Regulatory issues

Electricity

SA transmission network revenue cap 2003-08—final decision

As a part of its responsibilities under the National Electricity Code, the Commission has completed its inquiry into the revenue cap to apply to the South Australian transmission network, owned and operated by ElectraNet.

On 11 December 2002 the Commission made its final decision which details the maximum allowable revenue that ElectraNet can earn from the use of its non-contestable transmission assets. The revenue cap will apply for five and a half years, commencing 1 January 2003.

The revenue cap will increase from $148 million in 2002–03 to $180 million in 2007–08. The decision is expected to decrease by 4 per cent (in real terms) transmission prices over the regulatory period compared with 2001–02.

In setting ElectraNet's revenue needs, the Commission assessed ElectraNet's capacity to achieve realistic efficiency gains in its proposed operating and maintenance expenditure with regard to future demand and service quality. The Commission has granted ElectraNet a figure of approximately $48 million per annum for operating and maintenance expenditure over the regulatory period (including grid support).

The Commission was also required to assess ElectraNet's proposed capital expenditure with regard to future demand and service quality. The Commission included a capital expenditure roll-in for the period 1 January 2003 to 30 June 2008 of $358 million. The Commission noted that ElectraNet must apply the regulatory test to justify the inclusion of the projects in its future asset base.

The Commission's final decision draws on ElectraNet's application, consultancy reports on the asset base, capital and operating expenditure, submissions from interested parties, and other information presented to the Commission during the course of its deliberations. The decision also includes an incentive scheme to encourage ElectraNet to maintain or improve its service quality and reliability.

The Commission also approved ElectraNet's request to use modified cost-reflective network pricing over the regulatory period as it considers that it provides more efficient pricing signals than the standard approach.

Victorian transmission network revenue cap 2003-08—final decision

The Commission recently considered the appropriate revenue cap to apply to the Victorian electricity transmission network for five and a half years commencing 1 January 2003. The Victorian network is planned by VENCorp and owned and operated by SPI PowerNet.

On 16 December 2002 the Commission released its final decision, drawing on VENCorp and SPI PowerNet's application, consultancy reports, submissions from interested parties and other information presented to the Commission during the course of its deliberations. The final decision sets a revenue cap for SPI PowerNet that increases from $271.23 million in 2004 to $303.05 million in 2008.

The draft revenue cap is based on a post-tax nominal return on equity of 11.09 per cent and an opening asset balance of $1835.60 million.

The Commission has included a total capex roll-in for the period 1 January 2003 to 30 June 2008 of $378.64 million to cater for demand growth and the ageing network. This will ensure a reliable electricity supply to Victorian consumers, while providing long-term investment incentives for SPI PowerNet. The Commission noted that SPI PowerNet must apply the regulatory test to justify including the projects in its future asset base.

The Commission considered submissions from industry and consumer bodies before issuing its final decision.

Reforming Australia's energy markets: Commission submission to the Energy Market Review

The Commission supports the broad aim of the Council of Australian Governments (COAG) Energy Market Review's final report of improving the operation and efficiency of Australia's energy markets and completing the move from fragmented state-based markets to genuinely national markets.

The review's final report includes recommendations on the institutional arrangements covering the energy sector. The Commission supports the aim of reducing the number of regulators and streamlining the electricity and gas code change processes. However, it does not believe that establishing a new industry-specific regulator will solve governance-related problems of the energy industries.

The main points made by the review and the Commission's response to them are as follows.

Electricity market structure

In its submission to the Energy Market Review, the Commission argued that the reforms introduced over the past decade have gone a long way towards achieving COAG's original objectives, but that further reforms are needed. The final report identifies aspects of energy markets for which the reform process falls short and proposes measures to make the markets work more effectively. The Commission supports many of the proposed solutions. It believes the final report's measures to increase competition in areas such as electricity generation by encouraging investment in transmission or new entry are sound and worthy of consideration.

Electricity transmission

The Commission supports the broad approach of the review for electricity transmission and the establishing of firm financial transmission rights to signal for new interstate transmission investment, taking the role of planning new interstate and intra-state transmission investment from TNSPs, and changing the regulatory test. But these issues are complex and they need to be analysed carefully for possible effects on the market before reforms are implemented.

Gas market issues

The Commission considers that while the proposal for a regulation-free option would appear at a cursory level to respond to industry fears about regulation effects on new pipeline investment, it also raises some significant concerns about the regulation-free period and the longer term. The Commission considers that the value of the regulatory holiday option is limited, relative to the existing arrangements available under the gas code. The alternative option, an upfront regulatory agreement, provides a level of regulatory certainty to pipeline proponents over the life of the asset that regulatory holidays cannot.

Institutional framework for regulation of the energy sector

The Commission agrees with the broad aim of the final report, that is, to reduce the number of regulators, and agrees that simplifying governance arrangements is an important part of the completion of energy market reforms. The Commission particularly supports the proposal to give industry a greater say in developing the electricity and gas codes.

The Commission considers that the institutional framework proposed in the final report, that is the industry-specific regulatory model, raises problems of:

- the model risking the breakdown of the consistent application of competition law as advocated in the Competition Principles Agreement, if regulation of energy markets were separated from the Commission
- a higher risk of 'regulatory capture'—regulatory capture describes the tendency for sector-specific agencies to be biased in decision-making in favour of industry over consumers and other interested parties
- overlap between the two national regulators with the Commission still involved in enforcement (arising from the TPA), energy related mergers and some authorisation functions
- inconsistency across sectors—in the UK, differences in approach among different industry specific regulators led to differing outcomes for different UK industries and this could distort private investment decisions
- loss of competition focus—an industry-specific agency is less likely to be attuned to the benefits of competition, and what constitutes and threatens a competitive market.

There could, however, be merit in proposals that seek to retain the competition focus of energy market regulation such as that forwarded by Minister Macfarlane.

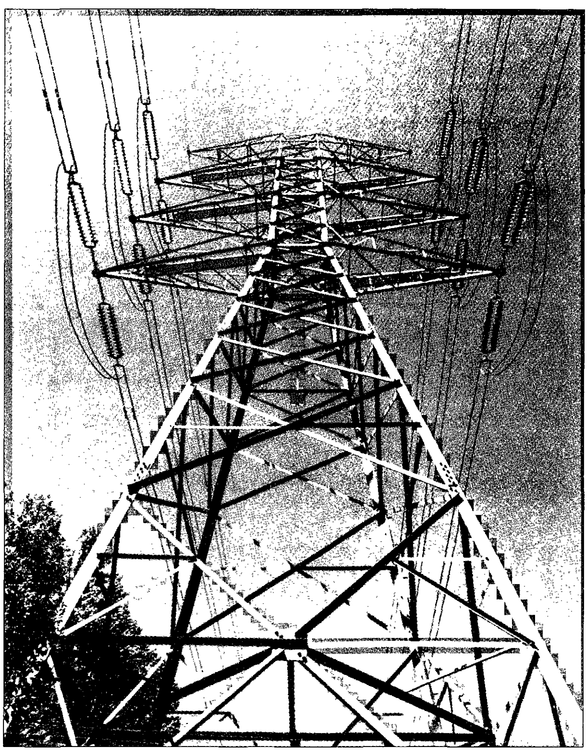
The Commission believes there are many proposals made in the final report that should be acted upon to improve the workings of Australia's energy markets. It looks forward to working on these with relevant parties. For other proposals, particularly that for a single sector regulator, the Commission has made known its concerns about how these agencies operate in practice.

Authorisation of amendments to the National Electricity Code safety net provisions and reserve contracting

On 10 September 2002 the Commission received applications for authorisation (A90844–6) of a derogation from the National Electricity Code for widening the scope of the existing reserve trader provisions. This would allow the National Electricity Marketing Management Company (NEMMCO) to enter into non-scheduled reserve contracts.

The National Electricity Code Authority (NECA) stated that the proposed derogation is intended to ensure:

- more reserve can be offered than is currently possible under the code
- reserve contracting is a more competitive process
- any inflexibilities associated with reserve contracts can be managed through intervention pricing.



NECA asked for and was granted an interim authorisation of the proposed derogation on 6 November 2002 to ensure that NEMMCO is able to enter non-scheduled reserve contracts for the coming summer.

The Commission received one submission on the proposed derogation.

The Commission issued its draft determination on 6 November 2002. It did not receive a request for a pre-determination conference and therefore released the final determination on 27 November 2002.

In its final determination, the Commission granted conditional authorisation to the proposed derogation. Overall, it considered that the derogation will improve the operation of the safety net and reserve contracting provisions by:

- providing additional sources of reserve capacity ensuring NEMMCO has a greater opportunity to meet reliability standards
- increasing competition among reserve contract and non-scheduled reserve contract suppliers, potentially lowering the total costs incurred by NEMMCO when activating the reserve trader
- promoting demand-side management as a way to alleviate supply scarcity.

The Commission also identified several issues on drafting of the proposed derogation. It considered that there are benefits in addressing these issues to make sure the derogation achieves its intended purpose. Subsequently, it imposed several conditions to help ensure the anticipated public benefits can be realised.

Authorisation of amendments to the National Electricity Code, SA FRC and system planning derogations

On 16 August 2002 the Commission received applications for authorisation (A90838–40) of amendments to the derogations contained in chapter 9 of the National Electricity Code.

The proposed derogations relate to the metering arrangements of chapter 7 of the code and the system planning provisions of chapter 5. The proposed changes to the South Australian derogations would:

- introduce transitional arrangements for metering services in the wholesale electricity market

- provide the local network service providers (LNSPs) with a monopoly for the provision of metering services
- ensure the derogation relating to system planning is consistent with the code as amended by the changes to the network and distributed resources code changes gazetted by NECA on 8 March 2002
- require NEMMCO to provide the Electricity Supply Industry Planning Council (ESIPC) with planning information.

The Commission received one submission on the proposed system planning derogation.

After considering the issues raised in the submission, the Commission issued its draft determination on 6 November 2002. It did not receive a request for a pre-determination conference and therefore released the final determination on 27 November 2002.

In its final determination, it granted conditional authorisation of the amendments to the derogations. It considered that for the full benefits of FRC to be realised, it is important to have an environment conducive to customer churn. Allowing LNSPs to have temporary exclusivity in metering services may provide such an environment by simplifying the process for customers who choose to switch retailers and minimising disruption to metering data systems. The Commission also considered that the system planning derogation will result in public benefits as it ensures the derogation is consistent with the code.

Queensland technical derogations—National Electricity Code authorisation

On 26 August 2002 the Commission received applications for authorisation (A90841–3) of amendments to chapter 9 of the National Electricity Code.

The amendments relate to Queensland technical derogations that specify technical standards to be adhered to by Queensland transmission and distribution companies to ensure the stability of the transmission system is maintained.

The extension to the derogations will allow Queensland code participants continuity of performance standards until the new performance standards regime, currently being considered for authorisation by the Commission, is implemented.

The Commission released its final determination for Queensland technical standards on 27 November 2002 extending the derogations for a further two years, to expire on either 31 December 2004, or 12 months after commencement of new performance standards, whichever is earlier.

Bidding and rebidding rules—National Electricity Code authorisation

On 13 September 2001 the Commission received applications from NECA to authorise code changes to the rebidding rules that would enable it to work with NEMMCO and the market to address issues such as:

- inefficiencies that have contributed to the short-term price spikes experienced in the market
- ensuring generators' bids and rebids are made in good faith and therefore represent their genuine intentions at the time they are made
- those aspects of generators' bidding and rebidding strategies that may prejudice the efficient, competitive or reliable operation of the market. For example, curtailing bids or rebids that withhold or withdraw capacity and succeed in artificially raising prices, exploit network constraints or reductions in capacity, or manipulate other aspects of the market design.

The proposed rebidding code changes were developed by NECA after criticism of price outcomes that arose during the summer of 2000–01.

NECA also proposed associated changes to the management of system security and ancillary services to improve network transfer capabilities, enable additional benefits of trade to be realised and reduce opportunities for local market power to be exercised.

The Commission received 22 submissions from interested parties on the application.

On 3 July 2002 the Commission released its draft determination outlining its analysis and views on the proposed code changes.

Good faith

On applying the authorisation test, the Commission found that the public benefits of the good faith proposal, on balance, outweighed the detriments. Public benefits arising from reliable pre-dispatch forecasts were an important component in the design of the national electricity market (NEM).

To address the issue of uncertainty about the definition of good faith, the Commission urged NECA to develop a definition.

Reverse onus of proof

The Commission did not support the reverse onus of proof proposal, as such a clause would require generators to prove themselves innocent to the satisfaction of the National Electricity Tribunal if their behaviour was questioned by NECA. This could impose significant costs on participants and would be inconsistent with the code objective 'to provide a regime of "light-handed" regulation'.

Conduct prejudicial

The Commission did not consider that the proposal delivers a net public benefit and has not authorised it because: it was considered to be unworkable; the compliance costs could have made the market less flexible thus reducing competitive responses; and the guidelines seem to go beyond the bidding and rebidding mechanism.

Power system security

The Commission found that the power system security code change would satisfy the authorisation test after conditions of authorisation were applied.

On 13 August 2002 a pre-determination conference was held in Melbourne. Interested parties were invited to make brief presentations in response to issues raised in the draft determination. Interested parties could lodge further submissions with the Commission after the draft determination was released. The Commission received 25 submissions.

In its final determination issued on 4 December 2002, it granted conditional authorisation to the proposed code changes.

Consistent with the draft determination, the Commission considered that the net public benefit of the good faith proposal, on balance, outweighed any detriment associated with the code change. However, considering any further uncertainty that may have arisen from the lack of a definition for good faith, and after taking into account further submissions, the Commission considered that providing a firm definition would alleviate any further concerns that participants may have with the code change.

Therefore, the Commission deemed it prudent to define good faith according to NECA's submission, as a participant's 'genuine intentions'.

The Commission continued to believe there is merit in the code changes aimed at enhancing network transfer capabilities through modifying arrangements for managing power system security and non-market ancillary services. However, the Commission imposed conditions of authorisation to ensure that the public benefits resulting from the code changes outweigh the potential detriment that could arise from its operation. Also, the condition relating to clause 3.11.3(b) was modified somewhat from what was proposed in the draft determination.

Queensland intra-regional loss factors—National Electricity Code authorisation

On 14 October 2002 the Commission received applications for authorisation (A90847–49) of amendments to chapter 9 of the code.

The applications relate to the provisions of the code that require wholesale electricity prices to be adjusted to reflect losses in transmission. These losses are caused by network resistance whenever electricity is transmitted from one point of the transmission or distribution network to another.

Queensland derogated from the code in 1998 and since this time has been calculating loss factors on a forward-looking basis, based on predicted load and generation data for the next financial year.

In its determination titled *Stage 1 of integrating the energy market and network services* (3 October 2002) the Commission authorised changes to the code allowing the NEM-wide implementation of forward-looking loss factors. The new methodology was intended to be implemented by 1 July 2003. However, NEMMCO has indicated that this may not allow sufficient time to develop the methodology and therefore NECA has decided to delay the implementation of those code changes until 1 January 2004.

Without extending their current derogation Queensland would be required to revert to backward looking loss factors until the implementation of NEM-wide forward-looking loss factors.

The Commission received no submissions on the proposed derogation.

The Commission considered it prudent that Queensland continue using the forward-looking loss factors method and accordingly released its draft determination on 4 December 2002. To ensure continuity of the derogation the Commission also granted interim authorisation on 4 December 2002. In its draft determination it proposes to extend the derogation until either 31 December 2004, or the implementation of NEM-wide forward-looking loss factors, whichever is earlier.

The Commission considered the move towards forward-looking loss factors would improve the representation of transmission losses in the NEM, and create public benefits by increasing the efficiency of wholesale market operations.

The Commission expects to release its final determination in January 2003.

Authorisation of amendments to the National Electricity Code technical standards

On 3 June 2002 the Commission received applications for authorisation (A90834–6) of amendments to the National Electricity Code to implement the conclusions and recommendations of NECA's review of technical standards in the NEM.

NECA's review concluded that the overriding imperative of maintaining the security and integrity of the power system means that there needs to be clearly defined standards for the overall performance of the network and the power system itself. But it concluded that to be consistent with achieving those system-wide needs, there should be flexibility within a defined range around the standards that an individual plant must meet to gain access to the network. This is consistent in practice with the existing grand fathered arrangements. Under these, plant connected to the network at the launch of the market has a variety of capabilities based on requirements at the time of its connection.

The proposed code changes seek to:

- establish a framework within the rules for the hierarchy of system, access, performance and plant standards proposed in NECA's report
- consolidate, and when necessary, update the existing system standards currently scattered throughout the rules
- determine proposed access standards based on recommendations developed by Sinclair Knight Merz in consultation with a working group established by NECA during the course of the review.

The Commission received 11 submissions on the proposed code changes.

After considering the issues raised, the Commission released its draft determination on 4 December 2002. Overall, the Commission found that the public benefits would outweigh any anti-competitive detriments associated with the proposed arrangements. It considered that the proposed changes provide a more flexible arrangement and allow specific performance characteristics of emerging technologies such as wind generators, gas turbines and co-generation to be considered. This would reduce barriers to entry for these participants and allow industry players to avoid unnecessary costs.

The Commission proposes to grant conditional authorisation to the technical standards code changes. Most of these conditions take into account that the current drafting of the proposed code changes do not reflect the intention of the agreed principles.

Gas

Greenfields guideline consultative forum

On 19 November 2002 the Commission held a consultative forum with industry and other interested parties on the *Draft greenfields guideline for natural gas transmission pipelines* before finalising it.

The forum was attended by industry participants, consultants, industry bodies, financiers and analysts across all sectors of the natural gas industry and other parties interested in the development of natural gas transmission infrastructure. In addition to presentations by a panel comprising Commissioner John Martin, Commission staff and consultants, interested parties could ask the panel questions about the greenfields guideline.

The comments and queries raised will be taken into account in finalising the guideline, which will be released in 2003.

Copies of the draft greenfields guideline (and information on submitting comments), related consultancies and a summary of the consultative forum proceedings can be found on the ACCC's website at <http://www.accc.gov.au> (under Gas, Broader Regulatory Issues).

NT Gas Amadeus Basin to Darwin pipeline

The final decision for the NT Gas access arrangement was approved by the Commission on 4 December 2002.

The final decision provides for a 10-year access arrangement period for the Amadeus Basin to Darwin pipeline. However, the Commission's final decision under the national gas code did not approve NT Gas' access arrangement in its current form and sets out the amendments it considers necessary for NT Gas' access arrangement to be approved.

After applying for an extension, which the Commission approved, NT Gas must now submit a complying access arrangement by 5 February 2003. If this is not submitted by then the Commission must draft and approve its own access arrangement.

The final decision is available on the ACCC's website.

Final decision on GasNet revisions

On 13 November 2002 the Commission decided not to approve the revisions proposed by GasNet for its access arrangements for the principal transmission system and western transmission system and issued a final decision to this effect.

The Commission did accept major changes to the arrangements it approved in 1998. These include merging GasNet's two access arrangements, including the southwest pipeline and the Murray Valley pipeline in the asset base, introducing pass-through mechanisms and prudent discounts, changing the tariff control formula and removing the automatic requirement for small pipeline extensions to be regulated. The Commission accepted GasNet's aggregate demand forecasts and that it recoup about $12.9 million of unrecovered revenue from the first access arrangement period. It also considered that GasNet should be able to retain about $16 million of tax allowances included in its target revenue for the first access arrangement period under the pre-tax approach adopted for that time.

However, it considered that some other proposals were inconsistent with the principles and objectives of the *National third party access code for natural gas pipeline systems*. These included GasNet's proposal to redetermine its initial capital base and its benchmark rate of return. The Commission specified 45 amendments as being needed for it to approve amended revisions submitted by GasNet.

On 6 December 2002 GasNet submitted amended revisions which it acknowledged did not incorporate several amendments on the rate of return and an allowance for asymmetric risks. It estimates that its benchmark revenues would be 5.8 per cent higher than those implied by the Commission's final decision.

The Commission is assessing GasNet's amended revisions and expects to release its further final decision in January 2003.