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Electricity contract design and wholesale market outcomes in Australia's National Electricity Market

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The emergence of variable renewable energy (VRE) technologies has created a range of different energy contracting techniques. Within Australia's National Electricity Market (NEM), Run-of-Plant (RoP) Power Purchase Agreements (PPAs) became the most common form of contract with purchasers of wind and solar energy agreeing to pay a fixed price for energy irrespective of when it is produced and therefore its actual value to the market. In November 2023, the Commonwealth Government adopted a 32 GW RoP PPA Contract-for-Difference (CfD) underwriting policy that aims to effectively shield the generator from market price risk. This article discusses different contract structures and their impact on participant behaviour during periods of material oversupply and negative prices. We find that embedded solar PV exports into the distribution network, which are not required to dynamically participate in the wholesale market, have increased wholesale energy supply enabling profit maximising vertically integrated renewable firms to drive prices lower in a manner that partially strands the output of RoP PPA CfD generators with a $0/MWh price floor. A key conclusion from our analysis is that requiring embedded solar PV to effectively participate in the wholesale market appears to be a pre-condition for the efficacy of government initiated RoP PPA CfDs.

Keywords: energy contract design; renewable energy; emissions reduction policies
JEL Codes: D04, D47, Q40, Q41, Q48

1. Introduction

Electricity markets are incredibly complex. At every moment in time, demand and supply must be equal to ensure the system provides electricity reliably to consumers. Unlike other markets, a failure to satisfy the last unit of instantaneous demand may result in all demand being unmet (i.e. a blackout). Historically, there has been no economic way to store significant quantities of electricity and this lack of inventory management has resulted in Australia's National Electricity Market delivering extremely volatile pricing. Electricity demand is largely weather driven and can often increase ~50% in just a few hours on a hot or cold afternoon/evening. Market design must not only achieve allocative efficiency for short-term market dynamics but must also provide appropriate price signals to incentivise efficient investment in long-lived generation assets.

The NEM was implemented in the 1990s as a gross, energy-only pool with a uniform clearing price. Generators are paid for the energy they generate, but not for the capacity they make available. In theory, generators earn a return on capital by capturing infra-marginal rents when higher short-run marginal generators are dispatched to meet increased levels of electricity demand. Over the course of the business cycle, it is envisaged that a well-designed energy-only market will ensure that an optimal generation mix is in place (see Nelson et al, 2018).

The NEM has a very high market price cap (MPC) of \$16,100/MWh and a low floor price of -\$1,000/MWh with rapid settlement (5 minute) to facilitate economically efficient dispatch of generation to meet volatile (weather dependent) demand. Acute pricing is used to make sure that a sharp price floor clears oversupply[1] and the price cap is high enough to incentivise generation or

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[1] Prior to the introduction of significant quantities of variable renewables, the price floor acted to clear surplus heavy fixed cost and inflexible generation from the bid stack.

demand response that is only required for a few hours a year (see Simshauser et al, 2014). Significant price risk that manifests in this volatile market is managed through financial derivative contracts entered into by buyers (retailers) and sellers (generators) (Deng et al, 2001). Wholesale hedging contracts allow market participants to manage their risks and obtain commercial finance to operate (see Nelson and Simshauser, 2013). Investment in all forms of power generation is effectively dependent upon some form of financial contract based on longer-term NEM pricing outcomes.

The focus on reducing greenhouse gas emissions has resulted in substantial investment in renewable energy technologies. At the household level, ~22 GW of solar PV has been installed behind the meter. At the utility-scale, Simshauser and Gilmore (2022, p. 2) note that 'Over the NEM's ~24 year history (1998-2021), 229 utility scale new entrant plants comprising 31,487 MW of coal, gas and renewables reached financial close,' but '….during 2016–2021 – more than half of the NEM's historical investment commitments, viz. 15,939 MW (51% of the total) with an aggregate value of $27.2 billion (48%) across 135 (59%) projects were wind and solar, including 86 utility-scale solar PV and 39 wind projects.' In other words, the vast majority of investments in the last decade have been in variable wind and solar technologies.

Wind and solar technologies are 'non-firm' (i.e. only available if the sun is shining or wind is blowing). Energy market participants developed simplistic contracting techniques for purchasing the output from these new projects. These new financial contracts, known as Run-of-Plant (RoP) Power Purchase Agreements (PPAs), effectively severed the link between the physical needs of the system and wholesale electricity prices. Buyers (retailers, governments and electricity customers) began purchasing the output from wind and solar projects for a fixed price irrespective of when the energy was produced (and therefore its value). Most RoP PPAs use a Contract-for-Difference (CfD) mechanism which results in revenues earned from prices above the contract price being returned to the retailer and revenues below the contract price being returned to the generator. The earliest of these contracts were particularly problematic as there were no provisions incorporated for negative pricing – effectively requiring the buyer to continue to purchase electricity and make the seller whole to the fixed contract price during negative pricing periods.

Australian governments have increasingly abandoned market mechanisms for addressing climate change (such as a carbon price or renewable portfolio standard like the Large-Scale Renewable Energy Target: LRET) in favour of reverse auctions for long-term purchasing by government of renewable energy output (government initiated RoP PPA CfDs) with the stated intention of reducing investment risks and stimulating investment (Commonwealth Government, 2023).[2] The Commonwealth Government announced in November 2023 that it would use an underwriting RoP PPA CfD style policy to induce 32 GW of new investment by 2030. Collectively Australian governments have established policies that could result in almost all generation investment being delivered via government underwriting.

The purpose of this article is to consider bidding behaviour within electricity markets with high penetrations of small and large-scale renewable energy. We find that embedded solar PV exports into the distribution network, which are not required to face dynamic wholesale pricing signals, have increased wholesale energy supply substantially, which enables profit maximising vertically integrated renewable firms to drive prices lower in a manner that can strand the output of RoP PPA CfD generators. The implication of our analysis is that unless small-scale solar PV is fully incorporated into NEM wholesale market dispatch, the efficacy of government underwriting policies is questionable.

Our article is structured as follows: Section 2 provides an overview of the literature in relation to market design, climate policy, electricity price modelling and the limitations of RoP PPAs and

[2] Victoria has introduced its VRET policy which has provided CfDs for new renewable projects aimed at achieving 50% VRE penetration by 2030. The NSW Government Energy Roadmap prescribes 12 GW of new projects to be underwritten by one-sided options for CfDs by 2030.

government-initiated CfDs; Section 3 provides a theoretical assessment of different energy market forward contracting structures and their likely supply curves and bidding strategies; a real-world example of how these contract structures impact on bidding behaviour is presented in Section 4 with policy recommendations and concluding remarks provided in Section 5 and Section 6.

2. Literature review and relevant history of Australian policy design

2.1 Market design – importance of spot and forward markets

The International Energy Agency (2016) established a taxonomy for energy market design in three timeframes: short-term (minutes to hours); medium term (months to three years); and long-term investment (three to twenty-five years). The temporal nature of this taxonomy is presented in Table 1.

Table 1: Energy market design

Objective	Long-term (decades)	Medium-term (3-4 years)	Short-term (minutes to days)
New investment in required capacity	Capacity market or forward contracts and PPAs		
Maintenance of existing capacity		Capacity market	
Efficient energy pricing		Forward markets (i.e. derivatives)	Day-ahead, spot markets
Reliability and reserves			Ancillary services, operating reserves

Source: IEA (2016)

While spot markets are critical for allocating existing resources, it is their interaction with medium term forward derivative and long-term contracts (such as retail contracts and PPAs) that drives new investment (noted by the IEA, 2016 in Table 1; and Simshauser, 2019). Forward markets act as a means of synthesising the 105,120 five-minute trading intervals in a year into a more digestible economic signal for investors. But spot markets are also guided by the positions taken by profit maximising participants utilising transient market power in forward markets (see Rai et al, 2021).

Average electricity prices cannot equal short-run marginal cost because the industry is capital intensive. Scarcity pricing is required so that volume weighted average prices exceed the levelised cost of energy (see Joskow, 2006; Finon, 2008; Meade & O'Connor, 2009; Caplan, 2012; Nelson & Simshauser, 2013). The shift to very high penetrations of VRE amplifies pricing volatility because such plant is even more capital intensive and often subsidised by environmental policies (Nelson et al. 2012; Joskow, 2013; Newbery, 2016). In this article, we extend the literature by considering the interaction of forward and spot markets on VRE generation bidding behaviour. In particular, we contrast profit maximising vertically integrated renewable firms and RoP PPA CfD generators in the NEM when oversupply is driven by small scale solar PV exports.

2.2 Climate policy design

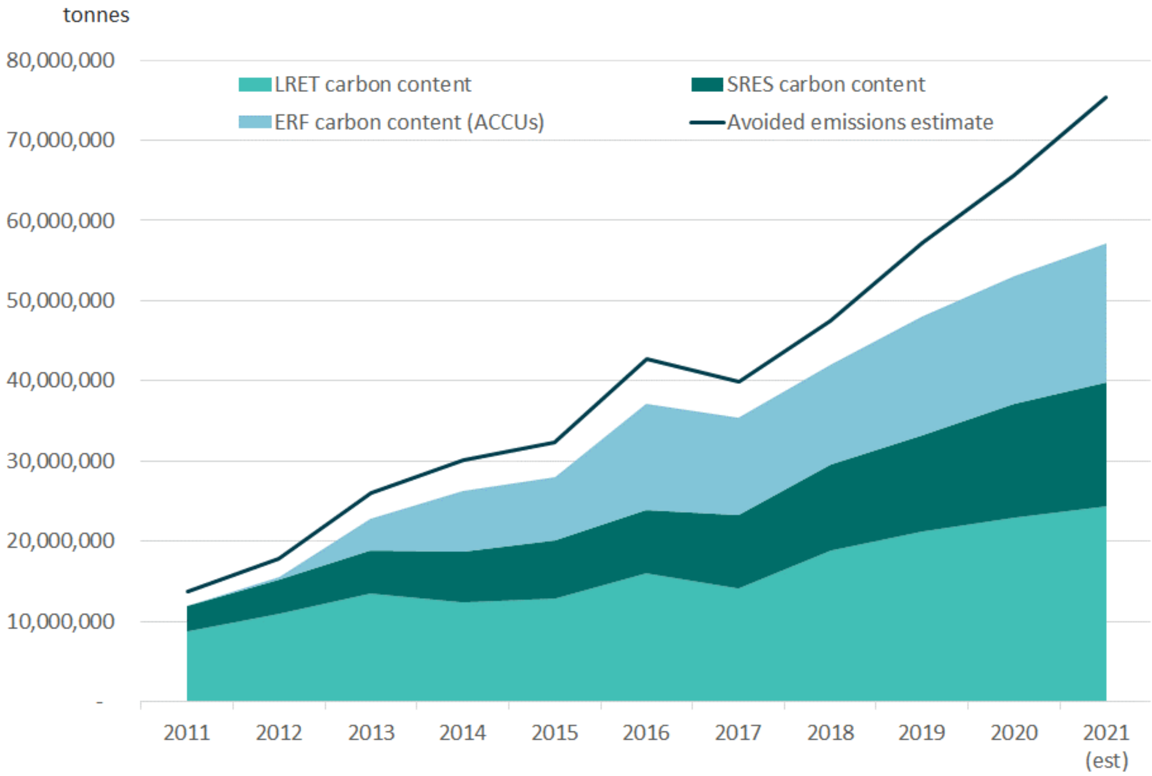
A well-designed carbon pricing mechanism such as a cap-and-trade scheme is almost universally regarded within the literature as the optimal policy for reducing greenhouse gas emissions (Freebairn, 2020). Australian policy makers, however, have been unable to introduce an enduring and stable carbon pricing mechanism with both the Clean Energy Future package of reforms and the New South Wales Greenhouse Abatement Scheme (GGAS) both abandoned (Nelson et al, 2022). Instead, policy makers almost entirely relied upon three types of other mechanisms: premium feed-in-tariffs (PFiTs); renewable obligation certificate (ROC) trading schemes; and more recently reverse auctions for government initiated RoP PPA CfDs (see Simshauser, 2019).

The use of upfront subsidies through the Small-Scale Renewable Energy Scheme (SRES) and PFiTs has driven material investment in behind the meter residential and small business solar PV. In mid-2023, Australia had around 22 GW of embedded PV and many of these solar PV systems are larger than individual household or business requirements. Investment has been driven by the nature of the SRES and PFiT subsidies as well as the lack of cost-reflective network tariffs (see Simshauser, 2017). Very importantly, all of the exported embedded PV is not actively participating in the wholesale market. In fact, most retailers will pay a FiT of between $50 and $100 per MWh at times of material oversupply despite large-scale renewable generators having to pay to generate during periods of negative pricing. It is this dynamic in the Australian market that has a material impact on the profitability of large-scale renewable energy generators depending upon their contracting strategy.

For inducing investment in large-scale renewables, Australia has largely relied upon a ROC scheme called the Large-Scale Renewable Energy Target (LRET). This policy requires retailers to purchase Large-Scale Renewable Energy Certificates (LGCs) from renewable energy generators so that 33 TWh of energy generation is supplied by large-scale renewable (principally wind and solar) generation. While not as efficient a mechanism as an emissions trading scheme, the LRET requires generators to find customers for their energy (either through retail supply agreements, direct customer agreements or wholesale market contracts). Bunn and Yusupov (2015) show that with negative correlation between renewable output and wholesale electricity prices, trading schemes and ROCs reduce risks for consumers/taxpayers compared with RoP PPA CfDs or PFiTs. ROC policies require market participants to manage the risks associated with participating in the electricity market, which RoP PPA CfDs do not. ROCs are generally more suitable for driving investment in relatively mature technologies, as demonstrated by Foxon and Pearson (2007), Wood and Dow (2010, 2011), and Sioshansi (2021).

Nelson et al (2022) argue that the LRET has been the most successful climate policy in the country, driving substantial investment in mature renewable energy generation without imposing risks on consumers or taxpayers. Between them, the LRET and the SRES have delivered the majority of Australia's greenhouse gas abatement which is shown in Figure 1 below (CER, 2023).

Figure 1: Australian abatement by policy driver 2022



Source: CER (2023)

Despite this success in utilising certificate policies, Australian governments have increasingly turned to government-initiated RoP PPA CfDs to support commercially mature technologies. For instance, the Victorian Government has utilised RoP PPA CfDs to underwrite new investments in VRE as part of its VRET policy, aiming for 50% renewable energy by 2030 as legislated in the *Renewable Energy (Jobs and Investment) Act 2017*. The Australian Capital Territory (ACT) has also set a goal of 100% renewable energy procurement through a series of RoP PPA CfD contracts, while the New South Wales (NSW) Government has legislated a complex version of RoP PPA CfDs known as 'swaptions' or long-term energy service agreements (LTSEAs) to drive 12 GW of renewable generation and storage capacity.

In the case of the Australian Capital Territory (ACT), cost transfers to consumers have been material. RoP PPA CfD arrangements have led to out of market costs flowing through to consumers as higher energy prices (Nelson et al., 2022). Wholesale energy prices were AUD $199m lower than the agreed amount in underwriting policies from their adoption through to September 2022. The ACT electricity distributor (Evoenergy) passed these costs on to consumers. Proponents of RoP PPA CfD programs argue that changes made to contract design through the use of a $0 price floor after these early Australian RoP PPA CfD schemes has eliminated these problems from occurring again.

In November 2023, the Commonwealth Government announced a 32 GW underwriting policy (Commonwealth Government, 2023). At the time of writing, it is understood that the policy will use a similar underwriting RoP PPA CfD structure to the NSW LTESAs. With this policy in place, almost all of the new generation in the NEM will now be induced by an underwriting agreement. These RoP PPA CfD contracts all utilise a $0 price floor which may have profound implications for their efficacy. This is the focus of our analysis in the subsequent sections.

Researchers have begun to suggest 'hybrid' ROC/CfD policies. Nelson et al (2022) have noted that CfDs could be written on the 'green certificate' rather than the bundled electricity and environmental credit revenues. This would then overcome the three limitations of government initiated RoP PPA CfDs identified by Simshauser (2019), the shielding of market participants from electricity generation price risk and the introduction of 'quasi-market' participants; the reduction in hedge market participation with associated impacts on retail competition; and the use of simplified metrics such as LCOE.

2.3 High VRE systems and their impact on pricing

The choice of policy instrument to decarbonize electricity systems is particularly relevant given the impact of new technology on electricity market pricing and risk management. The concept of the merit order effect, whereby low short-run marginal cost (SRMC) variable renewables reduce wholesale electricity prices, has gained traction in the academic literature since at least 2008, with studies analysing its impact in various markets (Sensfuss et al, 2008; Poyry, 2009; Pirnia et al, 2011; and Gelabert et al, 2011). Periods of high renewable output have been associated with lower (and often negative) wholesale prices (Sensfuss et al., 2008; McConnell et al., 2013; Csereklyei et al., 2019) and decreased utilisation of coal plants. Arguably, there is now more risk associated with operating in electricity markets due to variable demand now being accompanied by far more variable (weather-dependent) supply (Rai and Nunn, 2020).

2.4 RoP PPA CfDs and cost of capital arguments

As markets have experienced greater volatility in pricing with increased penetrations of VRE, policy makers have gravitated towards policies such as RoP PPA CfDs with policy intent to 'reduce the cost of capital' and therefore electricity costs to consumers. This is obviously a contestable proposition as lower costs of capital simply reflect the reduced risks to market participants and increased risks to governments, taxpayers or consumers who take on these risks via RoP PPA CfD counterparty positions.
That said, Peluchon (2019, p.1) notes that, 'We find that Contracts for Difference (CfDs) or capacity markets lower the equilibrium cost of capital, and thus lead to more capacity investment when perfect competition applies, as well as to lower expected costs for consumers. As a consequence, these mechanisms should not be seen as subsidies, but as welfare improving market-design reforms.' ARUP (2018, p.3) states, 'Our analysis shows that a CfD can lower the WACC of an onshore wind project by between 140 and 320 basis points, which in turn lowers the levelised cost of energy of an onshore wind project by between £6/MWh and £12/MWh relative to a position where no revenue stabilisation is being provided.' NAB (2020, p.13) finds, 'We expect the overall impact of the Long-Term Energy Services Agreements as described in the Roadmap may lead to lower PPA strike prices than would be expected under a standard CFD contract, which could result in a nominal vanilla WACC that is between 0.08% lower to 0.49% higher for a Representative Project, depending on the design of the auction and contracting process.'

Our subsequent analysis shows that it may not necessarily be true that the long-term cost of capital will be lower with long-term RoP PPA CfDs in place. In certain circumstances, the use of a RoP PPA CfD simply shifts the risks incurred by market participants from inadequate pricing to curtailed output which is outbid in the generation bid stack by alternative business models during conditions of oversupply driven by embedded solar PV exports.

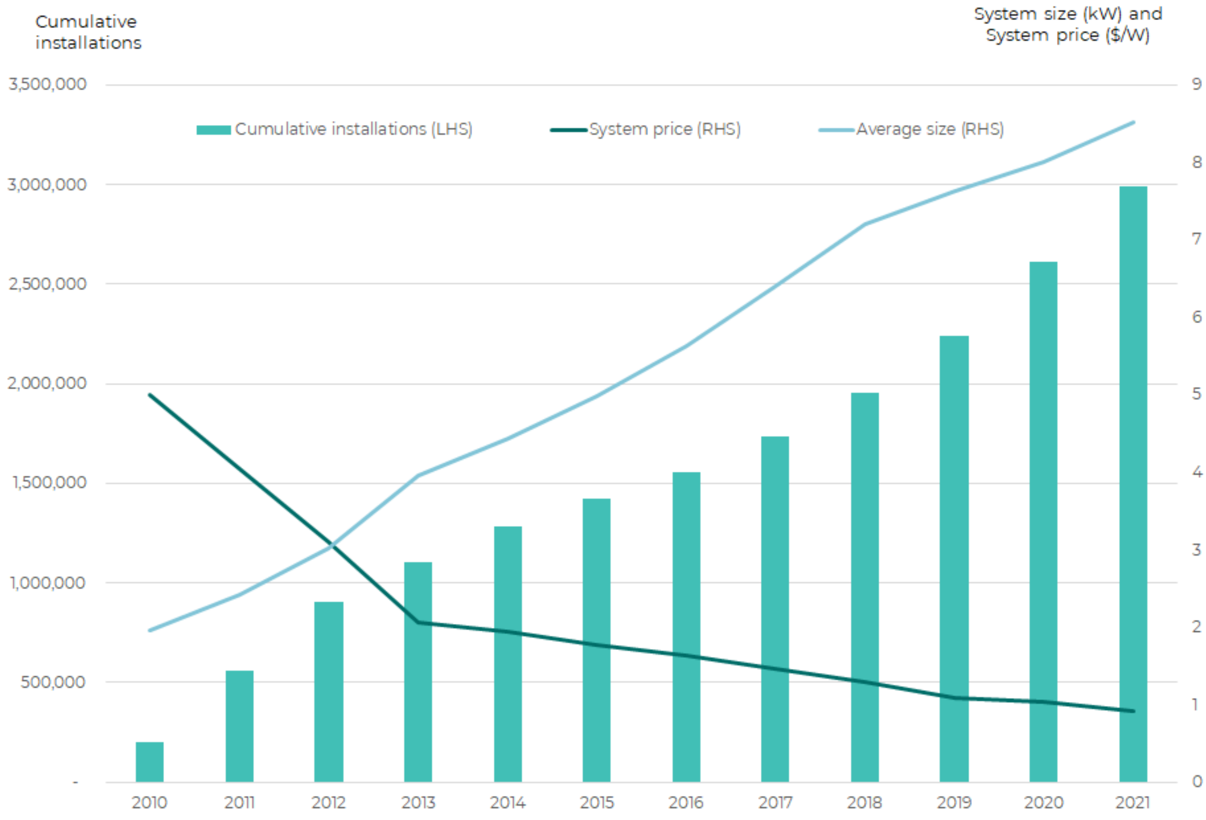
3. Contract design structure and its implications for generation output

The focus of our article is the nature of real-world contracting and how it impacts the behaviour of generators and potential implications for policy makers. We separate our analysis into contract design for small scale behind the meter PV and large-scale renewables.

3.1 Small-scale solar PV

As noted earlier, Australia has one of the highest penetrations of embedded solar PV of anywhere in the world. There are currently around 3.5 million installations totaling around 22 GW of installed capacity. Figure 2 shows the uptake in installations, the growth in average system size and the reduction in system cost from 2010 to 2021.

Figure 2: Solar PV installations, system size and system cost



Source: CER (2022)

Figure 2 shows the significant increase in total solar PV system installations which have been driven by a number of factors. Firstly, upfront subsidies such as the SRES have significantly improved the economics for households and small businesses considering solar PV installation. Secondly, the system cost has progressively fallen as solar technology continues to improve. However, the final reason is less well understood. Households with solar PV continue to benefit from cross-subsidies through network tariff design (see Simshauser, 2017) and they are shielded from wholesale market impacts through the quasi-regulation of FiTs paid by retailers.

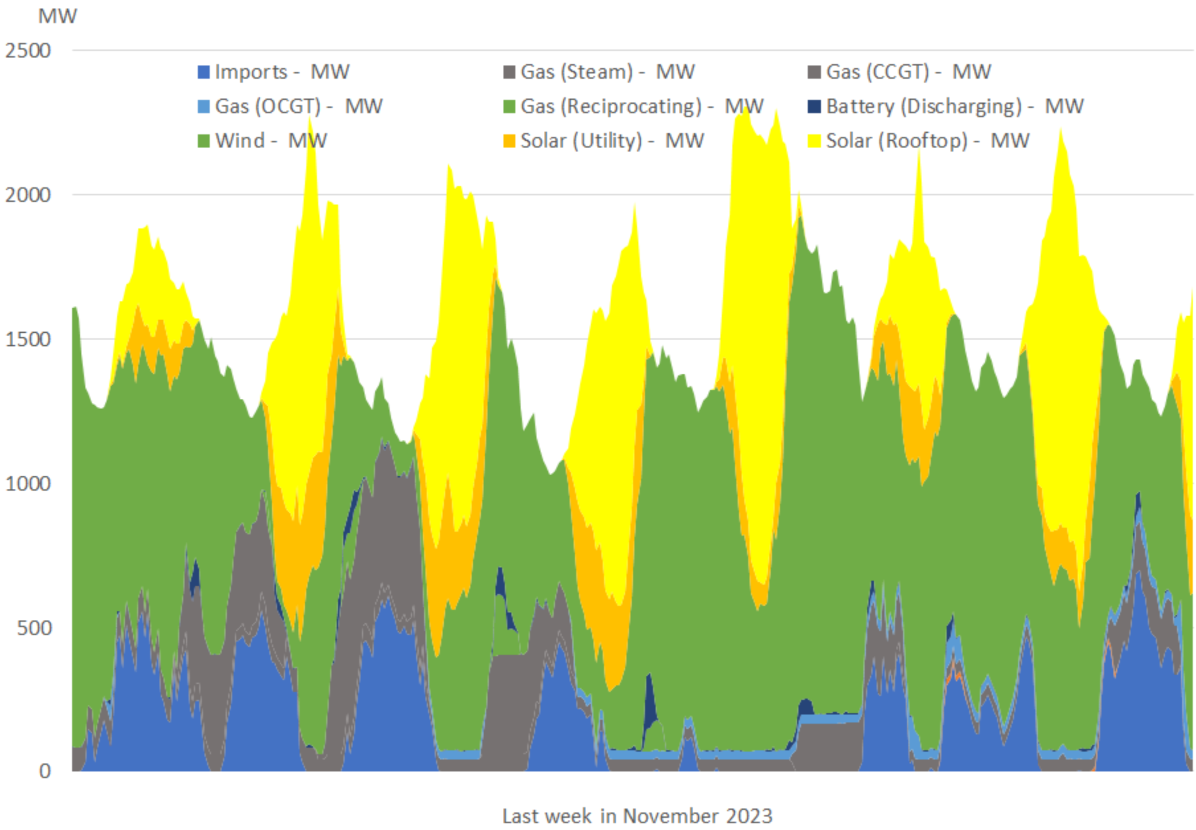
While data is difficult to obtain, governments estimate that typically around 30 to 50% of the electricity generated by a PV system is consumed in the home and 70 to 50% is exported to the grid.[3] From a contract design perspective, these exports are not remunerated via dynamic participation in the wholesale electricity market. Instead, retailers pay a FiT to represent the 'average' value of solar energy exported to the grid (see AER, 2023). This results in a situation where embedded solar PV is effectively contracted to generate and export to the grid even if prices are at the price floor of -$1000/MWh. Consequently, embedded solar PV exports become the first energy dispatched at all times if the energy is available. From a retailer's perspective, they pay the FiT for solar PV energy

[3] See https://www.sustainability.vic.gov.au/energy-efficiency-and-reducing-emissions/save-energy-in-the-home/solar-power, Accessed online on 30 November 2023.

exported by one customer and consumed by another but obviously not all retailers have a perfectly balanced position.

The lack of a dynamic pricing signal for embedded PV exports is problematic when one considers the seasonal and diurnal nature of electricity supply and demand. Figure 3 shows a typical week in the shoulder seasons of Spring and Autumn. Small-scale solar PV exported generation dominates overall production in the middle of the day because it will be offered into the market at all times (i.e. the price floor of -$1,000/MWh). The impact on large-scale generation contract design is explored in the subsequent sub-section.

Figure 3: Generation in South Australia during a typical Spring or Autumn shoulder season



Source: AEMO Data

3.2 Large-scale generation contract design

We consider four main contracting structures used by market participants to manage price risks associated with operating in the energy-only Australian NEM. While these are not the only contracts used, they are useful for demonstrating how electricity contract design can significantly alter wholesale market outcomes in certain conditions. We contrast these four main types of financial contracts in Table 2.

Table 2: Taxonomy of financial contracts underpinning VRE output

Contract Type	Description	Typical Tenor	Comment
Financial derivative (OTC or exchange based)	Swap contracts are effectively an agreement to pay the difference between the average wholesale electricity price and the contract price for a block MW across a period, typically a quarter or a year	Up to 3 years	These contracts are commonly used by thermal generators (such as coal) to underpin revenues and reduce risks. It has been uncommon for VRE generators to use these contracts as they effectively substitute output and price risk
Run-of-Plant (RoP) PPA CfD (no price floor)	RoP PPA CfD contracts are an agreement to pay the difference between the wholesale energy price and the contract price for each MWh produced during the relevant pricing period	7-15 years	These contracts were used by some of the early adopters of VRE. However, the lack of a price floor resulted in substantial payments being made to generators during times of VRE oversupply (e.g. middle of the day)
RoP PPA CfD with $0 price floor	As above, these evolved forms of RoP PPA CfD contracts are an agreement to pay the difference between the wholesale energy price and the contract price but with a floor of $0/MWh	7-15 years	These are the most commonly used contracts to underpin investment in VRE. Project proponents generally use these contracts to achieve high levels of project financing (reducing financing costs) as price risk is thought to be removed from the project structure
Vertically integrated renewable energy retailer/generator	A vertically integrated renewable energy firm sells wholesale or firm retail energy contracts to end customers. Options contracts such as CAPs (limiting prices to $300) or owned firming generation (BESS, hydro etc) are used to mitigate price risks when VRE is not available	Up to 15 years	These contracts are becoming increasingly common – companies offer to sell 100% VRE to customers[4]

[4] See University of Sydney to be powered by 100% renewable electricity new partnership with Snowy Hydro and Red Energy - Snowy Hydro as an example. Accessed online on 10 May 2023.

Profit maximisation by generators is achieved by optimising their production in spot markets with regard to their specific contract position. To demonstrate, let us consider a standard electricity system with a real time aggregative supply curve (Q_s) at a time where there is surplus capacity.

$$Q_s(P, v, w) = \sum_{i=1}^{n} q_i(P, v, w) \qquad \text{Equation 1}$$

Any individual generator has total revenues given by Equation 2 and profit given by Equation 3

$$TR(q) = P(q) * q \qquad \text{Equation 2}$$

$$\pi(q) = P(q) * q - TC(q) = TR(q) - TC(q) \qquad \text{Equation 3}$$

Each generator will then seek to maximise profit as per Equation 4, effectively setting marginal cost (MC) equal to marginal revenue.

$$\frac{d\pi}{dq} = \pi'(q) = \frac{dTR}{dq} - \frac{dTC}{dq} = 0 \qquad \text{Equation 4}$$

Profit maximization also requires that marginal profit is optimised. This is achieved when marginal profit is decreasing at the optimal level of quantity (a second order condition). Equation 5 shows how this condition would be satisfied.

$$\left.\frac{d^2\pi}{dq^2}\right|_{q\ =\ q\ *} = \left.\frac{d\pi'(q)}{dq}\right|_{q\ =\ q\ *} < 0 \qquad \text{Equation 5}$$

Each generation contract structure in Table 2 will have a distinctly different objective function. RoP PPA CfD generators will have an incentive to maximise production when the realised spot revenue and CfD closeout is greater than any costs incurred from operating during negative pricing. However, the objective function for vertically integrated renewable energy retailers is more complex.

Mansur (2007, p. 8) provides the objective function for a vertically integrated generator and notes that, ‘the greater the retail obligation, the less incentive a firm has to set high prices.’ The objective function is:

$$maxP_iQ_i.\left(q_i - q_d^i\right) + r_i^d q_i^d - C_i(q_i) \qquad \text{Equation 6}$$

P_iQ_i is the inverse residual demand function the vertically integrated firm (i) faces in the spot market, q_i is its production, $r_i^d q_i^d$is the retail price and retail load and $C_i(q_i)$ is the production cost. Importantly, Mazur (2007) demonstrates that this firm has the incentive to increase prices where it has surplus generation and is therefore a net seller (i.e. $q_i > q_i^d$).

We extend this thinking by considering a scenario where the same firm has an incentive to decrease prices (i.e. is a net buyer). For example, a retailer with a large industrial customer is short to its position but can utilise surplus solar PV exports for part of its position. In this scenario, the firm is supplying renewable energy in a market with significant spare renewable generation due to the proliferation of small scale solar PV exports. The objective function above is effectively the same form but instead of maximising the price/quantity of surplus generation, the objective is to maximise the negative price for an optimal quantity of short generation where the firm is a net buyer (i.e. $q_i < q_i^d$).

We present individual TC and TR functions for each generation type in Appendix 1. These can then be utilised to generate stylised supply curves which are presented in Figure 4. The supply curves are effectively the ‘offers’ each generator will make in each five-minute interval based upon their generation economics and their contract structure.

Figure 4: Stylised Representation of Supply 'Offer' Curves for Four Contract Structures

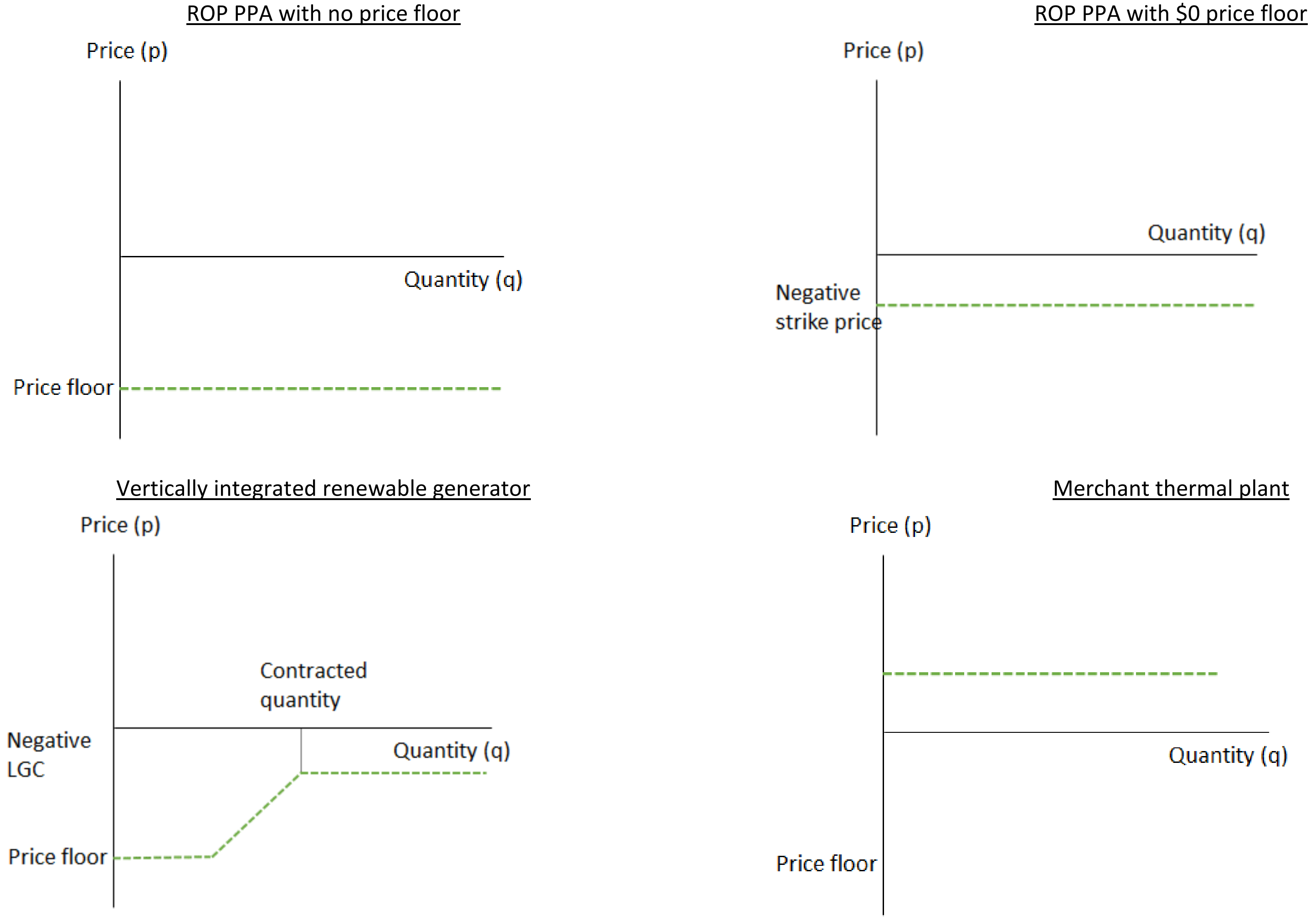


Figure 4 shows the four stylised supply curves associated with the contract structures outlined in Appendix 1. Firstly, the ROP PPA CfD (with no price floor) allows the generator to offer all of its generation at the price floor. It is guaranteed the contract price irrespective of the wholesale price in each five-minute interval. Secondly, the ROP PPA CfD (with a price floor) allows the generator to offer all of its generation at the negative contract strike price. As long as the clearing price in the market is higher than this, its marginal costs (of operation and perhaps paying to generate if the price is negative) will be lower than its marginal revenue. Thirdly, a vertically integrated renewable energy generator may offer its renewable generation into the market at the price floor up to the optimal supply/price quantity. Beyond its contracted quantity, the generator will only offer its output at the negative LGC price so that marginal profit is maximised. Finally, a merchant thermal plant will offer its generation at its marginal cost.

A simple example of the economics of a vertically integrated renewable energy generator and RoP PPA CfD is provided below. For simplicity, we have assumed green credits (LGCs) do not exist and there is a $0 price floor for the RoP PPA CfD. In this example, two generators have distinctly different contract positions:

- The first is a RoP PPA CfD for up to 75 MW of output at $50/MWh

- The second is a retail contract for 75 MW of output at $50/MWh

The profit/loss for each contract position assuming the generator is running at 50 MW for one hour is shown in Table 3. A heat map table with the various levels of profit and loss at different wholesale prices is provided in Table 4.

Table 3: Profit and loss statement for simple example to contrast contract structures

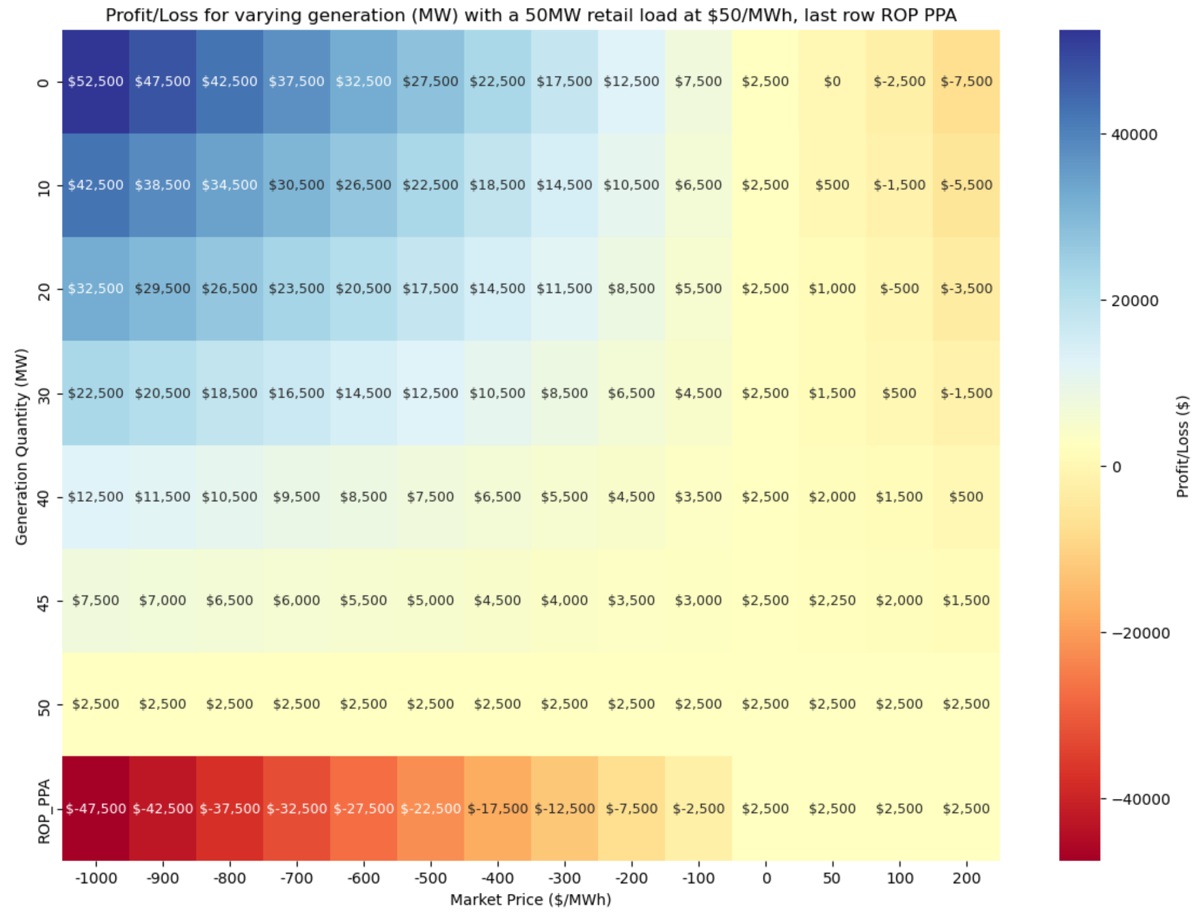
RoP PPA CfD

Wholesale price	Contract Revenue	Gen Pool Revenue	Contract exposure	Profit/Loss
$-1,000/MWh	$2,500	$-50,000	$0	$-47,500
$-500/MWh	$2,500	$-25,000	$0	$-22,500
$-100/MWh	$2,500	$-5,000	$0	$-2,500
$0/MWh	$2,500	$0	$0	$2,500
$100/MWh	$2,500	$5,000	$-5,000	$2,500

Vertically integrated renewable generator

Wholesale price	Gen Pool Revenue	Customer Pool Exposure	Contract Revenue	Profit
$-1,000/MWh	$-50,000	$75,000	$3,750	$28,750
$-500/MWh	$-25,000	$37,500	$3,750	$16,250
$-100/MWh	$-5,000	$7,500	$3,750	$6,250
$0/MWh	0	$0	$3,750	$3,750
$100/MWh	$5,000	$-7,500	$3,750	$1,250

Table 4: Profit and loss heat maps for RoP PPA CfD and vertically integrated renewable generator



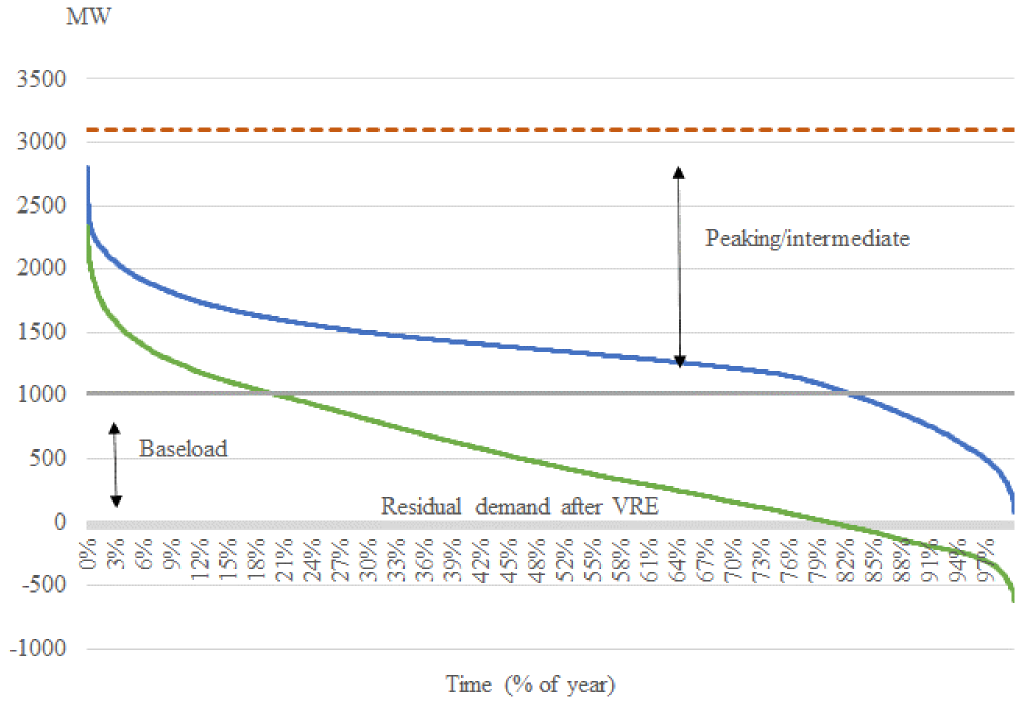
Put simply, in any market with a material temporal surplus of renewables and deep negative pricing a vertically integrated renewable generator will be profitably dispatched when it is short to its contract position. This therefore reduces the output achieved by RoP PPA CfD generators and therefore their overall project economics.

The purpose of this analysis is not to highlight the superiority of any particular contract design. Instead, it is aimed at highlighting the risks to governments and generation proponents of entering into long-lived contracts that may not be able to respond to evolving market conditions. We consider these evolving market conditions in the next section with a focus on South Australia in Australia's NEM.

4. Real world example – the South Australian electricity market

The South Australian market has one of the highest penetrations of VRE in the world. Figure 5 shows the load duration curves with and without VRE for the 2022 calendar year.

Figure 5: South Australian load duration curve



South Australia is the smallest mainland regional market in Australia's NEM with peak demand of around 3 GW. It has one of the highest penetrations of both embedded PV and large scale wind and solar in the world. In 2022, around 20% of demand was met by embedded PV, there was ~2.5 GW of operating wind and ~0.5 GW of operating utility-scale solar. Figure 5 shows the significant carve out of renewables with residual demand negative for around 20% of the year. Utilising a simple Optimal Plant Mix model (see Berrie, 1967), we are able to show that the market is significantly long energy and capacity. This is shown in Table 5.

Table 5: Optimal plant mix in South Australia (2022)

	Optimal Plant Mix	Actual 2022	Imbalance	Weighting
Baseload	5,363	9,805	4,442	overweight
Intermediate	4,883	502	-4,381	underweight
Peaking*	3,295	4,485	1,190	overweight
	13,541	14792	1,251	overweight

*Assumes 15% reserve capacity

Figure 6: Dispersion of South Australian wholesale electricity prices

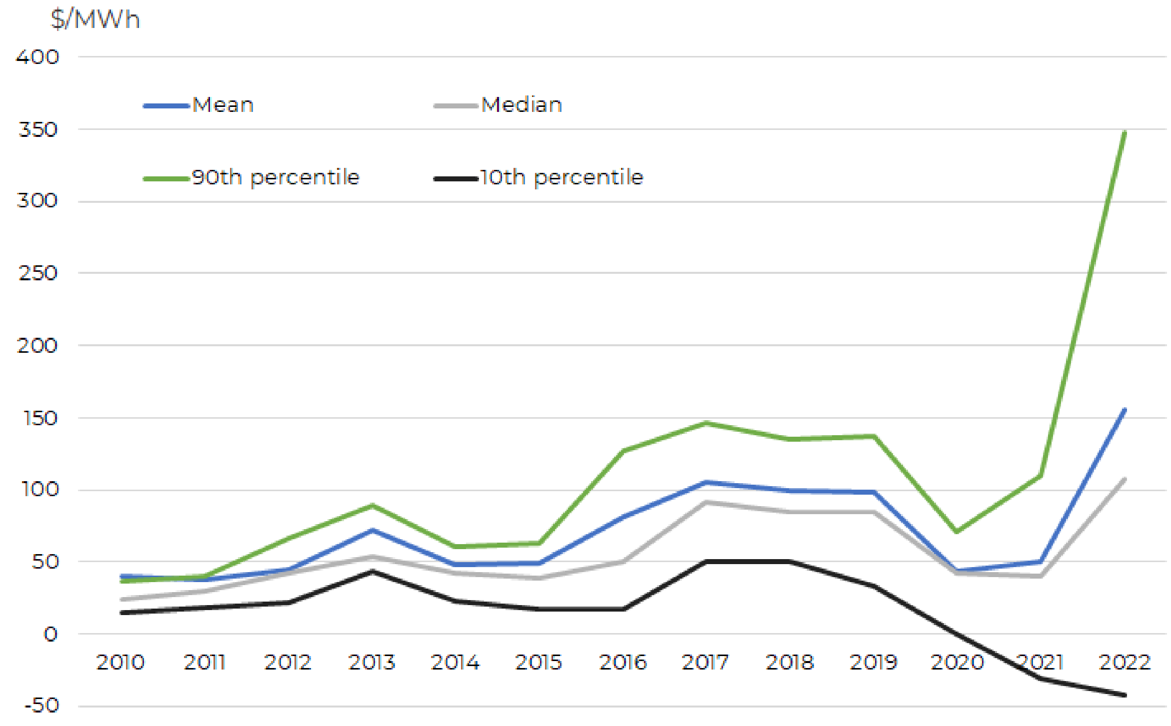
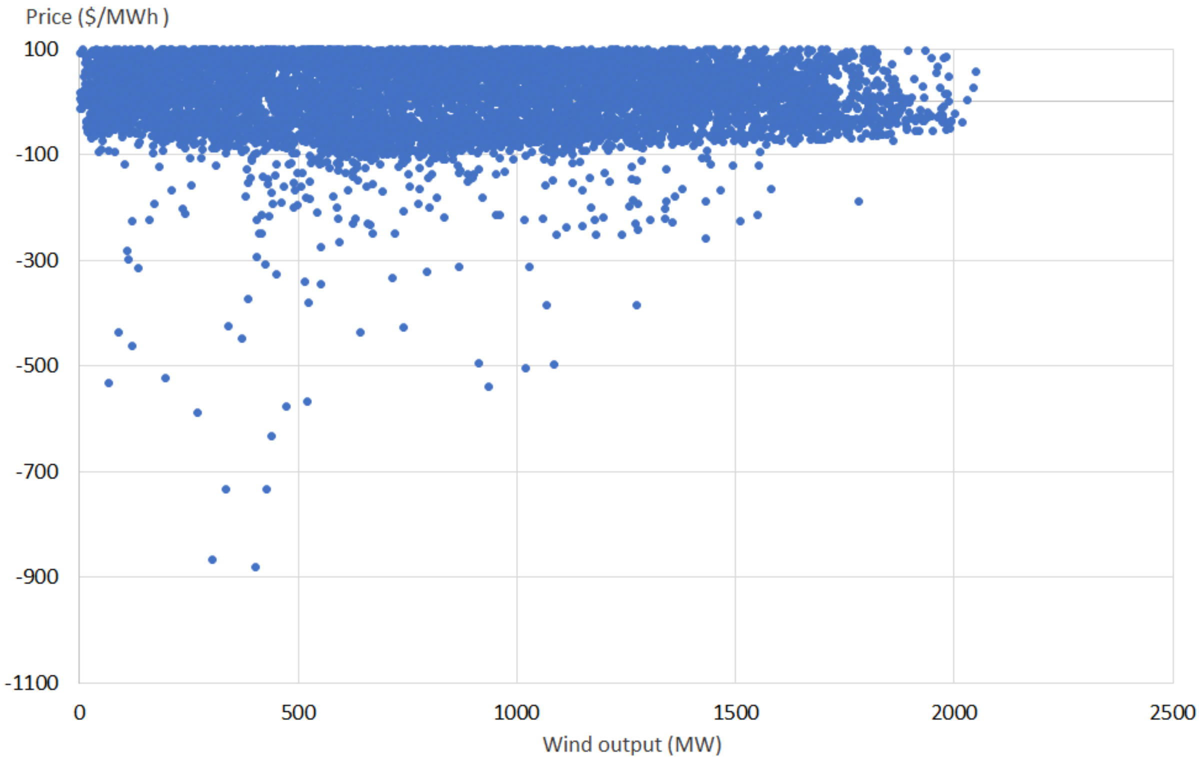


Figure 7: Scatter plot of wind production and wholesale electricity price (limited to $100/MWh)



Given the variability of renewable production, there has been an increasing dispersion of prices. This is shown in Figure 6. The 10th percentile of prices is now approaching -$50/MWh and around one-fifth of pricing intervals are now negative. But the 90th percentile and average price are significantly higher. These pricing dynamics are being driven by the coincident production of wind and solar with low levels of grid-demand (which is also now materially lower due to record embedded PV production with nearly one in three detached homes having PV installed). Figure 7 shows a scatterplot of wind production and wholesale pricing outcomes. It is clear that wind generators are exposed to material negative pricing dynamics with a very significant number of observations between $0 and negative $100/MWh and a not immaterial number of observations below negative $100/MWh. In fact, the dispatch weighted average price (DWA) of a wind farm in South Australia in 2022 was $113/MWh – compared to the average price of ~$155/MWh. This means that the DWA of a wind farm in South Australia is around 72% of the time-weighted average (TWA).

With these market dynamics in place, the interaction of contract design and wholesale pricing outcomes cannot be ignored when designing public policy. While we are unable to precisely estimate the quantity of embedded solar PV exports, we know that during daylight hours, there is now a large volume of energy from solar PV exports which is dispatched at any price. Therefore, at times of material oversupply of renewable generation in the middle of the day (during maximum solar output), individual generation contract positions will determine whether they can be dispatched profitably or be curtailed. To demonstrate this, we have analysed offers of VRE generation by price band made by generators during the period between September to December 2022 and contrasted these with varying levels of demand. This is shown in Figure 8.

Figure 8: Offers of VRE generation within price bid bands contrasted with demand in South Australia

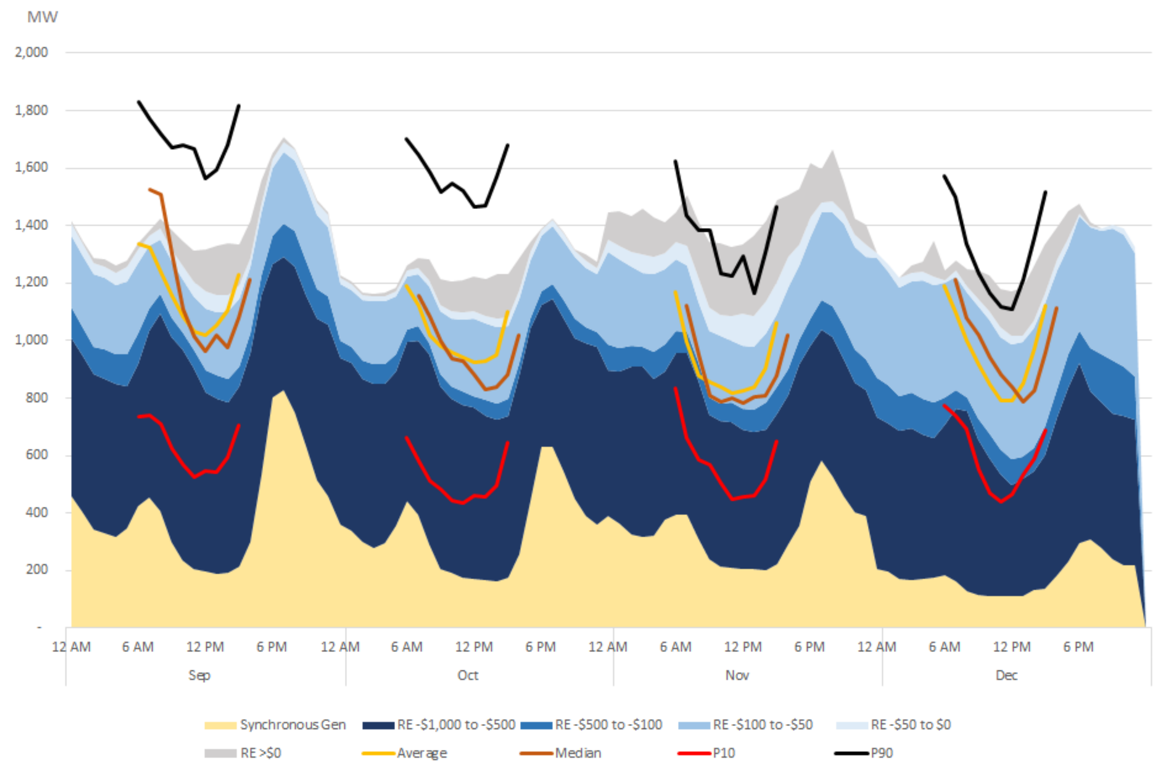


Figure 8 shows that there is now a significant volume of energy regularly being offered into the South Australian market at prices between -$1000/MWh and -$500/MWh. These generation portfolios are clearly indifferent to the pricing outcome at certain quantities. While we do not know the specifics of their commercial position, we can deduce from their bidding behaviour that they are either RoP PPA CfDs with no price floor or vertically integrated renewable generators with retail or wholesale contracts. The P10 demand in the middle of the day is clearly within this deep negative pricing band

and even the median and average demands are approaching it. The continued reduction of daylight demand (due to increased solar PV deployment behind the meter which is effectively offered to the market at the price floor at all times) is likely to result in material reductions in output from wind generators that are exposed to reduced (or negative) profitability because of deep negative prices.

To consider this from a specific generation portfolio perspective, we have selected a single day within this timeframe to demonstrate how contract design clearly influences output of portfolios during deep negative pricing. Figure 9 shows the South Australian wholesale price and individual generator portfolio output for the 24 hours of 20 November 2022. This day was selected due to the very high wind conditions, very low demand and therefore very low wholesale price which averaged negative $132.05/MWh.

Figure 9: Generator portfolio output and wholesale prices in South Australia on 20 November 2022

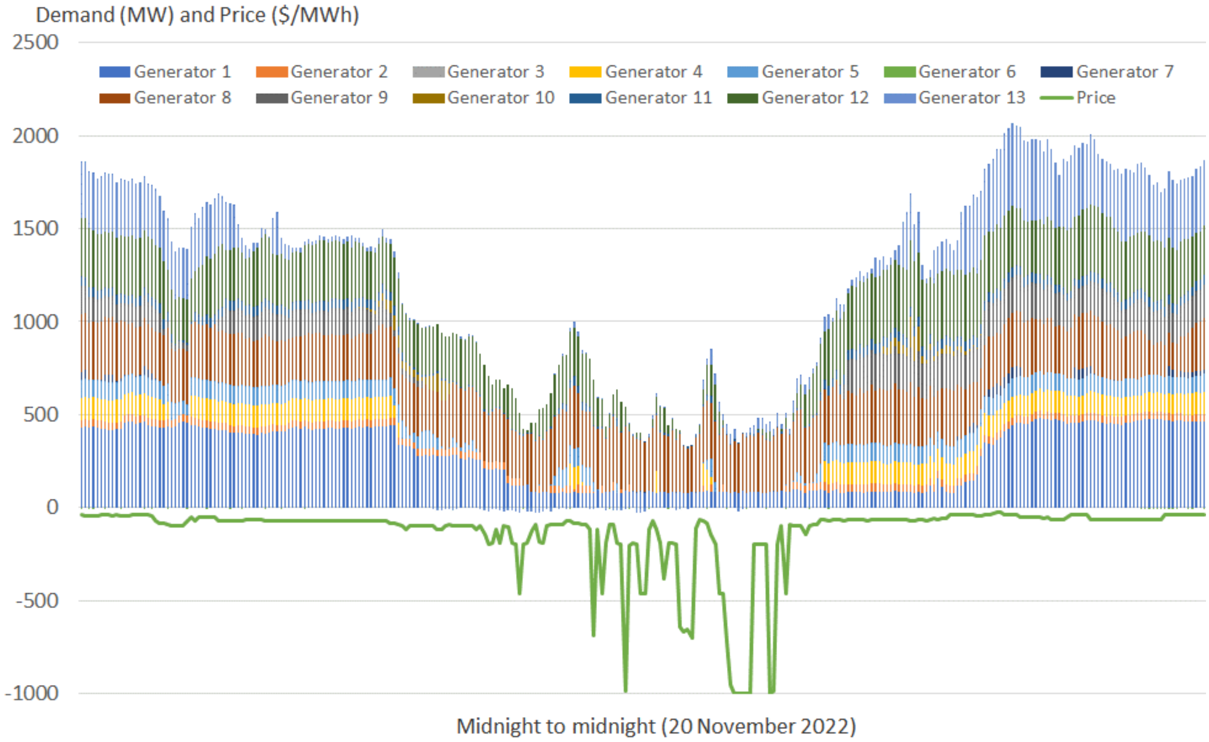
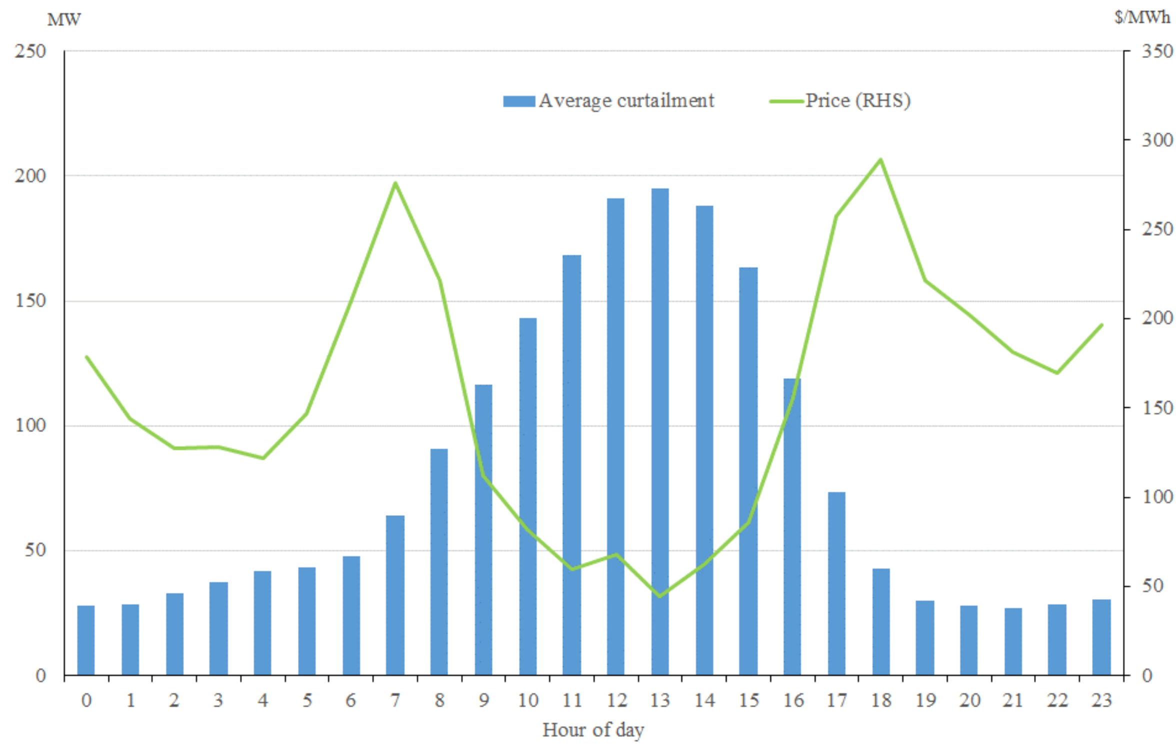


Figure 9 shows the reduction in output from many of the VRE portfolios in response to deep negative pricing during the middle of the day in South Australia on 20 November 2022. Three portfolios continued to produce during these conditions indicating that deep negative pricing must (in certain circumstances) allow for continued profitable operation. This extreme example shows that our proposition in Section 3 is at least partially observed in practice: contract design influences the total output achievable by a renewable generator. RoP PPA CfDs are economically curtailed in these circumstances and their project economics negatively impacted (due to lost production). Over the course of a year, the curtailment can be significant. This is documented in Figure 10 which shows the average MW of curtailment in SA by hour of day during the 2022 calendar year.

Figure 10: Average curtailment and wholesale price during 2022



It should be noted that the South Australian market continues to evolve and change so our analysis should be seen as relevant for these specific circumstances only. While it is true that operational demand continues to decline due to the proliferation of behind-the-meter solar PV, new interconnection is being built with NSW (allowing surplus generation to be exported into NSW) and companies are adding batteries (BESS) to their portfolios. However, at least in the case of BESS development there is incentive for integrated portfolios of generation and retail customer contracts to build a BESS for two purposes that are not relevant for long dated RoP PPA CfDs. Firstly, by installing a BESS, a firmed renewable portfolio shifts the retail or sold position to the right in its supply curve. This effectively increases the amount of generation it can offer to the market at deep negative prices. And secondly, a BESS allows the portfolio to minimise the risks of meeting retail/wholesale contract obligations associated with higher prices when VRE production is low (i.e. evening peak demand).

5. Discussion and Policy implications

The volatility associated with Australia's energy-only NEM is very useful for driving the right operational decision making in real time. A high market price cap and very low floor create the right incentives for clearing the market in a system with significantly variable demand (due to weather) and increasingly weather dependent supply (VRE). The interaction of these dynamic pricing settings with forward contract markets and longer-term financing structures are what drives an efficient level of investment.

However, investors must now also consider the interaction of these market design settings with climate policy and the coincident nature of renewable generation output and the associated impact on wholesale electricity prices. This article has looked at the interaction of these factors within the prism of contract design. Our findings are that contract design can fundamentally shift incentives to generate at different wholesale electricity prices.

Specifically, we have considered how a vertically integrated renewable energy generators can achieve priority dispatch relative to more traditional RoP PPA CfD contract structures during periods of material VRE oversupply driven by embedded PV exports that are indifferent to negative pricing. As government issued RoP PPA CfD policies are increasingly used to drive investment in renewables, our analysis should at least be considered as a reason to pause and assess whether RoP PPA CfD policies really can ever reduce costs to consumers by reducing risks and the cost of capital. In fact, our analysis suggests that in certain circumstances (and maybe others we haven't considered), RoP PPA CfDs may in fact constrain optimal decision making by generation participants due to the inherently volatile conditions associated with very variable weather-induced demand and supply. This is particularly relevant given that the nature of seasonal weather patterns may mean that an optimal level of VRE capacity will result in output being 'spilled' or 'curtailed' during high production weeks and months (see Bernstein, 2023). Our analysis shows that contract design may in fact determine which renewable generation is curtailed. This has non-trivial implications for investors, consumers and governments. In fact, further research should be done on whether the \$/MWh 'savings' achieved by lowering the cost of capital through RoP PPA CfD issuance are outweighed by the \$/MWh increase in LCOE due to fewer MWh being dispatched. The current financial state of RoP PPA CfD generators (particularly solar) would be an ideal test case for this analysis and future research.

Accordingly, we propose that there are three key policy implications from our analysis: the use of non-electricity price based government-initiated CfDs; the development of new financial products; and the importance of transparency in relation to RoP PPA CfD issuance.

Utilising alternatives to electricity price based CfDs

Around one in three Australian households now have solar PV installed behind the meter and new installation rates remain steady. It is therefore questionable whether governments will be able to reform the way in which embedded PV is dispatched in the market. Even if retailers cease to pay any FiT at all, the continued growth in system size is likely to see continued solar exports into the distribution network. In the absence of governments requiring embedded solar PV to participate in the wholesale market, the efficacy of government initiated RoP PPA CfDs is likely to be questionable. This is because the policy shields investors from price risks but not output risk during periods of renewable oversupply, and output risk is material if embedded solar PV exports continue to receive priority dispatch due to the non-application of dynamic pricing signals.

There is very little in the literature to support ongoing use of government-issued RoP PPA CfDs to support new investments in conventional wind and solar technologies (recall the literature in Section 2). Arguments in relation to reducing costs by removing risk and lowering the cost of capital are unlikely to be valid when markets continue to evolve with new forms of electricity contracting to address changing risks and consumer preferences (as demonstrated in this article). Specifically, the use of government issued RoP PPA CfDs may not reduce capital costs if price risk is simply substituted for generation output risk.

However, given existing government RoP PPA CfD policy design, it may be that governments could pivot their CfD frameworks to give effect to a more efficient outcome. Specifically, Nelson et al (2022) suggest that governments write the CfD for solar and wind on the green credit or carbon abatement value. Rather than a RoP PPA CfD that is for the 'bundled' green right (LGC or Renewable Energy Guarantee of Origin: REGO) and electricity, the contract could be structured as a CfD for LGCs/REGOs only. This would avoid the need for governments to allocate long-dated electricity market risk to either participants (in the form of reduced output in times of VRE oversupply) or consumers. Furthermore, as suggested by Nelson et al (2022), such a policy would allow government CfD policies to become a carbon abatement buyer of last resort and facilitate fungibility with other abatement policies (such as voluntary VRE purchases by electricity consumers and the Safeguard Emissions Reduction Policy). The major advantage of this approach is that markets, rather than governments, would be required to develop new means of contracting to manage both the electricity price and the production risk.

New financial products

A key observation in relation to the South Australian market is the prevalence of negative pricing due to material temporal oversupply of VRE at times of high production relative to demand. It may be that markets need to evolve. Specifically, the market would benefit from the equivalent of a cap (option product limiting prices to $300/MWh) for negative pricing (Billimoria, 2021). This 'floor' product could be sold by developers of new BESS infrastructure. The option premium would reflect the benefit to a VRE generator of capping their exposure to negative pricing. Importantly, this more stable revenue stream would improve the stability of business cases for new BESS infrastructure. In time, the option premium for a cap and a floor would effectively become the energy market arbitrage premium for a BESS – in the same way that a cap has historically been used a proxy for the capital cost of new firming generation.

The importance of transparency in relation to CfD issuance

Improved disclosure of government issued RoP PPA CfD impacts on the electricity market and consumer bills is necessary for policy evaluation. None of the existing government-issued RoP PPA CfD policy documents require disclosure of these metrics. Investors and consumers would benefit from greater disclosure as it would add to the wealth of knowledge about how these policies interact with the electricity market's design parameters and adjacent climate policies.

6. Concluding Remarks

This article has considered how the design of wholesale electricity contracts drives outcomes in the wholesale spot market in certain circumstances in Australia's NEM. In particular, the article has shown that a vertically integrated renewable generator will profitably generate at deep negative prices (as long as the overall generation is short to the contracted quantity). In environments of significant oversupply driven by embedded PV dispatching into the distribution network with indifference to wholesale market prices, vertically integrated portfolios are able to continue to operate while RoP PPA CfD exposed wind and solar plants are curtailed.

Our analysis shows that long-term blunt price-based contract designs such as RoP PPA CfDs may be unsuited to allocating risk in a market that relies upon acute pricing signals to clear oversupply and address temporal scarcity. Accordingly, governments should be cautious in continuing to utilise these types of contracts via government-issued RoP PPA CfDs as it is unclear that the risks are indeed mitigated appropriately.

Electricity markets will continue to evolve as new technology and consumer preferences drive changes in supply and demand. Market participant contracting techniques will also need to adapt to these changing conditions so that risks and costs can be appropriately allocated to those best placed to address them.

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Appendix 1

Each generator has a fixed upper installed generation capability in any discrete time period (K) and a ‘fuel cost’ (FC). Generators that have sold ‘firm’ contracts at quantity FCQ receive a fixed contract price (CP). The spot market price is given by P. The total cost (TC) and total revenue (TR) functions are shown in the Tables below.

Total cost structures

Contract Structure	Total Cost
1. ROP PPA (no $0 price floor)	$TC(q) = FC * q$
2. ROP PPA ($0 price floor)	$TC(q) = if P(q) \begin{cases} < 0, & 0 \\ > 0, & FC * q \end{cases}$
3. Fixed price sold VRE output	$TC(q) = if P(q) \begin{cases} > CP, if \left\{ K \dfrac{> FCQ, FC * q}{< FCG, FC * q + (FCG - K) * p} \right. \\ < 0, \left\{ K \dfrac{> FCQ, FC * q + (K - FCQ) * p}{< FCG, FC * q} \right. \end{cases}$
4. Merchant fast-start thermal plant	$TC(q) = FC * q$

Total revenue structures

Contract Structure	Total Revenue
1. ROP PPA (no $0 price floor)	$TR(q) = CP * q$
2. ROP PPA ($0 price floor)	$TR(q) = \ if \left\{ P(q) \dfrac{> 0, CP * q}{< 0, 0} \right.$
3. Fixed price sold VRE output	$TR(q) = if P(q) \begin{cases} > CP, if \left\{ K \dfrac{> FCQ, CP * FCQ + (K - FCQ) * p}{< FCG, CP * q} \right. \\ < 0, \left\{ K \dfrac{> FCQ, CP * FCQ}{< FCG, CP * FCQ + (FCG - K) * p} \right. \end{cases}$
4. Merchant fast-start thermal plant	$TR(q) = p * q$