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Over the period 2016-2021 Australia's National Electricity Market (NEM) experienced an investment supercycle comprising 24,000MW of renewables. One of the more intriguing aspects of the supercycle was a partial shift of investment decision-making from utility boardrooms to family kitchen tables – rooftop solar PV comprised 8,000MW of the 24,000MW total. In NEM regions such as Queensland, take-up rates have now reached ~40% of households, currently the highest take-up rate in the world. At the household level there is a distinct mismatch between peak demand and solar PV output, which tends to suggest any peak load problem will be exacerbated. When the contribution of rooftop solar PV is abstracted to the power system level these results reverse. The partial equilibrium framework of Boiteux (1949), Turvey (1964) and Berrie (1967) has historically been used to define the optimal plant mix to satisfy demand growth. In this article, their partial equilibrium framework is used to define conventional plant 'dis-investment' in the presence of rising rooftop solar PV and utility-scale renewables in an energy-only market setting. Queensland's 4400MW of rooftop solar displaces 1000MW of conventional generation in equilibrium, 500MW of peaking plant and somewhat counterintuitively, 500MW of baseload coal plant – falling 'minimum system demand' being a driving factor. The NEM's energy-only market and its $15,000/MWh price cap proves tractable through to a 50% renewable market share, but relies critically on frictionless coal plant divestment and bounded negative price offers.

Keywords rooftop solar PV, renewables, power generation, energy-only markets, peak load problem

JEL Classification D25, D80, G32, L51, Q41

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Rooftop solar PV and the peak load problem in the NEM's Queensland region

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September 2021

Abstract

Over the period 2016-2021 Australia's National Electricity Market (NEM) experienced an investment supercycle comprising 24,000MW of renewables. One of the more intriguing aspects of the supercycle was a partial shift of investment decision-making from utility boardrooms to family kitchen tables – rooftop solar PV comprised 8,000MW of the 24,000MW total. In NEM regions such as Queensland, take-up rates have now reached ~40% of households, currently the highest take-up rate in the world. At the household level there is a distinct mismatch between peak demand and solar PV output, which tends to suggest any peak load problem will be exacerbated. When the contribution of rooftop solar PV is abstracted to the power system level these results reverse. The partial equilibrium framework of Boiteux (1949), Turvey (1964) and Berrie (1967) has historically been used to define the optimal plant mix to satisfy demand growth. In this article, their partial equilibrium framework is used to define conventional plant 'dis-investment' in the presence of rising rooftop solar PV and utility-scale renewables in an energy-only market setting. Queensland's 4400MW of rooftop solar displaces 1000MW of conventional generation in equilibrium, 500MW of peaking plant and somewhat counterintuitively, 500MW of baseload coal plant – falling 'minimum system demand' being a driving factor. The NEM's energy-only market and its $15,000/MWh price cap proves tractable through to a 50% renewable market share, but relies critically on frictionless coal plant divestment and bounded negative price offers.

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1. Introduction

Like most global power systems, Australia's National Electricity Market (NEM) is experiencing a rapid supply-side structural adjustment, marked by the recent and sudden (if not disorderly) exit of coal plant and a sharp increase in intermittent renewables. In 2015, the NEM-wide market share of coal plant was 84.0% – the highest amongst the OECD – while the renewable market share was 6.6%. The *2016-2021 investment supercycle* saw AUD[1]$26.5 billion of commitments in utility-scale renewables across 135 projects, totalling almost 16,000MW. By 2020 the market share of coal had fallen to 64.7% with renewables approaching 30% and rising sharply.

An interesting aspect of the NEM's structural adjustment has been a dilutionary shift in investment decision-making from utility boardrooms to *family kitchen tables*[2]. The NEM's energy-only, real-time gross pool market spans five regions including Queensland, New South Wales, Victoria, South Australia and Tasmania. There are ~10 million households and by 2021, 3+ million had installed a rooftop solar system.

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[1] Unless otherwise stated, all financial numbers are expressed in Australian Dollars. At the time of writing, AUD/US = 0.74, AUD/£ = 0.53 and AUD/€ = 0.62.

[2] I should acknowledge AEMO CEO Daniel Westerman who recently coined this phrase.

Indeed, running in parallel with the utility-scale supercycle was a rooftop supercycle. From 2016-2021, Australian households invested in 8,000MW of rooftop solar PV. Aggregate renewable plant commitments including rooftop capacity during the 2016-2021 supercycle was therefore 24,000MW – a non-trivial increase relative to the NEM's ratcheted power system maximum demand of 35,000MW.

Queensland, historically amongst the lowest cost NEM regions, is especially interesting due to its rapidly transitioning plant stock and pronounced *kitchen table investor base*. Queensland has the highest rooftop solar PV take-up rate in the world with 39.6% of households having installed a system (Fig.1).[3]

The purpose of this article is to examine supply-side impacts of rising renewable market shares in an energy-only market historically dominated by coal plant. The analysis that follows sits within the peak load pricing and market design literature, with a focus on generation investment under uncertainty in the presence of periodic demand. Using 2020 as the reference year, aggregate final electricity demand is reconstructed by combining self-consumed rooftop solar PV and grid-dispatched supply.

The classic static partial equilibrium framework that evolved through Boiteux (1949), Turvey (1964), Berrie (1967) and Crew and Kleindorfer (1976) has traditionally been used to define *investment* plans to achieve an optimal plant mix. In this article, the same framework is used to identify *dis-investment plans* for conventional plant as rooftop solar PV and other utility-scale renewable resources are progressively introduced with a focus on peak load pricing and *market tractability*[4]. In equilibrium this can be achieved either through a Boiteux capacity payment (i.e. at the carrying cost of peaking gas turbine) or a very high market price cap (i.e. the NEM's $15,000/MWh). This study focuses on the latter and produces striking results.

First, in spite of the mismatch between Queensland household demand and rooftop solar output, at the whole-of-market level the peak load problem is partially defused with 500MW of peaking plant displaced, and somewhat counterintuitively, 500MW of baseload coal plant. The emergent issue of declining minimum loads explains the latter dynamic. Adding utility-scale renewables intensifies the need for coal plant dis-investment but the addition of new peaking capacity becomes necessary. The peak load problem remains tractable in an energy-only market with a $15,000/MWh VoLL throughout the range studied (i.e. 0-50% VRE market share).

This article is structured as follows. Section 2 provides a brief review of relevant literature. Section 3 provides market background while Section 4 introduces the model. Section 5 & 6 presents model results and sensitivities. Policy implications and concluding remarks follow.

2. Review of Literature

Power systems face joint problems of i). non-trivial sunk costs, and ii). periodic stochastic demand – the latter being amplified by the absence of inventories at-scale given storage is costly. For the purposes of the present analysis, two related strands of literature are relevant, viz. peak load pricing, and energy-only markets.

2.1 Peak load pricing

In the late-1800s when electricity utilities first emerged, power was sold to consumers at uniform prices in order to compete with other forms of energy. But by the mid-1890s it had become clear in multiple jurisdictions (e.g. London, New York) that

[3] Indeed, the installed capacity of rooftop systems (4430MW) currently exceeds Queensland's utility-scale solar deployment (~3850MW installed and under construction).

[4] The market can be considered 'tractable' when resource adequacy and revenue adequacy are capable of being met simultaneously. Merit order effects and/or missing money are thought to make energy-only markets intractable.

historically profitable utility businesses were heading towards financial distress. This was the point at which the *peak load problem* was first revealed in such acute form (Wright, 1896; Simshauser, 2016). A proliferation of *'short-hour customers'* (i.e. residential households using electricity for 'evening illumination') was driving the addition of capital-intensive capacity to meet peak demand (Greene, 1896, p.29). Power system capacity factors were plunging, and uniform prices were failing to recover spiralling fixed and sunk costs.

It was at this point that the two-part tariff emerged, as a response to the increasing financial instability of otherwise robust power systems. Power system engineers responded to the peak load problem by designing the two-part pricing structure comprising a maximum demand charge ($/kW)[5] and an energy charge (¢/kWh) (Hopkinson, 1892; Greene, 1896; Wright, 1896). The demand charge was intended to form the dominant component to match the industry's onerous fixed and sunk costs. Doherty (1900) would later extend this to the three-part tariff by including a fixed charge.[6]

The first article by an economist on the peak load problem appeared in a 1911 edition of the *American Economic Review*[7] (Clark, 1911), while the first economic text was published by Watkins (1921). The key difference between the pioneering works of rate engineers and economists was their relative focus. Rate engineers designed ornate tariff structures based on meticulous *cost allocations* and *cost causations*, taking demand as fixed. Economists focused on incentives that tariffs produced and turned their focus on designs that would better utilise idle plant capacity in off-peak periods to lower overall system costs and maximise welfare.

This variation in emphasis is prominent in the works of Bye (1929) who, to the best of my knowledge, developed the first peak-load pricing model for public utilities by combining the principles of off-peak pricing at marginal cost with peak period prices bearing some resemblance to the classic works of Dupuit (1844) and Ramsey (1927) vis-à-vis price discrimination. Regardless, both rate engineers and energy economists would spend an inordinate amount of attention dealing with the problem of how to recover the overwhelming fixed and sunk capital costs in the least distortionary way (Hausman and Neufeld, 1989).

It took ~50 years before the theoretical and applied principles of the economics of peak load pricing would be settled. This occurred progressively over the period 1938-1957 commencing with Hotelling (1938), Lewis (1941), Coase (1946), Houthakker (1951), Boiteux (1949), Dessus (1949), Boiteux and Stasi (1952), Boiteux (1956) and Steiner (1957). Of these, Boiteux's 1949 masterpiece – trapped in the French language until translations by Izzard in 1960 and Nelson (1964) – would prove pivotal.

To summarise the literature briefly, Hotelling (1938) established that tariffs should be set at marginal cost with capacity charges as demand approached the limits of installed capacity (with intervening shortfalls subsidised by general taxation). Lewis (1941) emphasized the importance of system peak (*cf.* the engineering approach, which had focused on non-coincident individual customer peak loads). Coase (1946) identified multi-period pricing and the importance of strict marginal cost pricing in off-

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[5] The demand charge was demonstrated to be vital because sunk capacity costs dominated the cost structure. Marginal running costs (i.e. mainly coal) were shown to be trivial in relative terms. Hopkinson (1892), Greene (1896) and Wright (1896) outline this in considerable (applied) detail.

[6] The three-part tariff added a fixed customer charge to the bill reflecting operating costs (i.e. local connection, meters, meter reading costs, and customer billing) and with the cost allocation method of determination driven by the number of utility customers. See Doherty (1900).

[7] As Clarke (1911, p473-477) noted "*A uniform rate – so much per kilowatt hour – would be sure to be wrong… only in one type of public utility, viz., electric light and power plants – has this problem [of large capital costs] been generally worked out to anything approaching a clean-cut solution. Now, on the cost or "responsibility" theory, how should this be shared amongst the consumers?*"

peak periods given extensive idle capacity. Importantly, at this point, system marginal running cost and long run marginal cost remained irreconcilable (and hence the two-part tariff took on a considerable importance).

The major breakthrough occurred in 1949 by *Electricité de France* Chief Economist, Marcel Boiteux, and almost simultaneously, Houthakker in 1951 (see variously Nelson, 1964; Williamson, 1966; Turvey, 1968; Joskow, 1976; Bonbright, Danielsen and Kamerschen, 1988). Both reconciled system marginal cost and the long run marginal cost of plant – and substantially reconciled system marginal cost with average total cost – courtesy of a fundamental proposition. With an optimal investment policy, price set at marginal cost exactly equals the marginal cost of the marginal plant, which in turn is equal to the average cost of the marginal plant.[8]

Translating Boiteux's principles into a schedule of optimal prices thus became relatively straightforward – viz. when there is idle capacity (i.e. off-peak), tariffs should be set to system marginal running cost. In peak periods, set tariffs to long run marginal cost (i.e. system marginal running costs plus the carrying capacity of a gas turbine).

Boiteux's (1949, 1956) propositions for generation plant were refined in Turvey (1964, 1968) while Berrie (1967) developed what would become a benchmark static partial equilibrium model for power system planning, comprising a load duration curve and marginal running cost curves for perfectly divisible mixed technologies, with the intercept representing annualised fixed and sunk costs, and the slope representing the marginal cost of production (subsequently illustrated in Figure 7).[9] US economists extended the analysis further with Steiner (1957) incorporating uncertain demand, Williamson (1966) accounting for plant indivisibility, and Crew and Kleindorfer (1976) and Wenders (1976) incorporated mixed technologies.

However to be clear, while short run system marginal cost and the long run marginal cost of plant capacity had been reconciled, financial equilibrium or 'revenue adequacy' had not because at any given moment, plant in-service would deviate from optimality and past decisions may not align with future requirements (see for example Boiteux, 1949, 1956; Houthakker, 1951; Turvey, 1964). Utilities at the time were either government-owned with pliable budgets and the explicit (credit) backing of a rated sovereign nation, or in the case of the US, regulated with the implicit credit rating of the rate base in which to issue debt to fund agreed expansion plans.

2.2 Energy-only markets and resource adequacy

Australia's NEM design is classed as a real-time, *energy-only* gross pool market. There is no day ahead market[10] – multi-zonal spot prices are formed every 5-minutes under a uniform first-price auction clearing mechanism, along with eight co-optimised frequency control ancillary service spot markets (MacGill, 2010). Being an energy-only design, the NEM does not have an administratively determined and centrally coordinated capacity mechanism to maintain a certain level of plant reserves. The

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[8] To see how optimal investment policy, short-term and long-term pricing is reconciled for a fleet of power stations under the conditions envisaged by Boiteux (1949), let ξ_i^1 and ξ_i^2 be gross margin in period i before and after plant expansion, where price p_i^k applies to each period i and let smc_i^k be system marginal running cost. Let β_e be the capacity cost of the new plant, and mc_e be the marginal running cost of the new plant, with smc_i^1 and smc_i^2 being system marginal running costs before and after the addition of new plant. Let q_i equal demand growth to be serviced in each hour and θ_e be output to be produced by the new plant each hour. Optimal investment will proceed at the margin when the following condition becomes binding:

$$PV\left(\sum_{i=0}^{n}\left(\frac{\xi_i^1+\xi_i^2}{2}\right).q_i+\left(\frac{smc_i^1+smc_i^2}{2}-mc_e\right).\theta_i\right)-\beta_e\geq 0 \mid \xi_k=\left(p_i^k-smc_i^k\right)$$

[9] Boiteux & Stasi (1952) explored the allocation of sunk capital costs in some detail, and uniquely, separately analysed distribution network pricing. While the general principles are the same, distribution network pricing has added complexity because there is no single system-wide peak load.

[10] Although as MacGill (2010) points out, the Market Operator does produce a transparent 40hr pre-dispatch forecast which is continuously updated.

NEM's equivalent is its very high Market Price Cap ($15,000/MWh) and associated forward markets, which guide investment commitments.

The NEM's forward markets comprise swaps (2-way CfDs) and $300 caps (1-way CfD), the latter being the NEM's capacity-market equivalent instrument. These derivative instruments are the quintessential link between physical market requirements, investment requirements and resource adequacy given the NEM's reliability standard of *not more than 0.002% Lost Load*. To summarise their functioning, the real-time spot markets coordinate scheduling and dispatch of resources, while the forward markets for swaps (i.e. energy) and $300 caps (i.e. capacity) tie the economics of the physical power system to resource adequacy and any requirement for new capacity.

In spite of the intuitive logic, policymaker concerns are *ever present* in energy-only markets vis-à-vis resource adequacy – that is, an adequate aggregate plant stock relative to forecast maximum demand. Resource adequacy implications of energy-only markets can be traced as far back as Von der Fehr and Harbord (1995), who noted indivisibility of capacity, construction lead-times, lumpy entry, investment tenor and policy uncertainty make merchant generation unusually risky investments. Early contributions focusing on the investment tractability of peaking plant (or lack thereof) include Doorman (2000). Besser et al. (2002), Stoft (2002), de Vries (2003), Oren (2003) and Peluchon (2003).

Bublitz *et al.*, (2019) provide an excellent summary of the rapidly growing literature in the field. Indeed, resource adequacy concerns in energy-only markets has been a matter of continual interest to energy economists and policymakers (Keay, 2016; Bhagwat *et al.*, 2017; Keppler, 2017; Simshauser, 2018; Billimoria and Poudineh, 2019; Bublitz *et al.*, 2019; Milstein and Tishler, 2019 amongst others). The concern with energy-only markets, which mirrors those from the original peak load pricing literature, is the stability of earnings and the flow-on effects to the plant stock. The contemporary terminology used is *missing money,* a phrase formally introduced by Cramton and Stoft (2005, 2006). The idea behind missing money is net revenues earned in energy-only markets are suboptimal *cf.* expected returns – i.e. the same concerns raised by Hopkinson (1892), Greene (1896) and Wright, (1896) more than a century earlier. Peaking plant are thought to be particularly susceptible given manifestly random revenues in organised energy-only spot markets (Peluchon, 2003; Bajo-Buenestado, 2017; Keppler, 2017; Milstein and Tishler, 2019).

Economic theory and power system modelling has long demonstrated organised spot markets can clear demand reliably and provide suitable investment signals for new capacity (Schweppe et al. 1988). But theory and modelling is based on equilibrium analysis with unlimited market price caps, limited political and regulatory interference, and by deduction – largely equity capital-funded generation plant able to withstand elongated 'energy market business cycles' (Simshauser, 2010; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019).

Good economic theory often collides with harsh realities of applied corporate finance. In practice, energy-only markets are rarely in equilibrium. Persistent pricing at marginal cost does not result in a stable equilibrium given substantial sunk costs. And because merchant generators face rigid debt repayment schedules, theories of organised spot markets suffer from an inadequate treatment of how non-trivial sunk capital costs are financed (Joskow, 2006; Finon, 2008; Caplan, 2012).[11]

[11] Fixed and sunk costs in energy-only markets are, in theory, recovered during price spike events. But participants are unable to optimise the frequency and intensity of price spikes (Cramton and Stoft, 2005). Moreover Market Price Caps are frequently set too low (Batlle and Pérez-Arriaga, 2008; Joskow, 2008; Petitet, Finon and Janssen, 2017; Bublitz *et al.*, 2019; Milstein and Tishler, 2019) in which case a stable financial equilibrium can only be reached if the power system is operating ***near the edge of collapse*** (Bidwell and Henney, 2004).

Generator pricing must deviate from strict marginal cost at some point, but given oligopolistic market settings distinguishing between loss-minimising behaviour and an abuse of market power is difficult (Cramton and Stoft, 2005, 2008; Roques, Newbery and Nuttall, 2005; Joskow, 2008). Further, actions by regulatory authorities and System Operators frequently suppress legitimate price signals (Joskow, 2008; Hogan, 2013; Spees, Newell and Pfeifenberger, 2013; Leautier, 2016).

Central to the assessment of resource adequacy is *incomplete markets* – the seeming inability of energy-only markets to deliver the optimal mix of derivative instruments required to facilitate efficient plant entry, specifically, long-dated contracts sought by risk averse project banks (Joskow, 2006; Chao, Oren and Wilson, 2008; Meade and O'Connor, 2009; Howell, Meade and O'Connor, 2010; Caplan, 2012; Meyer, 2012; Newbery, 2016, 2017; Grubb and Newbery, 2018; Bublitz *et al.*, 2019; Simshauser, 2020). Collectively, these characteristics create risks for timely investment required to meet power system reliability criteria (Bidwell and Henney, 2004; Cramton and Stoft, 2006; de Vries and Heijnen, 2008; Roques, 2008; Hirth, Ueckerdt and Edenhofer, 2016).[12]

Near-zero marginal running costs of VRE plant, historically subsidised through side-markets, are thought to further destabilise energy-only markets through *merit order effects*[13]. The basic principle underpinning the merit order effect is (subsidised) zero marginal cost VRE plant enters at the top of the merit order of plant, thus shifting the long-flat baseload component of a power system's aggregate supply function to the right. Ceteris paribus, prices fall (Sensfuß et al., 2008). But the assumption of ceteris paribus is an important caveat and various studies illustrate prices rebounding or varying from strict merit order effects – Bushnell and Novan's (2021) analysis of California's solar resources being a case in point (see also Hirth, 2013; Simshauser, 2020).

Yet provided an energy market's reliability standard has a tight nexus with the administratively set VoLL[14] and with no economic constraints on generator offers, there should be no question that investment in energy-only markets will flow under conditions of diminishing supply-side reserves. Imbalances induce a growing number, and intensity of, price spike events which drives investment in new capacity (Simshauser and Gilmore, 2019). The central question is whether plant investment occurs in a timely manner, or in response to a crisis, noting practical political limits exist vis-à-vis the severity and duration of wholesale market price shocks (Besser et al., 2002; Hogan 2005; Simshauser 2018; Bublitz et al. 2019). With this background, the analysis now turns to the tractability of the NEM, and the impact that rooftop solar PV and VRE has on peak load pricing.

3. Salient features of the NEM's Queensland region

It is useful to examine the salient features of Queensland, the NEM's most northern region. Tables 1-2 set out key market statistics. Table 1 notes Queensland's population in 2020 was 5.185m following strong growth in the region's minerals and resources sector. Queensland's tropical climate is similar to California and consequently is distinctly *summer peaking*. Power system (i.e. grid) maximum final

[12] Concerns over Resource Adequacy are compounded by 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 remains costly (Batlle and Pérez-Arriaga, 2008; Cramton and Stoft, 2008; Finon and Pignon, 2008; Roques, 2008; Bublitz *et al.*, 2019).

[13] Various countries including Germany, Denmark, Spain, Australia and North America are now routinely experiencing negative spot prices (Bunn and Yusupov, 2015).

[14] In theory, from a power system planning perspective the overall objective function is to minimise $VoLL\ x\ USE + \sum_{i=1}^{n} c(R)\ |\ VoLL\ x\ USE + c(\hat{R}) = 0$, where $VoLL$ is the Value of Lost Load, USE is Unserved Energy, and where $c(R)$ is the cost generation plant, and $c(\hat{R})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the Market Price Cap. 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. See Zachary et al., (2019).

demand during 2020 was 9802MW with grid-supplied energy demand of 53,626GWh.

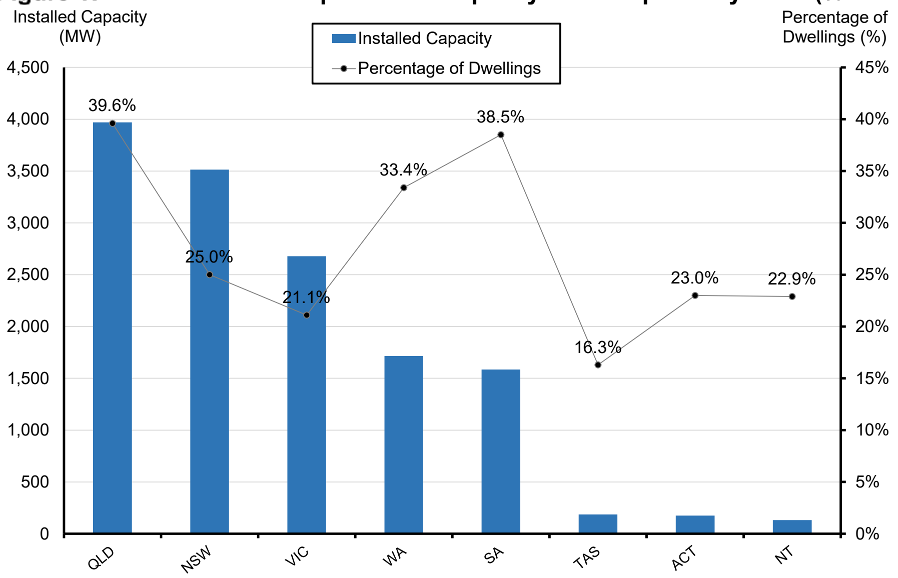
Table 1: Overview of Queensland energy demand

		1998	2010	CAGR (1998-2010)	2020	CAGR (2010-2020)
Population	('000)	3,424.1	4,510.0	2.3%	5,185.0	1.4%
Residential Elec. Accounts	('000)	1,295.0	1,742.5	2.5%	2,010.6	1.4%
Commercial & Industrial	('000)	200.6	204.8	0.2%	238.3	1.5%
Power System Demand						
Maximum Demand*	(MW)	5,591	9,070	4.1%	9,802	0.8%
Energy Demand*	(GWh)	31,752	50,703	4.0%	53,626	0.6%
Residential Load**	(GWh)	8,188	13,634	4.3%	11,567	-1.6%
Commercial & Industrial Load **	(GWh)	20,706	33,840	4.2%	37,209	1.0%
*Generated. **Delivered.						

Data Sources: ABS, esaa, AEC, APVI, AEMO.

Energy demand growth from 1998-2020 was 2.4% per annum but was uneven over this period. The 4.3% CAGR for residential loads from 1998-2010 was driven by mass take-up of household air-conditioning systems, and the ever-increasing floorspace of the housing stock. The growth rate from 2010-2020 saw residential load *contract* by -1.6% pa driven by the prolific uptake of behind-the-meter rooftop solar systems. As Figure 1 illustrates, the household take-up rate of rooftop solar in Queensland is 39.6%, to the best of my knowledge, the highest in the world.

Figure 1: Australian rooftop solar PV capacity & take-up rate by State (% of dwellings)



Source: APVI.

The supply-side structure of Queensland's power system in 2020 is illustrated in Table 2 and comprises 12,450MW of conventional plant (i.e. coal, gas, hydro) and 6,870MW of VRE – the majority of which is rooftop solar PV (i.e. 4430MW). At the time of writing an additional 1800MW of VRE plant was under construction[15] with multiple-1000's MW under development. Power generation in Queensland has been historically dominated by a fleet of very low-cost black coal generators.

Coal seam gas discoveries in the mid-2000s led to the rise of gas turbines and by the early-2010s had a market share of c.20%. This quickly reversed following the commissioning of 3 x LNG export terminals in the mid-2010s, with gas prices rising to export parity (Billimoria et al., 2018). Gas-fired generation has since been replaced by VRE – which by the end of 2020 was approaching 20%.

[15] This includes 1263MW of utility scale solar PV, 193MW of wind, 100MW of battery storage and a 250MW pumped hydro scheme.

Table 2: Overview of Queensland's plant capacity

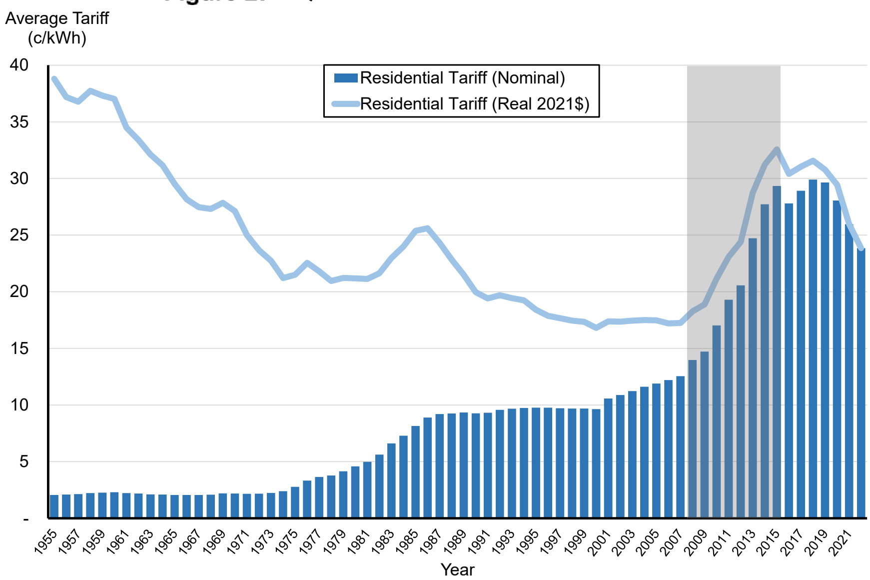
Plant Capacity / Energy		2020 (MW)	2020 (GWh)	Mkt Share (%)
Coal		8,126	47,289	80.1%
Gas		3,587	2,115	3.6%
Hydro		722	638	1.1%
Wind		633	1,348	2.3%
Solar PV		1,799	3,318	5.6%
Sub-Total		14,867	54,708	92.7%
Rooftop Solar PV		4,430	4,305	7.3%
Total		19,297	59,013	100.0%

Data Sources: ABS, esaa, AEC, APVI, AEMO.

3.1 Queensland retail tariffs

An important backdrop to the prolific take-up rates of rooftop solar PV in Queensland was sharply rising residential electricity tariffs from 2007-2015 (shaded area, Fig.2). Over this 8-year period, residential electricity tariffs increased by 121% (*cf.* 22% consumer price inflation, 27.8% wages growth) due to a combination of policy and forecast error vis-à-vis network investment, rising renewable subsidies, stalled load growth and gas price movements.

Figure 2: Queensland residential retail tariffs 1955-2022



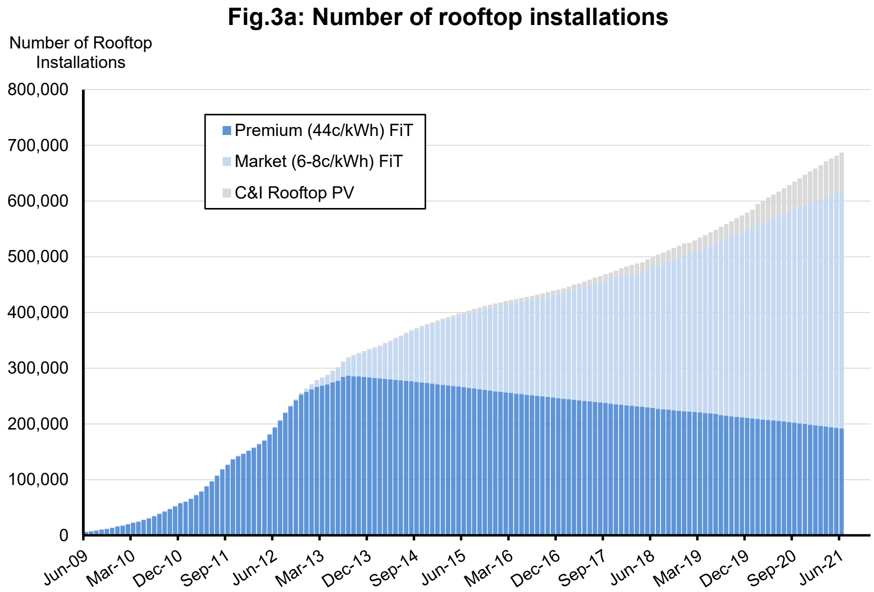
Source: esaa, QCA, ABS.

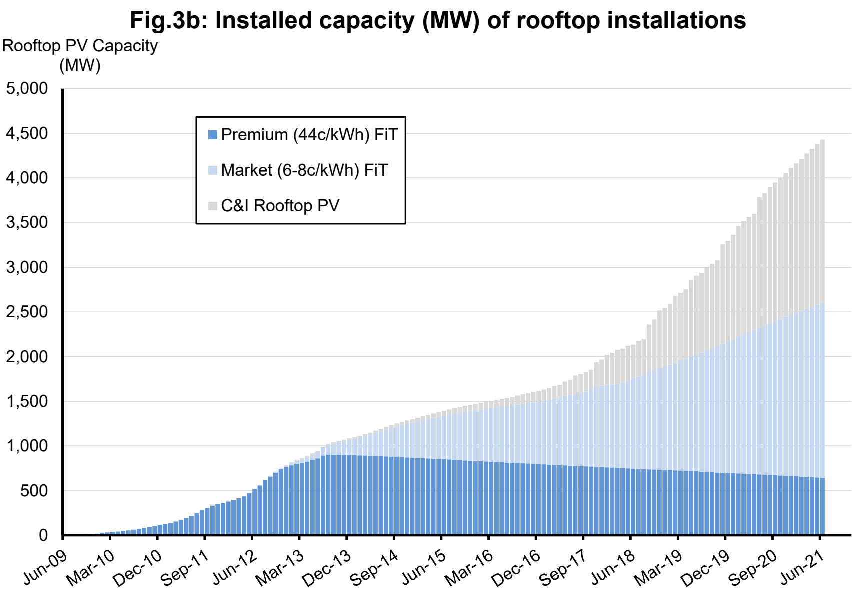
3.2 Queensland rooftop solar installation rates

The first rooftop solar PV installations can be traced back to 2007 and from there growth was exponential. The run-up in Queensland rooftop systems is illustrated in Fig.3a (number of rooftops) and Fig.3b (installed capacity) with three 'market segments' identified. The 'Premium (44c/kWh) Feed-in Tariff' segment comprised households who benefited from an overly generous 44c/kWh FiT policy[16] (*cf.* retail tariffs of ~27c/kWh), which spanned the period 2009-2013. The 44c policy was disbanded due to concerns over scheme subsidy costs, rising inequity and risks of distortionary outcomes. From this point FiT pricing was deregulated (i.e. Market segment in Fig.3) with energy retailers able to choose their own value for PV exports. FiTs reverted to a fair market value (i.e. wholesale prices) of ~6-8c/kWh. C&I is the commercial and industrial segment.

[16] For clarity, the 44c FiT applied to the net exports of a household.

Figure 3: Queensland rooftop solar PV (2009-2021) by segment



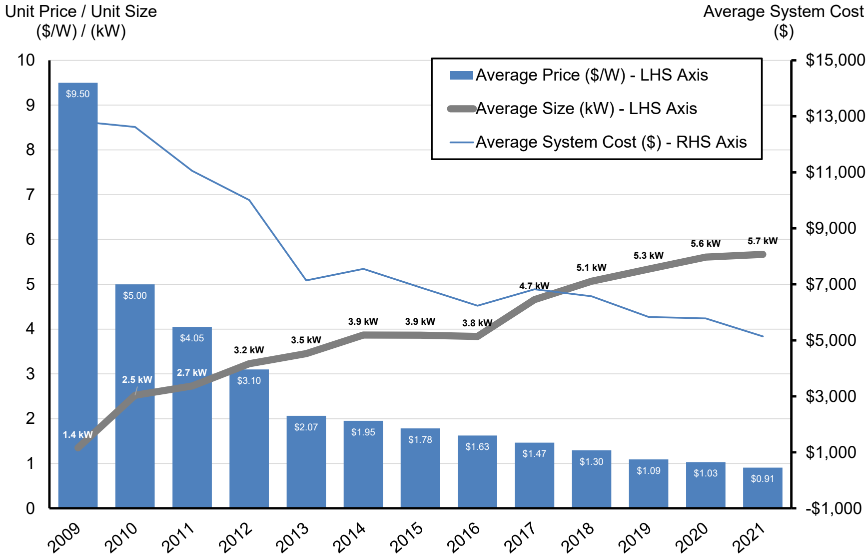


Source: Energex, Ergon Energy.

Solar advocates argued abandoning the 44c FiT would lead to a collapse of the rooftop solar market. The evidence is the installer market became more competitive, with panel costs and margins falling dramatically (Fig.4). By 2014, the acquisition of a solar PV system could be comfortably accommodated on the family Visa Card – noting average system cost in Fig.4 is pre-capital subsidy[17]. At the time of writing, a 6kW rooftop solar PV system could be installed for $3300 in Queensland's capital city, Brisbane.

[17] Subsidies are generally taken to be ~$40 per MWh (deemed output) per year through to 2030. For a 3kW system in Brisbane in 2014, the up-front subsidy would be ~$2500, thus reducing system prices to ~$4500.

Figure 4: Rooftop Solar PV cost index 2009-2021 ($ per Watt installed)



Data sources: Energex, Ergon, BNEF, IEA.

3.3 Queensland household demand

Assessed at the household level, rooftop solar PV output and household final demand has a mismatch. Fig.5 illustrates typical final demand at the customer switchboard circuit level (average of ~70 Brisbane households[18]). Household final demand is ~7,500 kWh per annum, and household maximum (summer) demand is ~2.33kW, driven by air-conditioning loads. Fig.5b and 5c capture household final demand across a series of critical-event summer and winter days, respectively, in which the total quantity consumed exceeded 2kW and 45kWh. The charts overlay event-day 3kW solar system output while the dotted line series shows grid-supplied electricity.

Prima facie, rooftop solar PV appears to exacerbate the peak load problem. Before solar, household peak demand was 2.33kW and energy demand was 7,562kWh (0.37 load factor). After rooftop PV is installed, peak load reduces to 2.10kW and energy demand reduces to 4,909kWh (0.27 load factor). But as Lewis (1941) explained long ago, it is not the individual peak load that matters, but the system peak.

[18] This data was collated by the CSIRO. See Ambrose et al. (2013).

Figure 5: Critical Peak Day – household final demand & 3kW solar PV output

Fig.5a Annual Average

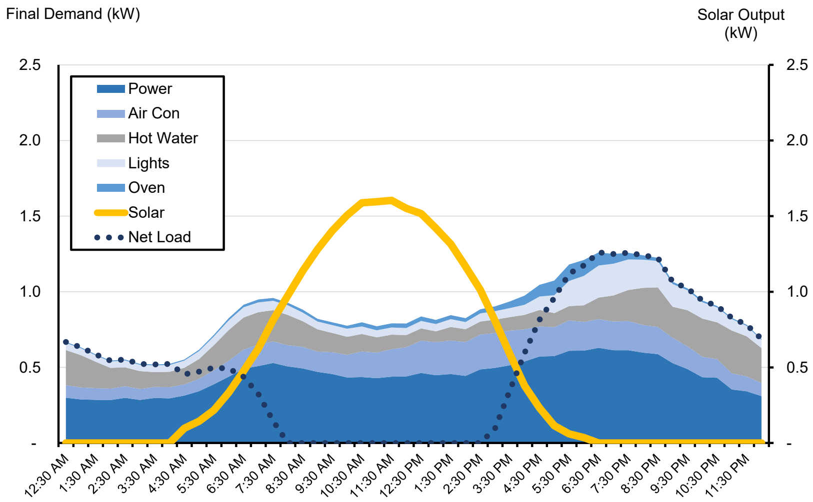


Fig.5b Critical Event Summer Days

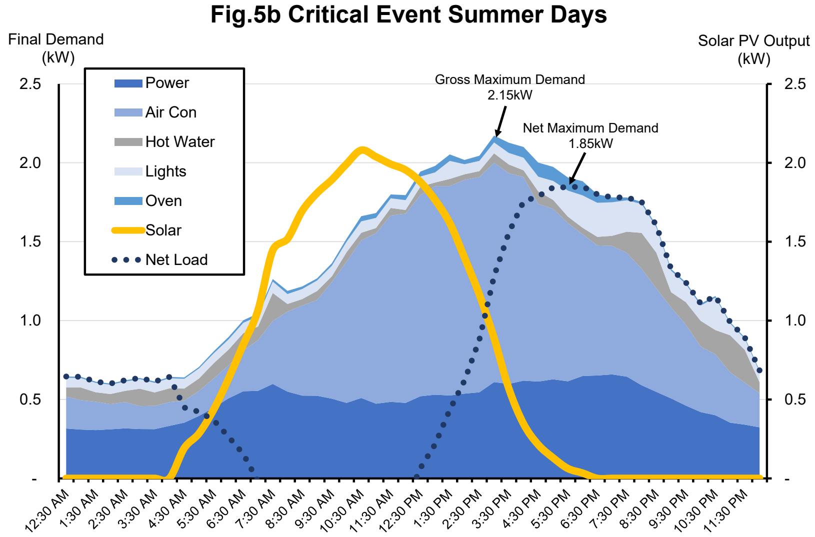
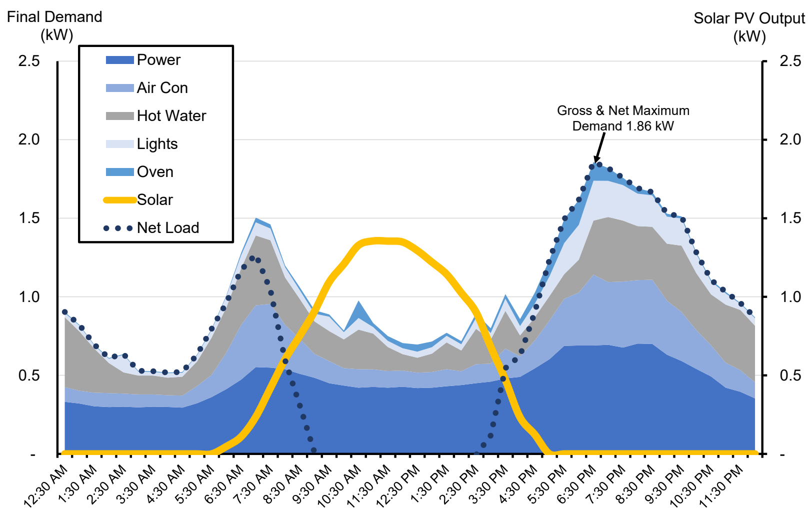


Fig.5c Critical Event Winter Days



Source: Simshauser (2016)

4. Data and Model

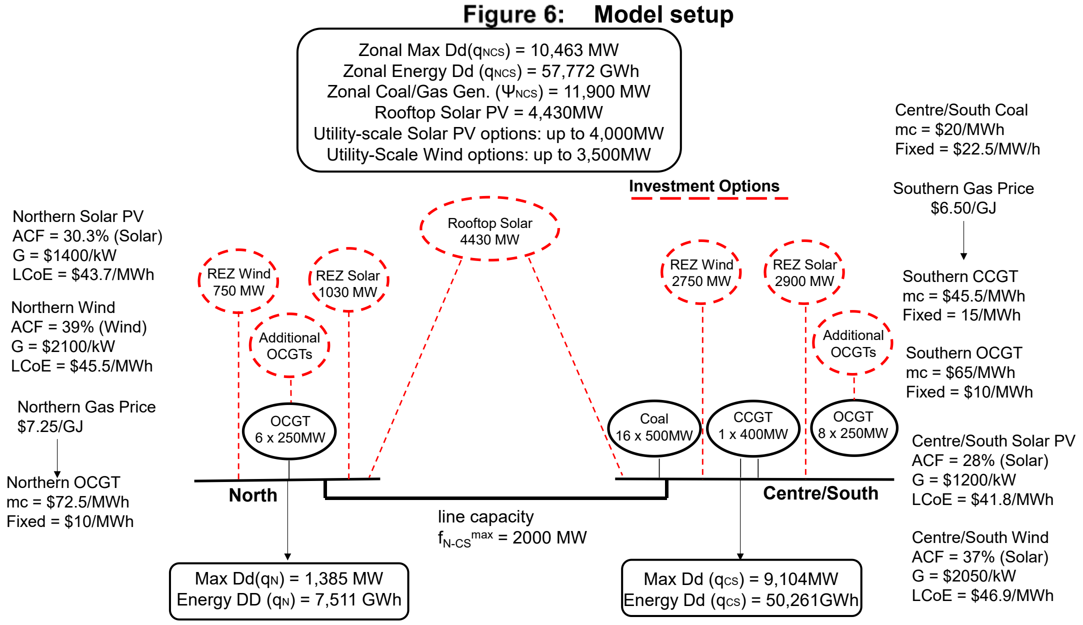
In order to analyse the impact of rooftop solar PV and rising levels of VRE, a dynamic partial equilibrium model comprising a security-constrained unit commitment engine with half-hourly resolution and price formation based on a uniform, first-price auction clearing mechanism has been used. As with Bushnell (2010), the model assumes perfect competition, free entry and exit to install any combination of indivisible capacity that satisfies differentiable equilibrium conditions within a lossless two-node network setup. And as with Hirth (2013), half-hour resolution modelling over a reporting year forms the focus of results.

4.1 Model setup and generation data

Fig.6 presents the Queensland zonal market model setup and comprises two nodes, North (i.e. open cycle gas turbines or OCGT) and Central/South (i.e. base coal, intermediate combined cycle gas turbines (CCGT) and peaking OCGT). Note in Fig.6 the coal fleet comprises 16x500MW units with marginal running cost of $20/MWh and fixed costs equivalent to $25/MWh (i.e. at 100% ACF). Unit gas prices are $6.50-7.25/GJ and there is 1x400MW CCGT and 13x250MW OCGT units, with six of these located in the northern zone and the balance in centre/south. The base case model commences with zero intermittent renewables.

The red dashed lines illustrate renewable plant options and are progressively introduced in various scenarios. These include i). Queensland's 4430MW of distributed rooftop solar PV capacity, and ii). numerous Renewable Energy Zones (REZ) across the north and central/southern nodes with total potential capacity of 3500MW of wind and ~4000MW of utility-scale solar PV. The capital costs and LCoE of the various VRE plant are highlighted on the LHS and RHS panels of Fig.6 and range from $41.8 – $46.9/MWh (having been derived from Simshauser, Billimoria and Rogers, 2021).

Figure 6: Model setup



4.2 Final demand data

Total electricity consumed has been reconstructed by combining total Queensland centrally-dispatched power with total Queensland rooftop solar PV production. When 30-minute rooftop PV production is added back to 30-minute centrally-dispatched production, Queensland's 2020 aggregate final electricity demand is found to rise by 8% to 57,772GWh while maximum demand increases by 6.7% to 10,463MW as Table 3 illustrates.

Table 3: Reconstructed aggregate final energy demand

Column 1	2	3	4	5	6
		2010	2020	Aggregate Final Demand	Power System Demand
				(CAGR)	(CAGR per Tab1)
Population	('000)	4,510.0	5,185.0	1.4%	1.4%
Residential Elec. Accounts	('000)	1,742.5	2,010.6	1.4%	1.4%
Commercial & Industrial	('000)	204.8	238.3	1.5%	1.5%
Power System Demand					
Maximum Demand*	(MW)	9,070	10,463	1.4%	*0.8%*
Energy Demand*	(GWh)	50,703	57,927	1.3%	0.6%
Residential Load**	(GWh)	13,634	15,008	1.0%	-1.6%
Commercial & Industrial Load **	(GWh)	33,840	38,069	1.2%	1.0%
*Generated. **Delivered, PV split 80/20..					

Source: AEMO, APVI.

In Tab.3., the CAGR in column 6 has been reproduced from Tab.1 for ease of comparison. Comparing columns 5 and 6 it is evident that growth in *final* energy demand is twice that which (grid-level) system statistics otherwise suggest. Note also the sign of residential segment growth reverses. Initially exhibiting contracting household grid-supplied demand of -1.6% pa, the inclusion of self-produced solar output reveals annual average growth in final electricity demand of 1.0%.

4.3 Model logic

Let *H* be the ordered set of all half-hourly trading intervals.

$$i \in \{1 \dots |H|\} \wedge h^i \in H, \tag{1}$$

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:

$$n \in (1..|N|) \wedge \eta_n \in N, \tag{2}$$

Aggregate demand at each node comprises residential and residential self-produced/consumed, commercial, and industrial consumer segments. Let *E* be the set of all electricity consumer loads in the model.

$$w \in \{1 \dots |E|\} \wedge e_w \in E, \tag{3}$$

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[19] 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 within the technical constraints outlined below. Let Ψ_n be the ordered set of generators at node n.

$$g \in \{1..|\Psi_n|\} \wedge \psi_{ng} \in \Psi_n, \tag{4}$$

Conventional plant are subject to a regime of planned and forced outages. Planned outages are simulated at the rate of 35 days every 4th year, while forced outages are the subject of random simulations equivalent to 3-6% per annum. $\mathrm{F}(n, g, i)$ is the

[19] This elasticity estimate is consistent with Burke and Abayasekara (2018); AEMO, 2019 and Sergici *et al.*, 2020).

availability of each plant ψ_{ng} in each period i. Annual generation fleet availability is therefore:

$$\sum_{g=0}^{|\Psi_n|} F\,(n, g, i)\ \forall\ \eta_n, \tag{5}$$

Conventional plant face binding capacity limits and minimum 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:

$$\min_{q^i_n} \left(\sum_i mc^i_{\psi_{ng}} \left(g_{\psi^i_{ng}} \right) q^i_n \right), \tag{6}$$

where

$$\exists \psi^i_{ng} \middle| if\ \left(g_{\psi^i_{ng}} \right) \begin{cases} \neq 0, 0 < \check{g}_{\psi_{ng}} < g_{\psi^i_{ng}} < \hat{g}_{\psi_{ng}} \forall\ \psi_n \\ = 0, 0 \end{cases} \wedge \left[\left(\sum q^i_{w,n} - \sum g_{\psi^i_{ng}} \right) / \sum q^i_{w,n} \right] \ngtr USE, \tag{7}$$

and

$$If\ \left(\sum q^i_{w,n} - \sum g_{\psi^i_{ng}} > 0 \middle| USE > 0, p_{\psi^i}(q) = \$15{,}000/\text{MWh}, \right), \tag{8}$$

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.[20]

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

$$t_j\ \in\ (1..|Ŧ|) \wedge\ t_j\ \in\ Ŧ, \tag{9}$$

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

$$\Omega_A\ \in\ \mathrm{N}, \wedge\ \Omega_B \in \mathrm{N}\ |\Omega_A \neq \Omega_B, \tag{10}$$

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

[20] 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).

vector of quantities demanded q_n^i 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 $g_{\psi_n^i}$ $(i.e. \sum g_{\psi_{ng}^i})$ and negative quantities imply net demand V_n^i:

$$if\ q_n^i \begin{cases} \geq 0, g_{\psi_n^i} = q_n^i \\ \leq 0, V_n^i = -q_n^i, \end{cases} \tag{11}$$

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

$$\text{Obj} = \left[\sum_{i=1}^{|H|}\sum_{w=1}^{|E|}\sum_{n=1}^{|\mathrm{N}|}\int_{q=0}^{v_n} V_n\left(q_{n,w}^i\right)\partial q\right] - \left[\sum_{i=1}^{|H|}\sum_{n=1}^{|\mathrm{N}|}\sum_{\psi=1}^{|\Psi|}\int_{q=0}^{g_{\psi n}} mc_{\psi n}\left(q_{\psi,n}^n\right)\partial q + FOM_{\psi n} + \sum_{n=1}^{|\mathrm{N}|} K_{\psi n} + \sum_{j=1}^{|\mathrm{Ŧ}|} K_{tj}\right], \tag{12}$$

S.T

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

5. Results

A stylised Base Case along with four ‘renewable scenarios’ from 8% to 50% VRE market share have been specifically developed, as follows:

1. Base Case: no rooftop PV, no utility-scale renewables
2. Existing rooftop solar PV fleet (renewables ≈ 8%)
3. Existing rooftop + existing utility-scale VRE (renewables ≈ 20%)
4. Existing rooftop + VRE + 2250MW new entrant VRE (renewables ≈ 35%)
5. Existing rooftop + VRE + 5500MW new entrant VRE (renewables ≈ 50%)

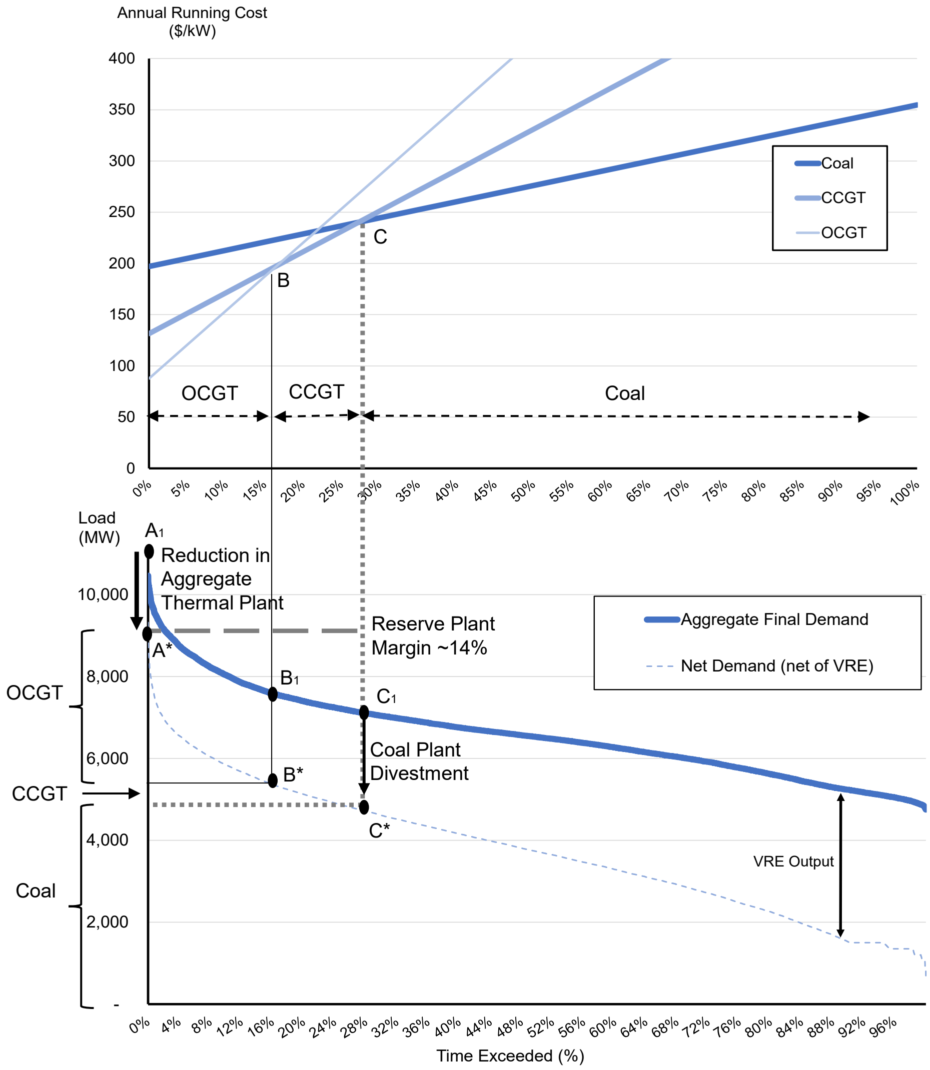
The renewable set-points in scenarios 2-5 were carefully selected. The Base Case (i.e. no renewables) provides a basis for subsequent comparative analysis. Scenario 2 isolates effects of existing rooftop solar. Scenario 3 isolates the effects of existing utility-scale VRE. Scenario 5, the final scenario, represents Queensland’s existing policy settings, i.e. 50% renewable market share by 2030 while Scenario 4 is the mid-point between the power system as it exists in 2020, and its target state in 2030. To be clear, as results in Section 5 subsequently reveal, endogenous modelling seeking to minimise costs will revert to Scenario 1 in the absence of a non-negative (albeit trivial) carbon price.

Before proceeding, it is helpful to conceptualise the task of *dis-investment* under the classic *static* equilibrium framework built-up during the 1940s-1960s by Boiteux (1949), Berrie, (1967) and others, per Fig.7. For those not familiar, the top chart in Fig.7 presents annual running cost curves for three conventional generation technologies, while the lower chart presents the power system’s load duration curve

(‘Aggregate Final Demand’, the solid line series). The intersection of the plant running cost curves in the upper chart (points B and C) are transposed down to the lower chart, with the initial optimal plant mix given by the points where they cross the load duration curve (i.e. points labelled A_1, B_1 and C_1 – A_1 correlating to a reserve plant margin of ~14%).

The second load plot (dashed line series) is a ‘residual’ load duration curve after deducting forecast output from VRE resources (i.e. 50% market share). This *‘net final demand’* highlights the task facing dispatchable plant. One again the upper chart is transposed to the lower chart, where point C_1 drops to C*. The difference between these points highlights the level of coal plant dis-investment (y-axis). Similarly, point A_1 drops to point A* which highlights the aggregate (dispatchable) plant stock reduction. The optimal plant stock is then re-established on the lower chart (see y-axis brackets). The new plant mix comprises less base plant and higher peaking plant. But to be clear, there is less thermal plant overall given 50% VRE.

Figure 7: Partial equilibrium framework – plant divestment (Scenario 1 v Scenario 5)



The static model in Fig.7 captures the power system requirements in equilibrium, albeit excluding stochastic plant availability and plant non-convexities. To incorporate these, we must revert to a dynamic partial equilibrium model (i.e. outlined in Section 4.3). The focus of modelling results are i). progressive changes in the optimal plant mix with rising VRE; ii). changes in CO_2 emissions, iii). ensuring security constrained dispatch meets the NEM’s reliability constraint, iv). peak load pricing and the financial tractability of the generation fleet in the presence of rising VRE in an energy-only market setting.

5.1 Impact of rooftop solar PV on peak load: base case vs scenario 2

The first modelling task is to identify the Base Case optimal plant mix. The Base Case comprises only conventional plant technologies undertaking base, intermediate and peaking duties. But whereas Boiteux (1949), Turvey (1964), Berrie (1967), Crew and Kleindorfer (1976) and others devised such partial equilibrium modelling frameworks for identifying optimal investment paths, here, the primary use of the Model and associated framework is to identify the *dis-investment path* of inflexible baseload plant.

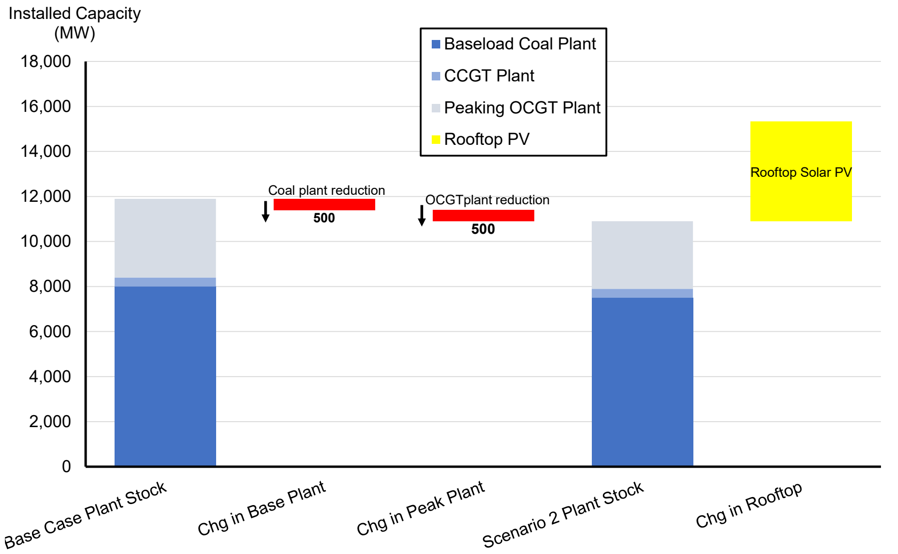
Before proceeding, some important modelling parameters are worth highlighting. First, results in Sections 5-6 represent the average of 100 iterations (i.e. 5 scenarios x 100 iterations each = 500 iterations in total).[21] The variation in iterations are driven by stochastic generation plant availability, periodic demand with own-price elasticity of -0.10 at the retail level, re-optimised plant stock and the levels of weather-driven renewable output. Second, from a peak load pricing perspective and consistent with Eq.7-8, the energy-only market model assumes VoLL of $15,000/MWh and reliability constraint of Unserved Energy not to exceed 0.002% of load served (i.e. the NEM's parameters). Third, generator offer prices are strictly marginal running costs, with coal plant minimum loads offered at -$100/MWh. VRE marginal running costs are taken to be $0/MWh.

Recall from Fig.5 household final demand and rooftop solar PV output had a peak period *mismatch*. During summer, household final demand peaked at 3:30pm when rooftop production was ~40% capacity. During winter, household final demand peaked at 6:30pm when rooftop PV production had fallen to zero. Prima facie, this suggests rooftop solar is likely to exacerbate any peak load problem. At the distribution network level, for residential-intensive feeders this would, evidently, be true.[22]

Our first task is to abstract to whole-of-system aggregate final demand and supply, and as Figure 8 reveals, a different outcome emerges. To begin with, Queensland's optimal plant mix under the Base Case (first bar series) comprises 8000MW of coal, 400MW of CCGT and 3500MW of OCGT plant – an aggregate supply of 11,900MW. Scenario 2 introduces Queensland's 4430MW rooftop solar capacity and the conventional plant stock is then re-optimised. Far from mismatched – the model *dis-invests* 1,000MW of utility-scale plant (representing ~$1.35 billion of avoided investment)[23]. Prima facie, one might expect an all-peaking plant exit result, but the re-optimised fleet reduces peaking plant by 500MW, and counterintuitively, 500MW of base plant (Fig.8).

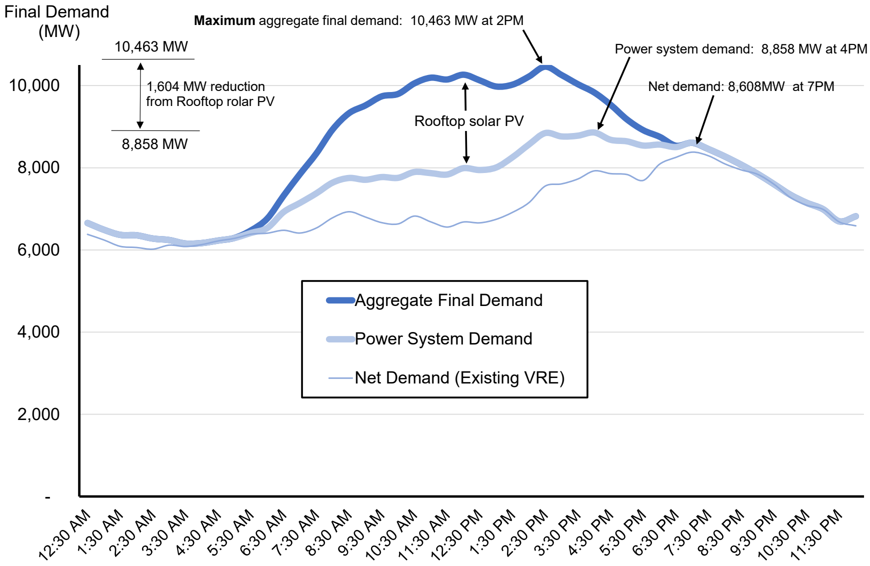
[21] The exception to this reporting convention is *Unserved Energy*, in which the *90th percentile* result is reported (nb. in order to assess any unbalanced tail risk within iteration sets).
[22] For a more detailed analysis see Simshauser, (2016).
[23] Capex estimates from AEMO's 2021 dataset, at $1804/kW for a CCGT plant and $903/kW for an OCGT plant.

Figure 8: Change in aggregate plant stock – Base Case vs Scenario 2



Exactly why 1000MW of plant capacity is avoided through rooftop solar PV is captured through Fig.9-11. Fig.9 illustrates various measures of final demand for Queensland's top-ranked *critical event summer day*. Maximum aggregate final demand is 10,463MW and occurs at 2pm. However at a grid level, Queensland's 4430MW rooftop solar fleet was generating 1,618MW at 2pm. Consequently, grid-level daily peak demand was pushed out to 4pm – and at 8,858MW – was well below power system maximum demand. Net demand (relating to Scenario 3) occurs even later (at 7pm) and is discussed further in Section 5.3.

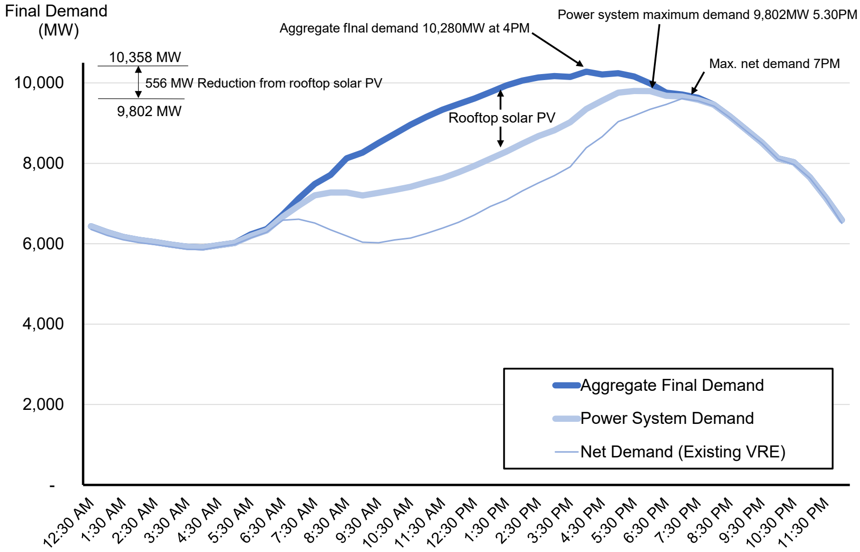
Figure 9: Aggregate maximum final demand (7th Dec. 2020)



Source: AEMO, APVI.

Fig.10 illustrates the power system's critical event day, which occurred in February. Here, aggregate final demand reaches 10,280MW at 4pm while power system *maximum demand* of 9,802MW occurs at 5:30pm.

Figure 10: Power system maximum demand (3rd Feb. 2020)

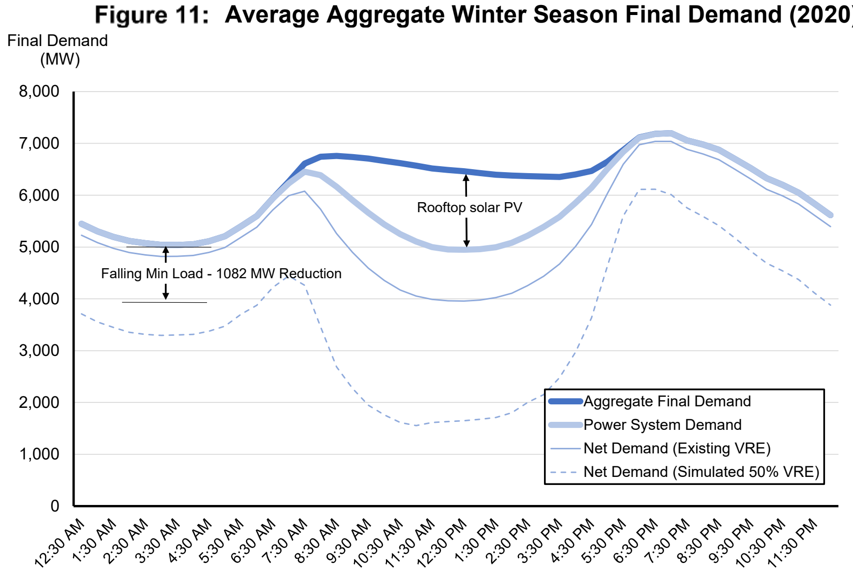


The reason 1000MW of plant is avoided is intuitive through inspection of Figures 9-10. What is not immediately obvious is why 500 of the 1000MW avoided is baseload coal plant – after all, solar PV produces during what has historically been termed the daytime (7am-10pm) 'peak period'.

Recall Figs.9-10 are critical event summer days where both aggregate final demand and power system demand are at their highest levels. Fig.11 presents average daily final demand during the 90 days of Queensland's winter months, during which daytime temperatures range from 20°C in the south to 26 °C in the north.

Queensland's (mild) winter days produce good solar resources, and with final demand naturally softening during the middle of the day (i.e. zero heating load), a critical issue emerges – *falling minimum demand.* Driven by sharply rising rooftop solar PV grid-exports, falling minimum demand has serious implications for inflexible baseload plant (along with system strength violations and high volts). Note from Fig.11 average minimum daytime load in winter is 1082 MW below conventional (i.e. overnight, 10pm-7am) off-peak period load. This is one reason why coal plant will ultimately be forced off the system.

Figure 11: Average Aggregate Winter Season Final Demand (2020)



Base Case vs. Scenario 2 results are presented in Tab.4. Note at Lines 1-3, thermal capacity has reduced as rooftop solar increases (Line 6). The largest output reduction is coal by 3,908GWh (Line 8) and consequently CO_2 emissions fall by 7% (Line 21). At Line 22, there is no material changes in System Average Cost, rising slightly to $53.1/MWh[24]. With spot prices at $51.2/MWh (Line 23) the market remains tractable given VoLL of $15,000/MWh. The reliability criteria has been met at the 90th Percentile (Line 25). The addition of rooftop solar proves to be welfare enhancing with a change of +$308m (Line 39) after accounting for a *shadow* CO_2 value of $25/t, the current clearing price of Australian Carbon Credit Units.[25]

Table 4: Impact of Rooftop PV on aggregate final demand

Line			Base Case (no Rooftop PV)	Scenario 2 (+ Rooftop Solar)	Base v Sc.2 Chg
	Installed Plant Capacity				
1	Coal	(MW)	8,000	7,500	-500
2	CCGT	(MW)	400	400	0
3	OCGT	(MW)	3,500	3,000	-500
4	Wind	(MW)	0	0	0
5	Solar PV	(MW)	0	0	0
6	Rooftop Solar PV	(MW)	0	4,430	4,430
7	Total	(MW)	11,900	15,330	3,430
	Generation Output				
8	Coal	(GWh)	56,255	52,348	-3,908
9	CCGT	(GWh)	584	516	-68
10	OCGT	(GWh)	872	639	-233
11	Wind		0	0	0
12	Solar PV		0	0	0
13	Rooftop Solar PV	(GWh)	10	4,294	4,285
14	Total Generation	(GWh)	57,720	57,796	76
	Market Statistics				
15	Maximum Final Demand	(MW)	10,452	10,467	16
16	Maximum Grid Demand	(MW)	10,452	9,806	-645
17	Final Energy Demand	(GWh)	57,711	57,796	86
18	Grid Energy Demand	(GWh)	57,711	53,502	-4,209
19	Constrained VRE	(GWh)	0	0	0
20	T_{REZ} Constraints	(hrs)	0	0	0
21	Carbon Emissions	(Mt)	51.4	47.7	-4
	Market Prices & Reliability				
22	System Average Cost	($/MWh)	52.2	53.1	1
23	Spot Price	($/MWh)	51.7	51.2	-1
24	Number of VoLL Events	(#)	0.6	3.1	2
25	Unserved Energy PoE90	(%)	0.000%	0.001%	0
26	Market Turnover	($m)	2,985	2,740	-245
27	Carbon @ $25	($m)	1,285	1,193	-92
	Resource Costs				
28	Coal	($m)	1,125	1,047	-78
29	Gas	($m)	83	65	-18
30	Fixed Costs	($m)	1,805	1,728	-77
31	Utility-Scale VRE	($m)	0	0	0
32	Total Resource Costs	($m)	3,013	2,840	-173
33	Producer Surplus	($m)	1,777	1,628	-149
34	Economic Profit	($m)	-28	-100	-72
35	Economic Profit	($/MWh)	-0.5	-1.9	-1
36	Chg in Resource Cost	($m)	n/a	173	*gain*
37	Chg in Economic Profit	($m)	n/a	-72	*loss*
38	Chg Consumer Surplus	($m)	n/a	380	*gain*
39	Welfare Gain / Loss	($m)	n/a	308	*gain*

[24] Note this excludes any rooftop solar PV costs, such as premium FiT recoveries.
[25] The direction of results are not sensitive to the price of ACCUs. When set to zero, results remain welfare enhancing. Consequently, a higher carbon price merely amplifies these results.

5.2 Utility-scale VRE: Scenarios 3-5

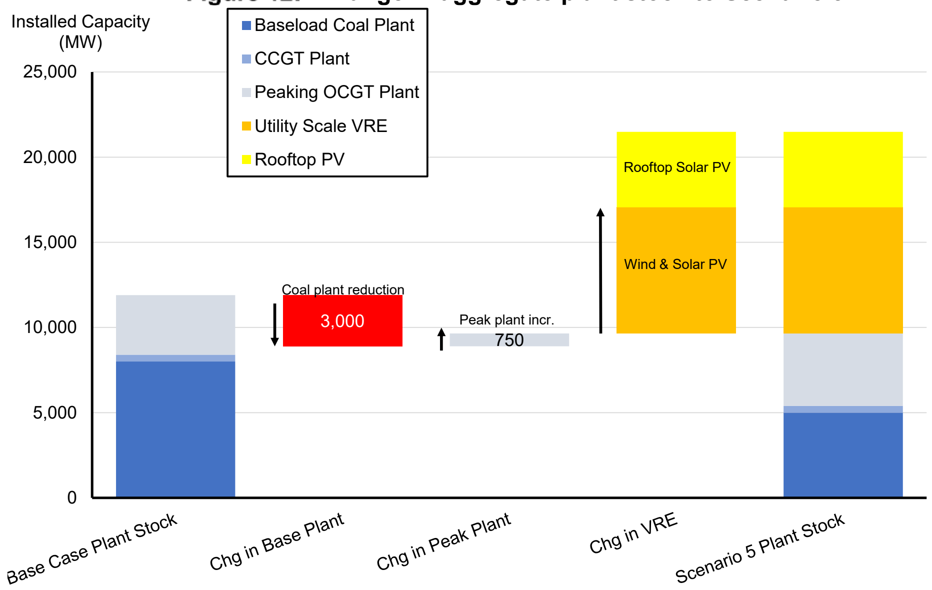
Next is the addition of utility-scale VRE. Scenario 3 introduces Queensland's existing fleet which takes renewables to ~20% market share. Queensland has a 2030 Target of 50% and hence two additional scenarios are simulated, 35% (midway) and 50%, respectively. Table 5 presents detailed results and Fig.12 presents changes to the optimal plant mix.

Table 5: Impact of utility-scale VRE at 20%, 35% and 50% market share

Line	Base Case (no Rooftop PV)			Scenario 3 +20% VRE	Scenario 4 +35% VRE	Scenario 5 +50% VRE	Base v Sc.5 Chg
		Installed Plant Capacity					
1	8,000	Coal	(MW)	7,000	6,000	5,000	-3,000
2	400	CCGT	(MW)	400	400	400	0
3	3,500	OCGT	(MW)	3,250	3,750	4,250	750
4	0	Wind	(MW)	480	2,103	3,725	3,725
5	0	Solar PV	(MW)	1,425	2,777	4,129	4,129
6	0	Rooftop Solar PV	(MW)	4,430	4,430	4,430	4,430
7	11,900	Total	(MW)	16,986	19,460	21,935	10,035
		Generation Output					
8	56,255	Coal	(GWh)	47,480	38,779	30,168	-26,087
9	584	CCGT	(GWh)	594	662	863	280
10	872	OCGT	(GWh)	776	1,220	1,822	950
11	0	Wind	(GWh)	1,343	6,413	11,441	11,441
12	0	Solar PV	(GWh)	3,314	6,413	9,470	9,470
13	10	Rooftop Solar PV	(GWh)	4,294	4,294	4,294	4,285
14	57,720	Total Generation	(GWh)	57,802	57,781	58,059	338
		Market Statistics					
15	10,452	Maximum Final Demand	(MW)	10,460	10,452	10,438	-14
16	10,452	Maximum Grid' Demand	(MW)	9,799	9,792	9,778	-674
17	57,711	Final Energy Demand	(GWh)	57,757	57,714	57,634	-77
18	57,711	Grid Energy Demand	(GWh)	53,463	53,420	53,340	-4,371
19	0	Constrained VRE	(GWh)	42	68	516	516
20	0	TREZ Constraints	(hrs)	176	176	108	108
21	51.4	Carbon Emissions	(Mt)	43.4	35.9	28.6	-23
		Market Prices					
22	52.2	System Average Cost	($/MWh)	53.9	55.3	57.1	5
23	51.7	Spot Price	($/MWh)	51.9	52.4	54.2	2
24	0.6	Number of VoLL Events	(#)	3.5	3.3	5.0	4
25	0.000%	Unserved Energy PoE90	(%)	0.001%	0.001%	0.001%	0
26	2,985	Market Turnover	($m)	2,777	2,801	2,891	-94
27	1,284.7	Carbon @ $25	($m)	1,086	897	715	-570
		Resource Costs					
28	1,125	Coal	($m)	950	776	603	-522
29	83	Gas	($m)	77	109	158	74
30	1,805	Fixed Costs	($m)	1,651	1,498	1,345	-460
31	0	Utility-Scale VRE	($m)	203	570	938	938
32	3,013	Total Resource Costs	($m)	2,881	2,953	3,043	30
33	1,777	Producer Surplus	($m)	1,547	1,346	1,193	-584
34	-28	Economic Profit	($m)	-105	-152	-152	-124
35	-0.5	Economic Profit	($/MWh)	-2.0	-2.8	-2.8	-2
36	n/a	Chg in Resource Cost	($m)	132	60	-30	*loss*
37	n/a	Chg in Economic Profit	($m)	-77	-124	-124	*loss*
38	n/a	Chg Consumer Surplus	($m)	431	573	626	*gain*
39	n/a	Welfare Gain / Loss	($m)	354	449	501	*gain*
		*Within Qld conventional plant there is ~3% renewable market share (hydro, biomass)					

Note in Tab.5 as VRE rises from 20%-50% the welfare maximising outcome is 3000MW of coal plant dis-investment (Line 1, final column). Conversely, plant undertaking peaking duties (Line 3) rises by ~750MW. CO_2 emissions (Line 21) fall by 45% to 28.6mtpa. As VRE market share increases, 516GWh curtailment occurs, the equivalent to the annual output of a 210MW utility-scale solar plant spilling *continuously*. System Average Cost (Line 22) drifts upwards from \$52.2 (Base Case) to \$57.1/MWh (Scenario 5). And in spite of concerns to the contrary within the literature, peak load pricing in the energy-only market remains tractable – spot prices consistently clear within 3-5% of System Average Cost (Lines 22, 23) *provided* coal plant dis-investment follows an optimal path. The reliability constraint is satisfied (Line 25) when the fleet of flexible peaking plant adjusts. The progressive increase in renewables proves to be welfare enhancing with aggregate gains of \$501m at the shadow CO_2 price of \$25/t. Cumulative plant stock changes (Base Case v Scenario 5) are illustrated in Fig.12.

Figure 12: Change in aggregate plant stock to Scenario 5



6. The peak load problem and the tractability of energy-only markets

Section 2.2 noted an endless literature querying whether energy-only markets are capable of delivering tractable results vis-à-vis resource adequacy. The historic performance of Australia's NEM and modelling from Section 5 tends to suggest otherwise. Why the divergence? There are four important elements underpinning these results.

1. The NEM's Market Price Cap of \$15,000 – designed to deal with the peak load problem – has a tight nexus with the reliability constraint of 0.002%. Amongst the average of 100 iterations, the plant mix and (stochastic) generator outages evidently produced an adequate relative pattern of prices and VoLL events to substantially reduce economic losses and missing money (Tab.3-4, Line 24);

2. The NEM's Market Price Cap of \$15,000/MWh is amongst the highest in the world, and apart from Section 46 of Australia's anti-trust laws (vis-à-vis abuse of market power) there are no enforceable caps on generator offer prices. Many energy-only markets that changed to organised capacity markets had set VoLL too low, or, VoLL events were suppressed by administratively determined caps on generator offer prices, actions of System Operators, or interference by regulatory authorities[26]. In contrast, from 2015-2021 the Queensland region experienced 2,429 dispatch intervals where spot prices exceeded \$300/MWh (i.e. double peaking plant marginal running costs) and 391 dispatch intervals where spot prices exceeded \$7500/MWh;

[26] See in partocular Joskow (2008), Hogan (2013). Spees, Newell and Pfeifenberger (2013).

3. In each Scenario, the plant mix is in a state of long run equilibrium. Any merit order effects from VRE were therefore neutralised by the assumption of perfect plant dis-investment. In the real world, electricity markets are *rarely* in such an idealised state (de Vries and Heijnen, 2008; Hirth et al., 2016); and

4. Plant non-convexities were dealt with through limited negative generator offer prices (i.e. -$100/MWh). However, inflexible plant and VRE with no exppsure to spot prices can offer the floor of -$1000/MWh. Over the period 2015-2019 there were 75 dispatch intervals where spot prices cleared below -$100/MWh (and no -$1000/MWh events). However, from 2019-2021 solar PV output increased, there were 477 negative price events below -$100/MWh and 98 dispatch intervals where spot prices actually cleared at -$1000/MWh.

In the following sections, some of these critical assumptions are relaxed.

6.1 Imperfect dis-investment and merit-order effects

In the results which follow, coal plant capacity does not *adjust and exit* as rooftop solar and utility-scale VRE ramps up. That is, the entire coal fleet is assumed to remain in-service (modelled as a 'hard constraint'). Inflexible offer prices remain limited to -$100/MWh for minimum loads, and VRE plant continues to offers at $0/MWh. At this point, the otherwise *clean results* from Tables 4-5 begin to unwind due to merit order effects (see Tab.6).

Changes to the aggregate supply function are illustrated in Figure 13. These summary level supply curves have been drawn from three of the scenarios at 12pm, viz. the Base Case, the 50% VRE Scenario (where coal plant adjusts perfectly) and a merit order case which incorporates the 50% VRE plant stock with no coal exit. The arrows in Fig.13 illustrate how additional coal plant pushes the aggregate supply curve to the right.

Figure 13: Aggregate supply curves – Base Case, 50% VRE and No Exit

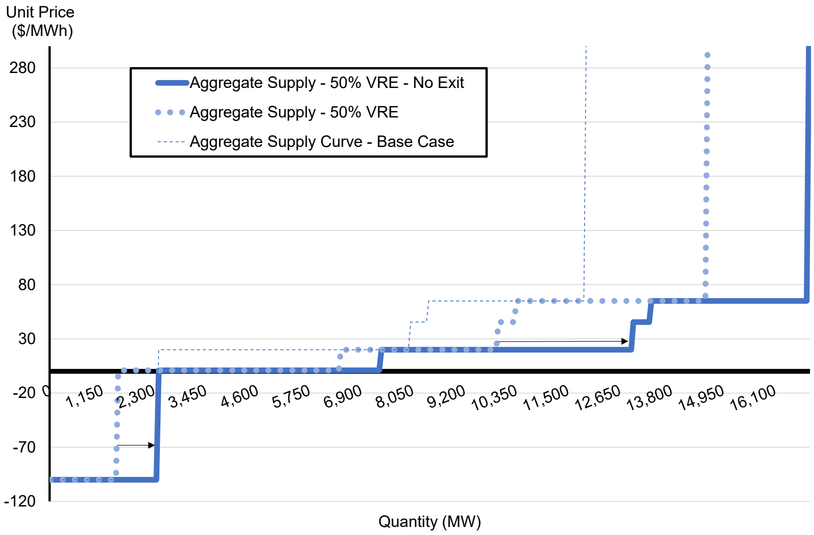


Table 6 results illustrate a heavily over-subscribed plant stock as VRE enters with all conventional plant remaining in service (Line 7). VRE plant face rising levels of curtailment (Line 19) with lost output the equivalent of a 545MW utility-scale solar plant (*cf*. 210MW, Tab.4). The most prominent impacts are sharply rising *utilisation effects*, and merit order effects. With a continuous build-up of plant, System Average Cost (Line 22) rises from $52.2 to $63.5/MWh (*cf*. $57.1, Tab.4), driven by higher fixed costs and *utilisation effects* (Höschle *et al*., 2017; Simshauser, 2020). Simultaneously, *merit order effects* of ~$10/MWh occur (Line 23) with spot prices falling to $41.2/MWh. This creates economic losses of ~$22/MWh (Line 35).

Aggregate producer economic losses of $1,206m per annum (Line 34) are material – and more than likely – financially perilous to marginal plants of all types.

Table 6: Merit order effects (no exit)

Line			Base Case (no Rooftop PV)	Scenario 2 (+ Rooftop Solar)	Scenario 3 +20% VRE	Scenario 4 +35% VRE	Scenario 5 +50% VRE	Base v Sc.5 Chg
	Installed Plant Capacity							
1	Coal	(MW)	8,000	8,000	8,000	8,000	8,000	0
2	CCGT	(MW)	400	400	400	400	400	0
3	OCGT	(MW)	3,500	3,500	3,500	3,500	3,500	0
4	Wind	(MW)	0	0	480	2,103	3,725	3,725
5	Solar PV	(MW)	0	0	1,425	2,777	4,129	4,129
6	Rooftop Solar PV	(MW)	0	4,430	4,430	4,430	4,430	4,430
7	Total	(MW)	11,900	16,330	18,236	21,210	24,185	12,285
	Generation Output							
8	Coal	(GWh)	56,301	53,215	48,922	41,129	34,340	-21,961
9	CCGT	(GWh)	589	283	165	62	28	-561
10	OCGT	(GWh)	872	304	170	55	23	-849
11	Wind		0	0	1,343	6,408	11,360	11,360
12	Solar PV		0	0	3,314	6,408	9,388	9,388
13	Rooftop Solar PV	(GWh)	10	4,294	4,294	4,294	4,294	4,285
14	Total Generation	(GWh)	57,771	58,096	58,209	58,356	59,433	1,662
	Market Statistics							
15	Maximum Final Demand	(MW)	10,461	10,521	10,534	10,549	10,569	108
16	Maximum Grid Demand	(MW)	10,461	9,859	9,871	9,886	9,905	-556
17	Final Energy Demand	(GWh)	57,762	58,096	58,164	58,248	58,356	594
18	Grid Energy Demand	(GWh)	57,762	53,802	53,869	53,954	54,062	-3,700
19	Constrained VRE	(GWh)	0	0	42	120	1,331	1,331
20	TREZ Constraints	(hrs)	0	0	176	156	56	56
21	Carbon Emissions	(Mt)	51.4	48.2	44.2	37.1	30.9	-20
	Market Prices & Reliability							
22	System Average Cost	($/MWh)	52.2	53.9	55.8	59.4	63.5	11
23	Spot Price	($/MWh)	51.7	45.8	44.7	43.2	41.2	-10
24	Number of VoLL Events	(#)	0.5	0.1	0.0	0.0	0.0	-0
25	Unserved Energy PoE90	(%)	0.000%	0.000%	0.000%	0.000%	0.000%	-0
26	Market Turnover	($m)	2,985	2,464	2,405	2,329	2,226	-759
27	Carbon @ $25	($m)	1,286	1,205	1,105	927	773	-512
	Resource Costs							
28	Coal	($m)	1,126	1,064	978	823	687	-439
29	Gas	($m)	84	33	19	6	3	-81
30	Fixed Costs	($m)	1,805	1,805	1,805	1,805	1,805	0
31	Utility-Scale VRE	($m)	0	0	203	570	938	938
32	Total Resource Costs	($m)	3,014	2,902	3,005	3,204	3,432	417
33	Producer Surplus	($m)	1,775	1,367	1,205	930	599	-1,176
34	Economic Profit	($m)	-29	-437	-599	-875	-1,206	-1,176
35	Economic Profit	($/MWh)	-0.5	-8.1	-11.1	-16.2	-22.3	-22
36	Chg in Resource Cost	($m)	n/a	113	10	-190	-417	*loss*
37	Chg in Economic Profit	($m)	n/a	-408	-570	-845	-1,176	*loss*
38	Chg Consumer Surplus	($m)	n/a	769	961	1,257	1,568	*gain*
39	Welfare Gain / Loss	($m)	n/a	361	391	412	392	*gain*

6.2 Negative price impacts

Thus far VRE offer prices were set to marginal running costs, taken to be $0/MWh. However, if VRE plant have *run-of-plant PPAs* with a strike price of ~$80/MWh, then such generators make a contribution to fixed costs whenever market prices exceed -$79/MWh. In practice, a large number of existing VRE plant in Australia's NEM offer at sub-zero prices for this purpose – to maximise profit. This is not a market design error, but a form of market imperfection (i.e. contractual error) by writers of PPAs, bearing in mind negative prices are an unloading price intended to ensure a secure system.

The impact of shifting VRE plant offers from $0 to -$80/MWh when coal plant fails to dis-invest increases the number, and intensity, of negative spot price events as VRE quantities rises. This is illustrated in Fig.14.

Figure 14: Merit Order Effect & Impact of negative offer prices

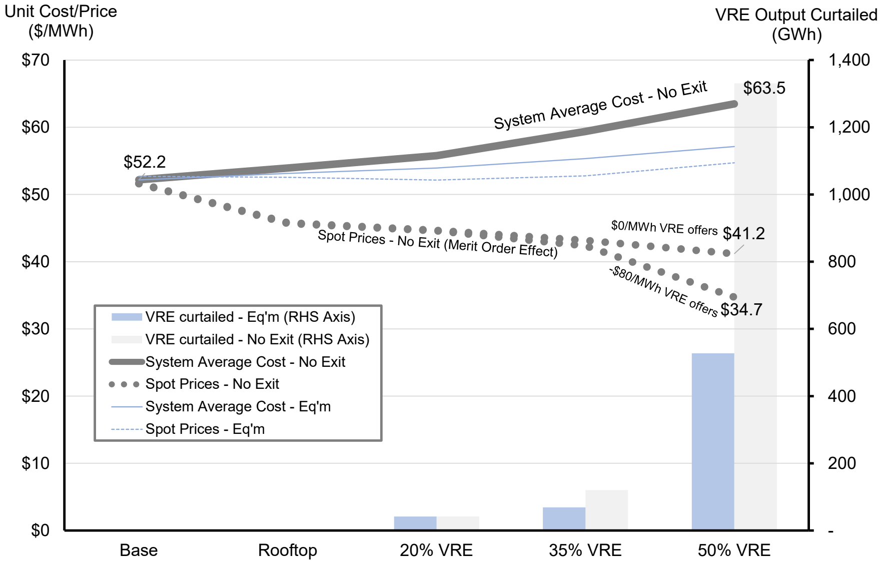


Fig.14 combines three data sets. The first is the benchmark data from Tab.4-5, represented by the thin blue line series (solid and dashed lines). Recall that because thermal plant dis-invests and adjusts seamlessly, the trajectory of system costs remains low, and peak load prices produce tractable results with VoLL at $15,000.

Second is cost/price data (thick grey line series) for the no dis-investment scenario drawn from Tab.6. This illustrates deteriorating average costs due to *utilisation effects*, and falling prices due to *merit order effects*. VRE offers are limited to $0/MWh.

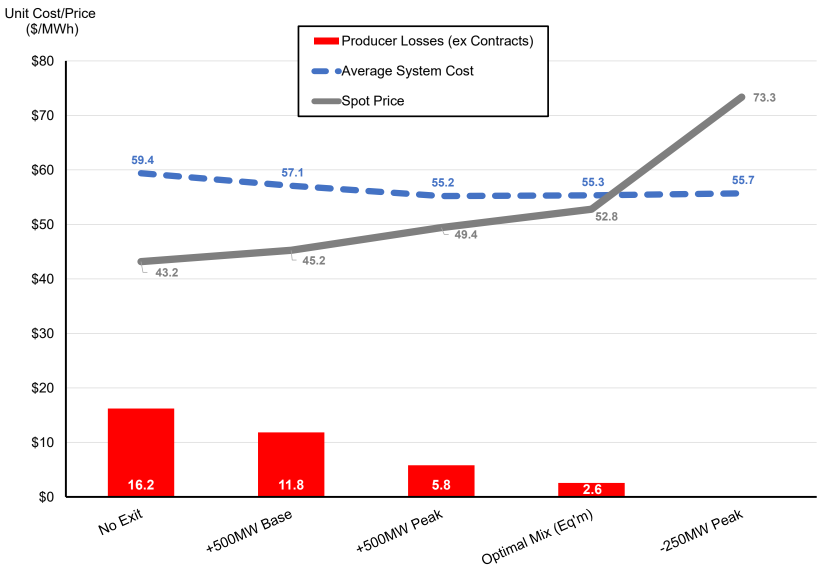
The final set of data incorporates -$80/MWh offer prices by VRE curtailment – and is only visible in the 50% VRE result. Here, spot prices deteriorate to $34.7/MWh if coal plant fails to dis-invest

To summarise, *merit order effects* are driven by two forces, i). imperfect coal plant dis-investment, and ii). the level of negative offers prices. As an aside, if VRE plant offer to the -$1000/MWh floor price the market becomes completely intractable.

6.3 Deviations from optimality

Maintaining a power system in a state of long run equilibrium with optimal plant is no doubt rare in markets of all designs because of the dynamic nature of the variables involved, viz. periodic demand is constantly evolving, plant is imperfectly available, entry and exit is indivisible (i.e. lumpy), with long lead times to construct, and the absence of inventories (Bidwell and Henney, 2004; Cramton and Stoft, 2006; de Vries and Heijnen, 2008; Roques, 2008; Hirth, Ueckerdt and Edenhofer, 2016; Simshauser and Gilmore, 2022). And in energy-only markets long run equilibrium is fragile, especially to undersupply. This is illustrated in Fig.15 using Scenario 4 (35% VRE) in which various deviations from optimality are presented.

Figure 15: Scenario 4 (35% VRE) plant stock sensitivities +/- base and peaking plant



Working from left to right in Fig.15, the first entry labelled 'No Exit' comprises 35% VRE and no coal plant dis-investment (see also Fig.14, 35% VRE data points) where System Average Cost is $59.4/MWh, spot prices are $49.2 and apparent producer losses are ~$16.2 (excluding any contract premia which may otherwise be earned from forward markets). Next is '+500MW Base' in which the optimal plant mix at 35% VRE is *weighed down* by an additional 500MW baseload unit, which produces Average System Costs of $57.1/MWh and losses of $11.8/MWh. Next is '+500MW Peak' whereby the optimal plant stock at 35% VRE comprises an additional 500MW of peaking plant mix. Axiomatically, 500MW of additional peaking plant has far lesser impacts on Average System Cost ($55.2/MWh) than 500MW of additional coal plant, and greatly reduces producer losses ($5.8/MWh). The final entry is '-250MW Peak' in which the optimal plant stock with 35% VRE is purposefully *undersupplied*. Note spot prices are *highly sensitive* to this and rise sharply with seemingly small underweight deviations owing to the market price cap of $15,000/MWh.

7. Policy implications and concluding remarks

Australia's NEM experienced an investment supercycle during 2016-2021 with ~24,000MW of renewable investments committed – 16,000MW of decisions made around Boardrooms tables, and 8,000MW around the *family kitchen table*. As Engelhorn & Müsgens (2021, p1) recently observed, VRE investment is a *'global megatrend'.*

This article examined rooftop solar vis-à-vis the peak load problem in the NEM's Queensland region. 4,430MW of installed rooftop solar capacity forms a non-trivial component of the Queensland aggregate supply function. The substantive finding is that at the household level, a mismatch exists between peak load and solar output. By comparison, abstracted to the whole-of-system level, Queensland's rooftop solar PV drives 1000MW ($1.35 billion) of utility-scale plant dis-investment in equilibrium, and perhaps surprisingly, 500MW of which is baseload plant. In the case of Queensland at the wholesale market level, rooftop solar has a positive impact on the peak load problem and proved to be welfare enhancing (setting aside subsidy costs).

Queensland's energy-only market was also *stress-tested* after introducing the rooftop solar PV capacity, and then augmenting this with a utility-scale fleet of solar and wind such that VRE market share reached 50%. Under equilibrium conditions, the energy-only market proved tractable given the NEM's VoLL of $15,000 and a reliability constraint of not more than 0.002% unserved energy. The addition of VRE was welfare enhancing for any shadow CO_2 price above $3.1/t.

There were important caveats, however. As VRE expanded through the modelling range, seamless coal plant dis-investment was crucial to maintaining a tractable equilibrium. And as coal plant was divested, peaking plant expanded in equilibrium. Section 6 showed any equilibrium was fragile – if coal plant dis-investment did not occur system average cost increased due to *utilisation effects*, and spot prices began to collapse due to *merit order effects*, with the net gap reaching $25/MWh in a c.$55/MWh power system. Importantly, the gap was not *missing money*, it was merely low prices due to structural oversupply.

Equilibrium conditions also presumed, critically, that coal plant non-convexities (i.e. minimum loads) were dealt with by generator offers of no less than -$100, and VRE plant was assumed to offer $0. In practice, this is not always the case. When these assumptions were relaxed in combination with plant exit frictions, merit order price effects were amplified with spot prices falling a further $7/MWh.

Whether an energy-only market design is a suitable and enduring format for a renewable transition is an open question. The weight of energy economics literature is, on balance, in favour of alternate market designs comprising capacity payments, *CfDs*, or some other form of administrative coordination. These alternate designs entail centralised decisions where consumers or taxpayers bear an elevated risk of heightened cost by comparison to an energy-only market design. And the energy-only market design is thought to elevate consumer reliability risks and accompanying price shocks. The fact that there is no uniform solution tells us this is a complex area.

Yet the energy-only market design contains many desirable features. Peak load pricing by way of a high VoLL provides a clear and unambiguous signal for performance at critical times. But the analysis above makes clear frictionless dis-investment is important, and, raises questions as to the viability of the NEM's negative price floor of -$1000/MWh. On the one hand it provides a strong signal for exit. On the other, if widespread *contract error* exists within VRE PPAs, it seems capable of de-stabilising the evolution of spot prices. This would seem an area worthy of further research.

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Appendix I: Load Duration Curves (Queensland 2020)