Energy Economics 72 (2018) 1–19

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneeco

On intermittent renewable generation & the stability of Australia's National Electricity Market

Paul Simshauser

Griffith Business School, Griffith University, Australia

ARTICLE INFO

Article history:
Received 4 July 2017
Received in revised form 30 January 2018
Accepted 5 February 2018
Available online 17 February 2018

JEL classification:
D61
L94
L11 and Q40

Keywords:
Energy markets
Missing money
Variable renewable energy

ABSTRACT

Energy-only markets have an inherently unstable equilibrium, even under ideal conditions, because participants are unable to optimise VoLL events. The addition of intermittent renewable generation is thought to make conditions harder. In this article, optimal VoLL events in an islanded NEM region is modelled by substituting high price caps for Boiteux capacity charges, then analysing the impact of adding progressively more Variable Renewable Energy (VRE) – up to 35% market share. Spot market conditions prove stable and tractable provided thermal plant exit and adjust perfectly. But VRE asset allocation is important; absent highly elastic demand or ultra-low cost storage, solar PV market share has economic limits because the technology rapidly cannibalises itself. Furthermore, as VRE rises in imperfectly interconnected regions, a tipping point appears to exist where hedge markets enter an unstable zone through shortages of 'asset-backed' firm intra-regional swaps and caps. Government-initiated CfDs for VRE need to be designed carefully to ensure any instability is not exacerbated by extracting contracts from an already shortening hedge market.

1. Introduction

Australia's National Electricity Market (NEM) formed part of a world-wide electricity industry microeconomic reform experiment which commenced in Chile from 1982 (Pollitt, 2004). England & Wales followed with their landmark 1990 reform while Australia commenced from 1994 (Green, 1999; Nelson and Orton, 2016). The initial wave of restructuring and deregulation had two or three template electricity markets designs involving various combinations of "energy-only" or "capacity & energy" market mechanisms, set in gross or net pools with day-ahead or real-time scheduling. These designs shared a market liberalisation objective but adopted different paths to achieve that outcome (Pollitt and Anaya, 2016). Results have been mixed.

By any measure the NEM had been a resounding success[1] and by 2005 was widely regarded as a template for power system reform (IEA, 2005). The NEM is an energy-only gross pool with a real-time (5-minute) uniform first-price auction clearing mechanism and forward derivative markets traded both on-exchange and Over-the-Counter at 300–400% of physical trade.[2]

Pollitt & Anaya (2016, p.75) noted a second wave of world-wide electricity market experiments currently underway – each involving a *'game-changing set of policies'* designed to achieve a decarbonisation objective through various combinations of carbon pricing, renewable energy targets, centrally-initiated CfDs, and distributed resources. As with the first wave, results will be mixed. A visible outcome of these policies is sharply rising levels of intermittent renewables (i.e. solar and wind).

When energy markets were first designed, they were applied to large thermal systems comprising dispatchable coal, gas and hydro plant. There was typically little in the way of intermittent renewable plant.[3] But Variable Renewable Energy (VRE) resources now form the dominant supply-side entrant in the NEM, driven by various policy

[1] Performance improvements included average cost, price, plant availability, and reserve margins (see Simshauser, 2005). In more recent research, the wholesale market was one of the few areas of the electricity market that was performing well (see for example Nelson and Orton, 2016; Simshauser, 2014). From mid-2016 however, market performance deteriorated significantly.

[2] See Simshauser et al. (2015) and in particular Appendix III.

[3] Data from the Energy Supply Association reveals that when the NEM commenced in 1998, the market shares of the various technologies were coal (88.4%), hydro (9.3%), gas (2.2%) and VRE (0%). Wind produced less than 1GWh in a 165000GWh system. By 2015, the energy mix was coal (75.7%), gas (12.9%), hydro (6.4%) and wind/solar (4.9%) with total load of 196,000GWh.

https://doi.org/10.1016/j.eneco.2018.02.006

initiatives, an extremely tight market for gas[4] and an abject inability to "bank" coal plant due to future CO_2 emissions risk.

Energy markets can comfortably integrate moderate levels of intermittent generation[5] but there is a broader question as to whether current market designs are capable of accommodating *high-levels* of VRE. Indeed, the energy-only market design has been the subject to a long line of inquiry vis-à-vis Resource Adequacy. Even with a high Value of Lost Load (VoLL)[6] and no VRE, such markets are volatile and frequently *off equilibrium* for extended periods which raises risks of timely plant entry.[7] Rising VRE market shares are thought to intensify price volatility and exacerbate the duration for which energy-only markets are *off equilibrium*, especially when "side-markets[8]" are involved because two new variables require optimisation viz. thermal plant exit and thermal plant adjustment. Consequently, and while by no means unanimous, an emerging theme amongst British and European energy economists is that the energy-only market design is broken given multiple policies and associated objectives (Edenhofer et al., 2013; Helm, 2014; Newbery, 2015; Keay, 2016; Pollitt and Anaya, 2016; Neuhoff et al., 2016; Green and Staffell, 2016).

While Australia's NEM has exhibited volatility and extended periods *off equilibrium*, it has also been characterised by consistent economic and technical performance over a two-decade period. However, from 2016 certain regions of the NEM appear unstable. The South Australian (SA) region in particular, which comprises 40% VRE, lost its last baseload coal plant in April 2016 in large part due to merit-order effects. As the literature predicts,[9] immediately following plant exit wholesale futures prices rebounded – trebling in the SA case – regional security of supply deteriorated, and culminated in a black system event on 28 September 2016. This was Australia's first grid collapse since 1964.[10] Soon after in April 2017 the Hazelwood coal-fired power station which supplied >20% of the Victorian region exited abruptly. Resource Adequacy in both SA and the Victorian regions became questionable and the rise in spot and forward electricity prices spread across all regions of the NEM.

Unsurprisingly concerns vis-à-vis the NEM's energy-only market design emerged. Market outcomes have breached Australian policymaker tolerances given the political economy of electricity supply and the central role that energy plays in a modern economy. To be clear, the NEM, with its particularly high VoLL, has experienced non-trivial price cycles over the past two decades, but at no point would the market described as "unstable". However, the combination of high prices, thermal plant exit, lags to plant entry, the NEM's first serious prospect of the Resource Adequacy problem in two decades, and the system collapse of an entire NEM region (i.e. SA) has brought the market's stability into question. At the very least, it has removed any doubt in the minds of Australian policymakers that the NEM design requires adjustment. Whether this translates to *tweaking at the edges* (e.g. enhancing Frequency Control Ancillary Service markets) or *major surgery* is an open question, but the status quo is widely acknowledged as unacceptable.[11]

The primary purpose of this article is to analyse the stability[12] of the energy-only electricity market design when Renewable Energy Targets (i.e. certificate "side markets") and CfDs policies intended to drive VRE plant entry are superimposed. A dynamic partial equilibrium model of an energy-only market with imperfect interconnection is used to stress-test conditions with progressively rising levels of *policy-induced* VRE. Subsequent modelling results and the analysis that follows reveal interesting policy challenges for Resource Adequacy, market stability and consumer welfare.

First, modelling results show in the Short-Term that the energy-only design can maintain spot market equilibrium conditions for up to at least 35% market share *provided* thermal plant exit and adjust perfectly. *If* VoLL is correctly priced relative to reliability criteria, and *if* the market optimises VoLL event frequency, there is no reason to think energy-only markets cannot produce equilibrium conditions, and therefore, Resource Adequacy.

Second, renewable certificate "side markets" and government-initiated CfDs, which operate to ensure VRE plant can enter at pace regardless of underlying spot electricity market conditions, drive disequilibrium if thermal plant fails to exit and adjust perfectly. From a practical perspective, these well-known merit-order effects eventually produce thermal plant financial distress and exit, but exit timing is uncertain and may occur with little warning, thereby creating temporal security of supply risks.

Third, while government-initiated CfDs ensure successful VRE plant entry, if programs are executed on the basis of flawed metrics such as the Levelised Cost of Electricity rather than market value, VRE fleet asset allocation may become distorted and produce a misinformed market. This may adversely impact prior (and future) VRE investment commitments.

Fourth, in the Long-Term when thermal plant exits, merit-order effects reverse and spot prices rebound to a tractable equilibrium. But at this point an entirely new problem appears to emerge in imperfectly interconnected regions, viz. imbalances in the market for forward derivatives contracts. When thermal plant exits, it also withdraws its "firm" hedge capacity (i.e. swaps and caps). Non-firm "run-of-plant" Power Purchase Agreements from new entrant VRE generators are poor substitutes for firm instruments. Modelling results show that under these conditions non-trivial shortages of asset-backed "primary" hedge contract issuance is far more than a theoretical possibility. And ironically, any shortage would coincide with sharply rising spot market prices.

Finally, government-initiated CfDs, while well intentioned, exacerbate forward contract market imbalances by "extracting" intermittent hedge contract capacity from forward markets altogether. The combination of VRE side markets and CfDs may result in policy-induced "systemic[13]" electricity market risks and the (unintended) foreclosure

[4] For further details on the Australian east-coast gas market, see Simshauser and Nelson (2015).

[5] See for example Simshauser (2011) in which South Australia is modelled with 17% VRE.

[6] This is of course an intentional design aspect of the NEM. In its place is a very high VoLL, currently $14,000/MWh.

[7] Many markets are frequently off equilibrium but the issue with energy-only electricity markets is the depth and length of variations from equilibrium. As one reviewer noted, the key role for policy advisors and policymakers with respect to energy markets is to focus on workably competitive results rather than being distracted by the pursuit of the ideal market design.

[8] That is, certificate markets or subsidy programs to certain generation technologies.

[9] See for example Gelabert et al. (2011) or Nelson et al. (2012).

[10] The New South Wales power system collapsed on 10 June 1964 during an electrical storm.

[11] The Council of Australian Governments 'Energy Council' commissioned the Finkel Review in response.

[12] Given the political economy of electricity prices and security of supply, a central tenet of this article is the importance of *relative market stability*, and the importance of *market tractability* vis-à-vis (physical) spot market and (financial) contract market outcomes as lead indicators of Resource Adequacy.

[13] By 'systemic risk' I am referring to the risk of a large market participant experiencing financial distress through adverse wholesale spot market price exposures, in turn resulting in cascading failures of other market participants (analogous to systemic risks to banking systems during a financial crisis).

of 2nd Tier non-vertical retailers who are unable to balance their hedge books.

Consequently, while the energy-only spot market design can be shown to accommodate rising levels of VRE, the market for forward contracts in imperfectly interconnected regions requires considerably more attention from policymakers – how "side markets" and CfD policies interact with the energy-only design are of vital importance to market stability. Above all, any contract capacity of CfDs-originated VRE plant need to be purposefully recycled in secondary markets.

This article proceeds as follows. Section 2 reviews relevant literature. Section 3 presents the corporate finance and energy-only electricity market Model used in this research. Results follow in Sections 4, 5 and 6 and analyse spot market stability, VRE asset allocation and hedge market instability, respectively. Conclusions follow.

2. Review of literature

Energy policy has three basic objectives; (1) a reliable supply (2) at an acceptable cost, (3) subject to an environmental constraint. Reliability is an all-encompassing term but can be broken down into Resource Adequacy and System Security (Batlle and Perez-Arriaga, 2008). Risks to Resource Adequacy in energy-only markets given administratively determined reliability constraints is well understood in energy economics (see Stoft, 2002; Besser et al., 2002; Oren, 2003; Bidwell and Henney, 2004 amongst many others[14]).

Literature on Resource Adequacy in energy-only markets can be loosely traced back to Von der Fehr and Harbord (1995) who noted indivisibility of plant capacity, long construction lead-times, lumpy plant entry, investment tenor and policy uncertainty make merchant generation investments unusually risky. Complicating matters are the fact that large segments of real-time aggregate demand are price-inelastic and unable to react to scarcity conditions, and similarly in the short run, supply is inelastic because storage is costly (Cramton and Stoft, 2008; Batlle and Perez-Arriaga, 2008; Roques, 2008; Finon and Pignon, 2008). Consequently, System Operators resort to non-price rationing and a regulator is forced to administratively determine VoLL. Participants are unable to optimise VoLL events and actions by regulatory authorities and System Operators compound matters by frequently suppressing legitimate price signals (Joskow, 2008, Spees et al., 2013; Hogan, 2013, Leautier, 2016 and others[15]). Energy-only markets are therefore rarely in equilibrium, and this creates risks for the continuity of timely investment to ensure administratively determined reliability criteria is met (Bidwell and Henney, 2004; Cramton and Stoft, 2006; Roques, 2008; de Vries and Heijnen, 2008; Hirth et al., 2016).

Early contributions describing difficulties investing in merchant peaking plant in energy-only markets in a timely manner include Doorman (2000), de Vries (2003) and Stoft (2002). Resource Adequacy became a mainstream issue with Peluchon (2003), Roques et al. (2005), Hogan (2005), Cramton and Stoft (2006), Joskow (2006), Finon and Pignon (2008), Simshauser (2008), Finon (2008) amongst others cataloguing "*missing money*" and risks to timely entry and supply-side structural faults; first in Europe, then the US and Australia. High levels of VRE are of course thought to complicate matters given negligible marginal running costs, subsidised side-markets and merit-order effects (Sensfuβ et al., 2008; Nelson et al., 2012; Joskow, 2013; Newbery, 2015). Three broad remedies are typically suggested to deal with the missing money viz. (1) introducing capacity markets,[16] (2) raising VoLL, or (3) increasing Operating Reserves, but each of these raises their own issues.[17] To be sure, none of these represent a choice between markets and intervention because each involve administratively-determined variables (Cramton et al., 2013).[18]

Along with missing money the energy-only design is also characterised by "*incomplete markets*" via their seeming inability to deliver the requisite mix of derivative instruments required to facilitate efficient plant entry (Hansen, 2004; Chao et al., 2008; Joskow, 2006; Meade and O'Connor, 2009; Howell et al., 2010; Meyer, 2012; Caplan, 2012; Nelson and Simshauser, 2013). Long-dated contracts are a pre-condition for optimal project finance. While Australia's NEM is noted for favourable forward market liquidity,[19] activity spans 3 years – well short of optimal financing that facilitate efficient ex-ante investment commitment, viz. 12-year semi-permanent project debt set within 18–25 year structures. Forward markets have failed to calibrate beyond 3 years because competitive Retailers cannot afford to hold hedge portfolios dominated by inflexible long-dated contracts when large components of their customer book switch supplier every 2–3 years. The short-tenor bias of merchant retailers can be traced to excessive retail-level competition, demand uncertainty and risks of being undercut by new entrant retailers with short-dated portfolios (Newbery, 2006; Green, 2006; Anderson et al., 2007; Finon, 2008; Simshauser, 2010; Howell et al., 2010).

The energy-only design is also prone to "*missing markets*" (Hogan, 2005; Newbery, 2015).[20] Some are obvious; for example there is no market for reserve capacity in energy-only markets.

[14] See also Neuhoff and De Vries, 2004; de Vries, 2004; Wen et al., 2004; Hogan, 2005; Bushnell, 2005; Roques et al., 2005; Cramton and Stoft, 2006; Joskow, 2006; Simshauser, 2008; Finon, 2008, 2011; Hogan, 2013; Cramton et al., 2013; and Spees et al., 2013. Indeed, entire editions of academic journals have been dedicated to the topic. See for example *Utilities Policy* Volume 16 (2008) or *Economics of Energy & Environmental Policy* Volume 2 (2013).

[15] See also Besser et al., 2002; Oren, 2003; de Vries, 2003; Wen et al., 2004; Batlle and Perez-Arriaga, 2008; Finon and Pignon, 2008.

[16] Hogan (2013) also notes there is no simple way to observe and measure delivery. Conversely, Cramton and Stoft (2008) observe that even if capacity is *overbuilt* as a result of capacity mechanisms, the incremental cost to consumers is small because excess 'peaking plant' is the cheapest form of capacity (viz. an extra 10% of peak capacity may increase consumer costs by say 2%). Additionally, Spees et al. (2013 pp15-16) observe that on balance capacity markets in the US have delivered good results in that they met their objective function, mobilised large amounts of low cost supply including Demand Response, energy efficiency, transmission interconnection, plant upgrades, deferred retirements and environmental retrofits.

[17] On capacity markets see Bidwell and Henney (2004); et al. (2013); Green and Staffell (2016). On setting higher VoLL and Vertical Integration see for example Newbery (2006), Finon (2008), Simshauser (2010), Simshauser et al. (2015). On increasing the requirement for operating reserves and enhancing reliability of supply see Hogan (2005, 2013).

[18] A higher VoLL involves administratively determining a price cap to meet an administratively-determined reliability constraint. As Joskow (2013) notes, the entire logic of capacity markets starts with administratively-determined reliability criteria and involves administratively determining the quantity required to meet that constraint. And relying on FCAS involves administratively determining spinning reserve quantities in order to meet the reliability constraint. Thus each solution involves some form of administrative judgement, and in all cases, the risk of error – viz. exercise of market power with VoLL (Hogan, 2013); over-investment with capacity markets (Leautier, 2016); or market power and excess reserves with FCAS – is ultimately borne by the customer.

[19] See for example Chester (2006); Anderson et al. (2007); Howell et al. (2010); and most recently, Simshauser et al. (2015, Appendix 3 and Figure C.1 on p.54).

[20] Although as one reviewer noted, energy markets are also prone to *too many markets*. In the UK for example there are >20 ancillary service products.

But there are other missing markets relevant to rising VRE. In the NEM, VRE resources (i.e. solar and wind) are connected asynchronously to the power system with power electronic interfaces and are *not* physically coupled to system Frequency. Consequently, VRE do not provide Inertia during Frequency deviations (Agranat et al., 2015). Furthermore, NEM-installed VRE plant are not designed to provide Frequency Control Ancillary Services (FCAS), and "raise" services in particular (MacGill, 2010). With high levels of solar PV comes greater requirements for Ramping Duties; solar PV output naturally declines in the evening which coincides with rapidly rising household peak demand – this combination may produce dramatically steeper rises in intra-period residual system demand. Consequently, as synchronous thermal plant exit to make way for asynchronous VRE, one can expect the supply of Inertia, FCAS raise and ramping capabilities to fall, meaning the existing levels and product range of Frequency regulating and contingent resources may become inadequate (MacGill, 2010; Hogan, 2013; Green and Staffell, 2016; Newbery, 2015; Riesz et al., 2015). Missing markets may include Inertia, Fast Frequency Response, Ramping Duties and forward markets for FCAS.

An under-researched aspect of the energy-only design is the concept of *"shrinking markets"*, viz. the impact of rising VRE on the supply of forward derivative contracts where transmission amongst trading regions is imperfect. To my knowledge, the only article which approaches the matter of the effects of renewable energy on both the spot and hedge contract market is Acemoglu et al. (2017), although their work was focused on the impact of hedge contracts on equilibrium market prices rather than the supply of asset-backed hedges.[21] Under normal conditions, NEM derivative market turnover runs at multiples of physical spot electricity market (Chester, 2006; Howell et al., 2010) although there have been sporadic episodes of hedge contract shortages in certain regions (Anderson et al., 2007[22]). NEM derivative market liquidity is being adversely impacted by two drivers, viz. climate change policy discontinuity and the constrained ability of VRE plant to produce liquidity (Simshauser et al., 2015; Nelson and Orton, 2016). When thermal plant exit in response to rising VRE, it changes the supply mix of asset-backed or "primary-issuance" intra-regional hedge contracts in transmission-constrained regions, viz. falling *firm* swap and cap contracts due to exiting thermal plant, and rising *non-firm* (i.e. run-of-plan) contracts from VRE resources.

These effects are being unintentionally reinforced in the NEM via sub-national governments constructing 'reverse auctions' involving various forms of CfDs in response to national-level climate change policy discontinuity. By the end of 2017, >3000 MW of government-initiated CfDs had been telegraphed to the market[23] and could potentially aggravate the *"shrinking market"* problem.[24] Aside from the progressive evaporation of *firm* hedge contract supply issuance as thermal plant exit, government-initiated CfDs can have the (unintended) effect of extracting the replacement *non-firm* run-of-plant contract supply from the market completely – potentially culminating in chronic hedge contract supply shortages and foreclosing competitive 2nd tier non-vertical Retailers.

In the NEM, shrinking markets are also at risk of being compounded by a "*mis-informed market*" effect. The market can become misinformed and regions overloaded with VRE if non market-participants (i.e. sub-national governments) over-rely on Levelised Cost of Electricity (LCoE) during the CfD execution stage. As is well understood in energy economics, as a stand-alone metric LCoE is flawed because it treats technology output as homogeneous products as if governed by the law of one price (Joskow, 2011; Mills and Wiser, 2012; Edenhofer et al., 2013).

In real-time, the law of one price does apply; output from wind and solar are good substitutes for thermal generation. However, each year there are 105,120 NEM prices[25] and when demand is higher than forecast, all else equal, dispatchable generators increase output and receive a higher average price. Conversely, stochastic generators rarely reduce output in periods of oversupply, and hence sell disproportionately at lower prices (Dargue and Koenders, 2016; Hirth et al., 2016).

Furthermore, as VRE technologies move from niche to material market shares, deployment success becomes a significant driver of market value (MacGill, 2010; Joskow, 2011; Nicolosi, 2012; Mills and Wiser, 2012; Hirth, 2013). Green and Staffell (2016) note this is *amplified* when thermal plant fails to exit. Consequently, the market value of VRE is affected by 'correlation effects', 'merit-order effects' and 'price-impression effects' (see Section 5).[26] Tangentially, as VRE market share increases Nicolosi (2012, pp.35-38) identifies a *'utilisation effect'* and a *'flexibility effect'* on thermal plant whereby their annualised capital costs increase as the capacity factor of such plant declines, and an increasing incidence of negative prices. These concepts are explored more fully in Sections 4–6, using the model and associated input data outlined in Section 3.

[21] The work by Acemoglu et al. (2017) is a form of application of the seminal works of Allaz and Vila (1993) with a focus on supplier preference for contract quantities and note that these are higher with larger diversified generation portfolios Green, 2006; Anderson et al., 2007; Finon, 2008; Simshauser, 2010; Howell et al., 2010 but they do not examine how these forward contracts are covered in the long term, only the mid term (i.e. they implicitly assume a large power system with perfect liquidity and the potential for a Merit Order Effect, meaning thermal plant has not yet exited or adjusted. The main finding is of course consistent with Allaz and Vila (1993) and Bushnell et al. (2007) and Mansur (2007) in terms of the dampening effect of forward contracts on spot prices.

[22] See also Simshauser et al. (2010) on episodes of hedge contract supply shortages in the NEM.

[23] As at March 2017, 750 MW had been executed. The Queensland Government had executed 150 MW of CfDs and telegraphed a further 400 MW. NSW Government telegraphed 250 MW of CfDs. ACT had executed 600 MW of CfDs. The VIC Government had telegraphed up to 1500 MW of CfDs by 2020 and a further 3900 MW by 2025. There are also a number of PPAs (VIC Government tenders totalling 171 MW for Renewable Certificates, and Sydney Northwest Metro totalling 52 MW) but these appear to be well-constructed, non-distortionary, government contracts designed to meet retail liabilities. Similarly, at the time of writing the Queensland Government was working on "recycling" its 150 MW CfDs back into the secondary market in order to minimise any such distortions.

[24] The clearest example of this was the Australian Capital Territory (ACT) government who issued 400 MW of CfDs to underwrite wind farms in South Australia, which in turn contributed to the exit of the final coal plant in that region. The CfDs have been hoarded (rather than recycled back into the market) by the ACT government. Liquidity in SA region has since plunged below 100% (compared to 230% only a few years earlier).

[25] In the NEM, dispatch has 5-min resolution and thus 105,120 dispatch intervals each year.

[26] Taking solar PV as an example, the *correlation effect* starts positive due to the diurnal correlation between solar resources and electricity demand. The *merit-order effect* is a well-known economic result; the price of a good falls as supply is increased. As thermal plant exits, merit-order effects can be expected to unwind but the stochastic nature of VRE plant means a *price-impression effect* persists. In an expansive literature review on the topic, Hirth (2013) reveals that as solar is progressively increased from 0% to 10–15% market share, its *relative value* drops from slightly >100% of base prices to 70% (i.e. *price-impression effect*). And as wind output is increased from 0% to 30% market share, its relative value drops to 70% of base prices.

3. On the stability of the spot market

In order to analyse the stability of spot markets with rising levels of VRE, the NEMESYS-PF Model has been used. NEMESYS-PF formally integrates a corporate & project finance model with a single-year dynamic partial equilibrium model of a template power system.

First-stage model outputs include generalised long run marginal cost estimates for generating plant technologies via a dynamic, multi-period post-tax discounted cash flow optimisation model. The model solves for multiple generating technologies, business combinations and revenue possibilities, and simultaneously solves for convergent price, corporate or project finance-sizing, taxation and equity returns. These outputs are similar in nature to levelised cost estimates but with a level of detail beyond the typical LCoE Model because corporate or project financing, credit metrics and taxation constraints are co-optimised.

The second-stage model is a security-constrained partial equilibrium unit commitment model with half-hourly resolution and price formation based on a uniform, first price auction clearing mechanism. As with Bushnell (2010) the model assumes perfect competition, transmission and ramp-rates, free entry and exit to install any combination of divisible capacity that satisfies differentiable equilibrium conditions, with VRE output being exogenously determined (i.e. and by way of policy). And as with Hirth (2013) the focus of simulations is half-hour resolution over a single year. The key advantages of the model are its granularity vis-à-vis the treatment of resource and financing costs at the plant and whole-of-system system level, and the speed in which multiple scenarios can be constructed and simulated. Limitations of the model include its single region and simplifying assumptions regarding the divisibility of plant and plant-related constraints (e.g. transmission, ramp rates). How these limitations may affect results are that; (1) a single region model may amplify merit order effects and utilisation effects (in Section 4) as adjacent regions are likely to have different plant portfolios and demand patterns; (2) divisibility of plant means that the dynamic adjustment presented in Sections 4–6 appear considerably smoother than would be the case with lumpy plant exit/entry; and (3) simplifying technical constraints (e.g. intra-regional transmission and ramp rates) may understate the type and capacity of plant required to satisfy aggregate demand. With these limitations acknowledged, key data inputs (see Tables 1 and 2) and model logic are as follows:

3.1. Generalised long run marginal cost estimates

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:

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

A discounted value for α_R of 0.75 reflects single factor learning rates that characterise generating technologies.

Energy output ρ_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.

$$\rho_j^i = CF_j^i . k^i . \left(1 - Aux^i\right) \tag{2}$$

A convergent electricity price for the i^{th} plant ($p^{i\varepsilon}$) is calculated in year one and escalated per Eq. (1).[27] Thus revenue for the i^{th} plant in each period j is defined as follows:

$$R_j^i = \left(\rho_j^i . p^{i\varepsilon} . \pi_j^R\right) \tag{3}$$

Plant marginal running costs are a key variable and used extensively in *NEMESYS-PF*. In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[28] 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 ρ_j^i and escalated at the rate of π_j^C.

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

[27] Note that thermal plant also earns ancillary services revenue, which in the model equates to about 0.3% of electricity sales. This has been the historic average although as VRE increases, this can be expected to change dramatically.

[28] The derivation of the constant term 3600 is: 1 W = 1 J per second and hence 1 W Hour = 3600 J.

Table 1
Technology assumptions.

Reference plant	Unit	$i =$	Black Coal	CCGT	OCGT	Wind	Solar
Plant capacity	MW	k	900	400	225	200	100
Capacity factor	%	CF	90.0	59.9	27.4	39.7	29.3
Auxillary load	%	Aux	6.0	3.0	1.0	1.0	1.0
Thermal efficiency	%	Z	39.0	55.0	36.0	n/a	n/a
Raw fuel	$/GJ	F	1.80	7.00	8.00	n/a	n/a
Variable O&M	$/MWh	V	1.28	4.08	10.19	12.23	5.50
Fixed O&M	$/MW	F	52,768	10,188	4075	40,750	20,000
Combustion emissions	kg CO2/GJ	$\dot{g}$	90.2	50.6	50.1	–	–
Fugitive emissions	kg CO2/GJ	$\hat{g}$	8.7	18.6	5.5	–	–
Overnight capital cost	$/kW	X	2500	1200	732	2000	2000
Capital works	$ '000	x	5000	2000	1000	1000	1000
Useful life	Yrs	L	40	30	30	25	25

Table 2
Corporate finance assumptions.

Variable	Unit	Variable	Input
Inflation	%	CPI	2.5
Equity returns (VI)	%	β_{VI}	11.0
Equity returns (IPP)	%	β_{IPP}	15.0
Tax rate	%	Tc	30.0
Effective tax rate	%	Te	21.3
3 yr interest rate swap	%	R_T	2.20
7 yr interest rate swap	%	R_T	2.71
PF credit spread (3 yr)	bps	C_T	237
PF credit spread (7 yr)	bps	C_T	229
BBB credit spread (3 yr)	bps	C_T	181
BBB credit spread (7 yr)	bps	C_T	194
BBB credit (FFO/I)	*times*	δ_{VI}	5.0
BBB credit (FFO/D)	*times*	ω_{VI}	0.2
PF DSCR	*times*	δ_{IPP}	1.35

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.

$$FOM_j^i = FC^i.k^i.\pi_j^C \tag{5}$$

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

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right) \tag{6}$$

Capital Costs (X_0^i) for each plant i are Overnight Capital Costs and incurred in year 0.[29] Ongoing capital spending for each period j is determined as the inflated annual assumed capital works program.

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

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:

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

[29] The model is capable of dealing with multi-period construction programs such that $X_j^i = -\sum_{k=1}^{N} C_k.(1+K_e)^{-k}$. However, for the present exercise, all plant capital costs are 'Overnight Capital Costs' (i.e. as if the plant were purchased at the completion of construction) and therefore include an allowance for capitalised interest during construction.

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

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

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 facilities involve 3- and 7-year money raised with an implied 'BBB' credit rating. With project financings, two facilities are modelled. The first facility is nominally a 3-year bullet requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over a 25-year period. The second facility commences with a tenor of 7 years as an amortising facility, again set within a semi-permanent structure with a nominal repayment term of 25 years. The decision tree for the two tranches of debt is the same, so for the Debt Tranche where $T = 1$ or 2, the calculation is as follows:Pl

$$if\ j \begin{cases} >1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ =1, DT_1^i = D_0^i.S \end{cases} \tag{10}$$

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 the model, 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:

$$P_j^i = \left(DT_j^i / \left[\frac{1-\left(1+\left(R_T^z + C_T^z\right)\right)^{-n}}{R_T^z + C_T^z} \right] | z \begin{cases} = VI \\ = PF \end{cases} \right) \tag{11}$$

In (11), R_T is the relevant interest rate swap (3 yrs. or 7 yrs) and C_T is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the j^{th} period (I_j^i) is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_j^i = DT_j^i \times \left(R_T^z + C_T^z\right) \tag{12}$$

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 (Eq. (10)). This is determined by the product of the gearing level and the Overnight Capital Cost (X_0^i). 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 the 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 (using 'BBB' rated corporate facilities) and Inpdependent Power Producers using Project Finance (PF).

$$if\ \gamma \begin{cases} = VI,\ Min\left(\frac{FFO_j^i}{I_j^i}\right) \geq \delta_j^{VI}\ Min\left(\frac{FFO_j^i}{D_j^i}\right) \geq \omega_j^{VI} \forall j \left| FFO_j^i = \left(EBITDA_j^i - x_j^i\right)\right. \\ = PF,\ Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall j \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i}, LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i}\right. \end{cases} \tag{13}$$

The variables $\delta_j^{VI}$and ω_j^{VI} are exogenously determined by credit rating agencies. 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.

At this point, all of the necessary conditions exist to produce estimates of generalised long run marginal costs of the various power generation technologies. The relevant equation to solve for the price ($p^{i\varepsilon}$) given expected equity returns (K_e) whilst simultaneously meeting the binding constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF}given the relevant business combination is as follows:

$$-X_0^i + \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{14}$$

The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$-X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{15}$$

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

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i-(1-\tau_c).FOM_j^i-(1-\tau_c).\left(I_j^i\right)-P_j^i+\tau_c.d_j^i+\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N}x_j^i.(1+K_e)^{-(j)} + D_0^i \tag{16}$$

The model then solves for P^{ε} such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} \tag{17}$$

3.2. Treatment of OCGT plant

Certain adjustments are required to accommodate long run marginal cost estimates for peaking plant. Defining a single electricity price $p^{i\varepsilon}$ for such plant is meaningless in the absence of an expected fixed $\overline{CF_j^i}$. Peaking plant requires a distinct revenue model to express generalised long run marginal cost estimates as the 'carrying cost' of plant capacity, $\overline{F}_0$. This requires small modifications to the Model. The result produced is a single capacity price P^k which reflects the equilibrium price of a sold call-option or ap contract. Eqs. (2) and (3) require reconfiguring as follows:

$$\rho_j^i = 0\forall j, \text{and } R_j^k = \left(k^i.P^k.\pi_j^R\right) \tag{18}$$

The value of energy output ρ_j^i is set to zero which means marginal running costs ϑ_j^i will also be zero. In practice ρ_j^i will have a non-zero value and so $p^{i\varepsilon}$ would also be non-zero, and under most conditions will exceed marginal running costs ϑ_j^i. The value for R_j^k, which equals $\overline{F}_0$, is important as it defines the 'missing money' in an energy-only market under conditions of perfect competition, perfect plant divisibility and availability as Section 4 later demonstrates.

3.3. Security-constrained unit commitment

The integration of the corporate and project finance and security-constrained unit commitment models centres around the transposition of three key variables, $p^{i\varepsilon}$, unit Marginal Running Cost v^i and total unit Fixed & Sunk Costs, φ^i such that:

$$\varphi^i = p^{i\varepsilon} - v^i\left|\left(v^i+\varphi^i\right)\cdot\rho_1^i \equiv R_1^i\right. \tag{19}$$

These two parameters (i.e. unit Marginal Running Cost v^i and unit Fixed and Sunk Costs φ^i) are key variables in the half-hourly power system simulation model, and are used extensively to meet the objective function (see Eq. (24)).

NEMESYS-PF dispatches the fleet of perfectly divisible power generating units to satisfy security constraints and differential equilibrium conditions given specified plant options available. In the power system sub-model, let H be the ordered set of all half-hourly periods.

$$n\in\{1\ldots|H|\}\wedge h_n\in H \tag{20}$$

3.3.1. Demand function

Let E be the set of all electricity consumers in the model.

$$k\in\{1\ldots|E|\}\wedge e_k\in E \tag{21}$$

Let $C_k(q)$ be the valuation that consumer segments are willing to pay for quantity q MWh of power. The model assumes that demand in each period n is independent of other demand periods. Let q_{nk} be the metered quantity consumed by customer e_n in each period h_k expressed in MWh.

3.3.2. Supply function

Let Ψ be the set of existing installed power plants and available augmentation options for each relevant scenario.

$$i\in\{1\ldots|\Psi|\}\wedge\psi^i\in\Psi \tag{22}$$

As outlined in Eq. (19), let φ^i be the fixed operating & sunk capacity costs and v^i be the marginal running cost of plant ψ^i respectively. Let $\overline{\rho^i}$ be the maximum continuous rating of power plant ψ^i. Power plants can be subject to scheduled and forced outages. $F(n,i)$ is the availability of plant ψ^i in each period h_n. Annual plant availability is therefore:

$$\sum_{j=0}^{|P|}F(n,i)\forall\psi^i \tag{23}$$

Let $O_{n,\,i}$ be the quantity of power produced by plant ψ^i in each period h_n.

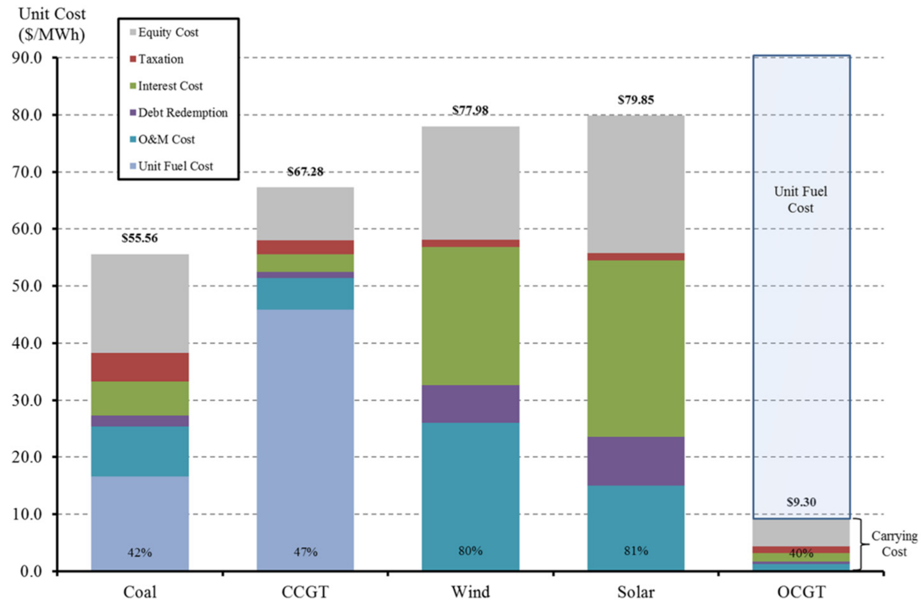

Fig. 1. Generalised long run marginal cost by technology.

3.3.3. Objective function

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integral of the aggregate demand curve less power production costs. The objective function is therefore expressed as:

$$Obj = \sum_{n=1}^{|H|} \sum_{i=k}^{|E|} \int_{q=0}^{e_k} C_k(q)dq - \sum_{n=1}^{|H|} \sum_{\psi=1}^{|\Psi|} \left(O_{\psi^i} \cdot v^i\right) - \sum_{\psi=1}^{|\Psi|} \left(O_{\psi^i} \cdot \varphi^i\right) \qquad (24)$$

Subject to $\sum_{i=1}^{|E|} q_{kn} \le \sum_{\psi=1}^{|\Psi|} O^0_{\psi^i} \le O_{ni} \le \mathrm{F}(n,i)^0 \le O_{n,i} \le \overline{\rho^{i.}}$

4. Generalised long run marginal cost estimates

Salient results from the present modelling exercise are as follows. Thermal plant (Coal, CCGT, OCGT) are Balance Sheet-financed (gearing ca.40–47%, BBB credit rating) and VRE plant (Wind, Solar) are Project Financed (ca.80% debt) and underpinned by investment-grade PPAs. Generalised long run marginal cost estimates from the Model are presented in Fig. 1 and are a high-resolution LCoE incorporating debt-finance and taxation variables. Gearing levels for each plant are displayed at the base of each bar. Thus in Fig. 1, Coal has 42% gearing and a generalised long run marginal cost of $55.56/MWh comprising Unit Fuel Costs of $16.62/MWh, O&M Costs of $8.74/MWh, Debt and Interest Costs of $1.90 and $6.04/MWh, and Taxation and Equity Costs of $5.01 and $17.25/MWh, respectively. Note that the OCGT cost structure focuses on the 'carrying cost' of the capacity due to its subsequent use as the "capacity payment", with the fuel cost added only for ease of comparison.

4.1. Base case

The Base Case load curve utilises QLD 2016 data (9097 MW peak demand, 54900GWh energy demand, ex-1500 MW rooftop solar PV). An own-price elasticity estimate of −0.10 has been used in all scenarios. The QLD system is modelled without interconnection to neighbouring NSW. The perfectly divisible plant stock is optimised and includes a starting reserve margin of 13% to ensure the NEM's administratively determined reliability constraint of not >0.002% Lost Load is met. Plants are initially assumed to be perfectly available with no ramp rate constraints, although this assumption is later relaxed in Section 6. Coal plant minimum loads are assumed to be 40% of Maximum Continuous Rating, and VRE plants are constrained-off if necessary (i.e. coal 'min gen' is priority dispatched).

One crucial deviation from the NEM's energy-only market design has been incorporated in the present Modelling exercise; there are no VoLL events, instead Boiteux capacity payments are paid to all dispatchable plant at a rate exactly equal to the carrying-cost of an OCGT (see Fig. 1) in line with Boiteux's (1949) seminal works. This ensures that in the Base Case, the market *'clears financially'* with two primary benefits; (1) it removes noise associated with market power and the optimal value, and number of, VoLL events; and (2) it allows the economic impacts of rising VRE to be cleanly isolated. As in the NEM, Renewable Certificates are incorporated for VRE plant with the value equal to the differential between the market value of output and generalised long run marginal costs estimates. Base Case results, where the power system has been optimised without utility-scale VRE plant, are presented in Table 3.

In Table 3, Lines 1–6 highlight 10,280 MW of plant is deployed including 6014 MW of coal. Resource Costs amount to $3564 m, System Average Cost is 64.88/MWh and the Capacity Factor (CF) of the power station fleet is 61.0%. Price and revenue parameters are presented in Lines 7–17. The Load-Weighted Average Spot Price is $49.64, and given System Average Costs of $64.88 the *missing money* amounts to $15.25/MWh. Missing money is eliminated via Boiteux capacity payments paid to each MW installed at a rate exactly equal to the carrying cost of OCGT plant[30] (i.e. $9.30/MW, see OCGT in Fig. 1). Note the time-weighted *Base Price* is $46.26/MWh (Line 15) – a result that will be used as a benchmark throughout this research.

[30] In this instance, $9.30/MW × 10,280 MW ÷ 54,924GWh = $15.25/MWh.

Table 3
Production duties and financial position of plant – Base Case.

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	$CF_j{}^i$ (%)
1	Wind	0	0	0	0	0	0.00	0.0%	0.0
2	Solar	0	0	0	0	0	0.00	0.0%	0.0
3	Coal	6,014	50,842	2,052	845	2,896	56.97	92.6%	96.5
4	CCGT	758	2,906	142	133	276	94.83	5.3%	43.8
5	OCGT	3,508	1,175	286	106	392	333.36	2.1%	3.8
6	Total	10,280	54,924	2,480	1,084	3,564	64.88	100.0%	61.0

		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	43.40	0	0.00	0	0	0	0	
8	Solar	51.59	0	0.00	0	0	0	0	
9	Coal	47.33	2,406	9.30	490	2,896	2,896	0	
10	CCGT	73.58	214	9.30	62	276	276	0	
11	OCGT	90.19	106	9.30	286	392	392	0	
12	Total	49.64	2,726	9.30	837	3,564	3,564	-0	
13	System Avg Cost	64.88							
14	Missing Money	15.25			$15.25/MWh				
15	Peak Price	83.78						Base Price (time-weighted):	46.26
16	Shoulder Price	52.59						Load-Weighted Avg Spot Price:	49.64
17	Off-Peak Price	23.32						Avg Renewable Certificate Price:	0.00

Fig. 2 presents a static equilibrium analysis based on Berrie's (1967) classic framework. The top chart highlights two Load Duration Curves, a Gross Load (i.e. net of 5% rooftop solar PV) and Net Load (i.e. net of 35% VRE output). The optimal plant mix is derived from the middle chart which extracts the LCoE results from Fig. 1 and transposes these data into Marginal Running Cost Curves for the three thermal technologies. The points of intersection are transposed to the Load Duration Curve to identify the optimal mix of Base, Intermediate and Peak plant. The bottom chart shows the distribution of prices; recall there are no VoLL events, just three spot prices prevail in equilibrium, averaging $46.26/MWh.

4.2. Mid-term and long-term scenarios

Utility-scale VRE is progressively introduced rising to 30% market share. Recall Gross Load is net of 5% rooftop Solar PV – thus in a practical sense scenarios run from 5 to 35% VRE (viz. 0–30% utility-scale VRE plus 5% small-scale VRE). Following Hirth (2013), two timeframes are analysed; Mid-Term and Long-Term and are distinguished by how the capital stock adjusts rather than time. In Mid-Term scenarios, thermal plant is held constant (Fig. 3). In Long-Term scenarios, thermal plant adjusts perfectly; coal exits and gas plant enters while meeting reliability constraints (Fig. 4).

Mid- and Long-Term 30% utility-scale VRE scenarios are presented in Tables 4–5. In the Mid-Term (Table 4), no coal plant exits and Resource Costs rise to $4579 m or $81.26/MWh (line 6) while Base Prices fall to $19.55/MWh (line 15). This result reflects an acute *merit-order effect* that cannot be remedied by capacity payments.[31] However, VRE plant clear financially (Lines 7–8) via rising Renewable Certificate prices, averaging $60.72/MWh (line 17).

Falling Base Prices are unsustainable for non-subsidised plant. In the Long-Term thermal plant are forced to exit and adjust. Table 5 shows perfect adjustment; compared to the Base Case – at 30% utility-scale VRE market share 2000 MW of Coal exits and 900 MW of flexible gas plant enters. Base Prices (line 15) rebound to $46.23/MWh and capacity payments ($9.30/MW) clear missing money. Renewable Certificates fall to $38.30/MWh.

Fig. 5 presents the evolution of Base Prices (Mid- and Long-Term) and cost traces for varying levels of VRE market share, along with other elements not obvious or clear from inspection of Tables 3–5. First, the top Line in Fig. 5 presents the evolution of System Average Cost, starting at $64.88 and rising to $74.13/MWh with 30% VRE. The two Lines immediately below identify two forces driving System Average Cost movements. (1) The *utilisation effect* pushes up System Average Cost via a deterioration in the thermal fleet's capacity factor, progressively falling from 61.0% in the Base Case to 47.8% in the 30% VRE scenario. (2) The *VRE Cost Differential* drives System Average Cost up through the higher cost structure of VRE plant. Of these, *utilisation effects* are more material.

Next, note in Fig. 5 that the equilibrium Long-Term Base Price of ca. $46.26/MWh can be maintained throughout any VRE market share *provided* thermal plant exits and adjusts perfectly. The gap between System Average Cost and Long-Term Base Price is the *missing money*, and is recovered via capacity payments (and Renewable Certificates). The gap between Mid- and Long-Term Base Price is the *merit-order effect*, and occurs whenever thermal plant fails to exit and adjust.

Figs. 2–5 and Tables 3–5 identify a series of important results. First, they demonstrate that in theory, energy-only markets can produce a stable equilibrium for any level of VRE up to 30% (35% including rooftop solar PV). However, it requires thermal plant to exit and adjust perfectly, and, it requires the optimal level and number of VoLL events in the absence of capacity payments.

Second, two forces work together to force adjustment; (1) *merit-order effects* damage thermal plant Profit & Loss Statements through lower prices, and (2) coincident *utilisation effects* impose further profitability damage by forcing thermal plant up their (downward sloping) cost curves. Consistent with *game-changing policy*, VRE plant have a side-market which shields them from adverse impacts (i.e. Renewable Certificate subsidies) thus allowing continual entry regardless of how long it takes for thermal plant to exit and adjust.

Finally, market analysis and policy development needs to be thoughtful about *merit-order effects*. Merit-order effects can be shown to exist, but benefits to consumers translate only in the Mid-Term. In the Long-Term, thermal plant will exit and adjust. And to be clear, merit-order effects are *not* necessarily welfare enhancing.[32]

[31] Note capacity payments are allocated at $9.30/MW on the optimal capacity identified in Table 3.

[32] Nelson et al. (2012, pp293-295) discuss this in some detail.

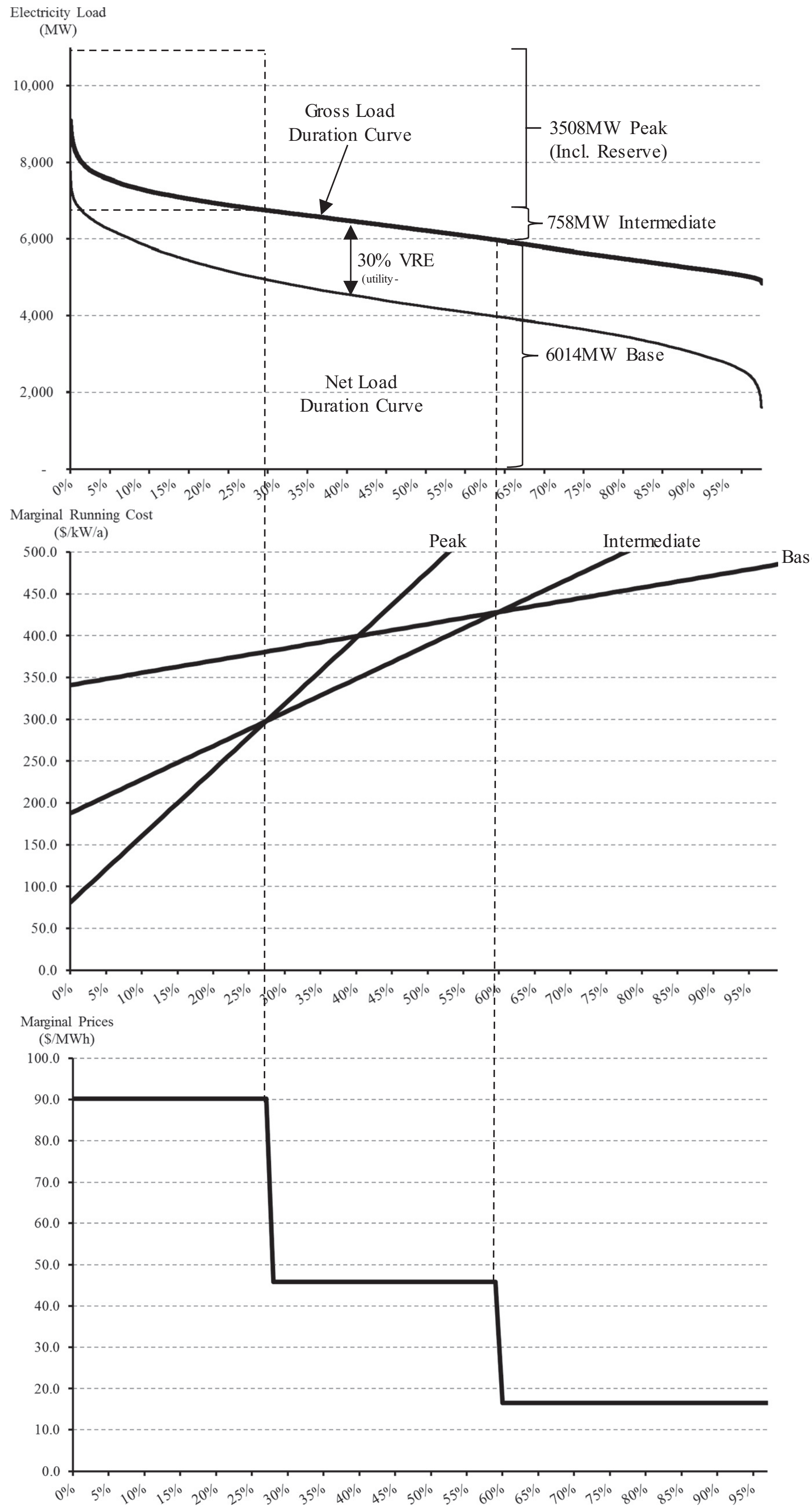

Fig. 2. Static partial equilibrium (net of 5% rooftop solar PV).

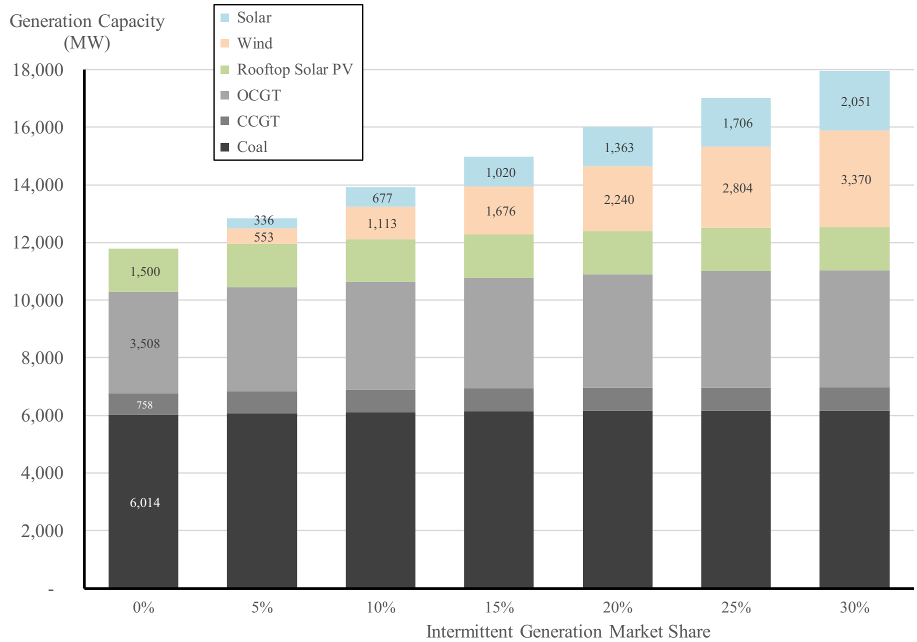

Fig. 3. Mid-Term capacity for rising VRE (no plant exit).

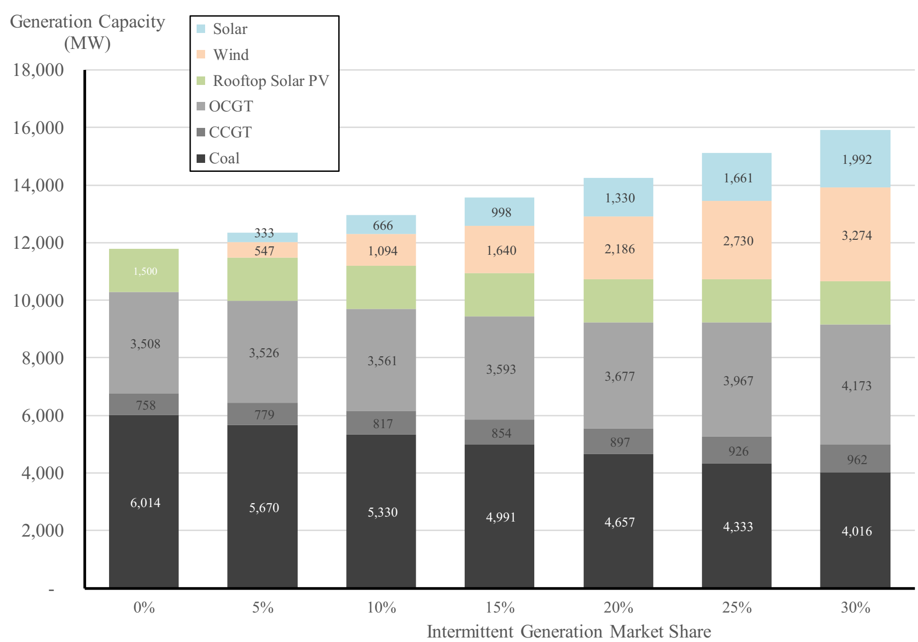

Fig. 4. Long-Term capacity for rising VRE (thermal plant adjusts perfectly).

5. On the ability of markets to optimise VRE asset allocation

An important characteristic of static LCoE calculations are that they produce two inherent biases; base over peaking plant, and stochastic over dispatchable plant (Joskow, 2011). Tables 3 and 5 showed results for 0 and 30% VRE which revealed certain characteristics about dynamic market values of utility-scale VRE plant output – but a more granular analysis is required, which is presented in Figs. 6–10.

5.1. Static analysis of the value of VRE output at 15% market share

Fig. 6 shows the evolution of Market Values of Wind output at 15% market share. Following Hirth (2013), the waterfall chart decomposes the forces progressively affecting wind output market values, in the Mid-Term, and in the Long-Term.

Fig. 6 commences with the Base Price ($46.26/MWh). The first variable impacting the Market Value of Wind output is a *correlation effect*. Queensland wind resources are marginally negatively correlated to wholesale demand and price and so the market value of the first wind farm is marginally below Base Prices (−$2.86/MWh).

As Wind is progressively added to the plant mix, two further forces impact Market Value; a *merit-order effect* which is transient, and a *price-impression effect*, which is enduring. Merit-order effects reflect transient oversupply. Price-impression effects occur because of the stochastic but correlated nature of wind resources. Therefore, as each new wind farm enters, they progressively (and cumulatively) impact Market Values of the entire wind farm fleet

Table 4
Mid-Term 30% VRE scenario.

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	$CF_j{}^i$ (%)
1	Wind	3,370	11,800	861	59	920	77.98	20.9%	40.0
2	Solar	2,050	5,057	404	0	404	79.85	9.0%	28.2
3	Coal	6,166	39,145	2,103	650	2,754	70.35	69.5%	72.5
4	CCGT	810	314	152	14	167	530.13	0.6%	4.4
5	OCGT	4,070	30	331	3	334	11,240.89	0.1%	0.1
6	Total	16,466	56,346	3,852	726	4,579	81.26	100.0%	39.1
		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	18.02	213	59.97	708	920	920	0	
8	Solar	17.38	88	62.47	316	404	404	0	
9	Coal	20.87	817	9.30	327	1,144	2,754	1,610	
10	CCGT	59.99	19	9.30	78	97	167	69	
11	OCGT	90.19	3	9.30	340	343	334	-8	
12	Total	20.22	1,139		1,769	2,908	4,579	1,671	
13	System Avg Cost	81.26							
14	Missing Money	61.04	→	→	$31.39/MWh				
15	Peak Price	32.75						Base Price (time-weighted):	19.55
16	Shoulder Price	17.88						Load-Weighted Avg Spot Price:	20.22
17	Off-Peak Price	16.41						Avg Renewable Certificate Price:	60.72

Table 5
Long-term 30% VRE scenario.

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	$CF_j{}^i$ (%)
1	Wind	3,274	11,490	839	57	896	77.98	21.0%	40.1
2	Solar	1,992	4,924	393	0	393	79.85	9.0%	28.2
3	Coal	4,016	32,887	1,370	546	1,916	58.27	60.1%	93.5
4	CCGT	962	3,574	181	164	345	96.39	6.5%	42.4
5	OCGT	4,173	1,843	340	166	506	274.60	3.4%	5.0
6	Total	14,417	54,719	3,122	934	4,056	74.13	100.0%	43.3
		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	39.74	457	38.24	439	896	896	0	
8	Solar	41.40	204	38.45	189	393	393	0	
9	Coal	48.30	1,589	9.30	327	1,916	1,916	1	
10	CCGT	74.47	266	9.30	78	344	345	0	
11	OCGT	90.19	166	9.30	340	506	506	0	
12	Total	49.01	2,681		1,374	4,056	4,056	1	
13	System Avg Cost	74.13							
14	Missing Money	25.12	→	→	$25.11/MWh				
15	Peak Price	82.97						Base Price (time-weighted):	46.23
16	Shoulder Price	47.54						Load-Weighted Avg Spot Price:	49.01
17	Off-Peak Price	29.97						Avg Renewable Certificate Price:	38.30

(−$5.32/MWh). In the Mid-Term, the Market Value of Wind output falls to $23.35/MWh but merit-order effects are transient and will unwind in the Long-Term, thus rebounding to $38.08/ MWh.

Fig. 7 presents the equivalent analysis for utility-scale Solar PV at 15% market share. This is a striking set of results vis-à-vis *price-impression effects* and is consistent with Hirth (2013),[33] Nicolosi (2012)[34] and Mills and Wiser (2012).[35] The first bar starts with the Base Price ($46.26/MWh). Unlike wind, *correlation effects* of the first solar PV farm are positive because solar output is positively correlated to demand and price (+$5.33/MWh). Merit-order effects for solar PV are comparatively minor compared to wind (−$3.39). However, unlike wind which stochastically add energy output across the entire day, solar PV output has a concentrated daytime bias. Price-impression effects are, therefore, acute (−$25.17/MWh). Consequently, there is little difference between Mid- and Long-Term results because price-impression effects dominate. These results highlight the role for low-cost storage at some point in the future. As Hirth et al. (2016) note, what is special about VRE is not the existence, but the size of the change in

[33] Empirical results in Hirth (2013) from Europe indicate that for every 1% increase in the market share of Wind, its market value drops by 1.62% for thermal systems but only 0.22% for hydro systems (although Hirth cautions that the sample size is small).
[34] See esp. figure 6.17

[35] See especially pp55–57.

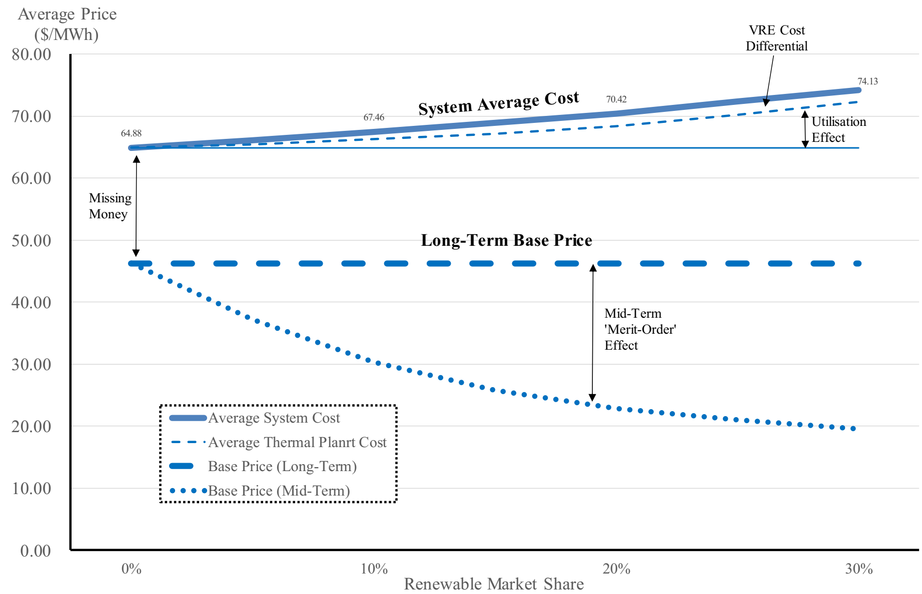

Fig. 5. Evolution of system costs & prices.

the Market Value of output as renewables move from low to high market shares.

5.2. Dynamic analysis of the value of VRE output 0–30% market share

Fig. 8 shows dynamic analyses for wind and solar output market values from 0 to 30% market share with continuous adjustment by thermal plant – thus removing transient merit-order effects. For wind, notice the starting point and 15% market share results aligns with Fig. 6 (viz. $43.80/MWh and $38.08/MWh, respectively). Thereafter *price-impression effects* results in wind output progressively declining to $35/MWh. Solar PV results are consistent with Hirth (2013) and others. Because solar PV output is concentrated it has a more acute price-impression effect; essentially, the technology cannibalises itself at a fast rate.

If solar PV was grossly over-represented in the VRE fleet, Time-of-Use market prices are capable of being reversed (given costly storage and irrelatively nelastic demand). Fig. 9 presents a dynamic comparison of peak (4 pm–8 pm), shoulder (7 am–4 pm, 8 pm–10 pm) and off-peak (10 pm–7 am) prices as solar market share increases from 0 to 30%. Shoulder (i.e. daytime) prices drop as solar PV market share rises. Conversely, off-peak prices rise as inflexible coal plant exit, off-peak duties increasingly fall on higher-marginal running cost CCGT plant.

5.3. On the market's ability to optimise VRE asset allocation

In theory at least, market participants will optimise the asset allocation of wind and solar PV in the same way that the market regulates and optimises the asset allocation of base and peak plant. When combined with wind resources, there is an optimal solar PV market share higher than that implied in Fig. 8 (i.e. in Fig. 8, each price trace assumes *only* wind or *only* solar VRE resources are deployed rather than a mix of the two technologies). Determining optimal VRE asset allocation has many dimensions, including total market share of VRE, correlation between wind and solar output, differential rates at which unit costs of technologies decline, site-specific resource endowments, transmission/connection costs, and speed of thermal plant exit and adjustment. It would be unhelpful to model such rich variation but two variables are worthy of exploration to illustrate the principles; (1) VRE market share, and (2) mix of

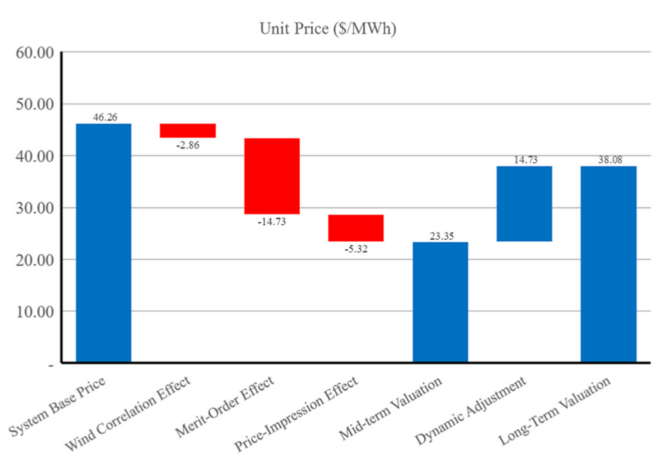

Fig. 6. Market Value of wind output (15% Market Share).

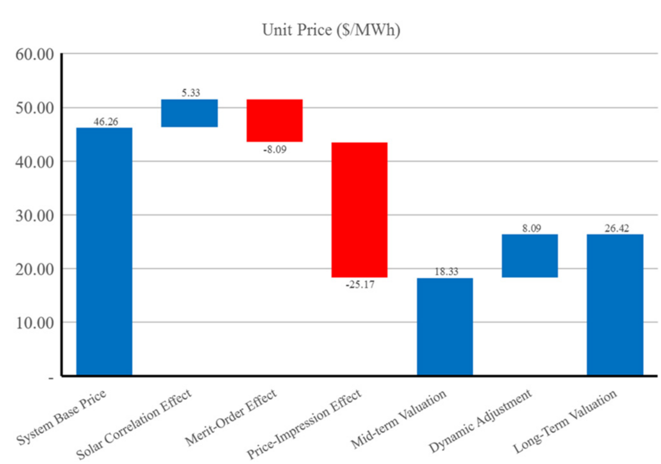

Fig. 7. Market value of solar output (15% market share).

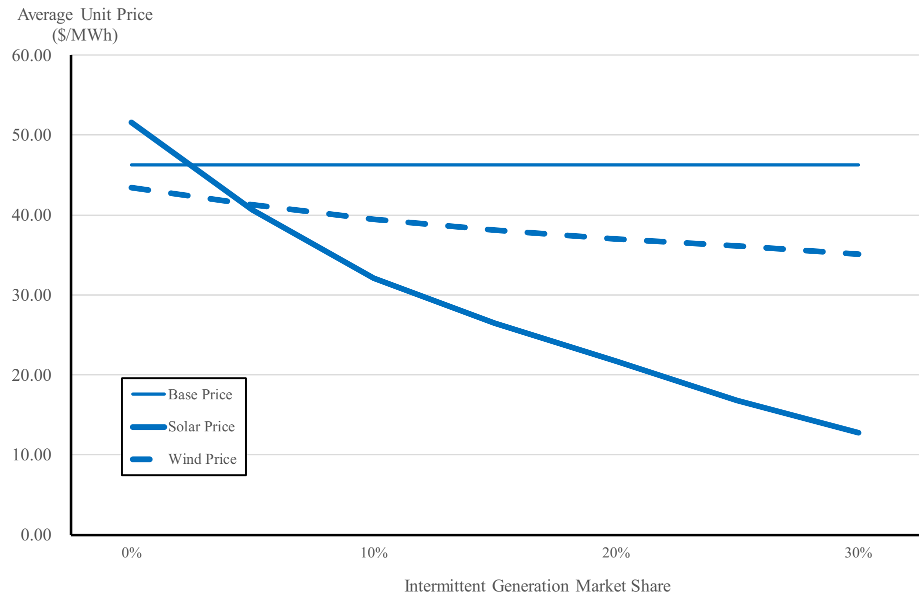

Fig. 8. Long-term market value of solar PV output (0–30% market share).

non-correlated technologies. Figs. 10–12 show how the market would regulate asset allocation for VRE Targets of 10%, 20% and 30% market share assuming thermal plant adjusts perfectly.

It is important to stress that in the following analysis, while system load adjusts for each combination of VRE plant (i.e. own-price elasticity of −0.10), cost estimates for technologies are fixed; viz. all wind and all solar PV plants have identical cost structures to those in Fig. 1. Fig. 10 reveals that under these conditions, optimal asset allocation between wind and solar at 10% VRE market share is 50/50. As VRE market share rises to 20%, optimal asset allocation is 60/40 (Fig. 11) and finally for 30% VRE market share, optimal asset allocation is 70/30 (Fig. 12).

Provided market participants are profit-maximising and focused on the Market Value of output, one should expect the market to regulate entry to an optimal asset allocation. Conversely, government-initiated CfDs based on LCoE (rather than market value) risk distorting the market, resulting in a misinformed market.

6. On the stability of the hedge market

As far as I am aware, there has been no direct analysis of the underlying stability of the market for forward hedge contracts as VRE resources rise and thermal plant exit and adjust in imperfectly interconnected regions. Identifying the supply of hedge contracts is inherently difficult (viz. with turnover of 300–400%, there are more than just asset-backed traders on the sell-side). But understanding the supply of asset-backed forward contracts provides some indication of stability and systemic security. In Simshauser et al. (2010), individual generation plant capacity was modelled according to a binomial

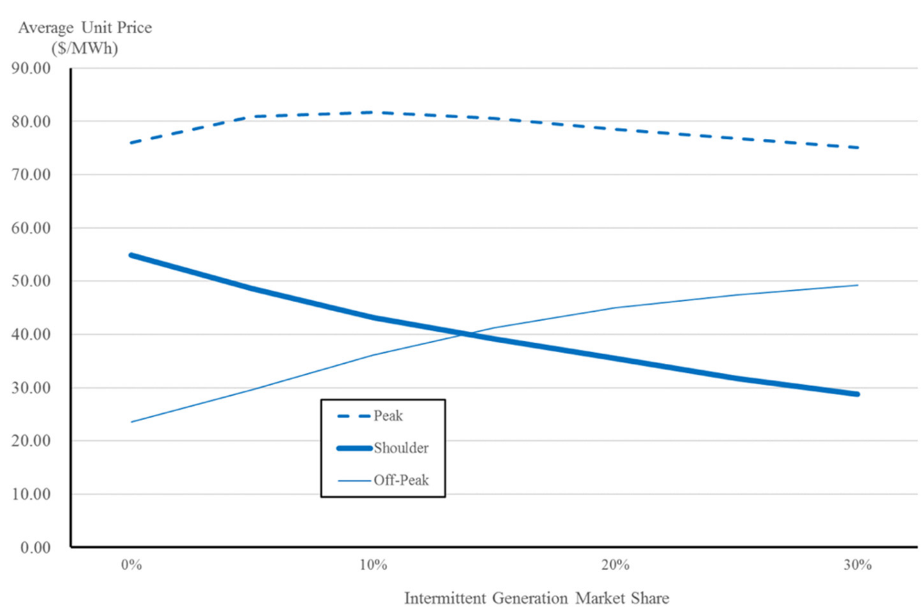

Fig. 9. Time-of-use prices & solar PV 0–30% market share.

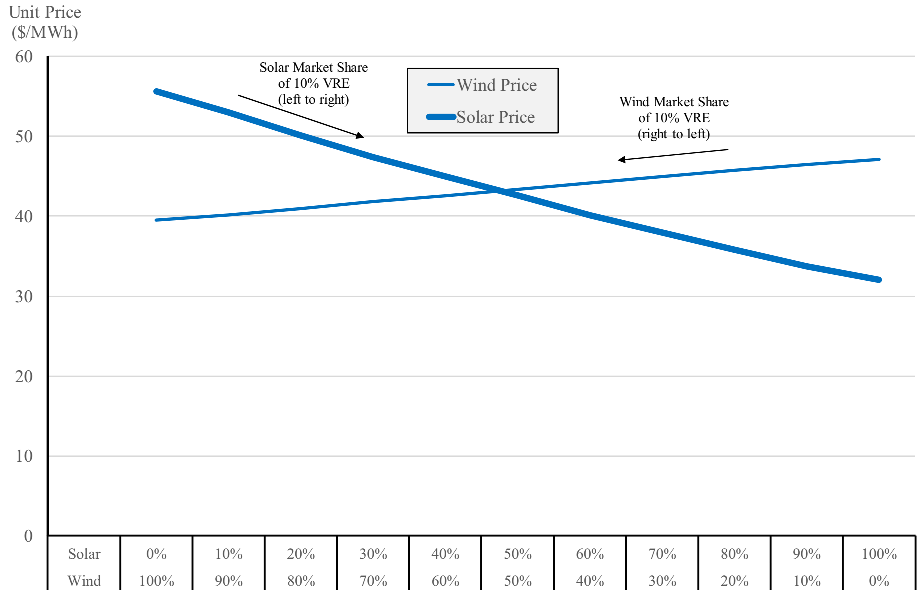

Fig. 10. Welfare maximising asset allocation: 10% VRE Target.

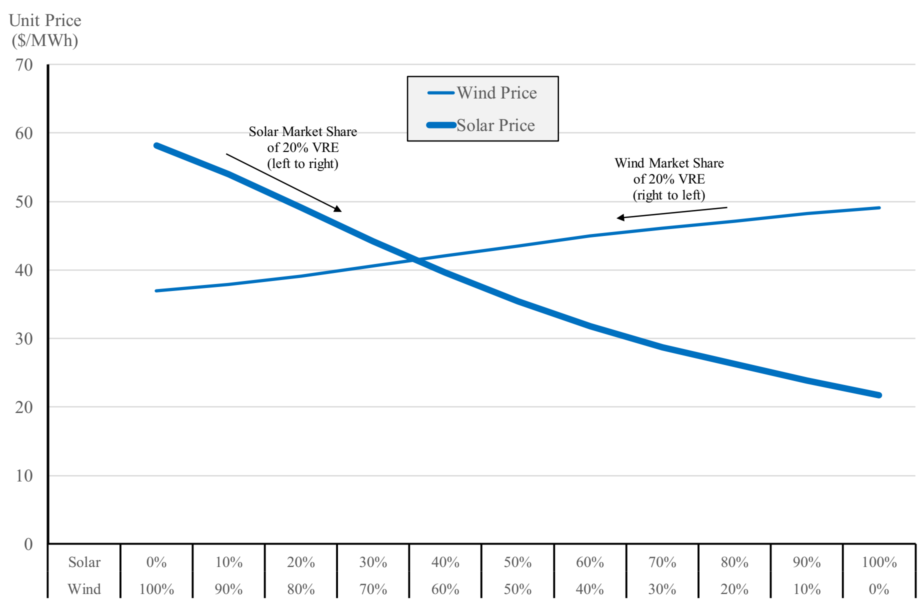

Fig. 11. Welfare maximising asset allocation: 20% VRE Target.

distribution using a Monte Carlo simulation to produce half-hourly availability. The data were then collated and assembled into joint probability availability curves for each generation portfolio, and from there a PoE90 limit was identified as the maximum supply of asset-backed hedges for each portfolio. The same process has been applied in the present analysis assuming 3 large generation portfolios exist, with a more aggressive PoE80 limit for the supply of asset-backed forward contracts (i.e. implying a high degree of co-insurance amongst portfolios).

Fig. 13 reveals the results of this analysis. The supply of asset-backed hedge contracts (y-axis) is measured against VRE market share (x-axis) over the Long-Term, where thermal plant exits and adjusts perfectly. Note Total Installed Thermal Plant Capacity starts at 10280 MW (per Table 3) and falls in the Long Term to 9141 MW (per Table 5). Plant in the NEMESYS-PF model is no longer perfectly available (per Eq. (23)) and so the reserve margin expands from 13% to 18% (vis-à-vis Net Load Duration Curve) to meet reliability constraints. Total "Potential" Supply of Hedges (dashed line) represents the average availability of thermal plant given by the average outage rate, starting at 9600 MW and falling to 8500 MW as thermal plant exits. But generators *do not* hedge 100% of average expected available capacity – they examine the probability of largest and coincident unit outages in the context of adverse spot prices, and additionally, seek to retain some risk-adjusted spot price exposure.[36] The PoE80 joint-probability distribution of the

[36] The extent to which a generator will seek spot price exposure is a dynamic question and is usually guided by volumetric and stochastic methods (such as Earning at Risk). Generator appetite for spot price exposure is inversely related to the reserve plant margin and any time when base plant is 'under-weight' in the plant mix and usually managed.

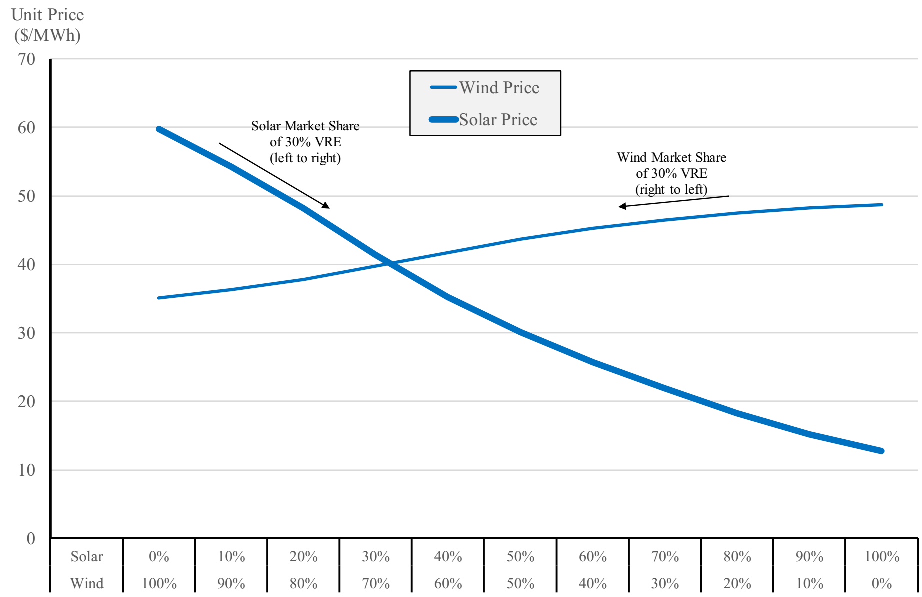

Fig. 12. Welfare maximising asset allocation: 30% VRE Target.

thermal generation fleet is represented by the Total "Practical" Supply of (asset-backed) Hedges, starting at 9200 MW and falling to 8200 MW.

When system Maximum Demand of 9077 MW is transposed to the analysis the possibility of an 'unstable zone' in the hedge market is revealed (see Fig. 14). That is, while Section 4 demonstrated spot markets can reach a tractable equilibrium at 35% VRE in the Long Term, Fig. 14 highlights that the hedge market appears to become increasingly unstable in the Long-Term as thermal plant exits. To be clear, this is *not* a Mid-Term problem (i.e. because thermal plant does not exit in the Mid-Term), it is a Long-Term problem *following* thermal plant exit. Notice in Fig. 14 that the supply of asset-backed hedge contracts (y-axis) falls below system Maximum Demand of 9077 MW (horizontal line) almost as soon as thermal plant begins to exit.

If thermal plant fails to exit, or the market is inherently oversupplied (i.e. above optimal levels), no shortage would appear (i.e. Mid-Term). And similarly, even with optimal levels of thermal plant exit and moderate levels of VRE, the market may operate without concern because some component of VRE PPAs will be considered *firm* and inter-regional hedges and speculative traders may fill any residual gap. But at high levels of VRE and non-trivial thermal plant exit, it is not at all clear that a sufficient supply of asset-backed *firm* hedge contracts will exist.

If government-initiated CfD policy execution a the compounding effect of extracting *non-firm* hedge capacity from the market (per Section 2), a chronic shortage of hedge contracts may be revealed and weigh heavily on retail competition – 2nd tier non-vertical retailers may be inadvertently *foreclosed* by this combination of forces. This appears more than a theoretical possibility, with early signs occurring in South Australia at the time of writing.

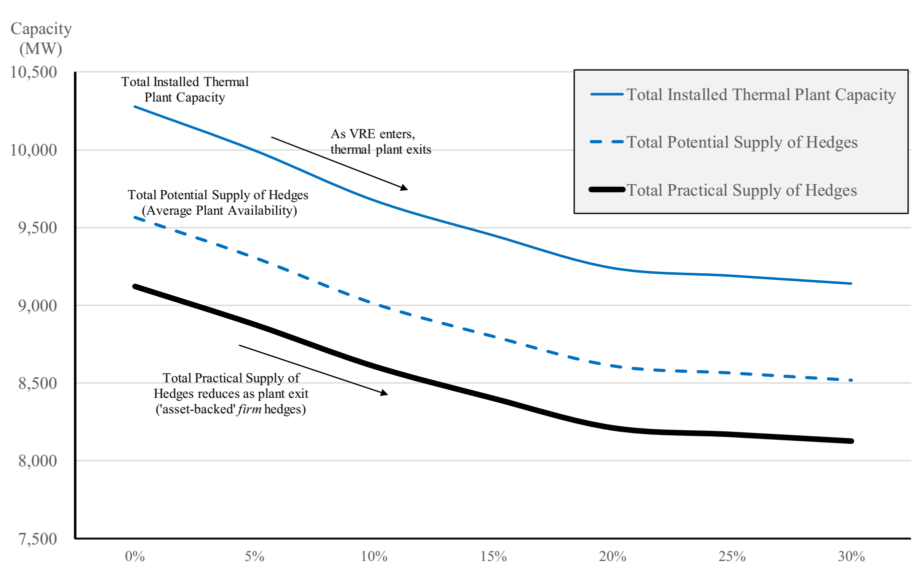

Fig. 13. Long-Term Supply of 'primary issuance' firm hedge contract capacity.

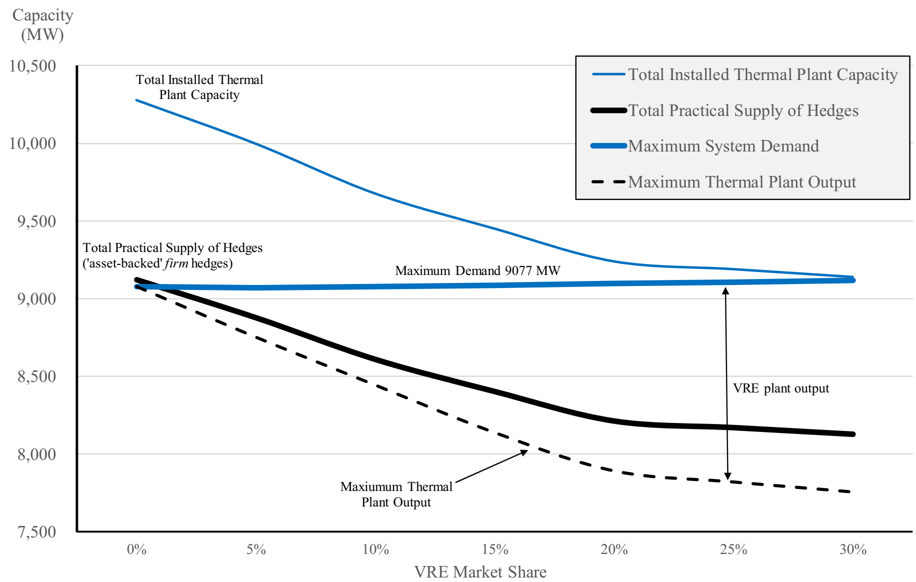

Fig. 14. Maximum system demand vs. supply of 'primary-issuance' hedge contracts.

7. Concluding remarks

The purpose of this article was to analyse NEM stability with rising levels of policy-induced VRE. Starting with a Base Case of coal and gas plant, VRE resources were added until their market share reached 35% comprising 5% small-scale and 30% utility-scale. The literature review revealed energy-only markets are *tough neighbourhoods* under ideal conditions due to missing money (i.e. extended periods of sub-optimal net revenues), incomplete markets (i.e. absence of buyers for long-dated derivative instruments), missing markets (i.e. no markets for Inertia, Fast Frequency Response, Ramping Duties and forward markets for FCAS), shrinking markets (i.e. the gradual reduction in the supply of asset-backed *firm* hedge contracts) and misinformed markets (i.e. Government-initiated CfDs reliant on LCoE rather than market values).

After introducing the model in Section 3, modelling results in Section 4 confirmed spot electricity markets can maintain equilibrium conditions for the entire envelope of VRE (i.e. 0–35% market share) *provided* thermal plant exit and adjust perfectly. *If* VoLL is correctly priced relative to reliability criteria, and *if* the market optimises VoLL event frequency, there is no reason to think energy-only markets cannot produce equilibrium conditions. Of course, there is a long way between theory and practice. In the real world, energy-only markets are *off equilibrium* for extended periods, and rising VRE makes this more, rather than less, likely because of the addition of two new variables requiring optimisation, viz. thermal plant exit, and thermal plant adjustment.

Section 5 analysed optimal VRE asset allocation. Modelling results demonstrated the dangers of LCoE as a metric. LCoE calculations are necessary inputs for power system planning. They are *not* outputs for investment commitment. As VRE becomes a larger share of the market, sub-national government CfD policy execution based on LCoE analysis may produce a misinformed market through non-rational commitment. Why this matters is prior commitments by market participants, acting in good faith and attempting to acquit policy objectives, can be adversely affected as Fig. 8 highlighted. There is nothing inherently wrong with governments stepping into a market to ensure policy objectives are met, particularly if known market failures exist. But how governments do this is important; they need to play by the same rules otherwise the market may become misinformed.

Section 6 analysed the hedge market with a focus on the supply of asset-backed primary issuance (i.e. *firm* swaps and caps). As VRE rises hedge contract shortages appear more than a theoretical possibility. There will be no problem in the Short- and Mid-Term because excess thermal plant exists as VRE enters. Shortages may become apparent in the Long-Term as thermal plant exits, just as spot prices rebound.

Ironically, in the Mid-Term ample hedge contract capacity will exist because thermal plant will not have exited, but the spot market will be inherently unstable through VRE entry and merit order-effects. Conversely, in the Long-Term the forced exit of thermal plant produces a stable spot market equilibrium but a shortage of asset-backed hedge contract supply. At such a tipping point, only Vertical Retailers will be assured of managing VoLL exposure. 2nd Tier non-vertical retailers may face a form of policy-induced foreclosure. This risk would be heightened if government-initiated CfDs for VRE plant extract non-firm contract supply. Each time a government originates investment, unless there is a purposeful mechanism to 'recycle' underpinning CfDs into the hedge market, further shortages may appear. How this is resolved seems worthy of further research.

Ultimately the solution to this Mid-Term/Long-Term disequilibrium may reside in expanding the volumes and services in FCAS markets; this expansion synthetically shifts the demand curve to the right and results in greater system reserves. And as Cramton and Stoft (2008) note, of all the forms of excess capacity in the energy supply chain, peak generating capacity is least damaging and may well reconcile gaps in the supply of hedge contracts. As long-dated PPAs mature, Independent Power Producers will also need to hedge their intermittent output through conventional forward market channels and this may induce further marginal investments in battery storage and OCGT plant. This also seems worthy of further research.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2018.02.006.

References

Acemoglu, D., Kakhbod, A., Ozdaglar, A., 2017. Competition in electricity markets with renewable energy sources. Energy J. 38 (S11), 137–155.

Agranat, O., MacGill, I., Bruce, A., 2015. Fast frequency markets under high penetrations of renewable energy in the Australian National Electricity Market. 2015 Asia-Pacific Solar Research Conference.

Allaz, B., Vila, J.-L., 1993. Cournot competition, futures markets and efficiency. J. Econ. Theory 59 (1), 1–16.

Anderson, E.J., Hu, X., Winchester, D., 2007. Forward contracts in electricity markets: the Australian experience. Energy Policy 35 (5), 3089–3103.

Batlle, C., Perez-Arriaga, I., 2008. Design criteria for implementing a capacity mechanism in deregulated electricity markets. Util. Policy 16 (2008), 184–193.

Berrie, T., 1967. The economics of system planning in bulk electricity supply. Electr. Rev. 22 (2), 425–428.

Besser, J., Farr, J., Tierney, S., 2002. The political economy of long-term generation adequacy: why an ICAP mechanism is needed as part of standard market design. Electr. J. 15 (7), 53–62.

Bidwell, M. & Henney, A. 2004, "Will Neta Ensure Generation Adequacy?", Power UK, 122, pp. 10–26.

Boiteux, M., 1949. La tarification des demandes en pointe: Application de la theorie de la vente au cout marginal. Revue Generale de l'Electricite (Translated by H. Izzard in Journal of Business, Boiteux, M. 1960, 'Peak load pricing', Journal of Business, 33(2): 157–80).

Bushnell, J., 2005. Electricity resource adequacy: matching policies and goals. Electr. J. 18 (8), 11–21.

Bushnell, J., Mansur, E.T., Saravia, C., 2007. Vertical Arrangements, Market Structure, and Competition an Analysis of Restructured US Electricity Markets. National Bureau of Economic Research.

Bushnell, J., 2010. Building Blocks: Investment in Renewable and Non-Renewable Technologies, Energy Institute at Haas Working Paper Series, EI @ Haas WP 202, Berkley.

Caplan, E., 2012. What drives new generation construction? An analysis of the financial arrangements behind new electric generation projects in 2011. Electr. J. 25 (6), 48–61.

Chao, H.-P., Oren, S., Wilson, R., 2008. Reevaluation of vertical integration and unbundling in restructured electricity markets. In: Sioshansi, F.P. (Ed.), Competitive Electricity Markets: Design, Implementation, Performance. Elsevier, Oxford, UK.

Chester, L., 2006. The conundrums facing Australia's national electricity market. Econ. Pap. 25 (4), 362–377.

Cramton, P., Stoft, S., 2006. The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISOs Resource Adequacy Problem. Center for Energy and Environmental Policy Research, Cambridge, MA.

Cramton, P., Stoft, S., 2008. Forward reliability markets: Less risk, less market power, more efficiency. Util. Policy 16 (2008), 194–201.

Cramton, P., Ockenfels, A., Stoft, S., 2013. Capacity market fundamentals. Econ. Energy Environ. Policy 2 (2), 27–46.

Dargue, M., Koenders, D., 2016. Are the Winds Changing on Renewables? Citi Equities Research - Utilities Australia/NZ, Sydney

Doorman, G., 2000. Peaking capacity in restructured power systems. PhD Dissertation. Norwegian University of Science and Technology.

Edenhofer, O., Hirth, L., Knopf, B., Pahle, M., Schlomer, S., Schmid, E., Ueckerdt, F., 2013. On the economics of renewable energy sources. Energy Econ. 40 (2013), S12–S23.

Finon, D., 2008. Investment risk allocation in decentralised markets: the need of long-term contracts and vertical integration. OPEC Energy Rev. 32 (2), 150–183.

Finon, D., Pignon, V., 2008. Electricity and long-term capacity adequacy: the quest for regulatory mechanisms compatible with electricity markets. Util. Policy 16 (2008), 143–158.

Gelabert, L., Labandeira, X., Linares, P., 2011. An ex-post analysis of the effect of renewables and cogeneration on Spanish electricity prices. Energy Econ. 33 (2011), 59–65.

Green, R., 1999. Draining the pool: the reform of electricity trading in England & Wales. Energy Policy 27 (9), 515–525.

Green, R., 2006. Market power mitigation in the UK power market. Util. Policy 14 (2), 76–89.

Green, R., Staffell, 2016. Electricity in Europe: exiting fossil fuels? Oxf. Rev. Econ. Policy 32 (2), 282–303.

Hansen, C., 2004. Improving hedge market arrangements in New Zealand. Paper Presented at the the Sixth Annual National Power New Zealand Conference, Auckland, New Zealand.

Helm, D., 2014. The return of the CEGB? Britain's central buyer model. Energy Futures Network Paper No.4 (available at). http://www.dieterhelm.co.uk/assets/secure/documents/The-return-of-the-CEGB.pdf, Accessed date: January 2017.

Hirth, L., 2013. The market value of variable renewables: the effect of solar & wind power variability on their relative price. Energy Econ. 38, 218–236 (2013).

Hirth, L., Ueckerdt, F., Edenhofer, O., 2016. Why wind is not coal: on the economics of electricity generation. Energy J. 37 (3), 1–27.

Hogan, W., 2005. On an 'Energy-Only' Electricity Market Design for Resource Adequacy. Centre for Business and Government, John F Kennedy School of Government, Harvard University, Cambridge.

Hogan, W., 2013. Electricity scarcity pricing through operating reserves. Econ. Energy Environ. Policy 2 (2), 65–86.

Howell, B., Meade, R., O'Connor, S., 2010. Structural separation versus vertical integration: lessons for telecommunications from electricity reforms. Telecommun. Policy 34 (7), 392–403.

IEA: International Energy Agency, 2005. Energy Policies of IEA Countries – Australia 2005 Review. IEA Publication, Paris.

Joskow, P., 2006. Competitive electricity markets and investment in new generating capacity. AEI-Brookings Joint Centre for Regulatory Studies, Working Paper No.06-14.

Joskow, P., 2008. Capacity payments in imperfect electricity markets: need and design. Util. Policy 16 (2008), 159–170.

Joskow, P., 2011. Comparing the costs of intermittent and dispatchable electricity generating technologies. Am. Econ. Rev. 100 (3), 238–241.

Joskow, P., 2013. Symposium on capacity markets. Econ. Energy Environ. Policy 2 (2), v–vi.

Keay, M., 2016. Electricity markets are broken – can they be fixed? OIES Paper EL17. The Oxford Institute for Energy Studies, University of Oxford

Leautier, T.-O., 2016. The visible hand: ensuring optimal investment in electric power generation. Energy J. 37 (2), 89–109.

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 (2010), 3180–3191.

Mansur, Erin T., 2007. Upstream competition and vertical integration in electricity markets. J. Law Econ. 50 (1), 125–156.

Meade, R., O'Connor, S., 2009. Comparison of long-term contracts and vertical integration in decentralised electricity markets. http://econpapers.repec.org/paper/rscrsceui/2009_2f16.htm.

Meyer, R., 2012. Vertical economies and the costs of separating electricity supply - a review of theoretical and empirical literature. Energy J. 33 (4), 161–185.

Mills, A., Wiser, R., 2012. "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California", LBNL-5445E. Lawrence Berkeley National Laboratory.

Nelson, T., Orton, F., 2016. Australia's National Electricity Market: Optimising Policy to Facilitate Demand-Side Response. Vol. 49(2) pp. 146–168.

Nelson, J., Simshauser, P., 2013. Is the merchant power producer a broken model? Energy Policy 53 (2013), 298–310.

Nelson, T., Simshauser, P., Nelson, J., 2012. Queensland solar feed-in tariffs and the merit-order effect: economic benefit, or regressive taxation and wealth transfers? Econ. Anal. Policy 42 (3), 277–301.

Neuhoff, K., De Vries, L., 2004. Insufficient incentives for investment in electricity generation. CMI Working Paper 42, Cambridge.

Neuhoff, K., Wolter, S., Schwenen, S., 2016. Power markets with renewables: new perspectives for the European Target Model. Energy J. 37 (S12), 23–38.

Newbery, D., 2006. Market design. EPRG Working Paper No. 0515. University of Cambridge Available at. http://www.eprg.group.cam.ac.uk/category/publications/working-paper-series.

Newbery, D., 2015. Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors, EPRG Working Paper 1508. University of Cambridge.

Nicolosi, M., 2012. The Economics of Renewable Electricity Market Integration. An Empirical and Model-Based Analysis of Regulatory Frameworks and their Impacts on the Power Market. (Ph.D. thesis). University of Cologne.

Oren, S., 2003. Ensuring generation adequacy in competitive electricity markets. University of California Energy Institute – Energy Policy & Economics 007. University of California, Berkley.

Peluchon, B., 2003. Is investment in peak generation assets efficient in a deregulated electricity sector? Research Symposium: European Electricity Markets, The Hague, September 2003

Pollitt, M., 2004. Electricity reform in Chile: lessons for developing countries. Working Paper 04–016, CEEPR. University of Cambridge Available at. https://dspace.mit.edu/handle/1721.1/45024, Accessed date: January 2016.

Pollitt, M., Anaya, K., 2016. Can current electricity markets cope with high shares of renewables? A comparison of approaches in Germany, the UK and the State of New York. Energy J. 37 (S12), 69–88.

Riesz, J., Gilmore, J., MacGill, I., 2015. Frequency control ancillary service market design: insights from the Australian National Electricity Market. Electr. J. 28 (3), 86–99.

Roques, F., 2008. Market design for generation adequacy: Healing causes rather than symptoms. Util. Policy 16 (2008), 171–183.

Roques, F., Newbery, D., Nuttall, W., 2005. Investment incentives and electricity market design: the British experience. Rev. Netw. Econ. 4 (2), 93–127.

Sensfuβ, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: a detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. Energy Policy 36 (2008), 3086–3094.

Simshauser, P., 2005. The gains from the microeconomic reform of the power generation industry in east-coast Australia. Econ. Anal. Policy 35 (1/2), 23–43.

Simshauser, P., 2008. The dynamic efficiency gains from introducing capacity payments in the National Electricity Market. Aust. Econ. Rev. 41 (4), 349–370.

Simshauser, P., 2010. Vertical integration, credit ratings and retail price settings in energy-only markets: navigating the resource adequacy problem. Energy Policy 38 (11), 7427–7441.

Simshauser, P., 2011. The hidden cost of wind generation in a thermal power system: what cost? Aust. Econ. Rev. 44 (3), 269–292.

Simshauser, P., 2014. From first place to last: the National Electricity Market's policy-induced energy market death spiral. Aust. Econ. Rev. 47 (4), 540–562.

Simshauser, P., Nelson, T., 2015. Australia's coal seam gas boom and the LNG entry result. Aust. J. Agric. Resour. Econ. 59 (2015), 602–623.

Simshauser, P., Molyneux, E., Shepherd, M., 2010. The entry cost shock and the re-rating of power prices in New South Wales, Australia. Aust. Econ. Rev. 43 (2), 114–135.

Simshauser, P., Tian, Y., Whish-Wilson, P., 2015. Vertical integration in energy-only electricity markets. Econ. Anal. Policy 48 (2015), 35–56.

Spees, K., Newell, S., Pfeifenberger, J., 2013. Capacity markets – lessons learned from the first decade. Econ. Energy Environ. Policy 2 (2), 1–26.

Stoft, S., 2002. Power System Economics. John Wiley-IEEE Press.

de Vries, L., 2003. The instability of energy-only electricity markets. Research Symposium: European Electricity Markets (The Hague, September 2003).

de Vries, L., 2004. Securing the Public Interest in Electricity Generation Markets, the Myths of the Invisible Hand and the Copper Plate. (PhD Dissertation). Delft University of Technology, The Netherlands.

de Vries, L., Heijnen, P., 2008. The impact of electricity market design upon investment under uncertainty: the effectiveness of capacity mechanisms. Util. Policy 16 (2008), 215–227.

Von der Fehr, N.-H., Harbord, D., 1995. Capacity investment and long-run efficiency in market-based electricity industries. In: Olsen, O. (Ed.), Competition in the electricity supply industry – experience from Europe and the United States. DJ0F Publishing, Copenhagen.

Wen, F., Wu, F., Ni, Y., 2004. Generation capacity adequacy in the competitive electricity market environment. Electr. Power Energy Syst. 26, 365–372.