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Renewable investments in hybridised energy markets: optimising the CfD-merchant revenue mix

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Abstract

Energy markets were designed to maximise productive, allocative and dynamic efficiency. Although renewables have become the dominant investment in deregulated energy markets, decarbonisation may not proceed at a pace consistent with the aspirations of policymakers. This has led governments in a number of jurisdictions to prime markets through 'Contracts-for-Differences' (CfDs) or Power Purchase Agreements (PPAs), thus bringing forward investment and decarbonisation efforts. The war in Ukraine and its adverse impact on energy prices only emphasises a sense of urgency on an energy security dimension. Variable Renewable Energy (VRE) projects in Australia are typically underpinned by run-of-plant PPAs, but an emerging trend has been rising number of semi-merchant projects whereby some level of spot market exposure is retained. In this article, we examine how and why the semi-merchant investment model has arisen along with the minimum contracted coverage for a bankable project financing. Results reveal for investors with a target of 60-65% debt within the capital structure, a revenue mix comprising 73-78% PPA coverage and 22-27% merchant plant exposure is viable and a tractable project financing. For policymakers seeking to elicit 5000 MW of VRE plant capacity, the auction need only offer ~3800MW of CfD's capacity, which has the benefit of reducing taxpayer exposures (cf. on-market transactions).

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

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1. Introduction

The outbreak of war in Ukraine from February 2022 and the progressive ratcheting down of Russian gas supplies to the European Union either side of the war [1] led to sharply rising energy prices across Europe (Batlle et al., 2022; Jamasb et al., 2023; Schittekatte and Batlle, 2023). Australia's National Electricity Market (NEM) is on the other side of the world, but the energy price shock was transmitted instantaneously (Nolan et al., 2022). Australian LNG prices ex-Queensland rose from ~ A$10/GJ (i.e. US$6.7/GJ or £5.4/GJ) [2] to $40+/GJ and thermal coals ex-New South Wales increased from ~$100/t to $600+/t. By early-2023 forward prices for both fuels had moderated to ~$25/GJ and $300/t – still well above the historic averages.

Coal and gas generators in Australia's NEM typically hold long term fuel supply contracts that are detached from global price dynamics. But for power production at the margins (i.e. above long term contracted levels), generators face export parity prices for fuel (Nolan et al., 2022).

During 2022, a surprisingly large number of coal plant outages and lower than expected output from Australia's solar PV fleet due to wet weather led to sharp increases in gas-fired generation. Significantly higher output from gas turbines linked marginal costs to export parity prices on a sustained basis. NEM prices increased from $70/MWh and converged with the 'JKM' or Japan-Korea Marker (i.e. the spot price for LNG cargoes in the Asia-Pacific region) from February 2022, with forward prices rising to ~$250/MWh. This was most evident in the NEM's northern regions of New South Wales and Queensland, where VRE market shares are lower and thermal plant output dominates the aggregate supply function.

The Commonwealth Government intervened in December 2022 by placing a $125/t cap on domestic coal prices, and a $12/GJ cap on domestic gas prices (Simshauser, 2022). This short-term measure has been effective in running down the wholesale price of electricity, with baseload swaps trading at ~$100/MWh at the time of writing.

As with many of the world's major energy markets, the NEM's gross pool is becoming increasingly hybridised (Roques and Finon, 2017; Joskow, 2022; Keppler, Quemin and Saguan, 2022). Certain jurisdictional governments are seeking to elicit VRE investments by auctioning taxpayer- or ratepayer-wrapped Contracts-for-Differences (CfDs) with the intended purpose of accelerating the speed of investment in renewables to i). better match decarbonisation efforts with policy intent, and ii). drive a wedge through adverse links between domestic energy prices the global price of coal and gas. There should be no doubt that such CfDs in the NEM are effective in delivering investments (Gohdes, et al., 2022; Simshauser et al., 2022).

Whether out-of-market, government-initiated and taxpayer-wrapped CfDs are necessary in Australia's NEM (cf. on-market transactions) is an open question. [3] Market demand for renewables via on-market Power Purchase Agreements (PPA) from both corporate and utility sectors has produced record levels of investment. Over the past six years, 149 Variable Renewable Energy (VRE) projects comprising 19,275MW have reached financial close with an investment value of $37.7 billion (Simshauser and Gilmore, 2022). Nonetheless, a certain level of 'CfD priming' by governments appears to have become a permanent fixture in many markets (i.e. the hybridisation of competitive energy markets).

One aspect which has received limited attention is the hybridisation of the VRE investments themselves (Flottmann et al, 2022; Gohdes et al., 2022). In the NEM, VRE investors are increasingly taking material exposures to the spot market, a characteristic we will refer to hereafter as *'semi merchant VRE plant'*. Of the 19,275MW of plant commitments, at least 3600 MW is exposed to the spot market (Simshauser and Gilmore, 2022). This pattern can be traced at least

[1] At the start of 2021, Russia supplied around 40% of Europe's natural gas, and this had been curtailed to less than 10% by the end of 2022.
[2] All financials are expressed in Australian Dollars. At the time of writing, A$1 = US$0.67 and GBP 0.54
[3] At a recent event in New South Wales by the state's auction coordinator (EnergyCo), two of the NEM's larger VRE investors suggested government-initiated CfDs are *nice to have but not necessary* given strong PPA demand from corporates and utilities.

as far back as the Victorian Government's 2017 CfD auction for 650MW, which in turn elicited an investment response of 800MW (Simshauser et al., 2022). The implication here is that 150MW or 19% of capacity committed was 'uncontracted' and therefore exposed to the NEM's energy-only spot market prices at the time of financial close.

Just as the hybridisation of the NEM and associated government-initiated CfDs appear to have become a permanent fixture, hybridised VRE investments into the semi merchant model – comprising a mix of long-term contracted and spot exposures – also appears to be emerging as an enduring feature (Simshauser, 2020; Flottmann et al., 2022; Gohdes et al., 2022). The purpose of this article is to explore the 'bankability' of semi-merchant projects within a hybridised market and to assess why this trend has emerged. Our research aims to identify a series of optimal contracting set-points for a given levels of capital structure risk. Our results may also guide policymakers vis-à-vis optimal auction quantities and taxpayer exposures for a given level of renewable capacity investment demanded.

Our analysis is therefore specifically concerned with the split between contracted revenues (by way of fixed price CfD or PPA) and merchant revenues via spot markets. We note in an energy-only gross pool market, both CfDs and conventional PPAs have the effect of exchanging a spot price exposure for a fixed price, and for our purposes the terms will be used interchangeably throughout.[4]

Our modelling results confirm that institutional equity investors seeking to acquire meaningful exposures to spot markets (20-30%) while maintaining a typical project financing structure (60-65% debt) is indeed tractable. Specifically, our modelling finds a VRE plant comprising 73-78% contracted capacity and 22-27% merchant capacity can meet typical financing covenants for debt of 60-65% within the capital structure ex ante. We also find ex post, the semi-merchant plant performs will with symmetrical risks around equity returns, whereas fully contracted plant tends to be skewed to downside risks. Our findings have significant implications for policymakers. Since semi-merchant VRE plants are emerging as the dominant form of entrant in Australia's NEM, a government seeking to target 5000MW of VRE entry commitments need only auction ~3500-4000MW of CfDs, thus reducing taxpayer exposures considerably.

This article is structured as follows. Section 2 reviews relevant literature. Section 3 sets up our modelling approach, noting the model maths appears at Appendix I. Section 4 explores the model outputs and Section 5 provides policy insights. Concluding remarks follow.

2. Review of literature

Relevant to the present analysis is the cost of capital, hybridisation of energy markets and transition challenges.

2.1 Cost of capital for renewables

When considering the entry of VRE plant capacity, access to debt finance represents a fundamental pre-condition given the capital-intensive nature of the investment commitment. VRE projects in the NEM are rising in size with average wind farm increasing from 80MW in the 2000s, to more than 350MW in the 2020s (Simshauser & Gilmore, 2022). Indeed, the NEM has multiple projects in the 450-1000MW range currently under construction and at current overnight capital costs of ~$2600/kW, this translates to investment commitments of $1.2 - $2.6 billion per project.

Such sizable investment commitments remain acutely sensitive to the cost of capital as a primary determinant of competitive entry costs (Steffen, 2018). Proportionally higher capital outlays are required for VRE projects (cf. their fossil fuel counterparts), making this dependence particularly pronounced (Newbery, 2016; Schmidt, 2014; Grubb and Newbery, 2018). The cost of capital invariably plays an important role in determining the unit cost of renewable projects – something

[4] For a more nuanced analysis of the intrinsic differences between CfDs and PPAs see Gohdes et al. (2022).

which has a long history in the literature (Mills and Taylor, 1994; Wiser, 1997; Kann, 2009) and has been re-iterated more recently (Newbery, 2016; Steffen, 2018; Nelson, 2020; Rai and Nelson, 2021; Gohdes et al., 2022).

A VRE project's Weighted Average Cost of Capital (WACC) is ultimately determined by the return demanded by its two capital sources – debt (bank finance) and equity (institutional investors) and the weighted proportions thereof (Myers, 1984). In their seminal work on the cost of capital, Modigliani and Miller (1958) showed that the weighting of debt and equity is irrelevant in perfect capital markets with no taxes, transaction costs, agency costs and asymmetric information. This 'irrelevance proposition' was the subject of a formal mathematical proof. But since we know the weightings of debt and equity are important (see Gohdes et al. 2022), by deduction it must relate to the factors assumed away (viz. taxation, transaction costs, asymmetric information in particular). The relative preferences and risk appetites of both sources are important and therefore require detailed analysis if investment commitment remains an objective.

Given the importance of capital structure to VRE project commitments, the dominant form of financing remains *Project Finance* (PF), which is distinguished via the use of high levels of debt on a project specific basis. PF makes use of a special purpose vehicle or 'SPV' (i.e. a newly created entity) for the sole purpose of project ownership and management (Esty, 2004; Steffen, 2018; Nelson and Simshauser, 2013). Financiers' claim on cashflows is inherently limited by the SPV structure, restricting the claim to the cash flows and assets associated with the project. Such a structure therefore impacts a project's relative risk, debt capacity and management protocols (Esty, 2004). A key characteristic of PF structures viz. VRE investment is the increased capacity for debt as a proportion of total capital expenditure (Simshauser and Gilmore, 2020). Project finance has consequentially become the preferred method of raising capital for VRE projects (Kann, 2009; Steffen, 2018). The relative simplicity of the PF structure facilitates higher gearing and lower equity contribution requirements (cf. portfolio assets on-balance sheet), both of which contribute to a lower overall WACC.

Project finance structures facilitate a more *optimised* capital structure whereby project sponsors replace prima facie higher cost equity capital with lower cost debt financing set within an SPV to quarantine risks of financial distress. It is also important to acknowledge that the literature has long noted the inherent risks associated with elevated leverage often secured via the project finance structure (Pollio, 1998; Lock, 2003; Arowolo, 2006; Vaaler et al., 2008; Shen-fa and Xiao-ping, 2009; White et al., 2000; McKeon, 1999; Churchill, 1996).

Project finance banks are traditionally satisfied from a risk perspective once the ability to make repayments under conservative circumstances and with appropriate covenants is demonstrated. In the case of PF with claims restricted to future plant revenues, project banks place a high value on prospective revenue quality (i.e. PPA with a reliable and creditworthy counterparty) when determining financing terms, gearing ratios, Debt Service Cover Ratios and credit spreads (Nelson and Simshauser, 2013; Rai and Nelson, 2021; Gohdes et al., 2022).

2.2 Power Purchase Agreements and hybrid markets

PPA contracts, and their many variations, have operated as a staple within energy markets for decades. Fundamentally PPAs represent a fixed agreement to purchase some, or all, of a generator's output at a pre-determined price throughout the agreed term. The original template for today's PPAs was provided by the U.S Public Utility Regulatory Policies Act (PURPA) of 1978 – which in turn sparked the first power project financing in 1981 (Simshauser and Nelson, 2012). The original policy design encouraged the development of cogeneration plants whose electricity was on sold to regulated electricity utilities (Yescombe and Farquharson, 2018). In many cases, this facilitated financing for new, independent plant with long-term PPA commitments providing necessary security.

The privatisation of the British electricity industry also prompted the formation of PPAs in the early 1990s with new combined cycle gas turbine plant (Newbery, 2021). Australian energy markets followed this path from the 1990s with a small number of pre-NEM investment commitments (Yescombe and Farquharson, 2018). Ever since, PPAs have operated as an important tool for renewable developers in the NEM, providing the necessary revenue security in an otherwise highly risky merchant market (Simshauser and Gilmore, 2020; Rai and Nelson, 2021). Alternatively, merchant plant refers to a project accepting more volatile spot and short-term forward market prices for generation output, rather than comparably stable revenues via long-dated PPAs (Finon, 2008; Finon and Pignon, 2008b; Nelson and Simshauser, 2013; Simshauser, 2020).

Roques and Finon (2017), Grubb and Newbery (2018), Joskow (2022), Keppler et al., (2022), Schittekatte and Batlle (2023) and others have argued that energy-only markets are being 'hybridised' through governments re-entering and offering long dated PPAs or CfDs. Hybridised markets are characterised by the separation of long-term investment decisions from short-term operations via an acceptance that PPAs play a structural role in procuring and facilitating supply – i.e. the long-term module described by Keppler et al., (2022). The corresponding short-term module refers to competitive wholesale markets which encourage existing assets to manage day-to-day operations in a cost-effective manner. The framework has the intended effect of de-risking long-term capital-intensive investment decisions from the risks associated with short-term pricing fluctuations, making theoretically optimal use centralised and de-centralised market elements (Keppler et al, 2022).

Other works have referenced the desirability of revenue security in supporting VRE project bankability (Steffen, 2018; Simshauser and Gilmore, 2020, 2022; Nelson *et al.*, 2013). Variable generation conditions and price volatility in the NEM's energy-only gross pool contributes to an environment where hedging is ultimately important to achieve minimum levels of revenue certainty (Simshauser, 2020; Flottmann et al., 2022). Generators relying on project finance are therefore often *presumed* to be underwritten by long-dated, run-of-plant PPAs (de Atholia, Flannigan and Lai, 2020; Chao, Oren and Wilson, 2008; Finon, 2008; Finon and Pignon, 2008a; Newbery, 2017). Gohdes *et al.* (2022) quantify the relationship between revenue quality (derived from both PPA coverage and counterparty credit ratings) and entry costs for VRE plant. It is found that plant operating under conditions of greater revenue quality - viz. higher coverage from an investment-grade counterparty, experience more favourable borrowing conditions and lower equity return requirements. Other works also make reference to PPA dependence for VRE plant, albeit the relationship is not explicitly quantified (Mills and Taylor, 1994; Kann, 2009; Grubb and Newbery, 2018; Steffen, 2018; Nelson et al., 2022).

Australian generators have a variety of options for procuring bankable revenue security – i.e. participating in the market's long-term module. Whilst there are no restrictions on who can participate in the market, in practice underwriters are represented by three groups, viz. (1) retailers motivated by acquitting obligations under renewable targets or decarbonising hedge portfolios, (2) state governments seeking to bring forward investments in VRE plant, and (3) corporates motivated by sustainability or cost objectives (Nelson et al., 2013; Nelson, 2018, 2020; Simshauser and Gilmore, 2020, 2022; Rai and Nelson, 2021).

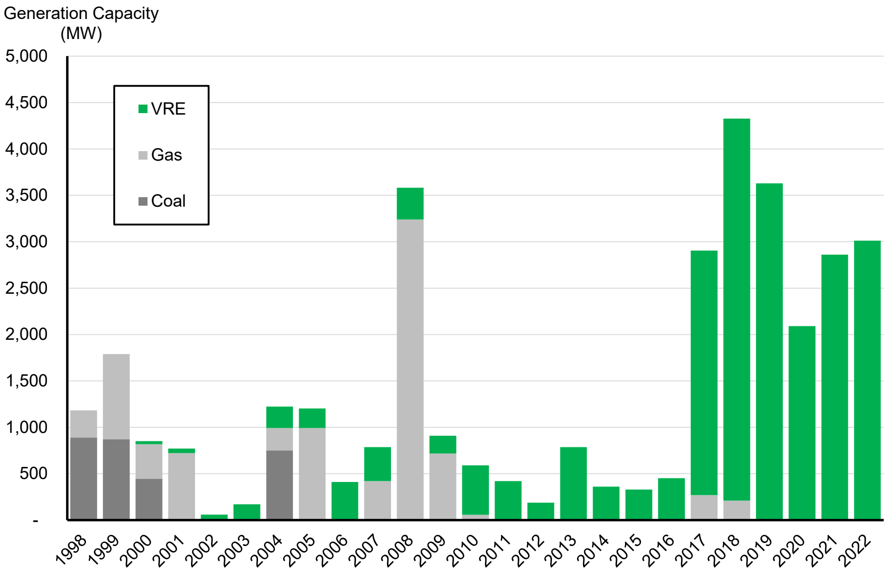
2.3 The NEM: transition challenges

As with other energy markets, the NEM is transitioning with sharply rising levels of VRE plant (Rai and Nelson, 2021; Pollitt and Anaya, 2016; Dodd and Nelson, 2019; de Atholia, Flannigan and Lai, 2020; Nelson et al., 2022; Newbery, 2016). However, the past decade has forced investors in Australian VRE projects to contend with numerous obstacles including policy uncertainty (2004-2015), an investment supercycle (2016-2021), and more recently (2022-2023) the energy crisis following the war in Ukraine (Nelson, Orton and Chappel, 2018; Nelson, Nolan and Gilmore, 2022; Simshauser and Gilmore, 2022).

A "policy war" between Australia's two main political parties has led to extended periods of policy discontinuity across multiple key climate change initiatives (Molyneaux *et al.*, 2013; Byrnes *et al.*, 2013; Simshauser and Tiernan, 2019; Nelson *et al.*, 2013; Garnaut, 2014; Freebairn, 2014; Nelson, 2015; Apergis and Lau, 2015). Indeed, an emissions trading policy received attempted implementation on seven separate occasions whilst Australia's 2020 Renewable Energy Target (RET) received six major reviews from 2004 to 2015 (Garnaut, 2014; Wild et al., 2015; Nelson et al., 2015; Simshauser and Tiernan, 2019; Nelson et al., 2022). Market participants ultimately internalise policy uncertainty, resulting in entry lags, investment hesitation, and elevated costs for VRE projects caused by increased premiums for debt and equity. Similar risks vis-à-vis uncertain policy changes are also referenced by Nelson et al. (2013), Byrnes et al. (2013) and Molyneaux et al. (2013).

Record investments in Australian VRE followed the settlement of 2015's revised RET policy. From 2016-2022 investors committed to 149 VRE projects worth ~37.7 billion and totalling 19,275 MW of generation capacity (Simshauser and Gilmore, 2022). de Atholia et al., (2020) distinguish the 2016-2022 period from the prior decade, noting significant investment increases in large-scale VRE projects, driven primarily by the private sector. Interestingly, only 80% of new VRE projects initiated during the period were underwritten by a PPA –comprising 48% by retailers, 17% by corporates and 25% by state governments (Simshauser and Gilmore, 2022). The remaining 20% of VRE projects were in fact almost completely 'merchant' (Simshauser, 2020). Figure 1 illustrates PPA vs merchant transactions for our generation dataset over the period 2000-2022, with the y-axis recording the number of projects reaching financial close.

Figure 1: NEM Project commitments (MW)

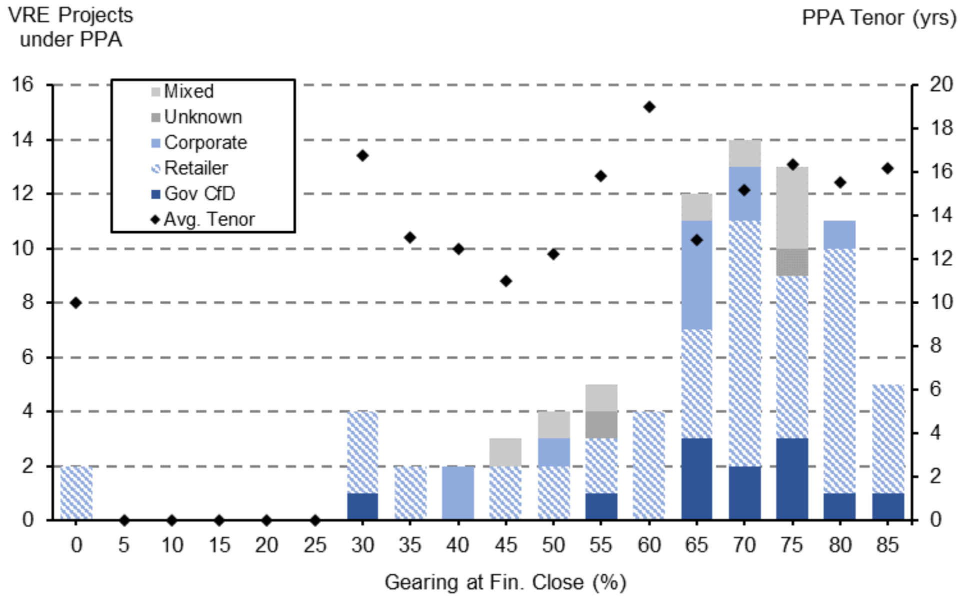


Source: Simshauser & Gilmore (2022)

A comprehensive 'NEM Generation' dataset was developed to further inform model inputs and outputs. The dataset is ultimately designed to provided detail on all projects originated in the NEM. Data on each plant includes project financing details, key dates, PPA information, project specification and capital costs. Data from a variety of authorities was consolidated to compile a comprehensive source vis-à-vis total NEM generation.[5] Figure 2 presents summary level data on the tenor of PPAs, counterparty category and gearing levels of VRE projects at financial close. One Reviewer noted the predominance of retailer-written PPAs, most of which will have been 'earmarked' against Australia's 2020 Renewable Energy Target (given the target applies to 2030).

[5] Data was retrieved from private energy information databases, such as Rystad Energy, the Australian Energy Council, Inframation, Bloomberg, and AEMO. Additional data was retrieved from investor announcements and news reports, allowing for verification and cross-checking.

Figure 2: VRE PPA vs project gearing at financial close



Source: BNEF, Rystad Energy, Inframation, Company Reports, RenewEconomy, Simshauser & Gilmore (2022).

3. Model and Data

Our analysis relies on our Project Finance model (PF model) which is an integrated, multi-year, dynamic power project finance and investment model tasked simulating 'typical' Australian VRE project parameters from the perspective of the two dominant capital providers, viz. project banks and institutional equity. Full details of the model are set out in Appendix I.

In our analysis, we focus on a typical 250MW wind project in the NEM region of New South Wales without any loss of generality (e.g. to solar PV). We assume the project commences operations from the start of the 2020 calendar year. The year 2020 was selected because it coincides with a period of *relative* electricity price stability (and if anything, subdued merchant prospects), stable entry costs, with forward prices preceding the market turmoil associated with Covid-19 and the war in Ukraine.

The PF Model is tasked with simulating four distinct scenarios. These involve both 'ex ante' (as at 2020) and 'ex post' (as at 2023) analysis, with the level of contractual cover operating as the second key altered variable:

1. Our 'ex ante' base case comprises a *fully contracted* wind project. The PF Model is run with an objective of optimising capital structure, minimising the LCoE with the constraint of an 8% equity IRR (expressed on a nominal, post-tax, post-financing basis, see Table 1). The task of the model is to identify the most competitive price ($/MWh) that could be bid at a CfD auction given the constraint of satisfying all project suitors (i.e. plant supplier, equity investors, project banks). To be clear, the base case assumes that a run-of-plant PPA covering 100% of plant output, including renewable certificates.

2. Our 'ex ante' *semi-merchant* case comprises a hybrid project of part-PPA, part-merchant exposure. This scenario aims to identify the *maximum viable level* of merchant exposure given the involvement of risk averse project banks, and a requirement to achieve at least 60% debt within the capital structure. Specifically, in this ex ante semi-merchant scenario, the PF model iterates and solves for the minimum PPA coverage at the competitive price level defined via the base case, and without violating a series of financing covenants (specified later in Table 1 and Appendix I). Importantly, merchant prices used are *ex ante*. For this purpose, we rely on the relatively subdued forward prices and spot price forecasts

relevant as at January 2020 (i.e. an ex ante scenario). These same merchant prices are initially adjusted downwards or 'discounted' in line with the practices of Australia project bankers to *'size'* total debt facilities reflecting their conservative view of merchant revenues (i.e. the 'banker's lens'). We then relax this discounting to capture the institutional equity return expectations (i.e. the 'equity investor's lens').

3. Our initial 'ex post' scenario returns to the semi-merchant plant, whereby the same ex ante model is populated with the available live spot and forward market data (2020-2027). This simulation demonstrates both the down- and up-side experienced by merchant exposed projects.

4. Finally, we stress test certain variables in an adverse manner, including construction cost overruns, time delays, unexpected curtailment and deteriorating marginal loss factors. The semi-merchant model is once again populated with live market data which allows for a performance comparison between an adversely impacted fully contracted project and an equivalent semi-merchant project, with the benefit of hindsight, with surprising insights emerging.

Finally, we assume the 250MW wind project is 'acquired' at the start of 2020 in its post-commissioning operating phase. In practice, the post-commissioning period would typically follow a construction period of 18-months and an intensive development period of 2-years. Our acquisition assumption allows for the removal of undue complexity associated with construction and development-related risks, financings and cashflows. Such risks are instead incorporated into a simulated 'cost of acquisition' relevant to the time of acquisition at $1855/kW, which is consistent with the observed market data contained in Simshauser & Gilmore (2022).[6] This and other relevant financial and engineering data to the PF Model appears in Table 1.

Table 1. Model inputs and assumptions

Assumptions for 250MW Wind Farm acquired in 2020					
Generation			**Inflation**		
Plant Size	(MW)	250	CPI	(%)	2.50
Annual Capacity Factor	(%)	35	Electricity Prices	(%)	2.50
Marginal Loss Factor	(%)	96			
Auxiliary Load	(%)	3.0	**Taxation**		
Equivalent Forced Outage Rate	(%)	3.0	Tax Rate	(%)	30
Technical Life	(Years)	30	Useful Plant Life	(Years)	30
Wind Dispatch Spot Price Adjust.	(%)	6.0	Turbine Depreciation	(Years)	20
Plant costs			**Capital cost**		
Acquisition Cost	($/kw)	1,855	Debt Tenor	(Years)	20
Turbine Cost	(% of Capex)	60%	PPA Tenor	(Years)	30
Acquisition Price	($M)	464	BBSW*	(%)	2.00%
Variable O&M	($/MWh)	N/A	Lock Up Covenant	(DSCR Multiple)	1.1x
Fixed O&M	($/MW p.a.)	25,000	DSCR for Spot Revenue*	(DSCR Multiple)	1.85*
Ancillary Services Cost	($/MWh)	1.00	DSCR for PPA Revenue*	(DSCR Multiple)	1.25*
Maintenance Capex	($M p.a.)	2.32			

*BBSW refers to Bank Bill Swap Rate (the benchmark base interest rate), DSCR refers to the Debt Service Coverage Ratio
**Final applied DSCR is determined on a dynamic basis via a "hybridised" weighted average according to spot/PPA revenue exposure

In Table 1, our assumed inflation of 2.5% applies the middle of the Reserve Bank of Australia's long-range inflation target of 2-3%.[7] The project has an applied tax depreciation tenor of 20 years, which is in line with Australian Taxation Office rulings. The project's useful life is assumed to be 30 years, with a financing life / debt tenor of 20 years. Plant specifications, generation and costs are sourced from the 2020 Costs and Technical Parameter Review, which is published by the

[6] Costs have since risen to ~$2600/kW following Covid-19 and Ukraine war impacts on costs and supply chains.
[7] We note that while post-2022 inflation levels have trended well above the typical target set by the Reserve Bank, the 2.5% rate adopted is applied for the full model life of c.30 years. In our opinion, the application of an inflation rate higher than the 3% long run target is likely to be unrealistic in this context, not to mention largely inconsequential for the purposes of a comparative analysis whereby the same rate is adopted for all scenarios.

Australian Energy Market Operator (AEMO).[8] As noted earlier, the plant's location is assumed to be New South Wales (NSW) with a transmission loss coefficient or Marginal Loss Factor (MLF) of 0.96.

Debt repayments are sculpted for each period via the application of minimum Debt Service Cover Ratio (DSCR) applicable to a given scenario and Cash Flow Available for Debt Servicing (CFADS). Payments include principal and interest, with the latter calculated as the bank bill swap rate (BBSW) plus a credit spread. The methodology used in Simshauser and Gilmore (2020) has been applied here, whereby BBSW is derived with reference to average returns on 2020 bond issuances.

In the PF Model, two critical financing constraints are applied. The first constraint involves a lock-up covenant, set at 1.1 times CFADS per Table 1. This restriction stipulates dividends to equity cease during periods where CFADS persists below the lockup value to ensure that financing commitments are met before dividend payments are considered. The second constraint involves the setup of a cash buffer designed to retain cash equal to six months of forecasted financing commitments. This delays a portion of dividends to provide lenders with additional security. Both constraints are established to mimic a commonplace cashflow restriction placed on project financed VRE plant. All financing assumptions and calculations were adopted following consultation with project financing experts currently operating in Australia's energy industry.

Table 2 sets out how scenarios are altered, how the base case (fully contracted) variables are built up, and how they differ from the semi-merchant cases. Another key variable is the ex-ante forward curve, and forecast spot prices thereafter. The use of this is somewhat nuanced. In practice, ex ante forward curves and spot price forecasts are automatically discounted by 20% by project bankers when sizing debt (i.e. the *Project Banker's version* of the model – refer to 2nd last column in Table 2). Conversely, equity investors do not discount forward curves and spot price forecasts when determining their expected returns (i.e. the *Equity Investor's version* of the model).

Table 2. Scenario dependant assumptions

Scenario Table

		Fully Contracted Base Case	**Semi-Merchant Bankers Case (1)**	**Semi-Merchant Equity Case (2)**
Cost of Capital				
Maximum Gearing Level	(%)	72*	64*	64
PPA Coverage	(%)	100	75*	75
Minimum DSCR	(DSCR Multiple)	1.25x	1.43x	1.43x
Target IRR	(%)	8.00	N/A	9.30
Credit spread	(bp)	180	200	200
Revenue				
PPA Price	($/MWh)	53.6*	53.6	53.6
Spot Ex Ante Forecast**	($/MWh)	N/A	Applied	Applied
Spot Ex Post Forecast**	($/MWh)	N/A	N/A	Applied
Spot Market Discount	(%)	0	20	0

*Model output
**See section 3.1 and Figure 3
(1) Size debt and PPA by stress testing project downside
(2) Use sized debt and PPA to calculate IRR

Regarding our assumptions, the maximum gearing, target IRR and credit spread are all adopted from Gohdes et al., (2022) which are in turn consistent with the market parameters observed in Simshauser et al., (2022) – all of which are driven by the level of PPA coverage. To summarise those findings, when projects have 100% PPA coverage, gearing levels are higher (~72%) due to low DSCRs (1.25x), target IRRs are lower (~8%), and credit spreads are lowest (~180 bps). Conversely, a fully merchant renewable project with no PPA coverage will have significantly lower

[8] 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

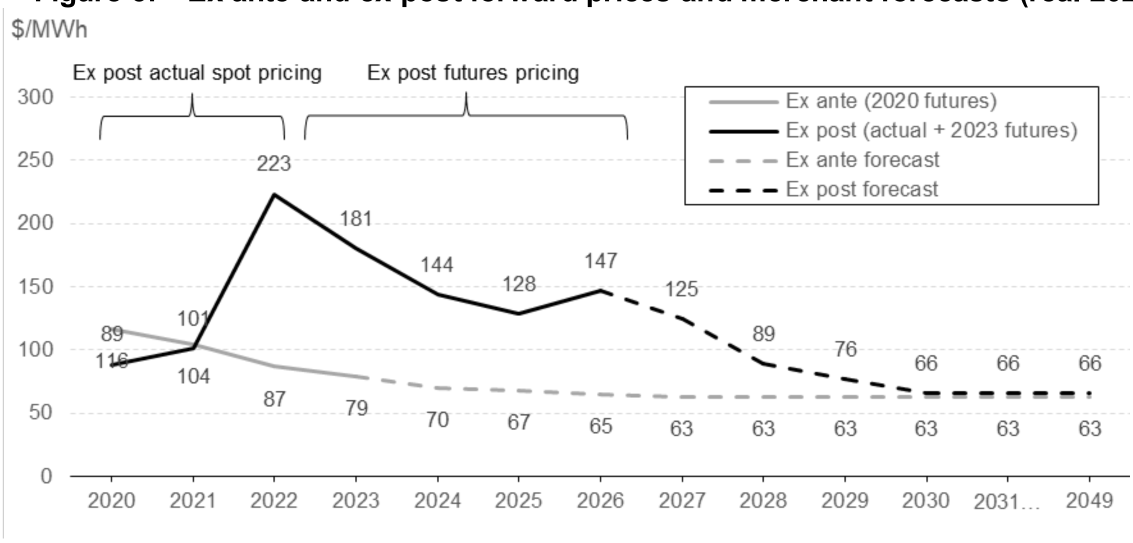
gearing (~50%) due to higher DSCRs (1.85x) higher IRRs (~12.25%) and elevated credit spreads (~200bps). Our semi-merchant plant will, axiomatically, be bounded by these two extremes.

Note that maximum modelled gearing under the fully contracted (base case) scenario calculated here is 72%, which aligns well with the upper bound for fully contracted projects operating in Australia's NEM (previously identified in Gohdes et al., 2022). Section 3.2 also provides further detail on semi-merchant assumptions and their calculations.

3.1 Forward prices and spot price forecasts

For semi-merchant scenarios, ex ante forward prices are used for the visible length of the forward curve. Thereafter, a spot price forecast is used. Figure 3 illustrates this for the ex-ante scenario – the solid grey line series shows forward prices from 2020-2023, with the spot price forecast thereafter represented by the grey dashed line series. The spot price forecast post-2023 was calculated at the 15-year historic average price, expressed in constant 2020$ and adjusted for wind generation dispatch in line with the principles of Hirth (2013). This ex-ante price series (grey line series) is designed to mimic the likely expectations of market participants as at the start of 2020.

Figure 3: Ex ante and ex post forward prices and merchant forecasts (real 2020$)[9]



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

The ex-post price series relies on similar principles, with the addition of live data from the spot and forward markets as at the end of 2022. Consequently, the first three years (2020-2022 inclusive) are the actual earned spot prices by the fleet of wind generators in the NSW region, and prices from 2023-2026 are derived from the latest forward curve as at the end of 2022. Thereafter, a spot price forecast again relying on a 15-year spot price average has been used. Scenarios largely converge by 2030 as a result, with the difference reflecting an ex-ante moving average.

3.2 Semi-merchant equity IRR and DSCR calculations – hybrid format

By necessity, our initial equity IRR and project DSCR constraints for the semi-merchant project need to be *derived* as a hybrid using the fully contracted and fully merchant survey data from Gohdes et al., (2022). The extent of contracted / merchant are then used by *geometric weight* to produce the semi-merchant equity IRR and project DSCR (see in particular Table 2, results signified by *). The hybridisation comes from the weighting of contracted vs merchant revenue

[9] Forecasts include bundled pricing for both generation and large-scale generation certificates (LGCs). LGCs are tradable renewable energy certificates introduced under the Australian Government's Renewable Energy Target.

exposures and represents a normative approach to equity investment hurdles and project banker debt covenants when determining equity IRR and DSCR requirements, respectively.

In the case of the semi-merchant plant, revenue derived from the assigned PPA during the tenor is calculated and volume-weighted against total revenues. So while the simple average starting point commenced with 75% contracted, 25% merchant plant capacity, when weighted by value (i.e. geometric average rather than simple average) equates to 69.6% contracted, 30.4% merchant, ex ante. These revenue weightings are in turn applied to equity IRR and DSCR values under hypothetically 'fully contracted' and 'fully merchant' conditions, resulting in a geometric average that reflects the risk associated with portfolio revenues. These calculations are illustrated in Table 3.

Table 3. Semi-merchant hybridised capital costs

Variable		Contracted Portion	Merchant Portion	Semi-Merchant Weighted Avg.
Weighting		*69.60%*	*30.40%*	
DSCR	(DSCR Multiple)	1.25x	1.85x	1.43x
IRR*	(%)	8.00*	12.25*	9.30

*Sourced from Gohdes. et al (2022)

4. Model Results

Our model results are organised as follows. We begin by establishing our ex-ante models as at 1 January 2020. These models provide a normative view of investor expectations. The first model is our Base Case and comprises a fully contracted 250MW wind farm. Our second ex ante model is the semi-merchant 250MW wind farm with 20-30% of capacity exposed to spot prices and has two specific sub-scenarios, viz. the risk averse project banker's model, and an equity investor's model. This completes the suite of 'expected' model results. To be clear on this, our models are:

- Base Case (fully contracted). The purpose of this model result is to solve for the competitive price of PPAs via a 250MW wind farm with 100% PPA coverage. This result becomes a key input to all other models.

- Semi-merchant (run of plant PPA, targeting 70-80% contractual cover)

    - Project Banker's semi-merchant case, with the PPA price drawn from the base case and merchant revenues from Figure 3 (ex-ante grey line series). Merchant prices are then discounted by 20% in line with the practice of risk averse project banks. The purpose of this model is to size the debt facility and determine the % of debt within the capital structure for a merchant exposure no less than 20% of plant capacity (and our expected maximum viable merchant exposure of no more than 30% of plant capacity);

    - Equity Investor's semi-merchant case, once again with the PPA price drawn from the base case, and merchant revenues from Figure 3 (ex-ante grey line series) but in this case, *are not discounted*. The purpose of this model is, once debt has been sized from the Project Banker's Model and the capital structure determined for a given merchant exposure, to seek to determine whether the appropriate risk-adjusted equity hurdle rate (from Tab.3) can be achieved, ex ante.

Once the suite of ex ante results are established, we time-shift our model forward to 2023 by applying ex-post data traces from Fig.3. Doing so captures the relative under- or out-performance of a semi-merchant plant (cf. fully contracted base case) when exposed to real spot prices observed during 2020, 2021 and 2022 and new forward prices for 2023-2027, along with stress tests for project cost shocks. For clarity,

- Ex post, the Project Banker's and Equity Investor's semi-merchant cases converge into one model because the 250MW wind project is operational, and all decisions vis-à-vis debt sizing, capital structure, the level of merchant exposure and expected returns to equity, are sunk and irreversible (and therefore common to both debt and equity investors).

4.1 Ex Ante Base Case vs. Semi-Merchant (Bankers and Equity Cases)

The first task for our PF model is to establish what we refer to as the *base case* scenario, a fully contracted plant originated in 2020 with corresponding debt sizing and gearing characteristics as detailed in Tables 1-3.[10] For our base case, this includes an equity IRR target of 8.0%, a Debt Service Coverage Ratio of 1.25x. Two key simultaneous model results emerge, as follows:

- The minimum PPA price required to meet financing and equity obligations under the base case scenario was solved by the model at $53.5/MWh in year one, escalated annually at CPI thereafter. Model outputs from the base case scenario appear as the first bar series in Figures 4a and 4b. Figure 4a shows results in $/MWh and 4b presents $'000, noting that in both charts break down the allocation between plant operations, debt servicing, taxation and equity returns.

- The modelled gearing result relating to this scenario is 72% debt within the capital structure. This result aligns well with the upper bound of VRE projects, fully contracted by way of PPA, currently operating in Australia's NEM in the survey results from Gohdes et al., (2022).

Recall from Section 3 that we assume this result to be the *competitive market price for wind PPAs*. Our point estimate of $53.5/MWh will therefore be used throughout all scenarios, including semi-merchant scenarios. This ensures consistency of modelling and eliminates the prospect of downside equity risks associated with residual merchant exposures being subsidised by a PPA counterparty through an alternate (higher) price.[11]

Recall semi-merchant scenarios have two sub-scenarios, the Project Banker's[12] model (discounted merchant prices by 20%) and the Equity Investor's model (no discount to spot and forward prices). These appear as the second and third bar series in Figures 4a and 4b, respectively.

[10] Whilst we acknowledge the project technically resumes spot exposure at year 16 (i.e. post PPA tenor), for the purposes of debt sizing and IRR considerations we consider the base case scenario as a fully contracted asset.

[11] Our simplifying assumption here is a common buyer seeking to minimize the LCoE.

[12] Note the banker scenario appears to depict a lower total operating cost. This occurs via a reduction in equity returns and is therefore strictly a "stress tested" scenario.

Figure 4: Ex Ante Fully Contracted vs Semi-Merchant Results

Fig.4a - Unit Cost

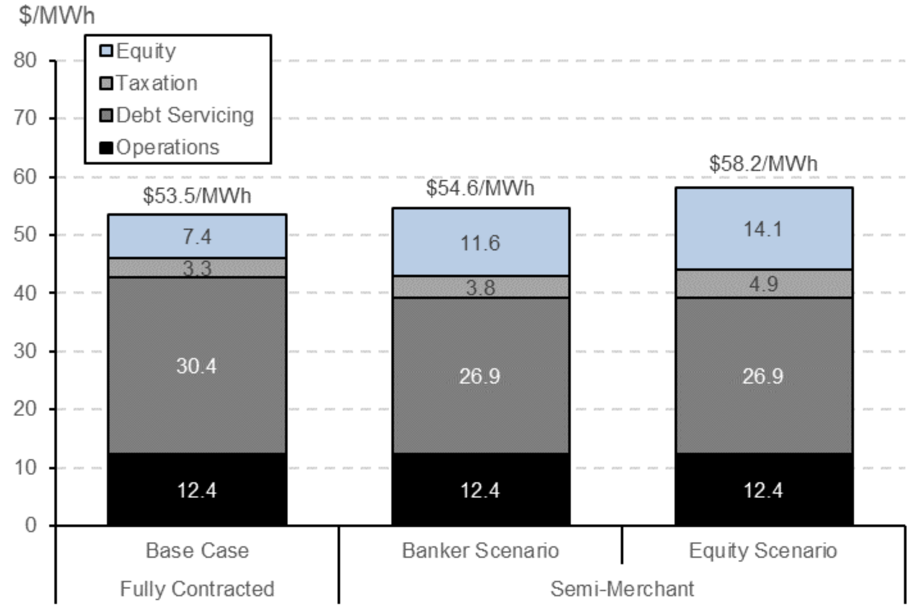
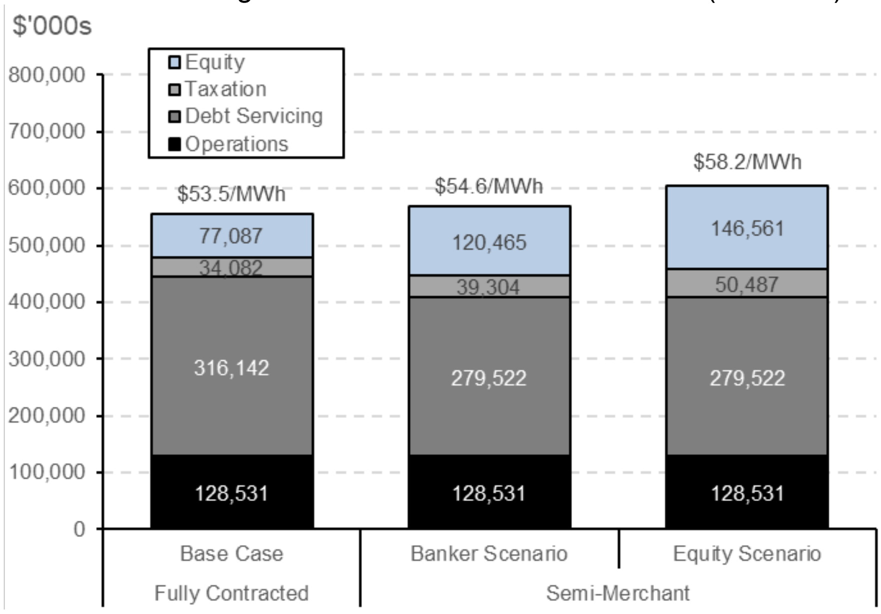


Fig.4b - Present Value of Cash Flows (15 Years)

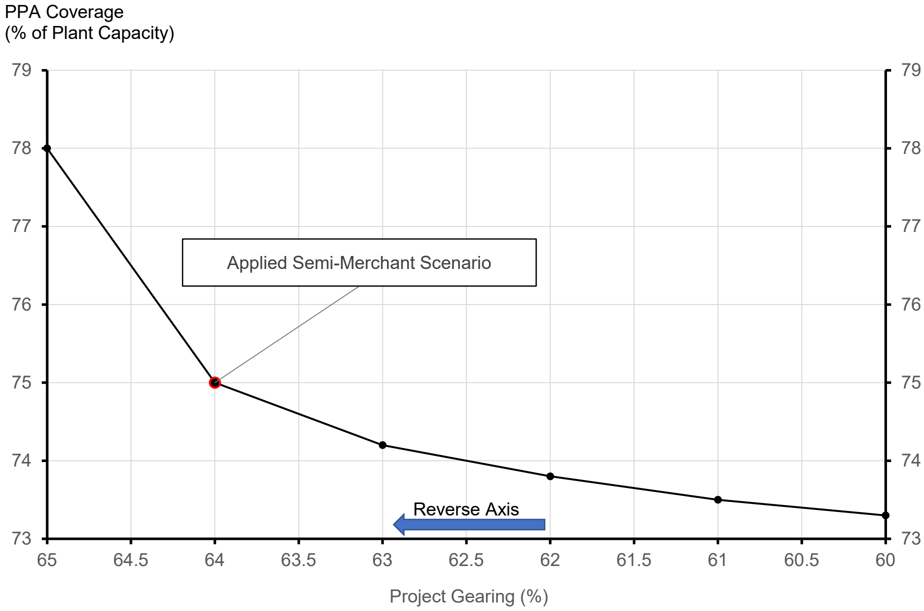


For the semi-merchant sub-scenarios, the PF model iterates and solves for two key variables. The first variable involves lowering the PPA coverage from 100% to a target range of 70-80% coverage, whilst simultaneously and dynamically introducing spot prices at various exposure levels instead of fixed PPA prices for that unhedged output (i.e. the uncontracted 20-30% of output). As noted above, the Project Banker's case (middle bar series) discounts all forward and spot prices and exposures by 20% with that model focusing on not breaching the DSCR metric from Table 3. For the Equity Investor's case (right bar series) merchant prices are not discounted, allowing the model to solve for the (dynamically determined) equity IRR constraint from Table 3, holding all else otherwise constant.

Ultimately, what the model is seeking to do is find the minimum PPA coverage, while simultaneously maximising the level of debt within the capital structure without violating the PF Model's inbuilt financing covenants (i.e. DSCR) through varying levels of merchant exposure.

Noting the expected solution was within the range of 70-80% PPA coverage, with debt levels of 60-65%, we found multiple equilibria with our tractable solution set illustrated in Figure 5.

Figure 5: PPA Coverage (%) vs Project Gearing (%)



For the purpose of the subsequent analysis, our preferred result is clearly highlighted in Fig.5 and is as follows:

- Optimal PPA coverage = 75% (lowered from 100% in the Base Case).
- Debt sizing of 64% within the Capital Structure (lowered from 72% in the Base Case).

With these setpoints, our Equity Investor's scenario in Fig.4a depicts an apparently higher overall project cost or LRMC ($58.2/MWh) than that of the base case ($53.5/MWh). This merely reflects the pricing of risk and has nothing to do with the plant acquisition cost. That is, the altered risk profile of future cash flows means that both project banks (+20bps) and institutional equity investors (+130bps) demand, ex ante, higher risk-adjusted returns under uncertainty.[13]

4.2 Ex-post Scenarios

We now turn our modelling efforts to an ex-post assessment, as at 2023, following three years of operations and a new forward curve spanning through to 2027 (i.e. 7 years of updated price data for any merchant exposures). The base case scenario, being a fully contracted project with no exposure to spot prices, requires no alteration. For the semi-merchant case, the PF Model dynamically applies updated market price assumptions for that capacity which has merchant exposures (i.e. 25% of generation) in line with the black line series or price trace in Figure 3. Recall Fig.3 comprises historic market prices for 2020, 2021 and 2022 and resets forward prices out to 2027, and a revised spot price forecast based on the moving average of the past 15 years.

During the first year of operations in 2020 ex post, the semi-merchant plant under-performs relative to the Equity Investor's case because 2020 actual spot prices fell below forecast results. Conversely, in 2021 and 2022 actual spot prices surged as did forward prices to 2027. In this instance, the semi-merchant plant earns supranormal profits (cf. base case) which are forecast to persist through to at least 2027, given the new forward curve. On average, supernormal returns equate to $8.7/MWh or $6m per annum (forecast) over and above the plant cost for 15 years

[13] The difference of $4.7/MWh is attributable to cost of capital optimization, viz. higher gearing, lower credit spreads and lower equity return requirements associated with fully contracted plant. See Gohdes et al. (2022) for further details.

(c.$90.6m excess returns in total). These results are depicted in Figures 6a ($/MWh) and 6b ($'000).

Figure 6: Ex-Post Full Contracted vs Semi-Merchant

Fig.6a - Unit Cost

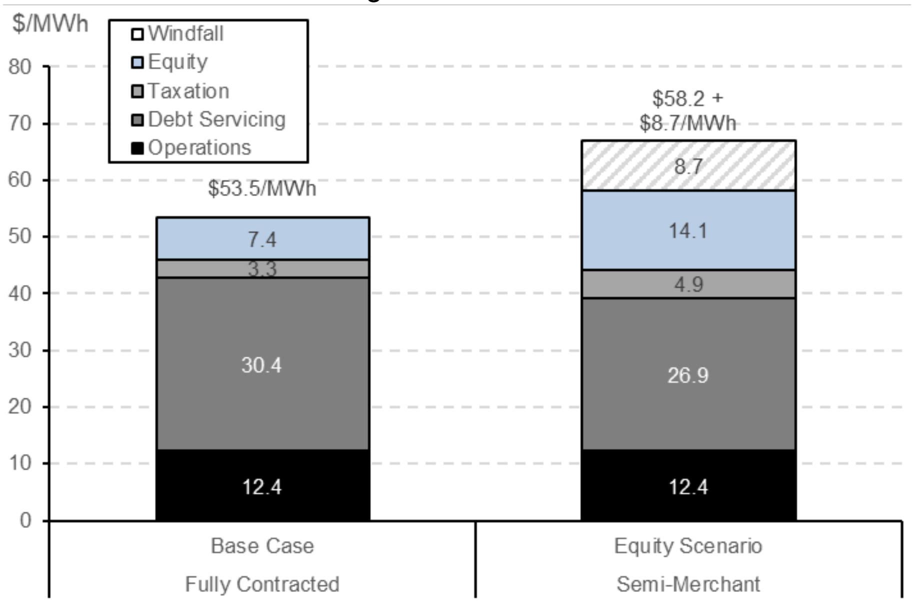
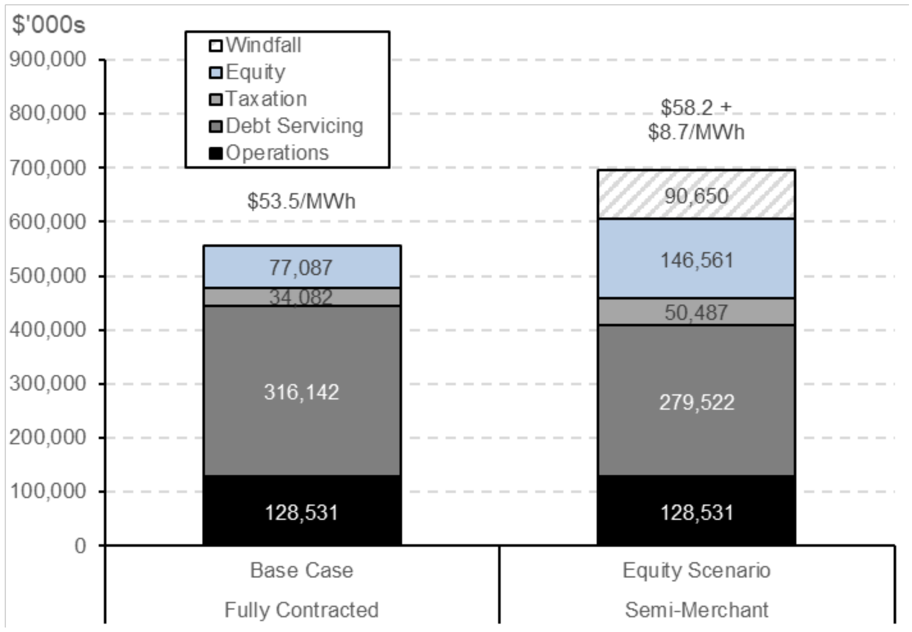


Fig.6b - Present Value of Cash Flows (15 Years)



The prima facie appeal for institutional equity investors to introduce some level of merchant exposure is evident from inspection of Figure 6. It is worth noting competitive PPA prices in Australia have been priced well below the forward curve over the past 5 years as technology costs continued to fall (see Simshauser & Gilmore, 2022). The estimated ex-post IRR equity returns with 25% merchant exposure rise to ~12.2% (cf. 8.0% return for base case plant and 9.25% for the semi-merchant plant, ex ante).

However to be clear, the risk profile of the semi-merchant investment deviates considerably from the base case. Recall from Figure 3 that historic spot prices during the 2020 year ($50/MWh) underperformed relative to ex ante forward prices ($80/MWh) and therefore the running yield to equity also underperformed significantly during that year – the point being semi-merchant plant is not a one-way bet. Nonetheless, the basis of selecting PPA coverage within the range specified in Fig.5 (rather than a lower set-point) was specifically targeted given the prospects of cyclical lows in the energy market and the ability of the plant to withstand low spot prices without entering financial distress. Conversely, the running yield of the semi-merchant plant throughout 2021, 2022 and beyond have vastly exceeded benchmark. This coincided with an episode of uncharacteristically high spot prices.

4.3 Distress Scenarios

In a scenario where spot prices experience a sustained cyclical downturn, returns to equity would be trimmed and fall below benchmark for a semi-merchant plant. If such a downside variation persisted it is plausible that a semi-merchant project could experience financial distress and ultimately bankruptcy. At the same time, energy markets are ultimately mean reverting and in theory at least (Pindyck, 1999; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019; Simshauser and Gilmore, 2022), this places an outer limit on the duration of such events, at least based on our current understand of energy-only markets – noting our modelled plant has substantial (i.e. 75% PPA) price coverage cover and is *not* fully exposed to spot prices.

Consequently in the following analysis, rather than examine such price sensitivities we examine plausible downside risks which may arise for either the fully contracted or semi-merchant project as they progress through to the early years of operations. Specifically, we explore ex-post modelling of the following variables:

- construction cost overrun of +5%
- a two-week delay to commissioning (holding costs constant)
- unexpected curtailment of plant output during the first 3 years of operation, reducing plant capacity factors by 2.5 percentage points (ppt), from 35% (Table 1) to 32.5%
- a significant 2.5 ppt reduction in the plant's marginal loss factor, from 0.96 (Table 1) to 0.935.

We have selected the above collection of adverse events based on market observation – that is, they are far more than theoretical risks and in some instances, renewable projects have been 'hit' by an accumulation of all variables and all at once (see Simshauser, 2021; Simshauser and Gilmore, 2022). We apply these shock events to our (ex post) financial model for the 2020 year. We selected this year because the ex-post spot prices during 2020 were also substantially below the ex ante forward prices for 2020 – thus presenting as a downside year for the semi-merchant plant in any event. Any cost shocks will therefore serve to amplify the result. The financial impact on 'year one' cashflows for the fully contracted and semi-merchant plants are depicted in Figures 7-8, respectively.

Figure 7: Ex Post Fully Contracted - Year One Cashflows

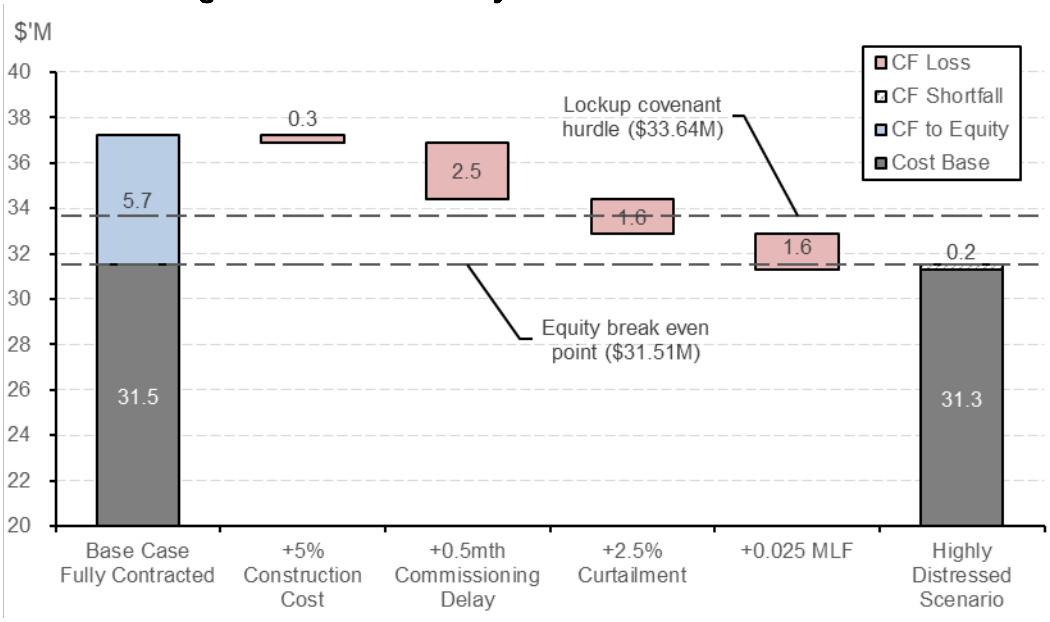
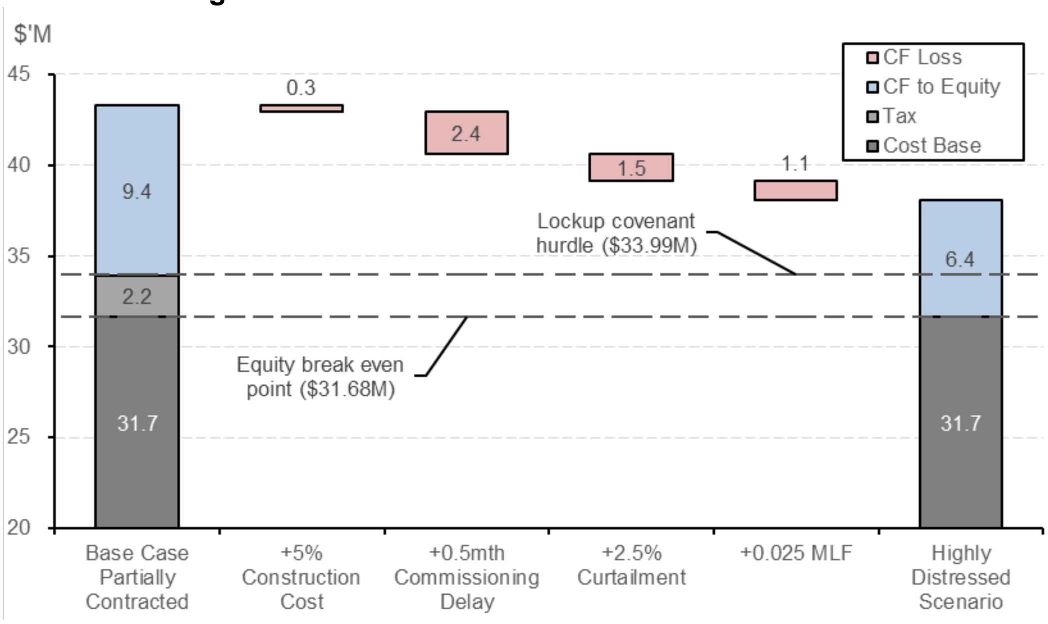


Fig.7 shows the combination of variables is capable of sending the fully contracted project into financial distress and lockup. Indeed, for the fully contracted plant, a sum of the MLF and commissioning variables alone (at a 2 week delay and 2.5ppt drop respectively) is sufficient to place the project into financial distress and lockup. As an aside, the MLF sensitivity in Fig.7 clearly illustrates why project finance banks active in Australia's NEM altered their standard terms and conditions on a uniform, market-wide basis in 2019g. Specifically, we find if a VRE project's MLF changes by 5ppt or higher ex post (i.e. a negative c.$3.2m/yr cashflow impact), any project banked after 2019 would automatically go into 'lockup' with any and all excess cash used to repay debt down as quicky as possible to restore the (ex ante determined) credit metrics. Such a clause did not exist prior to 2019, but emerged after a series of poorly located VRE projects experienced large drops in MLF (Simshauser, 2021; Simshauser and Gilmore, 2022).

Figure 8: Ex Post Semi-Merchant - Year One Cashflows



Conversely, Fig.8 notes that the semi-merchant plant in this instance appears capable of avoiding financial distress and does so even under conditions of low ex post spot prices – noting its leverage is lower to begin with. Perhaps the most important insight from this analysis is that with respect to any and all cost shocks, the fully contracted project faces only downside risk and returns. If the conditions outlined in Fig.7 persisted beyond Year 1, institutional equity returns would fall from ~8% to ~4.2% (Fig.9). On the other hand, while the semi-merchant plant has also suffered in this Year 1 scenario (Fig.8), it is capable of recovering some element of profit in cyclical upswings, with equity returns of 10.3% as illustrated in Fig.10. Importantly, we note here that ex post windfall profits are sufficient for the distressed semi-merchant plant to retain an IRR ~1.0% higher than forecast ex ante, effectively eliminating plant underperformance during the project life.

Figure 9: Ex Post Distressed Fully Contracted - Return to Equity

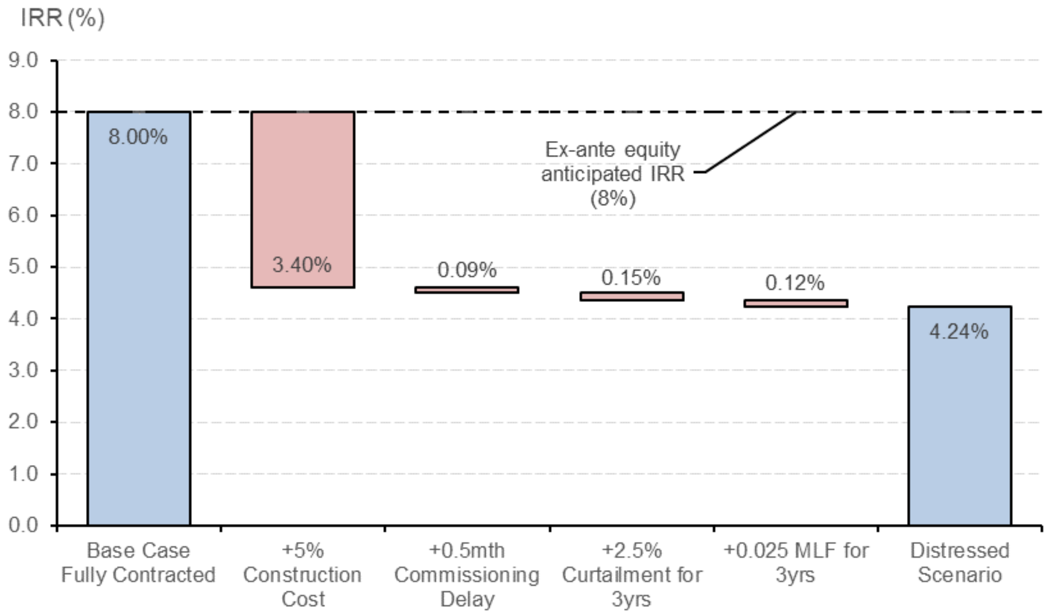
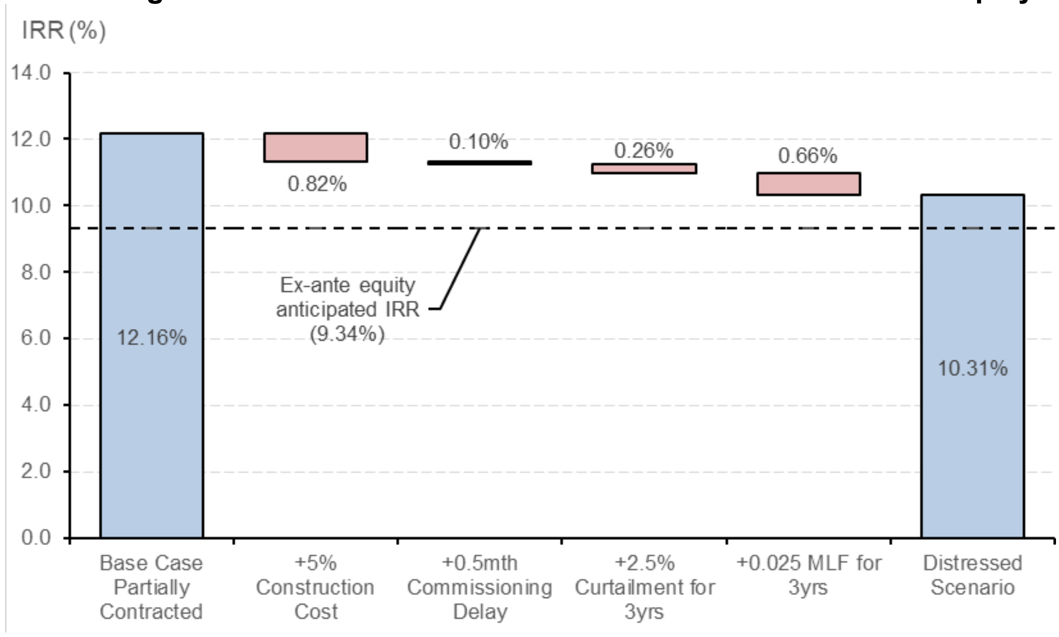


Figure 10: Ex Post Distressed Semi-Merchant - Return to Equity

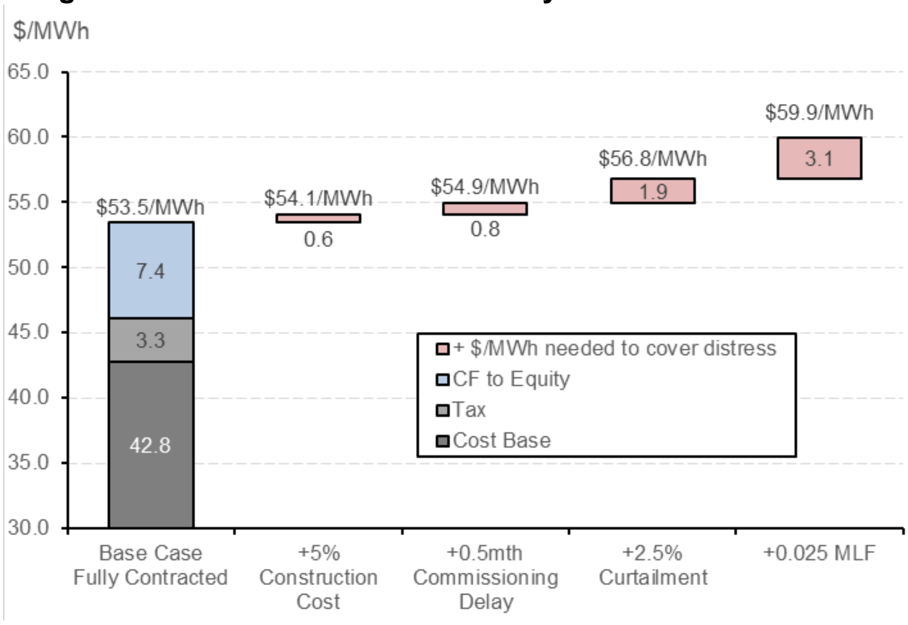


For an institutional equity investor, significant losses in expected equity IRR's naturally impacts balance sheets via asset write-downs. For the present asset, the initial $130m equity investment associated with the fully contracted 250MW wind farm would need to be written down to ~$65m. The sheer severity of these outcomes may not have been obvious in the absence of our analysis, particularly given that three of the four distress characteristics only impact the asset performance during the first 3 years of the 30-year project life. For the semi-merchant project, any write-down would be more nuanced. The fact that a merchant exposure exists for 25% of plant capacity means stochastic simulations could be warranted, and represents an avenue for further research.

4.4 Quantifying PPA Mispricing for the Fully Contracted Plant

Our base case produced a competitive PPA price of \$53.5/MWh (Fig.4a) and our analysis in Section 4.3 revealed that various cost shocks could send such a project into financial distress in the post-construction environment. Figure 11 identifies what a fully contracted plant would require in incremental pricing to compensate for any (or all) of the risk condition examined for a 15 year PPA.

Figure 11: Ex Post Distressed Fully Contracted - PPA Mis-Pricing



5. Policy considerations

As an absolute general conclusion, for most of the past two decades it has been the view of renewables investors that a fully contracted VRE project via 100% PPA coverage minimised risk in Australia's NEM. In an environment where renewable projects required a subsidy, and that subsidy was somehow reflected in PPA pricing (e.g. via bundled energy and renewable certificate pricing), this is not a contentious proposition. But such a view, given the results of our analysis, no longer seems warranted. By 2017 the entry cost of VRE projects fell below the marginal cost of the thermal generating fleet and consequently the requirement for 100% PPA coverage began to dissipate.

This was first revealed to the Australian market through the Victorian CfD auction process in 2017. Recall that in that 650MW Victorian auction process, VRE investors sought to access upside merchant risk by developing 800MW of plant (81% PPA contractual cover). As renewable entry costs continued to fall (i.e. from 2017-2021), PPA prices exhibited a steadily growing discount to forward prices.

Our modelling of a 2020 plant confirmed that coverage between 73-78% was viable and tractable for a project finance with a capital structure in the range of 60-65% debt, ex ante. Ex post results confirmed underperformance in year 1, supranormal profits in years 2 and 3, and a likely continuation for at least the next 4 years given prevailing forward prices.

As VRE projects in the NEM became larger and entered simultaneously with other entrants (see Simshauser & Gilmore, 2022), operational risks began to materialise. This included sporadic episodes of construction and commissioning/connection delays, unexpected curtailment due to falling system strength and variability of MLFs. Consequently, the *'lower risk'* description that typically accompanies a fully contracted VRE plant with 100% coverage via a run-of-plant PPA no longer seems adequate – at least in Australia's NEM. While perhaps not intended as an initial motivation, access to merchant (upside) risk has, ex post, served to offset a level of downside risk associated with project operations.

We believe an important conclusion from our research is that the notion of a fully contracted VRE plant exhibiting *lower risk* appears to conflate the concept of *lower volatility* with the concept of *risk-adjusted returns*. To be clear, there should be no doubt that for a wind farm with 100% contractual cover by way of a run-of-plant PPA, *revenue volatility* is substantially reduced. A semi-merchant plant will experience considerably more *revenue volatility* than the counterfactual. But given other project variables capable of adversely impacting VRE investment returns ex post, 100% PPA contractual cover does not reduce, and may in fact amplify, the volatility of equity returns – skewed only to the downside as Figures 7 and 9 illustrated. In short, 100% coverage places a cap on returns.

In Australia's NEM, semi-merchant projects now dominate entry statistics following the Victorian 2017 CfD process. The literature has observed this to be a growing trend (Nelson, 2020; Rai and Nelson, 2021; Flottmann et al., 2022; Nelson et al., 2022; Simshauser and Gilmore, 2022; Gohdes et al., 2022). Whilst past works have highlighted the trend, we believe our quantitative results and analysis explain *why* the trend emerged, and why it is expanding. We are also aware of this being an emerging trend in certain US markets.[14]

Our findings have important implications for policymakers with respect to government-initiated CfD auctions. CfDs are ultimately speculative derivative instruments which do not change form when written by governments. CfDs are 'wrapped' by a counterparty over long durations in a highly volatile commodity market. Compared to on-market transactions, taxpayer-wrapped CfD commitments absorb scarce government balance sheet capacity. Alternatively when government-initiated CfDs are ratepayer-wrapped, any consequential losses arising from out-of-the-money periods are typically funded by levying charges onto regulated network tariffs (see Hartmann, 2021).[15] The burden of recovering any shortfall is invariably regressive, at least in the Australian experience as illustrated in Nelson et al., (2022).

That said, government-initiated CfD auctions appear to have become an enduring feature with the classic market design becoming hybridised (Joskow, 2022). These auctions accelerate the rate of VRE entry to meet policy objectives, or in response to the present energy market crisis arising from the war in Ukraine. Our findings suggest that for auction process where the hybridised market comprises semi-merchant participants, entry is likely to overshoot auction requirements. Based on our modelling results of ~73-78% coverage being viable and tractable for project finance, a Government seeking to facilitate 5,000MW of VRE entry need only offer ~3,500-4,000MW of CfDs at auction, and can moderate the risk faced by taxpayers or ratepayers.

6. Conclusions

In this article, we sought to identify a bankable semi-merchant project in which project debt comprised at least 60% of the capital structure and a merchant exposure of between 70-80%. Our modelled results found than project debt levels of 60-65% were tractable with 73-78% PPA coverage, and by implication, 22-27% merchant exposure. Ex post, our model found an initial year of underperformance and subsequent years of clear outperformance. Our analysis revealed why this semi-merchant model presents as a developing trend amongst institutional equity investors.

[14] See for example Aurora Energy's Podcast #120 with Intersect Power CEO, Sheldon Kimber, available at https://www.youtube.com/watch?v=g6WXD5QQJlI

[15] End user electricity network tariffs in the Australian Capital Territory were increased by 41% in 2021 in order to cover rising costs of CfDs written in prior periods by the ACT government. The CfDs were extremely low cost at the time (i.e. ~$70/MWh during 2016-2017) but changes in costs and market prices have historically left these transactions out-of-the-money, with taxpayer exposure re-allocated to electricity consumers by raising network tariffs. When equivalent mistakes in retrospect are made by retailers or corporates, shareholders (not taxpayers) absorb any inefficient costs / losses.

The fully contracted plant exhibited a skewed, and we would suggest a less-intuitive, downside risk in the post construction environment brought about by risks of construction and other exogenous market conditions. The semi-merchant model appears to be an emerging and expanding trend for VRE plant developers in Australia's NEM. The policy implications for hybridised markets is that priming investment via CfD auctions, now a fixture of many markets, requires less MW on offer to reach a given MW target.

Our findings provide previously absent context to a *real* and growing trend observable in Australia's energy markets, and in energy markets globally. Future research in the field should consider extending the present analysis to stochastic forecasts, to stress test the robustness of the semi-merchant model. Doing so would serve to provide further direction vis-à-vis optimal policy implementations.

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Appendix A – PF Model Overview

The PF model logic is as follows:

In each annual period costs are increased at the assumed inflation rate (CPI), represented by π in period (year) t:

$$\pi_t = \left[1 + \left(\frac{CPI}{100}\right)\right]^t. \quad \text{(A.1)}$$

total energy output q_t is calculated using installed capacity k adjusted for plant capacity factor CF, auxiliary load Aux and the marginal loss factor MLF_t at time t:

$$q_t = \frac{CF \cdot k \cdot MLF_t \cdot (1 - Aux) \cdot YrHrs_t}{1000}. \quad \text{(A.2)}$$

$YrHrs$ represents operational hours per annum and is calculated based on a forced outage rate FO:

$$YrHrs_t = \left(YearDays_t \cdot (1 - FO)\right) \times 24. \quad \text{(A.3)}$$

The convergent price of electricity $Price_t^p$ for the p^{th} scenario (the base case/fully contracted) is calculated for year one and escalated per eq. (1). Period one pricing is synonymous with project long run marginal cost (LRMC), allowing the model to solve for minimum $Price_t^p$ or price under given equity return constraints:

$$Price_t^p = LRMC \cdot \pi_t. \quad \text{(A.4)}$$

For the semi-merchant case, $Price_t^p$ is calculated as the sum of PPA revenues PPA_t and spot revenues $SPOT_t$:

$$Price_t^p = PPA_t + SPOT_t \cdot \pi_t. \quad \text{(A.5)}$$

PPA and spot revenues are calculated in accordance with the total PPA contract coverage CC^p:

$$PPA_t = CP \cdot CC^p \cdot \pi_t, \quad \text{(A.6)}$$

and:

$$PPA_t = MP_t \cdot (1 - CC^p) \cdot \pi_t, \quad \text{(A.7)}$$

where CP and MP refer to the PPA contract price and the merchant price in period t respectively.

Plant revenue is therefore:

$$R_t^p = Price_t^p \cdot q_t, \quad \text{(A.8)}$$

where R_t^p is revenue at time t. Operational expenses consist entirely of operations & maintenance (O&M) costs. Fixed O&M costs FOM_t are calculated as the escalated product of assumed fixed costs FC calculated as \$/MW/year and installed capacity k:

$$FOM_t = \frac{FC \cdot k \cdot \pi_t}{1000}. \quad \text{(A.9)}$$

Variable O&M expenses VOM_t are dependent on q_t and assumed variable cost VC are calculated on a \$/MWh basis:

$$VOM_t = VC \cdot q_t \cdot \pi_t. \tag{A.10}$$

Earnings before interest tax depreciation and amortisation (EBITDA) for scenario p at time t is calculated as:

$$EBITDA_t^p = R_t^p - FOM_t - VOM_t. \tag{A.11}$$

Capital expenditure

Capital investment and ongoing capital works include capex cost of plant acquisition (\$463.75M) as well as ongoing capital maintenance. Each of these expenses are escalated at π_t. Capital expenditure at time t is calculated using the following decision rule:

$$if\ t\begin{cases} = 1,\ X_t = Capex + x_t \cdot \pi_t \\ \neq 1,\ X_t = \ x_t \cdot \pi_t \end{cases}, \tag{A.12}$$

where X_t denotes total capex during a given period. $Capex$ denotes plant acquisition cost and is calculated as the product of the assumed overnight capital cost (\$1,855/kW) and the installed capacity k. x_t represents forecasted capital works required to maintain functional plant operating conditions.

Taxation

During income years where tax losses occur, the model is designed to carry losses forward to offset future profits. Both the asset depreciation shield ADS and capital depreciation shield CDS are calculated using a straight-line method.

oL and tL denote the project operational life and turbine operational life respectively. T denotes the monetary cost of replacing turbines. Total depreciation shield DS_t is calculated as the sum of turbine and capex tax shields at time t:

$$DS_t = \left(\frac{Capex - T}{oL}\right) + \left(\frac{T}{tL}\right). \tag{A.13}$$

The project pays a cash tax τ_t at the Australian corporate tax rate τ_c:

$$\tau_t = \left(EBITDA_t^p - I_t - DS_t - L_t\right) \cdot \tau_c. \tag{A.14}$$

where L_t represents tax losses carried forward from previous income years, calculated as:

$$L_t = Min(0, \tau_{t-1}), \tag{A.15}$$

and I_t is defined in the following section when discussing financing calculations. Cash flow available for debt servicing $CAFDS_t^p$ is found by subtracting X_t and τ_t from $EBITDA_t^p$:

$$CAFDS_t^p = EBITDA_t^p - X_t - \tau_t. \tag{A.16}$$

Debt parameters

The model assumes two tranches of debt, with a refinancing of tranche one according at period 7.[16] The second tranche persists to period 20.

The calculation for opening debt balance B_t follows the decision rule:

$$if\ t\begin{cases}= 1,\ B_t = D \\ \neq 1,\ \ B_t = B_{t-1} - \ P_{t-1}{'}\end{cases} \tag{A.17}$$

where n depicts the debt term, P_t depicts the principal repayment, and total debt D is the product of the scenario p gearing capacity G^p and $Capex$:

$$D = G^p \cdot Capex. \tag{A.18}$$

The principal repayment for a given period t is sized using the target debt service coverage ratio (DSCR) $DSCR^p$ and follows:

$$P_t = \frac{CFADS_t^p}{DSCR^p} - I_t$$

The applied interest rate i is calculated as the sum of BBSW, the credit spread CS^p for scenario p:

$$i = CS^p + BBSW. \tag{A.19}$$

The interest payment I_t is calculated as the product of the period's opening balance B_t and the applied interest rate i:

$$I_t = B_t \cdot i. \tag{A.20}$$

A lockup covenant of 1.1x is applied to the project cash flows, thereby pausing dividend payments following two consecutive periods of insufficient DSCR:

$$DSCR_t^p = \frac{CAFDS_t^p}{(I_t + P_t)}. \tag{A.21}$$

Dividends and PPA Price / LRMC

Dividend payout Div_t is found by subtracting the total cost of debt servicing, DP_t, from the cash available for debt servicing:

$$Div_t = CAFDS_t^p - DP_t, \tag{A.22}$$

$$DP_t = I_t + P_t. \tag{A.23}$$

The model is then capable of iterating to solve for $Price_t^p$ when applying a cost of equity k_e^p in accordance with scenario p:

$$0 = -Capex + \sum_{t=1}^{N} \begin{pmatrix} \left(Price_{t=1}^p \cdot q_t \cdot \pi_t\right) - FOM_t - VOM_t - DP_t \\ -\left(\left(Price_{t=1}^p \cdot q_t \cdot \pi_t\right) - FOM_t - VOM_t - I_t - DS_t - L_t\right) \cdot \tau_c \end{pmatrix} \cdot \left(1 + k_e^p\right)^{-t}$$

$$0 = -Capex + \textstyle\sum_{t=1}^{N} Div_t \cdot \left(1 + k_e^p\right)^{-t}. \tag{A.24}$$

[16] Average reported debt tenor for wind and solar remains under 6.5 years according to data sourced from Rystad Energy, Inframation, RenewEconomy, websites & media releases

When solving for the PPA price, the model is tasked with determining the minimum value for $Price_{t=1}$ resulting in k_e^p being equal to equity returns required by a given scenario p. This provides an appropriate estimate minimum *competitive* PPA price, considering operations, taxation and capital structure.

When solving for PPA contract coverage, the model iterates and solves for the contract coverage CC^p (see A.6 and A.7) required to ensure k_e^p is equal to equity returns required by a given scenario p.

Appendix B – Model Sensitivity Results

To ensure that model outputs are reasonable, a sensitivity analysis was also conducted on the results. Key assumptions were relaxed by applying inflated cost inputs in order to stress-test the PF model. Figures A1 and A2 display the impacts of changes to overall LRMC, which is synonymous with minimum viable PPA price for the fully contracted scenario. Given the scale of metrics selected, Capex, interest rates and equity IRR appear to be the most sensitive. This makes sense intuitively given that the majority of operational costs associated with VRE constitute debt and equity payments on year one capital expenditure. Variables such as interest rates should be considered carefully given the potential for future cash rate increases beyond the increment selected here (i.e. 1%). Additional adjustments beyond those depicted in Figure A1 and A2 results will amplify unit costs approximately in the same proportions.

Figure A1. Cost element sensitivities for fully contracted VRE plant

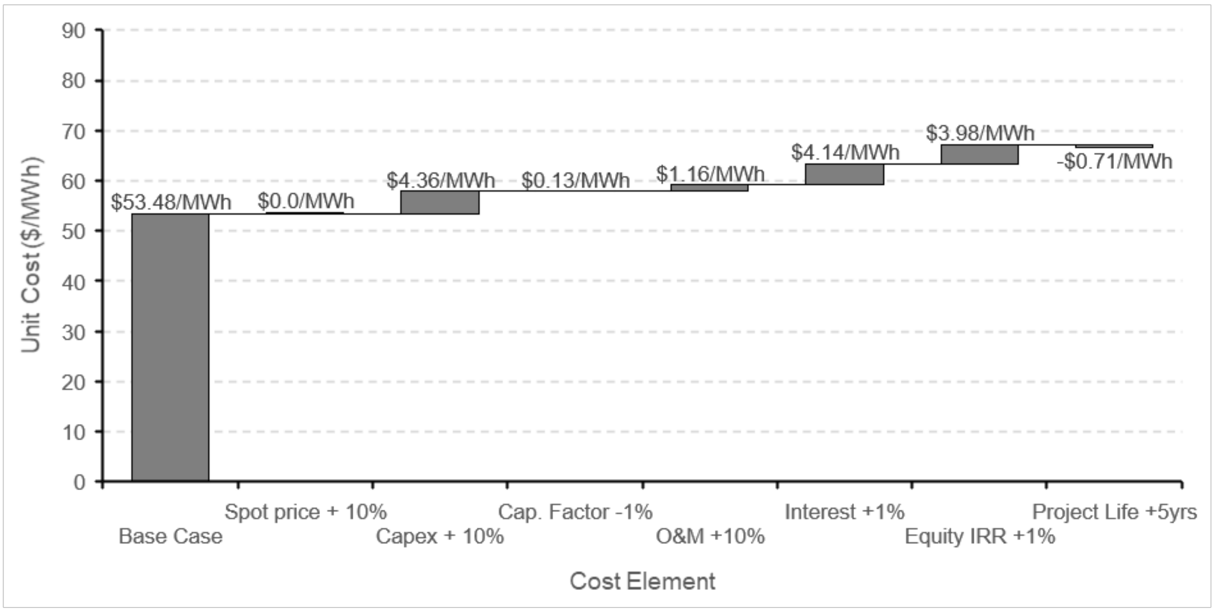

Figure A2. Cost element sensitivities for semi-merchant VRE plant