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Griffith Business School
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The regulation of electricity transmission in Australia's National Electricity Market: user charges, investment and access

Paul Simshauser[♥ ♣ ♠ 1]
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Abstract

The creation of Australia's National Electricity Market and the associated structural reforms triggered the separation of transmission from generation during the 1990s. The economic framework which governs electricity networks is largely based on the British model and Littlechild's (1983) RPI-X incentive regulation. This framework was designed to correct over-capacity, a characteristic of the pre-reform era. The NEM experienced one episode of network over-investment (viz. 2007-2015) but there is no evidence of regulatory failure per se. Investment mistakes in retrospect were driven by policy error and forecast error – noting this period was preceded by very strong growth in electricity demand, and then coincided with the Global Financial Crisis (2007-2009) and Australia's rapid uptake of rooftop solar PV – the effects of which were virtually unforecastable, ex ante. From 2015, the regulatory framework proved effective in correcting the 2007-2015 cycle with electricity networks now considered the more stable part of the energy supply chain. However, while NEM regulation has been effective in dealing with episodes of overcapacity, as to whether the rigid and highly prescriptive Rules are capable of dealing with the accelerating task of decarbonisation is an open question. NEM State Governments are legislating outside the Rules to meet their own policy objectives and timeframes.

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♥ Powerlink Queensland.
♣ Centre for Applied Energy Economics & Policy Research, Griffith University.
♠ Energy Policy Research Group, University of Cambridge.
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1. Introduction

The Australian Electricity Supply Industry was dominated by state-owned, vertically integrated monopoly utilities through to the 1990s reform era. It was during these reforms that electricity transmission networks were structurally separated from generation (i.e. vertical restructuring). Australia's National Electricity Market (NEM) formed part of a world-wide microeconomic reform experiment which as Pollitt (2004) and Schmalensee (2021) note, commenced in Chile in 1982. Australia's electricity market reforms were largely based on the British template – including industrial organisation, economic regulation of networks and large parts of its wholesale and retail market design (Newbery, 2021b, 2023a; Simshauser, 2021a).

Australia's interconnected NEM comprises the five eastern and south-eastern states of Queensland, New South Wales (NSW), Victoria, South Australia and Tasmania. As a product of history, electricity transmission in Australia is organised around state boundaries. Consequently, there are five transmission network utilities matching the five eastern and south-eastern states, with their legal formation dating back to the mid-1990s in time for NEM commencement. Three of the five transmission utilities were privatised (Victoria during the 1990s, South Australia in the 2000s and NSW in the 2010s) while the other two remain state-owned corporations (Queensland, Tasmania). The regulatory framework which governs transmission networks is applied symmetrically regardless of ownership and as noted above is based largely on Great Britain's incentive regulation model (viz. RPI-X) which in turn can be traced back to the Telecoms industry in 1984 (Littlechild, 1983; Simshauser, 2021a; Newbery, 2023a).

The purpose of this article is to review the regulatory framework and the performance of electricity networks over the past two decades, and to highlight the strengths and weaknesses of the Australian model. This article is structured as follows. Section 2 provides a brief background to Australian energy market reforms. Section 3 reviews the Australian institutional design while Sections 4-7 provide an overview of the form of economic regulation including user charges, access and investment. Section 8 analyses the performance of regulation and Section 9 presents strengths and weaknesses of the Australian model. Conclusions follow.

2. Background to Australian Electricity Market Reforms

From the 1950s to the 1990s, the Australian Electricity Supply Industry was dominated by state-owned vertically integrated monopoly electricity utilities with public assets built up within state boundaries. *State Electricity Commissions* were non-taxpaying entities responsible to their State Government owners vis-à-vis system planning, investment, system operations, reliability of supply and the array of customer tariffs including yearly price changes. As with many vertical utilities around the world, during the 1980s and early 1990s the status of the monopoly Electricity Supply Industry in South-eastern Australia[2] was bordering on critical. The industry was characterised by overcapacity and electricity tariffs substantially above competitive levels (Simshauser, 2021a). Consequently, the requirement for, and objectives of, microeconomic reform were clear. Schmalensee (2021) provides an excellent summary of the reform objectives from a global perspective.

Microeconomic reform of Australia's power industry can be traced back to 1991 when the Commonwealth Government initiated a national inquiry via one of its economics agencies, the Productivity Commission[3]. What evolved was a recommendation to restructure, deregulate and establish a four-state competitive interconnected grid covering eastern and south-eastern Australia – including Queensland, NSW, Victoria and South Australia.[4] The island state of Tasmania would later be interconnected via an undersea HVDC cable.[5]

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[2] The exception to this was the Queensland Electricity Commission, which at that time had the 5th lowest electricity prices in the world. See Booth (2000).

[3] At the time, the Productivity Commission was known as the Industry Commission.

[4] In 1992, the Federal Government established a committee to investigate a national competition policy framework. The committee handed down its blueprint for the implementation of a formal competition policy in August of 1993, with the report becoming known as 'The Hilmer Report', after the committee chairman, Professor Fred Hilmer. See Hilmer (1995).

[5] Western Australia and the Northern Territory could not be connected due to geographical distances.

This reform would create Australia's National Electricity Market or *NEM*. Co-operation amongst participating State Governments was essential and was successfully achieved.[6] There were four key steps to reform, as follows:

1. State-owned monopoly Electricity Commissions were 'corporatised' (i.e. commercialised). The entities became businesses incorporated under Australian Corporations Law, given a commercial mandate and profit motive, and subsequently exposed to a taxation equivalence regime.

2. Corporatised monopoly utilities were then vertically restructured into three segments (generation, transmission and distribution/retail supply) within existing state boundaries. The credit standing of each business was also simulated *'as if'* the firm was non-government owned, which removed any perceived benefit that may otherwise arise in transacting and raising capital. This corporatisation process proved to be a critical step in levelling the playing field and removing residual unfair advantages that would otherwise exist.

3. Horizontal restructuring would soon follow. That is, the competitive segments of generation and retail supply were horizontally restructured into a number of rival entities within each region.

4. All businesses *were* to be privatised. But the timing and execution of this final stage varied considerably across states due to regional political agendas. Victoria privatised its electricity businesses (including transmission) in the mid- to late-1990s. South Australia followed in the early-2000s. New South Wales privatised its industry during the 2010s. Queensland privatised its retail supply businesses (in the Southeast corner) in 2007 and has since resolved to retain the balance of the industry in public ownership (including transmission). In Tasmania, the industry also remains publicly owned. In all cases, generation and retail are deregulated in an open access regime with entry dominated by private sector participants.

3. Institutional Design

Before turning to the form of network regulation, it is worth noting the unique features of the NEM's institutional design. The centrepiece of the NEM is its wholesale market, a uniform first-price, energy-only market design with five regions or zones (based on State boundaries) and a very high Market Price Cap – at AUD $15,500/MWh (USD $10,300 or £8300) it is amongst the highest in the world. The spot electricity market and associated Frequency Control Ancillary Services spot markets (over 4 timeframes) guide scheduling, dispatch and security of supply. Reliability and investment in generation plant is guided by the forward market for contracts with baseload swap prices (2-way Contracts-for-Differences or CfDs) identifying energy imbalances, and $300 Cap prices (1-way CfDs with a $300 strike price) identifying capacity imbalances.

While generation and retail supply were structurally separated in the mid-1990s, the dominant form of industrial organisation to emerge was the vertically (re-) integrated generator-retailer model, colloquially known as 'Gentailers[7]'. With respect to transmission resource adequacy, all new investments would be subjected to an economic cost benefit analysis assessment known as the 'Regulatory Investment Test - Transmission' or 'RIT-T' as Section 6 subsequently explains.

A fundamental principle of the NEM design was the independence of transmission, given its natural monopoly status and potential for adverse impacts on competition if the organisational form spanned the adjacent segment of generation. Noting the dominant form of industrial organisation in the pre-NEM period was largely based on the Central Electricity Generating Board of England and Wales (viz. a bulk supply entity comprising generation and transmission), the structural separation of transmission from generation was a paramount first step.

[6] At this point policy and regulatory functions undertaken by the various State Electricity Commissions were largely transferred to State Governments.
[7] Godofredo et al., (2017) note that the term 'Gentailer' is commonly used in Great Britain, New Zealand and Australia and first appears in the literature in Meade (2005).

When the transmission network utilities were first formed (mid-1990s), network-specific economic regulation followed and was initially undertaken by Australia's competition regulator, the Australian Competition and Consumer Commission. At that time, distribution network utilities were regulated by state-based regulatory authorities - for example in Queensland, the (then) seven regional distribution network utilities were regulated by the Queensland Competition Authority – and this format was replicated across each of the NEM States).

During the mid-2000s, NEM governance arrangements were rearranged to separate and consolidate rulemaking and regulation, respectively[8]. Two new NEM-wide agencies emerged – the Australian Energy Market Commission (rulemaking) and the Australian Energy Regulator (regulator). Consequently, in Australia's NEM the functions of Policymaking, Rulemaking, Regulation and Market Operations are segregated, as follows:

- Policymaking – Energy Ministers from each State Government and the Commonwealth Government form the 'Energy Council' (currently known as the Energy and Climate Change Ministerial Council). Ministers are served by their respective State or Commonwealth Departments of Energy;

- Rulemaking – the Australian Energy Market Commission (AEMC) operates on behalf of the Energy Council as the market's rulemaking entity, and policy advisor;

- Regulation – the Australian Energy Regulator (AER) enforces the Rules, and is the economic regulator of the NEM's transmission and distribution network utilities (and covered gas pipelines); and

- Market Operations – the Australian Energy Market Operator (AEMO) is the Independent Market Operator, responsible for central dispatch, power system operations and wholesale market operations.

A defining characteristic of the AEMC vis-à-vis the National Electricity Rules ('Rules') is their *'open source'* approach to rulemaking. The AEMC consistently attempts to capture the wisdom of the crowd through its processes. Any electricity market participant (generator, network, retailer), capital markets participant, consumer group, interested entity (including the AER and AEMO) or individual can originate a Rule change. The AEMC is the institution charged with running a politically independent Rule change process in a manner consistent with the National Electricity Objective[9] and does so using a conventional policy and regulatory development cycle incorporating i). an initial issues paper, ii). a formal public consultation process, iii). a draft determination subject to a further round of consultation, and iv). a final determination.[10] The AEMC assesses any rule change against *statutory objectives* (viz. the five AEMC Commissioners are bound by these statutory objectives including, above all, *'the long-term interests of consumers'*).

4. Form of Economic Regulation of Transmission Networks

With respect to the shared network, transmission network utilities are subject to regulation in the form of an 'incentives-based' revenue cap. Once the 'base year' regulated revenue cap is established, subsequent adjustments occur throughout the five-year determination period following Littlechild's (1983) *'RPI-X'* approach. Key components of the regulatory framework are described in the Rules which were established during the 1990s, refined during the 2000s and subject to continuous change thereafter. While the Regulator provides additional guidelines on some aspects of the regulatory framework (some

[8] Prior to this there were three entities each with some involvement in rulemaking. This included the National Electricity Code Administrator (known as 'NECA', the predecessor organisation to the AEMC), the then market operator (NEMMCo, the National Electricity Market Management Company, predecessor to AEMO) and the ACCC each had some level of involvement.
[9] That is, to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity.
[10] The AEMC can undertake four types of rule change processes, viz. i). standard, ii). expedited (urgent, non-controversial requests), iii). fast-track and iv). trial Rule changes.

of which are mandatory), in practice the AER has very limited ability to deviate from the *highly prescriptive* Rules.

The high-level objective of the Rules and regulatory framework is *to serve the long-term interests of consumers*, with the relevant parameters being economic efficiency, price, quality, safety, security and reliability of supply (and as an aside, an 'emissions reduction' parameter is being added to the objective at the time of writing). For transmission network utilities, regulatory rate cases – formally known as 'regulatory determinations' – are usually framed over a five-year period[11] and comprise proposals for Operational Expenditure (Opex), Capital Expenditure (Capex) and an associated revenue requirement within a conventional 'propose and respond' model. A transmission network utility will therefore submit its draft proposal (known as a 'Revenue Proposal') for Opex and Capex, forecast load and revenues amongst other variables, and the AER responds with 'draft' and 'final' determinations through a public consultation process. Over time, consumer advocates have been increasingly involved through orchestrated panels which has been highly beneficial to all parties involved. Additionally, a regulator-sponsored 'Challenge Panel' (similar in concept to British counterparts in energy and water) has operated over the past decade largely to inform the regulator.

Opex and Capex proposals are governed by the Rules. One consequence of having highly prescriptive Rules is that the Regulator has commensurately limited ability to adapt to emerging issues or respond to broader policy objectives as they emerge. For example, at the time of writing it was questionable as to whether the AER had the ability to adjust its decision-making in response to decarbonisation efforts even though Australia has committed to net zero by 2050 – noting this follows two decades of climate policy discontinuity as Nelson (2015, 2018) and Rai and Nelson (2020, 2021) explain. Indeed, a significant level of coordination is required to amend the Rules before such Capex would be acceptable.[12] However, the Rules accommodate, ex-post, natural disaster events within the five-year determination windows.

One aspect of the regulatory framework which has always been contentious is the regulated rate of return applied to the Regulatory Asset Base or 'RAB'. The rate of return had historically formed part of the regulatory determination process with networks using the Capital Asset Pricing Model and observed costs of debt, collectively forming the Weighted Average Cost of Capital or 'WACC'. More recently, the regulatory framework has shifted to a largely unilateral process whereby the AER deems the rate of return, following legislative changes sponsored by Energy Ministers in 2018 (involving the removal of the Limited Merits Review framework). This change followed two decades of heated litigation between regulated electricity transmission[13] and distribution networks and the regulator (which in turn was triggered by identification of errors, or perceived errors, in regulatory decisions). This history will be examined in more detail in Section 8.3.

5. Transmission prices and the allocation of user charges

Transmission charges for the shared network are levied on end-use consumers, with shallow power station connection costs paid by generators. Locational signals and investment decisions by generators are influenced by the combination of shallow connection costs, zonal spot prices and more prominently, the NEM's Marginal Loss Factor (MLF) coefficients.[14] MLFs are a 'spot price multiplier' which directly impact generator revenues (i.e. generator revenue = spot price x quantity produced x MLF, for each 5-minute trading interval). Section 7.1 provides more details on MLFs.

Transmission revenues for the shared network, levied on end-use customers, are determined via a conventional building block approach to form the Annual Revenue requirement. That is, for each regulated network utility i, Annual Revenue (AR_t^i) in year t comprises allowances for Operating Expenses θ_t^i, Return *of* Capital δ_t^i, Taxation τ_t^i and Return *on* Capital r_t^i.

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[11] There have been instances of shorter or longer terms for specific reasons with the agreement of the AER.

[12] An alternate view is that the AER has an obligation to do so under the National Electricity Law via the definition of 'Regulatory Obligation' (see Section 2D of the NEL).

[13] To the best of my knowledge, Powerlink was the only network in the NEM that did not challenge the AER via the Limited Merits Review framework on the matter of regulated returns.

[14] Transmission Loss Factors, known as Marginal Loss Factors or 'MLFs' are essentially a forecast of the marginal losses at each bulk supply point for each financial year ahead. For example, the maximum and minimum MLFs in the NEM during 2022 were 1.02 and 0.78 respectively.

$$AR_t^i = \sum\left(\theta_t^i, \delta_t^i, \tau_t^i, r_t^i\right) \mid \ \delta_t^i = \left[\left(RAB_t^i / l_t^i\right) - \left(RAB_t^i \cdot \pi_t\right)\right] \wedge r_t^i = \left(RAB_t^i\right) \cdot WACC^u \qquad (1)$$

For clarity, δ_t^i is also known as Regulatory Depreciation with l_t^i being the remaining useful life of Assets, and π_t being the inflation rate. Depreciation is dominated by straight line methods (Crawford, 2015). In practice, the variables which tend to drive AR_t^i include the Regulatory Asset Base RAB_t^i and the regulated rate of return applied to all utilities, $WACC^u$.

Annual Revenue AR_t^i is converted to a series of transmission charges, which are expected collectively to meet the Annual Revenue determined for each transmission network utility during each five-year regulatory determination period. The structure of transmission prices to end use consumers (i.e. to distribution networks and large direct-connect customers) essentially comprises a locational component (based on maximum demand or average demand, the latter being phased out over time) and a postage-stamp component based on historical energy demand. Ultimately, what distribution network-connected customers see is a bundled network charge (T&D) which comes in the form of a conventional two-part tariff for households and small businesses, or three-part tariffs for medium-sized commercial and industrial customers, respectively. For the average household the combined T&D network charge comprises a fixed $ rate per day and a variable charge expressed in c/kWh, with the revenue split being roughly 20/80. In the scale of the typical household, transmission network charges amount to ~7% of the final electricity bill (with T&D collectively ~36% - see Fig.4).

As noted above, generators are liable for their shallow connection costs (i.e. those assets necessary to connect to the shared network). Shallow connection assets are contestable in nature. Furthermore, connecting generators can coordinate their own connections through various supplier and Original Equipment Manufacturer (OEM) partners. As such, the competitive shallow connections market and associated pricing is unregulated. There are two key connection asset categories, as follows:

- Identified User Shared Assets or 'IUSA' are assets required to facilitate connection to existing assets that form part of the shared network (i.e. where a generator connects into a substation that forms part of the shared network). Examples of IUSA include busbars, isolators and circuit breakers up to the connection point in an existing substation, or the whole of a new substation cut into existing lines. Design, construction and ownership of these marginal assets is contestable if the value of works exceeds $10 million, otherwise it is the responsibility of the incumbent transmission network utility. Any third-party owner must enter into a network operating agreement with the incumbent transmission utility.

- Dedicated Connection Assets or 'DCAs' are contestable components required to facilitate connection that can be electrically isolated from the shared network. Examples include transmission lines and transformers that connect a generator to a substation.

    - If the dedicated transmission infrastructure is less than 30 km long, the dedicated connection is termed a small DCA, and is not subject to an access regime. Any access sought by a third-party subsequently will be the subject of negotiation between the parties involved.

    - If the dedicated transmission infrastructure is greater than 30 km long, it is classified as a Designated Network Asset or 'DNA' and is deemed part of the shared transmission network (and is therefore technically 'open access'). As such, the primary transmission network utility will be responsible for operations, maintenance and functional specifications even though a generator proponent may own the DNA infrastructure and be responsible for managing third party access[15].

[15] DNA's are required to have a radial network infrastructure and each third party connected to the DNA will have a separate Transmission Network Connection Point.

In practice, a majority (but not all) generators seek to connect via the local transmission network utility. The economic explanation is that connecting generators seek to simplify interfaces, meet project development timeframes and above all, minimise transaction costs associated with the project financing of renewable projects (i.e. with the intent of reducing the number of counterparties involved in project financings of new renewable generation assets). The most common variation to this arrangement is for the generator to undertake the connection asset development in their own right – which again minimises transaction costs and counterparties involved. Shallow transmission connection charges are typically structured as a fixed annual payment, escalating at the rate of consumer price inflation, and struck over very long-dated timeframes reflecting the expected useful life of the connecting generation asset.

There are isolated examples of generators making one-off contributions to augment the shared network where the generator anticipates reduced downstream congestion risk, but such examples are rare in practice given the NEM is an 'open access' regime.

6. Transmission Investment in the Shared Network

As noted in Section 4, investment in the shared network is subject to highly prescriptive Rules. In a 'propose and respond' model, the regulator can only accept forecast Capex if it is satisfied that the investment profile submitted reasonably reflects that of a benchmark efficient network business seeking recovery of efficient costs that meet the 'Capex objectives' (viz. the efficient costs of a prudent operator with realistic expectations of inputs per clause 6A.6.7 of the Rules). Under the Rules, the Capex objectives include meeting demand and maintaining a safe, reliable and secure supply (and in this sense, they mirror the National Electricity Objective). Specifically, under clause 6A.6.7 of the Rules, the transmission utility has an obligation to ensure they:

- *meet or manage the expected demand for prescribed transmission services over each regulatory period;*
- *comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;*
- *maintain the quality, reliability and security of supply of prescribed transmission services;*
- *maintain the reliability and security of the transmission system through the supply of prescribed transmission services; and*
- *maintain the safety of the transmission system through the supply of prescribed transmission services.*

Although regulatory determinations approved by the AER contain Capex forecasts, all discrete investments in new transmission assets above a set threshold (currently $7 million) are subject to a Regulatory Investment Test for Transmission, known as the 'RIT-T'. A parallel 'RIT-D' exists for distribution network investments. The RIT-T is subject to a specific objective, viz. to identity the credible option that maximises the present value of net economic benefits to the market (i.e. 'the market' being a strictly partial equilibrium concept comprising generators, consumers and networks – as distinct from the broader economy). Options may also include non-network investments such as embedded generation, demand response or some other offsetting technology which achieves the Capex objective. In practice, non-network investment solutions have been extremely rare as an outcome of the RIT-T – although the rising requirement for essential system services (i.e. inertia, system strength) is starting to change this dynamic.

6.1 RIT-T - the 'Regulatory Investment Test for Transmission

The Rules clearly set out the economic benefits that transmission network utilities should consider under a RIT-T. As noted above, these are limited to partial equilibrium changes in resource costs (i.e. reductions in generation fuel used, avoided generation capital invested), unserved load and changes in network losses. It is noteworthy that at the time of writing, the RIT-T *still excludes* the value of changes in CO_2 emissions despite Australia's commitment to 'net zero by 2050'[16]. Interestingly, Chapter 5 of the

[16] Although it is worth noting the AEMC's most recent report into transmission investment and planning recommends changes in CO2 emissions should be incorporated into certain projects as Section 6.3 (and footnote #15) later highlight.

Rules govern investment planning and the RIT-T framework – yet there is scant reference to the National Electricity Objective[17]. Recall from above that at the time of writing, the National Electricity Objective is to be amended and include reference to CO_2 emissions, and detailed re-drafting of specific Rules will be required to give it effect.

From a process perspective, a RIT-T (excluding those identified in the Integrated System Plan, see Section 6.2) comprises two or three sequential steps depending on the threshold of capital expenditure proposed.

- First, a RIT-T involves identifying a demonstrated network need, proposing a catalogue of credible options and the associated estimated costs (including the technical characteristics required for any potential non-network option) and then undertaking a 12-week period of consultation with the broader electricity market. These details form part of what is known as a Project Specification Consultation Report or 'PSCR'. If the proposed preferred option is under $46m, the PSCR also contains the required cost-benefit analysis.

- Where a proposed capital project is expected to exceed $46m, a Project Assessment Draft Report or 'PADR' is also required. The PADR includes the information noted in the PSCR along with a cost-benefit analysis, identifies the proposed preferred option under the RIT-T and discusses submissions received to the PSCR, followed by a six-week consultation process.

- The final step is the Project Assessment Conclusions Report or 'PACR'. The PACR includes the information contained in the PSCR and/or PADR, responses to any submissions received and an updated cost-benefit analysis if required (noting a considerable time lapse may have occurred by this point depending on matters such as technical complexities, internal and/or external changes since publication of prior reports and the nature of the submissions received during the consultation process).

- Based on specific criteria, Registered Participants, the AEMC, Connection Applicants, Intending Participants, the Australian Energy Market Operator (AEMO) and interested parties may raise a dispute with the Australian Energy Regulator (AER) after the 'PACR' or conclusions report has been published.

- In aggregate, a significant transmission project can take three years to reach the end of the RIT-T and Contingent Project Application (CPA) processes – at which point it then enters the formal development, construction and commissioning cycle.[18] A recent example was 'Project Energy Connect' – a major interconnector between the NEM's NSW and South Australian regions. The project was initiated in 2016 ($1.2 billion), the PACR was completed in 2019 ($1.53 billion), and a Contingent Project Application[19] was submitted to the regulator noting an expected cost to complete of $2.3 billion, with commissioning expected to occur in late-2024.

6.2 'ISP Actionable Projects' - Transmission Investment

Load growth was an important driver of RIT-T activity over the period 2000-2010. However, in a practical sense most RIT-Ts over the subsequent decade were focused on addressing reliability constraints or the replacement of aging assets. It is perhaps for this reason that from c.2018, a second avenue of transmission investment approval emerged through the Integrated System Plan or 'ISP[20]' – a biennial long-range forecast of NEM development undertaken by the independent market operator, AEMO.

[17] In some respects this is not surprising. The Rules were written to give effect to the Objective. Consequently the Rules do not give options for interpretation of the Objective.
[18] Apart from the NSW-SA Project Energy Connect interconnector, other examples include the NSW-VIC Humelink project (2019-2021, $3.3b), the VIC-NSW 'VNI West' 2019- , TAS-VIC MarinusLink (2018-2021, $3.8bn).
[19] Once a transmission utility has completed a RiT-T for an ISP transmission project it may submit a Contingent Project Application in relation to future adjustments to regulated revenues.
[20] The first of these ISPs was issued in 2018, with subsequent publications in 2020, 2022 and the next in 2024. The ISP was a form of acknowledgement that a major transformation would be required.

The framework which governs the ISP is now detailed in the Rules with its purpose being to identify the 'whole of power system plan' which maximises efficient development and serves the long-term interests of consumers. When preparing each biennial ISP, AEMO incorporates certain announced and/or legislated state-based energy policies – including those that deviate from the ISP objective.

At a conceptual level, the ISP is intended to identify the least cost pathway given a range of plausible scenarios, with one of the key outputs being priority transmission projects (typically interconnectors). Once identified and accepted as a priority project, a RIT-T is performed to identify the least cost option of that 'actionable' transmission project. The nuance here is that the RIT-T does not query whether the project should proceed, but rather, which option presents as lowest cost.[21] This makes certain ISP-sanctioned projects somewhat contentious, particularly where forecast costs have increased considerably from the planning (i.e. modelling) stages to the development (i.e. real-world cost) phase because RIT-T's initiated under the ISP are not re-testing the validity of the investment thesis.

6.3 Problems with the RIT-T

There are known problems with the RIT-T. The first and most obvious problem is the time it takes to navigate large transmission investments, and the uncertainty of cost recovery of 'early works' (i.e. route selection, environmental permitting, landholder approvals, ordering long-lead items etc) should a RIT-T fail. Early works could otherwise 'run in tandem' with the RIT-T process and accelerate network augmentation. However in practice, early works are rarely originated ahead of an accepted RIT-T[22], although recently, there have been bespoke examples of individual governments funding (or ensuring recovery) of early works for strategically significant projects. Moreover, the rule-maker (AEMC) has recently released a report[23] which recommends changes to the Rules to enable early works to run in tandem with the RIT-T, albeit for ISP-sanctioned projects.

Initial cost estimates and associated modelling data used to assess a transmission investment thesis age quickly in dynamic environments (noting that initial cost estimates rarely have the benefit of revealed tender costs and prices for equipment supplies and construction contractors). At the time of writing, this has been amplified by disrupted supply chains and tight labour markets for the lines construction workforce. Indeed, project 'cost blowouts' have heightened the focus on RIT-Ts by consumer groups – querying how projects that double in cost continue to commitment – the reference to 'Project Energy Connect' in Section 6.1 being a recent case in point. Spot electricity market dynamics are also changing rapidly, as are historical load flow patterns as the plant mix changes.

Other core issues with the RIT-T process include the fact that modelling is typically undertaken on a deterministic basis (cf. weighted probabilistic), and model parameters often reflect boilerplate assumptions used by the market operator in their Integrated System Plan, which are imperfect. Recall from above the ISP includes prevailing state-based policies – and in some cases such policies are partially or fully discounted by renewable investors (and project banks) in their private modelling and associated investment commitments – meaning material gaps can and frequently do exist between the centrally coordinated ISP assumptions and those used by real world investors (i.e. renewable developers and PPA counterparties).

The ISP is also bounded by our ability to model market complexity. For example, the ISP has persistently revealed no onshore wind developments would occur in Queensland's Isaac region (near Mackay and the Whitsundays) at any time, reflecting carefully and appropriately constructed model inputs including renewable resources derived from the Bureau of Meteorology. However, a $1 billion wind farm is currently under construction and another $800 million wind farm is headed towards financial close in the Isaac region – the point being that despite the best efforts of modellers, system-wide modelling suffers natural limitations.

[21] The RiT-T does not place an absolute obligation on transmission network utilities to make investments. This has caused some consternation by the AEMC and various State Governments when large proposed projects have risked 'adversely triggering' the credit metrics of the transmission network utilities (which is a product of large incremental projects, and the indexation of the RAB which delays revenues to later years).
[22] The author is aware of one example of early works being undertaken in tandem (i.e. 'at risk') with coincident development of RiT-T commencing in 2022 in Queensland.
[23] See Stage 3 Final Report by the AEMC which formed part of a Transmission Planning and Investment Review.

Another matter which is often raised as an inadequacy of the RIT-T framework is the inherent assumption of perfectly competitive markets. With this assumption, the focus of economic benefits associated with transmission investment collapses down to avoided resource costs (i.e. generation fuel and capital costs), unserved load and transmission losses. There is no ability in the economic assessment to contemplate whether consumer welfare might be enhanced through increased competition and a reduction in generator market power. Presently, any change in competitive dynamics vis-à-vis generation is treated as a wealth transfer.

To be sure, that the RIT-T has inherent problems relating to the speed of investment should not come as a surprise. After all, when energy markets and the associated rulebook were being designed in the 1990s, the problem to be solved was overcapacity and consumer prices set above efficient levels (Newbery, 2021b; Schmalensee, 2021; Simshauser, 2021a). Axiomatically then, the RIT-T *should* have been designed to place pressure on capital propositions, slow the rate of investment to be 'just in time' (without presenting genuine risks to security of supply) and ensure delivery occurs when absolutely necessary.

Other RIT-T deficiencies are surprising – especially to an international reader. For example, as at 2023 changes in the values of CO_2 emissions, and any changes to the value of Frequency Control Ancillary Services are excluded from the RIT-T. CO_2 emissions are clearly a critical variable and Frequency Control Ancillary Services are expanding in value and scope (see Joskow, 2019). Concepts of 'social licence' – which are known to be rising in importance – are similarly excluded. And the RIT-T currently fails to identify how the ~$20 billion of concessional finance proposed to be made available by the Commonwealth Government should be treated vis-à-vis consumer prices and shareholder returns.[24] Government-wrapped concessional finance is becoming more prominent and has an underlying policy intent of protecting consumers from the materially necessary cost of the energy system transformation (cf. enhanced returns to equity).

For these reasons and given the newly emerging issues arising in the context of the so-called *energy transformation*, many (but certainly not all) stakeholders are beginning to query the appropriateness of the existing RIT-T process and whether the regulatory framework more broadly is fit-for-purpose. The fact that ISP-sanctioned and government-initiated transmission investments exist at all provides the practical evidence that this concern is justified.

6.4 Renewable Energy Zones and transformational investment

Over the period 2020-2023, state governments in Victoria, NSW and Queensland began to construct their own legislative frameworks to originate transmission investments which may form part of a Regulatory Asset Base. These government-initiated investments typically have a 'power system transformation' and/or 'renewables hosting capacity' focus.

One recent example is MarinusLink, a proposed undersea HVDC interconnector between the island State of Tasmania and Victoria. As Newbery (2023b) explains, Tasmania has an abundance of hydroelectric resources and potential for greater pumped hydro storage – particularly by comparison to its less well-endowed neighbour, Victoria.

In New South Wales a series of state-based authorities (including EnergyCo, the Consumer Trustee and the Renewable Energy Sector Board) have been variously involved in the origination of competitive Renewable Energy Zones (REZ), the first being 'Central West Orana' (Bridge, 2023). Tenders were called for the transmission development with three consortiums being shortlisted. The process was announced in 2020 with the preferred consortium nominated in 2023. The cost of the 500kV development involved is thought to be $3.5bn+ with energisation unlikely prior to 2028. The majority of the REZ asset will form part of a RAB.

Queensland has identified a series of transformational (500kV) investments in its 'Queensland Energy and Jobs Plan' which will ultimately form part of the RAB (see Bridge, 2023). More interesting however

[24] At the time of writing, the Commonwealth Department of Energy had submitted a Rule change to the AEMC which intends to identify the various options for the treatment of concessional finance.

is the path Queensland has chosen for REZ's – namely, a series of merchant (radial) REZ funded by the connecting generators and will therefore sit outside the RAB. Commencing in 2021, two radial REZ (i.e. double circuit 330kV and 275kV REZ on Queensland's Southern Downs and Western Downs, respectively) are currently under construction, each with renewable hosting capacity of ~2+GW and capital values of less than $200 million, with energisation dates of late-2023 and late-2024. The novel approach for these 'merchant assets' sees an anchor (large wind farm) tenant underwrite the pro-rata user charges associated with REZ development, and the incumbent transmission network utility taking on the remaining subscription risk (i.e. as a non-regulated asset). This merchant REZ model and associated financing structures are explained in detail in Simshauser (2021b) and Simshauser, Billimoria and Rogers (2022).

6.5 The transmission 'finance-ability problem'

To generalise, transformation of the energy system will inevitably require large investments in new transmission to enhance interconnection and increase renewable hosting capacity. The scale of new investments relative to the existing Regulatory Asset Base may begin to raise '*finance-ability issues*' for incumbent transmission network utilities. There are two issues driving this problem.

1. The nature of the regulatory model means the timing of cashflows are delayed via RAB indexation and regulatory depreciation methods (see Eq.1).

2. The building block approach and its associated regulated rate of return assumes debt (60% of the benchmark capital structure) is raised symmetrically over a 10-year window with long-dated facilities.

Both issues are well understood by investors and consumer groups, and neither issue has a material impact when marginal transmission investments are small relative to the total existing RAB. However, when marginal network investments are very large relative to an existing RAB, cashflow timing (i.e. driven by the RAB indexation approach) and the assumptions around accumulated historic debt costs (i.e. driven by the regulated rate of return framework) become critical, especially in a rising rate environment.

Ultimately, RAB indexation and accumulating debt assumptions associated with rate of return calculations can convert an otherwise financially robust transmission network utility into a sub-investment-grade business in which credit metrics are fractured – the circumstances of which are binary and an entirely empirical matter. This problem has previously emerged in New Zealand in the early-2010s, with resolution involving a set of regulated cashflows escalating at CPI and without RAB indexation, reflecting a classic NPV calculation, and notably, being NPV neutral to consumers (Frontier Economics, 2022).

In the case of the NEM and its highly prescriptive Rules, remediation can only come about through a formal rule-change process and has thus far been surprisingly contentious despite the matter being completely *binary* and *empirical* – the problem either exists and can be demonstrated through very transparent quantitative financial analysis, or it does not and no such adjustments for marginal investments are required.

7. Transmission Access

For all incumbent and new entrant generators, the NEM operates an 'open access' regime with connection and access being *strictly non-firm*. No generator has a guaranteed right to export – noting the historic costs of building, operating, maintaining and augmenting the shared network was, and continues to be, borne by end-use consumers. Recall from Section 5 that generators only pay shallow connection costs.

7.1 Locational signals

As noted in Section 5, locational signals for connecting generators comprise two basic forms – the five zonal spot (and forward) energy prices associated with each NEM region and Marginal Loss Factors or 'MLFs' (i.e. the spot price multiplier) ascribed to each of the NEM's ~1400 connection points. MLF coefficients are an ex ante annual calculation posted by the Market Operator for the year ahead, based on recent and expected changes to load flows and associated marginal transmission losses. For any given bulk supply point, MLFs are a static coefficient spanning a range of ca 0.7500 – 1.0300 and do not differentiate by the time of day per se – they are a representation of the marginal losses from that location applied during all time periods for the year in which they are set.

Crucially, and despite the fact the NEM is not a 'nodal market' per se, the collective signals provided by the five zonal prices and ~1400 MLFs are acute and result in wide variations in locational wholesale prices (or earned prices) for generators, with Eicke et al., (2020) recently observing these to be amongst the highest in the world's major electricity markets (including comparison to well-known nodal markets such as PJM and ERCOT). For example:

- In 2022, a typical Wind Farm in Far North Queensland will have ascribed MLF coefficients of 1.0201 (meaning non-negative wind production has the effect of reducing transmission system losses by reducing intra-regional flows). As a spot price multiplier, the wind farm earns 1.0201 times the prevailing spot price.
- Wind Farms in the far west of the adjacent NSW region will have MLF coefficients of 0.7973. This means they will earn ~20.3% less than the prevailing spot price.
- Taking zonal price differences into account, the aggregate difference between the average spot prices in QLD and NSW ($29.71/MWh) and the +1.0201 / -0.7973 differential in MLFs means the absolute locational difference between Far North Queensland and Western New South Wales was ~$35/MWh in 2022 (with current base forward contract prices of ~$100/MWh).

Crucially, the NEM's strict non-firm access regime and associated locational signals transcend the wholesale market. The default position for payment under bilateral Power Purchase Agreements (PPA) and government-initiated Contracts-for-Differences (CfD) is for

i). 'metered volume output', and

ii) at the regional reference node (i.e. after accounting for MLFs).

Consequently, if a renewable generator selects a poor location and experiences either network congestion, a deteriorating MLF, or both, it is the renewable generator who bears the entire financial consequence of the locational decision and congestion. To be clear on this, there is currently no mechanism for renewable generators to shift locational risks, network congestion risks or curtailment risks to the consumer base unless a PPA or CfD counterparty agrees to absorb that risk.[25] To generalise, the NEM's basic convention across market matters is to allocate risks to the party best able to manage them.

Prima facie, one might anticipate that the cost of capital for renewable developers are elevated under such market conventions (cf. Great Britain and Germany, where the *deemed output* of a renewable generator forms the market convention for PPAs and CfDs). However, the practical evidence is that NEM renewable costs of capital are low (Gohdes, Simshauser and Wilson, 2022) with the key counterbalance being market competition, the availability of inherent renewable resources (given Australia's land mass) and the extent of due diligence undertaken by generation developers and project banks. There have been examples of renewable investments which exhibit poor locational decision-making, but these tended to occur during cyclical booms and involved new entrants with inadequate historical experience (and therefore understanding) of potentially adverse MLF changes (Simshauser, 2021b).

7.2 NEM connection queues

In certain markets, renewable developers face ever-growing queues for connection. The PJM market is a recent case in point (see Seel et al., 2023). In Australia's NEM, applications to connect to the shared

[25] A wholesale market counterparty (e.g. energy retail supplier) may deviate from these boilerplate conditions, but in doing so they take on that risk and there is no guarantee that any such losses arising from a 'deeming' PPA may be passed on in competitive market conditions.

network by potential new entrant generators do not face a 'formal queue' on a strict 'first come, first served' basis. The 'low transaction cost' early-stages of a *connection enquiry* do of course follow a first come, first served process. But the 'higher transaction cost' middle and latter stages of a *connection application* is better described as 'first ready, first served'. In my view, this has proven to be beneficial in a busy marketplace. Being 'first ready' is costly and this tends to *regulate and rationalise* (in a helpful manner) the demand for scarce technical, construction and capital resources associated with development, permitting and construction on both the generation plant and the transmission connection side of project commitment.

Specifically, before a generator can reach financial close and investment commitment in Australia, project banks (a dominant provider of capital) now require a fully executed 'Connection and Access Agreement'. This is a universal commitment for project financings. Prior to 2018, a *draft* Connection and Access Agreement would typically suffice. However, a small number of poorly located generators[26] triggered a market-wide tightening of financing conditions.

The significance of this 2018 change to financing terms is that before a Connection and Access Agreement can be executed, in a strictly practical sense, the generator must have been through the costly exercise of selecting their Original Equipment Manufacturer (and the specific equipment being deployed) and provide the full details of the generation control systems to the transmission network utility and Market Operator. This process is required to assess the technical viability of the connection vis-à-vis 'generator performance standards' (s.5.3.4a of the Rules) and impacts on 'system strength' (s.5.3.4b of the Rules - see Hardt et al., 2021). In my professional experience, total generation development costs incurred by this point is *typically $5-10 million* – meaning a non-trivial commitment 'at risk' has been made (and this tends to regulate or *filter-out* speculative renewable developments). It is for this reason that 'queues' are not cited as a major problem in Australia's NEM. The more common criticism is the complexity of reaching financial close and completing the laborious process of achieving signoff of the generator performance standards (s.5.3.4a) and system strength studies (s.5.3.4b).

8. Performance of Regulation

By virtually any metric, for most of the past two decades Australia's NEM has been *a marvel of microeconomic reform*. A vast oversupply of generation plant was cleared, unit costs plunged, plant availability rates reached world class levels, requisite new investment flowed when required, investment risks were borne by capital markets rather than captive consumers, and reliability of supply – despite the energy-only market design – has been maintained with few exceptions (Simshauser, 2021a). However, as with all electricity markets there have been times where outcomes (i.e. required changes in residential tariffs, reliability of supply) tested political tolerances. Network policy, network regulation and overall network performance had been among the more contentious aspects of Australia's energy market reforms during the period 2007-2015 (Mountain and Littlechild, 2010; Nepal, Menezes and Jamasb, 2014; Simshauser, 2014, 2017; Grant, 2016). Conversely for electricity networks, the period between 2015-2023 has been 'benign' and a reflection of the regulatory response that followed.

In the discussion that follows, network over-investment over the period 2007-2015 is examined and to be sure, there is little evidence of regulatory failure per se. Investment mistakes in retrospect were driven by policy error and forecast error – noting this period was preceded by very strong growth in electricity demand, and then coincided with the Global Financial Crisis (2007-2009) and Australia's rapid uptake of rooftop solar PV – the effects of which were virtually unforecastable, ex ante.

Nonetheless, the outcomes exhibited a unique combination of a sharply rising capital base driven by policy, an elevated WACC allowance driven by extreme capital market conditions and ex post, deteriorating aggregate final demand. Combined they would amplify network tariffs and create an unstable regulatory environment (Simshauser and Akimov, 2019). Consequently, this period provides a salutary lesson for policymakers and regulators regardless of the jurisdiction in which they operate.

[26] These renewable generators suffered very material production constraints over elongated periods due to 'system strength' shortfalls. In some instances, remediation of the system strength shortfall required installation of a synchronous condenser post financial close. See Simshauser & Gilmore (2022) for details.

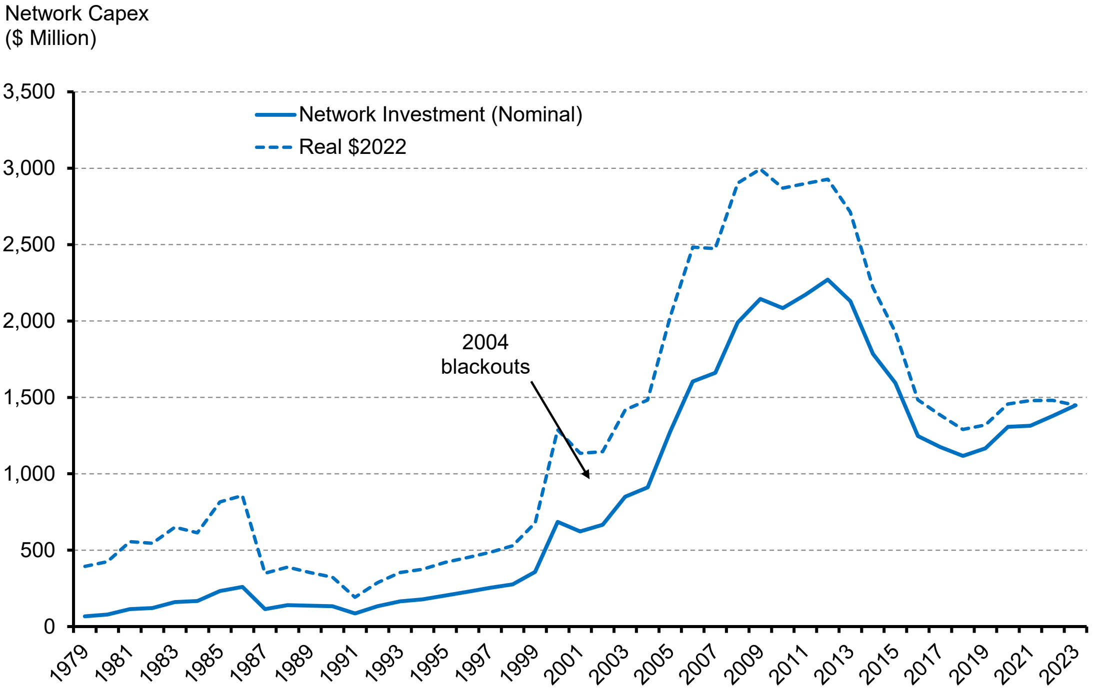
8.1 The 2007-2015 episode of *network gold plating*

It was Averch & Johnson (1962) who first observed the potentially adverse incentives facing regulated utilities when a regulated Weighted Average Cost of Capital (WACC) allowance exceeds the firm's actual cost of capital. So it was that during the 2007-2015 period (and 2009-2011 in particular) that the regulated WACC allowance appeared to exceed actual costs of capital. Yet while this might prima facie explain the surge in network investment – the cumulative Regulatory Asset Base rising by $41 billion to $83 billion in nominal terms (103%) terms – the reality is state-based policy decisions were largely responsible (Simshauser, 2017).

In the NEM's northern regions of NSW and Queensland, the combined network capital stock had been rising steadily during the late-1990s and early-2000s (as Fig.2 illustrates) due to surprisingly strong electricity demand growth driven by mining expansion, sustained population growth and the rapid uptake of air-conditioners in the residential sector. However, in the 2003/04 financial year a series of unfortunate network-related load-shedding events occurred in the capital cities of Sydney and Brisbane. These distribution network-level outages tested political tolerances and produced an energy crisis in both states.

As Helm (2014) explains, an energy market crisis will trigger 'a government inquiry'. A government inquiry will produce a series of policy recommendations, some of which will invariably be misguided because *the market* is rarely afforded the opportunity to scrutinise the (predictable) unintended consequences of policy recommendations. In this instance, the misguided policy recommendation which occurred in both Queensland and NSW was to tighten network reliability standards (shifting away from probabilistic to deterministic planning) – aimed at reducing forward risks of load-shedding events. The predictable (and predicted) unintended side-effect was an episode of policy-driven network over-capacity. The combination of ongoing *forecast* load growth *and* tighter reliability standards led to record levels of capital expenditure between 2007-2015, as Figure 1 (Queensland example) illustrates.

Figure 1 - Queensland 'T&D' Network Capex (1979-2022)



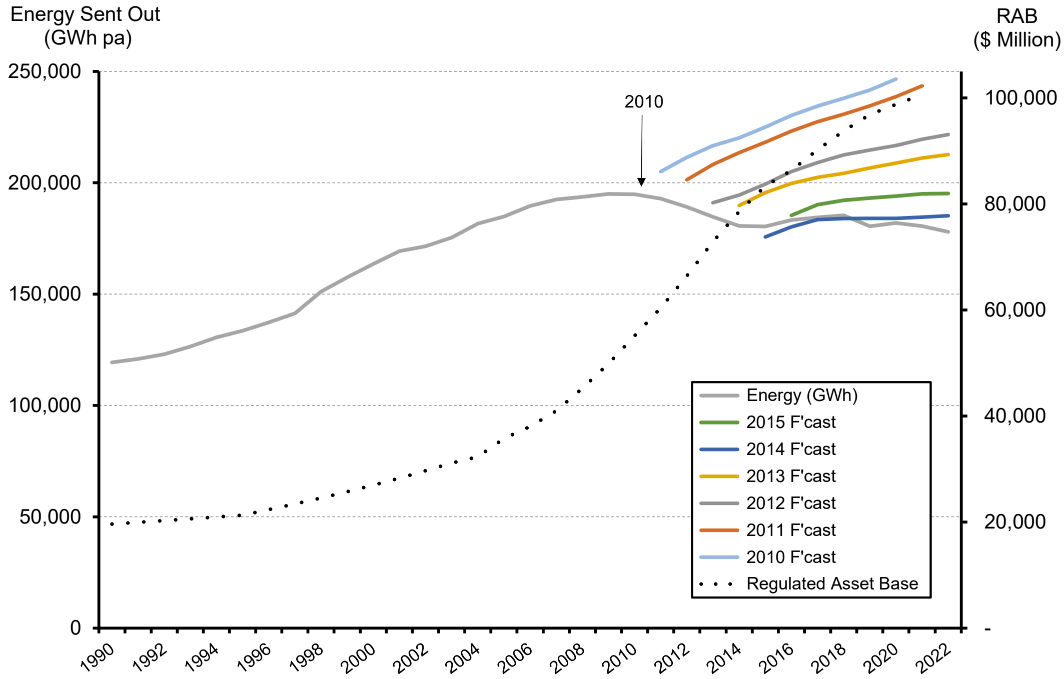
Source: Simshauser (2017), AER.

8.2 Contracting aggregate final (grid) demand 2010-2015

While the blackouts of 2003/04 triggered elevated capital expansion from ~2007-2015, the timing would coincide with the NEM's first episode of *contracting demand*. In the case of Queensland, first power was produced in Brisbane on 9 December 1882 (see Egeberg, 1958) and from that moment onwards, final electricity demand experienced year-on-year growth regardless of economic conditions (Simshauser and Akimov, 2019).[27]

The Global Financial Crisis and the rise of distributed rooftop solar PV resources combined to produce the first sustained contraction in final electricity demand in Australian power industry history from 2010 (see Figure 2 – LHS axis). Not only did prior-period load forecasts prove too optimistic (also illustrated in Fig.2 – LHS axis), load began to contract in a manner consistent with a *network in decline* – colloquially known as a utility death spiral, and formally defined as a network experiencing a sustained, non-temporary reduction in demand that produces excess capacity on large parts of a network (Decker, 2016; Simshauser and Akimov, 2019). By 2015, energy demand in the NEM had fallen to 2004 levels. Consequently, rather than deploying scarce capital productively to meet power system load growth, significant investment mistakes in retrospect added an expensive layer of excess capacity[28] (see Figure 2 – RHS axis).

Figure 2 - Final (grid) electricity demand vs. Regulatory Asset Base (1990-2022)



8.3 Formulaic Regulation and the WACC Allowance: 2008-2011

Network tariffs are ultimately driven by four key variables, i). the size of the Regulatory Asset Base, ii). depreciation policy, iii). Opex and Capex allowances, and iv). the cost of capital or 'WACC allowance. A *policy decision* made by State Governments in 2006 had the effect of making network regulation *formulaic and highly prescriptive* – a recurring theme throughout Sections 4-7. This policy decision would have implications for consumer pricing during the 2008-2011 period.

Recall from Section 3 that the AER took over T&D network regulation from Australia's competition regulator (Transmission) and State-based regulators[29] (Distribution) from 2005 onwards. Evidently lacking trust in a new national regulator, State Government Senior Officials attempted to minimise the risk of regulatory error by 'hard wiring' a surprising number of variables which would otherwise require considerable professional judgment. This had the unintended consequence of constraining the AER when undertaking regulatory determinations under periods of economic uncertainty, specifically, during the collapse of Lehmans Investment Bank and the subsequent Global Financial Crisis of 2007-2009:

[27] Negative demand growth was experienced in Tasmania (1968, 1983, 1995, 2005-2006), New South Wales (1983 & 2005), Queensland (2004) and in South Australia (1984, 1996, 2002 & 2004) but combined, the NEM regions posted persistent year-on-year growth until 2010.
[28] As described by Pierce (1984) albeit in relation to a similar pattern with nuclear power stations in the USA.
[29] The Queensland Competition Authority (QCA), the New South Wales Independent Pricing & Regulatory Tribunal (IPART), The Essential Services Commission of South Australia (ESCOSA) and so on.

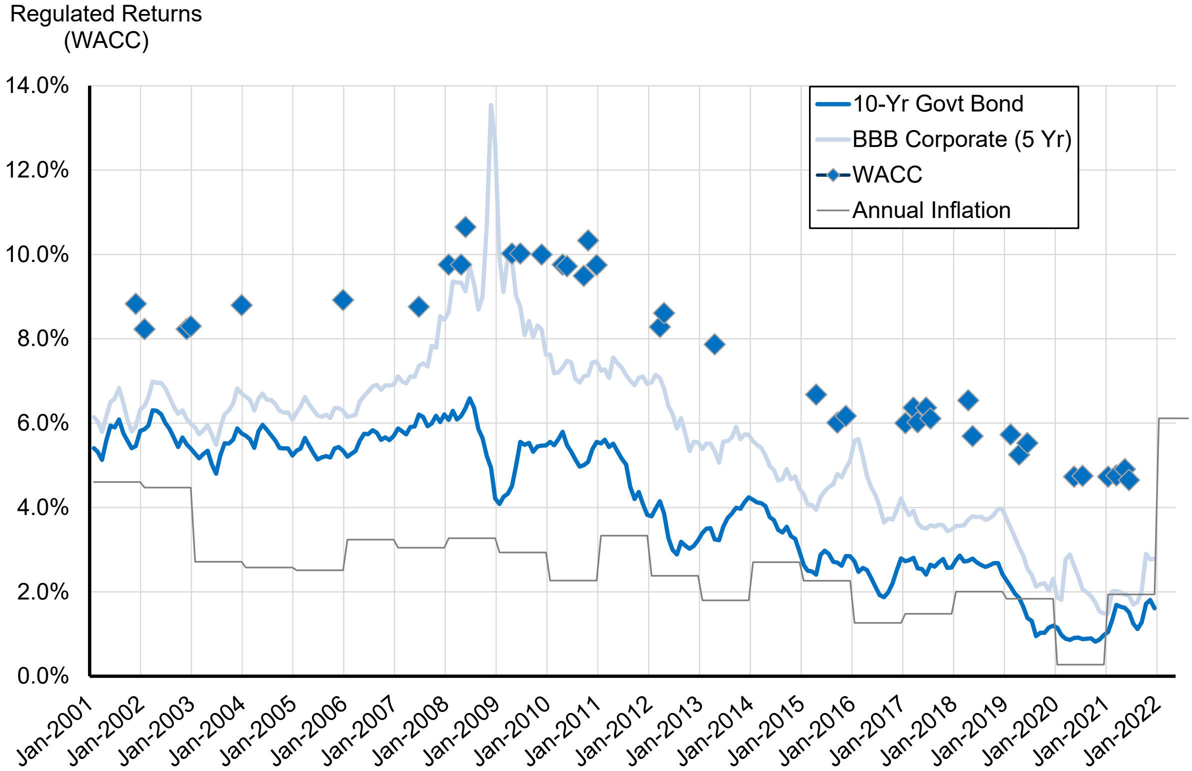
- The cost of capital allowance for electricity networks in Australia is determined by estimating a fair WACC using the Capital Asset Pricing Model (for equity returns), and 'BBB+ rated' corporate bonds (for debt returns).

- When the regulator attempted to make determinations during, and in the aftermath of the *Global Financial Crisis* (2007-2010), Australian credit markets had largely closed and the market for Australian long-dated corporate bonds virtually disappeared overnight[30].

- Bond markets were experiencing their worst conditions since the 1929-1932 financial crisis. This is illustrated in Fig.3 – note the gap between 10-Year Commonwealth Government Securities (falling) and 5-Year Corporate Bonds (rising sharply) that emerged during 2008-2009 – an episode which last occurred at such levels in the 1929-1932 financial crisis (see in particular Bernanke, 1983).

- Using conventional WACC calculations, these conditions would produce abnormally high regulated rates of return for monopoly utilities, and consequently some level of professional judgement was required. However given formulaic regulation, the AER was forced to use thin markets and proxy estimates taken within short sample periods, which in the event set elevated allowances for debt returns and would be locked-in through various five-year regulatory determinations.[31]

Figure 3 - Regulated Returns (5 Year Determinations made over the period 2002-2018)



Source: RBA, AER, ACCC.

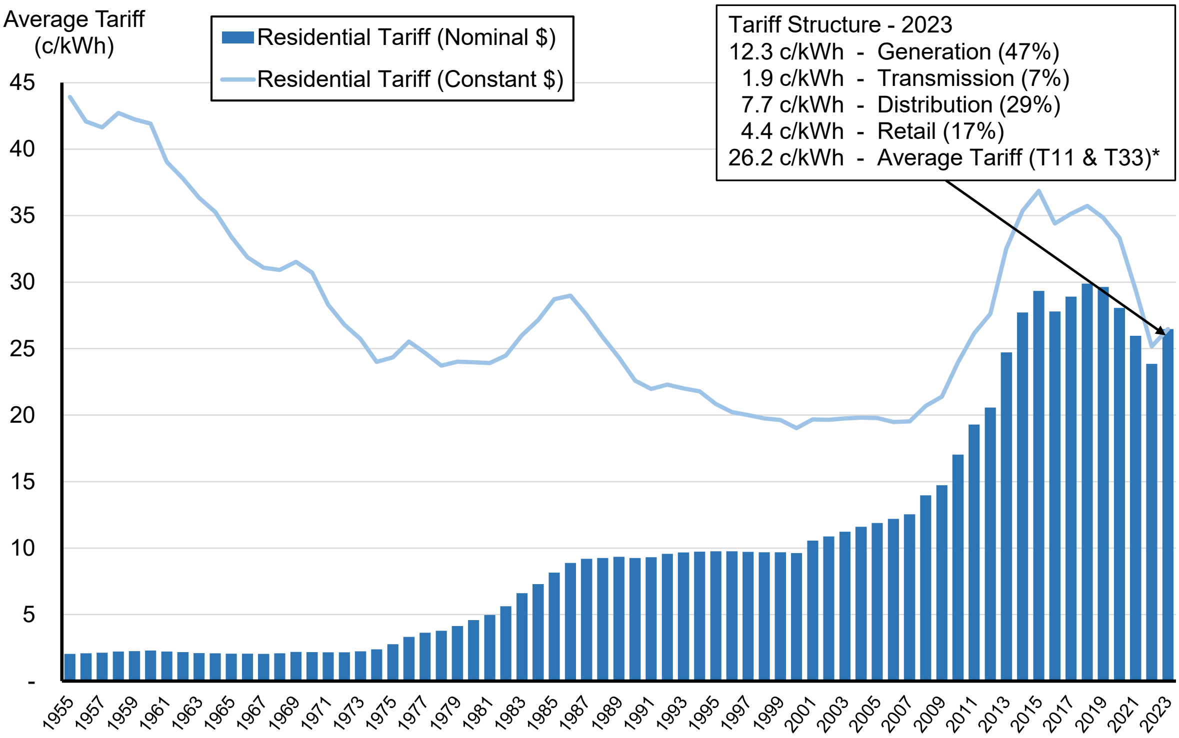
- Investment mistakes in retrospect (per Figs.1-2) over the period 2007-2015 would thus be amplified by elevated regulated rates of return. When combined with contracting load, retail-level

[30] See for example the SP Ausnet Determination (January 2008) at page 98 or the Electranet Determination (April 2018) at page 66. Available at https://www.aer.gov.au/system/files/AER%20Final%20decision.pdf and https://www.aer.gov.au/system/files/Final%20decision%20%2811%20April%202008%29.pdf respectively.

[31] I specifically recall the then Chief Executives of Energex and Ergon Energy in the early 2010's being embarrassed by the return levels in WACC determinations applying to their businesses. They were also at pains to point out that any future determination will be ~250 basis points (bps) lower. By the time the AER completed their Determinations in 2015, they were 400bps lower.

tariffs soared from 12.5c/kWh in 2007 to 29.3c/kWh by 2015 – a compound annual growth rate of 11.2% or 8.3% above the 2.7% average annual inflation rate, as illustrated in Figure 4.[32]

Figure 4 - Average Retail Tariff in Queensland[33] (1955-2023)



(*T11 is the standard household tariff and T33 is a controlled tariff (16 hours supply))

Source: Simshauser (2022)

- Formulaic regulation adopted to reduce regulatory risk eliminated the ability of the Australian Energy Regulator to pursue Regulatory Asset Base write-downs (the absence of any *regulatory threat* being a deficiency vis-à-vis incentives of the firm) or defer cost recovery more flexibly over time. Indeed, during this period *any* capital invested by a network over and above the 5-year regulatory allowance could be automatically rolled into the RAB at the next regulatory reset without any prudency or efficiency review (Grant, 2016).

8.4 Mid-2010s and *death spiral* concerns

If there is a first law of decarbonisation, it is that *anything that can be electrified, will be*. In the era of 'net zero by 2050', this makes the concept of an electricity market death spiral somewhat puzzling. The electrification of industrial loads, transport fleets and residential heating tends to suggest very large increases in the aggregate final demand for electricity with household loads more than likely to double (see Griffiths, 2022). Yet during the mid-2010s, such a future was not so obvious.

Soaring network- and therefore retail-level electricity tariffs over the period 2007-2015 (Fig.4) induced a material demand response. Household take-up rates of Distributed Energy Resources rose sharply. Indeed in regions such as Queensland and South Australia, more than 45% of detached households have installed a rooftop solar PV system – the highest take-up rate in the world (Simshauser, 2022). For a large household historically consuming ~7500 kWh per annum, installation of a 5kW system would reduce grid supplied power by some 40% to 4,500 kWh (the 3000kWh balance being 'self-consumed PV output'). Total final demand had not reduced. But the demand for grid-supplied energy in the residential sector was falling sharply given self-consumed PV production.

[32] As an aside, the average transmission charge in Queensland during 2023 was AUD ~$15/MWh (US$10 or £8) and ~1.9c/kWh (US 1.2c/kWh or 1.0p/kWh) for residential households.
[33] Retail tariff series in Figure 3 uses Queensland data and is the final end-use tariff including generation + network + retail + environmental charges and is structured as a two-part tariff. Average use in this calculation is approximately 6250kWh including 1250kWh on a discounted ripple control hot water tariff. There is tariff variation amongst NEM regions, but directionally tariff changes have been broadly consistent.

In a purely practical sense, falling (grid-supplied) demand for electricity causes a material regulatory problem. Inherent in the design of monopoly regulation and our current tariff structures is a presumption of non-negative load growth along with an objective function that is intended to simulate competitive market dynamics and guide inter-temporal cost growth at some lower rate. This objective function is frequently implemented via Professor Littlechild's (1983) classic regulatory prescription, *RPI-X*. But despite best intentions of policymakers, economic regulation of monopoly utilities can produce unintended consequences (Douglas, Garrett and Rhine, 2009).

For monopoly utilities, prices are structured as two-part tariffs – a practice which dates back to Hopkinson (1892). Hopkinson's counsel was for the volumetric charge to be small but in modern tariffs, invariably the volumetric charge (c/kWh) dominates the structure. A requirement for tariff reform in the NEM was identified by the AEMC at least as far back as 2012. World-record solar PV uptake rates makes this more, not less, important from the perspective of tariff efficiency, tariff stability and fairness of the burden of fixed cost recovery. However, only one network utility (in the Australian Capital Territory) has thus far managed to establish a residential demand tariff where consumers have a smart meter installed unless they specifically opt out (see Hammerle and Burke, 2022). In all other jurisdictions, the political economy of electricity prices and the impact tariff of reforms (which invariably creates winners and losers) has proven to be intractable.

Consequently, if disruptive competition causes aggregate (grid) demand to contract in the absence of tariff reform, then the regulatory mechanics that follow with volumetric-dominated energy tariffs means the variable rate (c/kWh) needs to rise to offset volumetric losses (kWh) and meet the Annual Revenue constraint. This feedback-loop of rising prices and contracting volumes in the presence of a discontinuity can produce a vicious cycle, viz. a *Death Spiral*. Note consumers disconnecting from a network is *not* a pre-condition for a network utility *Death Spiral*. The *necessary condition* is that consumers, in aggregate, reduce system load year-on-year, and the *sufficient condition* is that cost growth is non-negative.

At this point, the regulatory framework may approach the limits of its design envelope (Simshauser and Akimov, 2019). The reason for this is axiomatic; a regulatory outcome of persistent price rises in the presence of falling aggregate (grid) demand due to competition from behind the meter resources produces a *strikingly different* result to equivalent competitive market conditions, where prices fall and assets are written-off (Pierce, 1984).

There is also the more general case of non-trivial demand forecast error and investment mistakes in retrospect, where prior period expectations proved too ambitious and the extent of excess capacity overwhelms the stability of regulated tariffs. In either case (*Death Spiral* or non-trivial *mistakes in retrospect*), while regulatory processes are *expected* to allow for recovery of lost revenues in future rate cases, the political economy of such an outcome may well be unacceptable, and this exposes network utility shareholders (Kind, 2013).[34]

Significant investment *mistakes in retrospect* occurred following the policy changes in 2004, particularly throughout the 2007-2015 period as noted in Section 8.1. As one international peer observed, these mistakes had real implications for politics more generally and played into a highly polarised narrative around energy policy in Australia (see also Nelson, 2015; Rai and Nelson, 2020).

8.5 Policymaker and Regulatory response

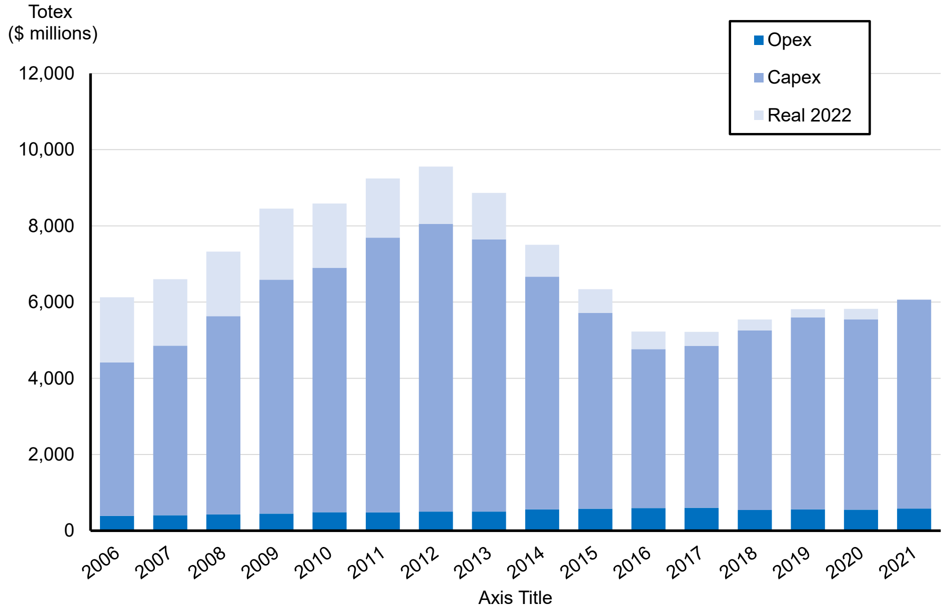
Once the combined effects of a tightened reliability standard, elevated rates of return and falling volumes became clear with regards to rising network tariffs, a series of policy and regulatory changes would follow. Queensland and NSW abandoned their recently devised deterministic reliability standards – essentially reverting to probabilistic planning approaches. The AER maximised the emerging low interest rate environment and pushed allowable WACCs in each subsequent Regulatory Determination

[34] In relation to a Death Spiral, Kind (2013, p1) explains that various Distributed Energy Resources (DER) and associated demand programs capture market share which reduces utility revenues. Regulatory processes are expected to allow recovery of lost revenues in future rate cases, but tariff structures generally require non-DER customer to pay for (absorb) lost revenues. As DER take-up rates increase, the cost-recovery structure may require a reversal of cross-subsidies, but the political economy of sharp rate-rises may result in utility stranded asset exposures.

down, from a peak of 10.65% (May 2008) to a low of 4.65% (June 2021) as Fig.3 highlighted. And as noted earlier, the Limited Merits Review framework was removed by the Energy Council which in turn largely eliminated the legal contestability of regulated WACC allowances.

The AER also adopted a hard line on Capex and Opex allowances, routinely rejecting ~25.3% of network Capex proposals and 9.7% of network Opex proposals – effectively retraining the industry vis-à-vis cost management[35]. Figure 5 illustrates this sharp change in Total Expenditure (Totex) allowances approved by the AER from 2006-2021.

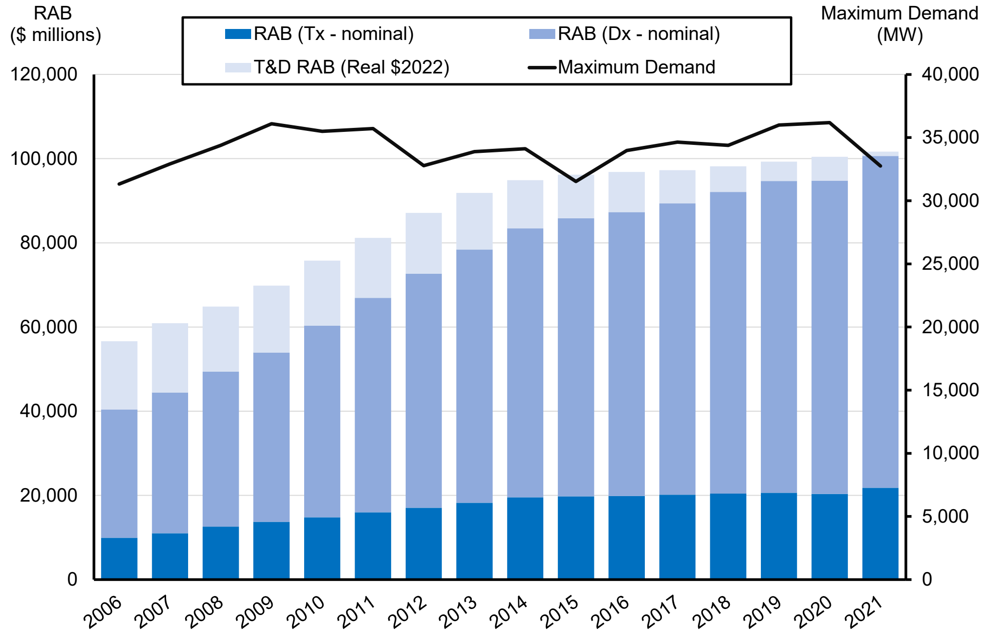
Figure 5 - Allowable Totex in constant 2017 dollars



Source: AER

This in turn would slow the rate of change of the combined market RAB, as illustrated in Fig.6.

Figure 6 - Combined T&D RAB (in nominal dollars) vs Maximum Demand 2006-2017

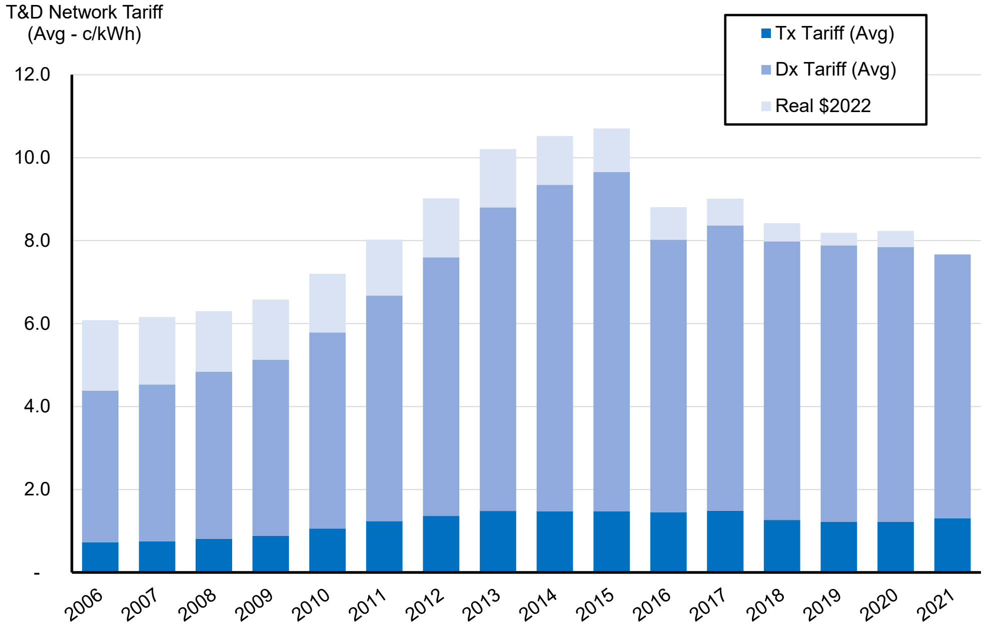


Source: AER, ABS.

[35] This comparison is the aggregate of the Revenue Proposal (first submission) and Final Decision for each of TransGrid, ElectraNet, Powerlink and TasNetworks. These Revenue Proposals were submitted by the respective entities over the period 2012-2014.

Collectively, these actions moderated growth in network tariffs such that the sector is now considered the more stable part of the industry, given gyrations in global energy markets and wholesale prices in particular arising from the war in Ukraine. Figure 7 presents the simple average T&D network tariff for the NEM (nb. considerable variation exists within NEM regions and NEM franchise areas[36]). The nominal average network tariff increased by 91%, from 4.5c/kWh to 9.7c/kWh over the period 2007-2015 and has since fallen to 7.7c/kWh.

Figure 7 - Average Transmission Network Tariff 2006-2017 (nominal dollars)



Source: AER, ABS.

8.6 The 2020's decarbonisation era: surviving *the droop*

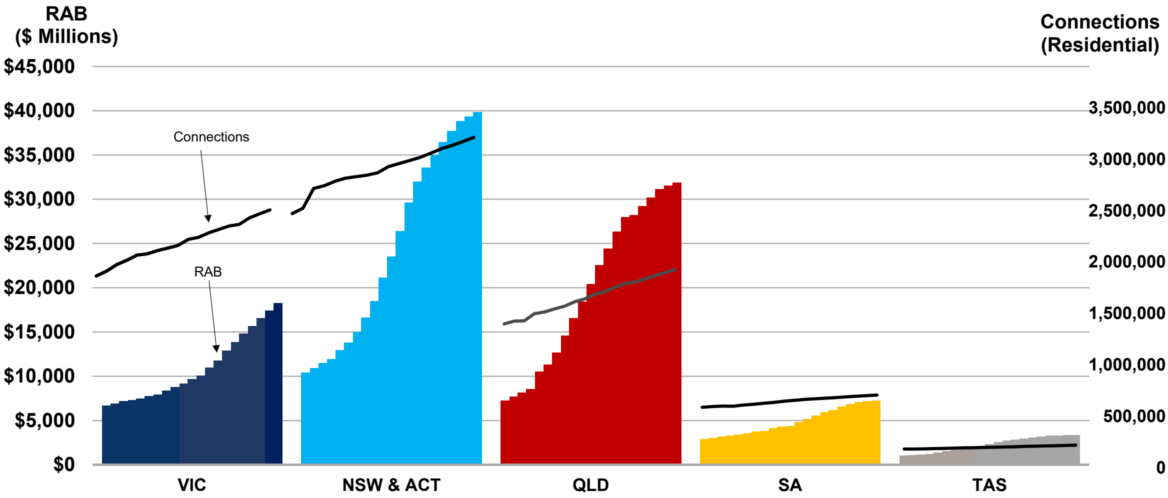
The performance associated with the 2007-2015 period is now well and truly in the rear-view mirror, again noting electricity networks have become the 'stable component' of the industry given elevated wholesale electricity market prices. Nonetheless, the gold-plating era is etched in the minds of NEM consumer groups and this history sets a certain context for policymakers and regulators attempting to navigate the decarbonisation task. This historical context makes any new regulated network investment complex.

Recall from Section 6.2 the Integrated System Plan or 'ISP' is intended to identify least cost pathways for the NEM, and all scenarios point to very large increases in the transmission network. Invariably, a shift to renewables will require material increases in intra-regional transmission (i.e. hosting) capacity to facilitate the rapid expansion of utility-scale wind and solar PV. It also requires greater inter-regional interconnection to facilitate greater diversity of these intermittent resources (Joskow, 2019; Newbery, 2021a, 2023a, 2023c). For transmission (and distribution) networks, the challenge is how to navigate what appears to be a *'droop period'* – that is, the period during which very large, capital-intensive network augmentations are required, while simultaneously, rooftop solar PV take-up rates rise, grid-supplied volumes stall or decline marginally, and *before* fuel switching (i.e. electrification) and associated volume increases occur in both the industrial and household sectors (Griffiths, 2022; Simshauser, 2022).

Conversely, while aggregate residential customer energy volumes have been declining, the number of residential customer connections continues to expand in line with Australia's ongoing population growth. Indeed in regions such as Queensland, (grid-supplied) maximum demand (MW) continues to rise, while energy demand (GWh) is largely flat, with the number of connected customers rising steadily at ~1.7% pa as Fig.8 illustrates.

[36] This data series has been constructed by dividing aggregate T&D revenues by T&D energy delivered, and as a result masks the rich variation of tariffs by location and consumer segment.

Figure 8 - RAB vs Residential Customer Connections by State (2001-2021)



Source: Simshauser and Akimov (2019)

As a separate aside, one Reviewer queried whether initial RABs (dating back to reforms in the mid-1990s) had adopted deprival values substantially higher than the legacy depreciated historic accounting cost of the shared network, with consumers effectively paying twice. The network RAB was set differently in each jurisdiction and before a mature regulatory regime existed (i.e. as part of the initial corporatisation process or in some cases, as privatisation was occurring). The basic principle adopted through various intergovernmental agreements between the Commonwealth and States was that discretion was granted for any RAB to be set between depreciated accounting cost and depreciated optimised replacement cost. From there, each State used its own process to set initial values (typically coordinated by the Treasury Department in each State, using combined engineering and finance studies).

9. The Strengths & Weaknesses of Australia's Regulatory Framework

The strengths of Australia's regulatory framework for transmission network utilities can be summarised as follows.

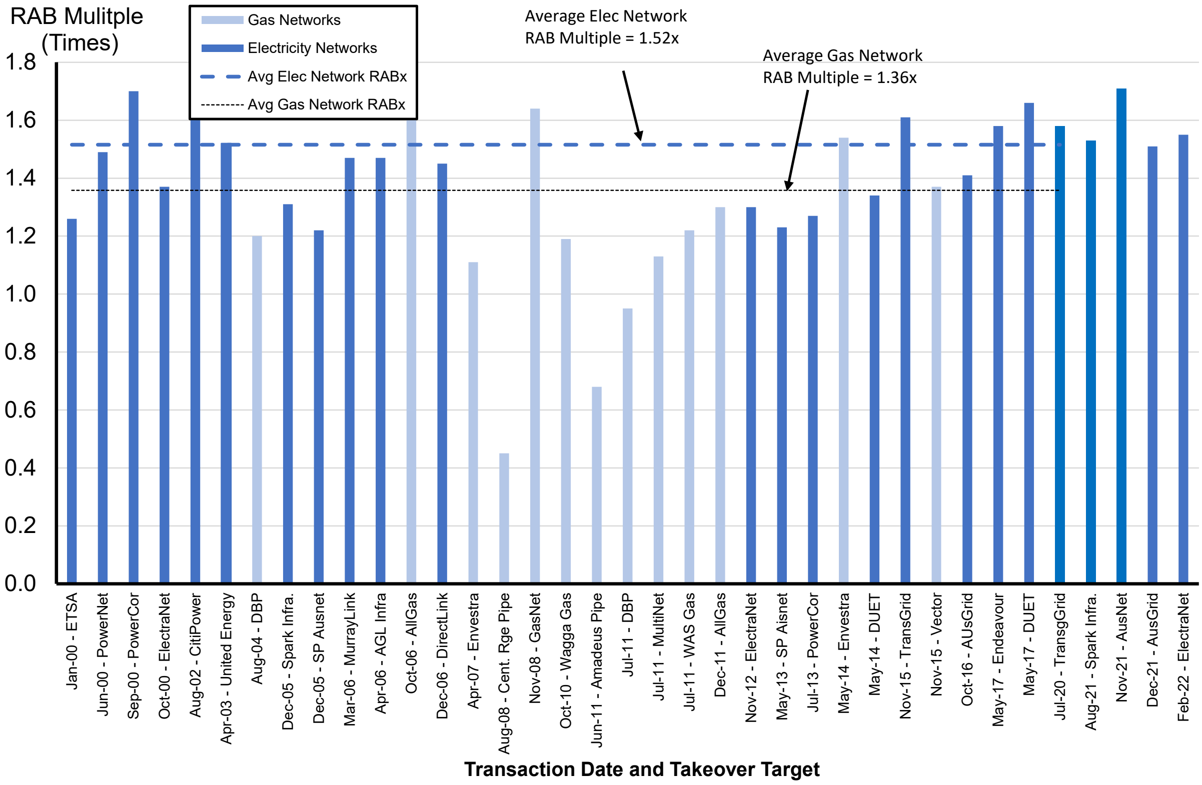
1. In my view, **the NEM's institutional design** is one of the strengths of the Australian market, and of network regulation. The separation of policymaking (Energy Ministers), rulemaking (AEMC), regulation (AER) and market operations (AEMO) ensures transparency for market participants. To generalise, the AER does not have a unilateral right to pursue capricious regulation.

2. In particular, the segregation between the AEMC and AER has the effect of separating Policy Advice and Rulemaking (AEMC functions) from the entity which enforces compliance with Rules, and acts as industry economic regulator (AER functions).

3. The **open-source approach to Rulemaking** has the beneficial effect of minimising misguided political interference vis-à-vis Rule changes. It also means that Rule changes sought by a market participant (investor focus) can be scrutinised by consumer groups and the regulator (consumer focus), and vice versa. Consequently, the Rule change process tends to ensure the various economic trade-offs are *purposefully* thought through.

4. Items 1-3 above provide confidence to institutional investors. There is practical evidence from capital markets which tends to support this statement via observation of Merger and Acquisition (M&A) events. Fig.9 illustrates that between 2000 and 2022 there were 37 regulated utility M&A events in Australia with a cumulative transaction value of $97.9 billion (real 2022$). One metric easily monitored (despite its occasional misuse) is transaction 'RAB Multiples' – i.e. acquisition price relative to the Regulatory Asset Base from which regulated revenues are determined. In Fig.9, the dark blue bars are electricity networks, light blue are regulated gas networks, and the horizontal line series depict average RAB Multiples for electricity and gas, respectively.

Figure 9 - Regulated energy network transaction metrics in Australia (2000-2022)



Source: (Simshauser, 2023).

5. When collectively observing Fig.3 (falling WACC allowances), Fig.5 (falling Totex allowances) and Fig.9 ('mean reverting' RAB transaction multiples), it would seem investors have confidence in the policy and regulatory environment. This is not to suggest there are not contentious issues or serious policy and regulatory 'battles' (Crawford, 2015). But on balance, the evidence suggests the regulatory framework is one in which institutional investors have confidence – and make large investment commitments accordingly.

6. Although contentious within Australia, by international standards, the NEM's approach to new renewable Connection and Access *applications* is a strength in that the typical congested 'connection queues' are not observed. To be sure, generator connection and access in the NEM post-2018 (when 'system strength' associated with asynchronous, inverter-based generation plant emerged as a serious issue) has undoubtedly become dramatically more complex and considerably longer. But there are no practical alternatives to dealing with matters of system strength, which cause less harm to generation investors ex post.[37]

The weaknesses of the regulatory framework are as follows.

1. It is noteworthy that **interference by State and Commonwealth Governments** in network investment and network coordination has been rising. This is in my view due to the rigidity of the current regulatory system, and its ability to satisfactorily deal with current policy objectives (viz. Net Zero policy objectives). The highly prescriptive nature of the NEM Rules outlined in Sections 4-7 contribute to (even exacerbate) this trend.

2. A strength overplayed may become a weakness. Specifically, the very strengths which provide investors with confidence (viz. institutional design, highly prescriptive Rules) have consequences. These characteristics may limit the ability of the AER to pursue capricious regulatory actions (a

[37] The point here is that it is better to spend an extra six months during the development phase (pre-commissioning remediation) than to spend 12 months post-commissioning in a remediation phase whereby plant output is curtailed by 50-100% during system strength shortfalls. The former adds marginally to development costs. The latter is capable of sending a plant into financial distress.

strength), but they also limit the AER's ability to sensibly adjust in real-time to policy circumstances (a weakness).

3. **Network Regulation** more generally proved to be a weakness throughout the period 2007 to 2015. While critical policy errors were made by certain State Governments vis-à-vis reliability standards, the Rules were too *formulaic* to respond to the unique conditions of the Global Financial Crisis with respect to the cost of capital allowance. Recall from Section 8.3 this was a policy choice. This has been less of an issue with the AER being granted a unilateral right to set the WACC allowance methodology from 2019 (and removal of the Limited Merits Review framework), but these new arrangements may in turn be tested by extreme capital market conditions in the future.[38]

4. The AER has been unable to adjust its frameworks and approach to 'net zero by 2050' policies of the Commonwealth and all State Governments. In practical terms, this appears to have dealt the AER out of facilitating market development. The Rules require the regulator to operate as a braking system on network development. State Governments evidently have different policy objectives and accelerated timeframes. As a result, State Governments are increasingly bypassing the Rules with their own State-based derogations for new network investment. To the best of my knowledge, the AER has not sought to submit a Rule change proposal to alter this dynamic.

5. While NEM governance has unique advantages (e.g. strict segregation amongst market institutions), in the absence of a formal binding agreement to meet certain policy objectives, **Energy and Climate Change Ministerial Council** (the successor body to the Energy Council) can be a weakness of NEM governance in that it requires multiple State and Territory Governments (and multiple political parties), and the Commonwealth, to agree to material policy change. Furthermore, State Governments have de-skilled their Energy Departments over time (notably, there are very few specialist Energy Departments remaining. In most (but not all) jurisdictions, the former Department of Energy now forms part of a broader mega-departmental structure, with the Departmental Secretary or Director-General is spread thinly across a long list of line responsibilities).

6. **Network Tariff Reform** was noted as important by the AEMC at least as far back as 2012. World-record solar PV uptake rates makes this crucial. But the political economy of electricity prices and the impact tariff reforms (i.e. winners and losers) has proven intractable in all NEM jurisdictions.

10. Concluding remarks

As a result of the 1990s electricity market reforms, transmission networks were unbundled from the vertically integrated, state-owned monopoly utilities that prevailed from the 1950s. Largely built-up around state boundaries, three of the five network utilities within Australia's National Electricity Market were privatised and two remained state-owned. The regulatory framework applied to the transmission utilities is based on the British model of incentive regulation, which can be traced back to the 1980s telecoms reforms.

Australia's institutional design separates rulemaking (AEMC) from economic regulation (AER) and this has been a strength of the Australian model, ensuring the prospect of capricious actions is minimised. However, the Rules are highly prescriptive, which has positives (i.e. predictability) and negatives (i.e. inflexibility). The recent performance of network regulation (2015-2023) has been advantageous for consumers – noting this follows a period of policy-driven gold plating (2007-2015). The challenges going forward are how to adapt a regulatory framework, and regulator, who has very successfully slowed the rate of investment and growth in network tariffs, to the new era of decarbonisation which requires accelerated and at times anticipatory investment in renewable energy hosting capacity and interregional

[38] The current Rate of Return Instrument moves inflexibility down a level, from the Rules, to the AER's draft instrument which must be followed and capable of automatic application. Therefore, it may also have broken under GFC conditions, as the AER would be obliged to hard-code debt and averaging decisions ex ante.

interconnections. Thus far, the Integrated System Plan and State Government legislation have been the primary response – both of which largely bypass the regulator.

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