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The Forward Market Dilemma in Australia's National Electricity Market

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Abstract
Energy-only markets with high market price caps such as Australia's National Electricity Market are inherently volatile. As a result, the forward markets for hedge contracts are a crucial design feature which guide systemic stability and allow the adequate operation of competitive wholesale and retail markets. Hedge contracts have historically been sold by large thermal base, semi-base and peaking generators. However, as the electricity sector decarbonises and intermittent renewable market share rises, baseload thermal plant exit is predictable, and along with them, so does their hedge contract capacity - traditionally sold to energy retailers to mitigate volatile spot price exposures. Many governments are seeking to accelerate the entry of renewable projects through government-initiated Contracts-for-Differences, typically by way of auction. Because government is the counterparty, these contracts are essentially 'off-market'. This article analyses the potential for primary issuance hedge contract shortages as thermal plant exits and is replaced by renewable capacity underwritten via off-market CfDs. Results indicate structural shortages may materialise if off-market methods dominate plant entry. Conversely, when on-market Power Purchase Agreements contracts dominate or CfDs are actively recycled, shortages are largely eliminated.

Keywords: Energy-only markets; forward contract derivative markets; renewables.

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1. Introduction

Under the classic energy-only gross pool wholesale electricity market design, a core feature is liquid forward markets for contracts, traded either through standardised contracts over different time horizons, or via long-term Power Purchase Agreements (PPAs). On-market forward contracting is important. Hedge contracts provide the link between financial revenues for the financing of plant construction, place a natural limit on generator spot market behaviour (i.e. to manage contract positions), and form the basis for energy retailers to manage price risk associated with customer loads. To date, there has been thousands of articles examining electricity spot markets and associated prices. Curiously, very few articles investigate and model contract market fundamentals.

When electricity market reforms led to the separation of generation from retail supply, there was an increasing requirement for coordinated risk allocation – something vertical integration had previously solved internally. The need for coordinated risk allocation across electricity markets is how electricity derivatives evolved, to cover generation and retail loads (Hogan, 2016; Wilson, 2002). In the simplest form, contracts were sold by generators to energy retailers to mitigate the spot market exposures of both counterparties, providing upward price risk protection to retailers, and downward price risk protection for generators. Some level of vertical re-integration would often supplement forward markets, and in the Australian case, with no loss of liquidity (see Simshauser, 2021).

Globally, electricity markets are now going through a transition with the requirement to reduce carbon emissions. In Australia, the Commonwealth Government aims to reduce CO_2 emissions in part through decarbonisation of the electricity grid (Flottmann, 2024; Hudson, 2019; Nelson, Gilmore, et al., 2022; Nelson, Nolan, et al., 2022; Warren et al., 2016). In consequence, legacy coal plant in Australia's National Electricity Market (NEM) are being replaced by increasing quantities of wind and solar PV. In doing so, traditional forward contract sellers (coal generators) are being progressively removed from forward markets, whilst traditional contract purchasers (energy retailers) remain.

An emerging trend across the world's major electricity markets is the increasing amount of wind and solar plant (Variable Renewable Energy or 'VRE') being contracted through government-originated Contracts-for-Differences (CfDs). Government-originated CfDs provide VRE projects with certainty of revenues – typically at the Special Purpose Vehicle level – thus allowing developers to meet project finance hurdles. To summarise their effect, projects receive top-ups (subsidy) if spot revenues fall below a nominated price or revenue threshold, and reimburse government when spot revenues rise above certain setpoints (Billimoria & Simshauser, 2023; May & Marotti, 2014; Nelson et al., 2024 Welisch & Poudineh, 2020).

When a project enters into a government-initiated CfD, unless the design has been very carefully orchestrated, the VRE Special Purpose Vehicle may not then separately forward sell generation output through on-market contracts because this would involve selling plant output twice – once to the Government counterparty, and once to a forward market participant. In volatile markets such as Australia's NEM, this would represent an unacceptable financial risk to shareholders and project banks – the risk of paying out twice during surging price spikes would surely send the renewable project towards financial distress. In effect then, government-initiated CfDs successfully facilitate the entry of new renewable plant into the spot market, but simultaneously may extract the same energy from the forward market in the absence of very careful design.

In Australia, the Commonwealth and several State Governments have originated 6.5GW of CfDs by way of auction in the NEM (AEMO, 2024; ClimateChoices, 2023; DEECA, 2023, 2024; DES, 2020). The first was the Australian Capital Territory which contracted plant ~1200 MW, mostly in the non-adjoining South Australian region. Victoria (1430 MW) and Queensland (150 MW) soon followed.

New South Wales (NSW) has undertaken ~3000 MW with 1000 MW proposed and the Commonwealth Government released its Capacity Investment Scheme of 27,000 MW. Queensland, NSW and the Commonwealth appeared to identify the potentially adverse risks to forward markets. Queensland recycled its CfDs in forward markets almost immediately – noting that 150 MW in an 11,000 MW system is not material in any event. NSW and the Commonwealth have attempted to adjust the auction contract design to enable ongoing forward market participation. This adjustment allows cashflows associated with forward contract sales to be included within the government CfD mechanism. The Commonwealth scheme, for example, operates as a revenue collar which enables spot and contracted revenues in the settlement process. However, portfolio investments appear to be excluded (i.e. CfDs are undertaken at the Special Purpose Vehicle level). Furthermore, there is a more than trivial risk that the designs will still be seen as a fundamental hedge (i.e. a floor on returns) and therefore discourage trade in forward markets.

Government underwritten projects have been split relatively evenly between wind and solar PV (Figure 1). However, the vast majority of the NEM's renewable and firming plant capacity has been financed through utility and corporate PPA's, that is, on-market transactions.

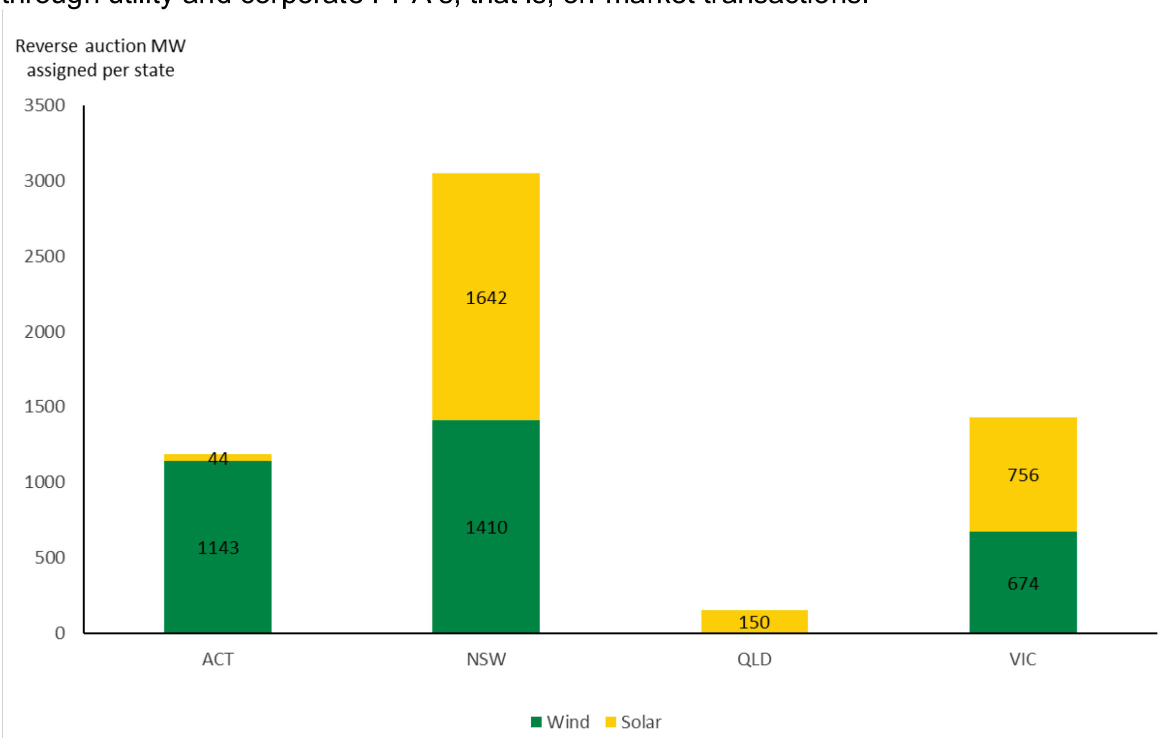

Figure 1: NEM reverse auction MW's assigned per state (note ACT is within NEM region of NSW and not all VRE capacity auctioned was within ACT).

Use of off-market government-initiated CfDs has thus far been relatively benign, exemplified by the comparative volume of on-market transactions. However, accelerating use of CfDs, intended to meet nominal renewable energy targets, raise questions with regard to the ongoing forward market depth, liquidity and capacity adequacy where governments – not energy retailers – become the dominant counterparty. The entities that serve end-use customers – energy retailers – could find themselves in an illiquid forward market with the result being progressive exit of second tier of rival retailers, and elevated tier one retail margins.

This article aims to assess whether baseload coal exit, driven by an increasing market share of VRE underwritten by off-market government-initiated CfDs could lead to shortfalls of 'primary issuance' hedge contract capacity – either due to perceived risks of paying out twice, or because the auction designs (by providing a floor on returns) unintentionally encourage spot market risk exposure by auction participants. Additionally, we seek to determine if certain regions of the NEM are currently experiencing, or are at risk of experiencing, hedge market shortfalls. Finally, we analyse which specific contracts would be most susceptible to shortfalls.

The balance of this article is structured as follows. Section 2 provides an overview of NEM spot and forward markets. Section 3 outlines methods and data used. Section 4 presents results for a generalised scenario which outlines how contracting levels are formulated. Section 5 presents the results for each mainland NEM region including the source of any shortfall. Policy recommendations and conclusions follow.

2. Overview of Australia's National Electricity Market

2.1 NEM spot market

The NEM operates on the eastern seaboard of Australia across six states and territories: Queensland, NSW, Australian Capital Territory, Victoria (VIC), South Australia (SA) and Tasmania. The Australian Capital Territory is included within the NSW region to make up the 5 market regions (Mayer & Trück, 2018). The regions are physically linked through interconnectors.

The mainland state with the largest market share of renewable energy is SA, with intermittent resources now exceeding 75%. SA regularly experiences over 100% renewables at times and must export excess electricity to neighbouring Victoria, curtail VRE production, or both. In comparison, Victorian electricity generation is made up of 40% VRE whilst still highly dependent on aging brown coal generators, gas-fired generation and inter-regional transfers to meet peak demand.

The rapid closure of coal power stations has caused problems for jurisdictional government electricity planning. For example, in 2016 SA's last coal generator (Northern Power Station) exited the market and was closely followed by the exit of large brown coal generator in the adjacent Victorian region in 2017 (Nelson, 2018). Combined, this resulted in elevated spot electricity prices across the NEM throughout 2016 – 2020.

NSW and Queensland have been slower in their transition with 32% and 29% of their current electricity generation sourced from renewables, respectively (McConnell et al., 2021). In both States, most of the current electricity demand is met by (ageing) black coal generators.

The NEM's spot market operates on a 5-minute basis with generators able to bid plant in or out of the market in real-time. The NEM's spot market has been studied extensively (see Anderson et al. (2007), Buckman and Diesendorf (2010), Leslie et al. (2020), MacGill (2010), McConnell et al. (2015), Rai and Nunn (2020), Simshauser (2018, 2020)). For the purposes of this research, three key facts related to NEM spot market operation are worth noting. The first is spot prices are extremely volatile, ranging from $17,500 to -$1,000 per MWh (Simshauser & Gilmore, 2020). The second is that, as a gross pool energy-only market design, all energy must first be sold into the spot market. And third, clearing prices are formed under a first-price auction mechanism (Leslie et al., 2020; Simshauser & Gilmore, 2022). Above all, market participants rely on forward markets to manage otherwise intolerable (gross position) spot market exposures (Boroumand & Zachmann, 2012).

2.2 Primer on electricity derivatives

The need for hedging in an energy-only electricity market arises from two interconnected factors. First, firms benefit from hedging as excessive volatility increases the risk of financial distress and may lead to suboptimal investment (Bessembinder & Lemmon, 2002). Second, energy-only markets with high market price caps are inherently volatile due to the nature of spot markets (Wilson, 2002). Apart from a few sophisticated industrial consumers, most market participants are either unaware of the 5-minute clearing process, or are unable (or unwilling) to respond to NEM spot prices. Energy retailers, who provide fixed electricity rates to consumers, are exposed to spot prices on the buy-side and face rigid limits to manage spot price risk (Anderson et al., 2007; Boroumand & Zachmann, 2012). On the other hand, as capital-intensive investments, generators are burdened with high fixed and sunk costs (including rigid debt repayment schedules) meaning they also face limits to spot price exposures – boards and banks invariably require some limited level of predictable revenue. Given mirror-image risks of retailers and generators, there are clear incentives provided in the market for energy retailers (on behalf of consumers), and generators to hedge the price paid or received for their electricity in on-market transactions.

For generators, good hedging practices provide more certainty over revenue, costs and margins (Deng & Oren, 2006). It has been shown that a generator's behaviour in an electricity market can greatly depend on the competitiveness of the market in which it is participating, and their level of hedge commitments (Hesamzadeh et al., 2020). At a simple level, generators have an incentive to hedge portfolios to provide a level of certainty over their revenues to avoid being exposed to prices that fall below marginal running costs, and over time, total cash costs including financing costs (Wolak, 2000).

From a generator's perspective, noting spot market transactions are mandatory for all output under a gross pool design, three theoretical options are available to manage forward price risk, 1). remove all risk by selling output under a run-of-plant PPA, 2). sell some percentage of plant output using a run-of-plant PPA or a mix of conventional derivative contracts to hedge the price of electricity through the forward markets, or 3). retain 100% exposure to the spot market (the latter being atypical) (Anderson et al., 2007; Flottmann et al., 2022). Each option comes with different risks and implications to the seller of contracts. A PPA provides the highest certainty of revenue and is generally preferred by developers and banks for project finance.

A current trend in Australia's NEM for renewable projects is ~75% PPA coverage and by implication, 25% merchant or spot market exposure (see Flottmann et al. 2022; Gohdes et al. 2022, 2023; and Simshauser, 2020). In contrast, derivative contracts require plant to take on volume risk, which are otherwise covered by PPAs (Flottmann et al., 2022; Simshauser, 2018, 2020). A portfolio of derivative contracts is the standard position of the thermal fleet, and in some instances have been combined with renewable portfolios (see Simshauser, 2020).

Energy retailers face the inverse risk to generators whereby good hedging practices mitigate exposure to financial distress brought about by highly volatile spot prices. This typically involves hedging forecast customer load and using a mixture of contracts depending on load flex and weather dependence (Anderson et al., 2007; Boroumand et al., 2012). Typically, energy retailers pass on the costs associated with hedging to consumers. Therefore, if hedging costs were to increase (e.g.. higher contract premiums due to lack of liquidity), the higher prices would be passed on to customer retail bills (Flottmann et al., 2024). It is ultimately the consumer who is most impacted by access to contract liquidity, and an energy retailer's ability to adequately hedge a given customer load.

The dominant derivatives traded in the NEM are (1) Swaps and (2) $300 Caps, in both on-exchange and over-the-counter formats. Electricity Swaps are similar to financial markets swaps of all kinds. An electricity Swap enables the holder to pay a fixed price for a (nominal) set quantity of electricity regardless of the spot price for a specified time period whilst the receiving party pays the spot price (Deng & Oren, 2006; Hepperger, 2012). In the NEM, Swap contracts provide price certainty for up to 3 years (i.e. the approximate length of the NEM's liquid forward market) and is therefore frequently used as a tool of risk management by baseload generators. Electricity Swap prices are mean-reverting (Simshauser & Gilmore, 2022) and in equilibrium should (historical) reflect entry costs of base load plant.

A $300 Cap contract is an option contract which – as the name suggests – places a Cap of $300 on spot price exposures for purchaser. A Cap contract requires the seller to compensate the purchaser every time the spot price goes above the Cap price level for the specified volume and in return the seller receives a payment of a premium. Consequently, the market for $300 Caps is the (energy-only) NEM's equivalent of a forward capacity market as they are perfectly suited to peaking plant. Indeed, the traded price of $300 Caps in equilibrium reflects the entry cost of an Open Cycle Gas Turbine plant undertaking peaking duties (see Simshauser, 2020).

In the present analysis, our task is to model the primary issuance or 'fundamental market supply' of Swaps and $300 Caps in each of the NEM's main zonal markets of Queensland, NSW, Victoria and South Australia – with and without government-initiated CfDs – in order to examine whether forward market shortages are predictable. This leads us to our model and associated data.

3. Models and Data

To adequately determine the impact of exiting thermal generation on the existing supply of 'primary issuance' hedge contract capacity within an energy only market, a power system simulation model known as NEMESYS has been used. The present model replicates that used in Simshauser (2018, 2019) but in expanded form to cover all NEM mainland zones. The model is a security constrained, unit commitment model with 30-minute price formation based on uniform first price auction clearing mechanism, consistent in the NEM. NEMESYS assumes perfect competition, a copperplate transmission system and perfect ramp rates with free entry & exit such that the market may install any combination of differentiable capacity required to satisfy equilibrium conditions. The modelled system begins with thermal plant only (i.e. coal and gas). We then introduce VRE progressively with the thermal plant stock adjusting accordingly, with coal plant exiting and gas turbine plant increasing as required to ensure reliability constraints are met.

Two scenarios are run in the first instance using the NEM's Queensland's region to tune the model. The first scenario examines a VRE buildout with government-initiated CfDs and no recycling of auction contracts. Our second scenario then examines a 100% CfD recycling scenario (essentially seeking to replicate the work in Simshauser, 2019). We then expand the sequence and findings by examining multiple regional markets simultaneously (i.e. the remaining mainland NEM jurisdictions).

3.1 NEMESYS model logic

Generation technologies and associated plant costs are essential inputs to a unit commitment model. To get optimal results unit marginal running costs ν^i and plant fixed costs φ^i are key inputs. The model logic has been derived from Simshauser (2019) with modifications and will be outlined within this section.

An entry cost model derives generalised generation technology average total costs $p^{i\varepsilon}$ and total revenues including profit R^i for a set output o^i.

$$\left(\nu^i \times o^i\right) + \varphi^i \equiv R^i \,|\, R^i = p^{i\varepsilon} \times o^i, \tag{1}$$

The model orders plant capacity according to strict merit order based on marginal running costs and dispatches them subject to the specified security constraints and differential equilibrium conditions.

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 $C_k\ (q)$ be the valuation that consumer segments are willing to pay for quantity q MWh of power. NEMESYS assumes demand in each period n is independent of demand in other periods. Let q_{nk} be metered quantity consumed by customer e_n in each period h_k expressed in MWh. Let Ψ be the set of existing installed power plants and available augmentation options for each relevant scenario.

$$i \in \{1 \ldots |\Psi|\} \wedge \psi^i \in \Psi, \tag{3}$$

As outlined in Equation (1), let φ^i be the fixed operating and sunk capacity costs and v^i be the (unit) marginal running cost of plant ψ^i respectively. Let o^i be the maximum continuous rating of power plant ψ^i. Power plants are subject to scheduled and forced outages. F(n, i) is the availability of plant ψ^i in each period h_n. The outage rate profile F(n, i) is calculated using a randomised integer between 0 and 1, if the integer is greater than the outage rate a unit is in-service if less than the outage rate the unit is considered unavailable.

Annual plant availability is therefore:

$$\sum_{j=0}^{|P|} F(n,i) \, \forall \, \psi^i, \tag{4}$$

Let o^i_n be the quantity of power produced by plant ψ^i in each period h_n.

The objective function seeks to maximise producer and consumer surplus, which is given by the integral of the aggregate demand curve less power production costs.

$$Obj = \sum_{n=1}^{|H|} \sum_{i=k}^{|E|} \int_{q=0}^{e_k} C_k(q)dq - \sum_{n=1}^{|H|} \sum_{\psi=1}^{|\Psi|} \left(o_\psi \cdot v^i\right) - \sum_{\psi=1}^{|\Psi|} \left(\varphi^i\right), \tag{5}$$

subject to

$$\sum_{i=1}^{|E|} q_{kn} \leq \sum_{\psi=1}^{|\Psi|} o_{\hat{\psi} i} 0 \leq o_n^i \leq F(n,i) \hat{}\, 0 \leq o_n^i \leq \overline{o^\iota}. \tag{6}$$

A full list of model inputs can be found in Table 1.

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Table 1: Model input symbols and definition.

Symbol	Definition
n	Number of half hourly periods
i	Number of scenarios
ν^j	Marginal running costs
φ^j	Fixed costs
$p^{i\varepsilon}$	Generalised technology long run cost
R^i	Total revenues including profit
o^i	Output
H	Half-hourly periods
E	Electricity consumers
C_k	Valuation that consumer segments are willing to pay
q	Quantity
q_{nk}	Metered quantity consumed
Ψ	Existing installed power plants
F(n, i)	Annual plant availability

3.2 Model inputs

The important features utilised in the model are outlined as follows: five generation technologies may be deployed in the power system including incumbent black coal plant, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT) and VRE (wind and solar PV). Thermal plant is modelled using generalised entry costs whilst VRE is assumed to be project financed and underpinned by government-initiated CfDs.

Plant and technology cost assumptions are illustrated in Table 2 with financial parameters following Aurecon (2023) and emission estimates from Elliston et al. (2014). To simplify the modelling process in regional scenarios, capital costs are held constant while plant size, unit fuel costs, wind and solar traces, and load curves are representative of each of the four zonal markets. Variation in plant sizes reflects the average for each region or zone.

Once combined, these data provide all the necessary inputs to produce generalised estimates of Average Total Cost for incumbent coal plant and generalised entry costs for new entrant plant including CCGT, OCGT, wind and solar PV. These are then utilised within the NEMESYS model logic to produce the optimal plant mix.

Table 2: Plant cost assumptions

Technology	Capital cost	Unit size	Variable O&M	Fixed O&M	Useful life	Heat rate	Fuel cost	Auxiliaries	Emissions
	($/kW)	(MW)	($/MWh)	($M pa)	(Yrs)	(GJ/MWh)	($/GJ)	(%)	CO_2 t/MWh
Coal	4,680	450	4.46	25.364	30	9	3	0.96	0.8
NGCC	1,950	400	3.9	4.624	25	7	8	0.98	0.4
OCGT	1,040	250	7.7	2.705	25	12	12	0.99	0.76
Wind	2,875	480	-	12.7	30	-	-	0.97	-
Solar	1,200	200		2.5	30	-	-	0.97	-

Source: Aurecon (2023)

4. Model results – general contract market

The NEMESYS model described in Section 3 was initially populated with plant costs from Section 3.2 and half hour load data derived from a random year of power system aggregate final demand from the Queensland region of the NEM. We assume an own-price elasticity of demand of -0.10 for modelling purposes, in line with the assumption contained in Simshauser (2018, 2020).

To keep results tractable, a single non-interconnected Queensland power system is modelled. The level of VRE within the system is exogenously determined to achieve a certain market share in line with current Australian Commonwealth & State government policy objectives. The QLD scenario commences with a fleet of thermal plant stock and 0% VRE, and progressively iterates to 60% VRE market share. An overview of Queensland model results is presented in Table 3.

Table 3: Overview of key model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	54,574	56,270	1,696
Maximum Demand (MW)	9,369	9,660	291
Plant Capacity			
Coal (MW)	5920	2,220	- 3,700
CCGT (MW)	800	1,800	1,000
OCGT (MW)	3740	5,780	2,040
Wind (MW)	0	8,191	8,191
Solar (MW)	0	5,459	5,459
Supply of Primary Hedges (MW)	9,350	8,720	- 630
Underlying System Price ($/MWh)	96.2	75.1	- 21
Unserved Energy %	0.001%	0.001%	

The results reflect an initial maximum demand of ~9,400 MW (0% VRE) and following a rise in VRE to 60% market share, maximum demand rises to ~9,700[1] following the fall in unit prices. The opening plant stock in the base scenario is predominantly coal plant, and at ~5,900 MW accounts for 57% of capacity in the system. A reserve margin to account for plant outages equates to ~11% noting that unserved energy of 0.001% remains within the NEM's stated reliability criteria of <0.002%.

[1] A sensitivity was conducted with stagnant demand. The results indicated a slight improvement in magnitude of contract shortfalls but it did not materially change the results. In summary, the problem we have identified is inherently structural.

To meet a 60% VRE market share, ~5,500 MW of solar and ~8,100 MW of wind are added to the aggregate plant stock, and under optimal conditions in equilibrium, -3,700 MW of coal plant exits the market. To maintain system reliability, +1,000 MW of new CCGT and +2,040 MW of OCGT plant is added to the plant stock.

CCGT and OCGT plant exhibit annual capacity factors (ACFs) of 51% and 10% respectively at 0% VRE market share, which fall to 40% and 7% at 60% VRE market share. It is important to highlight that mid-merit and peaking plant have been modelled as CCGT & OCGT but could also comprise some level of pumped hydro or battery storage. For the purposes of modelling forward contracts, non-duration limited CCGT & OCGT plant were used. In this way, modelling provides an indication of maximum contract volumes which may be offered to the market under optimal conditions as CCGT & OCGT plant are not theoretically limited in operational run-times in the same way pumped hydro and battery plant may be.

4.1 Queensland scenario contract market results

In the Queensland scenario, the quantity of 'primary issuance' hedge contract capacity from the thermal generation fleet needs to be determined. For this purpose, we rely on the methodology in Simshauser (2019) – which in turn is broadly consistent with the findings in Anderson et al. (2007). To summarise, this involves a Monte Carlo-based simulation of coal and gas turbine availability and identifying the 90th percentile result for a given portfolio of generation plant (see Fig.2). Queensland's 10,500MW opening plant stock (from Table 3) has been nominally split into three rival (and diversified) generation portfolios, designed to replicate market conditions in Queensland (which has three large portfolio generators, albeit with a number of fringe generators). The three modelled portfolios are clearly identified in Table 4 for both 0% VRE and 60% VRE market shares.

Table 4: Portfolio capacity and change in capacity for dispatchable units

VRE Market Share		0%	60%	Change
Portfolio 1	Coal Capacity (MW)	2200	740	-1460
	CCGT Capacity (MW)	400	600	200
	OCGT Capacity (MW)	1360	2040	680
	Total	3960	3380	-580
Portfolio 2	Coal Capacity (MW)	1850	740	-1110
	CCGT Capacity (MW)	200	600	400
	OCGT Capacity (MW)	1190	1870	680
	Total	3240	3210	-30
Portfolio 3	Coal Capacity (MW)	1850	740	-1110
	CCGT Capacity (MW)	200	600	400
	OCGT Capacity (MW)	1190	1870	680
	Total	3240	3210	-30

In the base or '0%' VRE market share scenario, Table 4 notes the first generator portfolio commenced with 3,960 MW of installed capacity, and the two remaining portfolio had 3,240 MW each. As outlined above, the Monte Carlo-based plant availability duration curves were constructed in a similar manner to Simshauser (2019), with the 90th percentile[2] used as the hedging 'setpoint' and is illustrated in

[2] A sensitivity of traditional N-1 hedging strategy was also conducted. The results showed an increased decline in primary issuance hedge contract shortfalls.

Figure 2. Note from Fig.2 the supply of hedges from Generator 1 equates to ~3,600MW, and ~2,700MW for Generators 2 and 3.

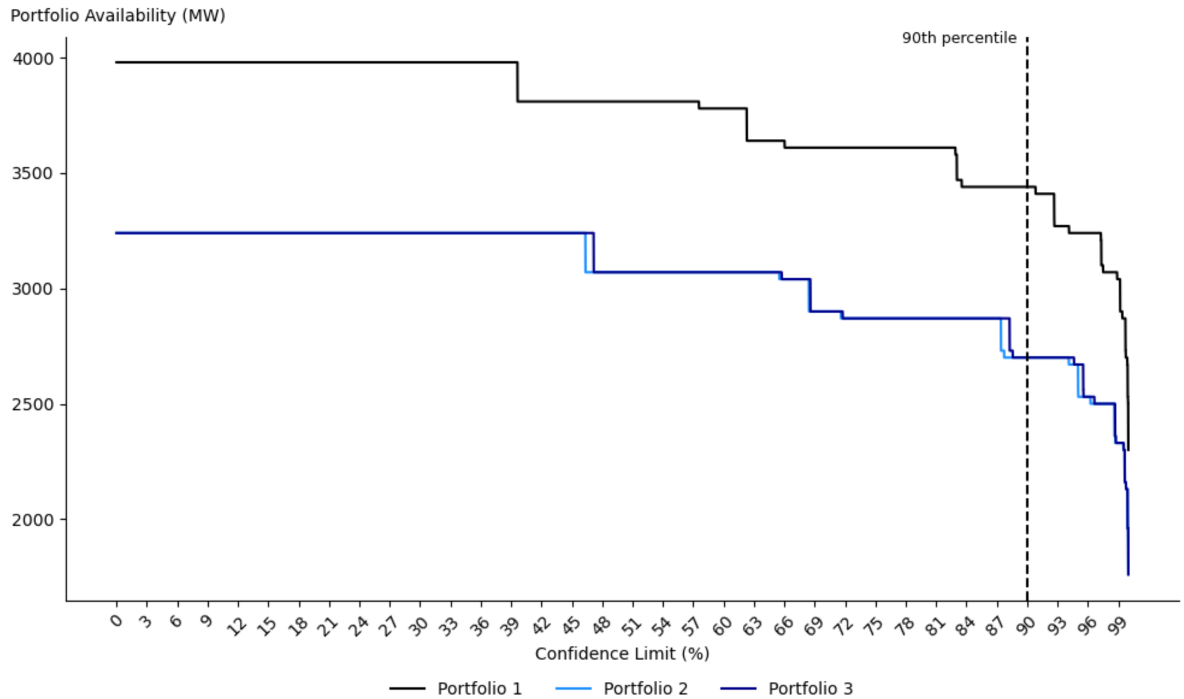


Figure 2: Primary supply of hedge contracts at 0% VRE market share

The change in portfolio capacity as VRE market share is increased from 0% to 60% is also shown in Table 4. Here, each portfolio loses the majority of its coal capacity, whilst building additional CCGT or OCGT plant capacity. Portfolios are visibly contracting in aggregate. The new VRE is not distributed amongst the portfolios because they are not assumed to enter by way of *on-market* PPA transactions, but rather, via *off-market* government-initiated CfDs. Consequently, the new capacity does not form part of the incumbent generation portfolios.

Note in Fig.3 the stacked bar series representing aggregate thermal capacity at 0% market share (x-axis) is ~10,500MW (y-axis). With this plant stock, the line series representing maximum demand is ~9,000MW and this also matches the aggregate supply of 'primary issuance' hedge contract capacity. But as renewable market share increases towards 60% along the x-axis, the supply of primary issuance hedge contract volumes declines, just as maximum system demand increases, albeit modestly, in line with elasticity effects. By 60% VRE, the physical system maintains reliability of supply but from a systemic perspective, a cumulative shortfall in primary issuance hedge contracts emerges, and accounts for 9% of the theoretical demand for hedge contracts from retail suppliers.

With a VRE market share of 60%, large loads and retail suppliers would in theory be forced to take on some level of spot market exposures due to the shortfall in primary issuance contracts. It is to be noted that structural shortfalls of hedge contract capacity invariably results in the exit of speculative participation in forward markets as explained in Simshauser (2019), and so we should not assume proprietary traders will fill this gap – the reason being the primacy of liquidity for their own risk mitigation (see also Goldstein and Hotchkiss, 2020). This is far more than a theoretical observation and is exemplified by experiences in the South Australian region of the NEM – where only a few remaining generators with physical asset backing were able to sell forward contracts, and at significant premiums, as identified by Flottmann et al., (2024).

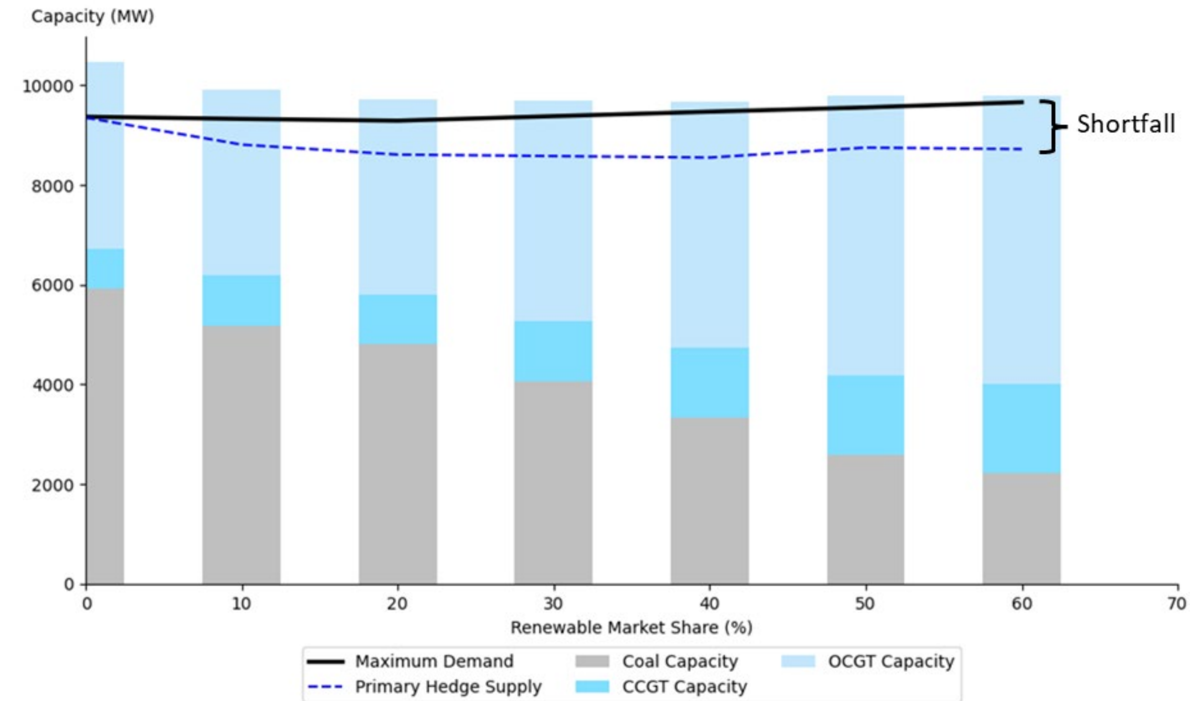


Figure 3: QLD model results primary supply of hedge contracts vs maximum demand (0% - 60% VRE)

As a final observation, note in Fig.3 that the hedge contract shortfall (see dotted blue line) progressively deteriorates from 0-40% on the x-axis, but then appears to stabilise between 40 – 60% VRE market share. The reason for this plateauing is that diversity of VRE output seems to reach its maximum in the Queensland region at ~40%. Thereafter, each MW of coal exit needs to be matched by a MW of dispatchable plant entry (i.e. CCGT & OCGT) in maintain power system reliability.

4.2 VRE contract supply levels

The analysis thus far has assumed all VRE plant enters through off-market government-initiated CfDs. This led to a market shortfall – and is perhaps not entirely surprising. What happens if all VRE plant enters via on-market PPAs, or the style of CfDs has been carefully designed to encourage recycling of the CfD hedge capacity in some way? Are hedge contract shortfalls inevitable with the loss of baseload capacity and the rise of intermittent capacity?

Under a 100% ‘on-market’ or ‘CfD recycling’ VRE scenario, drastic change occurs as illustrated in Figure 4. Primary issuance hedge contract shortfalls are largely mitigated if all new entrant plant enters via on-market contracts (or are recycled) rather than off-market CfDs. As with the physical market, the loss of coal plant is matched by the gains from entering VRE and gas turbine plant capacity. In Figure 4, the improvement is clearly seen as the available VRE plant capacity increases.

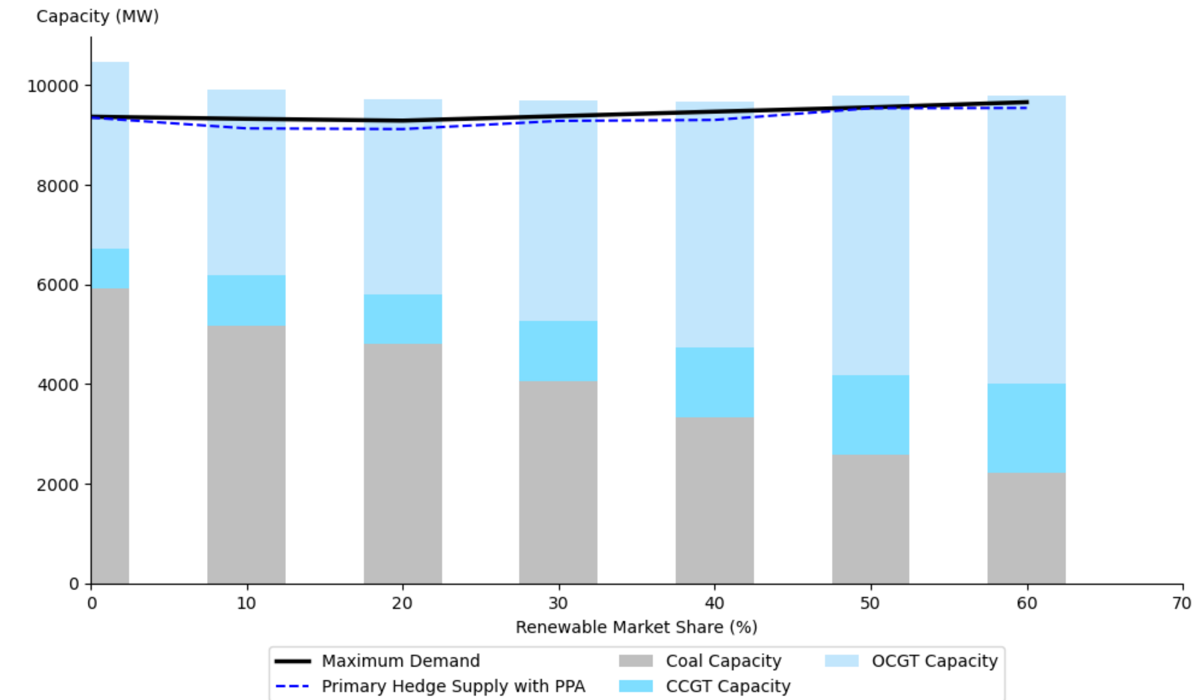


Figure 4: On market PPAs with 90th percentile thermal hedge supply (dotted blue line) against QLD region demand

To summarise, on-market transactions or active recycling of CfDs in the NEM's Queensland region ensures the hedge market re-balances itself, even with the loss of the traditional baseload hedge contract providers (i.e. coal plant) and it does so in a manner identified in Simshauser (2020), through run-of-plant PPAs with dispatchable plant synthetically recreating baseload swaps. The analyses contained above in Section 4.1 (Fig.3 off-market CfDs) and Section 4.2 (Fig.4 on-market PPAs) will now be replicated throughout Section 5 to examine the remaining three mainland NEM regions – with surprising results for at least one NEM region.

5. Regional contract shortage results

The scenario outlined in Section 4 was designed to be a non-interconnected system in an energy only market using Queensland data – noting basis risk exists between regions. Given the results, it is valuable to explore how 'primary issuance' hedge contracts within each remaining NEM mainland region (i.e. NSW, VIC, SA) evolve through advancing stages of decarbonisation. Table 5 identifies the size of each unit and the associated fuel costs used in the analysis below.

Table 5: Region capacity and SRMC for dispatchable units

Technology	NSW		QLD		VIC		SA	
	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)	Unit Size (MW)	SRMC ($/MWh)
Black Coal	700	21.37	370	21.37	485	10.26	260	25.64
NGCC	400	56.54	200	56.54	400	63.61	300	70.68
OCGT	200	151.70	170	151.70	200	151.70	170	163.70

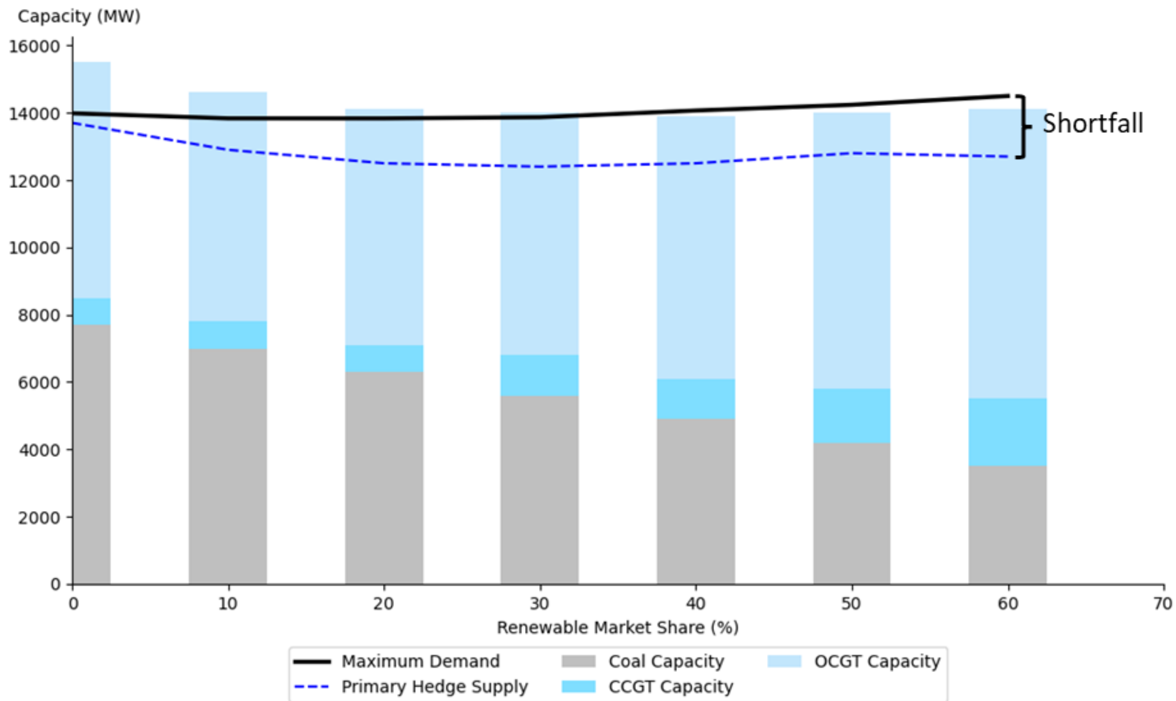
5.1 New South Wales primary issuance hedge contract shortage

NSW is the most populous state of the NEM and as a result has the highest historical demand levels and a large coal fleet. Each coal unit is at least 660 MW with the average being 700 MW. Compared to Queensland where the average unit is nearly half the size, this disparity could have adverse impacts on contract supply (i.e. lumpier exit).

Model results for NSW in Table 6 sees maximum demand rise by ~600 MW as VRE market share increases from 0 – 60%. In the model, 4,200 MW of coal capacity exits as ~10,800 MW of wind and ~4,500 MW of solar enter, along with 1,200 MW of CCGT plant and 1,600 MW of OCGT peaking capacity. Modelling suggests mid-merit plant runs at an ACF of 36% at 60% VRE, whilst peaking plant run at 5% ACF. In this scenario, the primary supply of hedge contracts would fall by 1,000 MW leaving a hedge contract shortage of 12% of maximum demand at 60% VRE market share (Figure 5A).

Table 6: Overview of key NSW model results.

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	70,552	73,144	2,592
Maximum Demand (MW)	13,986	14,500	514
Plant Capacity			
Coal (MW)	7,700	3,500	- 4,200
CCGT (MW)	800	2,000	1,200
OCGT (MW)	7,000	8,600	1,600
Wind (MW)	0	10,780	10,780
Solar (MW)	0	4,522	4,522
Supply of Primary Hedges (MW)	13,700	12,700	- 1,000
Underlying System Price ($/MWh)	99.74	70.4	- 29
Unserved Energy %	0.001%	0.001%	



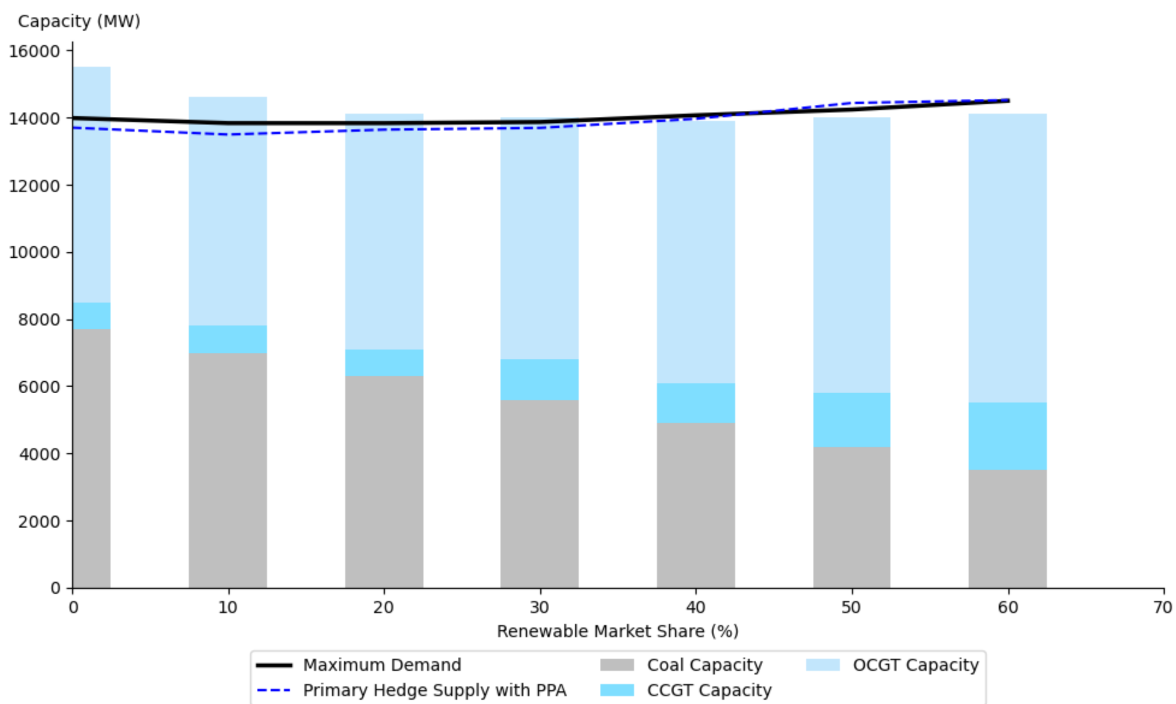


Figure 5: A (Top) NSW model results thermal primary supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) NSW model results thermal primary issuance hedge supply and on-market PPA hedge supply

The impact of VRE being underwritten by CfDs is particularly important for NSW, where a state government-initiated scheme exists to incentivise VRE deployment along with an overlapping Commonwealth scheme. The NSW CfD scheme comprises Long Term Electricity Supply Agreements or 'LTESAs' and essentially operates as a put option (or floor) over VRE project revenues. When activated, LTESAs do not easily facilitate 'portfolio hedging' because winning participants must ensure their revenues are traceable – and this means any on-selling of the capacity must be sold to a third party, not within a firms' own dedicated hedge portfolio for its own customer loads (due to the risk of 'un-traceability', that is, the usual *transfer pricing risks* within a single firm). When not exercised, the LTESA CfDs do not appear to preclude a portfolio developer or utility from forward selling the run of plant output from a renewable project into forward markets per se, including as an internal portfolio hedge. However, as a taxpayer-wrapped put option or floor on project revenues, it may also encourage greater risk taking and spot market participation – the results in Gohdes et al.(2023) very clearly suggesting this to be profit maximising compared to writing on-market PPAs. Conversely, if 100% of VRE plant CfDs are recycled or sold via on-market PPAs, contracts shortfalls are mitigated as Figure 5B illustrates.

5.2 Victorian primary issuance hedge contract shortage

Next, we analyse Victorian primary issuance hedge contract market capacity. The expected shortage is analysed using the same financial inputs as in the previous three modelled scenarios based on information from Section 3 but as outlined in Section 2.1, Victorian coal units use lignite, a far cheaper fuel source. As a result, unit fuel costs have been significantly reduced in the Victorian scenario noting Australia's NEM does not have an explicit price on CO2 emissions. Thermal unit size also been adjusted to represent the average plant size of units in Victoria.

Model results in Table 7 indicate ~6,800 MW of wind and ~3,300 MW of solar capacity is added to the region along with 400 MW of CCGT and 200 MW of peaking OCGT capacity to achieve 60% renewable energy and maintain a secure system. This capacity addition allows for the closure of 2,425 MW of coal capacity. Interestingly, coal closures are lower in VIC as a % of starting capacity compared to the NSW and Queensland regions – which also reflects observed NEM results. This is due to the low fuel costs associated with VIC coal units (and the absence of a price on carbon). However, in closing 2,425 MW of coal capacity the primary supply of hedges falls by ~1,200 MW to ~7,300 MW implying a shortfall of 17% to final maximum energy demand (Figure 6A).

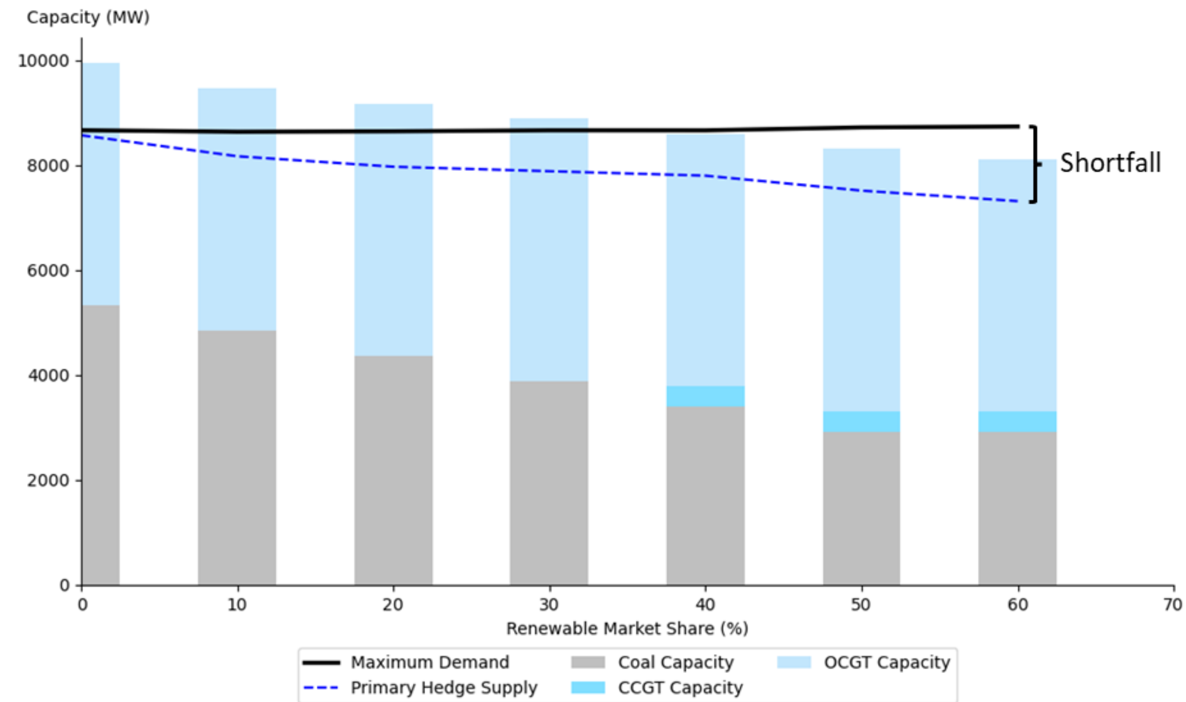
Table 7: Overview of key VIC model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	43,418	43,983	565
Maximum Demand (MW)	8,661	8,773	113
Plant Capacity			
Coal (MW)	5,335	2,910	- 2,425
CCGT (MW)	0	400	400
OCGT (MW)	4,600	4,800	200
Wind (MW)	0	6,823	6,823
Solar (MW)	0	3,363	3,363
Supply of Primary Hedges (MW)	8,565	7,310	- 1,225
Underlying System Price ($/MWh)	75.4	55.1	- 18
Unserved Energy %	0.001%	0.001%	

A sensitivity analysis was conducted using a carbon price of $30.5/t[3] of CO_2 applied to all thermal generators in Victoria. Emissions intensities were derived from Table 2 except for coal. As Victoria uses lignite it has a higher emissions intensity therefore an emissions intensity of 1.22 t/MWh was used (Saha et al., 2016; Tian et al., 2010). The results show little change in the contract shortfalls but

[3] This price was taken using the $23/t carbon price implemented as part of Australia's carbon tax in 2012 and inflated to 2023 dollars.

with higher marginal running cost the model exits more coal, at 3,880 MW. There is also significantly more mid-merit plant entry at 1,200 MW. This sensitivity highlights the importance of adequately replacing exiting coal capacity to ensure hedge contracts are maintained at operable levels.



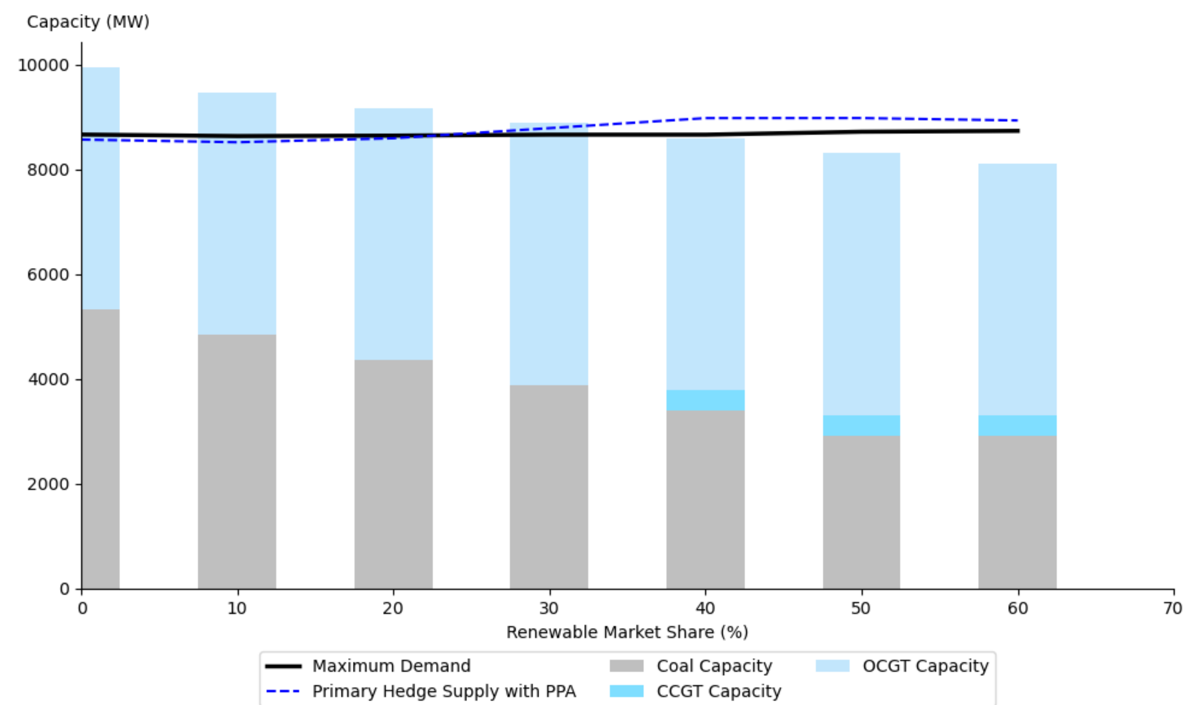


Figure 6: A (Top) VIC model results primary issuance supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) VIC model results thermal primary issuance hedge supply and on-market PPA hedge supply

Adding VRE capacity via on-market PPAs to the primary hedge supply does significantly improve the growing shortfall such that at 60% VRE market share there is a net positive against maximum demand (Figure 6B).

5.3 South Australian primary issuance hedge contract shortage

The South Australian region has been the fastest to decarbonise its energy mix in the NEM, and globally. This NEM region has already closed all of its coal-fired generation, which occurred when the state had approximately 40% VRE market share (in 2016). To reflect this development, the model has been forced to close coal capacity at the same time to adequately replicate the supply of primary issuance hedge contract capacity available to the region. As with previous analyses, unit size and fuel costs have been changed to reflect the current regional generating capacity.

Model results in Table 8 indicate the entry of ~2,000 MW of wind, ~800 MW of solar, 600 MW of CCGT and no peaking OCGT, allowing for the closure of all 1,300 MW of coal capacity. As a result of this coal capacity exiting, ACFs of CCGT plant increase from 45-74% between 30 – 40% VRE market share, but then falls to 52% by 60% VRE market share. Throughout this time, OCGT ACFs are maintained below 10% within expected range.

Primary issuance hedge contract capacity falls by 700 MW, ultimately resulting in a shortage of 26% to maximum demand (Figure 7A). This result presents as the largest proportional shortage of any NEM zonal market modelled. The results are also aligned with market observations contained in Flottmann et al. (2024), where the SA region sees high contract premiums for both Swap and $300 Cap contracts.

When 100% of VRE CfD capacity is recycled to the market or originated via on-market PPAs, the improves from a 26% shortage, but does not completely clear (see Figure 7B). SA seems to be the only NEM region with a structural shortage with 100% on-market PPA transactions. Consequently, the SA market will be highly sensitive to any government-initiated CfD (including those undertaken by other jurisdictions – recall the Australian Capital Territory originated ~1200MW of CfDs, many of which were in South Australia and have not been recycled – and has no doubt contributed to the findings in Flottman et al., 2024). This indicates the SA region may require particular attention to ensure structural shortfalls of hedge contract capacity does not exacerbate an already present problem.

Table 8: Overview of key SA model results

VRE Market Share	0%	60%	Change
Energy Demand (GWh)	11,581	11,956	77
Maximum Demand (MW)	3,046	3,144	20
Plant Capacity			
Coal (MW)	1,300	0	-1,300
CCGT (MW)	300	900	600
OCGT (MW)	1,870	1,870	-
Wind (MW)	0	1,949	1,949
Solar (MW)	0	799	799
Supply of Primary Hedges (MW)	2,960	2,260	-700
Underlying System Price ($/MWh)	86.3	85.0	-3
Unserved Energy %	0.001%	0.001%	

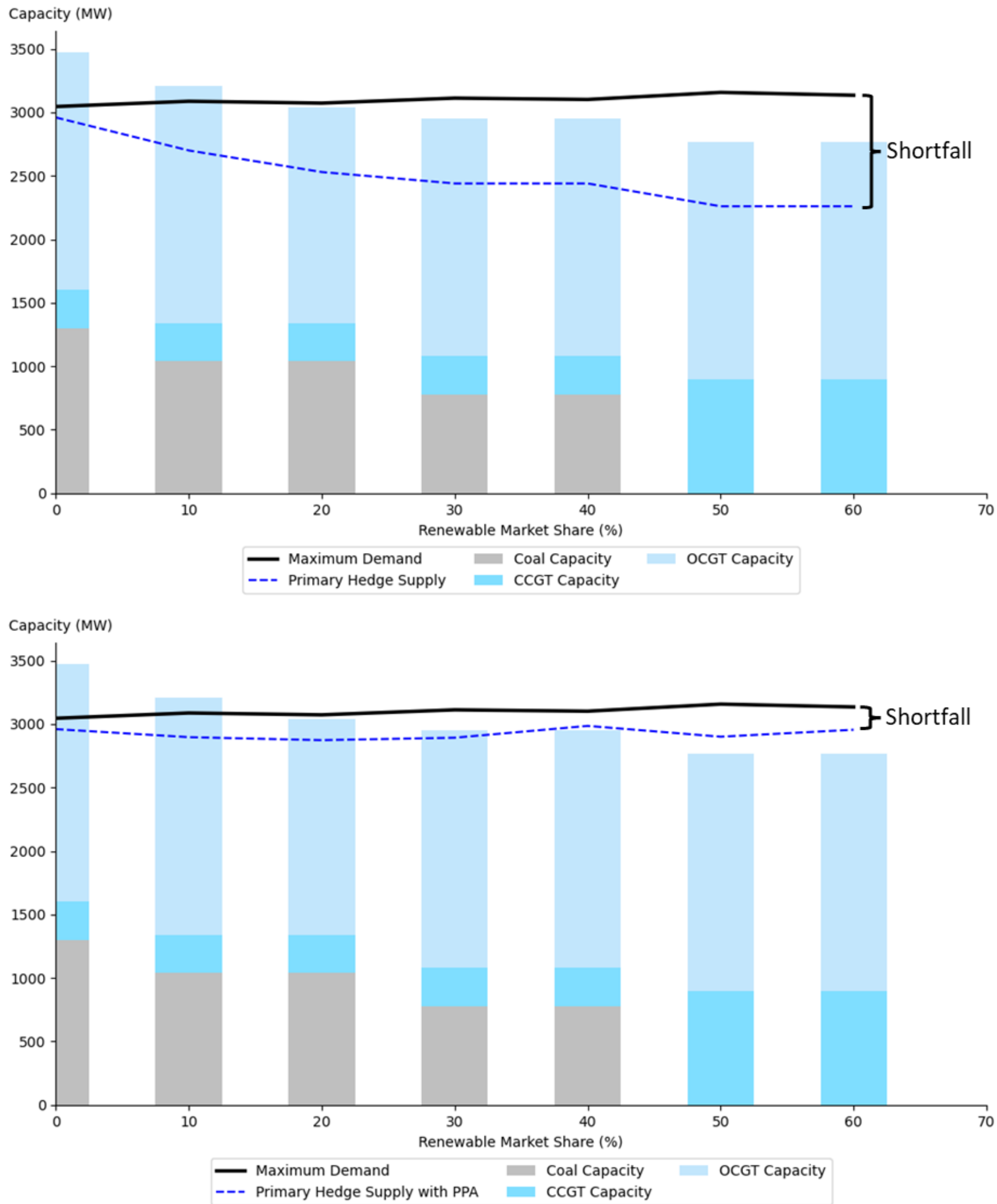


Figure 7: A (Top) SA model results primary issuance supply of hedge contracts vs maximum demand (0% - 60% VRE). B (Bottom) SA model results thermal primary issuance hedge supply and on-market PPA hedge supply

5.4 Is the shortfall a Swap or a $300 Cap problem?

At first glance, given baseload coal plant is exiting the market, hedge contract shortfalls may logically appear to be dominated by baseload Swaps – the most liquidly traded instrument in the NEM.

Traditionally, large baseload thermal generators have been the predominant natural suppliers of Swap contracts. Indeed, regions where Swap contract volumes have reduced have exhibited statistically significant risk premiums (see Flottmann et al., 2024). However, when given the opportunity, VRE projects can sell on-market forward contract capacity including Swaps when combined with firming generation technologies such as gas generation or batteries (Flottmann et al., 2022; Simshauser, 2020). As our quantitative results have shown, any contract market shortfall can be reduced to varying degrees by ensuring VRE contract capacity is either on-market, or recycled, into forward markets.

We conducted an analysis of VRE market shares as a percentage of aggregate demand over different periods of the day. This included 'Morning Peak' (5am – 8:30am), 'Solar Peak' (8:30am – 4:30pm), 'Evening Peak' (4:30pm – 9pm) and 'Overnight Period' (9pm – 5am). Figure 8 illustrates that in each region, wind serves as the best proxy for Swap contracts as, on average, it may meet *at least* 30% of demand throughout the day. However, neither solar nor wind is particularly well suited to meet evening peak demand which has historically seen the most $300 Cap payouts, and therefore where Cap contract sales are most valuable.

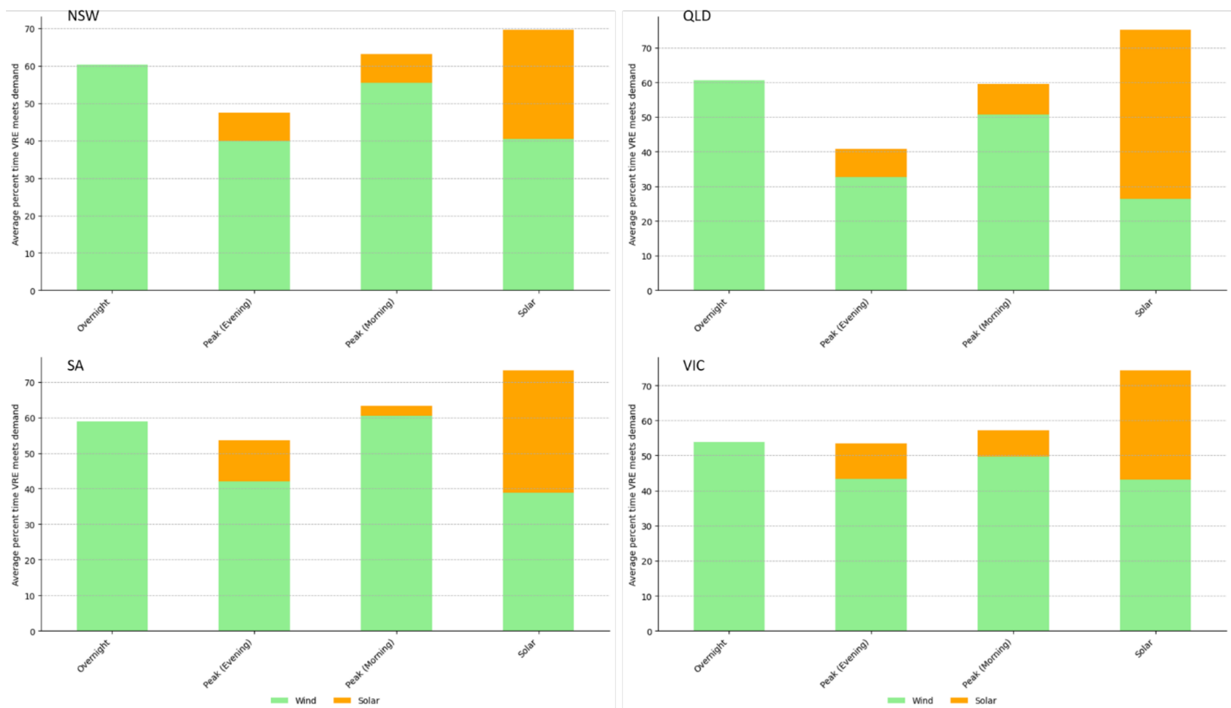


Figure 8: Average VRE market share as a percentage of demand over defined times of the day (Overnight, Evening Peak, Morning Peak, Solar)

When considering whether a $300 Cap contract shortfall may exist in the NEM, results are less clear. The impact depends on what dispatchable capacity replaces coal plant. To ensure our modelling was tractable and to provide a bookend result, our analysis used CCGT & OCGT plant capacity as the sole replacement for coal units. This provides a *'best case outcome'* for primary issuance hedge contract capacity (cf. energy limited pumped hydro and batteries). The ability for pumped hydro & batteries to capture Cap payouts and therefore sell Cap contracts varies depending on their warranted duration.[4]

[4] In the case of gas generation such as CCGT & OCGT their ability to defend $300 Cap contracts would be significantly impacted by continuity of natural gas supplies (or other backup fuel sources) as Simshauser & Gilmore (2024) explain.

Ultimately, both Swap and $300 Cap contracts are likely to be in shortfall as coal plant exit the system. While coal exit implies Swap shortages, in Simshauser (2020) an OCGT plant was blended with wind to provide baseload swaps – suggesting shortages in $300 Caps. The extent to which each contract type is in shortfall will be dependent on how plants are able to enter and participate in the market –

6. Policy implications and concluding remarks

The quantitative analysis presented in Sections 4-5 indicates if off-market, government-initiated CfD methods dominate VRE entry, significant shortfalls of primary-issuance hedge contract capacity is predictable. Conversely, our modelling suggested in all regions but SA, carefully designed CfDs where recycling is possible will all but eliminate such shortages.

Although considerable CfDs have been undertaken in NSW, Victoria and SA, shortfalls are yet to materialise in NSW and Victoria. The reason for this may vary but includes characteristics such as VRE plant entry being dominated by on-market transactions, coal plant exit being imperfect and lagging optimal exit, and/or mid-merit and peaking assets may currently be structurally oversupplied – thus providing a transient buffer to a shortage.

In other regions, viz. SA, structural shortages have been a slowly emerging issue which to date has not been adequately addressed. Importantly, if VRE is to enter through on-market PPAs or CfDs are recycled, adverse impacts to forward markets – their depth and liquidity – seem avoidable. The question for policymakers is whether on-market transactions can move at the same speed as policy intent, or what architecture a government requires to recycle CfDs back into the market.

Evidence from other jurisdictions usually suggests markets lag policy intent, or entry costs for certain high-cost technologies (e.g. off-shore wind) require some level of policy priming through CfD-subsidisation. Either way, investment lag or high technology cost may well warrant government-initiated CfDs. But this research has highlighted such activity is not compatible with contestable retail markets without careful design. That is, the hedge contract capacity extracted by off-market government CfD auctions needs to be recycled, or some other on-market policy mechanism needs to prevail to ensure forward markets remain with adequate depth and liquidity. This is important with regards to the retail price of electricity.

This finding applies not only to VRE, but also to replacement dispatchable capacity. Indeed, recycling of any CfD underwriting of batteries, pumped-hydro or gas turbines is even more important. Such plant *must* be able to enter the contract market in such a way that allows firms to hedge a portfolio – which in turn is how intermittent run-of-plant PPA contracts become "usable" by energy retailers. In this sense, extracting firming capacity (i.e. batteries, pumped hydro, gas turbines) from forward markets makes things much worse than extracting VRE capacity, as it may render larger parts of the system *unhedgeable*.

There is anecdotal evidence that some projects in Australia's NEM, underwritten by government CfDs, have forward-sold their plant output into the forward markets as on-market transactions – as was envisaged in the design of the Commonwealth's Capacity Investment Scheme CfD contracts. However, to the best of our knowledge, this has so far been fairly limited in scope and at least some risk exists that 'CIS' projects use the CfD design as a floor on revenues. This is not to say CIS design has not or will not achieve its intended purpose – including recycling of plant in forward markets. If projects use the design as a floor instead of an option collar design, it may require a more nuanced approach to recycling CfD contracts in forward markets, such as the establishment of a government trading house.

In this article, we aimed to highlight whether structural shortages of hedge contract capacity may arise if projects choose not to participate in forward markets upon being awarded government-initiated CfDs due to the risk of paying out twice during surging prices. Our substantive point is that the risk of shortfalls in hedge contract markets is plausible and likely, and should therefore be a policy focus of government. Ultimately, failures in the forward markets are borne by consumers through a shrinking pool of energy retailers, higher hedge contract premiums, and all things being equal, higher electricity bills. A notable example is the SA region of the NEM - premiums for contracts sold to predominantly retailers or large loads were extremely high as outlined in Flottmann et al. (2024).

Our analysis was designed to identify whether the forward market for contracts would adjust as large baseload coal generation plant exits at scale, with on-market PPAs and off-market CfDs. Results in our QLD scenario showed as coal plant exits due to uneconomic operation and increasing VRE deployment, the volume of hedge contract supply from base plant naturally declines. Importantly, to ensure enough generation is available to meet maximum demand significant quantities of mid-merit and peaking plant are required. The addition of this new plant adds to the supply of hedge contracts and helps to slow the loss of primary issuance hedge contract capacity. If VRE plant capacity enters by way of on-market PPAs, shortages at the margins may appear in some NEM regions – which suggests additional peaking capacity or alternate hedge contracts (e.g. weather derivatives) may be required.

Policy resolution seems to require one of two options. First, drive VRE plant entry by way of alternate market structures to facilitate on-market PPA entry (e.g. expansion of certificated Renewable Energy Targets, or write CfDs on the carbon component and leave the electrons exposed to the spot electricity market). Or second, establish a government trading house to facilitate secondary issuance, that is, the re-trading of CfD capacity acquired under auction and extracted from the NEM's forward markets. As renewable market shares continue to rise, one of these two options will ultimately be necessary, or the retail market will begin to malfunction.

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