2002 |
| 5 | Bardak Ventures Pty Ltd | 04 April 2002 |
| 5.1 | Further submission | 22 June 2002 |
| 6 | Australian and New Zealand Solar Energy Society (ANZSES QLD Branch) | 12 April 2002 |
| 7 | Australian Institute of Petroleum | 06 April 2002 |
| 9 | Australian Conservation Foundation | 18 April 2002 |
| 10 | Andrew M Brown | 18 April 2002 |
| 11 | Energy Development Association Australia Inc | 18 April 2002 |
| 12 | Australian Liquefied Petroleum Gas Association | 18 April 2002 |
| 13 | Southern Hydro Partnership | 08 April 2002 |
| 14 | Australian Consumers' Association | 18 April 2002 |
| 15 | Energex | 18 April 2002 |
| 16 | Australian Petroleum Production & Exploration Association | 18 April 2002 |
| 17 | Ergon Energy Pty Ltd | 19 April 2002 |
| 18 | Ergon Energy Corporation Ltd | 19 April 2002 |
| 19 | Alan Pears | 19 April 2002 |
| 20 | Bioenergy Australia | 19 April 2002 |
| 21 | Hydro Tasmania | 19 April 2002 |
| 23 | Energy Intensive Industry Alliance | 19 April 2002 |

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|---|---|---|
| 24 | Orrcon Pty Ltd | 19 April 2002 |
| 25 | PricewaterhouseCoopers | 19 April 2002 |
| 26 | ANZSES | 19 April 2002 |
| 27 | Alternative Technology Association | 19 April 2002 |
| 28 | Dr Clive Anderson | 19 April 2002 |
| 29 | Gippsland Development Ltd | 19 April 2002 |
| 30 | Institute of Public Affairs | 19 April 2002 |
| 31 | Australian Coal Association | 19 April 2002 |
| 32 | ExxonMobil | 19 April 2002 |
| 32.1 | Further submission | 27 September 2002 |
| 33 | Energy Market Reform Forum | 19 April 2002 |
| 33.1 | Further submission | 12 June 2002 |
| 34 | Loy Yang Power | 19 April 2002 |
| 35 | Centre for Distributed Energy and Power (CSIRO) | 19 April 2002 |
| 36 | Queensland Major Gas Users Group | 19 April 2002 |
| 36.1 | Further submission | 23 August 2002 |
| 37 | Barry J O'Brien & Associates | 19 April 2002 |
| 38 | Australian Greenhouse Office | 19 April 2002 |
| 39 | White Mining Limited | 19 April 2002 |
| 40 | ESAA Transmission Directorate | 19 April 2002 |
| 41 | TransGrid | 19 April 2002 |
| 42 | National Retailers Forum | 19 April 2002 |
| 42.1 | Further submission | 19 August 2002 |
| 43 | United Energy, Citipower & TXU | 19 April 2002 |
| 44 | ESAA Distribution Directorate | 19 April 2002 |
| 45 | Powerlink Queensland | 19 April 2002 |
| 45.1 | Further submission | 04 July 2002 |
| 46 | Holden, WMC Limited, Visy Paper Limited, OneSteel Limited and BHP Billiton | 19 April 2002 |
| 47 | CS Energy | 19 April 2002 |
| 48 | AGL | 19 April 2002 |
| 50 | Woodside Energy | 19 April 2002 |
| 50.1 | Further submission | 11 October 2002 |

| | | |
|---|---|---|
| 51 | TransEnergie Australia | 19 April 2002 |
| 52 | Energy Planning and Policy Group, Faculty of Engineering, University of Technology, Sydney | 19 April 2002 |
| 53 | Tarong Energy | 19 April 2002 |
| 54 | Amcor Ltd and Paperlinx Ltd | 19 April 2002 |
| 56 | Latrobe Valley Generators | 19 April 2002 |
| 57 | NEMMCO | 19 April 2002 |
| 58 | InterGen (Australia) Pty Ltd | 19 April 2002 |
| 59 | Citipower | 19 April 2002 |
| 61 | Plastics and Chemicals Industries Association Inc | 19 April 2002 |
| 62 | Business Council of Australia | 19 April 2002 |
| 62.1 | Further submission | 10 May 2002 |
| 63 | Australian Wind Energy Association | 19 April 2002 |
| 64 | Nillumbik Shire Council | 19 April 2002 |
| 65 | ElectraNet SA | 19 April 2002 |
| 66 | BP Australia | 19 April 2002 |
| 67 | Australasian Natural Gas Vehicles Council | 19 April 2002 |
| 68 | Australian Industry Greenhouse Network | 19 April 2002 |
| 69 | Enertrade | 19 April 2002 |
| 70 | Pulse Energy | 19 April 2002 |
| 71 | Origin Energy Ltd | 19 April 2002 |
| 72 | Climate Action Network Australia | 19 April 2002 |
| 73 | Australian Gas Association | 19 April 2002 |
| 73.1 | Further submission | 1 August 2002 |
| 73.2 | Further submission | 30 September 2002 |
| 74 | Conservation Council of South Australia | 19 April 2002 |
| 75 | SPI PowerNet | 19 April 2002 |
| 76 | Westpac Institutional Bank | 19 April 2002 |
| 77 | Australian Aluminium Council | 19 April 2002 |
| 78 | Powercor Australia | 19 April 2002 |
| 79 | Australian Council of Infrastructure Development | 19 April 2002 |
| 79.1 | Further submission | 17 May 2002 |

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|---|---|---|
| 80 | Duke Energy International | 19 April 2002 |
| 81 | NECA | 19 April 2002 |
| 81.1 | Further submission | 28 June 2002 |
| 82 | Australian Paper Industry Council | 19 April 2002 |
| 83 | Chris Finn | 19 April 2002 |
| 84 | Australian Financial Markets Association | 19 April 2002 |
| 85 | Business SA | 19 April 2002 |
| 86 | Australian EcoGeneration Association | 19 April 2002 |
| 87 | NRG Flinders | 20 April 2002 |
| 88 | Energy Users Association of Australia | 21 April 2002 |
| 89 | Electricity Markets Research Institute | 22 April 2002 |
| 90 | Energy Action Group | 22 April 2002 |
| 91 | Australian CRC for Renewable Energy and University of NSW | 22 April 2002 |
| 92 | Trans Tasman Tariff and Fuel Consultants Ltd | 22 April 2002 |
| 93 | Renewable Energy Generators Australia | 22 April 2002 |
| 94 | Douglas Huntley | 19 April 2002 |
| 96 | National Competition Council | 19 April 2002 |
| 97 | Rio Tinto | 19 April 2002 |
| 99 | Energy Australia | 22 April 2002 |
| 100 | Santos Limited | 22 April 2002 |
| 101 | Public Interest Advocacy Centre | 22 April 2002 |
| 102 | Renewable and Sustainable Energy Roundtable | 22 April 2002 |
| 103 | Cement Industry Federation | 22 April 2002 |
| 104 | Sustainable Energy Industry Association | 23 April 2002 |
| 105 | Australian Petroleum Cooperative Research Centre | 22 April 2002 |
| 106 | ESAA Generation Directorate | 22 April 2002 |
| 107 | Stanwell Corporation Limited | 22 April 2002 |
| 107.1 | Further submission | 24 June 2002 |
| 108 | The Australia Institute | 22 April 2002 |
| 109 | BHP Billiton | 22 April 2002 |
| 109.1 | Further submission | 14 October 2002 |

| | | |
|---|---|---|
| 111 | The Institution of Engineers, Australia | 22 April 2002 |
| 112 | CIC Global | 23 April 2002 |
| 113 | Great Southern Development Commission | 24 April 2002 |
| 114 | National Farmers Federation | 23 April 2002 |
| 115 | Hastings Funds Management | 23 April 2002 |
| 116 | Toshiba International Corporation Pty Ltd | 23 April 2002 |
| 117 | Electricity Consumers Coalition of South Australia | 23 April 2002 |
| 118 | Edison Mission Energy | 24 April 2002 |
| 119 | Australian National Power | 24 April 2002 |
| 120 | Western Australian Government | 24 April 2002 |
| 122 | VENCorp | 26 April 2002 |
| 122.1 | Further submission | 27 May 2002 |
| 123 | Minerals Council of Australia | 26 April 2002 |
| 124 | Email Metering | 26 April 2002 |
| 125 | CSIRO Energy Technology | 29 April 2002 |
| 126 | Department of Natural Resources and Energy, Victoria | 29 April 2002 |
| 127 | Paspaley Pearls | 29 April 2002 |
| 128 | Australian Pipeline Industry Association | 29 April 2002 |
| 128.1 | Further submission | 03 September 2002 |
| 128.2 | Further submission | 26 September 2002 |
| 129 | Queensland Government Treasury | 29 April 2002 |
| 130 | Australian Chamber of Commerce and Industry | 02 May 2002 |
| 131 | Western Power | 02 May 2002 |
| 132 | Macquarie Generation | 03 May 2002 |
| 133 | Australian Democrats | 08 May 2002 |
| 134 | Delta Electricity | 08 May 2002 |
| 135 | CRC for Clean Power from Lignite | 10 May 2002 |
| 136 | ACCC | 10 May 2002 |
| 137 | Australian Industry Group | 16 May 2002 |
| 138 | Australian Biofuels Association | 17 May 2002 |
| 139 | Environment Business Australia | 21 May 2002 |
| 140 | Tasmanian Government | 24 May 2002 |
| 141 | City of Greater Bendigo | 27 May 2002 |

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|---|---|---|
| 142 | Epic Energy | 05 June 2002 |
| 143 | Joint Infrastructure Owners and Investors | 11 June 2002 |
| 144 | Northern Territory Government | 21 June 2002 |
| 145 | Chevron Texaco Australia Pty Ltd | 26 June 2002 |
| 146 | South Australian Government | 28 June 2002 |
| 147 | NSW Government | 17 July 2002 |
| 148 | Incitec Manufacturing | 22 August 2002 |
| 149 | CSIRO Manufacturing and Infrastructure Technology | 19 September 2002 |
| 150 | North West Shelf Gas Pty Ltd | 17 October 2002 |

# APPENDIX 5

## Responses to Draft Report

| No. | Person/Organisation | Received |
|---|---|---|
| 004.3(DR) | Electricity Supply Association of Australia | 06 December 2002 |
| 006.1(DR) | Australian and New Zealand Solar Energy Society (QLD Branch) | 03 December 2002 |
| 009.1(DR) | Australian Conservation Foundation | 06 December 2002 |
| 010.1(DR) | Mr Andrew Brown | 25 November 2002 |
| 013.2(DR) | Southern Hydro | 05 December 2002 |
| 014.1(DR) | Australian Consumers Association | 06 December 2002 |
| 016.1(DR) | Australian Petroleum Production and Exploration Association Ltd | 03 December 2002 |
| 018.1(DR) | Ergon Energy Pty Ltd | 06 December 2002 |
| 019.1(DR) | Sustainable Solutions | 06 December 2002 |
| 020.1(DR) | Bioenergy Australia | 06 December 2002 |
| 021.3(DR) | Hydro Tasmania | 09 December 2002 |
| 026.1(DR) | Australian and New Zealand Solar Energy Society | 06 December 2002 |
| 029.1(DR) | Gippsland Development Ltd | 11 December 2002 |
| 030.1(DR) | Institute of Public Affairs | 21 November 2002 |
| 031.1(DR) | Australian Coal Association | 06 December 2002 |
| 032.2(DR) | ExxonMobil | 27 November 2002 |
| 034.1(DR) | Loy Yang Power | 06 December 2002 |
| 036.2(DR) | Queensland Major Gas Users Group | 06 December 2002 |
| 038.2(DR) | Australian Greenhouse Office | 11 December 2002 |
| 042.2(DR) | National Retailers Forum | 05 December 2002 |
| 045.3(DR) | Powerlink Queensland | 06 December 2002 |
| 046.1(DR) | Visy Paper Limited | 21 November 2002 |
| 047.1(DR) | CS Energy Ltd | 06 December 2002 |
| 048.3(DR) | AGL | 06 December 2002 |

| | | |
|---|---|---|
| 049.1(DR) | EnviroMission Limited | 06 December 2002 |
| 051.1(DR) | TransEnergie Australia | 06 December 2002 |
| 053.1(DR) | Tarong Energy | 06 December 2002 |
| 054.1(DR) | Amcor Ltd. and Paperlinx Ltd | 06 December 2002 |
| 056.1(DR) | Latrobe Valley Generators | 06 December 2002 |
| 057.2(DR) | NEMMCO | 05 December 2002 |
| 058.1(DR) | InterGen (Australia) Pty Ltd | 06 December 2002 |
| 061.1(DR) | Plastics and Chemicals Industries Association | 06 December 2002 |
| 062.1(DR) | Business Council of Australia | 11 December 2002 |
| 063.2(DR) | Australian Wind Energy Association | 06 December 2002 |
| 065.1(DR) | ElectraNet SA | 06 December 2002 |
| 071.2(DR) | Origin Energy | 05 December 2002 |
| 073.5(DR) | Australian Gas Association | 06 December 2002 |
| 074.1(DR) | Conservation Council of South Australia | 06 December 2002 |
| 075.1(DR) | SPI PowerNet | 06 December 2002 |
| 076.1(DR) | Westpac Institutional Bank | 06 December 2002 |
| 077.1(DR) | Australian Aluminium Council | 04 December 2002 |
| 078.1(DR) | Powercor Australia | 06 December 2002 |
| 080.1(DR) | Duke Energy International | 09 December 2002 |
| 081.1(DR) | NECA | 09 December 2002 |
| 082.2(DR) | Australian Paper Industry Council | 06 December 2002 |
| 084.1(DR) | Australian Financial Markets Association | 09 December 2002 |
| 086.1(DR) | Australian Business Council for Sustainable Energy | 03 December 2002 |
| 087.1(DR) | NRG Flinders | 06 December 2002 |
| 088.2(DR) | Energy Users Association of Australia | 10 December 2002 |
| 089.1(DR) | Electricity Markets Research Institute | 09 December 2002 |
| 091.1(DR) | Australian CRC for Renewable Energy | 04 December 2002 |
| 093.2(DR) | Renewable Energy Generators Australia | 06 December 2002 |
| 096.1(DR) | National Competition Council | 11 December 2002 |
| 097.3(DR) | Rio Tinto | 06 December 2002 |
| 098.1(DR) | TXU | 06 December 2002 |
| 101.1(DR) | Public Interest Advocacy Centre | 06 December 2002 |
| 102.1(DR) | Renewable and Sustainable Energy Roundtable | 10 December 2002 |

| | | |
|---|---|---|
| 103.1(DR) | Cement Industry Federation | 06 December 2002 |
| 106.1(DR) | ESAA Generation Directorate | 02 December 2002 |
| 109.4(DR) | BHP Billiton | 29 November 2002 |
| 113.1(DR) | Great Southern Development Commission | 28 November 2002 |
| 117.1(DR) | Electricity Consumers Coalition of South Australia | 06 December 2002 |
| 118.2(DR) | Edison Mission Energy | 06 December 2002 |
| 122.2(DR) | Vencorp | 05 December 2002 |
| 123.1(DR) | Minerals Council of Australia | 06 December 2002 |
| 124.1(DR) | Email Metering | 03 December 2002 |
| 128.3(DR) | Australian Pipeline Industry Association | 06 December 2002 |
| 130.1(DR) | Australian Chamber of Commerce and Industry of WA | 06 December 2002 |
| 132.2(DR) | Macquarie Generation | 06 December 2002 |
| 134.1(DR) | Delta Electricity | 06 December 2002 |
| 136.1(DR) | Australian Competition and Consumer Commission | 09 December 2002 |
| 137.2(DR) | Australian Industy Group | 09 December 2002 |
| 139.1(DR) | Environment Business Australia | 06 December 2002 |
| 141.1(DR) | City of Greater Bendigo | 06 December 2002 |
| 143.1(DR) | Australian Council for Infrastructure Development | 06 December 2002 |
| 145.1(DR) | Chevron Texaco | 09 December 2002 |
| 150.1(DR) | North West Shelf Gas | 06 December 2002 |
| 151.1(DR) | National Generators' Forum | 06 December 2002 |
| 153(DR) | Eriks Velins | 25 November 2002 |
| 154(DR) | Viridis Energy Capital | 28 November 2002 |
| 155(DR) | Southern Cross Windpower | 28 November 2002 |
| 156(DR) | Pacific Hydro Limited | 29 November 2002 |
| 157(DR) | Solaire | 29 November 2002 |
| 158(DR) | Mr Peter Lewis | 02 December 2002 |
| 159(DR) | Mr Fallon Stuart | 02 December 2002 |
| 160(DR) | Hermes Systems Pty Ltd | 02 December 2002 |
| 161(DR) | Alinta Gas | 29 November 2002 |
| 162(DR) | Griffith University | 02 December 2002 |
| 163(DR) | Strike Oil | 02 December 2002 |
| 164(DR) | Gallaugher & Associates Pty Ltd | 03 December 2002 |

| | | |
|---|---|---|
| 165(DR) | ResourcesLaw International | 03 December 2002 |
| 166(DR) | NEG Micon Australia | 03 December 2002 |
| 167(DR) | Mr Ian Allott | 03 December 2002 |
| 168(DR) | Office of the Renewable Energy Regulator | 03 December 2002 |
| 169(DR) | Mr Peter Stafford | 18 November 2002 |
| 170(DR) | Mr & Mrs Minty | 04 December 2002 |
| 171(DR) | Prom Coast Guardians Inc. | 05 December 2002 |
| 172(DR) | Mrs Maureen Smith | 05 December 2002 |
| 173(DR) | D.U.T Pty Ltd | 05 December 2002 |
| 174(DR) | Wambo Power Ventures Pty Ltd | 05 December 2002 |
| 175(DR) | Essential Services Consumer Council | 05 December 2002 |
| 176(DR) | Mr & Mrs Wills | 05 December 2002 |
| 177(DR) | Babcock & Brown | 05 December 2002 |
| 178(DR) | Mr R Pratt | 05 December 2002 |
| 179(DR) | Mr & Mrs Stevens | 05 December 2002 |
| 180(DR) | Benchmark Melbourne | 05 December 2002 |
| 181(DR) | Simcoa Operations | 05 December 2002 |
| 182(DR) | Mr Ralph Crook | 05 December 2002 |
| 183(DR) | Shell Companies in Australia | 06 December 2002 |
| 184(DR) | The Hon Paul Henderson MLA - Minister for Business, Industry and Resource Development | 06 December 2002 |
| 185(DR) | Landis & Gyr Pty Ltd | 06 December 2002 |
| 186(DR) | Mr Andrew Aitken | 06 December 2002 |
| 187(DR) | True Friends of the Southern Mt Lofty Ranges | 06 December 2002 |
| 187.1(DR) | Mr W.D Taylor | 06 December 2002 |
| 188(DR) | Mr Matthew Paxton | 06 December 2002 |
| 189(DR) | Tarwin Valley Coastal Guardians Inc | 06 December 2002 |
| 190(DR) | Mr & Mrs Webb | 06 December 2002 |
| 191(DR) | Mr David Dixon | 06 December 2002 |
| 192(DR) | Basslink Concerned Citizens Coalition | 06 December 2002 |
| 193(DR) | Ms Waite | 06 December 2002 |
| 194(DR) | Enecon Pty Ltd | 06 December 2002 |
| 195(DR) | Mr Trevor Gleeson | 06 December 2002 |

| | | |
|---|---|---|
| 196(DR) | South East Australia Gas | 06 December 2002 |
| 197(DR) | Heritage Coast | 06 December 2002 |
| 198(DR) | Conservation Council of the South East Region and Canberra (Inc) | 06 December 2002 |
| 199(DR) | M.J Kimber Consultants Pty Ltd | 06 December 2002 |
| 200(DR) | Ms Rachel Crowley | 06 December 2002 |
| 201(DR) | In Tempore Advisory | 06 December 2002 |
| 202(DR) | Western Australian Sustainable Energy Association | 06 December 2002 |
| 203(DR) | Energy Markets Reform Forum | 09 December 2002 |
| 204(DR) | The Hon Paul Lennon MHA - Minister for Economic Development, Energy and Resources | 09 December 2002 |
| 205(DR) | ANZ Infrastructure Services | 06 December 2002 |
| 206(DR) | Mr Mark Burfield | 06 December 2002 |
| 207(DR) | C & D Tipper | 06 December 2002 |
| 208(DR) | J.M Murphy | 06 December 2002 |
| 209(DR) | M.P Taylor | 05 December 2002 |
| 210(DR) | G & S Bushell | 06 December 2002 |
| 211(DR) | M Wooding | 06 December 2002 |
| 212(DR) | L.S Prance | 06 December 2002 |
| 213(DR) | Hans Jurgen Ossa | 06 December 2002 |
| 214(DR) | NRG Flinders Operating Services Pty Ltd | 09 December 2002 |
| 215(DR) | Denise Maguire | 06 December 2002 |
| 216(DR) | Envestra | 06 December 2002 |
| 217(DR) | The International Council for Local Environmental Initiatives | 06 December 2002 |
| 218(DR) | T. Rickard Dun | 06 December 2002 |
| 219(DR) | Comalco Limited | 06 December 2002 |
| 220(DR) | Sinclair Knight Merz | 06 December 2002 |
| 221(DR) | Envirogen Pty Ltd | 06 December 2002 |
| 222(DR) | BP Australia Pty Ltd | 06 December 2002 |
| 223(DR) | The Institution of Engineers, Australia | 11 December 2002 |
| 224(DR) | Energy Users Coalition of Victoria | 10 December 2002 |
| 225(DR) | Ministry of Energy and Utilities | 10 December 2002 |

| | | |
|---|---|---|
| 226(DR) | Solar Heat and Power Pty Ltd | 10 December 2002 |
| 227(DR) | The Hon Patrick Conlon MP - Minister for Energy | 10 December 2002 |
| 228(DR) | Corrs Chambers Westgarth | 06 December 2002 |
| 229(DR) | Robin Chapple MLC - For the Mining and Pastoral Region | 06 December 2002 |
| 230(DR) | Benchmark Economics | 10 December 2002 |
| 231(DR) | Perth Energy | 06 December 2002 |
| 232(DR) | International Power | 09 December 2002 |
| 233(DR) | The Chamber of Minerals and Energy | 10 December 2002 |
| 234(DR) | The University of Queensland | 10 December 2002 |
| 235(DR) | Charles River Associates | 09 December 2002 |
| 236(DR) | P & L Wilkin | 11 December 2002 |
| 237(DR) | Drelmark Pty Ltd | 06 December 2002 |
| 238(DR) | Conservation Council of Western Australia | 06 December 2002 |

# APPENDIX 6

## References and consultancies

### Documents cited in report

ABARE 2001, *Australian energy: projections to 2019-20*, research report 01.11, Canberra.

—— 2002, *Australian commodities forecasts and issues*, vol. 9 no. 1.

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# APPENDIX 7

## Acronyms and abbreviations

| | |
|---|---|
| ABARE | Australian Bureau of Agricultural and Resource Economics |
| ACCC | Australian Competition and Consumer Commission |
| ACA | Australian Consumers' Association |
| ACT | Australian Capital Territory |
| AEA | Australian Ecogeneration Association |
| AFMA | Australian Financial Markets Association |
| AGA | Australian Gas Association |
| AGO | Australian Greenhouse Office |
| ANZMEC | Australia and New Zealand Minerals and Energy Council |
| APIA | Australian Pipeline Industry Association |
| APPEA | Australian Petroleum Production and Exploration Association |
| APRA | Australian Prudential Regulation Authority |
| ASC | Australian Securities Commission |
| ASIC | Australian Securities and Investments Commission |
| ASX | Australian Stock Exchange |
| BCA | Business Council of Australia |
| BPA | Benchmark Pricing Agreement |
| COAG | Council of Australian Governments |
| $CO_2$-e | Carbon dioxide equivalent |
| CPA | Competition Principles Agreement |
| CRNP | Cost-reflective network pricing |
| CSO | Community Service Obligation |
| DEI | Duke Energy International |
| DNRE | Department of Natural Resources and Environment (Victoria) |

| | |
|---|---|
| DSM | Demand Side Management |
| DUOS | Distribution use of system |
| EBIT | Earnings before interest and tax |
| EGP | Eastern Gas Pipeline |
| EIR | Emissions Intensity Requirement |
| ESAA | Electricity Supply Association of Australia |
| ESC | Essential Services Commission (Victoria) |
| ETEF | Electricity Tariff Equalisation Fund |
| EUAA | Energy Users Association of Australia |
| FRC | Full retail contestability |
| FTRs | Financial transmission rights |
| GDP | Gross Domestic Product |
| GEC | Gas Electricity Certificates (Queensland) |
| GGAP | Greenhouse Gas Abatement Program |
| HHI | Herfindahl-Hershman Index |
| IEA | International Energy Agency |
| IPART | Independent Pricing and Regulatory Tribunal (NSW) |
| IRPC | Inter-regional Planning Committee |
| IRR | Internal Rate of Return |
| IT | Information Technology |
| LNG | Liquefied Natural Gas |
| MCE | Ministerial Council on Energy |
| MRET | Mandatory Renewable Energy Target |
| MSP | Moomba to Sydney Pipeline |
| Mt | Million tonnes |
| MW | Megawatt |
| MWh | Megawatt hour/s |
| NCC | National Competition Council |

| | |
|---|---|
| NECA | National Electricity Code Administrator |
| NEM | National Electricity Market |
| NEMMCO | National Electricity Market Management Company |
| NER | National Energy Regulator |
| NET | National Electricity Tribunal |
| NETA | New Electricity Trading Arrangements (UK) |
| NGPAC | National Gas Pipelines Advisory Committee |
| NRF | National Retailers Forum |
| NSW | New South Wales |
| NT | Northern Territory |
| OECD | Organisation for Economic Cooperation and Development |
| OFGEM | Office of Gas and Electricity Markets (UK) |
| ORG | Office of the Regulator-General (Victoria) |
| OTC | Over-the-counter |
| PC | Productivity Commission |
| PJM | Pennsylvania New Jersey Maryland (US Market) |
| PNG | Papua New Guinea |
| PSLA | Petroleum (Submerged Lands) Act 1967 (Commonwealth) |
| QNI | Queensland/NSW Interconnector |
| RIEMNS | NECA's Review of the Scope for Integrating the Energy Market and Network Services |
| SA | South Australia |
| S. E. Aust | South Eastern Australian |
| SFE | Sydney Futures Exchange |
| SNI | South Australia to New South Wales Interconnect |
| SNOVIC | Snowy to Victoria Interconnect Upgrade |
| SOO | Statement of Opportunities |
| SPP | Special Power Payment (Victoria) |
| SRA | Settlement Residue Auction |

| | |
|---|---|
| SWIS | South Western Interconnected System (WA) |
| tcf | Trillion cubic feet |
| TNSPs | Transmission network service providers |
| TPA | Trade Practices Act 1974 (Commonwealth) |
| TUOS | Transmission use of system (charges) |
| tWh | Terawatt hours |
| UK | United Kingdom |
| USA | United States of America |
| UIWG | Upstream Issues Working Group |
| VENCorp | Victorian Energy Networks Corporation |
| VoLL | Value of lost load |
| WA | Western Australia |