Centre for Energy and
Environmental Markets

Cluster Project 4 – Robust energy policy frameworks for investment in the future grid: Deliverable Report 1b – Part A: Frameworks for transmission locational and sizing decisions

by

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List of Acronyms

Acronym	Definition
AC	Alternating current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Electricity Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
CEC	Clean Energy Council
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	Direct current
ERIG	Energy Reform Implementation Group
LRIC	Long Run Incremental Costing
MCE	Ministerial Council on Energy
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NTNDP	National Transmission Network Development Plan
OFA	Optional Firm Access
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
SCER	Standing Committee on Energy and Resources
SENE	Scale Efficient Network Extension
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider

Introduction

CSIRO Cluster Project Background

The broad objectives of this CSIRO Cluster project are:

- The development and application of an interdisciplinary policy assessment framework to better understand and assess existing and proposed policy options for driving appropriate investment in the electricity industry given its unique technical(e.g. system security), economic (e.g. network investment) and wider social (e.g. affordability imperatives) characteristics. A key focus is on the interactions between these policies.
- Development of a high level (ie. focused on broader policy relevant perspectives rather than just detailed technical and economic modelling) quantitative policy analysis tool for exploring the potential impact of different policies on the most economic future electricity generation portfolios.
- Application of this policy assessment framework and quantitative policy analysis tool to develop high level insights on coherent and comprehensive climate and energy policy frameworks to drive appropriate investment in the future grid. A particular focus is on maximising the synergies and minimising possible conflicts between multiple policy instruments such as might be seen with renewable energy targets and network investment drivers.

Scope of this report

This report represents the second agreed milestone for the project: a literature review on Australian and international policy options.

The issue of policy frameworks for future grids is complex and multifaceted. This means that there is a correspondingly vast array of relevant literature. Given the project objectives we have elected to focus our efforts in this literature review on the following areas:

- ***Transmission networks*** – The review will target transmission level networks, rather than distribution level networks. There are many significant issues relating to the evolution of distribution networks in future, but these are quite different in nature and deserving of independent analysis focused solely in this area.
- ***National Electricity Market*** – This review will focus on the National Electricity Market (NEM), which serves around 80% of the electrical load in Australia. The regulatory frameworks for grid planning and investment in Western Australia, the Northern Territory, and off-grid locations will not be dealt with in this review.

- ***Drivers for asset location*** – The review will focus on the factors that influence the ways in which locational decisions are made, both for new transmission assets and new generation investments (since these are highly inter-dependent).
- ***Drivers for asset size*** – The review will focus on the factors that influence the ways in which transmission augmentation sizing decisions are made. This includes consideration of the scale efficient sizing of connection assets for remote renewable projects, as well as optimal levels of congestion and appropriate incentives for sizing of transmission assets related to variable renewable generation.

The following questions have been used to guide the review:

The Australian experience to date

1) What is the current approach to transmission investment in Australia?
2) Where does it work well, and where has it failed?
3) What reforms are under consideration or implementation, and what are the motivations for that reform?
4) What new challenges may arise in future, and is the current approach likely to successfully handle those new challenges?

International experiences

1) What alternative models have been applied in other nations?
2) How have those models been successful, and where did they fail?
3) What reforms are under consideration or implementation, and what are the motivations for that reform?
4) What are the key learnings for Australia?
5) Are there any factors that make the Australian context unique, such that models applied internationally may work differently in Australia?

Structure of this report

This report is organised in two parts. Part A explores the general regulatory and market frameworks that drive decisions on transmission location and size. General theory from international research is outlined, followed by an outline of the Australian framework that is applied at present. Current reforms and processes in progress in Australia are then outlined, leading to a summary of issues for further consideration in future work.

Part B of the report considers the special case of connection of remote renewable resources to the grid. The Australian experience to date is outlined, including the 2010 review on Scale Efficient Network Expansion (SENEs). This is compared with a range of international models. Part B concludes with a description of the implications of current reforms, and recommendations of issues for further consideration.

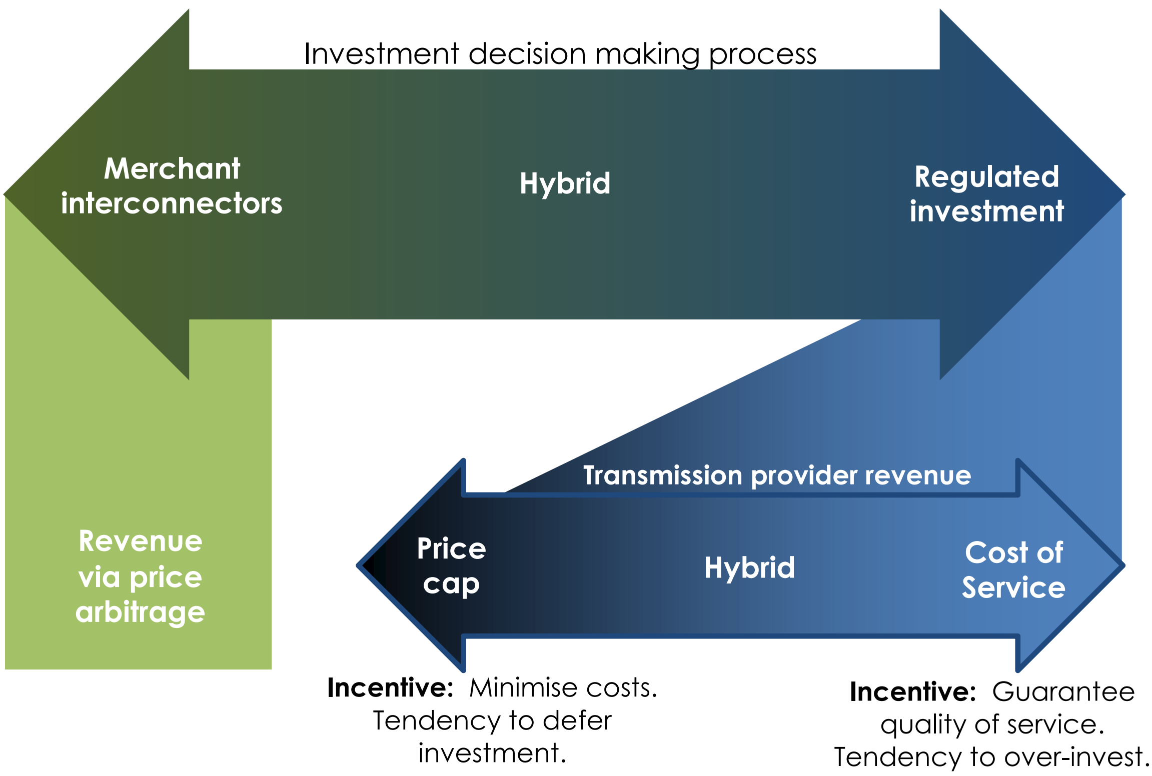
Frameworks for transmission locational and sizing decisions

General Theory

A range of transmission investment frameworks have been implemented in international markets. Each has unique merits and disadvantages. Transmission investment frameworks are innately challenging because they resist traditional competitive market models; transmission infrastructure is large, lumpy, capital intensive, and many would argue naturally monopolistic (since it is generally inefficient to establish multiple network lines between the same locations).

The discussion below follows the characterisation structure proposed by Chatzivasileiadis (Chatzivasileiadis, 2012). As illustrated in Figure 1, transmission investment frameworks are characterised on a spectrum ranging from "merchant" investments through to "regulated" investments, with a range of hybrid schemes in between. Regulated regimes can be further characterised by the way in which transmission operators earn revenue, ranging from "price cap" schemes to "cost of service" schemes, each described in more detail below.

Figure 1 – Frameworks for transmission investment



Source: Based upon (Chatzivasileiadis, 2012)

1.1.1 *Regulated investment*

Under a regulated approach, proposed investment is typically subject to a cost-benefit analysis supervised by an independent authority (generally the market or transmission system regulator). The regulator would also examine whether alternative investment options might better maximise social welfare. The optimal investment option is identified, and can then be constructed either by the incumbent transmission owner/operator, or perhaps by an independent party.

Revenue models

As illustrated in Figure 1, regulated investment approaches can be further characterised by the way in which the revenues of the transmission provider are determined.

Some markets apply a "cost of service" mechanism, whereby the transmission owner is compensated for costs incurred (Joskow P. , 2006). Under this approach the transmission provider is generally incentivised to maximise the quality of service and minimise power interruptions, while there is an absence of incentives for investment efficiency. This can promote over investment in the network, leading to customer prices that are higher than optimal. The cost-benefit analysis performed during the regulatory process should prevent large over-investment, but information asymmetry between the regulator and usually means that regulation is imperfect.

At the opposite end of the spectrum are "price cap" regimes, where a fixed price (or total revenue cap) is determined at the beginning of a regulatory period. This is generally calculated through a process intended to determine economically efficient revenue requirements. The transmission operator is then allowed to charge that price to customers (or collect fees up to that revenue cap), and can increase profitability by operating and investing in such a way as to reduce costs. This creates incentives for the transmission operator to explore more efficient options (Joskow P. , 2006). However, although costs may be lower, customers may not receive the benefit (with additional profits being retained by the transmission operator).

Furthermore, price cap schemes can lead to poor service quality since the transmission operator is incentivised to minimise and defer expenditure. An obvious mechanism to ameliorate this effect is implementation of mandatory service quality and reliability standards. These can be defined as a 'hard' minimum standard, or in the form of performance-based incentives (such as penalties based upon the duration and frequency of customer outages).

The application of reliability standards can be effective in distribution networks, but is more problematic when applied to transmission networks. Transmission networks typically experience outages rarely, but failures are extreme when they do occur. Problems may lie latent for extended periods, until a number of coincident factors combine to produce a cascading failure affecting large numbers of customers for a significant duration. This makes it challenging to define adequate reliability indicators upon which to base an incentive-based reliability scheme (Productivity Commission, 2013). Thus, the application of a price cap incentive approach to transmission networks can incentivise transmission providers to defer investment, gradually putting the system into increasing risk of catastrophic failure (Chatzivasileiadis, 2012). An additional complexity is the process by which future regulatory determinations are made which will typically factor in reduced network investment.

Hybrid schemes are also possible, with the price charged by the regulated transmission provider being partially dependent upon actual costs, and partially fixed at the start of the regulatory period (Joskow P. , 2006).

Merits and disadvantages

Regulated frameworks are favoured in many markets because they offer a degree of certainty that sufficient investment will occur. Although investment may not be optimally efficient, customers are unlikely to experience extremes of under or over investment.

Regulated frameworks suffer the obvious disadvantage that fully informed regulators do not exist, so transmission providers may be able to utilise their position of superior information to derive additional economic rents (Chatzivasileiadis, 2012). Furthermore, regulated frameworks can be prone to political interference, where there is a political preference for investments of a certain type to proceed.

1.1.2 Merchant interconnector regimes

Under a merchant investment model, independent parties identify opportunities to invest in additional transmission capacity. The merchant investor is entirely responsible for the decision on when and where to install new network.

In return, the investor receives property rights that allow them to collect congestion rents. These congestion rents are equal to the difference in energy prices between the nodes or regions that the transmission asset physically connects (Productivity Commission, 2013). Essentially, the transmission owner earns revenue via price arbitrage by transporting electricity between two differently priced regions.

Price differentials are an essential component of a merchant interconnector regime, so it relies upon the presence of an energy market featuring nodal pricing, or would only apply to interconnectors between differently priced regions (in a regional pricing market such as the NEM).

Under this model the merchant investor accepts (and is responsible for managing) the risks associated with their investment. In many cases a long term agreement is negotiated with electricity market participants (loads and generators) in the regions to be connected, providing a firm revenue stream over many years to support the large investment that is generally required.

Merits and disadvantages

Some researchers are strong proponents of merchant interconnector frameworks. They argue that this mechanism challenges the conventional wisdom that transmission networks are a 'natural monopoly', and propose that merchant interconnector models could create an effective and competitive market for transmission, leading to optimal investment (Hogan W. , 1992; Littlechild S. , 2004; Littlechild S. , 2011; Hogan W. W., 2003; Littlechild S. , 2003).

Other authors have argued that although merchant investment models may be appealing in theory, they are unlikely to be appropriate in reality (Brunekreeft G. , 2005; Joskow & Tirole, 2005). Effective merchant interconnector models would require highly competitive markets with low barriers to entry, while electricity markets typically feature lumpy investments and issues related to market power and strategic behaviour (Joskow & Tirole, 2005). The authors suggest that merchant investment could complement regulated transmission, but is unlikely to be able to effectively replace it.

There can be perverse incentives for merchant investors to undersize their transmission asset, or to artificially limit flows on the interconnector (Joskow & Tirole, 2005). Merchant investors may well maximize revenues by limiting the flow on their transmission asset to retain a price difference between the regions. This can create inefficient outcomes and elevate prices for consumers. Brunekreeft suggests that a centralised "bidding" process could mitigate this problem by identifying the corridor to be augmented and calling for tenders, with the bid proposing the highest capacity being selected to proceed (Brunekreeft G. , 2005). However, this re-introduces elements of central planning.

Merchant transmission investment models may also lead to imperfect co-optimisation of generation and transmission investment. Generation and transmission are often in competition with each other, with investment in one being able to displace investment in the other in many circumstances. At other times of course, generation and network investment may be complementary in terms of allowing additional supply to get to market.

Generation projects typically feature shorter lead times for licensing, corridor procurement and construction, which means that generation projects can "pre-empt" the need for transmission augmentation (Joskow & Tirole, 2005). When sufficient new generation capacity is installed in the high priced region the price will fall, removing the arbitrage opportunity for the merchant transmission provider. This effect can lead to a potentially inefficient preference for generation investment above transmission investment.

The in ability to precisely control flows over AC power lines can also inhibit efficient network investment under a merchant model, due to the technical limitations around controlling sharing of flows across lines that may be owned by different parties. Loopflows in meshed networks can also be problematic. DC power lines can alleviate these issues by allowing full controllability (Brunekreeft G. , 2004).

Merchant investment regimes do remove the need for a central authority (such as a regulator) to conduct cost-benefit analyses; merchant investors would undertake this process internally. Furthermore, the party exposed to investment risk (the merchant investor) is the party best placed to manage that risk.

The merchant investment model can only be applied in markets with nodal or regional pricing (Joskow & Tirole, 2005). These markets have their own challenges, including increased opportunities for market power (a discussion of these issues is beyond the scope of this analysis). Exertion of market power by generators at the nodes that a merchant transmission line connects can lead to over or under investment in the network. Where generators own a significant share of the interconnector, they may be able to exert market power to maximise profits from the transmission asset (Brunekreeft G. , 2005).

1.1.3 Hybrid

Hybrid schemes attempt to combine the merits of both merchant and regulated approaches. One possible hybrid approach is for part of the capacity to be subject to regulation, with the remainder generating profit from trade.

Strong regulatory mechanisms combined with opportunities for merchant investment appear to offer many attractive features (Joskow & Tirole, 2005; Brunekreeft G. , 2004). Nevertheless, the design of effective transmission investment frameworks remains challenging, and controversial.

The current framework in Australia

Australia applies a hybrid approach to transmission investment. The majority of investment is regulated with a combination of price cap and cost of service approaches. Additional merchant investment between pricing regions is also permissible.

1.1.4 Economic Regulation of TNSPs

The economic regulation of Transmission Network Service Providers (TNSPs) is described in chapter 6A of the National Electricity Rules. Within this framework, there are three different sets of arrangements currently in place (FTI Consulting, 2013):

1. ***South Australia*** - a private TNSP makes transmission decision investments. Regulatory oversight is provided by the Australian Energy Regulator (AER). AEMO advises the AER as to the appropriateness of the TNSP's revenue proposal.
2. ***NSW, QLD and TAS*** - a state-owned TNSP makes transmission decision investments. Regulatory oversight is provided by the AER. There is no specific role for AEMO.
3. ***Victoria*** - AEMO makes investment decisions and "procures" new investment. In practice the new investment is almost always procured from the incumbent (privately owned) TNSP, SP AusNet, which owns and maintains the network. Funding for projects is only allocated once a project has been confirmed.

Every five years, TNSPs in SA, NSW, QLD and TAS prepare a forecast of their expected expenditure to meet growth and changing demands on their network. The AER considers these applications and makes revenue determinations. This process involves the AER assessing the revenue requirements needed to cover efficient costs and provide a commercial return on capital investment (Productivity Commission, 2013).

The revenue determination sets a 'pool' of allowed revenue for the TNSP. The TNSP is not required to build any particular project, but is required to meet specified reliability standards. There are also additional incentive payments and penalties that drive TNSP performance. For example, the Service Target Performance Incentive Scheme (STPIS) provides payments for network reliability.

TNSPs that provide network services at a lower cost than forecast keep the resulting margin (the difference between forecast and actual costs) within the five year regulatory period. This creates an incentive for TNSPs to meet the reliability standards at least cost, although decision making is invariably also shaped by its potential implications for their next determination. After the five year regulatory period any new assets installed become part of the Regulated Asset Base (RAB), and the network revenue is reset to incorporate actual expenditure levels from the previous period and updated expenditure forecasts for the upcoming period, in effect returning a proportion of the savings to consumers in the form of lower prices (Productivity Commission, 2013).

TNSPs recover the revenue allowances from electricity customers through a variety of 'control mechanisms', including price caps and revenue caps.

1.1.5 Reliability standards

The reliability standards are key driver of network investment. Higher standards necessitate higher investment, resulting in higher costs for consumers.

At present, each jurisdiction in the NEM has a separate planning framework for setting reliability standards, reflecting the historical development of the network. Previous attempts to develop a national framework for transmission reliability have been hampered by disagreement on the scope of jurisdictions abilities to set their own standards (AEMC, 2008). A process is currently underway to attempt to establish a common national framework for reliability standards (described further in section 1.1.12). The Productivity Commission has recommended that this national framework be based upon the value that customers place on network reliability, rather than being defined by Governments or political processes (Productivity Commission, 2013).

1.1.6 Regulatory Investment Test for Transmission

The Regulatory Investment Test for Transmission (RIT-T) is another, only recently introduced, mechanism that is applied in the NEM to promote efficient network investment. The RIT-T is applied in parallel with the above-described regulatory and planning process, as illustrated in Figure 2.

The RIT-T is a cost-benefit analysis that is done before a potential network investment exceeding $5 million is undertaken. For projects between $5 and $38 million a 'streamlined' version of the RIT-T is conducted with lower consultation requirements. Projects above $38 million require a standard RIT-T (Productivity Commission, 2013).

The RIT-T aims to quantify the costs and benefits that accrue to those who consume, transport or generate electricity as a result of the new project, and to ensure that only projects with the highest net present value proceed. There are requirements that non-network options (such as demand management or generation investment) are considered, and an assessment made as to whether they would achieve a better cost-benefit outcome.

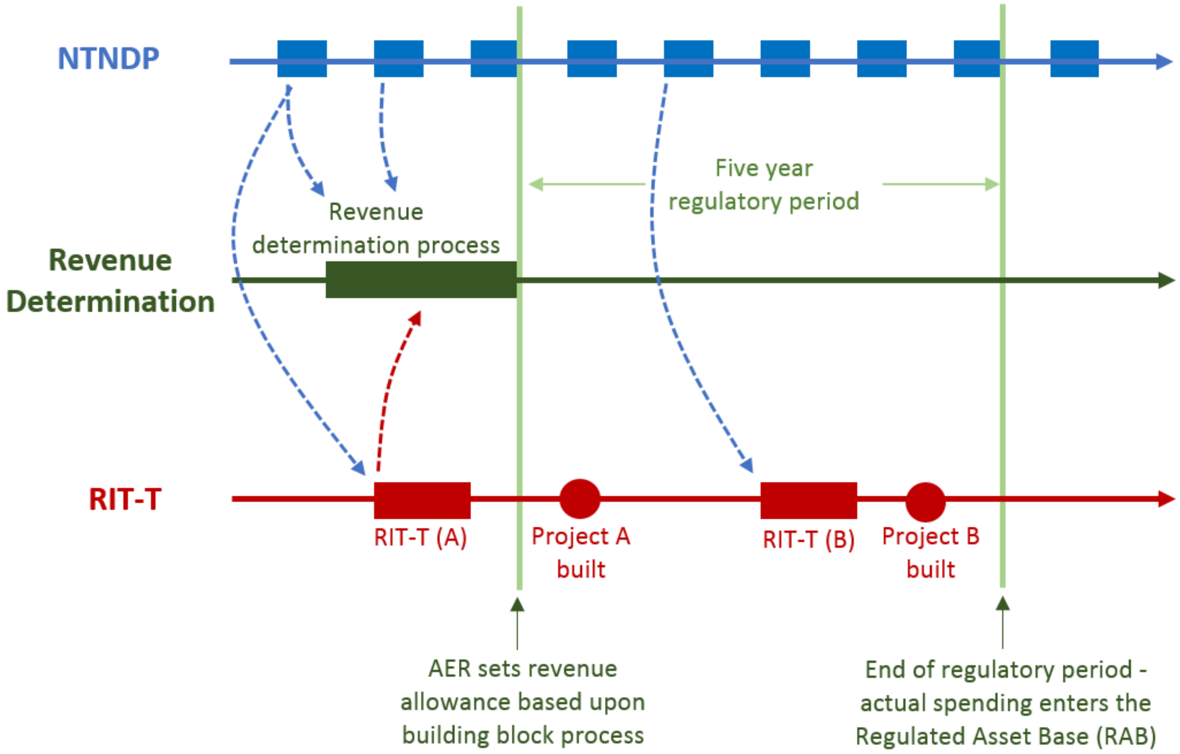


Figure 2 – The parallel processes involved in economic regulation and planning (applies to NEM states other than Victoria). Dotted lines illustrate information flows between processes. Source: Based upon Figure 16.1 in (Productivity Commission, 2013)

The RIT-T process begins with the party proposing the new investment publishing a Project Specification Consultation Report (PSCR). This document facilitates consultation from interested parties by describing the 'identified need' (reason for new investment), 'credible options' and technical requirements for non-network solutions. Interested parties can then raise alternatives that must be considered, or provide a rationale for the exclusion of certain options.

The TNSP then prepares the Project Assessment Draft Report (PADR), which includes calculating the expected costs and benefits associated with each option for a range of forecast scenarios, weighted by the probability that each scenario will occur. The possible costs and benefits that can be considered are given in Table 1.

Table 1: Costs and benefits assessed under the Regulatory Investment Test for Transmission

Costs	Benefits
• Construction • Operation and maintenance • Compliance with applicable laws, regulations and administrative requirements	• Changes in fuel consumption • Changes in voluntary load curtailment • Changes in involuntary load shedding • Changes in costs to parties other than TNSP • Differences in timing of investment • Changes in network losses • Changes in ancillary service costs • Competition benefits

Source: (AER, 2010)

The project with the highest, probability-weighted, net present value is chosen by the TNSP for development. An option that has a negative net economic benefit can still be chosen for implementation if it is needed to comply with a reliability requirement.

The RIT-T is undertaken by the local TNSP, or in the case of Victoria, by AEMO. The AER only plays a role in monitoring issues of process, and does not play an active role in approving the RIT-T outcomes. This means that the RIT-T process is more like a 'due diligence' process undertaken by the TNSP prior to investment (Productivity Commission, 2013).

Given that the RIT-T has no role in determining revenue, it must be considered as a part of the larger framework of network regulation. If other parts of the regulatory framework are working well and providing appropriate incentives to deliver an efficiently reliable, low cost network, the RIT-T would be less important. But if the regulatory system is providing weak incentives, the RIT-T plays a more important role in directing efficient investment (Productivity Commission, 2013).

The RIT-T also provides value by:

- Facilitating public involvement and transparency in major projects
- Ensuring that non-network solutions are considered.

The application of the RIT-T in Victoria tends to differ somewhat from other jurisdictions, because it is applied by AEMO (an independent party) rather than the local TNSP. This in effect creates an independent 'approval' process, changing the role and nature of the RIT-T. In addition, AEMO also conducts a broader cost-benefit analysis in the course of its own planning process, and applies probabilistic reliability standards, meaning that projects must pass a cost-benefit analysis (in contrast to the existing special treatment for reliability under the RIT-T) (Productivity Commission, 2013).

1.1.7 National Transmission Network Development Plan

AEMO is the National Transmission Planner, and in this role is responsible for the annual National Transmission Network Development Plan (NTNDP). The NTNDP provides an independent strategic plan offering nationally consistent information about transmission capabilities, congestion and investment options for a range of plausible market development scenarios (AEMC, 2013).

The intent of this document is to facilitate the efficient development of the national electricity network by considering potential transmission and generation investments. The plan takes a 25 year outlook and considers multiple future scenarios. The NTNDP involves a least-cost planning approach whereby the location of future generation is modelled as being located to minimise the total combined cost of new generation and transmission, with consideration of mandated reliability standards.

The NTNDP operates in parallel with the above described regulatory planning processes. It aims to provide a system-wide view of network planning, and should play an important role in identifying inter-regional interconnector augmentations that may be justified by changing market conditions. For example, potential market benefits associated with an upgrade of the Heywood interconnector were identified in the 2010 NTNDP, which led to a RIT-T being jointly undertaken by AEMO and ElectraNet (the transmission planning authorities in the regions involved).

1.1.8 Interconnector investment

Investment in interconnectors (connecting NEM regions) is managed via the RIT-T process. Typically, an interconnector project will be first identified as having a positive net benefit during the NTNDP. The transmission planners in the regions involved (the TNSPs and AEMO in Victoria) then collaborate to conduct the RIT-T process.

Interconnectors are not subject to reliability standards. This means that the RIT-T must demonstrate a positive net present value in order to proceed (that is, the project must be justified on market benefits grounds). This means that it can be easier for TNSPs to justify investment in intraregional transmission, potentially giving priority to these projects over interconnector augmentation (Productivity Commission, 2013).

1.1.9 Merchant interconnectors

Market participants may elect to invest in a merchant interconnector in the NEM. Investors would anticipate earning revenue by trading on the spot market (purchasing electricity in a lower priced region and selling it in a higher priced region), or by selling the rights to revenue traded across the interconnector (Productivity Commission, 2013). A merchant interconnector does not need to pass the RIT-T in order to be installed, since it is paid for by the investors that install it (costs are not recovered directly from consumers).

It was originally expected that merchant interconnector investment would be an important aspect of network development in the NEM, but this has not eventuated. Of the three merchant interconnectors that have been constructed, two have since converted to regulated status, and the third (Basslink) is arguably not a genuine merchant interconnector due to the unique commercial relationship with Hydro Tasmania. Further details are listed in Table 2.

Table 2: Merchant interconnectors in the NEM

Link name	Regions connected	Notes
Basslink	TAS - VIC	Rights to inter-regional revenues were assigned to the Tasmanian generator, Hydro Tasmania, for 25 years under the Basslink Services Agreement. This means that Basslink is shielded from commercial risks by receiving a flat fee from Hydro Tasmania.
Murraylink	SA - VIC	Converted to regulated status soon after commencing operations
Terranora (previously Directlink)	NSW - QLD	

Source: (Productivity Commission, 2013)

The lack of interest in investing in merchant interconnectors is likely related to the fact that regional price differences are too small to justify the large costs involved. Furthermore, the installation of a large interconnector erodes the price difference that does exist, further diminishing returns. Merchant interconnectors therefore have an incentive to either undersize their asset or artificially limit the amount of electricity they transport in order to maintain regional price differentials from which they derive their revenues.

Furthermore, experiences with the Murraylink interconnector may have deterred further merchant investment. In that case, soon after Murraylink was installed (on a merchant basis) the transmission provider (Transgrid) received permission to construct a regulated interconnector in parallel, decreasing Murraylink's revenue potential. This was considered a controversial decision (Littlechild S. , 2003; Brunekreeft G. , 2005).

The introduction of nodal pricing and transmission rights could increase interest in merchant interconnectors, but this would require fundamental changes to NEM design (Brunekreeft G. , 2004). The Optional Firm Access model proposed under the Transmission Frameworks Review represents a move in this direction (AEMC, 2013).

Reviews and reforms in progress

Transmission frameworks have been under review in Australia since the commencement of the restructuring process in Eastern Australia; a selection of the major transmission policy development processes are listed in Table 3.

Table 3: Transmission policy development in Australia

Year	Author	Review Name
1997	National Electricity Code Administrator (NECA)	Transmission and Distribution Pricing Review
1999	Australian Competition & Consumer Commission (ACCC)	National Electricity Code – Network Pricing Code Changes (response to NECA review)
2002	COAG 'Parer' review	Towards a Truly National and Efficient Energy Market – Transmission recommendations
2007	Energy Reform Implementation Group (ERIG) to COAG	Energy Reform – the way forward for Australia (Transmission)
2010 to 2013	Australian Energy Market Commission	Transmission Frameworks Review
2012 to 2013	Productivity Commission	Electricity Network Regulatory Frameworks
2013	Australian Energy Market Commission	Optional Firm Access – ongoing development and implementation

Source: (Camroux, 2013)

The latest review by the Australian Energy Market Commission (the Transmission Frameworks Review) has been particularly comprehensive, extending over the past three years. The recent Productivity Commission report on regulatory frameworks for electricity networks was also particularly detailed and comprehensive. The details of these most recent and most significant transmission reviews are summarised in the following sections.

1.1.10 AEMC - Transmission Frameworks Review

Background

In 2008 the MCE directed the AEMC to conduct the Review of Energy Market Frameworks in light of Climate Change Policies (AEMC, 2009). This review assessed whether energy market frameworks are sufficiently resilient to changes in behaviour that would result from the introduction of the carbon price and the expanded Renewable Energy Target (RET). The AEMC found that climate change policies will fundamentally change the utilisation of transmission networks over time, both between and within regions of the NEM, and that this would place stress on existing market frameworks. The Climate Change Policies review therefore recommended that further work be undertaken in relation to the efficient provision and utilisation of the transmission network (AEMC, 2009).

In response to this, in April 2010, the Ministerial Council on Energy (now the SCER) directed the AEMC to conduct a review of the arrangements for the provision and utilisation of electricity transmission services in the NEM (the Transmission Frameworks Review).

The Transmission Frameworks Review has only recently concluded, with publication of the final report in April 2013 (AEMC, 2013). Following several rounds of consultation, the AEMC has concluded that a 'piecemeal' approach to transmission framework reform is unlikely to yield positive results, and have therefore proposed the introduction of a fundamental change to the market via the Optional Firm Access (OFA) model. This would introduce a form of firm access rights for generators, changing the way market settlements occur during periods of congestion. Due to the scale of the market changes required the AEMC recommended that another year of detailed design and testing be conducted (commencing at the start of 2014) before the final decision to proceed with implementation. Implementation would then proceed over the following three years, involving progressing the necessary rule changes and organisational adjustments (AEMC, 2013).

The SCER has agreed to proceed with investigating detailed design and testing of the OFA model, subject to further work by officials on the preferred approach (to be concluded by end of July 2013) (SCER, 2013).

The Optional Firm Access Model

The OFA model would introduce the option for generators to purchase firm financial access rights. These rights provide generators with financial access to the regional reference price during system normal conditions. This is intended to provide greater certainty to generators, helping to underpin contracting (for example).

Under the OFA model, generators would have the option to purchase firm access from their TNSP. In exchange for a fee, the TNSP would be required to plan and operate the network to deliver that contracted level of firm access to that generator, to a prescribed standard of reliability. If a network constraint binds, the rules determining the physical dispatch would remain unchanged from the present system[1]. However, if a generator without firm access is dispatched ahead of a generator with firm access, "compensation" payments would be made, with the non-firm generator paying compensation to the firm generator (via AEMO).

The end result is that:

- Firm generators become relatively indifferent to whether they are physically dispatched or not when network constraints bind – they will receive profits equivalent to receiving the Regional Reference Price regardless.
- Non-firm generators will have to pay compensation payments when constraints bind, if they are dispatched ahead of a firm generator. However, they will never 'regret' being dispatched in any particular period, because their total payment (minus compensation payments) will always equal or exceed their bid price.

Access rights are firm, but not fixed, meaning that generators still do not have confidence of full access at all times. In particular, outside of system normal conditions access may be substantially reduced due to outages of transmission elements. Generators would also still need to carefully consider the risk of a unit

[1] However, the incentives faced by market participants would change in many circumstances, leading to different offers being made by generators, and therefore a different dispatch outcome.

forced outage at times of high prices when contracting. For unreliable generators this could be a much more significant source of uncertainty that inhibits contracting.

Incumbent generators would initially be allocated firm access. Later generators connecting to the market would negotiate a price to purchase firm access with the relevant TNSP. Pricing would be based upon a Long Run Incremental Costing (LRIC) methodology which calculates the additional cost to the TNSP of providing the requested quantity of firm access to that generator.

The AEMC identifies the key benefits of the OFA model as being (AEMC, 2013, p. 96):

1. ***Support for a deep and liquid contracts market*** – By providing:
    a. A mechanism for generators to obtain firm financial access that is not affected by congestion; and
    b. A mechanism for market participants to obtain inter-regional access, which should encourage contracting between generators and retailers in different regions.
2. ***Efficient investment in generation and transmission*** – By establishing:
    a. Transparent and cost-reflective locational signals for new generation investment through access pricing, encouraging co-optimisation of transmission and generation investment
    b. Greater market-led development of the transmission network, where generators procurement of firm access would fund and guide network expansion; and
    c. A new mechanism for the efficient expansion of inter-regional transmission capacity which would allow financially interested parties to internalize the costs and benefits of interconnector capacity
3. ***Efficient dispatch of generators*** – By reducing the current incentives on generators to engage in disorderly bidding. With the implementation of OFA, generators with firm access would be indifferent to physical dispatch, and generators without firm access would risk receiving their local price, which might be set by their own negative bids. Thus, in many circumstances disorderly bidding is projected to decrease under OFA (ROAM, 2013).
4. ***Efficient operation of transmission networks*** – By exposing TNSPs to some part of the market impact of transmission constraints

The OFA model represents a very significant change to the operation of the NEM, arguably the most significant since the introduction of the market. A range of costs and risks of implementing the OFA model have been identified, including (CEC, 2012):

- ***Implementation costs*** – This OFA model represents a dramatic change to NEM design, and will therefore carry substantial implementation costs. The AEMC has sought $5 million for detailed design and testing of the model over the coming year, with a further $15 million estimated to be required for the following implementation (AEMC, 2013). Further costs are likely to apply to other market participants in adjustments to the new regime.

- ***Complexity*** – The OFA model is extremely complex, with many areas requiring further design and analysis. Many of the remaining issues that will need to be resolved prior to implementation could be characterized as 'wicked problems', involving substantial complexity, a wide range of actors with differing incentives and information asymmetry. These problems are likely to be resistant to resolution.
- ***Transitional access arrangements risk barriers to exit*** – The proposed transitional arrangements would 'gift' the existing network to incumbent generators. Access would be scaled back over time to a 'residual level' which generators would retain for the duration of their 'economic life'. At present it is proposed that the 'economic life' of each generator would be determined prior to implementation of the OFA model based upon the individual characteristics of each generator. However, this is likely to be an extremely challenging negotiation process involving every existing generator, and will create strong incentives for rent seeking behavior. To avoid this it may be tempting to allow generators to retain residual access until they elect to retire, but this creates further difficulties. If generators retain access upon retirement (in perpetuity) they receive a substantial windfall gain, by retaining (and being able to sell) access beyond the lifetime of their asset. This is the preferred outcome of some groups of generators (International Power GDF SUEZ, 2012). However, if generators lose access upon retirement this creates a substantial barrier to exit. This is one example of the 'wicked problems' that are likely to challenge the effective implementation of the OFA model.
- ***Transitional access arrangements create barriers to entry*** – The proposed transitional arrangements would mean that incumbents are granted the existing available firm access at no cost, while new entrants would need to purchase firm access. This cost could be substantial. This creates a competitive disadvantage for new entrants compared with incumbents. Present market projections show incumbents remaining in the market for an extensive period, with many indicating economic life of a range of incumbents beyond 2050. This suggests that the 'transition' period to OFA may extend well into the coming decades, exactly (and by definition) coinciding with the period over which Australia's power system needs to transform to low emissions alternatives. Exacerbating competitive disadvantage for new entrants and raising barriers to entry is at odds with this necessary transformation of the sector. The AEMC acknowledges this issue, but responds by indicating that the OFA would simply introduce one more competitive disadvantage among many facing new entrant technologies, and that these can be overcome by increasing the carbon price or Renewable Energy Target sufficiently (AEMC, 2013). It should be carefully considered whether this is an optimal approach to achieving desired outcomes.

- ***Queuing*** – Under the OFA model, the order in which generators connect to the network will dictate the Long Run Incremental Cost of providing firm access. This means that ordering during the connection and market entry process becomes critical. Detailed queuing provisions will need to be introduced, which create significant challenges in other markets. These issues do not apply at present in the NEM (due to the open access regime).

These issues are identified as important areas for further work, where the CSIRO Future Grid project may be able to contribute meaningfully to the major reform processes already in progress.

Other recommendations

The Transmission Frameworks Review also identified a number of relatively minor recommendations which could be progressed independently of the OFA model. The SCER has decided to proceed with most of these, including (SCER, 2013):

- Introduction of new arrangements that promote the identification and implementation of network investment options that cross regional boundaries;
- Formalisation of a process for transmission network service providers (TNSPs) to provide greater input into the NTNDP to ensure that coordination between national and local issues occurs at the outset of the planning process;
- Improving the consistency of TNSPs' Annual Planning Reports (APR) and requiring AEMO to report on the consistency of TNSPs' Annual Planning Reports (APRs) in the NTNDP.

Connections

A second area of focus in the Transmission Frameworks Review was on rules around connections, which proved to be an area of particular interest to stakeholders. Amendments to the rules were proposed to clarify that generators may own and operate their own connection assets. The construction of connection assets would be fully contestable, with the TNSP retaining control over any cut-in works and parts of the shared network (which may affect other customers). Generators would be required to negotiate "reasonable terms" for the connection of a third party to their dedicated connection asset, to prevent network duplication. In general, these amendments clarify ambiguities in the Rules and make official the process that is applied 'in practice'. This added clarity will become increasingly important with the scale of connection assets growing to accommodate connection of remote renewable resources (discussed further in Part B).

1.1.11 Productivity Commission – Electricity Network Regulatory Frameworks Inquiry

This Productivity Commission Inquiry, completed in April 2013, was commissioned in response to 'spiralling network costs', and seeks to identify the inefficiencies in the industry and flaws in the regulatory environment that may be contributing to these costs. They suggest that a "fundamental nationally and consumer-focused package of reforms" is required. These would include:

- Modified reliability requirements to promote efficiency
- Improved demand management
- More efficient planning of large transmission investments
- Changes to state regulatory arrangements and network business ownership
- More urgently progressing the existing reform process (through the SCER and AEMC).

With specific relation to transmission planning, the Commission has recommended a new system that incorporates an approval process for large investments based on the current 'contingent projects' model. The AER would play a role in the RIT-T, approving revenue allowances for individual projects. Furthermore, AEMO would conduct parallel analysis for large projects, using this as a basis for providing the AER with advice on the technical aspects (such as timing, choice and costs), and any relevant NEM-wide effects.

The Government responded to this review in June 2013 (Australian Government, 2013), broadly agreeing with most of the Productivity Commission's recommendations. Further investigation of the Optional Firm Access model proposed under the Transmission Frameworks Review was determined to be warranted.

1.1.12 AEMC – Review of national framework for transmission reliability

The AEMC is currently developing national frameworks for distribution and transmission reliability, responding to a request from the SCER. A consultation paper was released on 12 July 2013, with submissions due by 9 August 2013.

Rather than attempting to impose a single harmonised level of reliability across the NEM, the review aims to implement effective frameworks for setting, delivering and reporting on required reliability levels and outcomes. Under the AEMC's proposed arrangements individual jurisdictions would retain responsibility for determining the appropriate level of reliability (with the option to delegate responsibility to the AER or a jurisdictional body).

The key features proposed include (AEMC, 2013):

- The setting of required reliability levels based on a transparent economic assessment process;
- The ability for jurisdictions to incorporate additional reliability requirements for areas of economic importance or to reflect community expectations (eg for customers in rural or remote areas);
- Greater opportunities to consult with customers and consider community preferences;
- A mechanism to update reliability requirements during the regulatory control period to reflect updated information; and
- National reporting of network reliability performance.

The AEMC has indicated that this national framework for transmission reliability would be more explicitly based around the economic trade-off between the costs of investment, and the value placed on reliable supply by consumers. The AEMC suggests this may then result in fewer investments with a net cost proceeding than has been the case to date (AEMC, 2013, p. 4). All else being equal, this might tend to increase the scarcity of transmission within regions to be rationed amongst generators.

This is highly relevant to the proposed introduction of the OFA model. Modelling has indicated an 'apparent overbuilding of the transmission system', such that implementation of the OFA model does not produce significant changes in the market for some time (ROAM, 2013). This may indicate that if reliability standards remain implemented as they are at present there may be little need for generation to invest in firm access, reducing the benefits in introducing the OFA model. The value in implementing the OFA model is then contingent upon successful reform of the reliability standards.

Conclusions

This review has presented some of the wealth of literature on regulatory frameworks for transmission, and the processes by which decisions around transmission sizing and location are made. In particular, this has been a topic of deep deliberation over the past several years in Australia, with both the Australian Energy Market Commission and the Productivity Commission releasing comprehensive reports on the topic in the past year. The AEMC's Transmission Frameworks Review, in particular, is founded upon years of analysis, extensive stakeholder consultation, and numerous consultancy reports.

Given the environment of ongoing active reform in transmission frameworks, it is proposed that UNSW's contribution under the CSIRO Future Grid would be most effective if it closely engages with the existing reform processes underway. Analysis should seek to "fill gaps" in the reform process that can be uniquely targeted from an academic perspective.

Academic analysis is relatively unique in being able to consider the big picture and the long term in more depth than most stakeholders. For example, the interests of future new entrants in the electricity market are rarely considered adequately in reform, because those new entrant stakeholders do not yet exist at sufficient scale. Furthermore, all stakeholders are typically prone to underestimate the magnitude of market changes that may occur in the future, and will tend to model the future market as being relatively similar to the present.

For these reasons, it is proposed that the UNSW team under the CSIRO Future Grid project focus on the analysis of the proposed arrangements in the Transmission Frameworks Review and Productivity Commission networks review. This would involve a particular focus on: considering future grids that may be very different to the present; the impacts of proposed amendments upon potential new entrants; and, the necessity of facilitating the smooth transformation of the grid towards low emissions technologies. An area that has already been identified for deeper review is the transitional arrangements under the Optional Firm Access model, which appear to risk elevating barriers to entry and exit. Alternative transitional pathways that may ameliorate these risks will be examined as a first priority.

Given the timing of these reform processes proceeding over the next several years, the CSIRO Future Grid project appears well placed to make a meaningful contribution to supporting informed policy development.

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