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# On the impact of government-initiated CfD's in Australia's National Electricity Market

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**Keywords** Variable Renewable Energy, Contracts-for-Differences, Hedge Contracts

**JEL Classification** D52, D53, G12, L94 and Q40

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# On the impact of government-initiated CfD's in Australia's National Electricity Market

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January 2019

*Abstract*

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## 1. Introduction

Australia's National Electricity Market (NEM) is an energy-only gross pool in which all generators bid into a central platform and are dispatched under a uniform first-price auction clearing mechanism. Being a mandatory gross pool, all generators must sell their output into the spot market, and energy retailers must buy all of their load from the spot market.

The volatility that accompanies organised electricity spot markets, particularly those with a high VoLL (NEM Value of Lost Load = AUD[1] $14,500/MWh) creates the conditions necessary for the emergence of, and active trade in, forward contracts. While there is an almost endless array of forward derivative instruments, the three primary contract types traded are fixed price swaps, $300 caps and increasingly, plant-specific Power Purchase Agreements (PPAs). Swaps and caps are traded both on-exchange and over-the-counter, and generally over a 1-3 year tenor with NEM forward market liquidity historically running at ~300% of physical trade – meaning that by the time each MWh is delivered it has, on average, been bought and sold 3 times over. There is of course considerable variation in liquidity by season, and by region. PPAs on the other hand tend to be long-dated (10-15 year), structured as run-of-plant instruments, and designed specifically to underwrite the entry of variable renewable plant (i.e. wind or utility-scale solar PV).

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[1] All figures presented in Australian Dollars. At the time of writing, AUD/US ~ 0.72 and AUD/GBP ~ 0.57.

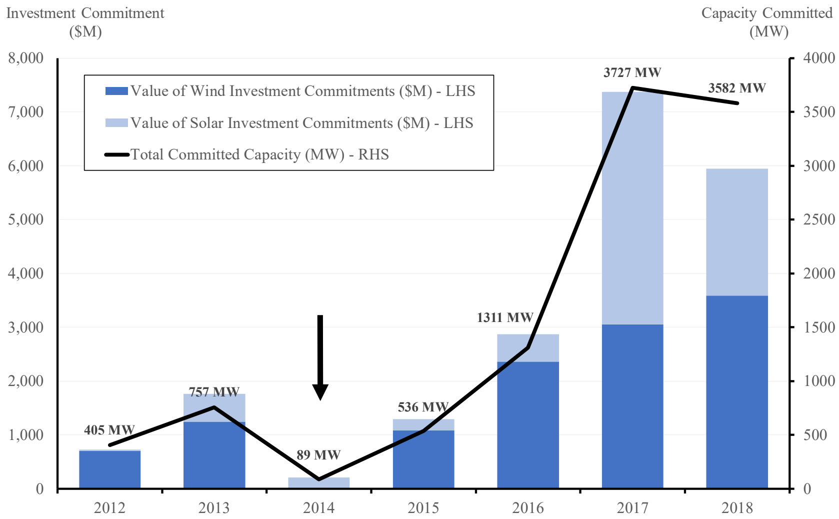
An intriguing characteristic of Australian energy market policymaking, and of NEM energy market research, is the almost exclusive focus on what can be loosely described as the spot market; viz. plant investment, supply, demand and spot prices. With the noteable exception of the *National Energy Guarantee* (which was grounded in the central role that the market for forward contracts plays), policy development displays a virtual disregard for, and of, the forward market. The irony is that forward contract prices form the *defining wholesale price input* to consumer tariffs.

At one level, a focus on the spot market and spot prices is understandable. Conditions in the physical system are enormously important given the necessity to match supply and demand in real-time, and the essential service nature of electricity supply. Spot markets are also comparatively easy to understand due to their transparency and link to real-time supply-demand dynamics. In contrast, the exchange-traded futures market and OTC derivative markets are little-understood, the array of derivative instruments is often described to the author as *'horribly complex'*, and while driving price transparency – forward market activity is ultimately characterised by anonymity and secrecy. To quote one of Australia's senior policymakers, 'you need an elementary understanding of economic principles to understand the spot market, and a Masters Degree in Finance to understand the derivatives market'.

But because consumer tariffs are derived from forward prices, policymakers cannot afford to ignore the potential unintended consequences of policy on the proper functioning of the power system's financial market. Poorly functioning forward markets increase operational risks facing incumbent market participants, produce excess contract price premiums, and can drive competition and investment activity below efficient levels – all of which may ultimately harm consumer welfare. The cessation of contract activity can adversely affect supply dynamics (i.e. barrier to entry or entry lags), and in the long run produce large cyclical swings in consumer prices. The political economy of large cyclical price swings generally invites further policy intervention, which can exacerbate investment continuity and consumer pricing.

Australia's NEM has experienced cyclical price swings due to a policy-induced malfunctioning of the forward market for contracts. For example, the Commonwealth Government's decision to review the Renewable Energy Target in early-2014, no matter how well intentioned, produced sufficient policy uncertainty as to result in the transient cessation of PPA activity. PPAs are an essential ingredient to Variable Renewable Energy (VRE) project commitment. Investment commitment data in Figure 1 clearly demonstrates this; notice the virtual blackout of investment commitments when the Renewable Target was subject of a formal review in 2014.

Figure 1: **Investment flows in VRE plant 2012-2018 ($M and MW)**




Source: BNEF

Given development and construction lags of 2-3 years, the unexpected downswing in VRE contract activity in 2014 and its adverse impact on investment flows meant that there was virtually no new renewable plant entering the NEM in 2016 and 2017. This relative deficiency of VRE plant entry against the Renewable Energy Target coincided with the sudden exit of Northern and Hazelwood coal power stations. Spot and forward electricity prices spiked to higher levels than would have otherwise been the case, and produced a simultaneous shortage in Renewable Certificates. Apart from harming consumer welfare, the elevated bundled price of electricity and renewable certificates, in my view, resulted in a period of VRE plant over-investment, tight construction market conditions, and elevated construction costs and premiums.

The implications of policy changes on forward markets matter, because there is a circular reasoning vis-à-vis spot and forward contract market prices, and consumer tariffs.

One response to Commonwealth climate change policy discontinuity and a lack of forward market liquidity for VRE plant entry has been the emergence of government-initiated Contracts-for-Differences (CfDs) undertaken at the State-level – first by the Australian Capital Territory (wind, 2015), then Queensland (solar PV, 2016), South Australia (semi-CfD for battery storage, 2017) and more recently Victoria (wind and solar, 2018).

Government-initiated CfDs are an interesting development (Wild, 2017). CfDs can play a legitimate role in dealing with energy market failures, specifically relating to missing and incomplete markets. As a policy mechanism they represent a means by which to deliver generation plant capacity that, for whatever reason, the market is failing to deliver. Government-initiated CfDs have the effect of diversify demand-side forward market liquidity and in doing so bring about certain short run benefits. Holding all else constant, CfDs also facilitate state development, and by adding new supply can reduce spot prices and $CO_2$ emissions.

But the use of government-initiated CfDs needs to be tempered by their adverse impacts on the proper functioning of the broader energy market. They should be used judiciously because, while they have the effect of diversifying demand-side forward contract liquidity, government CfDs simultaneously extract from supply-side contract market liquidity. As power system modelling later in this article demonstrates, undertaken at-scale, government-initiated CfDs have the potential to damage forward markets. Damaging liquidity can produce anti-competitive results by unintentionally foreclosing non-integrated (2nd tier) energy retailers, raise contract price premiums above the efficient level, needlessly force price-elastic Industrial (manufacturing) customers into unwanted spot market exposures, and harm overall consumer welfare.

The purpose of this article is to review the use and implications of CfDs on energy markets and is structured as follows. Section 2 provides a brief review of literature. Section 3 reviews government-initiated CfDs in practice. Section 4 introduces a partial dynamic equilibrium model of the NEM. Section 5 reviews Model results and Section 6 provides an assessment of policy implications. Conclusions follow.

## 2. Review of Literature

Hirth et al. (2016) noted that energy markets are never complete or free of market failures. One of the more prominent failures inherent in energy-only markets is their seeming inability to deliver the requisite mix of derivative instruments required to facilitate efficient and timely plant entry (Hansen, 2004; Chao, Oren and Wilson, 2005; Finon, 2008; Meade and O'Connor, 2009; Finon, 2011; Meyer, 2012; Nelson & Simshauser, 2013; Newbery, 2015, 2016; Grubb & Newbery 2018).

Long-dated contracts are a general pre-condition for the timely entry of project financed plant, and while Australia's NEM is noted for favourable forward market liquidity[2], the majority of activity spans only 1-3 years – well short of contracts that deliver optimal financing and facilitate timely and efficient ex-ante investment commitment. 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 (Newbery, 2006; Chester, 2006; Anderson et al. 2007; Howell, Meade & O'Connor, 2010[3]).

In the context of the energy industry CfDs (for transmission congestion) can be traced at least as far back as Hogan (1992). Government-initiated CfD's have been progressively gaining prominence amongst policymakers more recently (UK Government, 2015; Victoria, 2015; ACT, 2016; QRET Expert Panel, 2016; Commonwealth of Australia, 2018) and amongst academics (see Kozlov, 2014; Bunn & Yusupov, 2015; Onifade, 2016; Wild, 2017; Simshauser, 2018).

Government-initiated CfDs have generally arisen due to a combination of missing or incomplete markets, and form one of a number of policy mechanisms used by governments to meet a decarbonisation objective or reliability constraint (see for example Pollitt & Anaya, 2016; Simshauser, 2018). Typically, a government-initiated CfD will attempt to minimise the Levelised Cost of Electricity (LCoE) as a surrogate for maximising value to taxpayers. At one level the use of LCoE as a prime metric is understandable because forecasting market outcomes 10-15 years in advance is notoriously difficult. But 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 & Wiser, 2012; Edenhofer et al. 2013; Simshauser, 2018). That is, while the *physical* properties of electricity are largely homogeneous over space and time, from a *market* perspective there is rich price variation over time, space and lead time-to-delivery, making the traded commodity a heterogeneous good (Hirth et al. 2016).[4] The economic value of plant output is not identical and assuming otherwise introduces two biases; base plant is favoured over peak, and stochastic plant is favoured over dispatchable plant.

In real-time, the law of one price applies; stochastic output from wind and solar are good substitutes for thermal generation. However, each year there are 105,120 NEM dispatch intervals and associated spot prices (i.e. every 5 minutes) 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 (Hirth, 2013; Hirth et al. 2016; Simshauser, 2018).

Furthermore, as VRE technologies move from niche to material market shares, deployment success becomes a significant driver of market value which is amplified when thermal plant fails to exit (MacGill, 2010; Joskow 2011; Nicolosi, 2012; Mills & Wiser 2012; Hirth, 2013; Green & Staffell, 2016; Simshauser, 2018). High levels of Variable Renewable Energy (VRE) shielded by CfDs and priority-dispatched will initially place downward pressure on price (see Nelson et al. 2012; Joskow, 2013; Newbery, 2015; Simshauser, 2018). Given negligible marginal running costs, these so-called *merit-order effects* arising from policy-induced VRE plant entry became apparent in markets such as Germany as early as 2008 (Sensfuβ et al. 2008) and had been prominent in the SA region of the NEM (Forrest and MacGill, 2013; Cludius et al. 2014; Bell et al. 2015; Bell et al. 2017). Consequently, market values of incumbent VRE (and future) plant will be adversely affected from a stream

[2] See also Simshauser et al. (2015, Appendix 3 and Figure C.1 on p.54).
[3] See also Green, 2006; Finon, 2008; Simshauser, 2010; Howell, Meade and O'Connor, 2010
[4] Heterogeneous goods satisfy three conditions; (1) an inability to arbitrage (i.e. storage is costly); (2) no single efficient technology exists (e.g. in electricity planning there is typically an efficient combination of base, intermediate and peak plant); and (3) non-horizontal supply costs (e.g. electricity merit-order supply curves are always upward sloping). As Hirth et al. 2016, p.5) explain, *storage* links electricity in time, *transmission* links electricity in space and *flexibility* (i.e. balancing services) links electricity in lead-time.

continual entry through a combination of production 'correlation effects', 'merit-order effects' and 'price-impression effects' (Nicolosi, 2012; Hirth, 2013). However, such effects eventually unwind when thermal plant is forced to exit (Felder, 2011; Nelson et al. 2012). This set of market dynamics has implications for a wide-ranging program of government-initiated CfDs.

## 3. Government-initiated CfDs: motivation and application

The policy objective of government-initiated CfDs is to introduce generation plant that energy markets are failing to deliver. In this sense, CfDs have the effect of bringing forward future power projects to today, with the benefits, costs and risks of doing so allocated to taxpayers.

### 3.1 The policy motivation of CfDs

There are many reasons why government intervention is legitimately required in energy markets. As is well understood in economics, organised spot markets and their associated forward contract markets fail to internalise known externalities. For example, energy-only spot markets may undervalue reserve capacity until it is actually required. Energy markets also undervalue $CO_2$ emissions and will therefore only be produced at the efficient level by chance. And as with many markets, research and development is not valued; but this is compounded in energy markets because participants are unable to capture the benefits of a first-of-a-kind plant investment – in fact, the contrary is usually the case in that the market avoids costly mistakes of the first iteration of a new technology. Absent some form of government intervention, R&D will be under-supplied by the market.

Government-initiated CfDs can have the effect of "priming" a market by helping emerging technologies to overcome certain entry barriers. The Queensland Government's Solar150 program in 2016 awarded CfDs to four solar PV projects totalling 150MW at a time when solar PV struggled to compete with wind. The policy had the effect of kick-starting a wave of solar developments; by late-2018 a total of 1945MW of solar PV had been committed on-market. In South Australia, a policy to introduce a 100MW utility-scale battery for system stability similarly primed the market for storage – there are now 215MW of commissioned batteries, a further 155MW have reached financial close, and 1897MW under active development across Australia[5]. In short, while there are many policy mechanisms available to remedy energy market failures, CfD's are indeed a viable policy option.

### 3.2 How a CfD works, and why they work

In the classic case, a CfD auction will specify a particular technology (e.g. solar PV), output or rated capacity (e.g. 100 MW) and timing for delivery (e.g. able to reach financial close within 6 months of being awarded a long-dated CfD). The CfD is in turn a form of long-dated fixed price contract, usually expressed in $/MWh. In application, a CfD is a derivative instrument because payouts are referenced against spot prices. In a two-way CfD with a strike price of say $65/MWh, the contracting government (i.e. taxpayers) will pay the difference to the renewable project proponent whenever spot prices fall below $65, and the renewable project proponent pays the government whenever spot prices are above $65. CfDs are typically run-of-plant instruments such that difference payments only apply when the renewable plant is producing. Absent material plant failure, in which case some form of liquidated damages may apply, all volume and price risk is effectively transferred to the contacting government (taxpayers).

A government-initiated CfD overcomes missing and incomplete markets and crucially in the context of Australia, can successfully navigate carbon policy uncertainty because CfDs provide revenue certainty (i.e. virtual market immunity) to the power project owner.

Finally, because power projects are capital-intensive, the cost of debt and equity capital is an important driver of overall plant unit costs ($/MWh). The direct involvement of a government through long-dated CfDs greatly enhances the credit quality of power projects,

[5] Source data from BNEF.

and this enables higher levels of debt, a lower cost of debt capital, and makes the task of equity capital raising easier (and in turn, at lower risk premiums). Consequently, holding all other variables constant, by transferring the price, volume, policy and credit default risks of power projects to taxpayers, government-initiated CfDs are capable of producing a materially lower LCoE for entering projects.[6]

### 3.3 The impact of CfDs vs carbon pricing & renewable certificate markets

$CO_2$ emissions reduction policies ultimately seek to alter the plant stock in a way that reduces output from coal plant and increase output from renewable and cleaner (e.g. gas-fired) resources. Regardless of the policy mechanism used (e.g. cap & trade Emissions Trading Scheme, Emissions Intensity Scheme, carbon tax, Portfolio Standard, Clean Energy Target or government-initiated CfD), wealth transfers amongst producers occur. Carbon-intensive forms of generation are adversely affected, while low and zero emissions plant benefit from any explicit or implicit price on $CO_2$ emissions.

Government-initiated CfDs differ from broad-based market schemes (e.g. carbon prices or clean energy targets) because of the direct involvement of government in the transaction and the reallocation of market, credit and policy risks to taxpayers. Project bankers and the credit committees of Banks, which allocate scarce debt capital, have a very strong preference for long-dated government-initiated CfDs because from a credit perspective, there is virtually no risk of default. By contrast to conventional NEM-based Over-the-Counter market transactions, a government-initiated CfD re-orientates policy and credit risk away from demand-side energy market participants, and vests this with taxpayers.

Original Equipment Manufacturers (i.e. wind turbine suppliers, solar panel suppliers) and renewable project developers also prefer government CfDs because of the certainty of MW capacity to be delivered – at least in theory.

### 3.4 A wide-ranging program of CfDs

When deployed judiciously, the implications of CfDs are generally benign. In the case of the Queensland Solar150 program for example, any distortionary impacts arising from 150MW (0.4 GWh) of solar-based CfDs in a 10,000MW (54,000GWh) regional market would be hard to detect. Taxpayers have a collective financial exposure to CfDs that will ultimately prove to be out-of-the-money; but this needs to be balanced with other policy objectives (e.g. state development, subsequent economic and environmental benefits of the 1945MW of on-market solar PV projects that followed). But what happens when CfDs are not used to 'prime' a market, but rather, are used to replace the market; that is, replace broad-based market mechanisms to drive non-trivial (and non-market-based) entry?

Holding all else constant, so-called *merit-order effects* can be expected. That is, adding more supply, renewable or non-renewable, will reduce wholesale prices. But it will do this in the short- to medium run. Because the purpose, and effect, of the entry of VRE plant at-scale is designed to replace coal plant output, it will inevitably do so. Ultimately, the marginal coal plant will find it unprofitable, and will therefore exit. At this point, prices can be expected to rebound – and in the context of the NEM this is more than a theoretical observation. There is nothing inherently wrong with this policy objective, or the course of events that follows per se. But government-initiated CfDs undertaken at-scale can adversely impact the efficiency of the market (as distinct from 'priming' a market) for three reasons.

First, governments are remote from power system operations and power system contract and risk management requirements. Government-initiated CfD auctions are therefore typically based on simplified metrics such as LCoE, or a discriminatory price benchmark to accommodate technological variation in production or cost. But as the Literature Review in

[6] Of course, power project experience curves are downward sloping with the general rule of thumb being that for each doubling of global installed capacity, technology costs will fall by 20%. Consequently, delaying project commitment can result in lower prices. Exchange rates influence imported equipment costs, and steady project commitment (i.e. avoiding boom-bust development cycles) can also reduce construction risk premiums.

Section 2 highlighted, LCoE is a flawed metric and an overreliance on it in CfD auctions risks introducing an inefficient pattern of plant entry in a way that on-market transactions would have avoided. In contrast, broad-based market schemes like the *National Energy Guarantee* or a well-designed Clean Energy Target require market participants to focus not on the LCoE, but on the timing, location and market value of new plant output.

Second, government-initiated CfDs introduce quasi-market participants that, through the design of the CfD, are almost completely sheltered from the NEM's short and medium-run locational, spot and forward price signals – the primary signals relied upon by policymakers to the regulate system performance, system reliability, investment patterns and long run consumer prices. In contrast, on-market transactions by profit-maximising firms forces market participants to assess the relative pattern of entry, locational considerations, and the risks of inadequate or excess entry relative to policy objectives (on the presumption that policy objectives exist in the first place). Broad-based market schemes can therefore be expected to outperform a central buyer, and market schemes do this by accumulating a more optimal composition of assets and allocation of investment & market risks, reflecting the combination of physical power system requirements, policy-related constraints and the risk appetite of participants to the transaction.

Third, and by far the most adverse implication of a non-trivial government-initiated CfD program is the potential to damage forward markets. A wide-ranging policy of government-initiated CfDs instruments that form a progressively larger share of a forward market will ultimately damage the primary-issuance of hedge contracts, and therefore market liquidity. Following an 'initial loss' of liquidity, the exit of proprietary traders will drive a 'secondary loss' of market depth and liquidity, which is capable of culminating in a severe structural shortage of hedge contracts (i.e liquidity dropping below 100%). With demand for hedges exceeding supply, hedge contract premiums will be elevated, the most price-elastic (Industrial/manufacturing) customers will then be forced to accept some level of risky spot market exposure which invariably reduces manufacturing productivity, and in the final stages inadequate contract market liquidity may drive the exit of independent non-integrated retailers. In short, a *well-intentioned* wide-ranging program of government-initiated CfDs can raise forward prices above the efficient level, unintentionally disrupt manufacturing productivity, foreclose retailers and replace a well-functioning forward market with quasi-market participants who are indifferent to the outcomes facing market customers – all of which harms consumer welfare. How these shortages emerge can be demonstrated quantitatively, and this forms the focus of Sections 4 and 5.

## 4. NEMESYS-PF Model

In order to analyse the impact of government-initiated CfDs on forward markets, the NEMESYS-PF Model has been used. The model formally integrates a corporate & project finance model with a single-year dynamic partial equilibrium model of a template power system (see Simshauser, 2018). The dynamic power system partial equilibrium model is essentially a security-constrained unit commitment model with 30-minute 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 (indivisible) capacity that satisfies differentiable equilibrium conditions, with VRE output being exogenously determined (i.e. by way of policy). And as with Hirth (2013) the focus of simulations is half-hour resolution over a single year. Model outputs also include plant cost estimates for various generating technologies via a dynamic, multi-period post-tax discounted cash flow optimisation model which solves for multiple generating technologies, business combinations and revenue possibilities through simultaneous convergent price, debt-sizing, taxation and equity return variables. 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 Model logic is organised as follows:

### 4.1 **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, the generalised cost of entry $p^{i\varepsilon}$, unit Marginal Running Costs $v^i$ and total unit Fixed & Sunk Costs, $\varphi^i$.

$$\varphi^i = p^{i\varepsilon} - v^i\big|\left(v^i + \varphi^i\right) \cdot \rho_1^i \equiv R_1^i \tag{1}$$

These two parameters (i.e. unit Marginal Running Cost $v^i$ and unit Fixed and Sunk Costs $\varphi^i$) are key variables in the half-hourly power system simulation model, and are used extensively to meet the objective function. The derivation of entry cost $p^{i\varepsilon}$ and Marginal Running Costs $v^i$ are defined subsequently in Eq.7-24.

*NEMESYS-PF* orders plant capacity and dispatches the fleet of power generating units to satisfy security constraints and differential equilibrium conditions given specified plant options available.

In the power system, let *H* be the ordered set of all half-hourly periods.

$$n \in \{1 \ldots |H|\} \wedge h_n \in H \tag{2}$$

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

$$k \in \{1 \ldots |E|\} \wedge e_k \in E \tag{3}$$

Let $\mathrm{C}_k(q)$ 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.

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

$$i \in \{1 \ldots |\Psi|\} \wedge \psi^i \in \Psi \tag{4}$$

As outlined in eq.1, let $\varphi^i$ be the fixed operating & sunk capacity costs and $v^i$ be the marginal running cost of plant $\psi^i$ respectively. Let $\overline{\rho^i}$ be the maximum continuous rating of power plant $\psi^i$. Power plants are subject to scheduled and forced outages. $\mathrm{F}(n,i)$ is the availability of plant $\psi^i$ in each period $h_n$. Annual plant availability is therefore:

$$\sum_{j=0}^{|P|} F\,(n,i)\ \forall \psi^i \tag{5}$$

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

**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:

$$Obj = \sum_{n=1}^{|H|}\sum_{i=k}^{|E|}\int_{q=0}^{e_k} C_k(q)dq - \sum_{n=1}^{|H|}\sum_{\psi=1}^{|\Psi|}\left(O_{\psi^i} \cdot v^i\right) - \sum_{\psi=1}^{|\Psi|}\left(O_{\psi^i} \cdot \varphi^i\right) \tag{6}$$

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

## 4.2 Generalised entry cost estimates

Costs increase annually by a forecast general inflation rate (CPI). Prices escalate at a discount to CPI. Inflation rates for revenue streams $\pi_j^R$ and cost streams $\pi_j^C$ in period (year) *j* are calculated as follows:

$$\pi_j^R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^j \text{, and } \pi_j^C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^j \tag{7}$$

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

Energy output $\rho_j^i$ 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.

$$\rho_j^i = CF_j^i . k^i . (1 - Aux^i) \tag{8}$$

A convergent electricity price for the *i^th^* plant $\left(p^{i\varepsilon}\right)$ is calculated in year one and escalated per eq. (7).[7] Thus revenue for the *i^th^* plant in each period *j* is defined as follows:

$$R_j^i = \left(\rho_j^i . p^{i\varepsilon} . \pi_j^R\right) \tag{9}$$

As outlined above, 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 $\zeta^i$ needs to be defined. The constant term '3600'[8] is divided by $\zeta^i$ 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 $\rho_j^i$ and escalated at the rate of $\pi_j^C$.

$$\vartheta_j^i = \left\{ \left[ \left( \frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i \right) + \left(g^i . CP_j\right) \right] . \rho_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000} \right\} \tag{10}$$

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.

$$FOM_j^i = FC^i . k^i . \pi_j^C \tag{11}$$

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

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right) \tag{12}$$

---

7 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.

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

Capital Costs $\left(X_0^i\right)$ for each plant *i* are Overnight Capital Costs and incurred in year 0.[9] Ongoing capital spending for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i.\pi_j^C \tag{13}$$

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:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L+1-j}\right) \tag{14}$$

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

$$\tau_j^i = Max(0, \left( EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c) \tag{15}$$

$$L_j^i = Min(0, \left( EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c) \tag{16}$$

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:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i.S \end{cases} \tag{17}$$

$D_0^i$ 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:

$$P_j^i = \left(DT_j^i / \left[\frac{1-(1+(R_T^z+C_T^z))^{-n}}{R_T^z+C_T^z}\right] \middle| z \begin{cases} = VI \\ = PF \end{cases}\right) \tag{18}$$

In (18), $R_T$ is the relevant interest rate swap (3yrs or 7yrs) and $C_T$ is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the $j^{th}$ period $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

9 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.

$$I_j^i = DT_j^i \times (R_T^z + C_T^z) \tag{19}$$

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 $D_0^i$. This is determined by the product of the gearing level and the Overnight Capital Cost $\left(X_0^i\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable $\gamma$ 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).

$$if\ \gamma \begin{cases} = VI, Min\left(\frac{FFO_j^i}{I_j^i}\right) \geq \delta_j^{VI} \wedge Min\left(\frac{FFO_j^i}{D_j^i}\right) \geq \omega_j^{VI} \forall j \ \left| FFO_j^i = \left(EBITDA_j^i - x_j^i\right)\right. \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall j \ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i}\right| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases} \tag{20}$$

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

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \tag{21}$$

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 $\left(p^{i\varepsilon}\right)$ given expected equity returns $(K_e)$ whilst simultaneously meeting the binding constraints of $\delta_j^{VI}$ and $\omega_j^{VI}$ or $\delta_j^{PF}$given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$-X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.\rho_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{22}$$

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

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i \tag{23}$$

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

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i + (1-\tau_c).FOM_j^i + (1-\tau_c).\left(I_j^i\right) + P_j^i - \tau_c.d_j^i - \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i}{\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.\rho_j^i.\pi_j^R.(1+K_e)^{-(j)}} \tag{24}$$

## 5. Model results: implications of CfDs on the systemic security of the energy market

Salient features of the present modelling exercise are as follows.

First, there are five generation plant technologies available for deployment in the power system, including conventional (incumbent) coal plant, Combined Cycle Gas Turbines (CCGT), Open Cycle Gas Turbines (OCGT), and VRE plant, specifically wind and Solar PV. Incumbent coal plant and incumbent and new entrant CCGT & OCGT plant are all modelled as Balance Sheet-financings (gearing ca.30-36% to maintain BBB credit metrics). In contrast, all VRE plant in any scenario are assumed to be Project Financed (ca.65-70% debt) and underpinned by government-initiated CfDs. Table 1 sets out the technology assumptions and Table 2 outlines all relevant corporate and project financing assumptions and when combined, provide the inputs necessary to produce generalised estimates of Average Total Cost (including a normal profit). Crucially, there is no 'two-step pricing[10]' assumed with VRE plant – a strict annualised cost/price is used in all modelling.

Table 1: **Technology Assumptions**

| Technology | Capex | Installed Capacity | Generating Units | Unit Heat Rate | Unit Fuel Cost | Capacity Factor | Fixed O&M Cost | Variable O&M | Capital Works | Auxillary Load |
|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW) | (MW) | (MW) | (kJ/kWh) | ($/GJ) | (%) | ($/MW/a) | ($/MWh) | (%) | (%) |
| | | | | | | | | | | |
| Incumbent Coal | 1,486 | 1,000 | 2 | 10,000 | 3.00 | 50-90% | 50,500 | 4.00 | 0.25% | 7.1% |
| CCGT | 1,500 | 400 | 1 | 6,930 | 8.50 | 30-70% | 10,000 | 7.00 | 0.05% | 3.0% |
| OCGT | 1,050 | 500 | 2 | 11,300 | 9.00 | 1-10% | 7,000 | 10.00 | 0.05% | 1.0% |
| Wind | 1,975 | 450 | 118 | - | - | 39% | 45,000 | 3.00 | 0.05% | 0.0% |
| Solar PV | 1,550 | 100 | - | - | - | 26% | 30,000 | - | 0.05% | 0.0% |

Table 2: **Corporate Finance Assumptions**

| Coal & Gas | | | | Wind & Solar | | |
|---|---|---|---|---|---|---|
| Debt Sizing Constraints | | | | Debt Sizing Constraints | | |
| - FFO/I | (times) | 5 | | - DSCR | (times) | 1.35 |
| - FFO/D | (times) | 3 | | - LLCR | (times) | 1.35 |
| - Gearing Limit | (%) | 40.0 | | - Gearing Limit | (%) | 70.0 |
| | | | | - Default | (times) | 1.10 |
| Corporate 'BBB' Bond Issue | | | | Project Finance Facilities - Tenor | | |
| - Tranche 1 (Bullet) | (Yrs) | 5 | | - Tranche 1 (Bullet) | (Yrs) | 5 |
| - Tranche 1 Refi | (Yrs) | 13-20 | | - Tranche 1 Refi | (Yrs) | 13-20 |
| - Tranche 2 (Amort.) | (Yrs) | 7 | | - Tranche 2 (Amort.) | (Yrs) | 7 |
| - Notional amortisation | (Yrs) | 18-25 | | - Notional amortisation | (Yrs) | 18-25 |
| BBB' Bond Pricing | | | | Project Finance Facilities - Pricing | | |
| - Tranche 1 | (%) | 3.60 | | - Tranche 1 Swap | (%) | 2.55 |
| - Tranche 1 Margin | (bps) | 105 | | - Tranche 1 Margin | (bps) | 200 |
| - Tranche 2 | (%) | 3.97 | | - Tranche 2 Swap | (%) | 2.68 |
| - Tranche 2 Margin | (bps) | 129 | | - Tranche 2 Margin | (bps) | 220 |
| | | | | | | |
| - Tranche 1 | (%) | 3.60 | | - Tranche 1 | (%) | 4.55 |
| - Tranche 2 | (%) | 3.97 | | - Tranche 2 | (%) | 4.88 |
| - Tranche 1&2 Refi | (%) | 3.97 | | - Tranche 1&2 Refi | (%) | 4.88 |
| | | | | | | |
| - Post Tax Equity Coal | (%) | 12.0 | | - Post Tax Equity | (%) | 10.0 |
| - Post Tax Equity Gas | (%) | 12.0 | | | | |
| | | | | | | |

Second, the model has been populated with half-hour load data (using Queensland data from 2016) and from this, multiple scenarios are simulated with a demand elasticity of -0.10 applied to all cases. To keep modelling results tractable, the power system is modelled as a single, non-interconnected regional energy market. Furthermore, the level of government-initiated CfDs are exogenously determined and designed to achieve a certain VRE market share. A base scenario is calibrated with 0% VRE plant (i.e. the power system commences as

[10] Recent NEM transactions for renewables in the $50s/MWh appear to reflect either of i). unique sites with excellent resource and network connection characteristics; or ii). more commonly, what Simshauser & Gilmore (2018) have labelled "two-step pricing". With two-step pricing, a low cost 15-year PPA is written is written in the first period, and in the second period from project years 16-30 elevated prices are assumed to prevail. The combination of the low contracted PPA prices (years 1-15) and high expected future spot prices (years 15-30) appear to collectively meet threshold equity returns. The implication of two-step pricing is that Average Total Cost of such projects is higher than recent PPA pricing suggests. Based on our input assumptions, we find the Average Total Cost, levelized over 30 years, to be $62.50/MWh.

a thermal system with zero renewable plant), with scenarios spanning up to 40% VRE market share.

Consistent with Eq.6, the objective of the power system model is to minimise resource costs and maximise consumer welfare whilst meeting a reliability constraint of no more than 0.002% Unserved Energy. An overview of model inputs and certain model outputs which assist in understanding subsequent Results for the two bookend scenarios (i.e. 0% and 40%) are presented in Table 3.

Table 3: Overview of market modelling results

| VRE Market Share | | 0% | 40% | Chg |
|---|---|---|---|---|
| Energy Demand | (GWh) | 54,718 | 55,048 | 330 |
| Maximum Demand | (MW) | 9,118 | 9,277 | 159 |
| Demand Elasticity | | | -0.10 | |
| Reserve Margin | (%) | 11% | 11% | - |
| Plant Portfolio | | | | |
| - Coal | (MW) | 6,720 | 4,200 | -2,520 |
| - CCGT | (MW) | 400 | 1,200 | 800 |
| - OCGT | (MW) | 3,250 | 3,750 | 500 |
| - Wind | (MW) | 0 | 3,797 | 3,797 |
| - Solar | (MW) | 0 | 2,711 | 2,711 |
| Supply of Primary Hedges | (MW) | 9,100 | 7,900 | -1,200 |
| System Cost | ($/MWh) | $79.33 | $83.04 | $3.70 |
| Underlying System Price | ($/MWh) | $74.15 | $62.95 | -$11.20 |
| CO2 Emissions | (Mt) | 53.4 | 30.9 | -22.4 |
| Imputed Carbon Price | ($/t) | n/a | $20 - $25/t | |
| Unserved Energy | (%) | 0.001% | 0.000% | - |

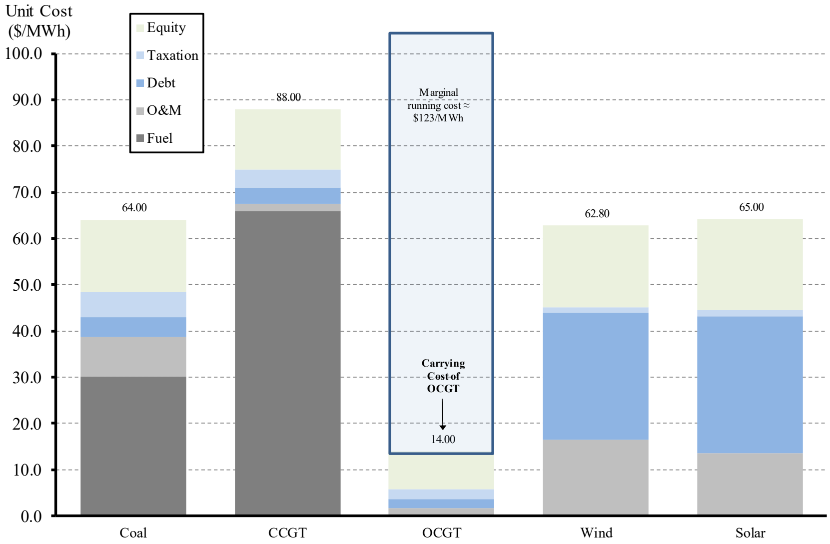
Note from Table 3 that the single-region power system has an initial final energy demand of 54,718GWh and maximum demand of 9,118MW. The opening plant stock is dominated by 6720MW of coal and in order to meet the reliability constraint (given plant outages) a reserve plant margin of ~11% is necessary. The power system has an average unit cost of $79.27/MWh and $CO_2$ emissions totalling 53.4Mt pa.

## 5.1 Model Results – plant cost estimates

The generalised Average Total Cost of incumbent and new entrant plant produced by the Model are presented in Figure 2. These data presented are essentially a high-resolution LCoE incorporating debt-finance and taxation variables. For example, in Figure 2 Incumbent Coal plant has a generalised Average Total Cost of $64/MWh comprising Fuel ($30/MWh), O&M ($8.71/MWh). Debt ($4.17/MWh), Taxation ($5.44/MWh) and Equity ($15.74/MWh). Note that the OCGT cost structure focuses on the 'carrying cost' of the capacity (at $14/MWh), and has a marginal running cost of $123/MWh (including Variable O&M). The data in Figure 2 are based on (static) capacity factors, but in NEMESYS-PF, plant costs arise on a dynamic basis with capacity factors[11] determined by market demand.

[11] VRE plant are generally priority dispatched in the model, but are subject to a minimum load constraint which binds as VRE market share approaches 40% or when coal plant fails to adjust and exit.

Figure 2: **Generalised entry costs**



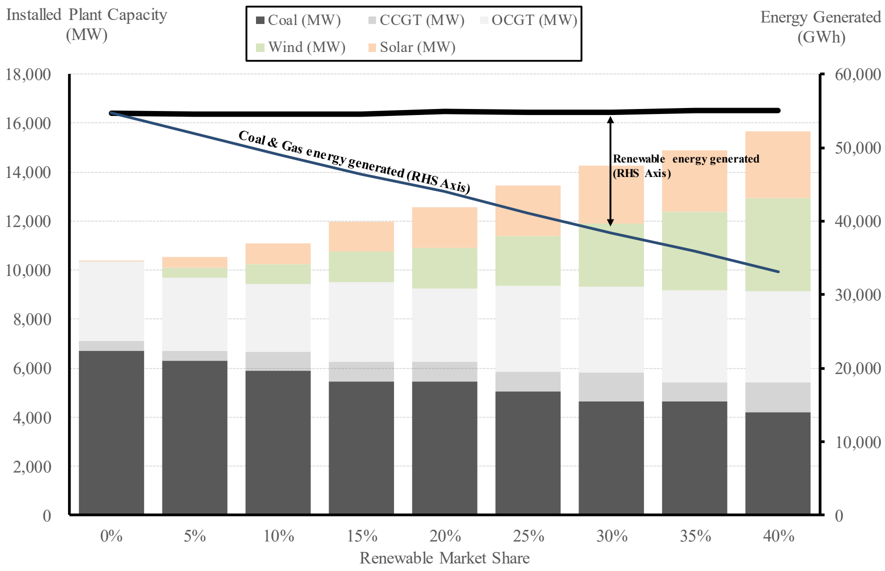

## 5.2 Model Results – power system spot market

Recall that the objective of the current exercise is to analyse the implications of a wide-ranging government-initiated CfD program on the functioning of the hedge market. To model a wide-ranging CfD policy, the installed capacity of wind and solar PV is exogenously increased such that the market share of VRE plant progressively rises to 40%. CfD's are assumed to be designed to minimise LCoE as this typically defines such programs, and as a result VRE technologies (i.e. wind and solar PV) dominate entry.

Given perfect entry, exit, exogenously determined levels of government-initiated CfD's to drive VRE market share, these are implicitly dynamic long-run scenarios measured by the time taken for the capital stock to adjust, rather than specifying a notional time period per se (see Hirth, 2013; Simshauser, 2018). As a result, the thermal plant stock is assumed to adjust perfectly in that VRE plant entry is accommodated by coal exit ('to make room' and in line with coal plant financial distress arising from forced entry), while CCGT and OCGT plant enter to ensure reliability constraints are met given the intermittent nature of wind and solar PV.

Figure 3 presents the dynamic supply-side adjustment given the CfD policy objective – in this instance a 40% VRE market share. Notice in Figure 3 that coal plant capacity (bar series, LHS axis) reduces from 6720MW to 4200MW. Coal-fired output (line series, RHS axis) reduces from about 50,000GWh to about 30,000GWh. Gas-fired plant increases; CCGT capacity commences at 400MW and rises to 1200MW while OCGT capacity commences at 3250MW and rises by a further 500MW. Consistent with the CfD policy objective, VRE plant increases from 0-40% market share with 2700MW of solar (15% market share) and 3800MW of wind (25% market share).

Figure 3: **Power system generation (LHS) and plant capacity (RHS)**




Given the model inputs outlined in Tables 1-3 and perfect plant entry and exit, NEMESYS-PF model results confirm the CfD policy objective can be met with the power system's spot market producing tractable results. However, what such modelling fails to reveal is a severe structural shortage emerging in the power system's financial market, viz. the forward market for hedge contracts.

## 5.3 Model Results – power system financial market

Identifying the supply of hedge contracts within a NEM region is inherently difficult because in a well-functioning power system financial market, there are cross-border trades, and, more than just asset-backed portfolio managers on the sell-side. Proprietary and non-asset-backed traders can add very substantially to market depth and liquidity.[12] The anonymity of trade makes this notoriously difficult to model, however.

Modelling the risk of structural shortages in a single region is an easier task. The reason for this is that proprietary traders, who add to forward market liquidity, 'do not appear out of thin air'. A necessary condition for proprietary trading is an inherent level of forward market liquidity to begin with. To be sure, if a market is illiquid, non-asset-backed traders cannot be relied upon to enter and make-up any shortfall. The reason for this is axiomatic; as Goldstein & Hotchkiss (2018) explain, holding-times of various securities is strongly correlated to market liquidity. That is, in an illiquid market, traders can be expected to close out positions, not open new positions. The reason proprietary traders exit illiquid markets or markets characterised by sharply falling liquidity is to avoid being caught with unwanted inventory.

Consequently, understanding the total primary supply (i.e. "primary issuance") of asset-backed forward contracts provides a basis for identifying inherent market liquidity. If the underlying supply or primary issuance of Swaps and Caps (nominally represented by coal and gas plant respectively) are sufficient relative to maximum demand, then the conditions necessary for trade at "multiples of physical" would appear to exist. Conversely, if an absolute shortage of primary issuance exists, then market liquidity is likely to remain below efficient levels (i.e. total turnover *less than 100%*, thus implying some positions are virtually "unhedgable") and proprietary trade is unlikely to materially alter suboptimal liquidity for the reasons outlined above.

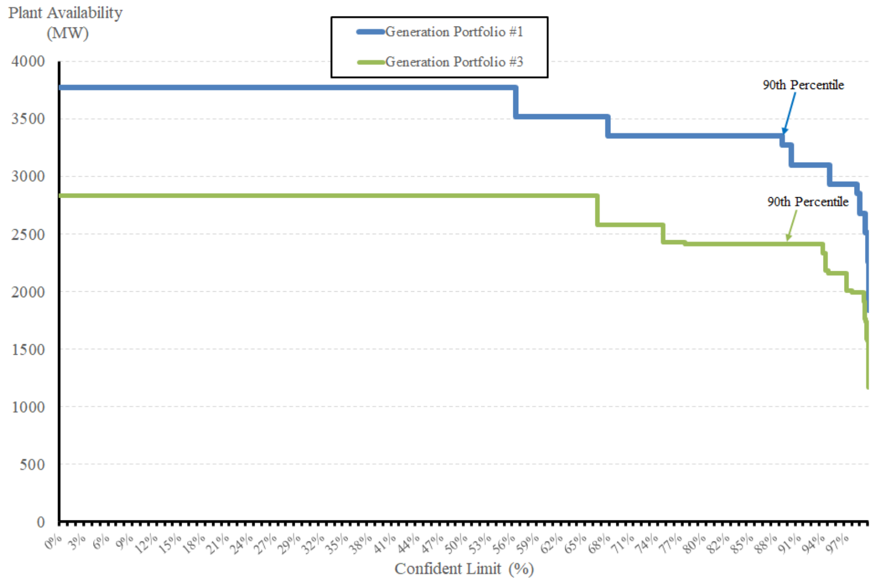
In the analysis that follows, the plant stock outlined in Figure 3 is separated into three rival generator portfolios comprising two large firms (~3750MW each) and one medium-sized firm

[12] The risk management of market exposures also arises from activity in tangential markets such as the market for weather derivatives. Such trade is not considered in this analysis.

(~2850MW). In the NEMESYS-PF model, individual generation plant availability is determined according to a stochastic binomial distribution with half-hour resolution given plant forced outage rates of ~5 - 6%. These generating unit-level data are then collated and assembled into joint probability duration curves for each of the three generator portfolios, and from there a 90th percentile Confidence Limit was identified as the maximum supply of asset-backed hedges, in a manner consistent with the methodology in Simshauser (2018). The modelled results that emerge are in turn consistent with the applied hedge market research findings contained in Anderson et al. (2007).

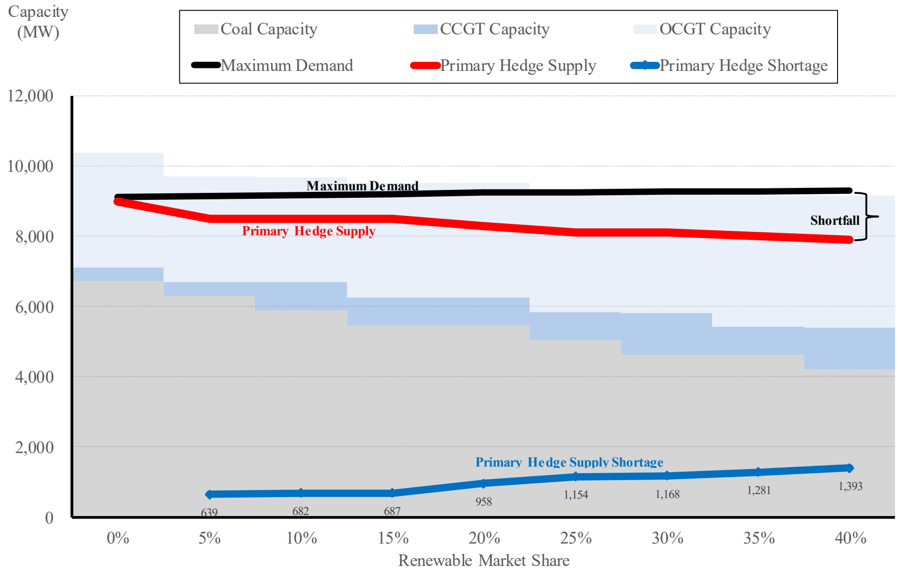
Results for Generation Portfolio #1 and Generation Portfolio #3 are presented in Figure 4. Notice that for the 3750MW Generation Portfolio #1 (and by implication, Generation Portfolio #2 which has an identical plant portfolio) the total potential supply of hedges at the 90th percentile is about 3300MW, whereas for the 2830MW Generation Portfolio #3 the total potential supply of hedges is about 2400MW.

Figure 4: **Primary supply of hedge contracts at 0% VRE Market Share**




In the model, as VRE plant enter via government-initiated CfDs, various coal generating units ultimately exit due to merit-order effects and financial distress. As coal plant exit, some level of gas-fired generation plant enters but as Figure 3 indicates, the overall coal and gas-fired fleet form a shrinking resource. Consequently, when the modelling process is undertaken for each of the three Generation Portfolios on a dynamic basis (i.e. as outlined in Figure 3 for VRE=0%..40%), primary hedge supply begins to contract, and this accelerates as VRE plant entry approaches 40%. This dynamic analysis is presented in Figure 5 and reveals a growing structural shortage of primary issuance hedge contract capacity:

Figure 5: **Primary supply of hedge contracts vs Maximum Demand (0-40% VRE)**




In Figure 5, the x-axis measures VRE plant market share, which has been exclusively facilitated by government-initiated CfDs (i.e. there are no on-market PPAs). The solid black line series depicts Maximum Demand given a demand elasticity of -0.10, and the solid red line series presents the combined primary hedge contract supply given VRE market shares from 0-40%. The gap between the black and red lines highlights the magnitude of any hedge shortfall, which is also represented by solid blue line series – culminating in a hedge market shortfall of almost 1400MW or 15% of final market demand at 40% Renewable Market Share. Note that even with a 5% Renewable Market Share , the impact of government-initiated CfDs produces a hedge shortfall *if* the thermal plant stock adjusts perfectly.

In Figure 5, the dynamic change in the conventional coal and gas plant stock is also captured by the area chart (grey for coal, dark blue for CCGT plant, and light blue for OCGT plant – and are essentially a reproduction of the data in Figure 3). In response to the wide-ranging policy of government-initiated CfDs, coal plant contracts from 6700MW to 4200MW, while CCGT & OCGT plant capacity expands by 800MW and 500MW, respectively. Note that overall there is a net loss of dispatchable plant, and when combined with the extraction of hedge contract capacity from government-initiated CfDs, combines and drives the shortage of primary issuance hedge contracts.

## 6. Policy implications of government-initiated CfDs

Are such contract shortages inevitable in a world of rising VRE market share? The short answer is *no*. The results in Figure 5 would look entirely different if VRE plant was able to provide its output, inspite of intermittency, into the hedge market by way of run-of-plant PPAs. Even with optimal levels of thermal plant exit and rising levels of VRE, the market may operate without concern because participants and portfolio traders are able to synthetically or physically reconstruct firm positions by combining run-of-plant PPAs with dispatchable plant, and rely on gains from exchange on a risk-adjusted basis.

But modelling in Section 5 explicitly rules out run-of-plant PPAs – CfDs make on-market investment risky. Instead Section 5 modelling assumes that VRE plant enters exclusively by way of government-initiated CfDs. Crucially, VRE projects cannot sell their output twice. Once a government initiates a wide-ranging program of CfDs, it will have the effect of adding capacity to the spot market which in the short run will lower prices and force coal plant out, but in the long run will extract 100% of the CfD plant output from the power system's financial market.

The quantitative analysis in Section 5 and Figure 5 in particular revealed that pursuing a wide-ranging program of government-initiated CfDs is likely to produce an 'unstable zone' in the hedge market. That is, while the spot market is consistently able to reach equilibrium for any level of VRE output up to 40% market share (given certain dispatch constraints), with government-initiated CfDs the forward hedge market becomes increasingly unstable and intractable as thermal plant exits and adjusts.

This is *not* a short run phenomenon. It is a long run problem (Hirth, 2013; Simshauser, 2018). If thermal plant fails to exit or thermal plant capacity remains above efficient levels, shortages in the hedge market may not appear. Indeed, in the short run government-initiated CfDs may well result in consumers benefiting from a surplus of hedge contract capacity (i.e. if thermal plant does not exit they are still available to supply hedge contracts), and short-run prices will be lower reflecting merit-order effects of adding VRE plant to the power system.

However, and to be clear, as coal plant exits the opposite occurs. Thermal plant must exit due to inevitable financial distress caused by VRE plant entry at-scale. And the exit of coal plant causes spot prices to rise once again. Furthermore, in such a scenario spot prices will rise just as hedge contract shortages appear; thus consumers would be unable to hedge against the very reason for hedging in the first place – viz. to hedge against the risk of sharply rising wholesale market prices. And in the modelling results in Section 5, the reason consumers cannot fully hedge in forward markets is because hedge capacity has been extracted through a wide-ranging program of government-initiated CfDs.

Hedge shortages in energy-only markets with a high VoLL are far more than theory. The South Australian (SA) region of the NEM was known to enter an episode of hedge contract shortages (i.e. hedge contracts < 100% of physical) in 2016 and 2017 when the final SA coal plant exited (i.e. Northern Power Station). The surprising sophistication, and level of energy market literacy now displayed by large Industrial customers in South Australia explains how the SA market adjusted. When hedge contract prices and premiums rose sharply, contract volumes and premiums were allocated across the SA power system given segment-level elasticities of demand. That is, prices in the residential consumer segment rose in line with elevated contract premiums. Through discussions with senior NEM policymakers and various Industrial customers in SA, it would appear that hedge market shortages were largely absorbed by Industrial customers, with a typical strategy being to secure some minimum level of hedging, and run the balance of manufacturing load to the spot market (while keeping a close eye on exposed load to pre-dispatch prices).

A wide-ranging program of government-initiated CfDs may adversely impact the residential and SME business market, however. The effect of extracting capacity from the hedge market will, in time, weigh heavily on retail competition. Large vertical retailers will continue to manage their position using a combination of physical plant and forward markets – and they generally have the financial capacity to allocate resources seamlessly between the two. But 2nd tier non-integrated retailers do not have the same financial resources and may in the event be inadvertently *foreclosed* by a wide-ranging program of government-initiated CfDs as financial market liquidity deteriorates. At this point, retail-level consumer pricing can also be expected to be adversely impacted.

At the extreme, unhedgable positions may introduce risks to the stability and systemic security of power market financial systems more generally. If a sufficiently large utility experienced financial distress due to excessive exposure to VoLL events because they were not able to allocate resources between physical plant and forward markets quickly enough, an unexpected financial distress event could lead to cascading failures across the power market economy; unlike Australian financial institutions which can access lender of last resort facilities with the Commonwealth Government, there is no centrally organised financial backstop in the NEM.

## 7. Conclusion

Used carefully, CfDs present policymakers with a reliable tool which can be used to overcome an array of market failures, including those associated with missing or incomplete markets (including emergency plant for security of supply reasons, certain positive or negative externalities including $CO_2$ emissions, R&D and externalities arising from first-of-a-kind commercialisation investments). In the NEM, CfDs have been used effectively by State Governments to 'prime' emerging markets, navigate Commonwealth Government policy discontinuity, with material on-market transactions following. The Australian Capital Territory government CfDs pioneered nominal-price transactions, the Queensland Government's CfDs led to more than 1900MW of follow-on solar PV projects, and the SA Government's semi-CfD for battery storage in response to an exit-induced Resource Adequacy market failure has since resulted in more than a dozen battery projects either under active development or commitment. From a project execution perspective, the effectiveness of CfDs are unquestionable.

But government-initiated CfDs must be used judiciously because they introduce 'quasi-market participants' who frequently do not respond to spot market signals per se, and do not participate in forward markets at all. Quasi-market participants are indifferent or substantially immune from future outcomes in spot and forward markets. This can result in plant entry that is poorly timed, poorly sized, poorly located and above all, poorly motivated to respond to the electricity and Frequency Control Ancillary Service spot price signals which keep the power system operating in a stable manner.

CfD plant also benefit from otherwise unachievable credit metrics owing to a taxpayer-financed and credit-wrapped CfD instrument – with the risks transferred to taxpayers. A wide-ranging program of government-initiated CfDs can therefore be expected to crowd-out on-market rival merchant/bilateral investments, and adversely impact prior market transactions and capital-heavy investments legitimately made in good faith by incumbent and independent generator and retailers in response to market (and other policy) signals. Used excessively, CfDs could damage investor market confidence in the NEM and at the extreme lead to a situation whereby *only* CfD projects become bankable.

The creation of the NEM was founded from the 'Hilmer Competition Reforms' of the 1990s, which amongst other things outlined the conditions by which government trading enterprises could compete with private firms on a level playing field. This required government owners to adjust borrowing rates of their trading enterprises to levels equivalent in the private-sector (with any premiums charged being returned to taxpayers) and creating a tax equivalence regime. The result was highly successful with more than $100 billion of private and public funded invested into the NEM and its network infrastructure.

Economics does not provide a basis for systematic conclusions on matters of equity and fairness – but introducing a wave of quasi-market-participants through government-wrapped CfDs, which have the effect of short- to -medium-run damage to recent past decisions of incumbent- and independent (including renewable-) market participants, does seem to introduce a legitimate query vis-à-vis procedural fairness.

If there is an upside to the present analysis, it is that the number of alternate policy instruments available to government to achieve policy objectives has expanded very rapidly (Peters 2002). A wide array of policy instruments exist to deal with the market failures which CfDs are intended to remedy; renewable energy policy objectives can be achieved by an emissions intensity scheme or well-designed Renewable Portfolio Standards[13]; the need for emergency capacity can be (and in the NEM recently has been) dealt with by establishing minimum exit notification periods for plant intending to exit the system; Resource Adequacy (i.e. adequate plant capacity including an appropriate reserve plant margin) can be maintained

[13] Australia's 20% Renewable Energy Target was lifted from 2% to 20% without considering the implications on system operations. See for example Buckman & Diesendorf (2010).

by ensuring the level of VoLL remains appropriate or by pursuing reliability options if this becomes necessary. All of these options work *with* the energy-only market design, including the forward market for contracts. CfDs, it would seem, ultimately work against it.

Throughout most of 2018, Australian policymakers developed a policy known as the *National Energy Guarantee* which had two embedded policy mechanisms for energy retailers to comply with; (i) an emissions obligation which was consistent with Australia's international $CO_2$ commitments under the Paris Agreement, and (ii) a reliability obligation which was consistent with the NEM's reliability criteria and was designed to ensure Resource Adequacy. The former was designed to encourage hedge contract activity with new renewable projects, and the latter was designed to be acquitted via ensuring adequate forward contracts were committed – both mechanisms were thus designed to add to liquidty rather than detract from it.

In contrast, as the quantitative results and analysis in this article explained, a *wide-ranging* program of *government-initiated CfDs* can be expected to impair market efficiency. While adding to demand-side liquidity, CfDs subtract from supply-side liquidity and this matters in loosely-interconnected energy markets because as coal plant exits, primary issuance hedge contract shortages become predictable. Shortages in the forward markets may harm consumer welfare by raising contract premiums – the primary input into consumer tariffs – and by forcing the most price-elastic Industrial customers into accepting spot market exposures, which at best disrupts manufacturing efficiency. Further, CfD-driven hedge market shortages may unintentionally foreclose non-integrated 2nd tier retailers – deeming such a program of government-initiated CfDs to be (unintentionally) anti-competitive. Consequently, the National Energy Guarantee or an equivalent suite of policies seems a better place for policymakers to focus on.

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