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Regulated electricity networks, investment mistakes in retrospect and stranded assets under uncertainty

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Keywords Electricity Utilities, Falling Demand, Stranded Assets

JEL Classification D4, L5, L9 and Q4

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1. Introduction

Australian residential electricity tariffs rose sharply over the period 2007-2015. Climate change policies, solar Feed-in Tariffs and Australia's 20% Renewable Portfolio Standard contributed to increases but the overwhelming driver related to regulated network tariffs.[1] Significant investment *mistakes in retrospect* occurred, commencing from 2004. Indeed, from 2004-2018 the Regulatory Asset Base (RAB) of electricity networks across Australia's National Electricity Market (NEM) tripled in value, from $32 billion to $93 billion. As one of our international peers noted, these mistakes have had real implications for politics more generally, and have played into the highly polarised narrative around energy policy in Australia.

The run-up in the capital stock was driven by forecast demand growth and in some regions a tightening of reliability standards by policymakers[2]. Power system load growth during the late-1990s to mid-2000s, particularly in NEM regions such as Queensland, were surprisingly strong due to mining-related demand expansion, sustained population growth and the rapid uptake of air-conditioners in the residential sector. In 2004, a series of unfortunate network-related load-shedding events occurred in the capital cities of Sydney and Brisbane. As Helm (2014) explains, an energy market crisis will induce an inquiry, an inquiry will produce policy recommendations, and some policy recommendations will inevitably be misguided because the market is rarely afforded an opportunity to scrutinise their (entirely predictable) unintended side-effects. In this instance, the misguided policy recommendation was to

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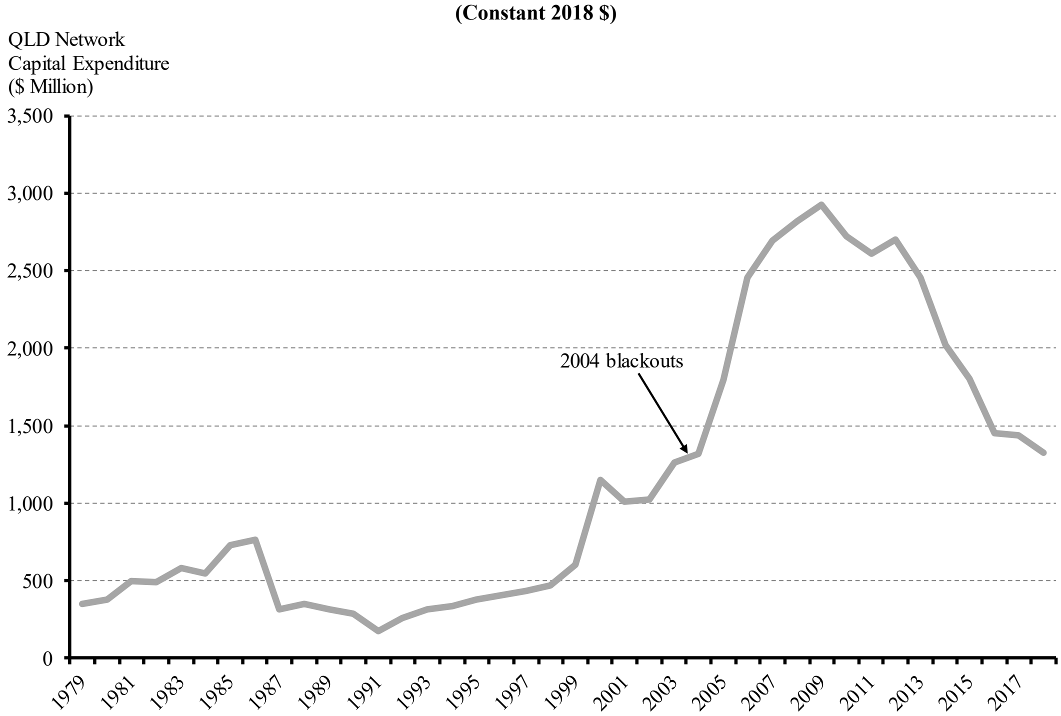
[1] The Australian Competition & Consumer Commission found the average electricity bill had increased from $1210 to $1636 (+35.2%) over this period. The single largest contribution was network charges, up $148 or 35%. See ACCC (2018 at p.6).
[2] Additionally, in Victoria a contentious ($2.4 billion) smart meter program was added to the capital stock.

tighten network reliability standards to reduce the incidence of load-shedding events - with the predictable (and predicted) unintended side-effect being Averch & Johnson (1962) gold-plating.[3] The combination of forecast load growth *and* tighter reliability standards led to record levels of capital expenditure between 2005-2015, as Figure 1 illustrates.

Figure 1: **Network Capital Expenditure (1979-2018 – Queensland)**
(Constant 2018 $)

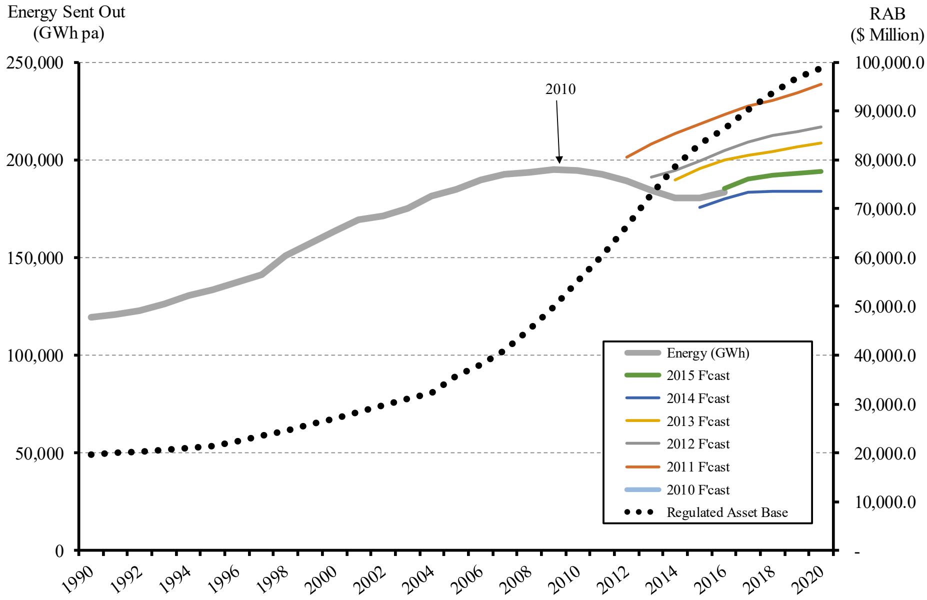


Source: Simshauser (2014a), Australian Energy Regulator (AER).

An energy market crisis usually involves many things going wrong at once. In Australia, power was first produced in Queensland's capital, Brisbane, on 9 December 1882 and from that moment onwards Australian final electricity demand experienced continuous year-on-year growth regardless of economic conditions.[4] But the Global Financial Crisis and disruptive competition in the form of distributed resources combined to produce the first sustained contraction in final electricity demand in Australian power industry history, from 2010 (see Figure 2 – LHS axis). Thus, not only did prior-period load forecasts prove too optimistic, 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). By 2015, NEM energy demand (GWh) had fallen to 2004 levels. Consequently, rather than deploying scarce capital productively to meet power system load growth, significant investment mistakes in retrospect merely added an expensive layer of excess capacity[5] (see Figure 2 – RHS axis).

[3] See Simshauser (2014a) for further details.
[4] 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.
[5] As described by Pierce (1984) albeit in relation to a similar pattern with nuclear power stations in the USA.

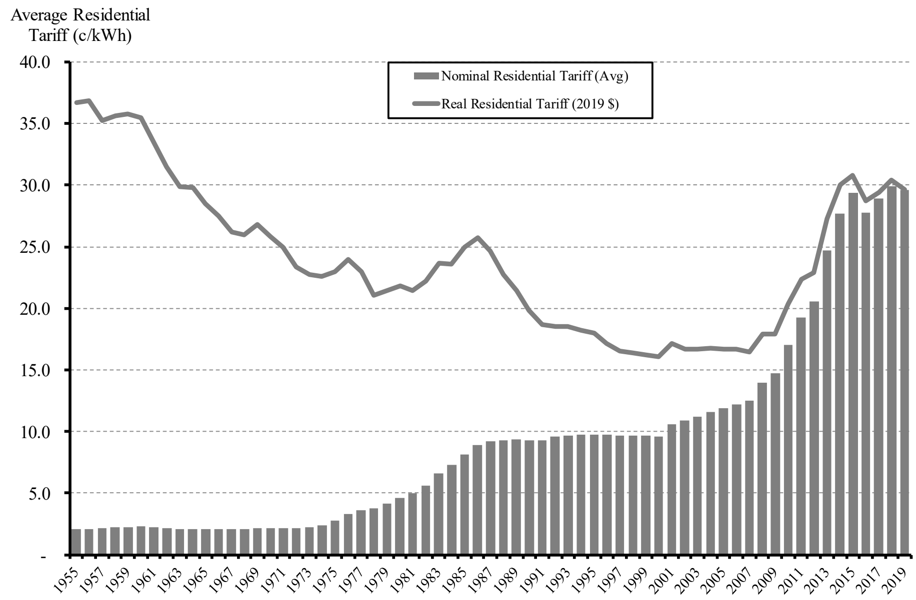
Figure 2: **NEM System Load 1990-2018 and Network Regulated Asset Base**



Source: Energy Supply Association of Australia (esaa), Australian Energy Market Operator (AEMO), Simshauser (2018a).

Compounding matters, when regulatory determinations were being finalised the financial markets (bond markets in particular) were experiencing their worst conditions since the 1929-1932 financial crisis.[6] These conditions fed directly into Capital Asset Pricing Models and produced abnormally high regulated rates of return for the monopoly utilities. Investment mistakes in retrospect were thus further amplified by an elevated regulated rate of return. When combined with contracting load, retail-level tariffs increased from 12.54c/kWh in 2007 to 29.34c/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 3.

Figure 3: **Average Retail Tariff[7] (1955-2019[8])**



Source: esaa, Simshauser (2018b)

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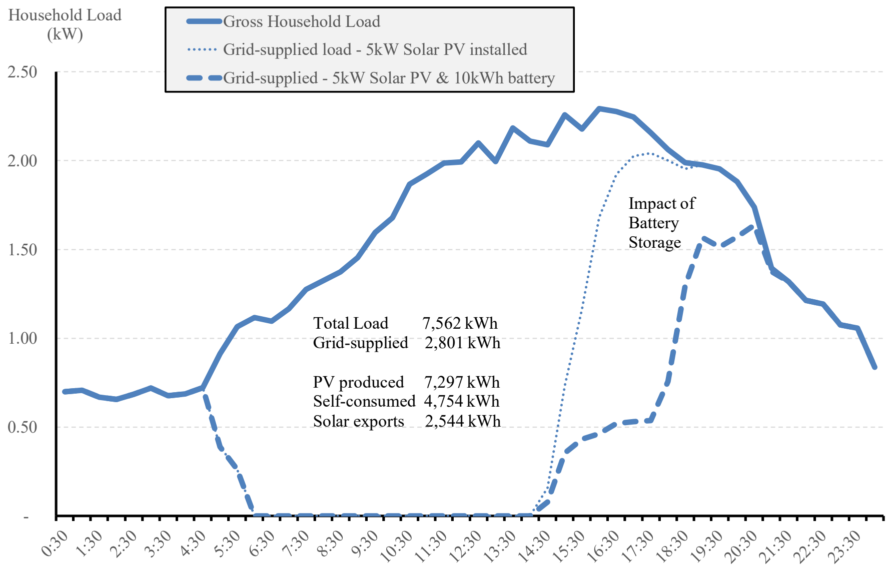
[6] See Simshauser (2014b) and in particular Figure 2 for a comparison of bond yields from 1929-1933 and 2006-2010.
[7] Retail tariff series in Figure 3 uses Queensland data, and is the final end-use tariff including generation + network + retail + environmental charges, and is structured as a two-part 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.
[8] Data is Australian Financial Year, which runs from 1 July to 30 June. 2019 tariffs (i.e. for the 2018/19 Year) were published in May 2018.

Rising tariffs induced a Demand Response for grid-supplied electricity, and as the forecasts in Figure 2 tend to indicate, at levels not previously seen in part due to rooftop solar PV. For a large household consuming 7562kWh per annum, installing a 5kW system (current installed cost of ~ $4500) reduces grid supplied power by -40.5% to 4,497kWh. The potential impact of battery storage could intensify grid loses to -63.0% as Figure 4 illustrates:

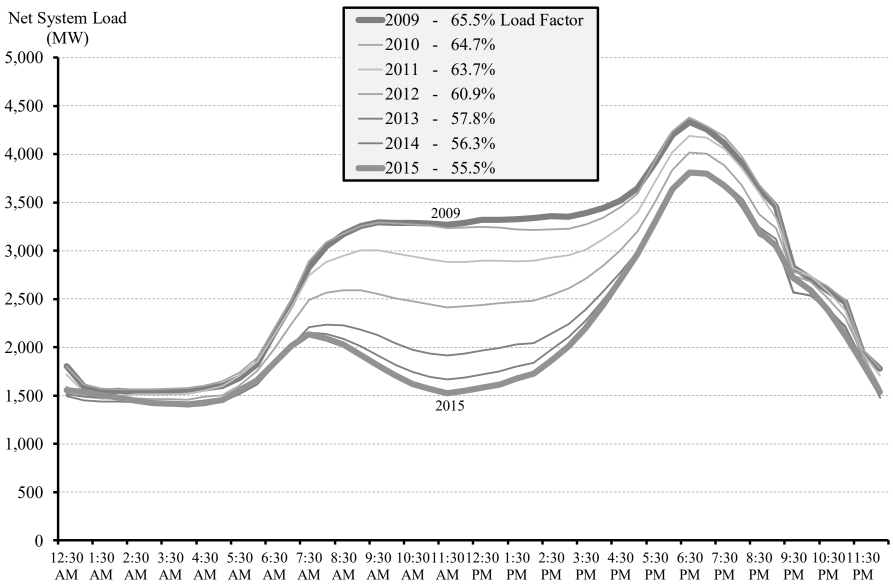
Figure 4: **Household summer load[9], solar PV and battery storage impacts**



Source: Simshauser (2016)

With the uptake of solar PV by more than 30% of detached households in regions such as Southeast Queensland, network load has been progressively *hollowed-out* (see Figure 5). This, coupled with inadequate tariff design, produced a genuine risk of networks in decline[10].

Figure 5: **Distribution Network 'Average Net System Load Profile'**



Source: Energex (Southeast Queensland), Simshauser (2018a)

When significant investment mistakes in retrospect are combined with a network in apparent decline, a certain level of assets will fail a *used and useful* test and will ultimately meet the

[9] This chart displays the average Southeast Queensland household load during 12 critical event days of summer with the full underlying annual data set with 30-minute resolution at the customer switchboard circuit level (i.e. including general power, air conditioning, hot water heating, lighting and cooking appliances) available in Simshauser (2016).
[10] See also Simshauser (2016).

definition of *stranded assets*, i.e. assets unlikely to be supported by future net revenues (Simshauser, 2017). In the Australian case, there have been numerous calls for network asset stranding (see for example Mountain, 2014; Grant, 2016; Grattan, 2018; ACCC, 2018).

A decision to pursue a large-scale asset stranding programme would likely require a well settled view of a network in decline. But rarely are policy and regulatory problems clear cut. In practice, future energy demand and electricity network use is inherently uncertain. We suspect few regulatory rule books are pre-populated with suitable policy prescriptions for clear-cut episodes of stranded assets, let alone uncertain, forward market conditions. Conversely, a failure to deal with significant investment mistakes in retrospect produces static efficiency losses and the allocative inefficiency that arises is likely to exacerbate a network in decline through investments in bypass options above the efficient level.

In this article, we develop a policy prescription for dealing with stranded assets under uncertainty[11]. Rather than permanently stranding assets that fail a used and useful test, our prescription aims to temporarily *Park* excess capacity; we then proceed to re-organise the financial and economic affairs of a template network utility by issuing government-sponsored (credit-wrapped) bonds to temporarily finance the *Parked RAB's* underlying debt. This produces an arbitrage between the network cost of capital, and the ultra-low cost of government-wrapped bonds. The Parked RAB balance is then re-tested on a used and useful basis at each five-year regulatory determination, at which point Parked Assets are *Un-Parked* and returned-to-service in line with customer connections growth, demand growth, or both.

The most interesting result is the immediate impact on network tariffs – as expected Parking the assets and securitisation of the stranded debt (i.e. cost of capital arbitrage) produces a reduction in tariffs under our generalised assumptions. The most contentious aspect of the model would be how stranded equity capital is treated.

This article is structured as follows. Section 2 reviews relevant literature. Section 3 presents a Regulated Monopoly Model and our Base Case scenario. Section 4 analyses the "Park and Loan" policy. Conclusions follow.

2. Review of Literature

A number of explicit and implicit assumptions underpin monopoly price regulation. Among the most fundamental implicit assumptions is growth in demand relative to growth in total network costs. As Decker (2016) explains, the 20th Century was characterised by ever expanding demand for utility services, and this underpinned a general stability of tariffs. But if this relationship breaks down such that demand growth stalls or contracts while cost growth remains non-negative, the mechanics of price regulation produce an increasingly unstable tariff trajectory (Simshauser, 2017).

Historically, significant investment mistakes in retrospect, which might cause a temporary surge in cost growth relative to energy demand, could be "sweated out" with comparatively little damage done to overall economic efficiency. Constant population growth and an expanding economy could be relied upon to produce ever higher power system demand and thus planning errors would self-correct over time. But various jurisdictions are now experiencing *networks in decline* (or as one reviewer noted, *networks in flux*) in the traditional utility services of electricity, gas, fixed line telecoms and postal services (Decker, 2016).

Significant investment mistakes in retrospect combined with an electricity network in decline will present policymakers and regulators with serious problems because the outcomes for consumers are in stark contrast to competitive markets (Simshauser, 2017). In the competitive generation market, investment mistakes in retrospect and declining demand result in (1) excess capacity, (2) falling spot and forward prices, (3) asset write-downs and plant

[11] The authors would like to acknowledge Mr Brian Carrick from Queensland Treasury Corporation, who described this concept to Prof. Simshauser (then Director-General of the Department of Energy & Water Supply) in 2017.

closures, (4) shareholder losses and (5) gains in consumer surplus through falling prices. Conversely, investment mistakes in retrospect and declining demand for a regulated network monopoly results in (1) a higher RAB, (2) a higher annual revenue requirement, (3) a correspondingly higher regulated tariff, (4) stable returns to shareholders, and (5) welfare losses borne entirely by consumers through higher tariffs.

Economic theory and the great regulatory treaties of Bonbright (1961) and Khan (1970, 1971) are silent on the concept and how to treat the stranded assets of regulated monopoly utilities. Recognition of the problem can be traced back to Hotelling (1938, p266), who first described the modern-day *utility death spiral,* viz. declining demand being aggravated by rising monopoly tariffs. Beyond this, literature can be traced at least as far back as Pierce (1984), Joskow & Schmalensee (1986) and Hoecker (1987) who focused on supply-side investment mistakes in retrospect, while MacAvoy et al (1989, p.214) first described the risk of a network in decline arising from disruptive competition.

A wealth of literature would subsequently emerge in the US (c.1995-2005) due to FERC Order 888[12] which as a policy had the effect of stranding monopoly generation assets with *full* economic recovery for shareholders. Recovery was typically by way of long-dated, non-bypassable stranding charges and in some cases credit-enhanced through the issuance of transition bonds (Joskow, 1996a; Michaels, 1998). More recently, interest in the implications of energy markets in decline (or minimal growth) has emerged in the 2010s, with contributions from Faruqui (2013), Sioshansi (2014), Crawford (2015), Decker (2016), Simshauser (2017) and others. Decker also catalogues numerous contemporary contributions from fixed line telecommunications and traditional postal services.

With significant mistakes in retrospect and a network in decline, asset stranding may become necessary in order to reduce the rates of bypass (and demand contraction), and in turn, tariff instability. The regulatory and policy challenge that follows is (1) what assets are to be stranded[13], and (2) the level of recovery – that is, what percentage of stranded assets should be recovered by non-bypassable charges, and what if any should be written-off?

The complexity of asset stranding policy is underpinned by the fact that efficiency arguments compete with fairness arguments (Hogan 1994; Baumol & Sidak 1995), the amounts at stake are inevitably large (Tye & Graves 1996; D'Souza & Jacob, 2001; Ritdchel & Smestad, 2003) and all available remedies[14] produce a zero-sum game – any credible solution at least partially unwinds the very benefits arising from the cause of stranded assets (Navarro, 1996; Wen & Tschirhart 1997). In the case of FERC Order 888, the full (i.e. 100%) recovery of stranded assets was justified on the basis of (1) the regulatory compact, (2) maintaining power system financial integrity, and (3) cost causation (McArthur, 1998). This was however a contentious decision (Rose, 1996).

2.1 The regulatory compact and arguments for *Full Recovery*

The *regulatory compact* can be traced back to 1983[15] and is largely consistent with Kydland & Prescott's (1977) theory of dynamic inconsistency. From a fairness perspective, utility investors make vast financial investments in long-lived assets to serve the public in exchange for a guaranteed rate-of-return. If a regulator approves as prudent a series of network investments at the time of commitment, and then subsequently deems such assets as stranded, capital markets (i.e. both debt and equity capital markets) will interpret policy as opportunistic and heighten the cost of capital in future regulatory periods, produce investment

[12] Federal Energy Regulatory Commission (FERC) Order 888 was enacted 24 April 1996, and had the effect of stranding generation assets of approximately $135 billion in value. See Rose (1996) for a summary of the standing estimate undertaken by Moody's.
[13] Note that ultimately it is the tariff that is stranded rather than specific physical network assets per se (see Simshauser 2017).
[14] Recovery typically occurs via accelerated depreciation, supra-competitive prices or non-bypassable surcharges.
[15] Michaels (1995) observes the use of "regulatory compact" formally appears in court and regulatory proceedings from 1983. Rose (1996) notes the notion of a *regulatory bargain* can be traced back to case law in the 19th century (regarding railroad regulation). In his 1972 article, Myers (p78) describes an 'implicit contract' between investors and regulators.

frictions and potentially block investment (Baumol & Sidak, 1995; Woo et al. 2003; Douglas et al. 2009; Kind, 2013).

MacAvoy et al. (1989, pp224-230) highlight *incumbent burdens* – tariff rigidity, an inability to adopt more efficient market segmentation through discriminatory prices, Universal Service Obligations, minimum service standards, limits on long term contracts, conflicts amongst regulation, policies which subsidise bypass (e.g. solar Feed-in Tariffs) and other mandated environmental schemes which all deviate from minimum cost (see also Hogan, 1994; Navarro, 1996; Boyd, 1998; Pagach & Peace, 2000; Martin, 2001; Decker, 2016; Simshauser, 2017). As MacAvoy et al (1989, p245) noted:

> *A commonly overlooked feature of most bypass settings is that bypassing customers not only receive the service that they purchase from [for example, Solar PV & Battery Storage], but also obtain back-up service from the existing utility at no substantial cost to them…*

Policymakers and regulators frequently force utilities to make sub-optimal investments to meet incumbent burdens, and such investments were only originated because returns were guaranteed. Economics may not provide a basis for systematic conclusions on matters of equity and fairness, but stranding these asset categories without recovery does present an *'inescapable issue of procedural fairness'* (Baumol & Sidak, 1995, p.843).[16] Crawford (2014) outlines the conditions whereby an asset stranding program may produce higher future tariffs in any event.[17] Consequently, FERC Order 888 and full recovery was argued to be sound public policy, noting recovery mechanisms can be structured without distorting competition (Joskow, 1996a; Tye & Graves, 1996).[18]

2.2 A normative economic and legal analysis of the regulatory compact

Efficiency and equity arguments can however be used in reverse (Boyd, 1998). For example, while it may appear unfair to strand a regulator-approved investment, it is also unfair to recover excessive and misguided utility investments from customers (Maloney & Sauer 1998). Indeed, as one reviewer noted, it is difficult to identify ex post who persuaded who to make such investments. Monopoly utilities that argue for full recovery are over-relying on regulation (Brennan & Boyd, 1998); and as Graffy & Kihm (2014) observe, those monopoly utilities that do are frequently presiding over businesses characterised by significant investment mistakes in retrospect.

A strict normative economic and legal analysis of the regulatory compact does not support full recovery of stranded assets as Rose (1996), Navarro (1996), Boyd (1998) and others[19] explain. Consumers have not agreed to the implicit terms of a regulatory compact whereas utility investors signed up for risky returns (Maloney & Sauer, 1998; Woo et al. 2003). The regulatory compact assumes regulators act as agents on behalf of consumers whereas a long historical line of economic literature explains why this is not necessarily the case (see Stigler, 1971; Posner, 1974; Peltzman, 1976). And because no written contract exists with consumers, anything not explicitly identified in regulation is immediately contentious (Brennan & Boyd, 1997). As Rose (1996) and Boyd (1998) explain, the sub-clauses of a regulatory compact are matters for pure speculation and cannot be relied upon to justify all of the upside, and none of the downside, inherent in long term contracts. Beard et al. (2003) highlight that long term contracts always include clauses for contingencies, viz. *price re-*

[16] Although not directly relevant to Australia, there is a strand of literature that extends this one step further and classes such regulatory action as a violation of the US Constitution's Takings Clauses of the Fifth Amendment and its application to the states under the Fourteenth Amendment. See Baumol & Sidak (1995), Rose (1996) or Graffy & Kihm (2014) for further details.
[17] The financial economics logic of Crawford (2014) considers a *zero recovery scenario* which differs from a *partial recovery scenario* in which a RAB is fundamentally unsustainable – even to the most optimistic equity investor.
[18] A reviewer noted that the US situation was unique in that utilities had to agree to deregulation. In many other countries (e.g. England & Wales, New Zealand, Singapore, Australia) it was forced upon them and this changes the nature of the recovery question. In New Zealand for example, arguments against full recovery focus on risk premiums; viz. since regulated utilities typically earn a 2% premium over the risk free rate, this implies writing off assets once every 50 years.
[19] See also McArthur (1998), Brennan & Boyd (1997), Graffy & Kihm (2014) and Simshauser (2017).

openers in circumstances when prices formed under a long-term contract breach certain limits or when Material Adverse Change clauses are triggered. A normative analysis of economics and law under conditions of long term contract ambiguity, which *ipso facto* exists with the regulatory compact, dictates that responsibility tends to fall on the party best able to adapt to the relevant circumstances. In the case of investment error and disruptive competition, it is difficult to argue this is *entirely* the consumer (Rose, 1996; Boyd, 1998; Simshauser, 2017).

2.3 Full vs Partial recovery of stranded assets

The obligation to supply and other incumbent burdens are, *prima facie*, compelling arguments in favour of full recovery and in certain instances will apply to specific investments (Navarro, 1996). However, rarely do utilities flag the risks of large capital expenditures with policymakers and regulatory authorities. McArthur (1998) observes that in hindsight, the regulatory compact argument appears designed to conceal the virtually exclusive role monopoly utilities have in planning national energy infrastructure, and their role in encouraging regulated capital-intensive outcomes.

Ideal regulation forces utilities to operate at competitive levels of investment, price, output and profit with prices set so utilities earn a 'fair return' on investment (Myers, 1972). But regulatory powers to enforce fair returns have limits and *do not* extend to setting rates that result in positive utility returns, or utility solvency when a network is in decline due to the presence of disruptive competition. The public policy goal economic regulation is not to protect firms from competition, but to simulate competition and protect consumers from monopoly prices; consequently there is no basis for full recovery arising from disruptive competition (Pierce, 1984; Rose, 1996).[20] As Graffy & Kihm[21] (2014, p26-27) explain:

> *…regulation and the fair return principle applies when a utility has monopoly power, not when it is besieged by disruptive competition that it is failing to navigate… If market values decline in response to successful competition, utilities cannot simply look to their regulators to undo the impact of fundamental changes in market forces…*

A crucial tenet of utility regulation is the *used and useful* principle (Hoecker, 1987).[22] Pierce (1984) explains the *prudent investment test* is a low bar and rarely used in its pure form because it would be unusual for utilities to make blatantly imprudent capital commitments. When prudent investment is combined with used and useful, excluding certain investments is based on an objective test rather than finding fault (McArthur 1998).[23] Regulatory approval at the time of investment commitment does not, therefore, form a basis for full recovery. Regulators have neither the resources, nor responsibility, to create and guarantee investment plans, and cannot be expected to match the expertise and resources of utilities, nor come close to second-guessing what constitutes a prudent investment program (Navarro, 1996; Maloney & Sauer, 1998; Douglas et al. 2009). Mistakes made by regulators approving apparently prudent investments are likely to be a contributing factor, not a primary cause of stranded assets and to say otherwise would be re-writing history (Pierce, 1984). Ultimately, the

[20] Boyd (1998) noted from an efficiency perspective, interpretation of implicit contractual obligations following an unspecified contingency should consider which party can best adapt to, or insure against, risks due to a costly future contingency (this should include considerations of moral hazard). Analyses of how courts and policymakers interpret duties in the franchise relationship with utilities does not mean stranded assets should be fully recovered. Both an analysis of precedent and an economic analysis of optimal contracting suggest partial recovery.

[21] Graffy & Kihm were referring to the 1945 *Market Streetcar* case. In summary, the San Francisco Streetcar company was incurring losses at a monopoly tariff of 5c in the face of disruptive competition (viz. buses and cars). The firm sought, and regulator approved, tariff increases to 7c. This exacerbated market share losses, demand plunged further, thus producing a *Death Spiral*. The regulator reduced tariffs to 6c and court proceedings were initiated. *Market Streetcar* lost the case and this key regulatory principle (i.e. no obligation to protect a firm from disruptive competition) was established.

[22] The *'used and useful'* principle can be traced back to a New York Public Service Commission decision in 1922. Hoecker (1987, p.306 – citing N.Y. Pub. Serv. Comm'n 1922) notes the principle established was that …*Consumers should not pay in rates for property not presently concerned in the service rendered unless (1) conditions exist point to its immediate future use, or (2) unless the property is such that it should be maintained for reasonable emergency or substitute service…* This latter condition clearly indicating reserve planning margins form part of the used and useful asset stock. See also D'souza & Jacob, 2001).

[23] Rose (1996, p70) explains that if a regulatory framework were to rely on a *'pure'* prudent investment test, then returns to stock and bond holders would be very low and commensurate with the low risk of stranding. Conversely, a *'pure'* used and useful test would have substantially higher returns to equity and debt holders because they would face stranding risks with no compensation because it is embedded in the rate of return. In practice, most regulatory frameworks employ a combination of both.

regulatory system leaves entrepreneurial decisions and capital management in the hands of utility management, not those of the regulator (Madian, 1997).

Economic arguments in favour of full recovery are constructed around the premise that network regulation has limited the ability of monopoly utilities from raising prices, and that asset stranding may ultimately inflate the cost of capital in future periods. But as Navarro (1996), Pagach & Peace (2000) and Woo et al. (2003) have noted, risk-adjusted profits are earned by monopoly utilities; and while utility tariffs have been "capped" they have also been "floored" – in no unregulated industry do inept firms enjoy such a low probability of failure (Michaels, 1995). Pagach & Peace (2000) and Martin (2001) explain that investors may have an initial adverse reaction to a policy of *partial recovery* but most will quickly discern the difference between bad historic investments and well-founded future investments. D'Souza & Jacob (2000) analysed stock price movements of 18 listed utilities in the US that disclosed stranded assets in their annual accounts during the 1990s which found that investors *did not* anticipate full recovery prior to FERC Order 888 being announced – anticipating on average only 76-77% recovery.

2.4 **Zero recovery not credible**

To be perfectly clear, there is no serious argument for *zero recovery* of stranded regulated monopoly assets (Pierce, 1984; Navarro, 1996; McArthur, 1998; Brennan & Boyd, 1997; Beard et al. 2003; Simshauser, 2017). Some recovery is appropriate, especially where utilities have been compelled to invest as a result of regulation or policy mistakes (Baumol & Sidak, 1995; Hirst & Hadley, 1998; Boyd, 1998; D'Souza & Jacob, 2001; Martin, 2001; Beard et al. 2003). At risk is the credibility of government policy – that is, providing stable rules for the market is an important function of policymakers and a pattern of random or capricious changes undermines the credibility of government (Hogan, 1994; Simshauser, 2017). As Kydland & Prescott (1977) explain, firms respond predictably to dynamic inconsistency.

In Simshauser (2017) a series of asset stranding principles for regulated networks were outlined. The necessary condition for stranded assets was defined as a network in decline, and sufficient condition being non-negative cost growth. Under these conditions tariffs will become unstable and the regulatory framework will approach the limits of its design envelope. The principles also suggested that stranded assets are a case-by-case proposition (Joskow, 1996b; Hirst & Hadley 1998).

In an asset stranding process, the recovery amount (%) and the mechanism for recovery to be selected is important. And while there are many possible mechanisms, it is ultimately a policy choice, not an analytical determination (Simshauser, 2017). A defining characteristic of electricity is that, from a pricing perspective, it has no natural form with flow (kWh), stock (kW), load volatility and customer numbers all being legitimate pricing mechanisms (Boiteux, 1956; Boiteux & Stasi, 1952; Nelson & Orton, 2013; Simshauser, 2016; Keay, 2016). Accelerated depreciation[24] is also a potential mechanism along with supra-competitive prices (Martin, 2001), explicit surcharges (Beard et al. 2003), return of capital only (Pierce, 1984) and securitised bond issues (Michaels, 1998; Pagach & Peace, 2000; Martin, 2001; Ritschel & Smestad 2003).[25] In the present exercise we have opted for the latter.

[24] Crew & Kleindorfer (1992) noted that in the presence of emerging technology there is limited time for regulators to take remedial action and that exposed assets can adopt more accurate depreciation methods. Depreciation methods have long been of interest to economists, dating at least as far back as Hotelling (1925). Under rate of return regulation, choice of depreciation method represents a key input to regulated prices and has a circular reasoning which materially affects how capital costs are recovered (Schmalensee, 1989; Burness & Patrick 1992).

[25] Michaels (1998) explains that as a financing tool, securitisation can be traced back to 1977 and its intended effect in the stranded asset case is to lower the cost of capital of the recovery target. The first deployment of transition bonds in the electricity industry was in California, where it was used to strand approximately $10bn in generation assets and deliver 10% tariff reduction. As quantitative analysis later in this article demonstrate, the effectiveness of a securitisation program is contingent upon (i) interest rate differentials being greater than debt-tenor differences and (ii) where capital markets have systematically overestimated the risk of utility default on utility bond payments (Ritschel & Smestad 2003). More directly, Michaels (1998, p60) notes that unless capital markets are wildly inefficient, securitization's effect on a utility's cost of capital is likely to be small.

3. Regulated Monopoly Model

In this article, we use the Regulated Monopoly Model which simulates a template regulated network utility once certain inputs have been defined (see also Simshauser, 2017). Outputs include the Annual Regulated Revenue Requirement, Tariffs, Profit & Loss, Balance Sheet and Cash Flow Statements and credit ratios. Model resolution is annual data over a 20-year window. Key assumptions (Table 1) are based on parameters typical of an Australian regulated monopoly but could be adjusted for any relevant jurisdiction.

Table 1: **Model Inputs**

Financial Inputs (t=1)				Network Inputs (t=1)		
CPI	π	2.25	%	Customer Numbers	1.5	million
X Factor	X	0.10	%	Avg Household Load	6,800	kWh
Remain. Asset Life	l	30	Yrs	Total Residential Load	10,025	GWh
Net Capital Exp.	C	$200	M	Connections Growth pa	1.6	%
Operating Exp.	θ	$300	M	New Households Load	4,500	kWh
Transmission Chrg.	ϑ	$275	M	Energy Efficiency Effect	-0.5	%
Accounting Tax	$a\tau^i$	30	%	Initial Solar PV Takeup	2.7	%
Est. Cash Tax	$c\tau^i$	15	%	Initial Batter Takeup	2.7	%
Benchmark Gearing	D^u/V^u	60	%	Initial EV Takeup	2.7	%
Risk Free Rate	Rf	2.90	%	Solar Self Consumption	3,064	kWh
Swap Rate	$R^u{}_t$	0.00	%	Battery Self Consumption	1,692	kWh
BBB Credit Spread	S^u	219	bps	EV Consumption	2,700	kWh
Market Returns	Rm	9.40	%	Own-Price Elasticity	-0.10	
Equity Beta	βu	0.70	%	Base/Park Scenario Elasticity	-0.10	
Bond Coupon	I^i	2.25	%	Network / Retail Tariff	40	%
Imputation Credits	γ^u	40	%			

Source: Simshauser (2017)

In the present exercise, and as with Simshauser (2017), the regulated electricity distribution utility modelled has an opening RAB of $10 billion, 1.5 million household customers, with existing households consuming on average 6,800kWh pa (intended to be representative of a typical distribution network in Queensland or New South Wales). Total residential load in the Base Case commences at 10,025 GWh and decays each year, starting at -0.7% and moderating to -0.3% through a combination of energy efficiency effects (0.5% lost load pa), solar PV (per Figures 4-5) and battery take-up rates. New connections growth (1.6%) results in new albeit smaller customers loads of 4,200kWh and in certain scenarios Electric Vehicle loads are added. Estimated own-price elasticity is -0.10 and given capital market inputs in Table 1, the benchmark WACC is 6.2% (see Eq.6).

3.1 Annual Regulated Revenue Requirement

For any network utility, the Annual Regulated Revenue Requirement (AR_t^i) involves a building block approach comprising approved Operating Expenses θ_t^i, Return of Capital (i.e. Regulatory Depreciation) δ_t^i, Cash Taxes $c\tau_t^i$, Return on Capital r_t^i and Transmission Use of System charges ϑ_t^i:

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

δ_t^i is derived through the combination of Straight-Line Depreciation (RAB_t^i / l_t^i) where (l_t^i) is average remaining useful asset life of the i^{th} utility at time t, then deducting RAB Indexation ($RAB_t^i \cdot \pi_t$) – the latter being how price inflation (viz. π_t) is accounted for in the sunk cost recovery process. $WACC^u$ for electricity utility sector, u, is subsequently defined in Eq.(6). With Operating Expenses, $\forall t > 1$, θ_t^i escalates at $CPI - X$.

Each year RAB_t^i is rolled-forward:

$$RAB^i_{t+1} = \left[RAB^i_t + C^i_t + \left(RAB^i_t \cdot \pi_t\right) - \left(RAB^i_t / l^i_t\right)\right] \tag{2}$$

In (2), C^i_t is Net Capital Expenditure (i.e. capital expenditure *less* asset disposals) and (π_t) is the inflation index. The non-linear tariff structures and quantities from the various network customer segments are given by AR^i_t:

$$AR^i_t \equiv \sum_{t=1}^{n} \sum_{j=1}^{m} \left(p^{kj}_t \cdot q^{kj}_t\right) \tag{3}$$

Where p^{kj}_t is the price of the k^{th} component of tariff *j* in year *t* and q^{kj}_t is the relevant expected quantity of component *k* of tariff *j* in year *t*. Note the relevant quantity may be kWh, kW or the number of days in year *t*.[26]

In order to derive underlying AR^i_t for a Park and Loan scenario, let ψ^i_t be the value of Parked Assets of the i^{th} firm. Equation (1) is thus modified as follows:

$$AR^i_t = \sum\left(\theta^i_t, \delta^i_t, c\tau^i_t, r`^i_t, \vartheta^i_t\right) \mid r`^i_t = \left(RAB^i_t - \psi^i_t\right) \cdot WACC`^u \ \wedge \forall\, t \tag{4}$$

Note $r`^i_t \neq r^i_t$ due to a reduction in RAB^i_t arising from ψ^i_t

In order to derive headline AR^i_t for Park and Loan scenario the recovery of Bonds must be accounted for. Let b^i_t be the annual cash flows associated with Park and Loan Bonds issued of φ^i with a tenor of y years and coupon I^i in order to finance the debt associated with Parked Asset amount ψ^i_t.

$$AR^i_t = \sum\left(\theta^i_t, \delta^i_t, c\tau^i_t, r`^i_t, \vartheta^i_t, b^i_t\right) \mid b^i_t = \left[\frac{\varphi^i_t}{\left[1-\left(1+I^i\right)^{-t}/\left(I^i\right)\right]} + \left(\varphi^i_t \cdot I^i\right)\right] \forall\, t \leq y \quad \varphi^i_t = \psi^i_t \cdot \left(\frac{D^u_t}{V^u_t}\right) \tag{5}$$

Note that the terms D^u_t and V^u_t are defined in Eq.(6).

3.2 Cost of Capital

A crucial input driving results in equations (1), (4) and (5) is the $WACC^u$ for regulated utility firms *u*:

$$WACC^u = \left\{\left(\frac{E^u_t}{V^u_t}\right) \cdot \left(\frac{R_f + [R_m - R_f) . \beta^u]}{[1 - c\tau^i_t . (1 - \gamma^u)]}\right)\right\} + \left\{\left(\frac{D^u_t}{V^u_t}\right) . \left(R^u_t + S^u_t\right)\right\} \tag{6}$$

Where:

- R_f = Risk free rate of return
- R_m = expected market return
- β^u = equity beta for the regulated electricity utility firms *u*
- E^u_t = sector benchmark value of equity
- D^u_t = sector benchmark value of debt
- V^u_t = total market value = $(E^u_t + D^u_t)$
- R^u_t = reference interest rate (swap rate) in year *t* of regulated utility firms *u*
- S^u_t = credit spread given BBB credit ratings of regulated utility firms u in year *t*
- $c\tau^i_t$. = effective taxation rate for the i^{th} firm
- γ^u = estimated utilization of imputation tax credits of regulated utility firms *u*

Equation (6) is based on Sharpe (1964) and Lintner (1965) with modifications by Officer (1994) to deal with dividend imputation (for those jurisdictions with taxation systems incorporating imputation credits).

[26] Consequently, the unit price may be c/kWh, $/kW or c/day.

3.3 **Dynamic Financial Model**

In the Profit & Loss Statement, Earnings Before Interest & Tax $(EBIT_t)$ and implied Cash Earnings $(EBITDA_t)$ are given by:

$$EBIT_t = AR_t^i - \sum\left[\theta_t^i, (RAB_t^i/l_t^i), \vartheta_t^i, b_t^i\right] \wedge EBITDA_t = EBIT_t + \vartheta_t^i \quad (7)$$

Net Profit After Tax $(NPAT_t)$ commences with $EBIT_t$ from which interest costs and accounting taxes $a\tau_t^i$ are deducted.

$$NPAT_t = \left[EBIT_t - \left[D_t^i \cdot (R_t^u + S_t^u)\right]\right] \cdot a\tau_t^i \;\middle|\; a\tau_t^i = 30\% \;\forall\, t \quad (8)$$

Net Cash Flow in time *t* (NCF_t) given by:

$$NCF_t = \left[EBITDA_t - c\tau_t^i - \left[D_t^i \cdot (R_t^u + S_t^u)\right] - \rho_t^i - C_t^i - Y_t^i\right] \left|\rho_t^i = \frac{D_t^i}{\left[1-\left(1+(R_t^u+S_t^u)\right)^{-n}/(R_t^u+S_t^u)\right]}\right. \wedge c\tau_t^i = \left[EBIT_t - \left[D_t^i \cdot (R_t^u + S_t^u)\right] \cdot 15\% \;\forall\, t\right] \quad (9)$$

ρ_t^i is principle repayments on outstanding debt D_t^i for the i^{th} firm in time *t*, and Y_t^i is dividends declared and paid to shareholders of the i^{th} firm in year *t* (dividends are paid in the year declared). All other variables are as described above. Note the model limits the running yield arising from ordinary dividends paid from surplus cash as follows:

$$if\left(\varphi^i \geq 0\right), \forall\, z, y, Y_t^i/E_t^i \leq 4\% \quad (10)$$

The Balance Sheet comprises working capital ω_t^i which is modelled to match anticipated quarterly outlays associated with cash costs θ_t^i, ϑ_t^i, $D_t^i \cdot \left(R_t^i + S_t^u\right)$ and ρ_t^i. Fixed assets are set to RAB_t^i. While the value of Debt D_t^i is initially set at the regulatory benchmark $\left(D_t^i/V_t^i\right)$, in subsequent years it provides the mechanism by which cash surpluses or deficits are absorbed:

$$D_t^i = \left[RAB_t^i \cdot \left(D_t^i/V_t^i\right)\right] \wedge D_{t+1}^i = \left(D_t^i - \rho_t^i - NCF_t + d\omega_t^i\right) \quad (11)$$

In certain circumstances $\left(D_t^i/V_t^i\right)$ falls materially below benchmark due to a build-up of cash arising from the constraint in equation (10). A special dividend or return of capital $\left(K_t^i\right)$ is initiated in the following year, as follows:

$$K_t^i = if\left[\left(D_t^i/V_t^i\right)\right] \geq 55\%, 0, RAB_t^i \cdot 5\% \;\forall\, t \quad (12)$$

Equity E_t^i is calculated as:

$$E_t^i = \left(\omega_t^i + RAB_{t+1}^i - D_t^i\right) \quad (13)$$

The Model produces three financial and three credit ratios:

Return on Assets	$EBIT_t/\left(\omega_t^i + RAB_t^i\right)$	(14)
Return on Equity	$NPAT_t/E_t^i$	(15)
Running Div. Yield	Y_t^i/E_t^i	(16)
Gearing	$D_t^i/\left(\omega_t^i + RAB_t^i\right)$	(17)
FFO/Debt	$FFO_t/D_t^i \;\middle|\; FFO_t^i = \left[EBITDA_t - D_t^i \cdot (R_t^u + S_t^u) - c\tau_t^i\right]$	(18)
FCF/Debt	$\left(FFO_t - C_t^i - d\omega_t^i\right)/D_t^i$	(19)

Base Case Results from the model are presented in Table 2 (Years 1-7 displayed). The basic format of Model Results includes Energy Sales, detailed Profit & Loss, Cashflow, Balance Sheet and Ratios. The key results to note from the Base Case are Energy Sold (GWh), which declines from 10,025GWh to 9,280GWh by Year 7 and continues to decay through to Year 20. The Average Tariff, which rises from 13.4c/kWh to 16.7/kWh is driven by the continual rise in Revenue ($1,347.6m to $1,548.8m) and Total Assets ($10,220.1m to $10,863.5m). Note throughout this period, the firm retains a BBB credit rating or better.

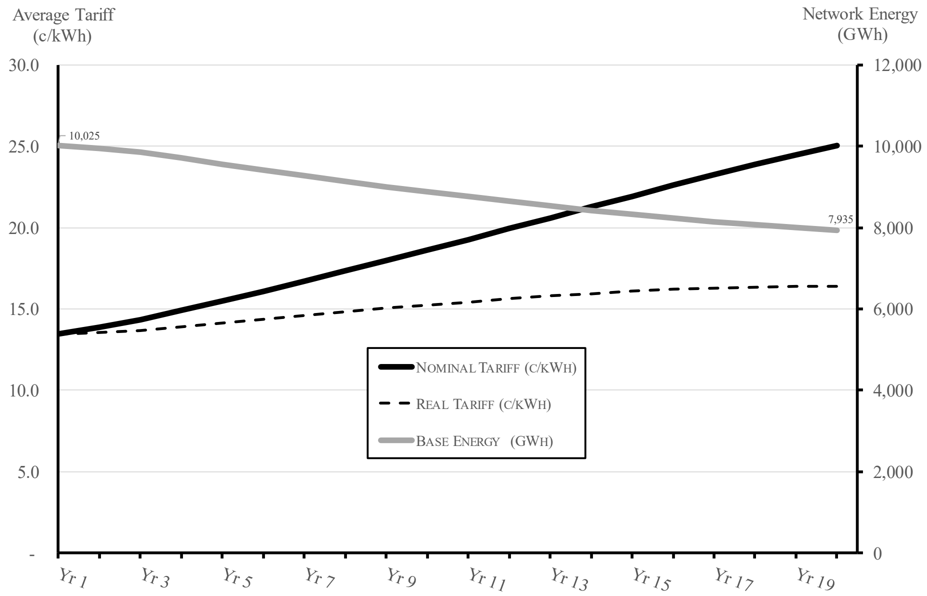
Table 2: **Base Case Results (Years 1-7)**

	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7
ENERGY SALES								
Energy Sold (GWh)		10,025	9,945	9,866	9,714	9,566	9,421	9,280
Fixed Rate (c/day)		0.49	0.50	0.50	0.50	0.51	0.51	0.51
Variable Rate (c/kWh)		10.8	11.1	11.4	11.9	12.4	12.9	13.4
Average Tariff (c/kWh)		13.4	13.9	14.3	14.9	15.5	16.1	16.7
Tariff Increase			3.1%	3.3%	4.0%	3.9%	3.9%	3.8%
PROFIT & LOSS								
Network Revenue		$1,347.6	$1,378.4	$1,411.9	$1,445.8	$1,479.8	$1,514.2	$1,548.8
Stranding Charge - Bond Issuance		*Not Used*						
Total Revenue		$1,347.6	$1,378.4	$1,411.9	$1,445.8	$1,479.8	$1,514.2	$1,548.8
TUoS		$275.0	$280.9	$287.0	$293.1	$299.4	$305.9	$312.4
Opex		$300.0	$306.5	$313.0	$319.8	$326.6	$333.7	$340.8
Interest - Park & Loan		*Not Used*						
Depreciation		$333.3	$347.8	$363.7	$380.1	$397.0	$414.3	$432.1
EBIT		$439.3	$443.3	$448.3	$452.8	$456.8	$460.4	$463.4
Interest		$305.4	$301.7	$297.4	$292.6	$313.5	$307.5	$301.0
Taxation - Accounting		$40.2	$42.5	$45.3	$48.1	$43.0	$45.9	$48.7
NPAT (Underlying)		$93.73	$99.14	$105.59	$112.12	$100.35	$107.00	$113.69
Significant Item - Stranded Assets		*Not Used*						
Significant Item - Wrapped Bonds		*Not Used*						
NPAT (Statutory)		$93.7	$99.1	$105.6	$112.1	$100.3	$107.0	$113.7
CASH FLOW								
EBITDA + Interest Park & Loan		$772.6	$791.0	$812.0	$832.9	$853.8	$874.7	$895.5
Park & Loan - Wrapped Bond Sales		*Not Used*						
Park & Loan - Interest		*Not Used*						
Taxation - Cash		$20.1	$21.2	$22.6	$24.0	$21.5	$22.9	$24.4
Debt - Interest		$305.4	$301.7	$297.4	$292.6	$313.5	$307.5	$301.0
Debt - Principal		$88.9	$93.4	$98.2	$103.2	$108.5	$114.0	$119.8
Capex		$200.0	$204.3	$208.7	$213.2	$217.8	$222.4	$227.2
Dividends *Limit:* 4.0%		$168.8	$175.6	$183.6	$191.7	$179.3	$187.4	$195.5
Special Dividend		$0.0	$0.0	$0.0	$515.4	$0.0	$0.0	$527.5
Net Cash Flow		-$10.6	-$5.2	$1.4	-$507.2	$13.3	$20.5	-$499.8
BALANCE SHEET								
Working Capital	$220.1	$225.1	$230.1	$235.3	$240.6	$246.0	$251.5	$257.2
Stranding Recovery	*not used*							
Fixed Assets	$10,000.0	$10,091.7	$10,204.3	$10,307.0	$10,399.1	$10,480.1	$10,549.3	$10,606.3
Total Assets	$10,220.1	$10,316.7	$10,434.4	$10,542.3	$10,639.7	$10,726.1	$10,800.9	$10,863.5
Debt Finance	$6,000.0	$5,926.6	$5,843.4	$5,749.1	$6,158.4	$6,042.0	$5,913.1	$6,298.8
Equity	$4,220.1	$4,390.1	$4,591.0	$4,793.2	$4,481.3	$4,684.1	$4,887.8	$4,564.7
	$10,220.1	$10,316.7	$10,434.4	$10,542.3	$10,639.7	$10,726.1	$10,800.9	$10,863.5
RATIOS								
Return on Assets (underlying)		4.3%	4.2%	4.3%	4.3%	4.3%	4.3%	4.3%
Return on Equity (headline)		2.1%	2.2%	2.2%	2.5%	2.1%	2.2%	2.5%
Running Yield to Opening Equity		4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Gearing	59%	57.4%	56.0%	54.5%	57.9%	56.3%	54.7%	58.0%
FCF/Debt *('Modest Positive' = BBB-)*		4.1%	4.4%	4.8%	4.8%	4.9%	5.3%	5.4%
FFO/Debt *(> 6% = BBB-)*		7.5%	8.0%	8.6%	8.4%	8.6%	9.2%	9.1%
Implied Credit Rating		BBB	BBB	BBB	BBB	BBB	BBB+	BBB+

FFO = EBITDA - Interest - Current Taxes. FCF = FFO - Capex - Chg Working Cap.

The policy dilemma facing this utility is the trajectory of Energy Sold and Average Tariffs, which is best illustrated through the full 20-Year outputs in Figure 6. Specifically, network load contracts from 10,025GWh to 7,935 GWh (RHS axis) while Average Tariff (LHS Axis) rises from 13.4c/kWh to 16.4c/kWh in real terms (and 25.0c/kWh in nominal terms, which is driven by inflation assumption).

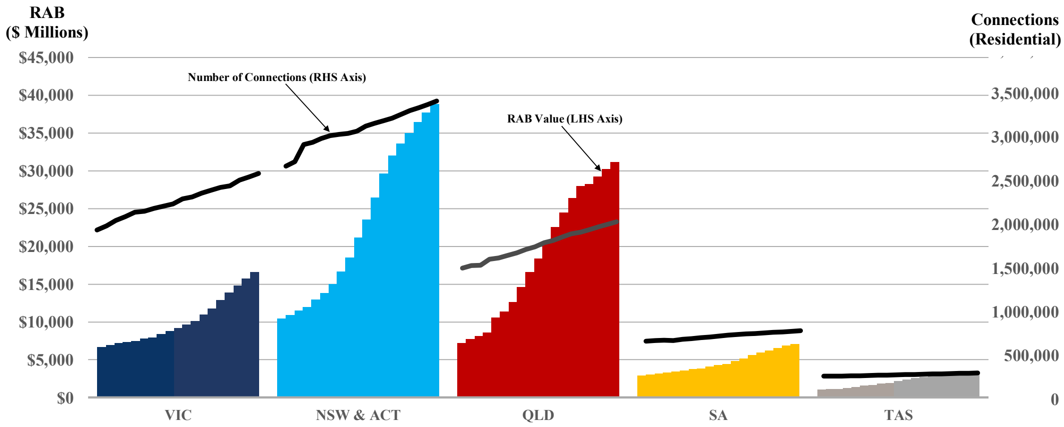
Figure 6: **Base Case Energy Sold (GWh) and Average Tariff (c/kWh)**



Recall the Year 1 network tariff is overinflated to begin with through a combination of Averch & Johnson (1962) gold-plating – the product of policy error through a tightening of reliability standards, and an additional layer of investment mistakes in retrospect through demand forecast error and the implications of disruptive competition (i.e solar PV).

In order to derive our assumed level of excess capacity, Figure 7 provides some context by presenting RAB by NEM region over the period 2001-2018 (LHS Axis) along with residential customer connections in each region (RHS Axis).

Figure 7: **Regulated Asset Base vs Customer Connections: 2001-2018**



Source: esaa; AER; Grant, 2016; Simshauser, 2017.

Table 3 takes the data from Figure 7 and presents an analysis of the change in network RABs per customer connection over the period 2005 to 2018 (with 2005 data inflated to 2018 $'s using the Consumer Price Index). The combined RAB in 2005 was $49,793 million (2018 $)[27], which serviced 7.47 million household accounts and a further 970,000 business customers. Combined Network RAB had risen to $93.7 billion (+88% in real terms) by 2018, whereas customer connections had only increased to 8.86 million (up 18.5%). Consequently, RAB per connections had increased by $3,922 (+59% in real terms). To the extent that this is

[27] The 2005 RAB was $35,768 million in nominal terms.

considered an indicator of excess capacity, the final column in Table 3 implies the system is carrying $34,755 million of excess network capital (see column J).

Table 3: **Change in RAB, Customer Connections, Excess RAB per Connection: 2005 & 2018**

	2005 (in 2018 $)			**2018**		
Region	RAB	Connections	RAB/Connect	RAB	Connections	RAB/Connect
A	B	C	D = (B÷C)	E	F	G = (E÷F)
	($ Million)	(Customers)	($/Connect)	($ Million)	(Customers)	($/Connect)
NSW	$18,021	2,919,583	$6,173	$37,715	3,337,844	$11,299
QLD	$14,656	1,574,167	$9,310	$30,209	1,976,904	$15,281
VIC	$10,428	2,097,560	$4,971	$15,697	2,533,147	$6,197
SA	$4,747	670,743	$7,077	$6,875	768,457	$8,947
TAS	$1,941	213,832	$9,077	$3,279	245,012	$13,383
Total	$49,793	7,475,885	$6,660	$93,776	8,861,364	$10,583

	Change			
Region	RAB/Connect	RAB/Connect	RAB Excess	RAB Excess
	H = (G-D)	I = (H÷D)	J = (H x F)	(J÷E)
	($/Connect)	(%)	($ Million)	(%)
NSW	$5,127	83%	$17,112	45%
QLD	$5,971	64%	$11,804	39%
VIC	$1,225	25%	$3,103	20%
SA	$1,870	26%	$1,437	21%
TAS	$4,306	47%	$1,055	32%
Total	$3,922	59%	$34,755	37%

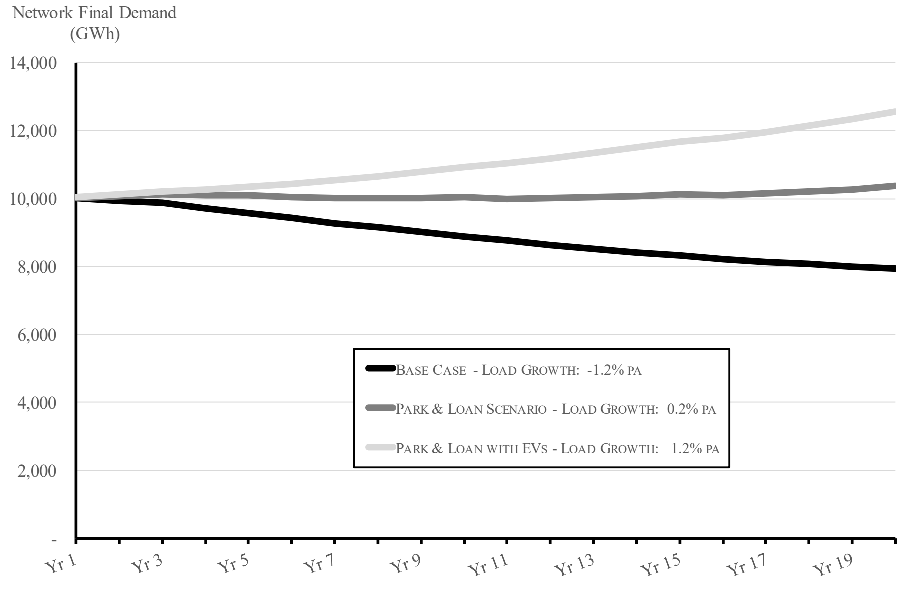
Source: Australian Bureau of Statistics (ABS), AER, esaa, Grant (2016), Simshauser (2017).

To be clear, it is not the purpose of this article to place a value on excess capacity. The analysis in Table 3 ignores important variables such as the required spatial composition of various networks, changes in customer density, peak load growth or growth in network *'hotspots'* – and accounting for such variables would surely produce a different estimate. But it does provide an indication of the relative impact of erroneous policy vis-à-vis the tightening of reliability standards – which were applied to the NSW and QLD regions following blackouts in the two capital cities of Sydney and Brisbane, respectively. Regardless, with the sharp increase in network RABs, well above connections growth and energy demand, any objective test will conclude some level of capital will fail a used and useful test in the short run (especially in NSW and QLD).

But the long run remains uncertain. After all, customer connections growth remains strong which tends to suggest the underlying network will remain used and useful (and perhaps the tariff design is a key source of the problem – see Simshauser 2016). In addition, a decline in system load over the long run is not a clear cut case given the alternate assumptions in Table 1 relating to Electric Vehicles (excluded from the Base Case). The NEM has 8.9 million residential electricity accounts, and 12.4 million motor vehicles[28] (an average of 1.4 vehicles for each electricity account). These two parameters, (i) customer connections, and (ii) Electric Vehicles (EV) may require further clarity before determining that some component of the capital stock would *permanently* fail a used and useful test. Figure 8 presents three scenarios of final energy demand given the load and elasticity assumptions in Table 1, (i) the Base Case which shows a network in decline (at -1.2% per annum), (ii) the Park & Loan Case which shows a limited opportunity scenario, and (iii) an EV scenario which shows a return to growth.

[28] See ABS series 9309, Motor Vehicle Census, Australia, 31 January 2018.

Figure 8: **Network Load under Base Case, Park and Loan Case and EV Scenario**



4. Asset stranding under uncertainty – Park and Loan

If the Base Case formed a dominant scenario, a policy decision to strand some component of the RAB would seem inevitable. The lower tariff arising from asset stranding would slow the rate of decline, reduce static efficiency losses, and reduce dynamic efficiency losses by curtailing over-investment in non-grid supply.

But because the present exercise involves demand uncertainty, network asset stranding may eventually prove to be an incorrect policy. Asset stranding is not a costless exercise. To the extent that equity capital and equity returns are adversely affected by such a policy, it would have ramifications for the future cost of capital and capital investment continuity.

Yet in the circumstances, excess capacity exists and is producing static and dynamic efficiency losses. An alternate policy instrument is to temporarily strand assets that fail a used and useful test, and progressively retest network utilisation at each regulatory reset (i.e. five-year intervals). In the following analysis, we use customer connections as the testing variable to maintain consistency with the method of determining excess capacity. Specifically, the basis for determining excess capacity and the percentage of the RAB to be Parked uses the following equation (along with Queensland Data from Table 3 for illustrative purposes):

$$\%\_Parked\_RAB_{t+1}^{i} = \frac{\left[\left(RAB_{2018}^{Qld}/Cust_{2018}^{Qld}\right)-\left(RAB_{2005}^{Qld}/Cust_{2005}^{Qld}\right)\cdot\left(CPI_{2018}/CPI_{2005}\right)\right]}{\left(RAB_{2018}^{Qld}/Cust_{2018}^{Qld}\right)} \tag{20}$$

The application of Eq.20 produces a Parked RAB of $3,907 million as follows:

$$\%\_Parked\_RAB_{t+1}^{i} = \frac{\left[\left(\frac{\$30{,}209m}{1.977m}\right)-\left(\frac{\$10{,}528m}{1.574m}\right)\cdot\left(\frac{112.9}{81.1}\right)\right]}{\left(\frac{\$30{,}209m}{1.977m}\right)}$$

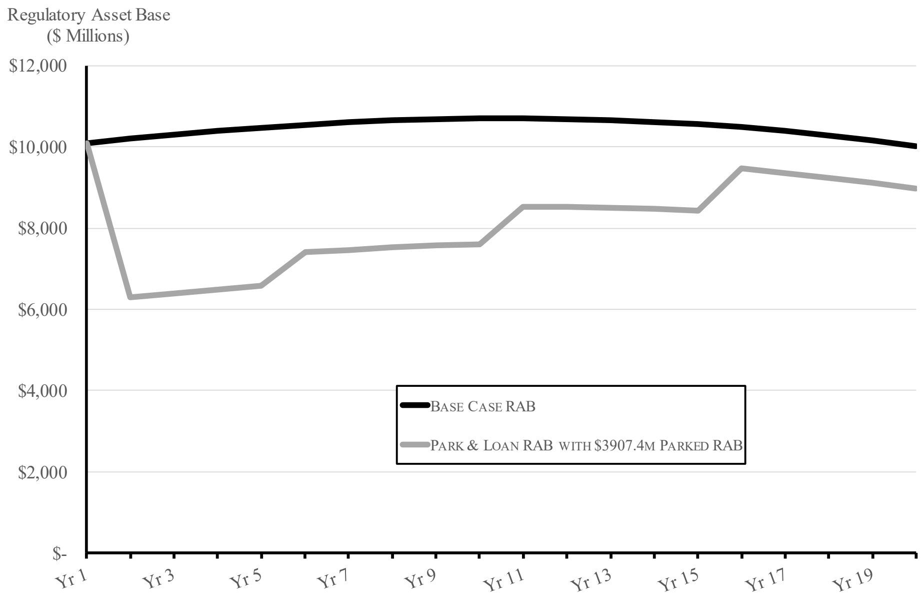
$$\%\_Parked\_RAB_{t+1}^{i} = 39.07\%$$

$$Parked\_RAB_{t+1}^{i} = RAB_{t}^{i}\ \times 39.07\% \mid RAB_{t}^{i} = \ \$10{,}000\, million$$

$Parked\_RAB_{t+1}^{i} = \$3{,}907\ million$

Figure 9 provides a conceptual illustration of the network RAB before, and after, the Park and Loan Asset Stranding Policy. With the Park and Loan scenario, $3,907 million of the RAB has been Parked in Year 2. This immediately reduces the RAB from $10,092 million to $6,184 million.[29] Then at the end of each 5-year regulatory period, a certain amount of the Parked RAB has been returned-to-service (i.e. in Years 6, 11 and 16) in line with customer connections growth.

Figure 9: **RAB – Base Case vs Park and Loan**



A policy decision to temporarily strand $3,907 million or ~39% of a network utility's RAB without some form of financial and economic reorganisation will produce a distressed business. The reason for this is axiomatic, but for clarity, the Model reveals that if $3,907 million is stranded with 0% stranded asset recovery, utility financials and credit metrics immediately deteriorate from "investment grade" (i.e. BBB- or higher) to "junk". The firm would enter severe financial distress and would be technically insolvent within 12 months because revenues and tariffs fall by 29.5% (with all other variables held constant).

Our Park and Loan policy involves the securitisation of the benchmark debt associated with the *Parked RAB*. That is, $2,344 million in credit-wrapped bonds (i.e. 60% of $3,907 million) are issued and wrapped by government, with bond proceeds used to repay outstanding network utility debt strictly associated with the Parked RAB. This Park and Loan approach ensures utility credit metrics continue to meet investment grade thresholds. Furthermore, bonds can be wrapped by government because the beneficiaries of the policy, the 1.5 million household consumers, collectively underwrite bond coupon payments through specific Park & Loan stranding charges. Table 4 presents the Park and Loan Model Results.

There are some vital changes to the financial and economic affairs of the network utility by comparison to the Table 3 Base Case results. First, notice from Year 2 in the Profit & Loss Statement that Total Revenue ($1025.3m) now comprises both Network Revenue ($972.6m) and Stranding Charges ($52.7m) – the latter being a charge to consumers to cover the credit-wrapped bond issue. Bond Interest also appears as a new expense item. The Profit & Loss also includes two Significant Items:

[29] Note also that as with the modelling results in Simshauser (2017), annual Capex was reduced marginally, from $200 million to $175 million in recognition that such a policy will induce a change in forward investments.

1. a charge against profit for the Stranded Assets (-$3,907m) in Year 2 while in Year 6 (and in Years 11 and 16) as Parked RAB is progressively returned to service, an equivalent component of the Stranded Asset charge is reversed (+$763.6m in Year 6, and in Years 11 and 16); and

2. proceeds from the sale of credit-wrapped bonds in Year 2 ($2,344.4m), while in Year 6 (and in Years 11 and 16) a charge against profit is applied for the redemption of the credit-wrapped bonds as Parked RAB is returned to service (and in consequence, proportional utility Debt Finance is resumed and underpinned by the reinstated RAB).

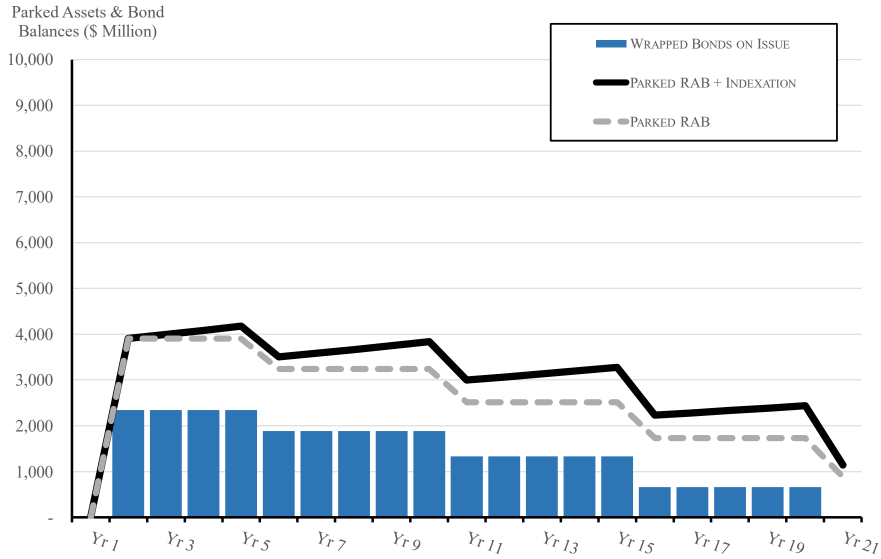
Table 4: **Park and Loan Scenario Results (Years 1-7)**

	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7
ENERGY SALES								
Energy Sold (GWh)		10,025	10,070	10,120	10,102	10,096	10,038	10,022
Fixed Rate (c/day)		0.49	0.35	0.35	0.36	0.36	0.39	0.40
Variable Rate (c/kWh)		10.8	7.7	7.9	8.2	8.4	9.3	9.6
Average Tariff (c/kWh)		13.44	10.18	10.41	10.72	10.97	12.08	12.40
Tariff Increase			-24.3%	2.3%	2.9%	2.4%	10.0%	2.7%
PROFIT & LOSS								
Network Revenue		$1,347.6	$972.6	$1,001.1	$1,030.2	$1,055.1	$1,169.7	$1,200.5
Stranding Charge - Bond Issuance		$0.0	$52.7	$52.7	$52.7	$52.7	$42.4	$42.4
Total Revenue		$1,347.6	$1,025.3	$1,053.9	$1,083.0	$1,107.9	$1,212.1	$1,243.0
TUoS		$275.0	$198.2	$203.5	$208.9	$213.5	$236.3	$242.2
Opex		$300.0	$306.5	$313.0	$319.8	$326.6	$333.7	$340.8
Interest - Park & Loan		$0.0	$52.7	$52.7	$52.7	$52.7	$42.4	$42.4
Depreciation		$333.3	$213.1	$224.1	$235.6	$247.5	$290.0	$303.4
EBIT		$439.3	$254.8	$260.5	$266.0	$267.5	$309.7	$314.2
Interest		$305.4	$182.3	$177.9	$194.6	$195.0	$195.1	$215.0
Taxation - Accounting		$40.2	$21.7	$24.8	$21.4	$21.7	$34.4	$29.7
NPAT (Underlying)		$93.7	$50.7	$57.8	$50.0	$50.7	$80.2	$69.4
Significant Item - Stranded Assets		$0.0	-$3,907.4	$0.0	$0.0	$0.0	$763.6	$0.0
Significant Item - Wrapped Bonds		$0.0	$2,344.4	$0.0	$0.0	$0.0	-$458.1	$0.0
NPAT (Statutory)		$93.7	-$1,512.2	$57.8	$50.0	$50.7	$385.6	$69.4
CASH FLOW								
EBITDA + Interest Park & Loan		$772.6	$520.7	$537.4	$554.3	$567.8	$642.2	$660.0
Park & Loan - Wrapped Bond Sales		$0.0	$2,344.4	$0.0	$0.0	$0.0	-$458.1	$0.0
Park & Loan - Interest		$0.0	$52.7	$52.7	$52.7	$52.7	$42.4	$42.4
Taxation - Cash		$20.1	$10.9	$12.4	$10.7	$10.9	$17.2	$14.9
Debt - Interest		$305.4	$182.3	$177.9	$194.6	$195.0	$195.1	$215.0
Debt - Principal		$88.9	$92.3	$57.2	$65.8	$69.3	$72.8	$84.3
Capex		$200.0	$178.8	$182.6	$186.5	$190.5	$194.6	$198.8
Dividends *Limit:* 4.0%		$168.8	$3.6	$121.0	$112.0	$115.7	$119.4	$137.3
Special Dividend		$0.0	$0.0	$314.5	$0.0	$0.0	$0.0	$0.0
Net Cash Flow		-$10.6	$2,344.4	-$380.9	-$68.1	-$66.4	-$457.6	-$32.9
BALANCE SHEET								
Working Capital	$220.1	$225.1	$230.1	$235.3	$240.6	$246.0	$251.5	$257.2
Stranding Account		$0.0	-$3,907.4	$0.0	$0.0	$0.0	$763.6	$0.0
Fixed Assets	$10,000.0	$10,091.7	$6,289.1	$6,389.0	$6,483.8	$6,572.7	$7,406.0	$7,468.0
Total Assets	$10,220.1	$10,316.7	$6,519.2	$6,624.3	$6,724.3	$6,818.7	$7,657.5	$7,725.2
Debt Finance	$6,000.0	$5,926.6	$3,494.9	$3,823.8	$3,831.4	$3,834.0	$4,224.2	$4,178.4
Equity	$4,220.1	$4,390.1	$3,024.2	$2,800.5	$2,892.9	$2,984.7	$3,433.3	$3,546.8
	$10,220.1	$10,316.7	$6,519.2	$6,624.3	$6,724.3	$6,818.7	$7,657.5	$7,725.2
RATIOS								
Return on Assets (underlying)		4.3%	3.9%	3.9%	4.0%	3.9%	4.0%	4.1%
Return on Equity (headline)		2.1%	-50.0%	2.1%	1.7%	1.7%	11.2%	2.0%
Running Yield to Opening Equity		4.0%	0.1%	4.0%	4.0%	4.0%	4.0%	4.0%
Gearing	59%	57.4%	53.6%	57.7%	57.0%	56.2%	55.2%	54.1%
FCF/Debt *('Modest Positive' = BBB-)*		4.1%	4.1%	4.2%	4.1%	4.3%	5.4%	5.4%
FFO/Debt *(> 6% = BBB-)*		7.5%	9.4%	9.1%	9.1%	9.4%	10.2%	10.3%
Implied Credit Rating		BBB	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+

Similar movements then flow through the Cash Flow Statement and the Balance Sheet. Notice the firm retains its investment grade credit metrics. To be clear, however, in this particular version of the model, the equity component of the Parked RAB is stranded without compensation until such time as it is returned-to-service. Equity return variations of the model are of course possible, and in certain instances, warranted.

Figure 10 illustrates the annual balance of the Parked RAB (both underlying Parked RAB, and headline Parked RAB which includes Indexation consistent with Eq.2) and wrapped Bonds on issue along with their redemption profile. While not evident from Table 4, Figure 10 also highlights that Bonds are fully redeemed in Year 21, whereas some residual Parked RAB equity remains outstanding (and may remain outstanding in an episode of decline).

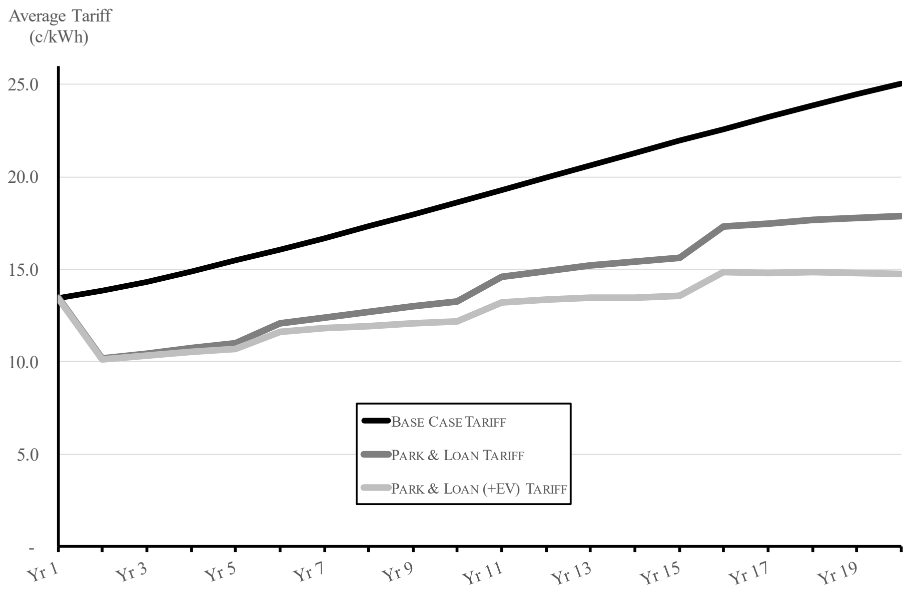
Figure 10: **Parked RAB Balance and Wrapped Bonds on Issue**



The effect of the Parked RAB and securitised bond issue is an immediate and pronounced reduction in network tariffs, as Figure 11 illustrates. The continuously rising Base Case tariff was driven by a rising RAB and contracting load. In the present model, the immediate reduction in the RAB produces a lower *Park and Loan tariff*, and when combined with modest own-price and inter-scenario demand elasticity assumptions (i.e. -0.10, and 40% thereof due to network tariffs forming only 40% of the final electricity bill), the rate of network load in decline slows (see Figure 8). Note however there are pronounced tariff rises as components of the Parked RAB are gradually returned-to-service.

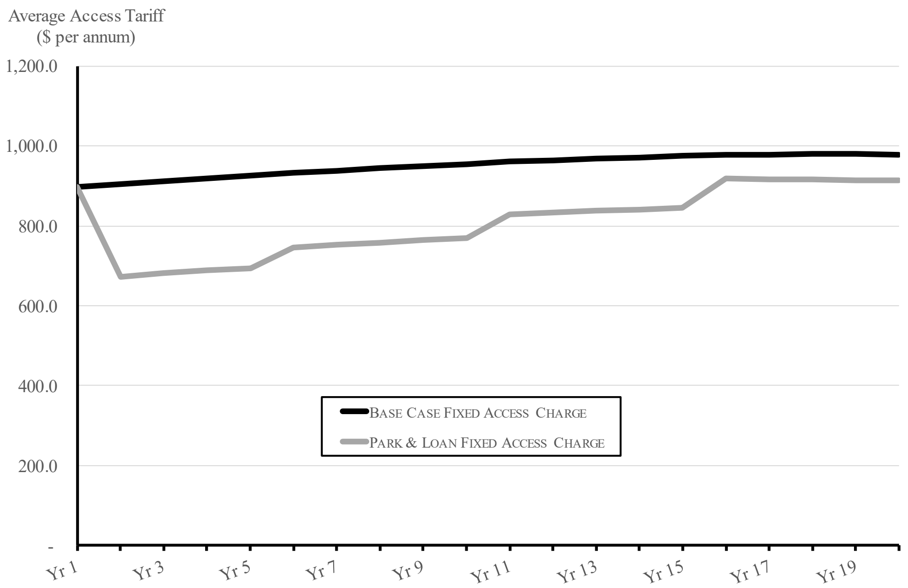
Figure 11 also includes a third scenario involving the Park & Loan structure but with the addition of EVs. The material expansion in network load (per Figure 8) produces a lower tariff due to better utilisation of the sunk network, albeit with pronounced rises in tariffs as components of the Parked RAB are returned-to-service.

Figure 11: **Base Case tariffs vs Park and Loan tariffs**



The results in Figure 11 are based on a simplified variable rate tariff. A variable rate structure (c/kWh) is a poor design for an electricity network given periodic load and intermittent solar PV (see Simshauser 2016). As noted earlier, backup services are greatly undervalued by two-part tariffs let alone a single rate tariff structure. To examine the other extreme of pricing structures would be a fixed connection charge ($ per connection per annum) for each customer. This is illustrated in Figure 12, and the same substantive result prevails, namely, a sharp initial reduction in the price of network services, with gradual step-ups as some component of the Parked RAB is returned-to-service.[30]

Figure 12: **Base Case Connection Charge vs Park and Loan Connection Charge**



While a variable rate tariff is a sub-optimal tariff design by comparison to a two-part tariff, a pure connection access charge is also likely to be suboptimal. The ideal tariff design likely to comprise some combination of fixed access, maximum demand charge and variable energy rate (Simshauser, 2016).

[30] Note in the Regulated Monopoly Model EVs do not add to customer connections, hence the EV scenario is the same as the Parked RAB scenario vis-à-vis fixed connection charge.

5. Conclusion

From 2004 to 2018 the Regulatory Asset Base of electricity networks in Australia's National Electricity Market tripled in value, from $32 billion to $93 billion following a misguided policy of tighter reliability standards, erroneous load forecasts and significant investment mistakes in retrospect. Not only did demand growth fail to materialise, load contracted over the period 2010-2015. The rising RAB, contracting demand and regulated revenue constraint produced sharply rising network tariffs. Various consumer groups and regulatory bodies argued that assets should be stranded (with zero recovery) and network tariffs reduced.

A change in network tariff trajectory did occur from 2015, not through asset stranding, but courtesy of record low interest rates, low and stable inflation rates, and a consequential (and severe) reduction in the regulated rate of return awarded to networks by the Australian Energy Regulator. The regulated rate of return for networks in 2009 for the 2010-2015 regulatory period was 10.06% following the Global Financial Crisis; this was reduced to just 6.01% in the 2015-16 determination – a reduction of 405 basis points.[31] From 2015-2018, final electricity demand increased once again across various networks – a reminder that network demand is inherently uncertain.

In this article, we presented a method for dealing with stranded assets under uncertainty. Rather than permanently stranding assets that fail a used and useful test, we temporarily Parked the excess network RAB and proceeded to reorganise the financial and economic affairs of a template network utility by issuing credit-wrapped bonds to finance the debt associated with the stranded capital stock. Our policy then re-tested the Parked RAB at the end of each five-year regulatory determination. Parked Assets were Un-Parked and returned-to-service in line with customer connections growth. The policy produced an immediate reduction in network tariffs and a more stable trajectory albeit with marked increases when assets were returned-to-service.

Our analysis has a number of limitations. We dealt seldom and lightly on how to determine the value stranded assets; we measured 'RAB per connection' before, and after, a material change in policy and market conditions, and our simplifying assumption deemed the difference to be excess capacity. While this may provide an indication of excess capacity, the measurement years selected (viz. 2005 and 2018) were arbitrary and it would therefore be an accurate valuation only by chance. The valuation also ignored important variables such as changes in peak demand growth, the required spatial composition of various networks and other parameters known to be important.

Additionally, we did not contemplate the macroeconomic significance of the policy; if our valuation of excess capacity is indicative, then a wide-ranging Park and Loan program would require wrapped government bonds totalling $20 billion (iof .e. $60% debt underpinning a $34 billion in Parked Assets, per Table 3). Such a large program is *unlikely* to have no effect on the future cost of money for participating governments. Finally, our analysis ignored the treatment of Parked equity capital, and it also ignored how to treat a Parked RAB that becomes permanently stranded. These items represent areas for further research.

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[31] See AER determinations at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f%5B0%5D=field_accc_aer_sector%3A4 The regulated rate of return data in this instance refers to Energex determinations.

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