Unhedged risk in hybrid energy markets: Optimising the revenue mix of Australian Solar

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Abstract
Australia is facing a historic investment challenge, with an estimated $1.2 to $1.5 trillion in newly invested capital required by 2030 in order to meet 2050 decarbonisation targets. In response policy makers have begun "re-entering" energy markets, which were deregulated and privatised in the 1990's. Public auctions for State-backed 'Contracts-for-Differences' (CfDs) now act as a key policy tool to "prime" energy markets for new variable renewable energy (VRE) capacity. In a phenomenon recently coined "market hybridisation", market participants form long-term investment decisions that are increasingly disconnected from short-run spot pricing dynamics and day-to-day operations. Historically, it has been common practice to underpin VRE projects with some form of power purchase agreement (PPA). However, increasing investor appetites for "semi-merchant" projects (i.e. projects partially exposed to spot prices) has become an emerging trend. This article examines the semi-merchant phenomenon, aiming to explain why the investment model is becoming popular for investors in VRE. Of particular interest are the foregone advantages attributable to highly contracted plant when securing bankable project finance. Results reveal that a revenue mix comprising 70-80% PPA coverage and 20-30% merchant exposure appears viable and tractable for investors in utility scale solar - whilst maintaining a typical project finance capital structure of c.60-70% gearing. By implication, policymakers targeting 4000MW of new solar capacity via CfD auction may need only offer ~3000MW of contracted capacity, thereby reducing taxpayer exposures and protecting scarce government balance sheet resources.

Key words: Cost of Capital, Counterparty Credit, Renewable Energy, Project Finance, PPAs.

1. Introduction

Australian energy markets are experiencing a structural supply shift away from fossil fuel dependant technologies and towards variable renewable energy (VRE). The scale and pace of this transition is only anticipated to accelerate, with regulatory and policy frameworks increasingly supporting net-zero and decarbonisation objectives. Given the sheer volume of required capital (between $1.2 and $1.5 trillion by 2030)[1], a successful transition is intrinsically dependent on the investment appetites of two primary capital providers – institutional investors and project banks.

Following sweeping microeconomic reforms in the 1990s, Australia's energy sector was restructured and privatised with the intent to "split up" vertically integrated monopoly utilities. The market was divided into three segments, broadly comprising retailing, transmission and generation. The reforms, in their totality, formally established Australia's National Electricity Market (NEM). Today, the NEM comprises five interconnected eastern and south-eastern states of New South Wales (NSW), Queensland (QLD), Victoria (VIC), South Australia (SA) and Tasmania. Improvements to productive, allocative and dynamic efficiency all constituted key microeconomic objectives of the reform. These were achieved, in part, via the privatisation of greenfield generation assets, which necessitated the commitment of

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[1] Net Zero Australia July 2023 mobilisation report - https://www.netzeroaustralia.net.au/wp-content/uploads/2023/07/Net-Zero-Australia-Mobilisation-How-to-make-net-zero-happen-12-July-23.pdf

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private capital to establish new generation capacity. The "Merchant Power Producer" was hence established as the canonical supply-side business model during the early years of newly deregulated energy markets (Finon, 2008). Such assets derived revenues by selling new electricity into the NEM's real-time energy-only gross pool at the spot price (i.e. "merchant" revenue).

VRE technologies deviated from this practice by instead exhibiting reliance on contracted cashflows secured by a third-party – cf. accepting prevailing spot market pricing. As a result, Australian State Governments have formed a practice of "priming" supply markets VRE by auctioning state credit-wrapped Contracts-for-Difference (CfDs) to private developers. CfDs fundamentally operate as financial instruments, allowing renewable generators to "lock in" a pre-determined fixed price for a set portion of generation. Note that long-dated contracts with private offtakers, referred to more commonly as power purchase agreements (PPAs), have existed in global energy markets since the 1970's. State-backed CfDs on the other hand, represent a more recent policy-driven phenomenon. Such contracts intend to provide a level of cash flow certainty to stand-alone generation assets - decoupling revenues from the volatile price fluctuations of the NEM's gross pool. The utility of revenue security is further amplified for VRE technology given that generation timing is entirely dependent on exogenous weather conditions. Increased revenue security reduces cash flow volatility for project owners and, consequentially, facilitates bankability.

The advantages and disadvantages of CfD auctions as a policy tool involve nuanced considerations, with widespread implementation seemingly introducing new risks vis-à-vis liquidity in adjacent contract markets (Simshauser, 2019).[2] Notwithstanding, at present the approach does appear to be favoured by Australian policy makers motivated by decarbonisation targets. The proliferation of such contracts, underwritten by both public and private counterparties, introduces what many have described as the "hybridisation" of energy-only markets. A phenomenon whereby generators initially compete "for the market" via security of long-dated offtake contracts, then "in the market" via participation in real-time spot markets, encouraging the cost-effective management of day-to-day operations (Keppler et al., 2022). Despite a growing literature, limited attention has been dedicated to the hybridisation of individual VRE investments – i.e. projects with revenues derived from both long-dated offtake contracts *and* real-time spot markets (Flottmann et al, 2022, Gohdes et al. 2023).

Hybrid VRE structures are highly concerned with the preferences of two aforementioned providers of capital - institutional investors (equity) and project banks (debt). The relative preferences of these parties under various contracted circumstances have been established in previous works (Gohdes et al. 2022). However, deeper investigation into the practical realities of hybrid projects is essential if market hybridisation continues to be the trajectory of the NEM. This analysis is focused on the split between contracted revenues (via fixed price PPA or CfD) and merchant revenues derived from spot markets. In the NEM, both CfDs and conventional PPAs operate by exchanging a variable merchant exposure for a fixed-price "contracted" exposure. The two terms will therefore be used interchangeably throughout this analysis.[3]

This paper builds on the results of Gohdes et al. (2023) by applying the same analysis methodology to Australian solar PV projects (cf. wind technology), albeit with

[2] These considerations are addressed in further detail in section 5.
[3] See Gohdes et al. (2022) for a more detailed analysis CfDs and PPAs, as well as their intrinsic differences.

additional improvements vis-à-vis robustness and modelling nuances.[4] The optimal contracting set-point for partially contracted (referred to hereafter as *semi-merchant*) solar plant is analysed, with simulated scenarios conducted for multiple major regions of the NEM – including NSW, QLD, VIC and SA. Modelling results confirm that meaningful spot market exposure (c.20-30%) appears tractable under a typical project finance structure (typically 60-70% gearing). Indeed, for Australian solar a revenue structure comprising 70-80% contracted capacity appears capable of meeting typical project financing covenants with a capital structure comprising 64-70% debt. It is important to highlight that these modelling results do not comprise a *prescriptive* recommendation for Australian solar plant in all contexts. Rather, these results simply serve to illustrate what is possible in Australian energy markets if VRE financing occurs under semi-contracted conditions.

An ex-ante vs ex-post analysis is conducted for two levels of contracted coverage (viz. fully contracted and semi-merchant) by applying historical datasets comprising real spot market data, regional-specific grid implications and investor/lender return appetites. Modelling results demonstrate and quantify the capacity for windfall profits via merchant exposure, as has been witnessed in Australia energy markets from 2021-2023. In addition, the arguably less intuitive risks associated with comparably "inflexible" fully contracted project arrangements are highlighted via a series of common distress scenarios. Taken in their totality, these results assist in explaining the increasing preference amongst VRE/solar investors to retain some proportion of merchant exposure. Furthermore, additional support is provided to the proposition put forward by Gohdes et al. (2023) that a policymakers targeting c.4000MW of VRE entry commitments may need only auction ~3000MW of CfDs (i.e. 75% contracted capacity), thus considerably reducing taxpayer exposures. It is pertinent to highlight that these findings to not comprise a commentary on the appropriateness of historical investment appetites amongst energy market participants. Rather, this analysis is simply focused on providing necessary context to an emerging trend in energy-only markets, viz. the hybridisation of VRE projects.

This article is structured as follows. Section 2 contains a review of the relevant literature; Section 3 describes the modelling approach and Section 4 reviews model outputs. Section 5 discusses related policy insights Section 6 provides concluding remarks.

2. Review of literature

This analysis is concerned with the capital structure of renewable generation and the hybridisation of energy markets. Literature concerning both areas is summarised as follows.

2.1. Capital structure of renewables

The capital-intensive nature of new entrant VRE *often* requires access to debt finance as a fundamental pre-condition vis-à-vis project feasibility. At present (2023), the NEM has multiple VRE projects under construction within a capacity range of 400-1000MW. This implies a total investment commitment of $1.2 - $2.6b per project, assuming current overnight capital costs of ~$2600/kW. Furthermore, grid-scale wind and solar capacity requires a 9-fold increase by 2050 (16GW to c.140GW) under the 2022 Integrated System Plan released by the Australian Energy Market Operator

[4] Gohdes et al. (2023) applies similar methodologies with respect to a typical Australian wind project located in NSW. This work aims to demonstrate that the same principles hold true for Australian solar (irrespective of regional location), whilst simultaneously enhancing model robustness via additional financing constraints and producing additional insights vis-à-vis bankability at *all* levels of contractual cover.

(AEMO).[5] The size and scale of investment required to bring such capacity online is apparent.

Investment commitments of this magnitude are inherently sensitive to the cost of capital when determining competitive entry costs (Steffen, 2018). Incumbent VRE projects further amplify this dependence due to proportionally higher capital outlays (cf. their fossil fuel counterparts) (Schmidt, 2014; Newbery, 2016; Grubb and Newbery, 2018). Project cost of capital therefore plays a critical role informing project long-run marginal unit cost (commonly represented in $/MWh) for renewable projects. This concept has been well established in the literature historically (Kann, 2009; Wiser, 1997; Mills and Taylor, 1994) and is reiterated in more recent works (Steffen, 2018; Nelson, 2020; Newbery, 2016; Gohdes et al., 2022, Rai and Nelson, 2021; McDonald, 2023; Gohdes et al. 2023).

The Weighted Average Cost of Capital (WACC) for renewable plant is determined by the return expectations of two primary capital providers (in their weighted proportions) - viz. debt (bank finance) and equity (institutional investors) (Myers, 1984). Modigliani and Miller (1958), in their seminal work on the cost of capital, demonstrated the relative weighting of debt and equity to be irrelevant, prima facie, when assuming perfect capital markets – i.e. with no transaction costs, agency costs, asymmetric information or taxes. In practice, capital markets do not operate in the absence of such frictions, meaning that the weightings of equity and debt do in fact play a critical role in optimising WACC and, by extension, long run marginal cost (LRMC) (see Gohdes et al. 2022). The relative risk appetites and investment preferences of both sources is necessarily critical, provided capital structure optimisation is the objective.

Project finance (PF), distinguished by the facilitation of high debt levels (i.e. between 50-80% of the capital structure), remains the dominant form of financing for VRE technology. PF establishes a newly created entity (i.e. special purpose vehicle or 'SPV') for the dedicated purpose of project ownership and management (Steffen, 2018; Esty, 2004; Nelson and Simshauser, 2013). Consequentially, financiers' claims become inherently limited to cashflows *within* the SPV structure, restricting debt repayments to project assets and operational cashflows. SPV structures therefore impact the relative risk, borrowing capacity and management protocols of the project (Esty, 2004). For VRE, a fundamental characteristic of the PF structure involves its ability to facilitate increased gearing levels (cf. financing "on-balance sheet"), ensuring that debt functions as the primary contributor to total capital outlay (Simshauser and Gilmore, 2020). Project finance has therefore become the preferred method of debt raising for renewable projects (Steffen, 2018; Kann, 2009).

The relative simplicity of the project finance structure facilitates higher levels of gearing and a lower requirement for equity contributions, both of which facilitate a lower project WACC and a more "optimised" capital structure by implication. Despite such optimisations, it is important to acknowledge that PF structures do not represent improvement without accompanying risk. The literature has long acknowledged the fundamental risks arising from the increased leverage facilitated by a PF structure (Churchill, 1996; Pollio, 1998; White et al., 2000; Lock, 2003; Vaaler et al., 2008). Section 4.3 of this paper clearly depicts the realisation of these risks.

The security of project cashflows is fundamental for debt serviceability within the PF structure. This is because project banks are restricted to claiming recourse over the future cash flows generated by the project. It is therefore typical that a financiers' risk appetite is only satisfied once the ability to repay principal debt is demonstrable under *conservative* circumstances (and whilst meeting appropriate financing

[5] See: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

covenants). Project banks therefore remain highly focused on the *quality* of prospective project cashflows (i.e. merchant vs. contracted revenues with a creditworthy counterparty) when determining financing terms, including credit spreads, debt service cover ratios and maximum gearing (Rai and Nelson, 2021; Nelson and Simshauser, 2013; Gohdes et al., 2022).

2.2. Hybrid markets and Power Purchase Agreements

PPA contracts, in their many variations, have operated as a staple within energy markets for decades. PPAs form a contractual arrangement between a generator and an offtaker to purchase a pre-determined proportion of capacity output at a fixed price for a fixed term. The concept can be traced as far back as the U.S Public Utility Regulatory Policies Act (PURPA) of 1978 - an initiative also responsible for sparking the first project financing of a power project in 1981 (Simshauser and Nelson, 2012). The original policy was devised to facilitate the development of cogeneration plants, with the intent to on-sell capacity to regulated electricity utilities (Yescombe and Farquharson, 2018). The security provided by such arrangement facilitated financing for new, independent plant, with long-term power purchase agreements providing the required revenue security to project investors.

The privatisation of the British electricity industry in the early 1990s also prompted the formation of PPA-style contracts for newly developed combined cycle gas turbine plant (Newbery, 2021). Australia followed suit with a small number of pre-NEM investment commitments originating throughout the 1990s (Yescombe and Farquharson, 2018). PPAs have since operated as a critical tool for VRE developers in Australia, providing projects with required revenue certainty in an otherwise highly risky merchant market (Rai and Nelson, 2021; Simshauser and Gilmore, 2020). “Merchant plant” refers to a generator operating in the absence of a PPA contract, instead operating fully exposed to volatile spot and short-term forward market prices for generated output (Nelson and Simshauser, 2013; Finon, 2008; Simshauser, 2020; Finon and Pignon, 2008b).

Existing literature often references the importance of revenue security in facilitating VRE bankability (Nelson *et al.*, 2013; Simshauser and Gilmore, 2020; 2022 Steffen, 2018). Price hedging is essential to achieve minimum levels of revenue certainty otherwise absent in the NEM’s energy-only gross pool (and further amplified by the variable generation conditions of VRE) (Flottmann et al., 2022; Simshauser, 2020). In fact, generators utilising a PF structure are often *presumed* to be underwritten by long-dated, run-of-plant PPAs (Finon and Pignon, 2008a; Newbery, 2017; de Atholia, Flannigan and Lai, 2020; Chao, Oren and Wilson, 2008; Finon, 2008).[6] Gohdes *et al.* (2022) quantify the relationship between VRE entry cost and the quality of project revenues as informed by contracted coverage and the counterparty’s credit rating. Their findings suggest that VRE plant operating with higher revenue quality – i.e. higher coverage from an investment-grade counterparty, become capable of securing more favourable financing terms and lower return hurdles from equity providers. VRE’s dependence on PPAs is referenced by numerous other works without explicit quantification of the relationship (Kann, 2009; Grubb and Newbery, 2018; Mills and Taylor, 1994; Nelson et al., 2022; Steffen, 2018).

An evolving body of literature has proposed that today’s energy-only markets are becoming ‘hybridised’ via long-dated PPAs and CfDs, see; Joskow, (2022), Grubb and Newbery (2018), Keppler et al. (2022), Schittekatte and Batlle (2023) and Roques and Finon (2017). Hybridised energy markets are characterised by disconnecting long-term investment decisions vis-à-vis capital allocation from short-

[6] Whilst PPAs do indeed facilitate revenue certainty via price hedging, the recent increased penetration of VRE technology does threaten the creation of volume-related risks caused by merit-order bidding and subsequent pricing cannibalisation during mid-day periods. Increasingly frequent periods of negative pricing do create unhedged risks within many traditional PPA arrangements and constitute an area worthy of analysis.

term market operations and spot market dynamics. The concession here constitutes an acceptance that PPAs play a structural role in procuring the supply of newly incumbent plant – i.e. the "long-term module" described by Keppler et al., (2022). The corresponding "short-term module" continues to promote efficient management of day-today operations via competitive wholesale markets. Participation encourages operators to align output with market demand irrespective of long-run revenue security. This framework effectively describes the decoupling of long-term capital-intensive investment decisions from the short-run risks associated with spot markets, theoretically optimising both centralised and de-centralised market elements (Keppler et al, 2022).

Regarding the PPA counterparty, Australian projects possess a variety of options when procuring bankable and secure revenue streams – i.e. participating in Keppler's long-term market module. Whilst no formal restrictions exist on who can participate in PPA markets, in practice underwriters can often be categorised into three distinct groups. These include (1) energy retailers motivated by decarbonising hedge portfolios or acquitting obligations under renewable targets, (2) state governments seeking to prime markets for new VRE capacity investment, and (3) corporates motivated by either sustainability targets or the allure of cheap electricity (Rai and Nelson, 2021; Nelson, 2018, 2020; Simshauser and Gilmore, 2020, 2022).

3. Model and Data

The present analysis is underpinned by a dynamic, integrated, multi-year power Project Finance model (PF Model). The PF Model is established to simulate a 'typical' Australian Solar PV project at utility scale, restricted by requirements from the two primary providers of project capital - project banks and institutional equity. The following section is dedicated to providing detail on key model inputs and assumptions.[7]

The simulated solar PV project size is 200MW and was selected to align with the "hypothetical project" AC capacity detailed in the 2020 AEMO Cost and Technical Parameters Review. The authors acknowledge the average size of solar PV projects has increased significantly since FY2020 (with plant size increasing to >400MW in some instances). Notwithstanding, 200MW remains a reasonable "typical" project size as of July 2020. The project commences operations on 1 July 2019 – i.e. at the start of the 2020 financial year (FY). FY2020 coincides with a period of *relative* price stability, stable entry costs and with forward prices preceding recent market turmoils.[8]

3.1. Model scenarios

The PF Model is tasked with simulating a series of distinct scenarios for four hypothetical solar PV projects across Australia's NEM. These scenarios comprise both 'ex-ante' (as at FY2020) and 'ex-post' (as at present, i.e. 2023) analysis. The scenarios are as follows:

1. The 'ex ante fully contracted' scenario simulates a *fully contracted* solar PV project. Here the PF Model is tasked with optimising the project's capital structure *whilst* minimising LRMC under an 8.0% equity return constraint. Note that a nominal, post-tax, post-financing equity return is considered - see Table 2. Solved LRMC is synonymous with the most competitive CfD price ($/MWh) that the project is capable of bidding at auction, whilst satisfying all project stakeholders (i.e. project banks, equity investors, plant supplier). Note that "fully contracted" refers to run-of-plant PPA covering 100% of generation output, including revenue from green certificates.

[7] Further detail vis-à-vis PF model algebra can be found in Gohdes et al. (2023).
[8] Energy markets have been impacted by Covid-19, the war in Ukraine, uncoordinated transition and other factors. See Flottmann (2023) for a holistic analysis vis-à-vis market challenges in years proceeding FY2020.

2. The 'ex ante *semi-merchant'* scenario simulates a "hybrid" project with a split of contracted (via PPA) and uncontracted (merchant) revenue. This scenario is tasked with identifying the maximum level of merchant exposure without sacrificing the project's ability to secure typical project financing terms and maintain 60% (at minimum) debt within the capital structure.[9] The scenario adopts previously established competitive PPA pricing and determines bankability via the ability to meet inbuilt financing constraints detailed in Table 1 and described in Section 3.2. Perhaps most critically, merchant prices applied are *ex ante* - see Figure 1. Once bankability is established, minimum viable PPA coverage is ultimately determined by the project's ability to simultaneously achieve sufficient equity return thresholds to procure necessary investor capital.

3. The first 'ex-post' scenario re-populates the PF Model with available live spot and forward market data (FY2020-2027), exposing the semi-merchant plant to *actual* market developments witnessed by merchant-exposed plant between 2020 and 2023. Years comprising both out- and under-performance are hence captured. Note that there is no reason to produce an 'ex post fully contracted' scenario, as the 100% PPA coverage ensures that the project's ex post returns do not deviate from the fully contracted ex ante forecast.

4. Finally, certain operational variables are adversely stress tested for both ex-post scenarios, including production delays, construction cost overruns, deteriorating loss factors and unexpected curtailment of generation. Both ex-post scenarios (viz. fully contracted and semi-merchant) are re-simulated under distressed conditions, allowing for performance comparison with the benefit of hindsight.

3.2. Project assumptions – applied to all scenarios

It is assumed that the 200MW solar project is 'acquired' upon the commencement of operations, i.e. post-commissioning. Note the post-commissioning period would ordinarily follow an intensive ~2-year development period and an additional 18-month period for project construction. This acquisition assumption removes undue complexity derived from construction and development-related risks. These risks have instead been captured by an assumed 'cost of acquisition' of $1200/kW, which is selected to align with the AEMO 2020 Costs and Technical Parameter Review. Table 1 provides detail on all other relevant financial and engineering assumptions.

Table 1. Model inputs and assumptions

Assumptions for 200MW Solar PV Farm acquired in FY2020					
Generation			**Inflation**		
Plant Size	(MW)	200	CPI	(%)	2.50
Annual Capacity Factor	(%)	Table 2*	Electricity Prices	(%)	2.50
Marginal Loss Factor	(%)	Table 2*			
Auxiliary Load	(%)	3.0	**Taxation**		
Equivalent Forced Outage Rate	(%)	1.5	Tax Rate	(%)	30
Technical Life	(Years)	30	Useful Plant Life	(Years)	30
Degredation	(% p.a.)	0.4	Module Depreciation	(Years)	20
Plant costs			**Financing**		
Acquisition Cost	($/kw)	1,200	Debt Tenor	(Years)	20
Acquisition Price	($M)	240	PPA Tenor	(Years)	15
Equipment Portion of Capex	(% of capex)	60.0	BBSW**	(%)	2.00
Variable O&M	($/MWh)	N/A	Lock Up Covenant	(DSCR Multiple)	1.10x
Fixed O&M	($/MW p.a.)	16,990	DSCR for Spot Revenue**	(DSCR Multiple)	1.80x***
Ancillary Services Cost	($/MWh)	1.0	DSCR for PPA Revenue**	(DSCR Multiple)	1.25x***
Maintenance Capex	($M p.a.)	1.2	Breakeven Price	($/MWh)	27.5

*Input varies by NEM region, refer to Table 2
** DSCR refers to Debt Service Coverage Ratio, BBSW refers to the assumed Bank Bill Swap Rate
***DSCR is determined on a dynamic basis via a "hybridised" weighted average, see Section 3.5

[9] A minimum of 60% debt within the capital structure conforms conservatively with historical Australian energy market trends.

As seen in Table 1, a 2.5% inflation rate assumes the middle bound of the 2-3% long range target set by the Reserve Bank of Australia.[10] The project has a useful life of 30 years, with an effective debt tenor (financing life) of 20 years. O&M Service Agreements regularly span 30 years for Australian solar projects, thereby allowing project banks to also accept the prior assumption of a 30-year useful life when assessing bankability. For taxation purposes, a 20-year depreciation tenor is applied to align with Australian Taxation Office rulings. Note that plant specifications including generation, size, operating costs and technical life are sourced from AEMO's 2020 Costs and Technical Parameter Review.[11]

Industry standard PF methodology is adopted when sizing debt and sculpting repayments. Debt service payments for each period are sculpted against cash flow available for debt serving (CFADS) by applying the scenario specific debt service cover ratio (DSCR). Repayments incorporate both principal and interest, with the latter calculated via the methodology of Simshauser and Gilmore (2020). To summarise, the total interest rate for a given period is built up using the scenario-specific credit spread and a bank bill swap rate (BBSW) - derived via the average return on 2020 corporate bond issuances.

Three critical financing constraints are applied to the PF Model. The first constraint comprises a cash buffer which retains cashflows equal to six months of forecasted total financing commitments. The net impact is a minor delay to a portion of dividends for the sake of providing lenders with additional security. The second constraint comprises a typical lock-up covenant. The covenant is set at 1.1 times CFADS (see Table 1) and stipulates that dividends are withheld during periods where cash flows are insufficient to maintain a 1.1x DSCR ratio. This ensures that long-run financing commitments are prioritised during periods with tight cash flows.

The final constraint - the breakeven pricing constraint, is arguably the most significant when determining project gearing. The constraint functions by initially sizing project debt (using the DSCR methodology described above) before calculating the project's loan life coverage ratio (LLCR). This ratio compromises the project's total debt balance divided by the total CFADS generated throughout the financing tenor *while* assuming constant merchant pricing of a specified value ($28.5/MWh in this case). The constraint restricts total borrowings to a level whereby the project is marginally capable of repaying all debt under circumstances where $28.5/MWh is the constant merchant pricing in the market.[12]

All cashflow constraints have been adopted to reflect those which are commonly agreed by project financed VRE plant. Note that financing calculations and assumptions are adopted following consultation with project finance experts actively operating in Australian energy markets.

Table 2 sets out the divergence in capital structuring inputs between the fully contracted scenario and the semi-merchant scenario. Note that all semi-merchant specific inputs are either solved for within the model or derived, per Table 4. Further details regarding derivation methodology can be found in Section 3.5.

[10] Note that the assumed inflation rate of 2.5% has been adopted for the full 30-year project life. By implication, a long-run average rate is most effective in this circumstance. Forecasting the midpoint of the Reserve Bank of Australia's (RBA) 2-3% inflation target is justifiable despite the volatility witnessed in global economies since 2020. This assumption is held constant across all scenarios, thereby limiting its impact on the results of this comparative analysis.

[11] Variable O&M costs are captured by the model within the 'fixed O&M cost' category at $16,990/MW, see: https://aemo.com.au/-/media/files/electricity/%E2%80%8Cnem/%E2%80%8Cplanning_and_%E2%80%8Cforecasting/%E2%80%8Cinputs-assumptions-methodologies/%E2%80%8C2021/Aurecon-Cost-and-Technical-Parameters-Review-2020.pdf

[12] Financing constraints acknowledging the possibility of prolonged periods of depressed merchant prices have become increasingly important to financiers as pricing cannibalization becomes a more present concern vis-à-vis solar PV projects.

Table 2. Scenario dependant assumptions

		Fully Contracted	Semi-Merchant
Capital structure			
Maximum Gearing Level	(%)	73.9*	68.8*
PPA Coverage	(%)	100	75*
Minimum DSCR	(DSCR Multiple)	1.25x	1.44x
Target IRR	(%)	8.00	9.46
Credit spread	(bp)	180	200

*Model output

Regarding the assumptions in Table 2, credit spreads[13], maximum gearing and target IRR (equity return) are aligned with Gohdes et al., (2022). Projects with 100% PPA coverage (i.e. “fully contracted" revenues) become capable, on average, of supporting higher gearing levels (~74%) due to low Debt Service Coverage Ratios (DSCR) (1.25x), minimised required equity returns (~8.0%) and reduced credit spreads (~180 bps). Conversely, fully merchant VRE plant has been demonstrated to, on average, be capable of supporting significantly lower levels of gearing (~40-50%) due to higher DSCR (1.85x) higher target equity returns (~12.25%) and elevated credit spreads (~260bps). Note that these assumptions are also consistent with observed market parameters in Simshauser et al., (2022). To summarise, renewable plant operating with fully contracted cashflows demand *lower* returns from capital providers, whilst plant with no contracted cashflows (i.e. fully merchant) demand *higher* overall returns from the same stakeholders. Semi-merchant inputs are naturally bounded by these two extremes.

3.3. Region specific inputs

Table 3 sets out the variations to key generation and revenue inputs dependent on the selected NEM region. Specifically plant capacity factor, grid marginal loss factor and project economic curtailment[14] are all varied in accordance with State specific averages. Long-run average spot pricing is also calculated to be region specific, represented in real FY2020 dollars (see Figure 1 for application). PPA pricing is solved for each region in accordance with the methodology described in Section 3.1, and again in Section 4.1.[15]

Table 3. Region dependant assumptions

[13] Credit spread refers to the “spread” between the BBSW and the “all-in” interest rate charged by project banks - i.e. the financier’s interest rate margin.
[14] Economic curtailment refers to the voluntary curtailment of generation by the plant operator during periods where it is not economically feasible to supply generation. This would typically occur during periods characterised by negative spot pricing. For this analysis, economic curtailment is calculated by sampling real-time biding data from solar projects located in the relevant NEM region.
[15] Economic curtailment rates sampled in SA are particularly high at c.20%. This can be rationalised by the fact that SA possesses the highest penetration of Solar in the NEM as a proportion of total generation (11.7% rooftop solar, 3.4% utility scale during FY2020 - second being QLD with 6.6% and 4.9% respectively). The synchronous nature of solar generation produces intra-technology revenue cannibalisation, ultimately manifesting as increasingly common negative pricing periods when solar resources are available.

		NSW	QLD	VIC	SA
Generation					
Annual Capacity Factor	(%)	23.05	26.04	25.14	22.87
Marginal Loss Factor	(MLF factor)	0.984	0.929	0.980	0.976
Solar Economic Curtailment	(%)	10.00	7.00	15.00	20.00
Revenue					
PPA Price*	($/MWh)	48.02	42.46	44.96	49.47
Long Run Avg Spot Price (Real FY20$)	($/MWh)	61.40	61.57	58.09	68.94
Spot Ex Ante Forecast**	($/MWh)	See section 3.1 and Figure 3			
Spot Ex Post Forecast**	($/MWh)	See section 3.1 and Figure 3			

*Model output

3.4. Forward prices and spot price forecasts

A forecast of NEM spot prices must be produced in order to inform semi-merchant scenarios. As a base principle, forward spot prices are applied where available before reverting to a 15-year CPI adjusted historic average for a given region. For the ex-ante forecast, forward prices for FY20-23 are applied as at 1 July 2019, before reverting to the 15-yr average. Figures 1a, 1b, 1c and 1d illustrate this, with the lighter solid line series depicting forward prices and the lighter dashed line series representing the 15-yr average. Note that all prices are expressed in constant $FY20 and adjusted for region-specific solar generation dispatch according to the principles of Hirth (2013). Ex-ante price series (lighter line series) are designed to reflect a reasonable expectation of market participants as at July 2029. Figures 1a, 1b, 1c and 1d depict the same methodology for NSW, QLD, VIC and SA respectively. All pricing is depicted post-curtailment (see footnote 14).

Regarding economic curtailment, historical generation is curtailed at the rate specified in Table 3 to accurately mimic profit-seeking bidding behaviour and reflect a true "earned price" for solar technology. The synchronous nature of solar generation produces revenue cannibalisation in regions where solar resources are available, thereby creating the need for this adjustment. Note that some regions experience greater curtailment than others, attributable to variance in uptake in solar technology by region (see footnote 15). The same curtailment rate is applied to both contracted and uncontracted generation, thereby implying a zero-dollar price floor for the PPA.

Figure 1: Ex ante and ex post forward prices and merchant forecasts (real $FY20)

Fig.1a – New South Wales (NSW)

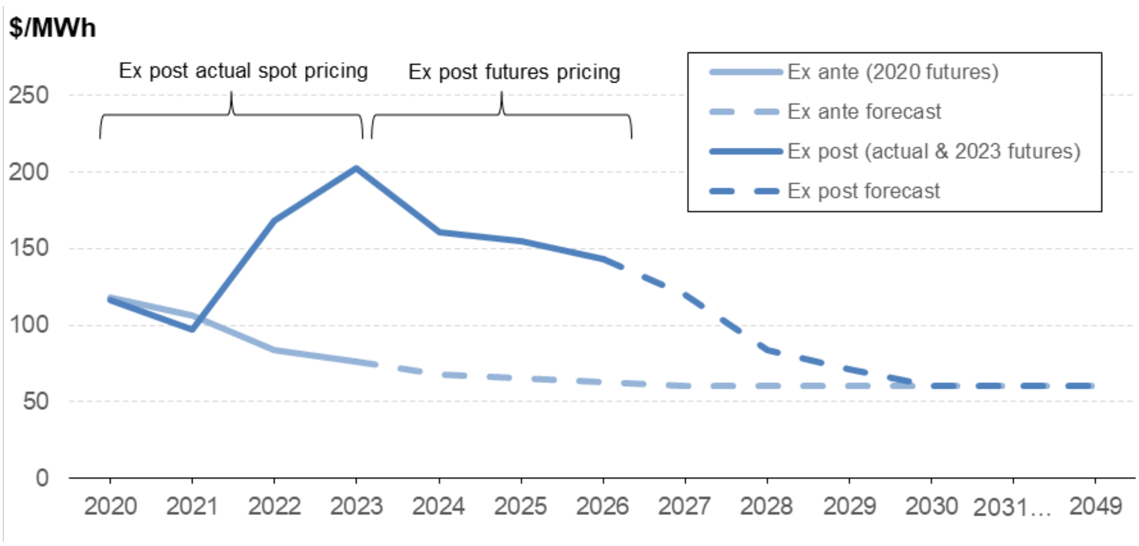


Fig.1b – Queensland (QLD)

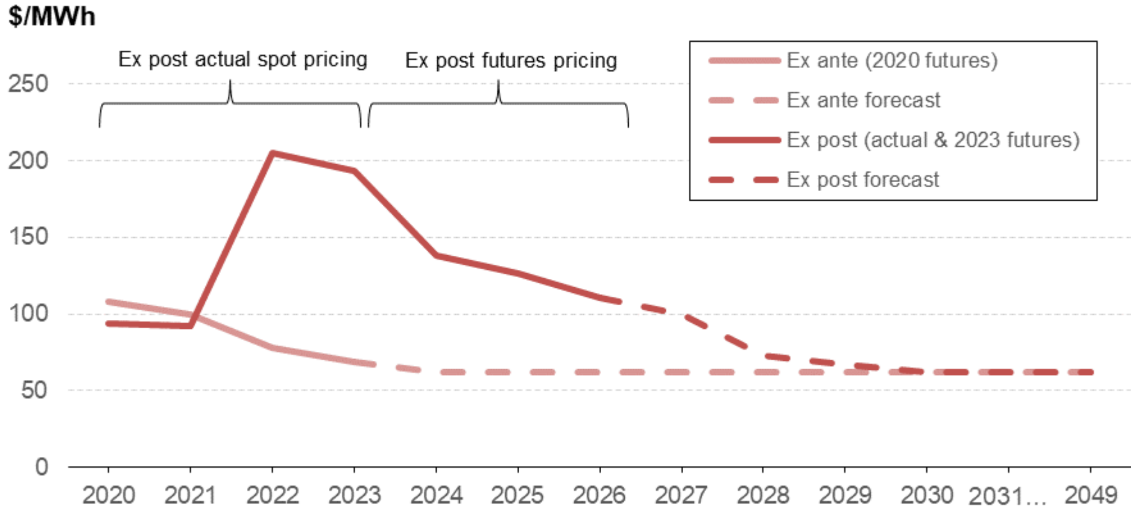


Fig.1c – Victoria (VIC)

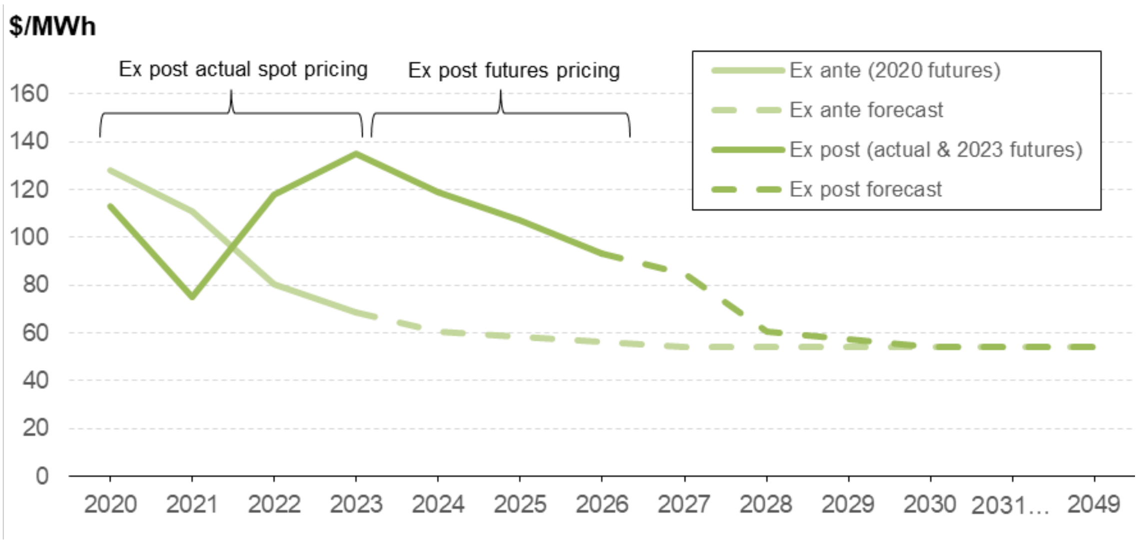
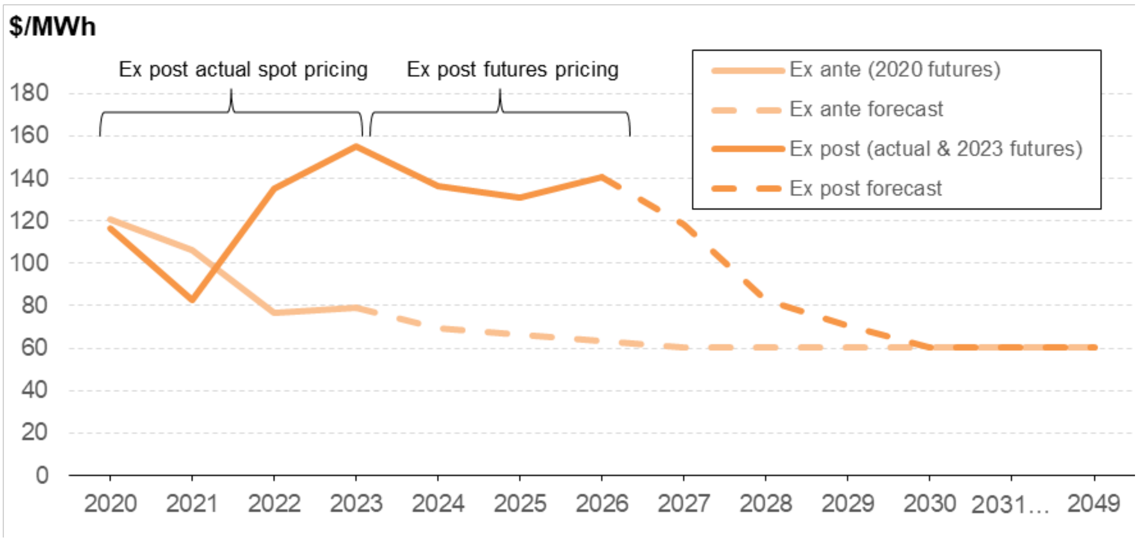


Fig.1d – South Australia (SA)



Source: D-Cypha Trade, Aust. Energy Market Operator

Identical forecasting principles are applied for the ex-post price series, albeit with live data from regional spot and forward markets as at FY2023. The depicted pricing for the first four years (FY20-23 inclusive) represent the actual earned spot prices by solar PV fleet in each NEM region. Note also that FY24-26 prices depict forward curves which are current as of FY2023. The 15-year historic average spot price forecast is applied post FY2026, producing converging pricing by 2030.

Whilst there is clear variance in both historical and forecast pricing across NEM regions, the following commonalities are worthy of acknowledgment. Firstly, all regions experience significant spikes in measured spot pricing in FY2022 and FY2023, far in excess of market expectations as at the commencement of FY2020. Secondly, all regions experience some degree of *under* performance relative to expectations in FY2020 and FY2021, with VIC and SA variance being the most amplified. Both of these details are relevant to the analysis described in Sections 4.2 and 4.3 respectively.

3.5. Semi-merchant DSCR and target IRR calculations – hybrid format

The hybrid source of revenues attributable to the semi-merchant project necessitates that DSCR and IRR assumptions must be *derived* in accordance with survey data from Gohdes et al., (2022). The geometric weight of forecast project revenues is calculated and applied to DSCR and IRR inputs. Hybridisation is produced via the weighting of contracted vs merchant inputs, which are used to derive the final "semi-merchant" input assumption. This represents a typical approach to project banker debt covenants and equity investment hurdles when determining DSCR and IRR targets, respectively.

For the semi-merchant plant, contracted and merchant revenues are volume-weighted during the PPA tenor. Indeed, while the project commences with 75% contracted and 25% merchant capacity, a revenue volume weighting (i.e. geometric average) produces 65.6% contracted and 34.4% merchant allocations. These are applied to "fully contracted" and "fully merchant" DSCR, target IRR and credit spread input values. The subsequent calculation produces a geometric average designed to reflect risk associated with VRE portfolio revenues. Table 4 depicts initial inputs and hybridised semi-merchant assumptions.

Table 4. Semi-merchant hybridised capital costs

Variable		Contracted Portion	Merchant Portion	Semi-Merchant Weighted Avg.
Weighting		*65.60%*	*34.40%*	
DSCR	(DSCR Multiple)	1.25x	1.85x	1.44x
IRR*	(%)	8.00*	12.25*	9.46
Credit spread*	(bp)	180	260	207

*Sourced from Gohdes. et al (2022)

4. Model Results

Simulated PF Model results are structured as follows. Two ex-ante model scenarios are initially established as at 1 July 2019. This is repeated for each NEM region. Ex-ante scenarios provide a view of investor expectations *prior* to the commitment of capital. The first ex-ante scenario reflects a fully contracted 200MW solar PV farm and is used to solve for the competitive PPA price. The second ex ante scenario is a partially contracted, i.e. semi-merchant, 200MW solar PV farm with 20-30% of AC capacity exposed to volatile spot market pricing.

A third scenario is produced by time-shifting the model to 2023 via the application of the ex-post data depicted in Figure 1. This new ex-post scenario is modelled to capture the performance of a semi-merchant plant, relative to the fully contracted plant, once exposed to observed 2020-2023 market prices and updated price forecasts for 2024-2027. Finally, ex-post scenarios are stress tested for shocks to operational project costs.

This methodology is repeated four separate times to simulate the same hypothetical plant across various NEM regions, viz. NSW, QLD, VIC and SA. There are 3 critical inputs that are varied for each region. These include post-curtailment merchant spot pricing (both ex-ante and ex-post, see Fig.1), grid marginal loss factor and annual capacity factor. The solved PPA price also varies between regions as a consequence of regional MLF and capacity factors impacting available energy for sale - see Figure 2.[16]

4.1. Ex Ante Fully Contracted vs. Semi-Merchant

The first task of the PF Model is to simulate a fully contracted utility scale solar PV plant commencing operations in July 2019. Capital structuring inputs are detailed in Tables 1, 2 and 4, and include an IRR target of 8.0% and a total DSCR 1.25x.[17] Two key results emerge simultaneously:

- Project LRMC/MWh of generation – i.e. the minimum year one PPA price required to meet equity and financing obligations. The model solves this to be between $42.5/MWh and $49.5/MWh for the four NEM regions – see Figure 2. PPA pricing is escalated at CPI for the duration of the 15-year tenor.
- The simulated maximum gearing for fully contracted solar plant ranges between 74.7% and 73.1% for all four regions – see later in

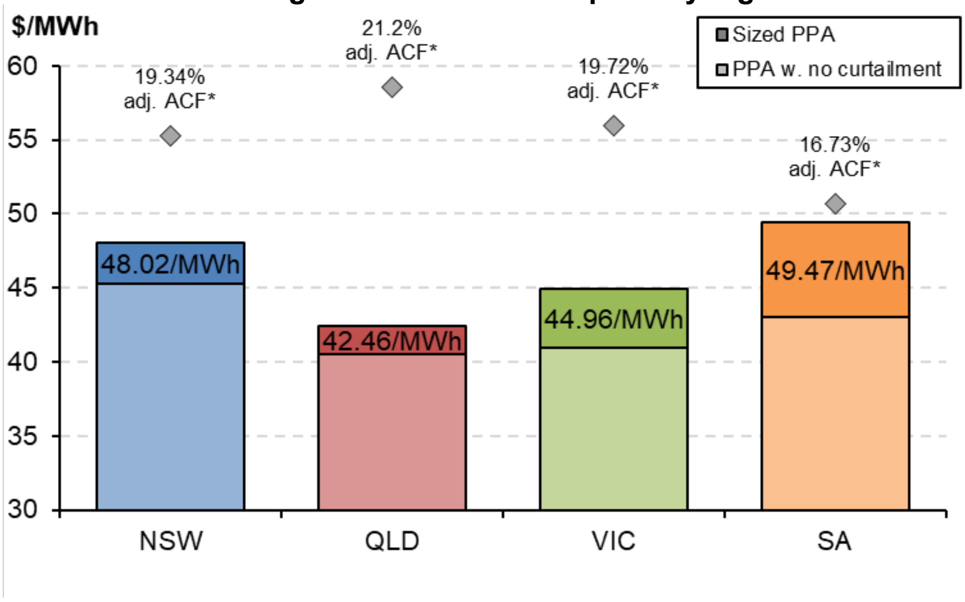
[16] A project with a less favourable MLF and capacity factor will not be able to generate (and therefore derive revenues from) the same quantum of electricity as a project with more favourable characteristics. The PF model compensates for this by solving a higher competitive PPA price for lower performing plant, which ensures the plant remains profitable and investable.

[17] Whilst it is acknowledged that the project technically resumes spot exposure post PPA tenor (i.e. at year 16), the asset has been treated as fully contracted for the purposes determining of debt sizing and investor return appetites.

Fig.3. Note this output aligns with the results of Gohdes et al. (2022), which catalogued survey responses for projects *currently operating* in Australia's NEM.

Recall from Section 3.1 that the arrived PPA price is assumed to reflect a *competitive market bid* for solar PPAs. The estimate(s) detailed in Table 3 are therefore applied to all region-specific scenarios, irrespective of contracted coverage. This assumption ensures modelling consistency *and* that project owners are not implicitly subsidising downside merchant risk by securing a higher PPA price.[18] Final PPA results are also presented in Figure 2, with the regional specific "adjusted capacity factors" (i.e. annual capacity factor adjusted for MLF, auxiliary loss factor, forced outage rate and curtailment) indicated to depict the causal relationship between total generation and estimated PPA pricing – i.e. regions that facilitate greater total generation require lower PPA pricing to achieve the same revenue outcomes.

Figure 2: Solved PPA price by region



*In the case of Fig.2, adjusted ACF refers to the regional annual capacity factor (ACF), adjusted for MLF, auxiliary loss factor (ALF), forced outage rate (FOR) and economic curtailment (EC): $adj.ACF = ACF \cdot \left(1 - \left((1 - MLF) + ALF + FOR + EC\right)\right)$. This value has been strictly created for the purpose of visualisation in Fig.2 and is not a model input or output.

Under the semi-merchant scenario, the PF Model iterates to achieve two key outcomes simultaneously. The first requires a gradual lowering of fixed-price PPA coverage to a range targeting 70-80%, dynamically exposing the project to spot prices in equivalent proportions (i.e. for the 20-30% of uncontracted plant output).

Ultimately, the model seeks to identify the minimum level of PPA coverage without violating the PF Model's inbuilt financing covenants (i.e. debt service coverage ratio) and without decreasing debt below the acceptable range. The second optimised variable comprises project IRR, which must *also* be achieved ex ante for the PPA coverage level to be deemed viable. Equilibria is ultimately found between 70-80% PPA coverage, with the tractable solution depicted in Figures 3 and 4.

Figure 3, referred to here as the "Bankability Frontier", depicts the achievable level of project gearing at all levels of PPA coverage, 0% to 100%. It is made clear that increased levels of PPA coverage leads to a greater capacity to finance upfront capex

[18] A common buyer seeking to minimize the levelized cost of electricity operates as the simplifying assumption here.

costs, at approximately +0.33% additional project gearing on average for each +1% increase in PPA coverage. Note that the applied breakeven constraint (see Section 3.2) is responsible for instances where proportional increases in gearing deviates from an approximately linear trajectory (see QLD 50-60% PPA coverage).

Regarding Figure 4, note that supposed IRR underperformance at <70% PPA coverage is largely attributable to the method by which the PPA is priced – i.e. to target 8.0% annual returns at 100% contractual cover. As PPA coverage decreases project revenues become increasingly subject to merchant prices, meaning that real-world investors become reliant on favourable market prices to make up this perceived shortfall. Note that a higher PPA price would allow for continued maintenance of IRR targets at lower levels of coverage. However, recall that the PPA was sized to avoid this outcome, thereby ensuring that merchant exposure is not "subsidised" by an elevated PPA price.

Figure 3: PPA Coverage vs Project Gearing – The "Bankability Frontier"

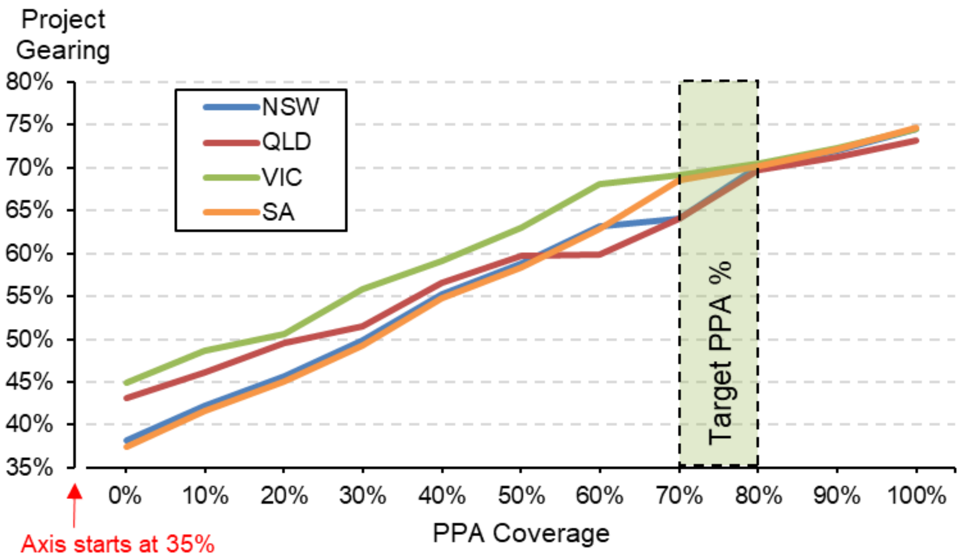
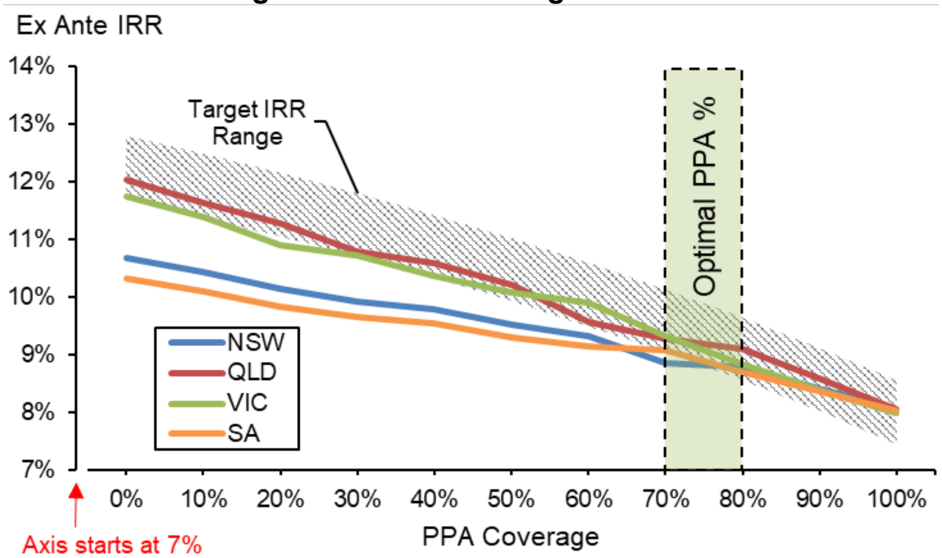


Figure 4: PPA Coverage vs Ex Ante IRR



The optimised contracting result is depicted visually in Fig.3 & 4, and is as follows:

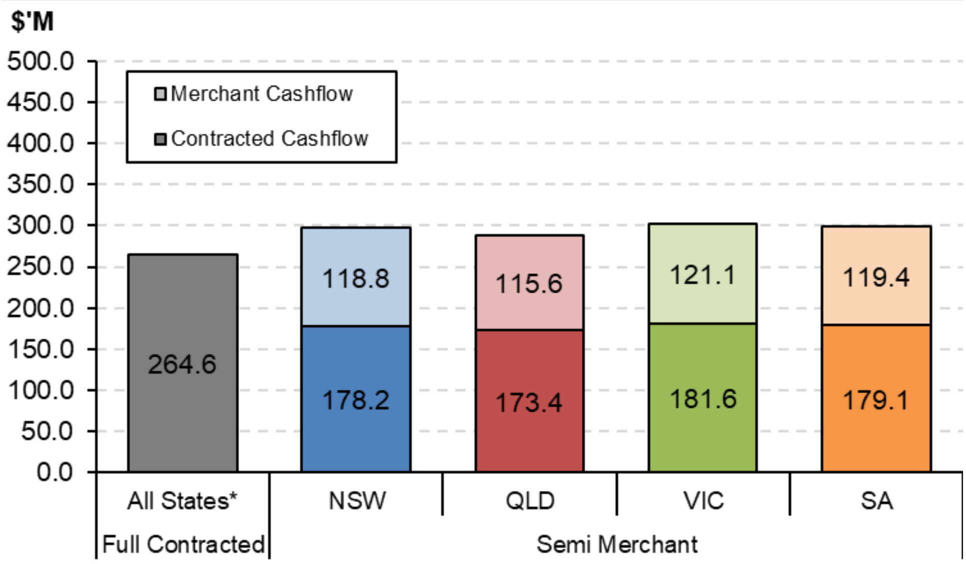
- Optimal PPA coverage ranges between 70-80%, with 75% selected as a mid-point.

- Project gearing of 69.3%, 64.3%, 69.9% and 69.3% of debt within the capital structure for NSW, QLD, VIC and SA respectively (lowered from ~74.2% in the fully contracted scenario).

To be clear, hypothetically reducing contracted coverage below the optimal range (i.e. below 70% PPA coverage) results in restricted borrowing capacity (Figure 3). This increases the requirement for equity commitments and ultimately reduces overall project returns below the target IRR range (Figure 4). For lower contractual coverage to be viable, a solar PV project would need to either; a) secure less restrictive borrowing terms with a project bank, b) secure a PPA priced above competitive market price, or c) accept lower returns on investor equity capital.

Figure 5 depicts the project's total forecast cashflow over 15yrs (the PPA tenor), varied by fully contracted and semi-merchant scenarios, and for each NEM region. Note that cash flows under the fully contracted scenarios converge to produce the same total revenue due to the solved nature of the PPA price depicted in Fig.2 – i.e. PPA pricing offsets regional specific generation loss factors. Therefore, performance variance only occurs once the plant is subjected to regional specific merchant pricing under the semi-merchant scenario.

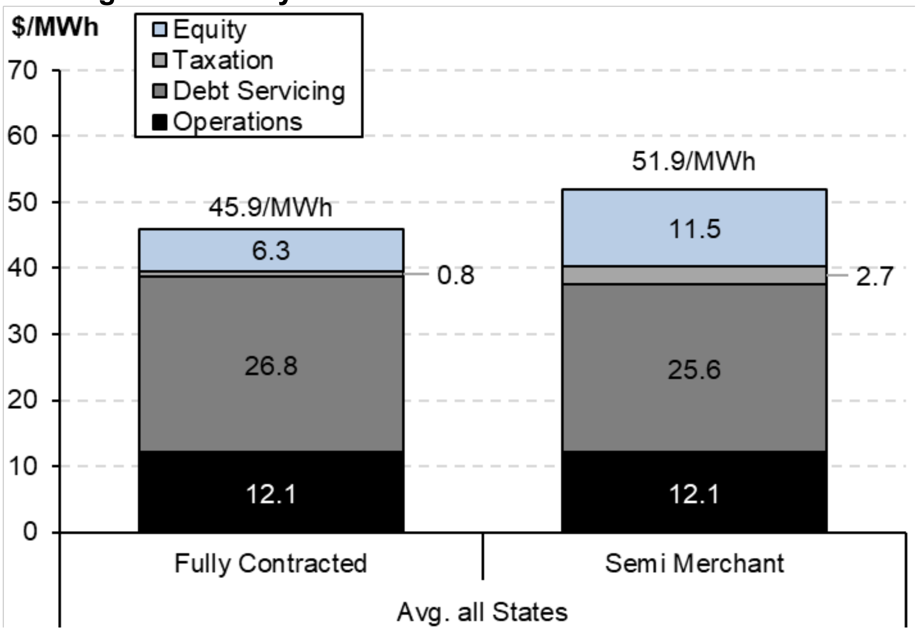
Figure 5: Ex Ante Cash Flow Over First 15yrs (Real $'s)



*Solved PPA pricing offsets region-specific generation loss factors, see Figure 2

Figure 5 clearly depicts elevated cashflows over 15 years, cf. the fully contracted scenario(s). Additional cashflows are logical, given that the project has adopted additional risk vis-à-vis revenue security in the form of merchant price exposure. A cash-allocation breakdown of the *average* fully contracted scenario and the *average* semi-merchant scenario is depicted in Figure 6. This depicts the LRMC efficiencies associated with increased gearing for fully contracted plant, and the elevated upside to equity sponsors associated with the semi merchant plant. Net variance in LRMC via efficient capital structuring has been analysed in depth – see Gohdes et al. (2022 & 2023) and Simshauser & Gilmore (2019). Note that fully contracted LRMC of $45.9/MWh aligns with the average PPA price across the four NEM regions.

Figure 6: Fully Contracted vs Semi-Merchant Ex Ante LRMC



Note also that Fig.6 prima facie depicts a higher overall project cost on a per/unit basis under the semi-merchant scenario ($51.9/MWh) – cf. the fully contracted scenario ($45.9/MWh). Once again, this bears no relation to the cost of plant acquisition. Rather the increased volatility of future cash flows produces an altered risk profile, prompting both capital providers to demand higher risk-adjusted returns ex-ante, viz. +20bps for project banks and +146bps for institutional equity investors.[19]

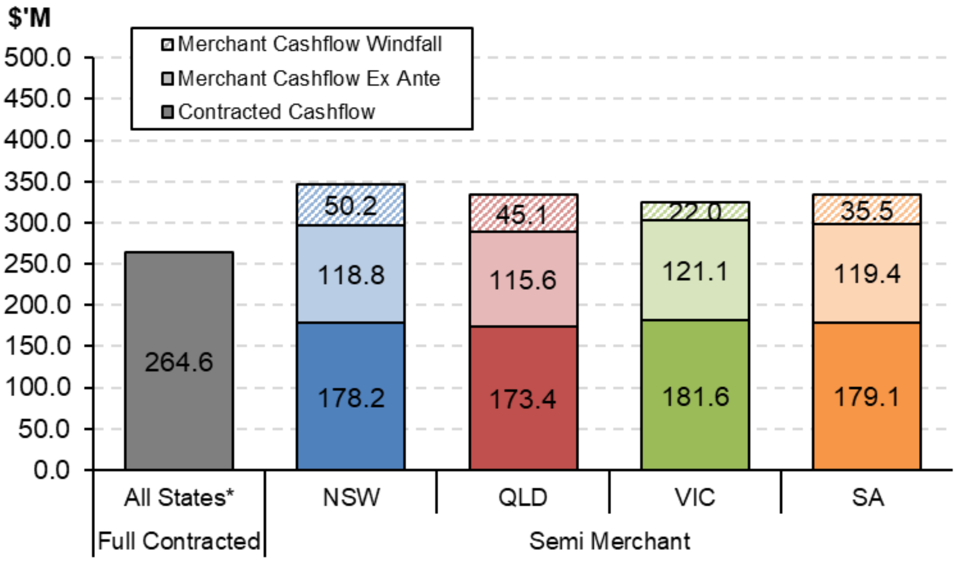
4.2. Ex-post Scenarios

Once ex-ante scenarios are established, the model is altered to develop an ex-post performance assessment. This assessment follows four years of spot market operations and applies the latest forward market curves, thereby comprising 7 years of updated merchant price data in total. Note the fully contracted scenario requires no alteration given it has no merchant exposure. For the semi-merchant scenario, the PF Model dynamically applies ex-post pricing (see ex-post line series in Fig.1) to 25% of total capacity – i.e. the proportion of capacity with residual merchant exposure.

The first two ex-post operational years (2020 and 2021) are characterised by under-performance for the semi-merchant plant (cf. the ex-ante forecast). This is because actual spot prices witnessed in 2020-21 fell below forecast across all regions. Conversely, 2022 - 2027 depicts a surge in regional spot prices, both actual and forecast. This produces supranormal profits for semi-merchant plant (cf. fully contracted). Supernormal returns equate to a forecast windfall of $6.7/MWh or $2.5m per annum *above* expected revenues on average over 15 years (c.$38.2m average total excess revenue over 15 years). Results are depicted on Figure 7 ($'M) and Figure 8 ($/MWh), with cashflows from this ex-post windfall separately depicted from operational plant costs and the ex-ante capital structure.

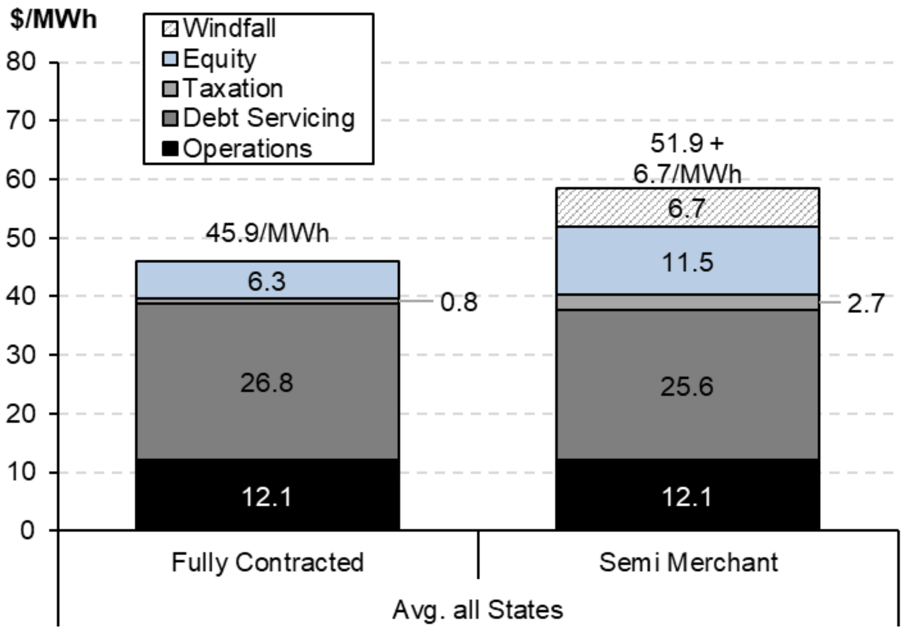
[19] The $6.0/MWh difference in cost is entirely attributable to optimizations within the capital structure, including higher gearing, lower interest rates and reduced equity return requirements, for fully contracted plant. See Gohdes et al. (2022) for in depth analysis of this phenomenon.

Figure 7: Ex-Post Cash Flow Over First 15yrs (Real $'s)



* Solved PPA pricing offsets regional specific generation loss factors, see Figure 2

Figure 8: Fully Contracted vs Semi-Merchant Ex Post LRMC



From the perspective of institutional equity investors, the appeal of the semi-merchant structure becomes self-evident following inspection of Figures 7 and 8. With 25% merchant exposure, the ex-post IRR rises to ~11.4% on average (cf. 8.0% for fully contracted plant and 9.66% ex-ante for the semi-merchant plant).

However, it remains prudent to note that the semi-merchant investment risk profile does deviate meaningfully from the fully contracted scenario. Recall from Figure 1 that historic spot prices during 2020 and 2021 financial years experienced relative underperformance (cf. ex-ante forward prices), implying overall project underperformance during these years. Clearly, semi-merchant plant does not represent a "one-way bet". Nonetheless, limiting merchant exposure to 20-30% (per Figures 3 and 4) ensures the plant retains an ability to weather periodic cyclical lows experienced by energy markets, thereby allowing the plant to withstand periods comprising low spot prices without immediately becoming financially distressed. Conversely, semi-merchant plant reliably exceeds ex-ante performance targets post

2021, due to its ability to benefit from uncharacteristically high (and un-forecast) market prices.

4.3. Distress Scenarios

If spot prices were to experience a sustained cyclical downturn (in line with those witnessed in 2020 and 2021), semi-merchant returns would be negatively impacted and eventually fall below ex-ante benchmarks. If cyclical downturns become extended, it is plausible that a post-operational semi-merchant project would experience financial distress and, in extreme cases, bankruptcy. However, it is relevant to acknowledge here that energy markets are ultimately mean reverting, which places a theoretical outer limit on the duration of such events (Cepeda and Finon, 2011; Pindyck, 1999; Bublitz *et al.*, 2019; Arango and Larsen, 2011; Simshauser and Gilmore, 2022). It should be re-iterated that the simulated plant retains substantial contracted coverage (i.e. 75% PPA) and is therefore *not* fully exposed to spot prices.

Rather than examine these price sensitivities, the following analysis adopts the methodology of Gohdes et al. 2023 to simulate plausible downside risks arising for both the fully contracted and semi-merchant projects during the initial years of operation. Specifically, the following variables are used to stress-test ex-post modelling:

- +5% engineering/development cost overrun,
- a 14-day commissioning delay (holding operational and financing costs constant),
- a reduction in plant capacity factors by 2.5% due to unexpected curtailment (limited to the first 3 years of project operations),
- a meaningful 2.5% reduction in marginal loss factor.[20]

Note that the above list of “distressed” events were selected based on market observation, making these risks far more than theoretical. In fact, some particularly unfortunate VRE projects in Australia’s NEM have experienced of all four variables simultaneously (see Simshauser, 2021; Simshauser and Gilmore, 2022. Distress events are applied to the PF Model for the FY2020 year (ex-post). This period was selected for conservatism, as ex-post spot prices reliably persist below the ex-ante forecast across all regions - thus representing a “downside” year for the semi-merchant plant. Results would only be amplified if the same analysis were conducted on a period comprising elevated spot prices. The financial impact of distressed variables on ‘year one’ cashflows are depicted on Figures 9 and 10 for the fully contracted and semi-merchant plants respectively.

[20] To avoid undue complexity, no variables beyond those listed are altered under distressed scenarios. This includes additional costs associated with liquidated damages, additional construction period interest and changes to economic curtailment.

Figure 9: Ex Post Fully Contracted – Distressed Yr1 Cashflows

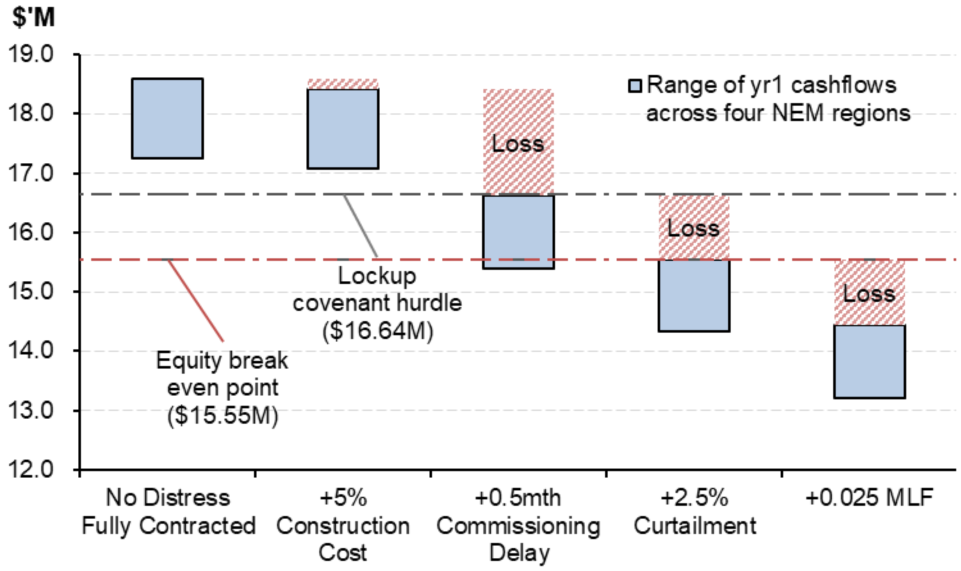
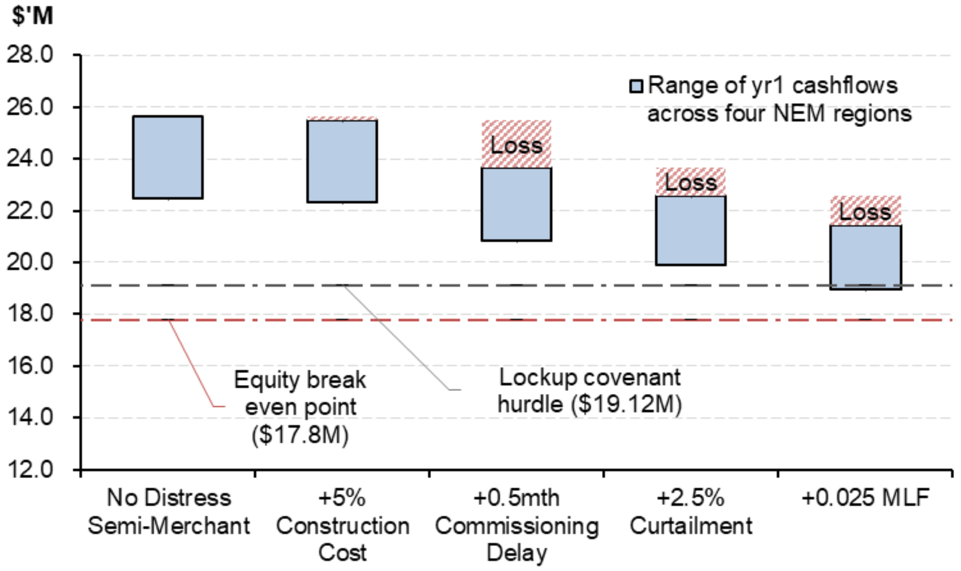


Fig.9 illustrates that the application of all four distress variables reliably sends the fully contracted solar project into lockup and, by extension, financial distress. Indeed, a project experiencing *only* commissioning and MLF distress is sufficient to violate typical project finance lockup covenants and place the project into financial distress.

Figure 10: Ex Post Semi-Merchant - Distressed Yr1 Cashflows



Conversely, Fig.10 illustrates that a semi-merchant solar PV plant (with 25% spot market exposure) appears capable of avoiding financial distress under the same conditions, even doing so during a period of lower-than-forecast spot prices. Note this is facilitated in part by lower lockup hurdle rates attributable to lower overall gearing levels (~70% vs c.74% gearing for fully contracted).

If the conditions outlined in Figure 9 were to persist beyond year one, institutional equity returns would fall below minimum return thresholds (8.0%) to ~6.72% (Fig.11). Furthermore, while the semi-merchant plant does indeed suffer under distressed scenarios, it also appears capable of recovering some proportion of lost profit during future cyclical upswings, producing a final return to equity investors ranging between 9.0% and 10.5% forecast over the full 30yr project life - illustrated in Figure 12. Perhaps most critically, note that semi-merchant windfall profits are sufficient to retain an equity return within a <0.5% range of the ex-ante anticipated IRR. A 25% merchant exposure therefore appears to significantly reduce, if not completely eliminate, plant underperformance when considering the full project life.

Note that Figure 12 depicts a wider range of returns as compared with the fully contracted plant in Figure 11. This is fundamentally due to the 25% spot exposure underpinning the semi-merchant scenario which, intuitively, results in greater variance in ex-post returns created by inter-regional variance in pricing forecasts.

Figure 11: Distressed Return to Equity Ex Post - Fully Contracted

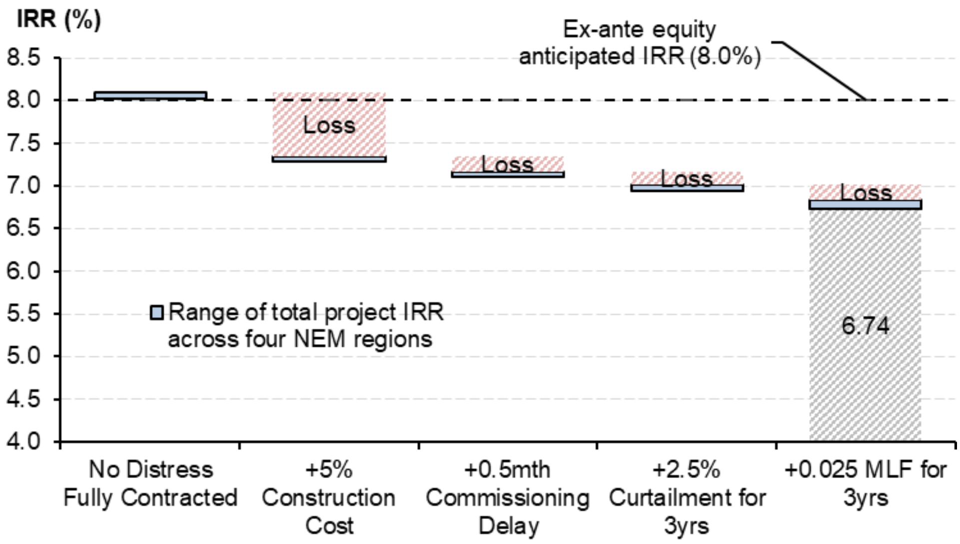
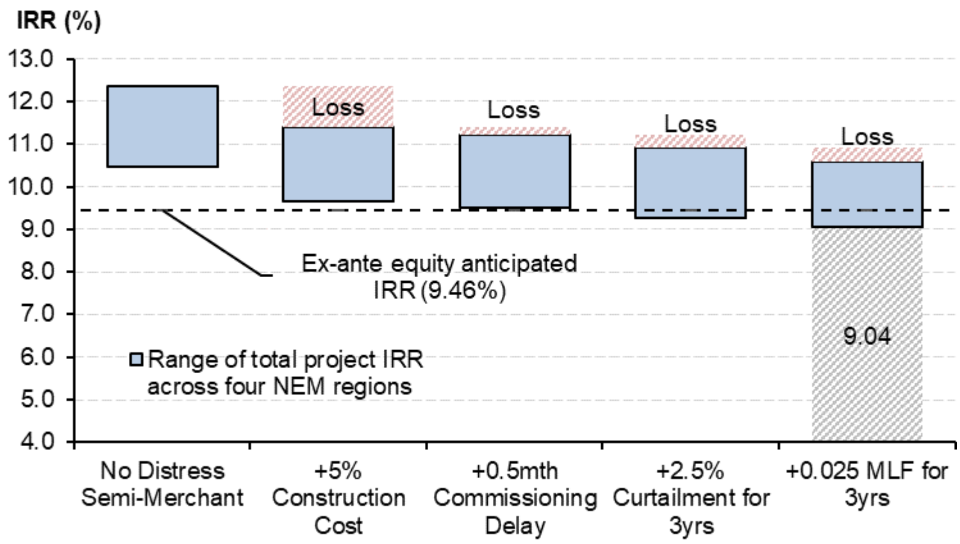


Figure 12: Distressed Ex Post Return to Equity - Semi-Merchant



For an institutional equity investor, asset write-downs on-balance sheet represent the ultimate outcome of equity returns persisting below forecast. For the fully contracted 200MW solar PV plant, an initial equity investment of $67m would need to be written down to ~$56m, a 16% loss in asset value (loss of ~$11m). These results are particularly severe after considering that the majority of simulated distress variables only impact the asset for the first 3 years of a 30-year project life. For distressed semi-merchant plant, a balance sheet write-down requires greater nuance.

Stochastic simulations viz. residual merchant exposures may be warranted here, representing an avenue for future research.

5. Policy considerations

For much of the past two decades, it has been the *general* view of Australian renewable investors that security via 100% run-off plant PPA minimised VRE project investment risk. This is evidenced by the substantial decrease in equity return expectations for fully contracted plant, as detailed by Gohdes et al. (2022). However, given the results of this analysis, such a view no longer seems warranted.

Furthermore, operational risks have materialised as VRE projects become larger and enter simultaneously (see Simshauser & Gilmore, 2022). These include sporadic episodes of construction and commissioning/connection delays, unexpected curtailment due to falling system strength and variability of MLFs. Note that it is not historically uncommon for a project's PPA to be agreed before the execution of other key contracts – viz. grid connection, procurement and construction contracts. Indeed, describing fully contracted VRE plant as the *'lower risk'* option seems inappropriate. While perhaps distinct from initial motivations, retaining access to a "merchant upside" appears, at least theoretically, capable of meaningfully offsetting ex-post operational risks.

An important conclusion from this research is that fully contracted Solar PV plant should not necessarily be considered *lower risk* when compared to the equivalent semi-merchant plant. Such claims appear to conflate the concept of *lower volatility* with the concept of *risk-adjusted returns* (Gohdes et al., 2023). To be clear, there should be no doubt that *revenue volatility* is substantially reduced for a solar farm with 100% contractual cover (cf. partially contracted). A semi-merchant plant will inherently experience greater revenue volatility post-operational commencement. However, given the capacity for exogenous variables to impact investor returns ex-post, it becomes highly relevant to acknowledge that 100% contractual cover may amplify, rather than minimise, the volatility of equity returns. Moreover, Figures 9 and 10 illustrate that return volatility appears skewed only to the downside for fully contracted plant. In effect, 100% PPA coverage inherently caps investor returns without implementing an equivalent hedge for project losses.

Gohdes et al. (2023) acknowledges that distressed results viz. fully contracted plant may be identifiable from first principles, given that pre-operational risks described in section 4.3 are unhedged within the PPA. Once materialised, risks are further amplified due to the higher leverage under the 100% PPA structure. Therefore, 'distressed scenario' results could plausibly be characterised as the realisation of a series of unhedged risks.

Findings of this nature should be carefully considered by policymakers vis-à-vis government initiated CfD auctions. It is critical to acknowledge that CfDs function as speculative derivative instruments, a fact that remains unchanged when underwritten by governments. Contracts are 'wrapped' by the counterparty to guarantee fixed long-term pricing in a highly volatile commodity market. Taxpayer-wrapped CfD commitments are therefore responsible for absorbing scarce balance sheet resources for state governments (cf. on-market transactions). Once CfDs are ratepayer-wrapped, post-auction out-of-the-money periods produce financial shortfalls, which are in turn typically funded by levying charges onto regulated network tariffs (see Hartmann, 2021).[21] The Australian experience has demonstrated

[21] In 2021, end user electricity network tariffs were increased by 41% in the Australian Capital Territory to cover rising costs of state-underwritten CfDs. These CfDs were considered low cost (~$70/MWh) at the time of underwriting in 2016-2017. However, evolving market dynamics have left these transactions out-of-the-money. In contrast, equivalent losses experienced via private PPAs underwritten by retailers or corporates, shareholders (rather than taxpayers) absorb the financial penalty.

the recovery of CfD shortfalls to be invariable regressive (Nelson et al., 2022). Furthermore, prior works have highlighted additional risks associate with widespread implementation of CfDs vis-à-vis retail competition and deteriorating contract market liquidity (Simshauser, 2019). Such risks alone should arguably give pause to policymakers when considering available tools to procure renewable supply.

Nonetheless, government initiated CfD auctions do appear to have become an enduring feature of hybridised energy markets, for better or for ill (Joskow, 2022). The findings of this analysis suggest that future CfD auction process may risk oversubscribing entry requirements, so long as investor appetites for hybrid projects remain a trend. With modelling results indicating that ~70-80% contracted coverage is indeed tractable to secure typical project finance, policy makers seeking to elicit 4000MW of solar PV entry may need only offer ~3000MW of CfD capacity at auction, thereby moderating the inherent risk attributable to taxpayers.

6. Conclusion

Semi-merchant projects now dominate entry statistics in Australia's NEM, with the recent literature observing this as a growing trend (Rai and Nelson, 2021; Nelson, 2020; Flottmann et al., 2022; Gohdes et al., 2022; Simshauser and Gilmore, 2022; Nelson et al., 2022). Whilst these works acknowledge the semi-merchant trend, the quantitative results of this analysis assist to explain *why* the trend is both emerging and growing amongst VRE developers in Australia.

Modelling of an FY2020 new entrant Solar PV plant with *typical* characteristics confirms that PPA coverage between 70-80% is viable and tractable ex-ante whilst securing project finance at 65-70% gearing. Ex-post analysis confirms underperformance in years 1 and 2, followed by windfall profits in years 3, 4 and beyond when incorporating prevailing forward prices. Conclusions adopt the perspective of a renewable investor seeking to maximise risk-adjusted returns for the sole purpose of providing ex-post context to recent investment behaviours.

The Australian NEM has witnessed 150 individual VRE projects reach financial close since 2017. It is prudent to point out that each new project exhibits unique characteristics which are highly determinant in managing the appetites of capital providers. Therefore, this analysis does not suggest that *all* new entrant solar PV plant can achieve capital structure optimisation by directly applying results (i.e. ~70% debt with a 25% merchant exposure). Rather, these results simply provide important context to an emerging trend in Australian energy markets vis-à-vis hybridisation of VRE plant. The literature would be well served by extending the present analysis via stochastic spot market methodologies to further stress test the semi-merchant investment model. Such methods may also assist in providing more granular direction vis-à-vis optimal CfD policy implementation.

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