Griffith UNIVERSITY
Griffith Business School
Queensland, Australia

Centre for Applied Energy Economics & Policy Research: Working Paper Series 2021-01

Renewable Energy Zones in Australia's National Electricity Market

Paul Simshauser[♣♠]
March 2021

Abstract

Australia's National Electricity Market operates in one of the world's longest and stringiest transmission networks. The 2016-2020 investment supercycle, in which 13,000 MW of renewables were committed, is slowly revealing the limits of network hosting capacity for renewable plant. In this article, side-effects arising from the supercycle are analysed. The majority sources of renewable investment failure relate to deteriorating system strength, viz. associated connection lags, remediation and curtailment costs. Although a multi-zonal market, the NEMs locational investment signals remain visibly strong. A change to nodal arrangements may refine dispatch efficiency but the bigger policy problem is rapidly diminishing network hosting capacity for new renewables, imperfect regulation and regulatory lag associated with augmentation. Markets participants seek to move faster than regulatory frameworks allow. Renewable Energy Zones (REZ) are examined through both i). a consumer-funded regulatory model and ii). a renewable generator-funded market model. A 'super-sized concessional mezzanine' facility is presented as a critical element of REZ capital funding. It forms the means by which to optimise market-based REZ transmission augmentation and moderate sponsor risks of transient underutilisation.

Key words: Electricity, Renewable Energy Zones, transmission investment, locational investment signals.

JEL Classification: D25, D80, G32, L51, Q41.

A peer reviewed version of this working paper was subsequently published as: Simshauser, P. (2021), "Renewable Energy Zones in Australia's National Electricity Market", Energy Economics, Vol.101, pp105446.

♣ Professor of Economics, Griffith Business School, Griffith University.
♠ Research Associate, Energy Policy Research Group, University of Cambridge.

1. Introduction

Rising market shares of utility-scale wind and solar PV is placing pressure on transmission networks and energy market designs in Australia, Europe, Great Britain and the US, amongst other jurisdictions. In the Australian case, a surge of VRE entrants with sporadic episodes of investment failure brought the adequacy of locational investment signals into sharp focus.

Australia's National Electricity Market (NEM), a real-time energy-only gross pool, operates in one of the longest and stringiest transmission networks in the world. The NEM is also one of the fastest transitioning power systems given a historic dominance of coal generation. From 2012-2016, 5000MW (~20%) of base load coal plant exited with little warning. Over the same period Australian policy discontinuity left a 20% Renewable Energy Target (by 2020) technically under-supplied. These events produced sharp increases in both electricity and renewable certificate prices. A sizeable supply-side response followed – 13,000MW of new projects across 121 sites totalling AUD$23 billion[1] – all in a 4-year window. Given a 35,000MW power system demand, it presented as an investment *'supercycle'*.

From a dynamic efficiency perspective, the market functioned as it should. At the end of the supercycle wholesale electricity prices had fallen from a cyclical peak of $103 to $40/MWh[2], CO_2 emissions had fallen from 171 to 132mtpa and the 20% Renewable Target was met. However, the supercycle produced adverse side-effects including 'system strength' connection lags, remediation and VRE curtailment, and sizeable swings in plant Marginal Loss Factors.

Ongoing VRE plant entry is predictable and necessary given the task of decarbonisation. However, as one of the world's longest and stringiest transmission systems, it is not immediately obvious that the network is capable of hosting a dramatic increase in VRE. This points to necessary increases in the transmission network.

One novel policy response has been the concept of developing Renewable Energy Zones (REZ) in regional areas of Australia with good wind and solar resources. REZ's are seen as a means by which to develop much needed VRE hosting capacity at scale. Under NEM Rules, (consumer funded) REZ augmentation needs to be triggered by either i). a looming reliability constraint, or ii). passing a regulatory cost-benefit test with a narrow definition of benefit (i.e. resource costs). Market participants seek to move faster than regulatory processes permit, and so alternate REZ models seem desirable.

In this article, adverse side-effects from the supercycle are analysed. The analysis suggests NEM locational investment signals are performing as they should, and while further reinforcement through locational marginal pricing may sharpen dispatch efficiency, it *will not* increase VRE hosting capacity. Conversely, adding a REZ will. Analysis suggests hosting capacity rather than refining dispatch efficiency is the NEMs policy priority.

Welfare implications of REZs are explored through power system modelling. The magnitude of welfare gains from *anticipatory transmission planning* and a transmission network utility *guiding the market* vis-à-vis VRE entry are evident but regulatory solutions lag competitive market outcomes. The complicating factor of a 'market REZ' is that they

---

[1] All results are expressed in Australian Dollars (AUD) unless otherwise signalled. At the time of writing, AUD$1 = USD 0.74, GBP 0.55 and Euro 0.62.
[2] Queensland region spot prices for calendar years 2017 and 2020.

are based on Pozo et al.'s (2013) *'if you build it, they will come'* principle[3]. To navigate this, a novel and pliable financing structure for a market REZ is presented.

This article is structured as follows. Section 2 analyses adverse side-effects arising from the VRE investment supercycle. Section 3 provides a review of relevant literature. Section 4 introduces the modelling framework. Section 5 presents model results. Section 6 examines both regulatory and market REZs. Policy implications follow.

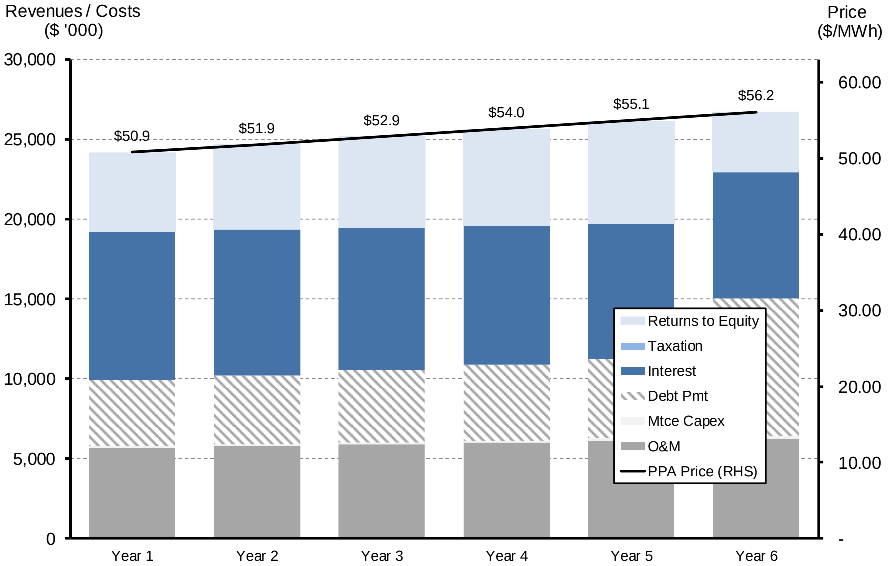
2. Nature of the problem: side-effects of the supercycle

NEM policymaker concerns regarding locational signals is best illustrated through an applied example, viz. a boilerplate 200MW Solar PV project committed in 2018. Key assumptions are as follows. Installed capital cost is based on the average of 12 NEM solar projects committed during 2018/19 at ~$1,390/kW (Simshauser and Gilmore, 2020). O&M Costs of $28,000/MW have been drawn from ARENA's (2020) recent survey of utility-scale solar plants. Annual Capacity Factor (ACF) assumed is ~27.5% (reflective of the Queensland solar fleet).

Project output is sold via a 15-year 'run-of-plant' Power Purchase Agreement (BBB counterparty) at the levelized cost of entry given *expected* equity returns of 8% at financial close. Plant forecast Marginal Loss Factor is 0.9900 (i.e. under NEM Rules this coefficient represents the plant's 'marginal losses' and is held constant for each hour of the year, and is revised annually).

The $278m, 200MW plant is to be project financed with rates and debt sizing parameters relevant during 2018 (i.e. Debt Service Coverage Ratio ~1.25x). The PF Model (Appendix I) was used to simultaneously solve the PPA price ($50.9/MWh) and debt package ($203m, 73% gearing). The PPA (line series, RHS) and Annual Cash Flows (bar series, LHS) for Years 1-6 are presented in Fig.1.

Figure 1: 200MW Solar PV - PPA Price (line) and expected cash flows (bars)



[3] A complicating factor in Australia relates to prior episodes of Averch and Johnson (1962) network gold plating and sharp increases in network tariffs over the period 2005-2012 (see Mountain and Littlechild, 2010; Nepal, Menezes and Jamasb, 2014; Simshauser and Akimov, 2019). Consumer groups are on *heightened alert* at the prospect of a repeat episode.

2.1 Problem #1: System strength remediation

Due to falling system strength in certain network locations, a NEM Rule change entered into force during 2018 requiring all new projects to demonstrate *'no harm'* on connection.[4] In certain locations, PSCAD modelling revealed inverter-connected VRE may amplify voltage oscillations, posing risks to power system security.

In the classic case, modelling results required the 250MW 'Kiamal' solar PV plant (NEM's Victorian region) to install a $20m synchronous condenser (SynCon) prior to connecting. This occurred *after* financial close, which sent a 'real-time shockwave' through the VRE development and project financing markets[5]. This is not an isolated example.

2.2 Problem #2: Connection lag

Following the Kiamal SynCon incident and others like it, an instantaneous change to Conditions Precedent for VRE project financings was implemented by risk averse project banks – PSCAD modelling needed to be completed *prior to* financial close. Consequently, a new development lag emerged as networks, generators and market operators struggled to model impacts. For those projects already committed, lags of 32-38 weeks emerged as a result (ARENA, 2020; Simshauser and Gilmore, 2020).[6]

2.3 Problem #3: Marginal Loss Factor volatility

Marginal Loss Factors (MLFs) are a critical locational signal in the NEM. MLFs are well understood by incumbent utilities[7] and the NEM's sophisticated VRE developers because they act as a spot price 'multiplier':

$$Plant\ Revenue = Energy\ Sent\ Out\ \times\ MLF\ \times\ Spot\ Price$$

Consequently, if a plant MLF decreases so do revenues. It would seem a trap emerged for *new* developers. Analytically, coal, gas and wind fleet MLFs appeared (historically) stable. But during the supercycle solar PV MLFs deteriorated sharply (Fig.2). Reasons included i). ease of solar entry, ii) synchronised solar output, iii). solar projects connecting to weaker parts of the transmission and distribution networks (i.e. away from load centres, access to cheap land etc), and iv). lack of visibility of simultaneous entry. The solar fleet-average MLF reduced by 10.5 percentage points.[8]

---

[4] s5.3.4B of the Rules required Transmission Networks and the Market Operator to create models of the power system, initially to establish available fault levels. Subsequently, it became clear that interaction amongst asynchonous generators (with a special focus on the risk of voltage oscillation) was more important.

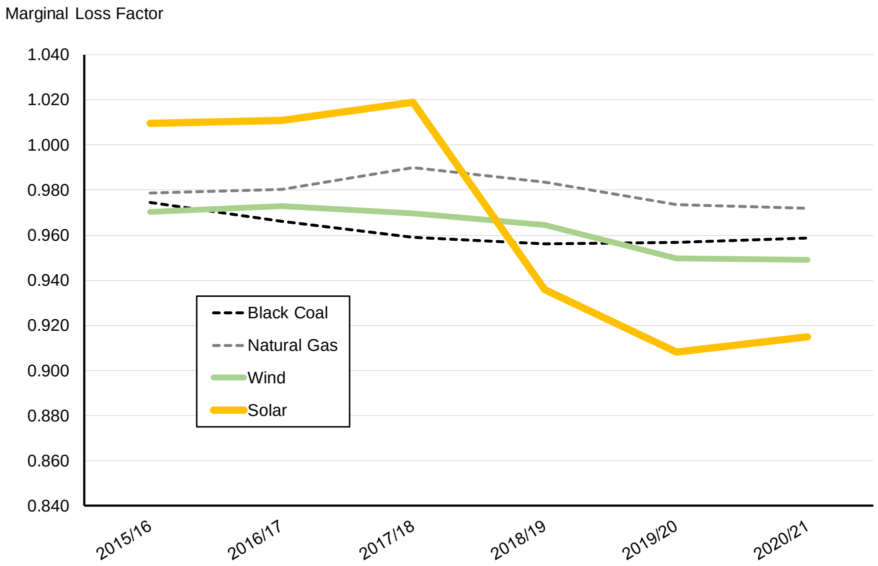
[5] Another case, known as the 'Rhombus of Regret', lead to five VRE projects in a rhombus shaped area of New South Wales & Victoria being constrained to 50% production for 6 months while the risk of voltage oscillations was remediated. There are numerous other applied examples across all NEM regions.

[6] With the benefit of hindsight, network businesses responsible for the system strength modelling weren't (and under timeframes involved, couldn't be) ready for the new regime in 2018 due to the sheer complexity of new models required. The only responsible alternative would have been to institute a complete moratorium on VRE entry while models were populated.

[7] Most utility generators have at some point experienced a transient MLF shock within their portfolio (i.e. compared to year-ahead budgets) due to, for example, changed load flows.

[8] A group of adversely affected VRE project owners proposed a Rule change to alter the NEM's transmission loss framework from marginal to 'average' losses. If the Rule change were to be accepted, it would have successfully restored large components of lost VRE project value. However, it would also defy the laws of physics and economics and allocate network losses of c.$400m pa to consumers. Power system dispatch would face a drag on efficiency, and the NEM's historically effective locational signal would be severely impaired. Unsurprisingly, the Australian Energy Market Commission (AEMC) did not find in favour of the proposed Rule change.

Figure 2: Marginal Loss Factors for the NEM Generating Fleet (2016-2021)



Source: AEMO.

2.4 Problem #4: VRE curtailment

With the supercycle came 121 new entrants. Solar quickly overran its own market given near perfect correlation of output amongst the fleet, amplified by world-record rates of rooftop[9] PV installations. Curtailment would follow and in the NEM, lost renewable production is *not* compensated (which differs from some other jurisdictions – see Höfer and Madlener, 2021). Data from the NEM's Queensland region for 2019/20 reveals potential utility-scale solar PV output of 3179GWh (26.4% ACF) from the 1372 MW fleet. Practical output however was 3001GWh (25.0% ACF) meaning 178GWh (-1.4% ACF) was subject to curtailment. Of this, 97GWh (-0.8% ACF) was economic curtailment, 54GWh (-0.5% ACF) related to system strength, and 27 GWh (-0.2% ACF) due to network congestion.

2.5 Ex post outcomes

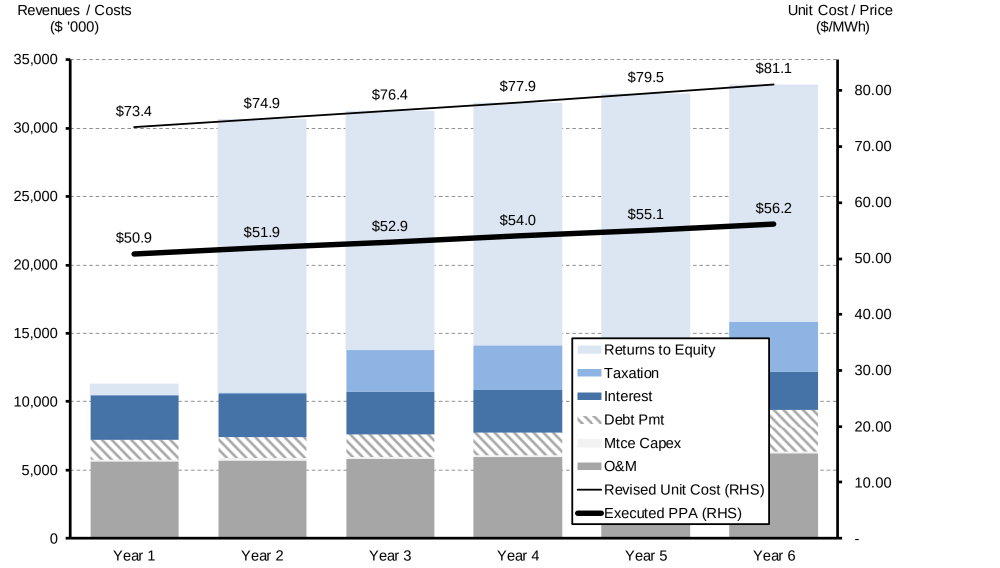
Adverse side-effects were compounding for our boilerplate 200MW solar PV project. Recall *expected* equity returns were 8%. Fig.3 presents revised project costings (bar series, LHS-Axis) after accounting for:

1. installation of a $20m SynCon;
2. 32-week connection lag;
3. 10.5 percentage point structural MLF drop;
4. VRE curtailment of -1.0% ACF.

Year 1 cash flows reduce due to connection lags. Thereafter, annual costs rise to ~$30 million per annum, $6m above ex ante (Fig.1) cost expectations. The revised PPA price required to achieve an 8% equity return is $73.4/MWh, ~$23/MWh higher (Fig.3, line series, RHS Axis).

[9] For example, in Queensland alone there is more than 3500MW of rooftop solar PV in a system with a maximum demand of ~10,000MW.

Figure 3: Ex post 100MW Solar 'required' project cash flows vs Executed PPA



Plant performance given the previously executed PPA at $50.9/MWh, ex post MLF of 0.8850, and a revised ACF of 26.5% translates to annual revenues of only ~$22m.[10] The running cash yield therefore falls from ~8% to ~1%. Restoring returns to 8% would require an asset write-down of ~$68m (i.e. 70% of the $96m equity cheque).

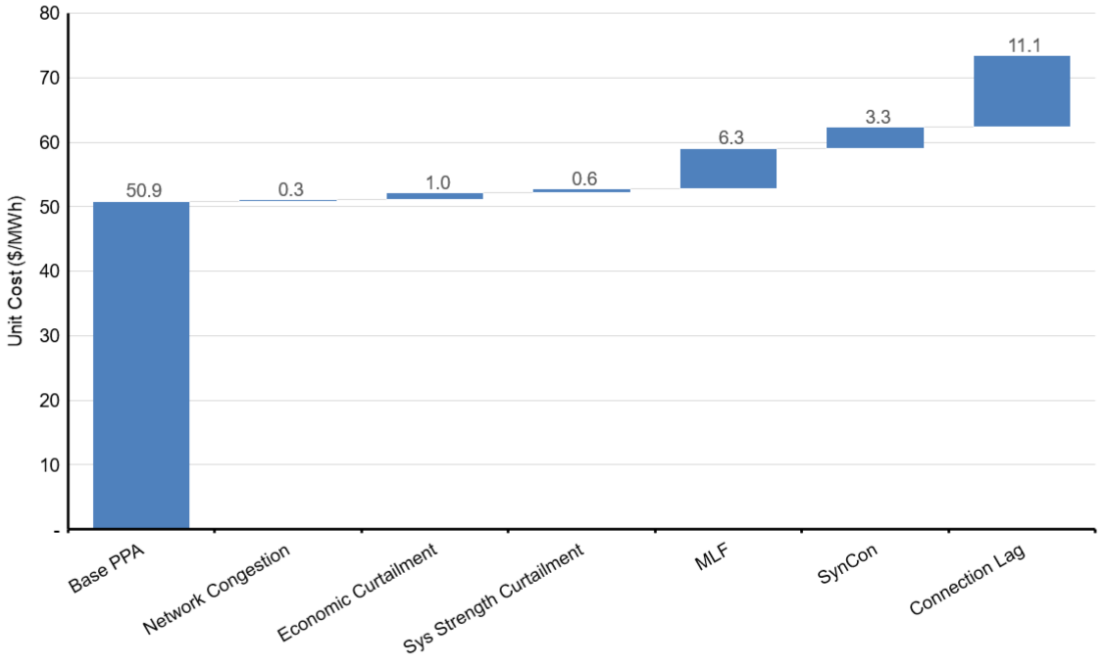
2.6 Policy implications

Identifying and quantifying specific sources of investment failure (see Fig.4) is important to ensure any policy response is undertaken with 'surgical precision' rather than create a mass disruption event. While our 200MW solar example was far more than a theoretical one[11], ~80% of the 121 VRE projects entered successfully notwithstanding universal connection lags (Simshauser and Gilmore, 2020).

Fig.4 identifies the sources of investment failure. Note network congestion accounts for only $0.3 out of $23/MWh and therefore presents as a 'minority source'. The 'majority sources' of investment failure are post entry impacts of System Strength connection lag ($11.1/MWh)[12], System Strength curtailment and System Strength remediation ($0.8 and $3.3/MWh) and post entry changes to MLFs ($6.3/MWh). Economic curtailment ($1.0/MWh) requires no policy attention whatsoever.

[10] The synchronous condenser may generate an additional revenue stream which has not been captured here.
[11] Another example involved international developer John Laing, who wrote down the value of their Australian VRE portfolio by £66m primarily due to adverse MLF changes. See Australian Financial Review 31 March 2020 "Slow start for $500m John Laing renewable Sales" by Thompson, MacDonald and Boyd.
[12] In theory at least, these lags should now occur prior to financial close. However, this also means that project development (and therefore capital at risk in the pre-closure stages) is dramatically higher as a result, thus raising barriers to entry.

Figure 4: 200MW Solar PV valuation impacts



3. Review of Literature

With the Section 2 analysis providing necessary background information, strands of literature relevant to the subsequent analysis include locational investment signals in energy markets, and policy discontinuity in Australia.

3.1 Locational investment signals in energy markets

The need for locational investment signals in restructured electricity markets is axiomatic. Prior to reforms, integrated resource planning by vertical monopoly utilities co-optimised generation resource costs and transmission plant investment options for a given load forecast. Co-optimisation is not possible in restructured markets because rival generator investment decisions are driven by forward prices or renewable policies, with transmission networks performing a 'responsive role' (Sauma and Oren, 2006; Torre et al. 2008). With few exceptions, network upgrades or augmentations are reliability-driven considerations in spite of the frequent potential for small transmission investments to result in surprisingly large competition benefits (Borenstein, Bushnell and Stoft, 2000).

Multiple jurisdictions (US, Great Britain, Europe, Australia) are experiencing sharp increases in utility-scale VRE. This is driving demand for costly transmission infrastructure, ancillary services, rising network congestion and greater Market Operator intervention (Neuhoff *et al.*, 2013; Bird *et al.*, 2016; Neuhoff et al., 2016; Bertsch *et al.*, 2017; Joos and Staffell, 2018; Ambrosius *et al.*, 2019; Wagner, 2019; Heptonstall and Gross, 2020; Simshauser and Gilmore, 2020; Pollitt and Anaya, 2021). The coordination of generation and transmission investment is therefore of rising interest (van der Weijde and Hobbs, 2012; Munoz et al., 2017; Pechan, 2017; AEMC, 2019; Ambrosius et al., 2019; Eicke et al., 2020).

With VRE expanding across an increasing number of sites, locational signals in energy markets is of unquestionable interest to policymakers. Does this mean zonal markets should be discarded in favour of nodal markets? As with Europe, questions of Australia's zonal power market design and adequacy of locational signals persist (AEMC, 2019).[13] However, as Section 2 illustrated the nature of the problem vis-à-vis rising VRE in Australia is quite different to primary concerns that exist in European countries such as Germany[14] (as Fig.5 subsequently reveals).

There should be no doubt a nodal market of the type envisaged by Schweppe *et al.*, (1988) will outperform a zonal market design from a dispatch efficiency perspective (Bjørndal and Jørnsten, 2001; Joskow, 2008; van der Weijde and Hobbs, 2011; Neuhoff *et al.*, 2013; Holmberg and Lazarczyk, 2015). That is, a primary benefit of nodal pricing is generally considered to be dispatch efficiency given varying unit fuel costs (Green, 2007; Joskow, 2008; Eicke et al., 2020). Although as one Reviewer noted this does hinge on how losses are treated in nodal markets, viz. socialised or specified, and when specified, the accuracy of the methodology (see for example Litvinov *et al.*, 2004)

However, recall from Section 2 that in the Australian context, dispatch efficiency and network congestion was a minority source of investment failure and of the order estimated by Green (2007) in relation to Great Britain at the time. Majority sources related to hosting capacity, system strength and the predictability of locational signals during an investment supercycle. Whether nodal market signals outperform zonal markets vis-à-vis generation investment locational decisions is more nuanced. There is a general lack of evidence that such markets impact the efficiency of future network investment, noting congestion rents form a small fraction of required transmission augmentation capital costs (Eicke, Khanna and Hirth, 2020).

As Hadush et al. 2011 explain, investment location decisions require signals to be i). stable, ii). predictable, and iii). of significant strength (see also Wagner, 2019; Eicke et al. 2020). Greater spatial locational signalling must *prima facie* be helpful, but, while zone splitting or nodal markets invariably enhance dispatch efficiency, they do not necessarily provide stable, predictable or strong signals as Hadush et al. (2011) illustrate. Further, all markets (including nodal markets) use multiple signalling mechanisms and consequently there are multiple pathways to establish or enhance locational signals for VRE investment (Eicke et al. 2020).

While establishing a power market with a nodal design is no doubt preferable, transitioning a mature power market from zonal to nodal (i.e. in the 2020s) is a very different policy decision. Transaction costs of such a change are often underestimated[15] or assumed away in market re-design analyses and therefore overlook consequences of a potential 'mass disruption event'[16]. Use of additional signalling mechanisms, zone splitting, or establishment of Renewable Energy Zones (particularly if hosting capacity is the problem) may be preferable, or provide an interim step.

---

[13] A not insignificant issue with NEM policymaking at the time of writing is, as Kristov et al. (2016, p.63) explain, the temptation to jump right in to 'sexy market design' and assume mundane operational matters, the laws of physics, and transition issues associated with a mass disruption event will sort themselves out. The most important (i.e. immediate) problems facing the NEM include Frequency regulation, voltage oscillations and falling system strength associated with inverter-connected plant, and falling inertia as coal plant exit (Simshauser and Gilmore, 2020).

[14] In Germany the problem of network congestion and lost VRE production is amplified by a requirement to allocate the (opportunity) cost of VRE curtailment to consumers (Höfer and Madlener, 2021). In Australia's NEM, no such requirement exists and therefore the consequence of poor locational decisions are, at least in the medium run, borne by the VRE investor.

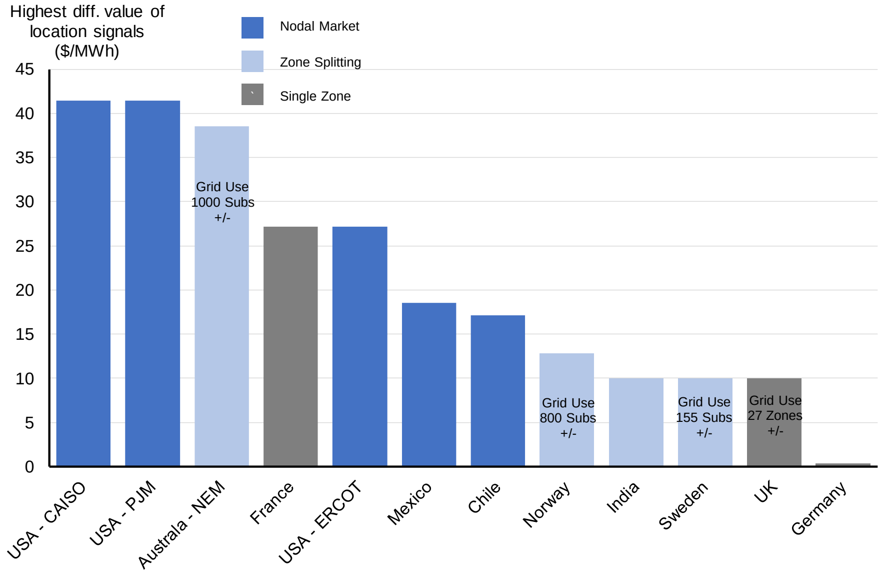
[15] See AEMC (2019) for example. In a more recent example, the 5 minute settlement rule change was thought to involve '$10s of millions' in system costs. Market participants have already spend over $400m and this excludes the costs of the market operator's system.

[16] Simshauser and Gilmore (2020) highlight if Australia's NEM was to change from multi-zonal plus MLFs to nodal prices, most contracts would break down because MLFs are quite fundamental to wholesale market transactions. This would therefore trigger the renegotiation of more than 100 Power Purchase Agreements (PPA) en-masse, and adversely impact $19bn of project and corporate finance underpinning Australian generators. The market operator's initial estimate of system changes was $300m for their own IT network.

Zonal markets have the benefit of greater transparency and simplicity (Eicke et al. 2020), are usually associated with lower market power risk (Bigerna and Bollino, 2016; Bigerna et al. 2016; Grimm *et al.*, 2016) and centralise market participants and therefore forward market liquidity (Simshauser, 2019a). And as Grimm et al. (2016) explain, multi-zonal markets frequently reflect transmission scarcities in a proximate way in any event (see also Bjørndal and Jørnsten, 2008). Ambrosius *et al.* (2019) find the mere threat of market structural changes to zonal markets can be expected to drive better locational decisions by new entrant generators. Above all, and of relevance to this article, a change from zones to nodes vis-à-vis spot pricing does not deliver additional VRE network hosting capacity in a market with already strong locational signals as Eicke et al (2020) illustrate.

Specifically, in their examination of 12 of the world's major wholesale power markets, Eicke et al. (2020) reveal *all* jurisdictions employ multiple locational mechanisms for signalling purposes, and that no dominant combination exists. Locational signalling for investment includes spatial granularity (zone splitting, nodal), temporal granularity & usage charges (e.g. time varying marginal loss factors), grid connection charges, capacity and VRE support mechanisms. Note from Fig.5 Australia's NEM transmits particularly strong locational signals through moderate spatial granularity (i.e. five zones) and acute temporal granularity (i.e. MLFs) across 1000 substations, as either bonus or penalty (+/-) through MLF multipliers[17] ascribed to each load and each plant connection point.

Figure 5: Highest value differences of locational signals across 12 markets



Source: Eicke et al (2020)

For VRE investment commitment decisions, what matters are *ex ante* expectations and the strength of locational signals rather than ex post actual outcomes, because once a locational generation investment decision is made it is irreversible (Hadush et al. 2011; Eicke et al. 2020). Locational signals that are rules-based enhance predictability and therefore accuracy of ex ante expectations. Ex ante signals are ideal for investment location decisions, while ex post adjustments optimise dispatch efficiency (but are bad for investment because they can only be forecasted imperfectly).

Additionally, as Hadush et al. (2011) explain, the stability, predictability and magnitude of locational signals are important variables in guiding location decisions of new plant but other factors can dominate investment decisions. Multiple studies show how policies such as ill-designed Contracts-for Differences auctions based on levelized costs can dismantle the efficacy of locational marginal prices, adversely impact location decisions or distort

[17] That is, as as a multiplier on the zonal spot price. MLFs are forecast annually for the year ahead.

incentives (Schmidt *et al.*, 2013; Alayo et al. 2017; Pechan, 2017; Wagner, 2019). Pechan (2017) finds fixed price contracts drive VRE investment to the best resource sites whereas stronger locational signals and VRE plant exposed to spot markets produce spatial diversity because the 'earned price' of output (or 'capacity value' per Peter and Wagner, 2021) is just as important as output levels.[18] With government-initiated CfD and Feed-in Tariffs, maximising output is the only driver (Schmidt *et al.*, 2013). Irrational exuberance in response to high market clearing prices can also dominate otherwise strong locational signals as Simshauser & Gilmore (2020) illustrate.[19] Consequently, if investment locational signals and hosting capacity are the source of the problem to be solved (rather than network congestion per se), an anticipatory transmission planner and the establishment of REZs may prove a viable policy option.

3.2 Anticipatory transmission planner: 'guiding the market'

The basic setup of deregulated markets usually places transmission networks in a responsive role rather than in a position to provide locational guidance (van der Weijde and Hobbs, 2011; Wagner, 2019). For most of the past two decades, it could be argued that a responsive role for transmission networks was appropriate. But if transmission continuously follows rising numbers of distributed VRE investments in deregulated markets, the lack of choice and ongoing policy distortions may amplify ill-advised plant siting decisions. And as Alayo et al. (2017) explain, badly sited generators induce inefficient levels of congestion and curtailment, and give rise to negative externalities in future transmission planning (Schmidt *et al.*, 2013; Bird *et al.*, 2016; Alayo et al. 2017; Bertsch *et al.*, 2017; Pechan, 2017). As an absolute general conclusion, badly sited generators can be expected to harm economic welfare.

Conversely, numerous studies show a benevolent 'anticipatory' transmission planner that guides the market regarding future location decisions in light of the sunk network can materially enhance welfare (Sauma and Oren, 2006; Tor et al, 2008; van der Weijde and Hobbs, 2012; Munoz et al., 2015; Alayo et al., 2017; Munoz *et al.*, 2017; Ambrosius *et al.*, 2019; Wagner, 2019). Solving (real-timeframe) network congestion is a different problem to solving (planning-timeframe) investment commitment location signals. In practice, there are limited options for dealing with the former, and as noted earlier, multiple options for guiding the latter (Hadush et al, 2011). The purpose of this article is to add a new variable to that list, viz. Renewable Energy Zones established as either a regulatory asset or market asset – the latter by a *risk-taking* transmission network planner seeking to *guide the market*.

3.3 Policy discontinuity – did NEM locational signals fail?

Data in Fig.5 suggests the NEM has strong locational signals. Yet approximately 20% of projects in the NEM's supercycle experienced various forms of investment failure. If the problem was not a lack of locational signalling, what was the problem? In short, it was a lack of transparency over 'MLF sensitivities' during an episode of simultaneous entry *en masse*. And the root cause of simultaneous entry *en masse* can be traced to what has become known as Australia's decade-long climate change policy war.

Australia's *underlying* electricity-related policies and energy-only market design has been stable, durable and world class (MacGill, 2010; Simshauser, 2014). But as Fleischman *et al.*, (2013)[20] explain, a key dilemma for policymakers has been an inability to achieve a united climate change policy architecture given strong political differences at the national

[18] Lion Hirth has produced a number of analyses emphasising this point from a plant portfolio perspective (see Edenhofer *et al.*, 2013; Hirth, 2013, 2015; Hirth, Ueckerdt and Edenhofer, 2016). See also (Simshauser, 2018b, 2019b; Eising, Hobbie and Möst, 2020; Peter and Wagner, 2021).
[19] See in particular Figure 20a and 20b.
[20] Fleischman et al., (2013) were examining US circumstances, but their description is equally applicable to Australia.

level (Simshauser and Tiernan, 2019).[21] Two policy mechanisms have been the subject of policy discontinuity, i). Australia's Renewable Energy Target and ii). Emissions Trading (Jones, 2010).[22]

Australia introduced the world's first Renewable Portfolio Standard after passing legislation in 2000 (Jones, 2010; MacGill, 2010). An initial obligation of '2% by 2010' was placed on electricity retailers and mobilised by tradeable Certificates (Jones, 2009; Simshauser and Tiernan, 2019). The 2% target was comfortably met four years ahead of schedule (Buckman and Diesendorf, 2010) but with Australia's international CO_2 obligations known and no further policy developments proposed, State Governments began to fill the policy vacuum. As Jones (2014) and Schelly (2014) explain, this also occurred in the US and Canada.[23]

Australia's two main political parties committed to more ambitious policies of 15-20% on the eve of the 2007 general election.[24] A united position also existed on an Emissions Trading Scheme (Jones, 2010; Apergis and Lau, 2015; Simshauser, 2018a). The social democrats were elected and passed their preferred policy in 2008, expanding the Renewable Energy Target from 2% to 20%. The initial design was held intact and expressed as a fixed volumetric target of ~44TWh by 2020 (i.e. 20% of projected 2020 demand, forecast in 2008).

By 2012, NEM aggregate demand was visibly contracting, wholesale prices had collapsed but retail-level electricity prices were rising sharply due to surging network tariffs and the cost of renewable subsidies, thus creating a political flashpoint (Nelson et al, 2012; Nelson *et al.*, 2013; Cludius, Forrest and MacGill, 2014; Garnaut, 2014; Simshauser, 2014; Nelson et al, 2015; Bell *et al.*, 2017). In response, an unscheduled Review[25] of the 20% target was initiated by the newly elected conservative government in 2013. The unwritten purpose of the Review was to reduce the 44TWh target. Given contracting aggregate demand, the Renewable Energy Target was moving closer to 30% *cf.* the 20% policy design. In the end, the policy was scaled-back to 33TWh (Biggs, 2016) but not before VRE investment flows were severely punctured during an elongated period of policy uncertainty (Simshauser, 2018a).

Stalled investment from 2012-2016 and a sharply accelerating trajectory, even with the lower 33TWh target, left little time for investors to respond to the 2020 policy closure date. Irrational exuberance and the supercycle was the outcome (Simshauser & Gilmore, 2020). Some policymakers had feared NEM locational signals were inadequate due to various investment failures. Far from it, locational signals were amplified as Figures 2, 4 and 5 illustrated.

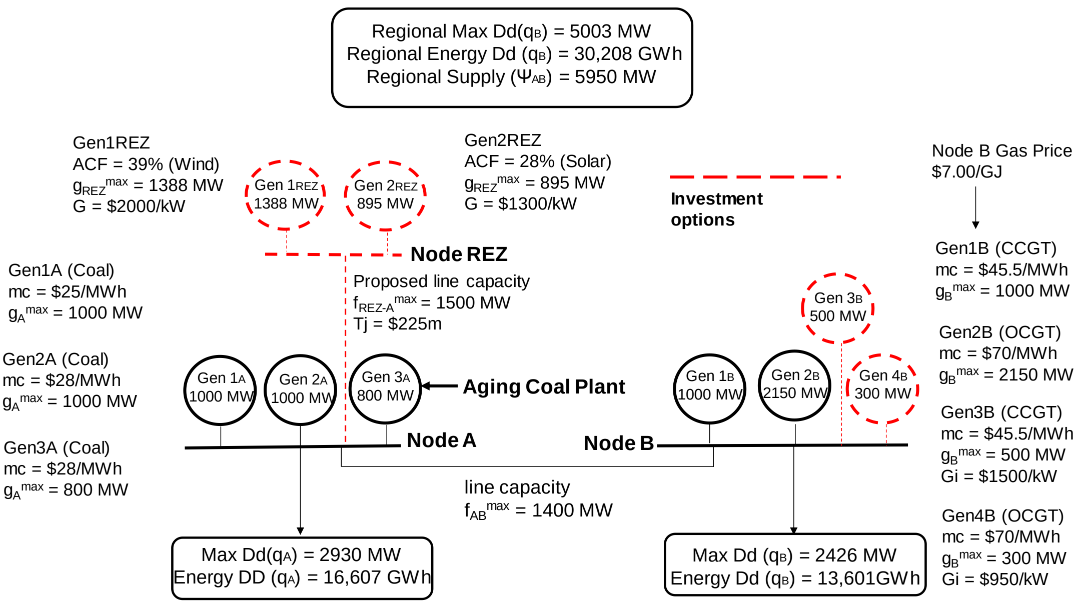
[21] See also Byrnes *et al.*, (2013); Molyneaux *et al.*, (2013); Nelson *et al.*, (2013); Freebairn (2014); Garnaut (2014); Apergis and Lau (2015); Nelson (2015); Simshauser (2018a).
[22] On emissions trading, formal policies had been developed and discarded in 1999-2001, 2005-2006 and in 2007-2010 (Simshauser and Tiernan, 2019). In late-2010 a minority Labor Government emerged from the 2010 Commonwealth election, revived an earlier policy that had been discarded only months earlier and legislated a $23/t fixed carbon tax from July 2012 as a precursor to an Emissions Trading Scheme (Garnaut, 2014; Wild, Bell and Forster, 2015). The policy was abandoned in 2014 following a change of government. Three further ETS policy attempts occurred in 2016, 2017 and 2018 but were discarded by the right of the conservative Liberal party. In all, from 1999-2018 seven formal attempts at an Emissions Trading Scheme were initiated with no tractable policy emerging (Simshauser and Tiernan, 2019).
[23] From the early-2000s State Governments began to mandate higher Targets for their own jurisdictions as Commonwealth Emissions Trading policy stalled (Nelson *et al.*, 2013; Cludius, Forrest and MacGill, 2014; Jones, 2014; Simshauser, 2018a). Work simultaneously commenced on a State-based National Emissions Trading Scheme (Nelson *et al.*, 2010; Simshauser and Tiernan, 2019).
[24] That is, a 15% Clean Energy Target or a greatly expanded '20% Renewable Energy Target by 2020'.
[25] Known as the "Warburton Review".

4. Model

In order to explore the potential role of REZs, NEMESYS, a partial equilibrium (security-constrained unit commitment) model with half-hourly resolution and price formation based on a uniform (first-price) auction clearing mechanism, has been used. As with Bushnell (2010), the model assumes perfect competition, free entry and exit to install any capacity combination that satisfies differentiable equilibrium conditions in a lossless network setup. And as with Hirth (2013), half-hour resolution simulation modelling over a reporting year forms the focus of results. The Model logic appears in Appendix II.

Five stylised scenarios are simulated, with each scenario comprising the average of 50 iterations (i.e. 250 iterations in total) given stochastic generation plant availability and load variation. Figure 6 presents the zonal market setup. There are two nodes comprising load and generation (coal plant at Node A, gas-fired plant at Node B). A possible third node option (Node REZ, dashed line series) also exists with good wind and solar resource options. Node A houses an aging coal plant, while Node B has possible CCGT and OCGT plant options (dashed line series).

Figure 6: Model setup



5. Model Scenarios and Results

In order to guide the market, an anticipatory transmission planner seeks to establish a REZ. In the model, a Base Case and four stylised variation simulations are tested, as follows.

1. The **Base** Case is per the initial model setup in Fig.6, excluding all investment options (indicated by red-dashed lines). To be clear, aging coal plant '3A' remains in-service in the Base Case.

2. In the **Regulated REZ** scenario, a transmission network utility plans to add a 'Regulated REZ' with capital cost (K_{tj}) \$225m, transfer capacity $(\hat{f})$ of 1500MW and new generation comprising 1388MW of wind, and 825MW of solar PV. Base+REZ results outlined in Section 5.1 demonstrate the REZ will not *prima facie* pass the NEM's regulatory test (and primarily because of the narrow definition of benefit, viz. carbon externalities are assumed away).

3. Next, in the **Coal Exit** scenario, the 'sudden exit' of the aging coal plant '3A' (2 x 400MW) located at Node A is simulated – reflecting the NEM's recent historical experiences in the regions of South Australia (2016) and Victoria (2017). Results demonstrate severe adverse welfare implications of *disorderly exit* including violation of the reliability constraint. To restore power system reliability, two alternate scenarios are simulated:

4. The **Exit+Gas** scenario involves plant replacement by way of gas-fired generation at Node B, 500MW CCGT (Gen3B) and 300MW OCGT (Gen4B).

5. The **Exit+REZ** scenario involves replacement by way of the $225m REZ with line transfer capacity of 1500MW and ~2200MW of VRE.

5.1 Model Results for Scenario 1: Base Case vs Regulated REZ

Table 1 presents model results for the Base Case and Regulated REZ ('Reg. REZ') simulations. In the Base Case, the fleet of coal and gas generators produce 30,316GWh (average of 50 iterations reported) with market shares of 75% and 25%, respectively. Transfer capacity of 1400MW between Nodes A-B operates unconstrained, market prices clear at $57.7/MWh and Unserved Energy is comfortably within the reliability standard (at 0.0011%). Resource costs are $986m and total costs (i.e. including incumbent fixed and sunk costs) amount to $1795m – slightly above market turnover of $1744m meaning that the generation fleet *largely recovers* all fixed and sunk costs.[26]

[26] There is a shortfall of ~$1.7/MWh, noting breakeven produces equity returns of ~8-10%.

Table 1: Scenario 1 – Base Case vs the Regulated REZ

		Base	Reg. REZ	Chg
Plant Capacity				
Coal (Node A)	(MW)	2,800	2,800	0
Gas (Node B)	(MW)	3,150	3,150	0
Wind (REZ)	(MW)	0	1,389	1,389
Solar (REZ)	(MW)	0	895	895
Total	(MW)	5,950	8,234	2,284
Plant Output				
Coal	(GWh)	22,793	19,685	-3,107
Gas	(GWh)	7,420	4,056	-3,364
Wind	(GWh)	0	5,174	5,174
Solar	(GWh)	0	2,218	2,218
Total Generation	(GWh)	30,213	31,133	921
Market Statistics				
Maximum Demand	(MW)	5,004	5,151	147
Energy Demand	(GWh)	30,213	31,101	888
Unserved Energy	(%)	0.0011%	0.0000%	-0.0011%
Constrained VRE	(GWh)	n/a	32	32
T_{REZ} Constraints	(hrs)	n/a	266	266
T_{AB} Constraints	(hrs)	0	1,389	1,389
Carbon Emissions	(Mt)	23.8	19.4	-4.4
Spot Price	($/MWh)	57.7	40.2	-17.5
Market Turnover	($m)	1,744	1,252	-493
Resource Costs				
Coal	($m)	613	527	-87
Gas	($m)	373	192	-181
REZ Trans. (Tj)	($m)	0	16	16
Wind/Solar/OCGT (Gn)	($m)	0	304	304
Resource Costs	($m)	986	1,038	52
Fixed & Sunk Costs	($m)	809	809	0
Total Economic Costs	($m)	1,795	1,847	52
Producer Surplus	($m)	758	214	-545
Economic Profits	($m)	-51	-595	-545
Economic Profit	($/MWh)	-1.7	-19.1	-17.4
Chg in Resource Cost	($m)	n/a	-52	*loss*
Chg Producer Surplus	($m)	n/a	-545	*loss*
Chg Consumer Surplus	($m)	n/a	468	*gain*
Welfare Gain / Loss	($m)	n/a	-76	*loss*

In Regulated REZ simulation (2nd results column, Tab.1), REZ augmentation with new entrant wind (1388MW) and solar (895MW) capacity delivers 7392GWh of VRE generation (24% market share) with annualised Transmission and VRE capital costs of $16m and $304m respectively. Gas-fired generation reduces by almost half and coal output reduces by 3107GWh (14%). The REZ produces a merit order effect, with prices reducing from $57.7/MWh to $40.2/MWh. Given own price elasticity of
-0.10, energy demand rises to 31,133GWh. There is a modest level of congestion on transmission line T_{REZ} (266 hours, and ~32GWh of constrained VRE Production) although to be clear VRE generators operate at very close to full potential output (i.e. unconstrained

through to the 97th percentile of potential output). Transmission line T_{AB} is congested for 1389 hours, with marginal coal plant output being adversely impacted[27].

The most important result from Table 1 is however resource costs, which rise to $1038m (up $52m) meaning REZ transmission augmentation would not *prima facie* meet the NEM regulatory test.[28] Although lower prices produce a material gain in consumer welfare (+$468m), an equally significant wealth transfer occurs with producer surplus falling by $545m. Economic losses incurred by the generation fleet total $591m.

Note however that CO_2 emissions are *not* priced in NEM regulatory tests. Note in Tab.1 that CO_2 emissions reduce by 4.4mtpa, and if these were priced at $17.5/t, in theory the regulatory test result. However, recall from Section 3.3 that Australia's NEM lacks a united climate change policy architecture due to strong political differences at the national level.

5.2 Model Results for Scenario 2: Coal exit: Gas vs REZ

Given the intractability of the Regulated REZ in Section 5.1, it is worth exploring the conditions under which a Regulated REZ would pass the cost-benefit test, i.e. a response to a looming reliability constraint. Table 2 presents results for a 'Coal Exit' scenario (LHS column) and two response scenarios (RHS columns), specifically, i). Exit+Gas with gas generation at Node B, and ii) Exit+REZ.

The first point to note in relation to the Coal Exit case is that the reliability constraint is violated (LHS column, red shaded cell, Tab.2) with Unserved Energy averaging 0.0175% (~90 half-hour trading intervals per annum). Consequently, this scenario is intractable and no further discussion is warranted. A supply-side response is absolutely necessary, and two credible alternatives are presented in the RHS columns of Tab.2.

The first response labelled 'Exit+Gas' comprises 800MW of new gas-fired generation with annualised capital costs of ~$119m (nb included in Gas resource costs of $673m). Coal output contracts to 55% market share with gas producing the remaining 45%. Transfer capacity between Nodes A-B operates unconstrained, market prices clear at $65.1/MWh and Unserved Energy falls back to within the reliability standard.

Resource costs are $1228m and total costs amount to $1922m – slightly above market turnover of $1947m with the generation fleet earning economic profits of $25m (or $0.8/MWh). A difficulty with this scenario, however, is that it is unlikely to represent a stable equilibrium because as the next scenario illustrates, VRE has lower entry costs (nb. and earned prices) than the $65.1/MWh clearing price.

The second response labelled 'Exit+REZ' adds the REZ and VRE fleet. Aggregate demand expands to 30,357GWh with coal, gas and VRE market shares being 53%, 23% and 25%, respectively. Unsurprisingly, CO_2 emissions are lowest at 17.4mtpa, down 27% on the Table 1 Base Case. There is a modest level of congestion on transmission line T_{REZ} (266 hours, and ~32GWh of constrained VRE Production) while transmission line T_{AB} is congested for 101 hours[29].

Wholesale prices in the Exit+REZ simulation clear at $56/MWh, $9/MWh lower than the Exit+Gas scenario. Note merit order effects observed in Table 1 (i.e. Regulated REZ simulation) unwind due to coal plant exit. Resource Costs of $1097m (including annualised REZ and VRE capital costs of $16m and $304m) are $131m lower than the Exit+Gas simulation. Producer Surplus falls by $115m while Consumer Surplus rises by

[27] If the market was operated on a nodal basis, spot prices at Node A would clear at -$2.7/MWh below Node B holding all else constant.
[28] After accounting for the expansion in output, the differential is actually closer to -$20m.
[29] If the market was operated on a nodal basis, spot prices at Node A and Node REZ would clear -$0.2/MWh below Node B, holding all else constant.

$229m, with total welfare increased by $114m per annum. Once again, CO_2 emissions have *not* been valued due to their current exclusion from the cost-benefit test.

Table 2: Scenario 2 – Coal exit, gas & REZ

Coal Exit				Exit+Gas	Exit+REZ	Chg
	Plant Capacity					
2,000		Coal (Node A)	(MW)	2,000	2,000	0
3,150		Gas (Node B)	(MW)	3,950	3,150	-800
0		Wind (REZ)	(MW)	0	1,389	1,389
0		Solar (REZ)	(MW)	0	895	895
5,150		Total	(MW)	5,950	7,434	1,484
	Plant Output					
16,441		Coal	(GWh)	16,469	15,924	-544
10,833		Gas	(GWh)	13,465	7,041	-6,425
0		Wind	(GWh)	0	5,156	5,156
0		Solar	(GWh)	0	2,204	2,204
27,274		Total Generation	(GWh)	29,934	30,324	390
	Market Statistics					
4,518		Maximum Demand	(MW)	4,958	5,028	70
27,280		Energy Demand	(GWh)	29,934	30,357	423
0.0175%		Unserved Energy	(%)	0.0006%	0.0010%	0.0004%
		Constrained VRE	(GWh)	n/a	32	32
n/a		TREZ Constraints	(hrs)	n/a	266	266
0		TAB Constraints	(hrs)	0	101	101
19.9		Carbon Emissions	(Mt)	20.7	17.4	-3.3
119.0		Spot Price	($/MWh)	65.1	56.0	- 9.0
3,444		Market Turnover	($m)	1,947	1,701	-247
	Resource Costs					
436		Coal	($m)	436	421	-15
581		Gas	($m)	673	356	-317
0		REZ Trans. (Tj)	($m)	0	16	16
0		Wind/Solar/OCGT (Gn)	($m)	119	304	185
1,017		Resource Costs	($m)	1,228	1,097	-131
663		Fixed & Sunk Costs	($m)	694	663	-31
1,680		Total Economic Costs	($m)	1,922	1,760	-162
2,428		Producer Surplus	($m)	719	604	-115
1,765		Economic Profit	($m)	25	-59	-84
65		Economic Profit	($/MWh)	0.8	-1.9	-2.8
-25		Chg in Resource Cost	($m)	n/a	131	*gain*
1,670		Chg Producer Surplus	($m)	n/a	-115	*loss*
-1,607		Chg Consumer Surplus	($m)	n/a	229	*gain*
n/a		Welfare Gain / Loss	($m)	n/a	114	*gain*

5.3 Summary of Results

To summarise the results, the Base Case comprised a fleet of coal and gas-fired generation plant. A 'Regulated REZ' could not be justified and the results in Table 1 were clear on this because in the NEM a narrow definition of benefits is used in regulatory cost-benefit analyses (i.e. typically limited to resource costs). If CO_2 emissions were included in the analysis at $17.5/t, the result would theoretically reverse (albeit noting highly stylised assumptions used).

The analysis and results presented in Table 2 illustrated that, in a practical sense, a Regulated REZ will be limited to reliability-driven augmentations, just as Borenstein, Bushnell and Stoft (2000) explain more generally. The Table 2 results showed that absent supply-side augmentation, the exit of a 2 x 400MW coal plant in Zone A would lead to wholesale prices surging to politically unacceptable levels of $119/MWh, and the reliability constraint would be violated. The default scenario of gas generation replacement at Node

B provided a benchmark solution for which the Regulated REZ and 2284MW of VRE plant was compared. Only at this point was the Regulated REZ able to maximise welfare (and did so regardless of whether CO_2 emissions were included given assumed spot gas and VRE prices).

Does this mean that REZs can only be built in response to scheduled coal plant retirements? In a regulatory sense, the answer is currently yes and the NEM's Integrated System Plan broadly follows this logic. Prima facie, this does appear to present a material problem for a power system that needs to be decarbonised.

However in a practical sense, ongoing VRE investments are predictable. Unlike the regulatory test, certain consumer segments (particularly large corporates) value variables beyond the regulatory test and are seeking to underwrite new entrant VRE plant to acquit their own 'Scope 2' or electricity-related CO_2 emissions objectives. Moreover, deterministic scenarios fail to capture sudden coal plant exit (which in the NEM have been 'un-forecasted and sudden') and the practical evidence is that jurisdictional Governments are increasingly seeking to 'defuse' reliability risk through pre-emptive policy. Furthermore, these same State Governments (i.e. Victoria, New South Wales, Queensland) are increasingly including CO_2 emissions objectives in their policies, and are increasingly 'side-stepping' imperfect regulation through policy or side-payments to augment transmission capacity. Ultimately if market demand for VRE plant exceeds supply and regulatory processes constrain transmission, we should anticipate market-based REZ's.

6. Renewable Energy Zones: regulated and market

Munoz et al. (2017) explain the usual assumption of the 'risk neutral transmission planner' is frequently erroneous due to parametric uncertainty vis-à-vis aggregate demand, VRE generation, construction costs, policy, long lead times and irreversible investments. Evidence (including from the NEM) suggests most transmission planners are not risk neutral, but are in fact *highly* risk averse.

The following analysis assumes a (bounded[30]) *risk seeking* transmission planner under uncertainty which guides locational decisions with an objective function of maximising welfare. REZ modelling and model inputs in Section 5 were based off worked examples from the NEM's Queensland region, viz. a $225m double circuit 275kV line splitting into two radial sections of single circuit 275kV to known VRE resource areas. Synchronous Condensers would be pre-supplied to ensure adequate system strength exists to form credible hosting capacity of ~1500MW (thermal) at a pro-rata capital cost of $150/kW.[31] Realistically, a REZ of this nature could be phased to minimise the cost of carrying idle capacity, but to simplify the subsequent analyses, the capital program is assumed to be 'built overnight'.

6.1 Regulated REZ (benchmark)

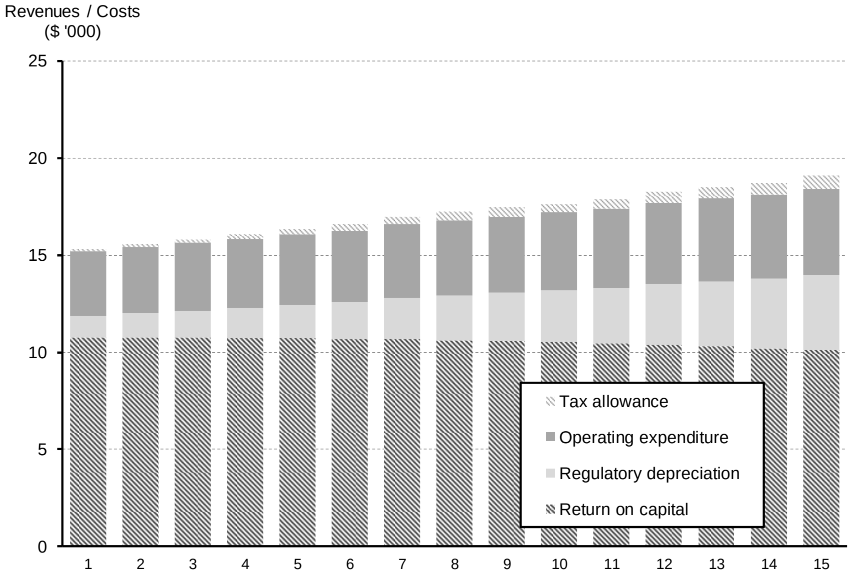
Given a $225m capital investment, ongoing O&M and re-investment costs at ~2% per annum and the current Weighted Average Cost of Capital applied to regulated network monopolies of ~4.8%, a regulated solution would enter into service with end-use consumers paying $15.3m per annum, structured per Table 3 with the trajectory set out in Figure 7:

[30] Risk appetite is bounded by the fact that NEM transmission networks typically have a capital stock of ~$8-10 billion, and the value at risk in the following exercise represents a small fraction of this.
[31] Template double and single circuit 275kV costs are ~$1.4m and $1.0m per km, $60m for synchronous condensers and in aggregate approximately $110m for multiple substations (with $90m of this directly partitioned to VRE developments).

Table 3: Regulatory Benchmark[32]

Total Revenue	15.3
Comprising	
Operating Expenditure	3.4
Regulatory Deprec.	1.1
Return on Capital	10.8
Taxation	0.1
Total Revenue	15.3

Figure 7: Regulatory REZ Benchmark Revenue (Yrs 1-15)



6.2 Market REZ

If a welfare enhancing REZ suffers from imperfect regulation or regulatory lag relative to market demand, logical counterparties to originate such infrastructure on a *merchant basis* are capital markets, transmission networks, VRE developers and their PPA counterparties. A *market REZ* would *not* enjoy a guaranteed regulated revenue stream. Development risks and costs are not allocated or underwritten by captive franchise network end-use consumers. But neither should the timing, sizing, cost, equity returns or quality of the market REZ investment constrained by regulatory processes. Instead regulation of a market REZ is applied by market forces because if VRE hosting capacity is over-sized, built too early or too capital-intensive (i.e. with connection charges above efficient levels) the risk of transient or permanent under-utilisation of the market REZ would be housed by the sponsoring transmission network. Conversely, for transmission networks the upside is that a well-crafted market REZ will eventually become a fully-contracted asset with risk-adjusted returns *cf.* regulated rates.

Most Australian transmission networks have sizable portfolios of non-regulated single customer 'Dedicated (shallow) Connection Assets', jointly developed with connecting VRE generators. The key issues for a market REZ are sizing, coordination of multiple counterparties, and (risk-adjusted) expected returns.[33] For VRE developers, the attraction

[32] Note 'Regulatory Depreciation' for the purposes of deriving Regulated Revenues is equal to Straight Line Depreciation ($5.6m) less RAB Indexation ($4.5m). The detail of the Regulatory Model used to produce these results is set out in detail in Simshauser and Akimov (2019) and so is not reproduced here.
[33] Some regulated network businesses will have constrained or no risk appetite for an (initially) under-contracted asset. Institutional and individual investors in regulated network monopolies are generally seeking exposure to a risk averse, asset class with a stable running yield. Maintenance of this dividend clientele effect is important. Consequently, strict and bounded

to a REZ is the prospect of defusing the 'majority sources' of investment failure outlined in Section 2 and Figure 4.

To illustrate the financing of a market REZ, the following simplifying assumptions have been used:

- $225m REZ comprises 1500MW of radial property rights;
- Property rights are sold on a uniform price basis in 250MW tick sizes to wind projects;
- Sale of the first property right originates investment; and
- Subscription of the remaining 5 x 250MW property rights are randomly distributed over a ~7 year window.

In practice, property rights would be divisible and priced according to resources used. Holders would be free to optimise holdings by, for example, on-selling some component to a solar or battery developer. The key matter is proportionate use of REZ radial capacity and incremental capacity use via trade in property rights.

Figure 8 presents a simulated or example of the ramp-up in property right subscriptions (thin line series, RHS Axis) along with market REZ 'cost element' cash flows (bar series, LHS Axis). For comparative purposes, the regulated REZ annual cash flows are also included as the bold line series (LHS Axis). The key difference between the regulated and market REZ cash flows relates to the source, timing and magnitude of revenues.

- The source of revenues for the regulated REZ is end-use consumers. By comparison, the market REZ is funded by connecting VRE generators;

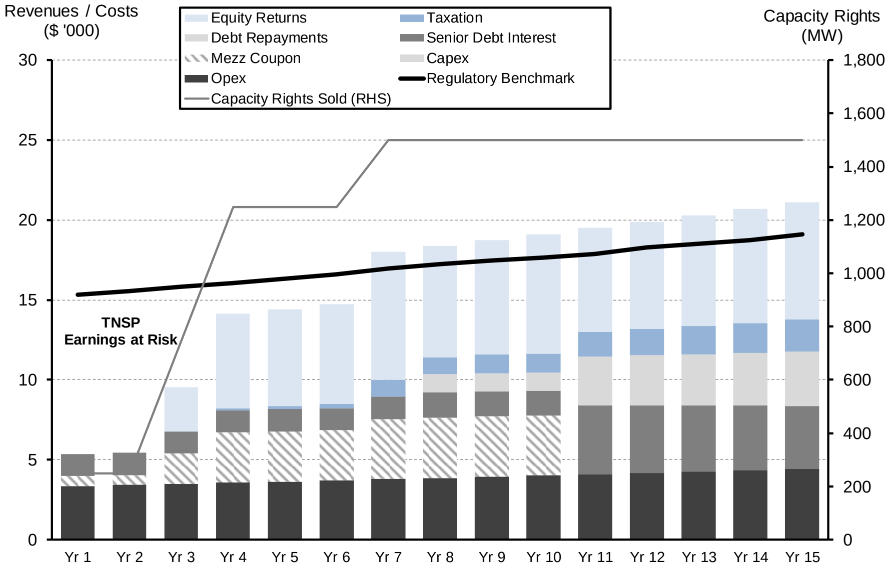
- The timing and magnitude of regulated REZ revenues commence from day one with certainty. By comparison, market REZ revenues (beyond the initial or 'foundation' generator subscription) is uncertain by both timing and magnitude.

Note in the Figure 8 worked example the market REZ is characterised by material revenue underperformance in Years 1-3 (*cf.* Regulatory Benchmark). Negative equity returns occur in Years 1-2, and positive but suboptimal returns in Years 3-6. However once fully subscribed, the market REZ meets investor expectations with the expected equity returns set closer to that of a merchant but contracted VRE generator at 7-8%. Over a 40-year asset life, the Present Value of revenues from the regulated and market REZ are virtually identical when both streams are discounted at the regulated WACC. This result is partially driven by the 'Mezz Coupon'.

---

exposure limits will exist vis-à-vis how much 'uncontracted' capacity any individual transmission network business can reasonably tolerate. In this example, the REZ is intended to be small relative to the total asset base (eg. 2-3%). The key issue will be the scale of a single REZ investment. As the size of the proposed asset rises, the more complex the task becomes.

Figure 8: Market-based REZ Revenues (LHS) and Capacity Rights (RHS)



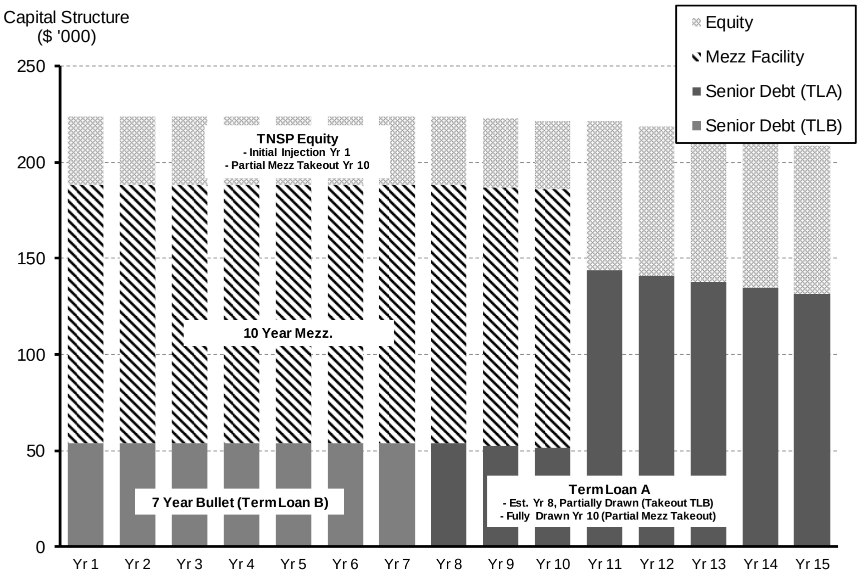
Central to the market REZ is the critical role that a structured, *Super-sized Concessional Mezzanine debt facility* plays. In finance, as the name suggests mezzanine or 'mezz' is a subordinated debt facility which when deployed typically forms a small (i.e. 10-15%) component of the overall capital structure. From a security perspective, it lies between senior debt and shareholder equity (i.e. Mezzanine level). Mezz usually fills any senior debt-raising underperformance[34], and because it ranks behind senior facilities pricing is typically characterised by a healthy premium.

In the current environment, super-sized *'concessional'* mezz with a pliable coupon (guaranteed on exit) is both possible and a policy imperative given the challenges of the energy transition.[35] Being super-sized and concessional, such a facility would have the complete opposite characteristics of conventional mezz.[36] And to be clear, without a super-sized concessional mezz (i.e. *'Super Mezz')* facility, a market REZ may prove too risky for transmission networks. But, capital market conditions, institutional capacity and policy settings are currently (i.e. in the early-2020s) ideal.

The market REZ capital structure including Super Mezz which underpinned the Fig.8 results is presented in Fig.9. To summarise the financing briefly, Super Mezz forms 60% of the capital structure during Years 1-10. The remaining capital structure comprises senior debt and equity at usual network benchmark ratios (viz. 60% debt, 40% equity). In practical terms, this means that the $225m REZ is funded via the Super Mezz $135m (60% of REZ), senior debt of $54m (i.e. 60% of the remaining 40% of REZ) and transmission equity of $36m (i.e. 40% of the remaining 40% of REZ).

[34] In practice, mezz most commonly reflects the difference between the credible maximum plausible senior secured debt achievable, and the actual level of senior secured debt raised.
[35] Australia has at least two agencies/institutions capable of providing such facilities.
[36] Orchestration may require a three-party covenant financing between the transmission network REZ sponsor, jurisdictional government seeking to expand VRE hosting capacity and the capital markets (see Rosenberg *et al.*, 2004; Simshauser *et al.*, 2016).

Figure 9: Capital Structure – market based REZ



Note in Fig.9 the first layer of capital (Years 1-7) is a senior secured debt facility. The senior debt facility is initially structured as a Bullet[37] (i.e. Term Loan B) with a BBB coupon rate of 2.58%. The second layer of capital is the Super Mezz with a guaranteed pliable 'lookback exit coupon rate' of 2%. It is modelled at the pro-rata subscription rate of ~2.8%. At Year 10, the Super Mezz is taken out with a lookback settlement such that it satisfies its ex ante aggregate coupon rate of 2% pa.

The third layer of capital is transmission equity, which in this instance is set to a 7.75% expected (risk-adjusted) return. The final component of the capital structure is a semi-permanent Amortising facility (Term Loan A) which is partially drawn at the end of Year 7 (when Term Loan B is taken out) and fully drawn at the end of Year 10 (when Super Mezz is taken out), and drawn at 3.0%.

The nature of the Super Mezz facility means coupon payments largely match REZ asset utilisation according to MW subscription (i.e. actual REZ revenue-earning). But Super Mezz must ultimately be 'squared away' at the ex ante coupon rate by Year 10. This pliable facility provides necessary breathing space to the 'risk-seeking' transmission network REZ sponsor, and the overall structure provides critical benefits to connecting generators such that they only ever pay their pro-rata subscription. In the event, the transmission network has an acute (and aligned) incentive regarding the majority sources of investment failure, those associated with connection lags and system strength. The faster generators successfully connect to the market REZ, the lower the economic consequence of REZ under-utilisation. And conversely, entry lags or disruption will surely harm the reputation of an under-utilised REZ.

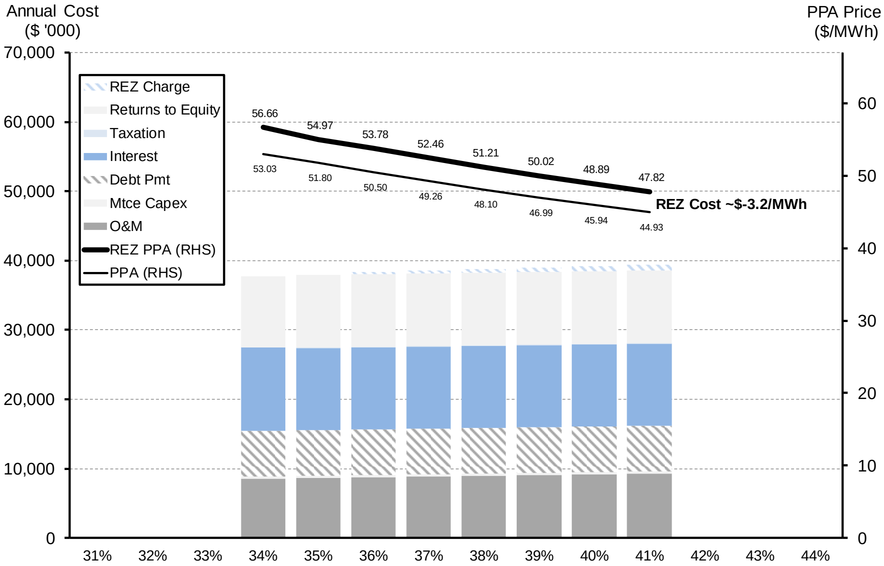
6.3 REZ cost and risk impacts on subscribing generators

In the Section 6.2 worked example, pro-rata annual (shallow REZ connection) charges equated to ~$2.5m per annum for each 250MW subscription. Fig.10 illustrates results from the PF Model (Appendix I) on how subscription alters the entry economics of a 250MW wind project with an assumed capital cost of $2049/kW (i.e. the average capital cost of the NEM's 2020 wind project fleet), fixed and variable O&M of $5m and $5/MWh respectively, equity IRR of 8% and a contemporary project financing with a run-of-plant fixed price Power Purchase Agreement (BBB rated counterparty).

[37] Interest only facility with the principal payable in full at the end of the term.

The bar series (LHS Axis) in Fig.10 presents the wind farm cost stack ($ '000) for annual plant capacity factors ranging from 34-41%, while the line series (RHS Axis) show the pre- and post-REZ PPA price required to meet debt sizing and equity return parameters. Note that the REZ subscription adds ~$3.2/MWh to plant costs as compared to a project cutting in to an existing 275kV line at a location with 0km of direct connection infrastructure.

Figure 10: Market REZ impact on Wind entry costs

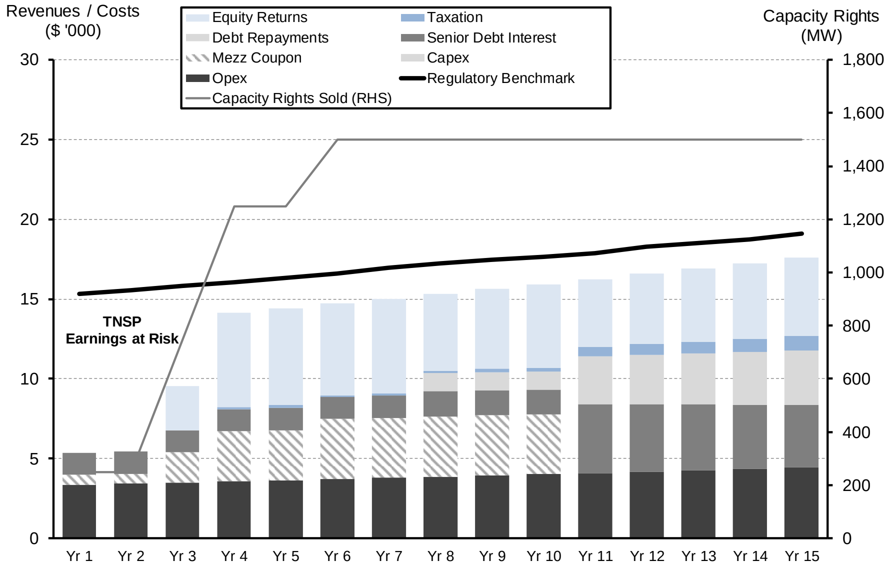


On one hand, $3.2/MWh is not insignificant. If the generator was unable to be pass these costs on to consumers, the running yield of the wind project would reduce from 8% to 6.4%. But by comparison to the $20+/MWh risk and a collapse in the distribution yield illustrated in Fig.5, $3.2/MWh pales into insignificance. Furthermore, given existing network hosting capacity is a rapidly diminishing resource, such costs will increasingly form part of common entry costs unless regulated REZs are somehow accelerated. Model results from Section 5 suggest this is unlikely to match preferences of certain consumer segments and the NEMs principle jurisdictional governments of New South Wales, Victoria and Queensland.

6.4 REZ investment risks for the anticipatory transmission planner

The primary risk of a market REZ for a transmission network is *structural* under-subscription. In the $225m example, if the 1500MW hosting capacity remained undersubscribed by (say) 250MW on a permanent basis (see Fig.11), the running yield to equity would fall by 190 basis points, i.e. from 7.75% to 5.85%.

Figure 11: Undersubscribed market based REZ



7. Policy Implications and Concluding Remarks

Australia's NEM experienced a VRE investment supercycle from 2016-2020, comprising 13,000MW of new plant commitments. A number of projects subsequently experienced significant entry frictions. The NEM's multi-zonal market design and strength of locational investment signals have been queried by policymakers. Yet an examination of the 'majority sources of investment failure' found post-commitment system strength connection lags, system strength remediation, system strength-related curtailment, and movements in MLFs to be primarily responsible. NEM locational signals were found to be among the strongest of 12 of the world's major wholesale markets, through zonal price differences and MLFs. Real-time dispatch constraints arising from network congestion were found to be a minority source of investment failure. Network congestion may be acute in select areas of the NEM (e.g. North West Victoria) yet these have been driven by policy, new plant underpinned by government-sponsored CfDs. As Section 3 explained, these are amongst the known causes of poor siting decisions.

To summarise, the common thread amongst the majority sources of investment failure was NEM hosting capacity – perhaps unsurprising given the NEM's transmission network is amongst the longest and stringiest in the world. One novel policy solution currently being explored by NEM policymakers is expanding network hosting capacity by way of special Renewable Energy Zones. But the NEM's regulatory framework typically adopts a narrow view of benefit (e.g. resource costs) when assessing augmentations. Consequently, the 'regulatory triggering' of a REZ is likely to be limited to forecast reliability shortages. VRE developers, customer preferences and jurisdictional governments – driven by environmental considerations vis-à-vis decarbonisation – demand faster action. As is commonly said amongst NEM participants, *'there's no transition without transmission'*.

Prima face, this tends to suggest policymaking associated with transmission regulatory benefits needs revision. The NEM's principal State Governments (Victoria, New South Wales and Queensland) have recently devised their own REZ policies which side-step imperfect regulation and regulatory lag. NEM Rules largely accommodate the possibility of a market REZ (albeit with minor modifications possibly required) and this may be preferable in the first instance due to the superior allocation of risk.

Analysis in this article therefore turned to the prospect of market REZs developed by a (bounded) *risk-seeking*, *anticipatory transmission network planners*. Benefits of a market REZ over regulatory solutions included speed of adjustment (given regulatory lag), and a superior allocation of investment risk (to proponents rather than franchise end-use consumers). A market REZ developed under uncertainty was underpinned by the sale of radial property rights, allocated on a subscription basis at planning timeframes in an otherwise open access regime.

Central to the market REZ was the nature, source and structure of capital deployed. Super Mezz, an oversized concessional mezzanine debt facility was demonstrated to provide the market REZ with a pliable and low-cost funding source. The pliable coupon rate delivered necessary 'financial breathing space' required by a (bounded) risk seeking, anticipatory transmission planner.

Regulatory processes run at half the pace of merchant markets. Regulated augmentations are dominated by reliability-driven investments. Consequently, relying on a centrally planned REZ may stifle opportunity through regulatory lag, and plausibly do more harm than good if they have the effect of delaying proceedings relative to the decarbonisation objectives of Australia's jurisdictional governments, the *'ESG*[38]*'* appetite and imperatives of Australian corporates and VRE developers.

With jurisdictional renewable targets of 50% by 2030 and an existing renewable market share of ~20%, a sophisticated, risk-seeking anticipatory transmission planner should expect good returns given their understanding of local network capacity and their unique line-of-sight over the universe of VRE development proposals (i.e. the first meeting a VRE developer typically organises for a new project is with the transmission network regarding grid connection). Conversely, the same anticipatory transmission planner may find their risk appetite wanning when renewable market share approaches 50% in the absence of more ambitious targets, in which case refining regulatory frameworks may become important.

8. References

AEMC (2019) *CoGaTI implementation - Access and Charging*. Australian Energy Market Commission, Sydney.

Alayo, H., Rider, M. J. and Contreras, J. (2017) 'Economic externalities in transmission network expansion planning', *Energy Economics*, 68, pp. 109–115. doi: 10.1016/j.eneco.2017.09.018.

Ambrosius, M. *et al.* (2019) *The role of expectations for market design - on structural regulatory uncertainty in electricity*. Energy Policy Research Group, Working Paper No.1914. University of Cambridge.

Apergis, N. and Lau, M. C. K. (2015) 'Structural breaks and electricity prices: Further evidence on the role of climate policy uncertainties in the Australian electricity market', *Energy Economics*, 52(October), pp. 176–182. doi: 10.1016/j.eneco.2015.10.014.

ARENA (2020) *Insights from the first wave of Large-Scale Solar Projects in Australia*. Australian Renewable Energy Agency, Sydney.

Averch, H. and Johnson, L. (1962) 'Behavior of the Firm under Regulatory Constraint', *Amercian Economic Review*, 52(5), pp. 1052–1069.

Bell, W. P. *et al.* (2017) 'Revitalising the wind power induced merit order effect to reduce wholesale and retail electricity prices in Australia', *Energy Economics*, 67, pp. 224–241. doi: 10.1016/j.eneco.2017.08.003.

Bertsch, J. *et al.* (2017) 'The relevance of grid expansion under zonal markets', *Energy Journal*, 38(5), pp. 129–152. doi: 10.5547/01956574.38.5.jber.

Bigerna, S. and Bollino, C. A. (2016) 'Demand market power and renewables in the Italian electricity market', *Renewable and Sustainable Energy Reviews*, 55(I), pp. 1154–1162. doi: 10.1016/j.rser.2015.10.130.

Bigerna, S., Bollino, C. A. and Polinori, P. (2016) 'Renewable Energy and Market Power in the Italian Electricity Market', *The Energy Journal*, 37(Special Issue 2), pp. 123–144.

Biggs, C. (2016) 'A resource-based view of opportunities to transform Australia's electricity sector', *Journal of Cleaner Production*, 123, pp. 203–217. doi: 10.1016/j.jclepro.2015.12.006.

Bird, L. *et al.* (2016) 'Wind and solar energy curtailment: A review of international experience', *Renewable and*

[38] ESG: Environmental, Social & Corporate Governance reporting frameworks adopted by large corporates.

Sustainable Energy Reviews, 65, pp. 577–586. doi: 10.1016/j.rser.2016.06.082.

Bjørndal, M. and Jørnsten, K. (2001) 'Zonal Pricing in a Deregulated Electricity Market Author', *The Energy Journal*, 22(1), pp. 51–73.

Bjørndal, M. and Jørnsten, K. (2008) 'Investment paradoxes in electricity networks', in Migdalas, A., Pardalos, P., and Pitsoulis, L. (eds) *Pareto Optimality, Game Theory and Equilibria*. Springer, pp. 593–608. doi: 10.1007/978-0-387-77247-9_23.

Borenstein, S., Bushnell, J. and Stoft, S. (2000) 'The Competitive Effects of Transmission Capacity in A Deregulated Electricity Industry', *The RAND Journal of Economics*, 31(2), pp. 294–325.

Buckman, G. and Diesendorf, M. (2010) 'Design limitations in Australian renewable electricity policies', *Energy Policy*, 38(7), pp. 3365–3376. doi: 10.1016/j.enpol.2010.02.009.

Bushnell, J. (2010) *Building Blocks : Investment in Renewable and Non-Renewable Technologies*, *Energy Institute at HAAS*.

Byrnes, L. *et al.* (2013) 'Australian renewable energy policy: Barriers and challenges', *Renewable Energy*, 60, pp. 711–721. doi: 10.1016/j.renene.2013.06.024.

Cludius, J., Forrest, S. and MacGill, I. (2014) 'Distributional effects of the Australian Renewable Energy Target (RET) through wholesale and retail electricity price impacts', *Energy Policy*, 71, pp. 40–51. doi: 10.1016/j.enpol.2014.04.008.

Edenhofer, O. *et al.* (2013) 'On the economics of renewable energy sources', *Energy Economics*, 40, pp. S12–S23. doi: 10.1016/j.eneco.2013.09.015.

Eicke, A., Khanna, T. and Hirth, L. (2020) 'Locational Investment Signals: How to Steer the Siting of New Generation Capacity in Power Systems?', *The Energy Journal*, 41(1), pp. 281–304. doi: 10.5547/01956574.41.6.aeic.

Eising, M., Hobbie, H. and Möst, D. (2020) 'Future wind and solar power market values in Germany — Evidence of spatial and technological dependencies?', *Energy Economics*, 86, p. 104638. doi: 10.1016/j.eneco.2019.104638.

Fleischman, L. *et al.* (2013) 'Ripe for retirement: An economic analysis of the U.S. coal fleet', *Electricity Journal*, 26(10), pp. 51–63. doi: 10.1016/j.tej.2013.11.005.

Freebairn, J. (2014) 'Carbon Price versus Subsidies to Reduce Greenhouse Gas Emissions', *Economic Papers*, 33(3), pp. 233–242. doi: 10.1111/1759-3441.12082.

Garnaut, R. (2014) 'Resolving Energy Policy Dilemmas in an Age of Carbon Constraints', *Australian Economic Review*, 47(4), pp. 492–508. doi: 10.1111/1467-8462.12087.

Green, R. (2007) 'Nodal pricing of electricity: How much does it cost to get it wrong?', *Journal of Regulatory Economics*, 31(2), pp. 125–149. doi: 10.1007/s11149-006-9019-3.

Grimm, V. *et al.* (2016) 'On the long run effects of market splitting: Why more price zones might decrease welfare', *Energy Policy*, 94, pp. 453–467. doi: 10.1016/j.enpol.2015.11.010.

Hadush, S., Buijs, P. and Belmans, R. (2011) 'Locational signals in electricity market design: Do they really matter?', *2011 8th International Conference on the European Energy Market, EEM 11*, (May), pp. 622–627. doi: 10.1109/EEM.2011.5953086.

Heptonstall, P. J. and Gross, R. J. K. (2020) 'A systematic review of the costs and impacts of integrating variable renewables into power grids', *Nature Energy*, pp. 1–12. doi: 10.1038/s41560-020-00695-4.

Hirth, L. (2013) 'The market value of variable renewables. The effect of solar wind power variability on their relative price', *Energy Economics*, 38(2013), pp. 218–236. doi: 10.1016/j.eneco.2013.02.004.

Hirth, L. (2015) 'The optimal share of variable renewables: How the variability of wind and solar power affects their welfare-optimal deployment', *Energy Journal*, 36(1), pp. 149–184. doi: 10.5547/01956574.36.1.6.

Hirth, L., Ueckerdt, F. and Edenhofer, O. (2016) 'Why wind is not coal: On the economics of electricity generation', *Energy Journal*, 37(3), pp. 1–27. doi: 10.5547/01956574.37.3.lhir.

Höfer, T. and Madlener, R. (2021) 'Locational (In)Efficiency of renewable energy feed-in into the electricity grid: A spatial regression analysis', *Energy Journal*, 42(1), pp. 171–196. doi: 10.5547/01956574.42.1.THOF.

Holmberg, P. and Lazarczyk, E. (2015) 'Comparison of congestion management techniques: Nodal, zonal and discriminatory pricing', *Energy Journal*, 36(2), pp. 145–166. doi: 10.5547/01956574.36.2.7.

Jones, S. (2009) 'The future of renewable energy in Australia: A test for cooperative federalism?', *Australian Journal of Public Administration*, 68(1), pp. 1–20. doi: 10.1111/j.1467-8500.2008.00606.x.

Jones, S. (2010) 'The national renewable energy target: An example of post-machiavellian policy-making?', *Australian Journal of Public Administration*, 69(2), pp. 165–177. doi: 10.1111/j.1467-8500.2010.00678.x.

Jones, S. (2014) ‘Flirting with Climate Change: A Comparative Policy Analysis of Subnational Governments in Canada and Australia’, *Journal of Comparative Policy Analysis: Research and Practice*, 16(5), pp. 424–440. doi: 10.1080/13876988.2014.942570.

Joos, M. and Staffell, I. (2018) ‘Short-term integration costs of variable renewable energy: Wind curtailment and balancing in Britain and Germany’, *Renewable and Sustainable Energy Reviews*, 86(March), pp. 45–65. doi: 10.1016/j.rser.2018.01.009.

Joskow, P. L. (2008) ‘Capacity payments in imperfect electricity markets: Need and design’, *Utilities Policy*, 16(3), pp. 159–170. doi: 10.1016/j.jup.2007.10.003.

Kristov, L., De Martini, P. and Taft, J. D. (2016) ‘A Tale of Two Visions: Designing a Decentralized Transactive Electric System’, *IEEE Power and Energy Magazine*, 14(3), pp. 63–69. doi: 10.1109/MPE.2016.2524964.

Litvinov, E. *et al.* (2004) ‘Marginal loss modeling in LMP calculation’, *IEEE Transactions on Power Systems*, 19(2), pp. 880–888. doi: 10.1109/TPWRS.2004.825894.

MacGill, I. (2010) ‘Electricity market design for facilitating the integration of wind energy: Experience and prospects with the Australian National Electricity Market’, *Energy Policy*, 38(7), pp. 3180–3191. doi: 10.1016/j.enpol.2009.07.047.

Molyneaux, L. *et al.* (2013) ‘Australian power: Can renewable technologies change the dominant industry view?’, *Renewable Energy*, 60, pp. 215–221. doi: 10.1016/j.renene.2013.05.009.

Mountain, B. and Littlechild, S. (2010) ‘Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria’, *Energy Policy*, 38(10), pp. 5770–5782. doi: 10.1016/j.enpol.2010.05.027.

Munoz, F. D. *et al.* (2017) ‘Does risk aversion affect transmission and generation planning? A Western North America case study’, *Energy Economics*, 64, pp. 213–225. doi: 10.1016/j.eneco.2017.03.025.

Munoz, F. D., Watson, J. P. and Hobbs, B. F. (2015) ‘Optimizing Your Options: Extracting the Full Economic Value of Transmission When Planning Under Uncertainty’, *Electricity Journal*, 28(5), pp. 26–38. doi: 10.1016/j.tej.2015.05.002.

Nelson, T. *et al.* (2010) ‘Delayed Carbon Policy Certainty and Electricity Prices in Australia*’, *Economic Papers*, 29(4), pp. 446–465. doi: 10.1111/j.1759-3441.2010.00084.x.

Nelson, T. *et al.* (2013) ‘An analysis of Australia’s large scale renewable energy target: Restoring market confidenc’, *Energy Policy*, 62, pp. 386–400.

Nelson, T. (2015) ‘Australian Climate Change Policy - Where To From Here?’, *Economic Papers*, 34(4), pp. 257–272. doi: 10.1111/1759-3441.12114.

Nelson, T., Reid, C. and McNeill, J. (2015) ‘Energy-only markets and renewable energy targets: Complementary policy or policy collision?’, *Economic Analysis and Policy*, 46(2015), pp. 25–42. doi: 10.1016/j.eap.2015.04.001.

Nelson, T., Simshauser, P. and Nelson, J. (2012) ‘Queensland Solar Feed-In Tariffs and the Merit-Order Effect: Economic Benefit, or Regressive Taxation and Wealth Transfers?’, *Economic Analysis and Policy*, 42(3), pp. 277–301. doi: 10.1016/S0313-5926(12)50030-5.

Nepal, R., Menezes, F. and Jamasb, T. (2014) ‘Network regulation and regulatory institutional reform: Revisiting the case of Australia’, *Energy Policy*, 73, pp. 259–268. doi: 10.1016/j.enpol.2014.05.037.

Neuhoff, K. *et al.* (2013) ‘Renewable electric energy integration: Quantifying the value of design of markets for international transmission capacity’, *Energy Economics*, 40, pp. 760–772. doi: 10.1016/j.eneco.2013.09.004.

Neuhoff, K., Wolter, S. and Schwenen, S. (2016) ‘Power Markets with Renewables: New Perspectives for the European Target Model’, *The Energy Journal*, 37(S12), pp. 23–38.

Pechan, A. (2017) ‘Where do all the windmills go? Influence of the institutional setting on the spatial distribution of renewable energy installation’, *Energy Economics*, 65, pp. 75–86. doi: 10.1016/j.eneco.2017.04.034.

Peter, J. and Wagner, J. (2021) ‘Optimal allocation of variable renewable energy considering contributions to security of supply’, *Energy Journal*, 42(1), pp. 229–260. doi: 10.5547/01956574.42.1.JPET.

Pollitt, M. G. and Anaya, K. L. (2021) ‘Competition in markets for ancillary services? The implications of rising distributed generation’, *Energy Journal*, 42, pp. 5–32. doi: 10.5547/01956574.42.S12.TEKH.

Pozo, D., Contreras, J. and Sauma, E. (2013) ‘If you build it, he will come: Anticipative power transmission planning’, *Energy Economics*, 36, pp. 135–146. doi: 10.1016/j.eneco.2012.12.007.

Rosenberg, W. G. *et al.* (2004) *Financing IGCC – 3 Party Covenant*. Available at: https://www.innovations.harvard.edu/sites/default/files/financing_igcc.pdf.

Sauma, E. E. and Oren, S. S. (2006) 'Proactive planning and valuation of transmission investments in restructured electricity markets', *Journal of Regulatory Economics*, 30(3), pp. 261–290. doi: 10.1007/s11149-006-9003-y.

Schelly, C. (2014) 'Implementing renewable energy portfolio standards: The good, the bad, and the ugly in a two state comparison', *Energy Policy*, 67, pp. 543–551. doi: 10.1016/j.enpol.2013.11.075.

Schmidt, J. *et al.* (2013) 'Where the wind blows: Assessing the effect of fixed and premium based feed-in tariffs on the spatial diversification of wind turbines', *Energy Economics*, 40, pp. 269–276. doi: 10.1016/j.eneco.2013.07.004.

Schweppe, F. C. *et al.* (1988) *Spot Pricing of Electricity*. US: Kluwer Academic Publishers.

Simshauser, P. (2014) 'From First Place to Last: The National Electricity Market's Policy-Induced "Energy Market Death Spiral"', *Australian Economic Review*, 47(4), pp. 540–562. doi: 10.1111/1467-8462.12091.

Simshauser, P. *et al.* (2016) 'Foreign aid via 3-Party Covenant Financings of capital-intensive infrastructure', *Journal of Financial Economic Policy*, 8(2), pp. 183–211. doi: 10.1108/JFEP-11-2015-0067.

Simshauser, P. (2018a) 'Garbage can theory and Australia's National Electricity Market: Decarbonisation in a hostile policy environment', *Energy Policy*, 120(June), pp. 697–713. doi: 10.13140/RG.2.2.34021.91367.

Simshauser, P. (2018b) 'On intermittent renewable generation & the stability of Australia's National Electricity Market', *Energy Economics*, 72(May), pp. 1–19. doi: 10.1016/j.eneco.2018.02.006.

Simshauser, P. (2019a) 'Missing money, missing policy and Resource Adequacy in Australia's National Electricity Market', *Utilities Policy*, 60, p. 100936. doi: 10.1016/j.jup.2019.100936.

Simshauser, P. (2019b) 'On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences', *Energies*, 12(13), p. 2566. doi: 10.3390/en12132566.

Simshauser, P. and Akimov, A. (2019) 'Regulated electricity networks, investment mistakes in retrospect and stranded assets under uncertainty', *Energy Economics*, 81, pp. 117–133. doi: 10.1016/j.eneco.2019.03.027.

Simshauser, P. and Gilmore, J. (2020) *Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle*. Energy Policy Reserch Group, Working Paper No.2014. University of Cambridge. Available at: www.eprg.group.cam.ac.uk.

Simshauser, P. and Tiernan, A. (2019) 'Climate change policy discontinuity and its effects on Australia's national electricity market', *Australian Journal of Public Administration*, 78(1), pp. 17–36. doi: 10.1111/1467-8500.12328.

Tor, O. B., Guven, A. N. and Shahidehpour, M. (2008) 'Congestion-driven transmission planning considering the impact of generator expansion', *IEEE Transactions on Power Systems*, 23(2), pp. 781–789. doi: 10.1109/TPWRS.2008.919248.

Torre, S. De, Conejo, A. J. and Contreras, J. (2008) 'in Electricity Markets', *IEEE Transactions on Power Systems*, 23(1), pp. 238–248.

Wagner, J. (2019) 'Grid investment and support schemes for renewable electricity generation', *Energy Journal*, 40(2), pp. 195–220. doi: 10.5547/01956574.40.2.jwag.

van der Weijde, A. H. and Hobbs, B. F. (2011) 'Locational-based coupling of electricity markets: Benefits from coordinating unit commitment and balancing markets', *Journal of Regulatory Economics*, 39(3), pp. 223–251. doi: 10.1007/s11149-011-9145-4.

van der Weijde, A. H. and Hobbs, B. F. (2012) 'The economics of planning electricity transmission to accommodate renewables: Using two-stage optimisation to evaluate flexibility and the cost of disregarding uncertainty', *Energy Economics*, 34(6), pp. 2089–2101. doi: 10.1016/j.eneco.2012.02.015.

Wild, P., Bell, W. P. and Forster, J. (2015) 'Impact of Carbon Prices on Wholesale Electricity Prices and Carbon Pass-Through Rates in the Australian National Electricity Market', *The Energy Journal*, 36(3), pp. 137–153.

Zachary, S., Wilson, A. and Dent, C. (2019) *The integration of variable generation and storage into electricity capacity markets*. arXiv:1907.05973 [math.OC]. Available at: http://arxiv.org/abs/1907.05973.

APPENDIX I – PF Model Overview

In the PF Model, costs increase annually by a forecast general inflation rate (CPI). Prices escalate at a discount to CPI. Inflation rates for revenue streams π_j^R and cost streams π_j^C in period (year) *j* are calculated as follows:

$$\pi_j^R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^j \text{, and } \pi_j^C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^j, \qquad \text{(A.1)}$$

The discounted value for α_R reflects single factor learning rates that characterise generating technologies.

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxillary losses Aux^i arising from on-site electrical loads are deducted.

$$q_j^i = CF_j^i . k^i . (1 - Aux^i), \qquad \text{(A.2)}$$

A convergent electricity price for the *i^th^* plant $(p^{i\varepsilon})$ is calculated in year one and escalated per eq. (1). Thus revenue for the *i^th^* plant in each period *j* is defined as follows:

$$R_j^i = (q_j^i . p^{i\varepsilon} . \pi_j^R), \qquad \text{(A.3)}$$

In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[39] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j^th^* period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{ \left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i \right) + \left(g^i . CP_j\right) \right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000} \right\}, \qquad \text{(A.4)}$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C, \qquad \text{(A.5)}$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the *j^th^* period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right), \qquad \text{(A.6)}$$

[39] The derivation of the constant term 3600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3600 Joules.

Capital Costs (X_0^i) for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending $\left(x_j^i\right)$ for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i . \pi_j^C, \tag{A.7}$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \tag{A.8}$$

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i\right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i\right)$ results in non-positive outcome, tax losses $\left(L_j^i\right)$ are carried forward and offset against future periods.

$$\tau_j^i = Max\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right), \tag{A.9}$$

$$L_j^i = Min\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right), \tag{A.10}$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures include semi-permanent amortising facilities and bullet facilities.

Corporate Finance typically involves 5- and 7-year bond issues with an implied ‘BBB’ credit rating. Project Finance may include a 5-7 year Bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology) and a second facility commencing with tenors of 5-12 years as an Amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two tranches of debt was the same, so for the Debt Tranche where DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i, \\ = 1, DT_1^i = D_0^i . S \end{cases} \tag{A.11}$$

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each tranche. In most model cases, 35% of debt is assigned to Tranche 1 and the remainder to Tranche 2. Principal P_{j-1}^i refers to the amount of principal repayment for tranche T in period *j* and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-\left(1+\left(R_{Tj}^Z + C_{Tj}^Z\right)\right)^{-n}}{R_{Tj}^Z + C_{Tj}^Z}\right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right), \tag{A.12}$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the j^{th} period $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_j^i = DT_j^i \times \left(R_{Tj}^z + C_{Tj}^z\right), \tag{A.13}$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the i^{th} plant is calculated as the sum of the above components for the two debt tranches in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost $\left(X_0^i\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\, j \ \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\, j \ \right| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\, j \ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases}, \tag{A.14}$$

Credit metrics[40] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ are exogenously determined by credit rating agencies and are outlined in Table 3. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}, \tag{A.15}$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $\left(p^{i\varepsilon}\right)$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF}given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_{0,}^i \tag{A.16}$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left-hand side of the equation:

Let $IRR \equiv K_e$

---

[40] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\Big[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\Big] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i, \tag{A.17}$$

The model then solves for $p^{i\varepsilon}$ such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\Big((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\Big)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}}. \tag{A.18}$$

APPENDIX II – NEMESYS Model Overview

In the Model, let *H* be the ordered set of all half-hourly trading intervals.

$$i \in \{1 \ldots |H|\} \wedge h^i \in H, \qquad \text{(A.19)}$$

Let *N* be the ordered set of nodes within the regional power system and let |*N*| be the total number of nodes in the set. Let η_n be node n where:

$$n \in (1..|\mathrm{N}|) \wedge \eta_n \in \mathrm{N}, \qquad \text{(A.20)}$$

Aggregate demand at each node comprises residential, commercial and industrial consumer segments. Let *E* be the set of all electricity consumers in the model.

$$w \in \{1 \ldots |E|\} \wedge e_w \in E, \qquad \text{(A.21)}$$

Let $V_w(q)$ be the valuation that consumer segment w is willing to pay for quantity q MWh of electricity. Let $q^i_{w,n}$ be the metered quantity consumed by customer segment w in each trading interval i at node n expressed in Megawatt hours (MWh). In all scenarios and iterations, aggregate demand is modelled as a strictly decreasing and linear function with own price elasticity of -0.10 applied by reference to average wholesale prices p against the 'base case'.

Generation investment and spot market trading are assumed to be profit maximising in a perfectly competitive market with all firms being price takers, thus yielding welfare maximising outcomes. Let Ψ_n be the ordered set of generators at node n

$$g \in \{1..|\Psi_n|\} \wedge \psi_{ng} \in \Psi_n, \qquad \text{(A.22)}$$

Conventional plant are subject to random maintenance outages. $\mathrm{F}(n, g, i)$ is the availability of each plant ψ_{ng} in each period i. Annual generation fleet availability is therefore:

$$\sum_{g=0}^{|\Psi_n|} F\,(n, g, i)\ \forall\ \eta_n, \qquad \text{(A.23)}$$

Conventional plant face binding capacity limits and minimum stable load constraints. Let $\hat{g}_{\psi_{ng}}$ be the maximum productive capacity of generator ψ_{ng} at node n and let $\check{g}_{\psi_{ng}}$ be the minimum stable load of generator ψ_n. Plant marginal running costs are given by mc_{ng}. Let $g_{\psi^i_{ng}}$ be generation dispatched (and metered) at node n by generator ψ_n in each trading interval i expressed in MWh. Let d^i_n be the cleared quantity of electricity delivered in trading interval i at node n expressed in MWh.

Let $p_{\psi^i}(q)$ be the uniform clearing price that all dispatched generators receive for generation dispatched, $g_{\psi^i_n}$. Were it not for network constraints, generation and transmission investment options, the problem to be solved is in fact a simple one:

$$\min_{q^i_n} \left(\sum_i mc^i_{\psi_{ng}} \left(g_{\psi^i_{ng}} \right) q^i_n \right), \qquad \text{(A.24)}$$

where

$$\exists \psi^i_{ng} \Big| if\ \left(g_{\psi^i_{ng}}\right) \begin{cases} \neq 0, 0 < \check{g}_{\psi_{ng}} < g_{\psi^i_{ng}} < \hat{g}_{\psi_{ng}} \forall\, \psi_n \\ = 0, 0 \end{cases} \wedge \left[\left(\sum q^i_{w,n} - \sum g_{\psi^i_{ng}}\right) / \sum q^i_{w,n}\right] \ngtr USE, \tag{A.25}$$

and

$$If\ \left(\sum q^i_{w,n} - \sum g_{\psi^i_{ng}} > 0 \Big| USE > 0, p_{\psi^i}(q) = \$15{,}000/\text{MWh}, \right), \tag{A.26}$$

Unserved Energy (USE) defines the reliability constraint. In the model, the NEM's reliability standard is used with USE not to exceed 0.002%. Eq.(7) constrains unit commitment of each generator $g_{\psi^i_{ng}}$ to within their credible operating envelope, and for the market as a whole to operate within the reliability constraint, USE. Eq.(8) specifies that any period involving load shedding, market clearing prices default to the Value of Lost Load of \$15,000/MWh, noting this has a tight nexus with the reliability standard (which modelling results subsequently reveal).[41]

Let Ŧ be the ordered set of all transmission lines t_j and let |Ŧ| be the number of transmission lines in the zone.

$$t_j \in (1..|Ŧ|) \wedge t_j \in Ŧ, \tag{A.27}$$

Let Ω_A and Ω_B be two nodes directly connected to transmission line t_j where

$$\Omega_A \in \mathrm{N}, \wedge\, \Omega_B \in \mathrm{N}\, |\Omega_A \neq \Omega_B, \tag{A.28}$$

Let f_{AB} be the flow between the two nodes. Let $\hat{f}_j$ be the maximum allowed flow along transmission line t_j and let $\check{f}_j$ be the maximum reverse flow.

The clearing vector of quantities demanded q^i_n or supplied at node n in each trading interval i is given by the sum of flows across all transmission lines starting at that node, less flows across transmission lines ending at that node, if applicable. Net positive quantities at a node are considered to be net supply $g_{\psi^i_n}$ $(i.e. \sum g_{\psi^i_{ng}})$ and negative quantities imply net demand V^i_n:

$$if\ q^i_n \begin{cases} \geq 0, g_{\psi^i_n} = q^i_n \\ \leq 0, V^i_n = -q^i_n, \end{cases} \tag{A.29}$$

Integration of plant costs in the model centres around the transposition of three key variables, Marginal Running Costs $mc_{\psi n}$ Fixed O&M Costs $FOM_{\psi n}$ & where applicable (annualised) new entrant generator Capital Costs, $K_{\psi n}$ and (annualised) new Transmission line Capital Costs, K_{tj}. These parameters are the key variables in the half-hourly power system model and are used extensively to meet the objective function.

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less marginal electricity production costs and any

[41] From a power system planning perspective, the overall objective function is to minimise $VoLL\ x\ USE + \sum_{i=1}^{n} c(G)\ |\ VoLL\ x\ USE + c(\bar{G}) = 0$, where $VoLL$ is the Value of Lost Load, USE is Unserved Energy, and where $c(G)$ is the cost generation plant, and $c(\bar{G})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the VoLL. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE = CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between VoLL and reliability criteria, see (Zachary, Wilson and Dent, 2019).

(annualised) generation $K_{\psi n}$ or transmission K_{tj} augmentation costs. The objective function is therefore expressed as:

$$\text{Obj} = \left[\sum_{i=1}^{|H|} \sum_{w=1}^{|E|} \sum_{n=1}^{|\mathbb{N}|} \int_{q=0}^{v_n} V_n\left(q_{n,w}^{i}\right) \partial q\right] - \left[\sum_{i=1}^{|H|} \sum_{n=1}^{|\mathbb{N}|} \sum_{\psi=1}^{|\Psi|} \int_{q=0}^{g_{\psi n}} mc_{\psi n}\left(q_{\psi,n}^{n}\right) \partial q + FOM_{\psi n} + \sum_{n=1}^{|\mathbb{N}|} K_{\psi n} + \sum_{j=1}^{|Ŧ|} K_{tj}\right], \tag{A.30}$$

Subject to

$$0 \leq q_i \leq V_i \wedge \check{f}_j \leq f_i \leq \hat{f}_j \wedge 0 \leq \check{g}_{\psi i} \leq g_{\psi i} \leq \hat{g}_{\psi i}.$$