The Evolution of Transmission Planning Arrangements in Australia

A report by

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1 Introduction

1.1 Background

On 10 February 2006, the Council of Australian Governments (COAG) agreed to establish the Energy Reform Implementation Group (ERIG) to recommend proposals for:

- achieving a fully national transmission grid;
- measures that may be necessary to address structural issues affecting the ongoing competitiveness and efficiency of the electricity sector; and
- measures that may be necessary to ensure there are transparent and effective financial markets to support energy markets.

ERIG reported in January 2007. Its recommendations included the establishment of a more co-ordinated approach to transmission planning, through the establishment of a strategic national planner under a reformed NEMMCO.

At its meeting in April 2007 COAG agreed to establish a National Energy Market Operator for both electricity and gas. This new entity will include a new national transmission planning function.

The MCE has asked the AEMC to conduct a review into the development of a detailed implementation plan for the national electricity transmission planning function, including the most appropriate legislative amendments and rule changes to implement COAG's response. As part of its preparation for that review, the AEMC has sought a fact-based description of existing processes affecting transmission planning and co-ordination.

1.2 Scope of work

The AEMC is seeking a detailed, fact-based report on the evolution of transmission planning functions in Australia. The scope of work includes a description of:

- *Institutional framework at jurisdictional level:* The differing approaches to transmission planning, investment decision making, and ownership and operation of the network; the objectives and accountabilities applying to the relevant bodies;

- *Licencing:* licencing and regulatory arrangements, including service standards and incentive schemes.

- *Planning and co-ordination arrangements:* the role and evolution of the ANTS and the IRPC, and the role of APRs. The assessment will have a particular focus on the efficient functioning of transmission planning where this requires coordination between transmission companies.

- *Regulation:* the nature of any links between existing planning processes, regulatory decisions on revenue caps and the implementation of TNSP investment programs.

The intention is that the report is principally fact-based. However, the AEMC is also seeking observations on performance and effectiveness.

1.3 Methodology

The scope of work is broad, given the time available. Our approach has been to draw on and distill existing reports and reviews. The principal sources have been the ANTS produced by NEMMCO and the Annual Planning Reports produced by planning bodies at jurisdictional level; the report by the Energy Reform Implementation Group, and associated consultancy reports; and Firecone's report to the MCE on the institutional and regulatory framework for transmission.

This has been supplemented with limited consultation with transmission planners and regulators.

1.4 Structure of the report

The report is structured as follows. Section 2 provides a brief summary of the evolution of the policy framework. It is intended to provide background on the major reviews undertaken and major decisions made as a result of those reviews.

This section describes the restructuring of large vertically integrated utilities to separate out the network businesses; the framework for co-ordination between regional transmission planning bodies; the Energy Markets Review and its transmission recommendations; the MCE review of the institutional and regulatory framework for transmission; and the ERIG report to COAG.

Section 3 describes the institutional framework at jurisdictional level. It covers the ownership and operation of transmission networks in the NEM, the principal corporate objectives and the approach to procurement.

Section 4 sets out TNSP obligations to plan for and provide reliable transmission services, under the National Electricity Rules and State-based instruments.

Section 5 describes processes for NEM-wide co-ordination of transmission planning and investment.

Section 6 describes the form of regulation, the way in which this regulation has developed, and the interaction between transmission regulation and the Regulatory Test.

2 Policy Framework

Historically, the electricity sector was characterised by large, vertically integrated utilities. Victoria and New South Wales have been interconnected since the completion of the Snowy Mountains hydro scheme. Otherwise, there was little interconnection between States and no competition in the supply chain. Structural change has introduced a separation between the competitive businesses of generation and retail and the network businesses of transmission and distribution.

This vertical separation established transmission as an independent function. The main stages in the evolution of the policy framework for transmission have been:

- Consideration of a single national transmission body in the early 1990s
- A decision to establish multiple largely State- based bodies during the mid-1990s, combined with a separate institutional and decision making framework for investment in transmission inter-connection between states, up to 2002
- An approach relying on delegated decision making by TNSPs, combined with obligations on how that decision making is undertaken. This was established in the NDR Code Changes in 2002, and has largely remained in place since
- The establishment of an Annual National Transmission Statement in 2004, and
- The decision to establish a reformed national transmission planner under a reformed NEMMCO.

The main reviews and decisions are briefly summarised below.

The Industry Commission was appointed in November 1990 to review the electricity industry and the feasibility of a national electricity grid The Industry Commission reported in May 1991. It recommended:

- Vertical separation of generation and retail from transmission and distribution, and
- Access to the networks on a non-discriminatory basis, enabling competition in generation and retail

The Industry Commission also recommended the establishment of a single transmission body for Queensland, New South Wales, Victoria, South Australia and Tasmania. The report stated:

> "*The Commission proposes that an independent body be formed to acquire transmission assets in New South Wales, Victoria, Queensland, South Australia and Tasmania. Initially, each participating government would own shares in this body in proportion to the value of the transmission assets which it had contributed…..Most state electricity authorities support the formation of a 'national' grid, but consider that ownership should remain with the individual states and that transmission should continue to be owned and operated by state generating*

> *authorities. …The Commission considers this alternative totally inappropriate. The proposal, which is an extension of the arrangements which have applied to the existing interconnected grid for some years, would perpetuate inefficiencies which have held back consideration of new interconnections in the past…There would be no guarantee that new capacity and grid extensions would be considered from a national perspective"*[1]

The July 1991 Special Premiers' Conference agreed to establish the National Grid Management Council. The Electricity Working Group, which reported to this Special Conference, recommended that the NGMC should coordinate the planning, design and development of the transmission system and associated works for interconnection between the State grids.

Consideration of a singe national transmission company was given added impetus by the Prime Minister's "One Nation" Statement of February 1992, which stated:

> *"The National Grid Corporation would, by establishing an independent grid, strengthen a national approach to development of the transmission facility. It would provide a key for the development of strong competition between generators of electricity . . ."*[2]

During 1992 the NGMC undertook a review of structural options for the interstate transmission network. The review considered four options. These were ring-fenced units within integrated businesses; legally separate subsidiaries; multiple network corporations; and a single national network corporation. The options were assessed against a range of criteria, mainly related to efficiency and to practical steps in implementation.

The review rejected the first two options, on the grounds that they did not establish sufficient separation. It concluded that there would be major costs associated with moving from multiple network corporations to a single national network business. The review also stated that the working group and its consultants 'could not quantify the benefits of moving to this option' (that is, the national network corporation). The review concluded that:

> *"Multiple Network Corporations be the objective for Governments to work towards in the ongoing reform of the Electricity Supply Industry."* and that *"..if, in the course of implementation experience or further cost benefit reviews, it is demonstrated that there is a better option than MNCs, then governments should reconsider their positions."*[3]

The COAG meeting in June 1993 agreed to implement necessary structural changes to the electricity industry. COAG decided that establishment of the interstate transmission network should be through adoption of the Multiple Network Corporation model outlined in the NGC report. COAG also agreed that, during the establishment of these multiple corporations, it would examine whether the preferred model should be a National Network Corporation, or another option[4].

The decision to proceed with largely state-based transmission planning and investment was combined with steps to ensure a co-ordinated approach to development of the grid. This

[1] Industry Commission, May 1991, Energy Generation and Distribution, Summary and Recommendations

[2] *One Nation* Statement, 26 February 1992, p.67

[3] National Grid Management Council, "The structure of an interstate transmission network for eastern and southern Australia", December 1992

[4] Council of Australian Governments communiqué, 8-9 June 1993

was reflected in the National Electricity Code. NEMMCO was required to establish an Inter-regional Planning Committee (IRPC). The IRPC was required to conduct an Annual Planning Review of the transmission networks and to provide transmission information for NEMMCO's annual Statement of Opportunities.

The IRPC was also required to apply a regulatory test to projects with material inter-regional impacts. This clearly included inter-connectors between regions, although its application to other investments was less clear. The regulatory test has since been modified:

- *Nature of the test:* the test was originally based on net customer benefits; was modified to a cost benefit test in November 1999; and was further modified in March 2002 to be a least cost test (for investments to meet reliability standards and other obligations) and a cost benefit test (for other investments). The March 2002 changes also introduced a distinction between large (above $10M) and small ($1M to $10M) investments. Further modifications to the nature of the test were made in August 2004, by the ACCC, focusing mainly on the calculation of competition benefits, but also a variety of other less significant detailed issues.

- *Responsibility for setting the test:* NEMMCO was originally responsible for defining the test. This responsibility was moved to the ACCC in November 1999

- *Conducting the test:* the IRPC was originally responsible for applying the test to inter-connectors. Following the NDR Code changes in March 2002, TNSPs were responsible for applying the test to all augmentations.

The role of the IRPC and the Regulatory Test are described more fully in later sections.

At its meeting of 8 June 2001, COAG endorsed the need for a national energy policy, and agreed to commission an independent review of energy market reform. The Energy Market Review (also known as the Parer report) proposed that NEMMCO should plan for the inter-regional and intra-regional transmission network. NEMMCO should not delegate transmission planning responsibility for the transmission 'backbone' to TNSPs. The Parer report stated that "For these purposes, the transmission backbone is represented by those elements of the network for which NEMMCO has system operation responsibilities under the Code"[5].

The report also recommended that NEMMCO should conduct competitive tenders for new, regulated transmission investments. NEMMCO should also auction firm financial transmission rights (FTRs). The price of FTRs should be used as the key indicator of the need for transmission augmentation. This competitive tender of regulated transmission augmentations should be combined with continuing merchant investment in transmission.

During 2003 the NEMMF commissioned a review of the institutional and regulatory framework for transmission, undertaken by Firecone. Following this review, the MCE recommended a reform package to COAG. The package included the establishment of an Annual National Transmission Statement, to be developed by NEMMCO in conjunction with market participants. The first ANTS was published by NEMMCO in 2004.

[5] Energy Markets Review, page 134

The ERIG review was tasked with recommendations on how to develop a truly national transmission grid. ERIG recommended establishment of a national transmission planner, to be based in a reformed NEMMCO.

COAG has stated that the new arrangements would not bind transmission companies to specific investment decisions; that accountability for jurisdictional transmission investment, operation and performance will remain with transmission network service providers; and, where possible, the new regime must be no slower than at present to gain regulatory approval for transmission investment. New South Wales stressed that its agreement to the establishment of the national transmission planning function was conditional on the planner not impeding the State's significant investment in its transmission network.

3 Institutional framework at jurisdictional level

3.1 Ownership and corporate form

The ownership, corporate form and approach to procurement of transmission network service providers in the NEM is summarised in Figure 1.

Figure 1: Ownership and operation of TNSPs in the NEM

	NSW	QLD	TAS	VIC	SA
TNSP	Energy Australia Transgrid	Powerlink	Transend	VENCorp	Electranet
Ownership	State Government	State Government	State Government	State Government *	Powerlink (41%) Hastings (19.9%) YTL (33.5% Other (5.5%)
	Board of Directors	Board of Directors	Board of Directors	Board of Directors	Board of Directors
Corporate form	Corporatised entities under *State Owned Corporations Act*	GOC under *Government Owned Corporations Act*	PLC owned by Government of Tasmnaia	Statutory Authority under *Gas Industry Act*	Proprietary Limited company
Approach to procurement	Standard	Standard	Standard	BOO contracts	Standard

Network agreements

SP AusNet

Other

* GOV appoints TNSP Board but does not own transmission assets

There are two TNSPs in Victoria. VENCorp is a statutory authority with sole responsibility for planning and procuring augmentation of the transmission network. VENCorp is a statutory authority under the Gas Industry Act. VENCorp is a not-for-profit entity. It is not subject to Commonwealth Income Tax or to a tax under the tax equivalence regime. VENCorp's costs for provision of the electricity transmission network are recovered under charges to the electricity distribution businesses. Other costs are recovered through a variety of user charges.

SP AusNet owns, operates and maintains most of the transmission network in Victoria. SP AusNet was publicly listed on the Australian and Singapore stock exchanges in 2005. Singapore Power Limited owns a 51% interest. Singapore Power Limited is wholly owned by Temasek Holdings.

There are two TNSPs in New South Wales, Transgrid and Energy Australia. Both are State owned corporations under the State Owned Corporations Act.

Transgrid was established under the Electricity Transmission Authority Act, 1994. It was corporatised in 1998.

Energy Australia is the largest retailer in Australia. It also owns a large distribution business and transmission assets.

Electranet is a proprietary limited company. The major shareholders in Electranet are Powerlink and YTL.

Transend is a limited company wholly owned by the State of Tasmania.

3.2 Corporate objectives

TNSP corporate and financial objectives are set out in their Annual Reports, in relevant legislation and in other instruments. A brief comparison of their stated objectives is set out in Table 1.

Table 1: TNSP corporate and financial objectives

	Main corporate objectives
Powerlink	Safety, reliability, cost effectiveness, reasonable returns to owners. Return on equity around 6.4% p.a. over last three years.
TransGrid	Efficient long term development of the transmission network. Government-determined target return on equity is below 6.88% p.a.
VENCorp	Efficient and effective delivery of energy.
SP AusNet	Management excellence; long term value for security holders; continual efficiencies; long term asset sustainability; operational delivery; strong stakeholder relationships[6]
Electranet	"The company's key business objective is to be an outstanding investment for our shareholders while maintaining a BBB+ credit rating"
Energy Australia	Safety, reliable networks, social responsibility, environmental protection and government-determined target return on equity of 7.4% p.a.
Transend	"Efficiently provide a reliable and secure transmission service at a cost commensurate with appropriate and sustainable returns to shareholders." Return on equity in 2005 was 4.8% p.a.

3.3 Approach to procurement

All TNSPs other than VENCorp have a standard procurement model. The TNSP owns the assets that it uses. In some cases these assets are procured under long term contracts which transfer significant risk to the contractor. In others, new investments are largely managed in-house.

VENCorp offers all significant transmission projects on competitive tender, under build-own-operate contracts. To-date it has let nine such contracts, of which seven have been secured by SP AusNet. VENCorp is not subject to incentive-based regulation in respect of these contracts.

[6] Source; SP AusNet prospectus, page 2

The predecessor to VENCorp was an entity called the Victorian Power Exchange (VPX). The rationale given for establishment of this structure was:

> *"VPX is suited to this independent role because it lacks direct commercial interests which favour any particular network solution, it is specifically structured to be able to assess the trade-offs between investment options in an independent manner."*[7]

VENCorp plans the shared transmission network, procures use of assets under network agreements with asset owners (predominantly SP AusNet), negotiates with parties who wish to connect to the network, and sets prices for the shared transmission network. SP AusNet is responsible for the provision of connection services.

VENCorp is able to direct that SP AusNet undertake an augmentation. The revenue received by SP AusNet is subject to economic regulation. VENCorp may also conduct a competitive tender. The revenue received by the owner is then determined by the tender process[8].

The revenues received in relation to refurbishment and maintenance costs associated with the existing asset base are also subject to regulatory control.

[7] Reforming Victoria's Electricity Industry: A Summary of Reforms, 1994, quoted in Allen Consulting Statutory Review of VENCorp, 2006
[8] This description is taken from the Allen Consulting review referenced above.

4 TNSP obligations

TNSP obligations are defined in a number of ways. The NER establishes broad requirements on how standards of service should be defined. State based instruments impose more specific obligations, which in turn determine the planning criteria against which the TNSPs plan and build their network. The state based definitions vary in the nature of the obligation and the level of codification.

The NER establishes an obligation for the AER to develop an incentive regime based on performance against defined service standards. The AER has developed and is currently extending that regime.

The NER also establishes obligations on the way in which the TNSPs conduct planning, and the way in which TNSPs manage outages. In both cases, this includes requirements for information disclosure. These obligations are described in turn below.

4.1 NER requirement on standard of service

Chapter 5 of the NER states that one purpose of the Chapter is to address a connection applicant's reasonable expectations of the level and standard of power transfer capability that the relevant network should provide.

Schedule 5.1 sets out the network performance requirements to be provided or co-ordinated by network service providers, and so the planning, design and operating criteria.

Schedule 5.1.2.2 sets out minimum standards within a region. The amount of network redundancy must be determined through planning processes set out in the Rules, and discussed below. The standard of service to be provided at each connection point must be included in a connection agreement, and must include a power transfer capability "*such as that which follows*":

"*(a) In the satisfactory operating state, the power system must be capable of providing the highest reasonably expected requirement for power transfer requirements … at any time;*
(b) During the most critical single element outage, the power transfer available through the power system may be:

(1) zero
(2) the defined capacity of a backup supply
(3) a nominated proportion of the normal power transfer capability (e.g. 70%); or
(4) the normal power transfer capability of the power system."

The Rules therefore define a process for network planning, and require connection agreements to set out a power transfer capability, but do not define the power transfer capability.

The Rules also allow for TNSPs to negotiate connection agreements that require the TNSP to deliver higher standards of reliability than specified in Schedule 5 or in State-based legislation or licence conditions.

4.2 State-based reliability obligations

The NER establishes an obligation to set out the power transfer capability and sets out indicative ways of defining power transfer capability. State-based legislation and licences impose specific obligations on individual TNSPs. The relevant legal instruments used for this purpose are summarised in Table 2 .

Table 2: State-based instruments to impose reliability requirements

Jurisdiction	Requirement
South Australia	ElectraNet SA is required by conditions in its transmission licence to comply with the South Australian Transmission Code. The Transmission Code sets out prescriptive reliability standards for each connection point, which range from N-0 to N-2 according to the category of that connection point.
Victoria	The *Victorian Electricity System Code* requires TNSPs to "develop and implement plans for the acquisition, creation, [etc.]… of transmission network assets to economically … meet reasonable customer expectation".
New South Wales	Section 6B of the *Energy Services Corporation Act* states that the success of TransGrid's business is judged, amongst other things, by reference to its ability to operate efficient, safe and reliable facilities for the transmission of electricity. The *Electricity Supply (Safety and Network Management) Regulation 2002* provides for the Director-General of the NSW Ministry of Energy & Utilities to require network service providers to lodge or amend "network management plans" to (among other things) address network safety and reliability issues.
Queensland	Section 34(2) of the *Electricity Act 1994* requires the transmission entity to ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and, if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid. Clause 6.2 of Powerlink's transmission authority (transmission licence) requires Powerlink to plan and develop its transmission grid in accordance with good electricity industry practice, such that power quality and reliability standards in the National Electricity Code are met for intact and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varied by agreement[9].
Tasmania	Transend has a licence obligation to develop its network in accordance with the Transmission Network Security and Performance Criteria set by the Reliability and Network Planning Panel.

4.3 State-based planning criteria

The obligations set out in State-based legislation are often high level. Jurisdictional planning bodies establish planning criteria within the framework established by the NER and State-based legislation.

The Electricity Rules require each NEM jurisdiction to nominate a body responsible for transmission planning within their State. Jurisdictions vary in how they allocate this

[9] This information is based on earlier consultation with Powerlink, and may be out of date. The transmission authority is not in the public domain.

responsibility, and in the extent to which it is integrated with the provision of transmission services.

In Queensland, New South Wales and Victoria, the planning criteria are established by the TNSP under delegated authority from the state governments. In Queensland and New South Wales, determination of the planning criteria is combined with provision of transmission services. As noted above, VENCorp in Victoria outsources the provision of transmission services.

In Tasmania, the Reliability and Network Planning Panel (RNPP) has advised the Office of Tasmanian Energy Regulator (OTTER). The proposed standards include provision for government to be formally involved in evaluating the merits of all projects greater than 10 MW.

The criteria in South Australia are set out in the Electricity Transmission Code administered by the Essential Services Commission of South Australia. These criteria are based on the advice of the Electricity Supply Industry Planning Council (ESIPC).

The State-based planning criteria that apply in the different jurisdictions are summarised in Table 3. These criteria differ in how they define and measure reliability, in the standard set, and in the level of definition and transparency of the standard.

Reliability outcomes are defined in a variety of ways including minimum network redundancy, minimum restoration times, maximum load to be interrupted, and maximum unserved energy. In some cases a combination of these measures is used. Victoria differs by defining the benefits and costs to be included in the decision on the standard.

Table 3: Jurisdictional planning criteria

Victoria	All significant transmission augmentations are subject to a cost/benefit assessment. VENCorp conducts a cost/benefit analysis that compares the cost of investment against possible benefits. Possible benefits may include: value of load that would otherwise be curtailed, additional cost of ancillary services, possible reduction of fixed and variable generation costs, reduction in cost of losses, benefit of deferring other network investments.
Tasmania	No credible contingency event (as defined by NEMMCO) will interrupt more than 25 MW of load. No single asset failure (such as a double circuit transmission line or substation bar) will interrupt more than 850 MW or cause a system black. Unserved energy related to a credible contingency must not exceed 300 MWh. Unserved energy as a result of asset failure must not exceed 3000 MWh. Where a network element has been withdrawn from service, the energy exposed to interruption must not exceed 18,000 MWh. In addition, projects worth more than $10m proposed to meet these criteria should be subject to consideration by the jurisdiction to take account of broader economic costs and benefits.
NSW	TransGrid is the Jurisdictional Planning Body and generally plans its network to an n-1 standard with variations from this standard in some circumstances.
QLD	Powerlink plans its network in accordance with its interpretation of Schedule 5.1 of the Electricity Rules. Section 34(2) of the Electricity Act 1994 requires the transmission entity to ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and, if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid. In addition, Clause 6.2 of Powerlink's transmission authority

	(transmission licence) requires Powerlink to plan and develop its transmission grid in accordance with good electricity industry practice, such that power quality and reliability standards in the National Electricity Code are met for intact and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varied by agreement. The detailed application of these rules by Powerlink is not publicly available.
SA	All connection points between the transmission system and transmission customers, generators or distributors are allocated to one of six load categories. The transmission service obligations are defined by category with category six requiring the highest standard and category one the lowest. Progressively higher levels of transmission line and transformer redundancy are required to serve connection points in higher load categories. Progressively quicker restoration periods are prescribed in the event of interruptions to supply in higher load categories. The highest category, category 6, applies to Adelaide Central only.

In addition to differing definitions and differing standards, jurisdictions differ by the degree to which reliability outcomes and planning criteria are formalised and codified. An example of a codified approach is that in South Australia. The planning criteria for Adelaide Central states that the TNSP (after 31 December 2011) must provide N-1 transformer capacity by means of independent and diverse transmission substations, one of which must be located west of King William Street.

In Victoria the criterion is more loosely defined as the need to develop networks to economically meet reasonable customer expectations. In some cases, reliability obligations are imposed by documents that are not readily available to other market participants and regulators. Queensland, for example, does not generally publish or make available copies of individual transmission authorities unless the holder consents.[10]

Further, as provided by the Rules, all TNSPs may negotiate connection agreements that require the TNSP to deliver higher standards of reliability than specified in Schedule 5.1 to the Rules or in State-based legislation or licence conditions.

4.4 Network augmentation

The TNSPs have no obligations to augment their transmission networks, other than as required to meet reliability standards and planning criteria.

The Regulatory Test requires TNSPs to go through a defined process for consideration of and consultation on augmentations. The process for augmentations that are not required to meet reliability or other mandatory standards is a cost/benefit assessment. The Regulatory Test is described further in section 6.4.

4.5 Service standards incentives scheme

Section 6A7.4 of the NER requires the AER to develop and publish a scheme to provide incentives for TNSPs. The scheme should provide incentives for TNSPs to provide greater reliability of the transmission system at times when users place the greatest value on reliability.

The incentives scheme developed by the AER is discussed in section 6.3.

[10] www.energy.qld.gov.au/electricity/licensing.htm

4.6 *Operational obligations in the NER*

The NER sets out obligations on the way in which TNSPs plan network expansion and consult on proposed investments; an obligation on NEMMCO to prepare the ANTS; and obligations on TNSPs on management of transmission outages. These are described in turn below.

4.6.1 Planning

Section 5.6.2A of the NER sets out an obligation for all TNSPs to publish an Annual Planning Report (APR) setting out the results of an annual planning review. The NER defines the issues to be addressed in the APR. The NER also defines timelines for consultation (for example, minimum timelines for requiring load forecast data from market participants) and for publication of the APR.

4.6.2 Investment processes

The APRs provide planning information. In addition, section 5.6.6 sets out specific obligations to be followed by applicants to establish large (above $10M) transmission network assets. The obligations include information to be provided on the proposed asset; analysis to be undertaken and made available, and timelines to be followed in consultation.

The NER also establishes an obligation on the AER to develop and publish the Regulatory Test, and guidelines on its application. The Regulatory Test in turn establishes processes to be followed and consultation to be undertaken for proposed investments. Section 6.4 discusses the Regulatory Test in greater detail.

4.6.3 Annual National Transmission Statement

Section 5.6.5 of the NER sets out an obligation for NEMMCO to conduct a review of national transmission flowpaths, forecast constraints and options for relieving constraints. The NER also sets out obligations for consultation, issues to be considered, and obligations for provision of required information during the preparation of the ANTS.

4.6.4 Management of transmission outages

Clause 3.7A of the Code includes requirements for NEMMCO and the TNSPs to publish planned network outage information for the following 13 months, updated on a monthly basis. NEMMCO is also required to determine and publish an assessment of the projected outages on intra- and inter-regional transfer capacities.

TNSPs are not bound to comply with an outage program, but it is required to be a statement of intentions and best estimates at the time the information is made available. The advance notification provided through these reports enables market participants to manage the impacts on them of scheduled outages planned by the TNSPs.

5 NEM-wide planning co-ordination

Victoria and New South Wales have had significant interconnection since 1959. Victoria and South Australia have been interconnected since 1990. Queensland's strong interconnection to New South Wales was established through QNI commissioned in 2001. Tasmania was connected when Basslink started operations in 2006.

As described above, an initial recommendation for a single transmission body was rejected. This increasing level of interconnection has therefore raised the issue of how efficient development of the network as a whole can be co-ordinated across the NEM, while relying principally on regional bodies for planning and investment.

The NEM has gone through three principal stages in its treatment of the co-ordination task. The first stage was to treat the co-ordination task as principally applying to inter-connectors between regions, and to establish separate decision making processes and institutional structures for inter-connector investments. The second stage was to rely on delegated decision making, with obligations to undertake that decision making with regard to wider impacts in the NEM. The third stage has been to combine this with a gradually increasing role for national transmission planning over and above the planning conducted by TNSPs.

Each of these stages is described below.

5.1 Market Start

From the start of the NEM to March 2002 the National Electricity Code dealt with the need for co-ordination by distinguishing between intra and inter-regional transmission planning and development. This was combined with separate institutional structures and separate decision making criteria for inter-regional investments.

TNSPs were required to conduct an annual planning review. This APR examined the adequacy of the transmission network in their region over a ten year period. Each TNSP was responsible for intra-regional augmentations in their area, subject to the technical requirements of the Code. It was unclear whether the Regulatory Test (described in section 6.4) applied to their decisions on intra-regional investments.

An Inter-regional Planning Committee (IRPC) was responsible for assessing the technical and economic merit of proposed inter-regional augmentations. The IRPC included representatives of NEMMCO and the jurisdictional planning bodies.

The IRPC had to approve that proposed inter-regional augmentations satisfied the Regulatory Test before they could be included in a TNSP's regulated asset base. The Code did not define "inter-regional augmentations".

If the IRPC approved an inter-regional augmentation, then its costs could be added to the TNSP's regulatory asset base. It was unclear from the Code whether the amount to be included in the RAB was the amount specified in the Regulatory Test, or the actual cost of the project that was actually developed.

This framework for reviewing and approving inter-regional augmentations was applied to two major investments, SNOVIC and SANI.

SNOVIC was a small project ($20m) that involved substantial increases in the capacity of existing transmission capacity between Victoria and the Snowy Hydro. The project's expected benefits (deferral of generation investment) substantially exceeded its costs, and the project had support by all state governments.

SANI was a highly controversial interconnection between New South Wales and South Australia. The Regulatory Test for this project was undertaken by NEMMCO, who assessed that the project passed the Regulatory Test. This was supported by the Governments of New South Wales and South Australia, but opposed by Transenergie (whose Murraylink DC interconnector would be stranded if the investment proceeded) and by some other market participants.

The Regulatory Test application by NEMMCO to SANI was tested in the National Electricity Tribunal and the NET's decision was subsequently rejected in certain areas by the Victorian Supreme Court. The project was ultimately withdrawn by its proponent, TransGrid.

5.2 NDR Code Changes

The Network and Distributed Resources (NDR) Code Change package in March 2002 substantially changed transmission planning arrangements in the NEM. The NDR Code Change made TNSPs responsible for planning all regulated transmission investment. This was combined with obligations on how they conducted that planning, and with measures to ensure information was provided to market participants.

The NDR Code Change removed the NEMMCO/IRPC responsibility for applying the regulatory test to proposed investments in inter-connectors. In authorising the NDR code changes, the ACCC commented that

> *"The Commission supports the applicant's proposal that TNSPs should have prime responsibility for the planning and augmentation of networks as they are accountable for network performance levels. These accountabilities arise from the reliability standards contained in Schedule 5.1 of the Code, various State imposed standards, and duty of care obligations under common law to the extent that it applies[11]."*

Following these changes there was no formal obligation on any entity to develop or oversee inter-connectors. However, the IRPC was required to publish an Annual Interconnector Review. The AIR was required to assess the need for inter-regional augmentations and to provide information on options for inter-regional augmentation.

The IRPC was also required to define when one TNSP's transmission plans are likely to have a material impact on other TNSPs, and to produce a technical augmentation report on request by a TNSP, if TNSPs were unable to resolve differences relating to proposed interconnector developments.

[11] ACCC (2002) Determination: Network and Distributed Resources code changes.

The augmentation technical reports produced by the IRPC in respect of investments that could have impacts in multiple regions were to cover:

- the performance requirements for the equipment to be connected
- the extent and cost of augmentations and changes to all affected transmission networks, and
- the possible material effect of the new connection on the network power transfer capability including that of other transmission networks.

The NDR Code changes delegated planning to regional TNSPs. This was combined with amendments to the Code to require TNSPs to provide a detailed description of all reasonable alternatives to proposed large network assets, including but not limited to inter-regional investments, alternatives in other regions, demand-side options and generation options[12]. The obligation to consider inter-regional investments and alternatives in other regions was a new obligation, designed to ensure that TNSPs take a NEM-wide perspective to planning.

The NDR Code changes also introduced information provision mechanisms that were intended to encourage co-ordination:

- TNSPs were required to publish the results of their annual planning reviews in the form of an Annual Planning Report. The information to be provided in the APRs was established in the Rules and includes data on expected demand growth, new connection points, forecast transmission constraints, and cost and transmission system information for proposed augmentations.
- TNSPs were required to apply the Regulatory Test to all proposed new network assets. This was combined with requirements for information disclosure and consultation. These requirements varied depending on whether the proposed investment was a small network asset or a large network asset.
- Any interested party could dispute the TNSPs economic assessment of new large network asset proposals (including the network alternatives considered, their relative ranking, and the basis on which the TNSP has assessed that the proposed option satisfies the regulatory test).

The NDR Code change broke the link that had existed between the IRPC's conduct of the Regulatory Test and the determination of the regulated asset base for inter-connector investments. There was no previous link between the Regulatory Test and the regulated asset base for other investment.

5.3 Annual National Transmission Statement

The accountability for investment and structure for co-ordination has been largely unchanged since the NDR Code changes in March 2002. TNSPs remain accountable for meeting their obligations, as defined in the Code and at jurisdictional level. They also

[12] ACCC Draft Determination, 20 August 2001

remain accountable for conducting their planning with regard to the impact on the national network.

The MCE undertook a review of the institutional and regulatory framework for transmission in 2003. Following this review, it was agreed to establish an Annual National Transmission Statement (ANTS).

The main purpose of the ANTS is to identify national transmission flow path augmentation opportunities, including a cost/benefit assessment of possible augmentations. The ANTS includes a review of forecast constraints on NTFPs; and options that, in NEMMCO's reasonable opinion, are technically capable of relieving those forecast constraints. The ANTS is not a national transmission investment analysis. It focuses only on potential investments whose "market benefits" (lower losses, more efficient dispatch, improved reliability, deferred generation investment) exceed expected costs. The ANTS represents the impact of routine and committed network augmentations (including those justified to meet reliability standards) when assessing market benefits of proposed augmentations. Only augmentation proposals put forward by TNSP/Jurisdictional Planning Bodies are assessed.

The first ANTS was published in 2004, and it has been published annually since then. The most significant changes in the development of the ANTS have been as follows:

- From 2005 onwards, the benefits of transmission augmentation were quantified in dollars. The 2004 ANTS – which was essentially re-badged work undertaken by the Annual Interconnector Review – had only quantified benefits of investment in terms of network utilisation.
- The 2005 ANTS included only scoping studies - which calculate market benefits from relieving congestion and use an approximate technique to allocate this market benefits to flow paths connecting regional reference nodes. The cost benefit assessment was approximate as it compared the allocated portion of the market benefit of removing all congestion against the costs of the conceptual augmentations which only removes some of the congestion on those flow paths.
- After publication of the 2005 ANTS, a supplementary report was produced containing verification studies. This second set of studies modelled scenarios with individual augmentations proceeding to more accurately quantify the market benefits delivered by the augmentations and verify whether they exceed their expected cost.
- From 2006 onwards both sets of studies have been incorporated in the ANTS. The scoping studies filter the potential augmentation options identifying those worthy of more detailed examination via the verification studies. The verification studies allow the market benefits of individual augmentations to be assessed.

The level of rigour in the preparation of the Annual National Transmission Statement has increased over time. NEMMCO has invested in its ability to perform increasingly sophisticated analyses of the transmission system and now has 4 full-time positions focussed on the ANTS preparation assisted by IRPC working groups.

However, notwithstanding the increasing resources allocated to the production of the ANTS, its value as a national planning tool has been questioned by NEMMCO, TNSPs and other interested parties. NEMMCO's main concerns relate to the reliance on conceptual augmentation proposals put forward by TNSPs, which are often developed inconsistently across the NEM. NEMMCO is also concerned that these options may not form an optimal package of investments when combined with augmentations being progressed by TNSPs to deliver mandated obligations within each jurisdiction.

Additionally, the ANTS only identifies the next round of augmentations worthy of further analysis and, therefore, does not result in a consolidated national transmission plan.

5.4 Energy Reform Implementation Group

The changes outlined above have resulted in a situation where investment decisions are delegated to TNSPs. This is combined with obligations on how they make investment decisions, and with the independent provision of information to the market on the national transmission system by NEMMCO.

The Energy Reform Implementation Group concluded that there would be benefits from better co-ordinated development of the national grid. It considered two options for achieving those benefits: a single national procurement body for the national grid, and a national transmission planner. It concluded that establishment of a national planner was the most appropriate response.

ERIG concluded that the National Transmission Planner would maintain the current accountabilities of TNSPs for investment and operating performance. It would also provide a focus for national development of the transmission system as a whole which is not currently being delivered.

6 Regulation

6.1 Market Network Service Providers

When the Code was first authorised it indicated that rules for unregulated transmission inter-connectors would be established by NECA through the Code change process.

NECA subsequently developed provisions in the Code for market network service providers (MNSPs). These Code changes allowed MNSPs to be supported by the revenue stream from trading electricity between two regions. The Code provisions also allowed for MNSPs to convert to regulated status, at the discretion of the regulator.

It was considered that there could be competition between regulated and unregulated investments. The Regulatory Test included an 18 month delay from the first identification of the need for a project, before new inter-connectors could be deemed to pass the Regulatory Test. The intention was to avoid regulated investments pre-empting unregulated investments.

Three investments proceeded under these Code provisions:

- Directlink is a 180 MW DC link between New South Wales and Queensland. Directlink started operations in 2000. The owner applied for conversion to regulatory status in 2005.

- Murraylink is a 220 MW DC link between South Australia and Victoria. Murray link started operations in October 2002 and immediately applied to convert to regulated status

- Basslink is a 600 MW DC link between Tasmania and Victoria. Basslink started operations in 2006. Basslink has not applied to convert to regulated status. Basslink was owned by National Grid. It was sold to CitySpring, a Singapore company, in August 2007.

The remainder of this section focuses on the regulation applying to TNSPs.

6.2 Regulatory Principles

The Australian Competition and Consumer Commission (ACCC) assumed responsibility for the regulation of transmission revenues in the NEM on a progressive basis from 1 July 1999. This responsibility was transferred to the Australian Energy Regulator (AER) from 1 July 2005.

The National Electricity Code set out the general principles and objectives of the regulatory regime to apply to transmission revenues. The ACCC subsequently developed regulatory principles which set out in greater detail how regulation would be applied. A draft statement of principles for the regulation of transmission revenues was issued in May 1999. A revised draft statement was issued in August 2004. A statement of regulatory principles was issued in December 2004.

The changes in the regulatory framework at these different stages is discussed below, and summarised in Table 4.

The May 1999 Draft Regulatory Principles (DRP) outlined the initial regulatory framework. The framework set out in the DRP was not a firm ex-ante cap. The DRP stated:

> *"The Commission may review the prudency of large capital expenditures and may seek reassurance that the TNSP has complied with the requirements of Clause5.6 of the NEC. Ultimately the TNSP is responsible for the capex it undertakes and will be subject to the sanction of periodic re-optimisation."*[13]

The Statement of Regulatory Principles in December 2004 removed this optimisation risk. The value of the regulatory asset base at the start of the period incorporated the depreciated value of actual expenditure during the regulatory period.

This was combined with the introduction of provision for uncertain projects which could have a material impact on capital expenditure during the regulatory period. Additional capital expenditure could be provided for the period, subject to the provisions for contingent projects being met. Further protection was provided to TNSPs by provision to re-open the cap within the period if there were one-off exogenous shocks.

Aspects of the detailed operation of the contingent project's regime were modified by the AEMC. The detail of these changes are described on page 57 of the AEMC's 16 November 2006 Rule Determination.

Table 4 tracks the development of revenue cap regulation

Table 4: Revenue cap regulation in the NEM

	Draft Statement of Regulatory Principles (DRP): 1999 to July 2004.	**Statement of Regulatory Principles (SRP): Since December 2004.**	**AEMC changes (took effect from January 2007)**
Operating expenditure incentives	Ex-ante target expenditure allowance for each year of revenue control. Starting value in year 6 has no defined relationship to historic opex in previous regulatory period.	Ex-ante target expenditure allowance for each year of revenue control with carry-forward mechanism to ensure constant power of incentive (proportion of savings to be retained by firm) over the regulatory period. Starting value in year 6 has no defined relationship to historic expenditure in previous regulatory period, but AER will take account of historic expenditure. Provision for pass-through of some costs including insurance costs, some taxes and other costs deemed to be outside the TNSP's control.	Unchanged, although AER instructed to re-examine carry-forward mechanism.
Capital expenditure incentives	At the end of the regulatory period, capital expenditure during the	Value of asset base at the end of the regulatory period is based on depreciated value of actual expenditure	Similar to SRP but some aspect of design of contingent project

[13] ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, page 55

	period is subject to ex-post prudency assessment to determine whether it should be included in regulated asset base. Alternatively, the value of the asset base could be periodically revalued using depreciated optimised replacement cost i.e. without regard to historic expenditure.	during the regulatory period. This provides progressively weaker incentives over the course of the regulatory period ranging from around 35 cents in the dollar in the first year of the period, to 3 cents in the dollar in the last year of the regulatory period. In addition, provision was made for excluded projects (later renamed contingent projects) whereby additional capital expenditure could be approved during the regulatory period. Provision made to re-open cap during the regulatory period if there were on-off exogenous shocks.	mechanism changed. Re-opener mechanism similar to SRP but detailed application different.
Determination of regulated asset base	Asset base subject to periodic revaluation or based on the roll-forward of historic depreciated expenditure.	Opening asset base at start of regulatory period rolled forward to end of regulatory after adjusting for CPI and depreciation. Excluding arrangements for contingent projects, the value of actual expenditure during the period is calculated based on the depreciated value of actual cash expenditure during each year of the period.	As before.

The arrangements described in Table 3 are applicable to all TNSPs other than VENCorp. Augmentation investments planned by VENCorp are not subject to regulatory incentives. For SP AusNet, the predominant owner of transmission assets in Victoria, regulatory incentives are in place for capex and opex associated with asset replacement, maintenance and operations.

6.3 Service standards and service incentive schemes

The original Code allowed the ACCC to determine standards of service that TNSPs must provide through its regulation of transmission revenues. The ACCC included performance measures in setting the 2003 revenue cap for the transmission networks in South Australia, and the 2003 revenue cap for the transmission networks in Victoria.

The incentives in South Australia were designed to be ±1% of the revenue cap. In Victoria, VENCorp already has incentives under its agreement with SPI PowerNet. The ACCC therefore set a lower incentive (±0.5%), which led to a greater variability in revenue (±2.5%) when combined with the VENCorp incentives.

In May 2003, the ACCC released draft service standards guidelines setting out core performance measures it will incorporate in future revenue cap decisions. These draft guidelines were based upon a report by SKM, and drew on comments by market participants on that report. Under the service standard performance scheme, the ACCC proposed to provide financial incentives of up to ±1% of a TNSPs revenue cap for exceeding or failing to meet service standards for the following performance measures:

- Transmission circuit availability
- Average outage duration;
- Frequency of 'off-supply' events;
- Hours per annum of binding inter-regional constraints; and
- Hours per annum of binding intra-regional constraints

The ACCC initially aimed to develop a performance incentive scheme that included performance measures linking market-impact to TNSP behaviour. The ACCC was unable to fulfil this objective due to difficulties in establishing the market impact caused by the TNSP action (or inaction)[14].

This approach was reflected in the ACCC's Statement of Regulatory Principles in December 2004.

As noted above, amendments to the Rules following the AEMC's Chapter 6 review required the AER to develop incentive for TNSPs to improve and maintain those elements of the transmission system that are most important to determining spot prices. Incentive should result in maximum adjustment of +/- 5% of annual maximum allowed revenue.

In August 2007 the AER published a Service Target Performance Incentive Scheme, consistent with Clause 6A.7.4 of the NER. The scheme defines performance measures against transmission circuit availability, loss of supply event frequency and average outage duration. It also establishes revenue adjustments which would enable a variation of up to 1% in revenues to reflect performance against these measures.

This scheme applies to all TNSPs, including SP AusNet. It does not apply to VENCorp.

The AER has recently released a paper discussing options for the introduction of an incentive scheme that may be related to the market impact of transmission constraints. This incentive would supplement the existing service incentive scheme.

6.4 Regulatory Test

The application of the Regulatory Test is a requirement under Chapter 6 of the Rules. It consists of a least cost test for investments to meet mandatory obligations, and a cost benefit test for other investments.

Prior to the NDR Code Changes, the Code included a direct relationship between the outcome of the Regulatory Test and the calculation of regulated assets (and hence revenues) for inter-connector investments. Prior to the NDR Code changes, inter-connector assets could only be added to the regulatory asset base if they satisfied the Regulatory Test. It was unclear whether the amount to be added to the regulatory asset base was the amount specified in the Regulatory Test or the actual cost of the project.

The NDR Code changes in March 2002 removed this distinction between inter-connectors and other assets. It introduced a new distinction between large and small projects. The

[14] ACCC (2003) Statement of Principles for the Regulation of Transmission Revenues. Service Standards Guidelines. Draft Decision, 28 May.

Electricity Rules requires TNSPs to apply the Regulatory Test to all augmentation projects greater than $1m, with a more comprehensive test for projects greater than $10m.

The amendment to the National Electricity Rules following the Chapter 6 review, and the Statement of Regulatory Principles have both removed any link between the Regulatory Test and the opening Regulatory Asset Base at the start of a regulatory period. The 2005 AEMC report on the Regulatory Test concluded that actual expenditure on any project that passes the Regulatory Test will be added to the Regulatory Asset Base at the start of the first regulatory year of the next regulatory control period. This is also true of expenditure which does not pass the Regulatory Test; and expenditure to which the Regulatory Test does not apply.

The Electricity Rules suggests that the AER must accept forecast capital expenditure proposed by the TNSP as part of its submission to a regulatory review so long as the Regulatory Test is satisfied and the AER is satisfied that the forecast is reasonable. However since the bulk of future expenditure by the TNSP (including expenditure on augmentation projects) relates to projects many years into the future, the Regulatory Test will not yet have been undertaken. Furthermore, the AER's ability to reject a TNSP's application because the AER considers it to be unreasonable, means that the Regulatory Test has no definitive role to play even in respect of projects that may commence construction at the start of the regulatory period.