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Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market

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Abstract

The cost of capital is among the most important variables determining the feasibility of investment in renewable energy projects. In Australia's National Electricity Market, the ability of new variable renewable energy (VRE) plant to arrange requisite project finance at favourable rates largely determines project viability. Such financings are typically only achieved when VRE projects are underpinned by long-dated Power Purchase Agreements (PPA), under which prices are guaranteed by an investment-grade counterparty. In this article, we quantify the relationship between PPAs, counterparty credit quality and the cost of capital in the context of Australia's energy-only wholesale market under conditions of policy uncertainty. Our analysis benefits from the application of confidential data from Australia's capital markets. We find higher credit quality drives higher gearing, and somewhat counterintuitively, lower expected returns to equity. This in turn produces a lower cost of capital and by implication, higher post-construction VRE plant valuations – an outcome seemingly at odds with Modigliani and Miller's classic 1958 article. In practice, risk has been repackaged and reallocated.

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

JEL Classification: D25, D80, G32, L51, Q41.

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1. Introduction

Global energy markets are now dominated by variable renewable energy (VRE) investment commitments, driven by falling technology costs and underpinned by a drive to reduce dependence on carbon emitting technologies. As Engelhorn and Müsgens (2021) explain, VRE is a global megatrend. Australia's National Electricity Market (NEM) experienced a renewable investment supercycle – 135 VRE projects totalling 16,000MW worth more than $26.5 billion was committed during 2016-2021, with the market share of coal-fired generation falling rapidly (Simshauser and Gilmore, 2022). What makes this renewable investment supercycle all the more striking is that it followed a two-decade long climate change policy war between Australia's two main political parties (Simshauser and Tiernan, 2019; Nelson, Nolan and Gilmore, 2022). However, while it would seem that a united position on climate change policy in Australia may have finally been achieved following the 2021 Glasgow Conference of Parties, the success of any ongoing transition in our view remains dependent on underlying VRE entry costs, as policymakers aim to limit potentially adverse short term pricing impacts on consumers. The association between entry costs and long run electricity price trends in Australia's NEM has been well established (Simshauser and Gilmore, 2020).

In this article, we focus on the capital component of VRE entry costs and attempt to measure its variance for a given 'revenue quality' in an energy-only gross pool under conditions of policy uncertainty. For our purposes, we define *revenue quality* as the combination of i). the extent of Power Purchase Agreement (PPA) *coverage*, and, ii). the *credit quality* of the PPA counterparty. We make use of novel data from Australia's capital markets and in particular, from a number of active VRE project originators/equity investors and project finance lenders. Our analysis segregates revenue quality into seven categories; BBB rated retail supplier, BBB corporate, AA+ State Government, and with varying levels of PPA cover, viz. 100% of run-of-plant volumes, 50% volume cover, and merchant (i.e. no PPA cover)[1]. Variances in entry costs for a given project are measured by reference to the post-taxation, post-financing entry cost[2] of VRE plant under each of these seven categories.

Various forms of long-dated, fixed-price PPA contracts have existed throughout the NEMs history. Traditionally, renewable PPA arrangements saw a retail supplier commit to purchasing 100% of the run-of-plant output of a VRE project over a 15-year period – the ideal terms for a project finance. Retail suppliers were motivated to write PPAs in order to acquit obligations under Australia's Renewable Energy Target (a 20% target by 2020). In doing so, the retailer receives a guarantee over the variable generation output and associated renewable certificates.

More recently, corporations and state governments have become prominent buyers of PPAs or Contract-for Differences (CfD). Corporates appear to be guided by sustainability targets and securing seemingly lower cost electricity[3]. State governments on the other hand contracted with VRE project originators to stimulate investment and meet state economic development objectives in the presence of climate policy discontinuity at the Commonwealth level (Simshauser and Tiernan, 2019).

It is generally understood in industry circles that revenue security through PPAs is important to securing a commercial cost of capital for new entrant plant in competitive energy-only markets (Chao, Oren and Wilson, 2008; Finon, 2008; Nelson and Simshauser, 2013; Newbery, 2016, 2017; de Atholia, et al., 2020; Rai and Nelson, 2021). Locking-in an

[1] Merchant revenue' refers to revenue derived solely from spot markets, without PPA or price hedging.
[2] Here, we rely on a Levelised Cost of Entry (LCoE) calculation albeit as noted on a post-taxation, post-finance basis and therefore with a level of detail and precision well beyond conventional LCoE calculations.
[3] Recent PPAs have been struck at prices below market rates. However, the matter of residual demand (customer load – PPA output) complicates matters considerably, especially for solar PPAs.

acceptable cost of capital is among the most important factors in determining a VRE project's economic feasibility once location and equipment costs are secured. Due to an absence of fuel expenses, the majority of ongoing plant costs exist in capital repayments – unlike gas plants which face significant fuel costs (Schmidt, 2014; Newbery, 2016; Grubb and Newbery, 2018; May and Neuhoff, 2021). Stable and predictable revenues are hence inherently associated with a project's ability to structure finance with higher gearing levels. Mitigating exposures to volatile spot prices via PPA allows new plant to raise capital at rates conducive to a lower overall entry cost.[4]

With this background, our analysis focuses on the following two lines of inquiry:

i. What is the measurable effect of a PPA on the cost of capital for a VRE project in Australia's energy-only gross pool market?

ii. Does the level of investment-grade credit rating of a PPA counterparty materially impact a project's overall cost of capital?

We analyse these questions by simulating the revenues and expenses of a standard onshore wind farm using a dynamic multi-year, integrated power project finance model. Our model produces VRE entry costs across seven PPA scenarios. Project gearing, credit spreads and expected equity returns are all varied in accordance with PPA conditions and counterparty credit quality, with our inputs informed by primary and secondary data sourced from a range of industry sources and the capital markets.

The cornerstone of our data is survey results from some of the NEM's most active VRE equity investors and project finance lenders. Survey data is used as inputs for the relevant PPA scenarios, ensuring results are novel and reflective of current industry practices and investor expectations. Additional secondary data (see also Simshauser and Gilmore, 2022) was also compiled from a range of sources and databases in order to provide additional robustness. The resulting dataset represents one of the more comprehensive collections of NEM VRE project data at the time of writing.

Our substantial findings are as follows. The cost of capital of VRE plant is a critical entry cost variable. Consistent with prior analyses in the field, we find the presence of PPA coverage (100% of plant output) lowers entry costs relative to partial (50%) or merchant plant exposure through higher levels of gearing and lower credit spreads. However, we also find enhanced counterparty credit quality can be as important as the level of PPA coverage under certain conditions. Lenders and equity investors evidently trade-off gearing, credit spreads and returns on invested capital when future revenues are secured through PPAs from higher credit quality counterparties. Indeed, our quantitative results show a material improvement in counterparty credit quality can offset a move from 100% to 50% PPA run-of-plant cover. PPA counterparties with higher credit ratings are preferred by financiers, who offer commensurately higher gearing levels and lower credit spreads, while equity investors appear to moderate expected returns, all of which prima facie defies Modigliani and Miller's (1958) classic theorem. In practical terms however, such structures do not create *'a magic pudding'* or defy financial economics. Project risks have merely been repackaged and reallocated.

This article is structured as follows. Section 2 provides a review of relevant literature. Section 3 details our model and data. Section 4 presents quantitative results while section 5 discusses the policy implications. Concluding remarks follow.

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[4] Energy-only gross pool markets such as Australia's NEM promote new entrant plant with low entry costs through competitive spot price bidding and liquid forward markets. The transitory nature of divergence in new entrant costs and average market spot prices has been well established (Simshauser & Gilmore, 2019).

2 Review of literature

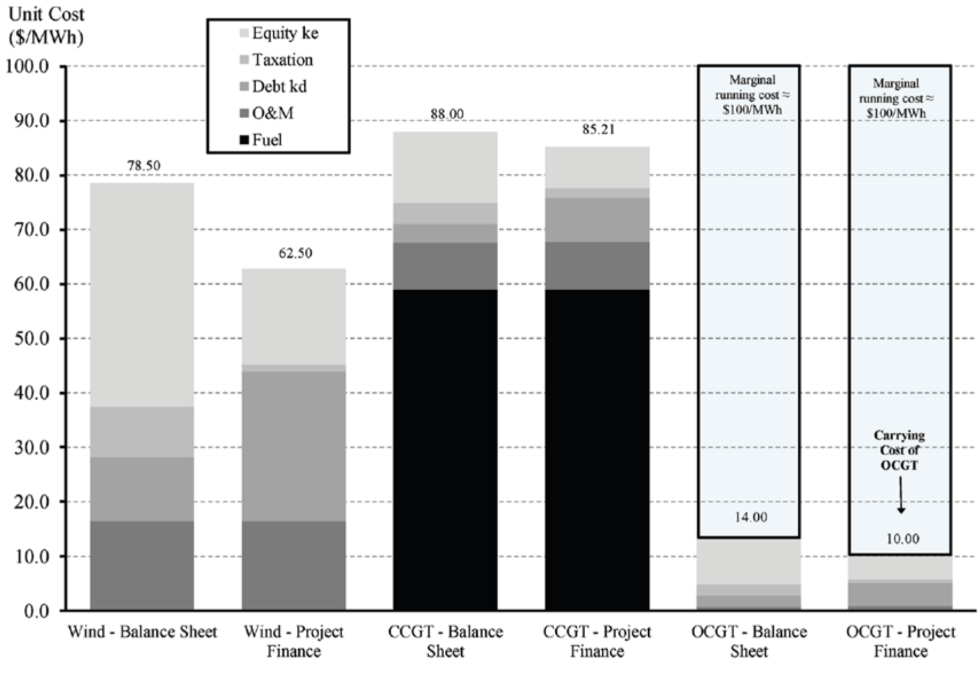
2.1 Financing structures

It is difficult to overstate the importance of access to capital in the energy sector. Projects with sizable investment requirements remain heavily dependent on the cost of capital as a primary determinant of both total profitability and, by extension, competitive cost of entry (Steffen, 2018). This dependence seems pronounced for VRE projects which require proportionally higher capital outlays *cf.* fossil fuel counterparts (Schmidt, 2014; Newbery, 2016; Grubb and Newbery, 2018). Financing structures for VRE plant therefore play a major role in determining ongoing entry costs. Plant financing options can be segregated into two primary structures, either project finance or balance sheet (i.e. corporate) finance (Wiser, 1997; Simshauser, 2021).

Financing projects on-balance sheet is a more traditional approach, requiring debt to be raised and serviced using the combined assets and resources of the sponsoring firm in order to guarantee credit (Esty, 2004). In contrast, project finance (PF) makes use of a newly created entity or company (i.e. special purpose vehicle or SPV) for the sole purpose of project ownership and management (Nelson and Simshauser, 2013; Steffen, 2018). SPV structures limit a financier's claim to the cash flows and assets held within the SPV. The impact on new entrant plant includes changes to risk, debt capacity and management protocols (Esty, 2004). Perhaps the most important distinction between the two structures is the increased capacity for debt as a proportion of total capital expenditure under a PF arrangement.

The capital-heavy cost structure of renewable plant facilitates a greater benefit to entry costs from a cheaper cost of capital. In consequence, project finance has become the preferred method of raising capital for VRE projects (Kann, 2009; Steffen, 2018). A lower overall weighted average cost of capital (WACC) is consequentially facilitated under conditions of higher gearing, and lower equity contribution requirements. Simshauser and Gilmore (2020) contrast the effects of project financing (cf. corporate finance) on the entry costs of wind and gas projects. They show measurable decreases in entry costs for wind projects employing a project finance structures with commodity price risks underwritten by PPAs (see Fig.1).

Figure 1: Project finance vs corporate finance (wind and gas plant)



Source: Simshauser and Gilmore (2020)

2.2 PPAs and Project Finance

PPAs represent an agreement to purchase some or all of a generator's output at a fixed price over a fixed term (Nelson & Simshauser, 2013). Such contracts, and their many variations, have operated as a staple within energy markets for decades. The U.S Public Utility Regulatory Policies Act (PURPA) of 1978 produced the original template for today's PPAs, and in turn sparked the first power project financing in 1981 (Simshauser and Nelson, 2012). The policy was designed to encourage the construction of cogeneration plants whose electricity could be sold to regulated electricity utilities at the time (Yescombe and Farquharson, 2018). The long-term commitments provided by existing utilities allowed for financing to be raised for new independent plant while using PPAs as security.

The privatisation of the British electricity industry also led to the formation of PPAs in the early 1990s with new combined cycle gas turbine plant. Australian energy markets followed this path from the early-1990s (Yescombe and Farquharson, 2018). PPAs have since operated as an important tool for utilities to secure independent generation while providing necessary revenue security to project developers in the form of spot price hedging. Alternatively, "merchant plant" refers to a project operating without a long-dated PPA, instead accepting more volatile spot and short term forward market prices for generation output (Finon, 2008).

Many works have acknowledged the desirability of revenue security in order to achieve bankability of VRE project finance (Nelson *et al.*, 2013; Steffen, 2018; Simshauser and Gilmore, 2022). Price volatility in the NEM's energy-only gross pool, along with variable generation conditions creates an environment where some form of hedging is ultimately important to achieve a minimum level of revenue certainty. Unsurprising generators relying on project finance are presumed to be underwritten by long-term PPAs (Chao, Oren and Wilson, 2008; Finon, 2008; Newbery, 2017; de Atholia, Flannigan and Lai, 2020). Nelson and Simshauser (2013) identify a dependant relationship when applied to gas plant, whereby PPAs are noted as necessary for entry under a project finance - primarily due to revenue volatility over the 10-year sample period. The same dependence for VRE plant is repeatedly referred to in existing literature, albeit not explicitly quantified (Mills and Taylor, 1994; Kann, 2009; Grubb and Newbery, 2018; Steffen, 2018; Nelson, Nolan and Gilmore, 2022).

Australian generators have a variety of options vis-à-vis spot price hedging, which include PPAs in various forms. Whilst there are no restrictions on who can write a PPA, underwriters can be usefully categorised into three groups, viz. (1) retailers motivated by acquitting obligations under renewable targets, (2) corporates motivated by sustainability or cost objectives, and (3) state governments. State governments, as of 2015, began initiating central auctions for fixed-term CfDs for VRE with the expressed purpose of stimulating renewables in an environment of policy discontinuity vis-à-vis climate change.

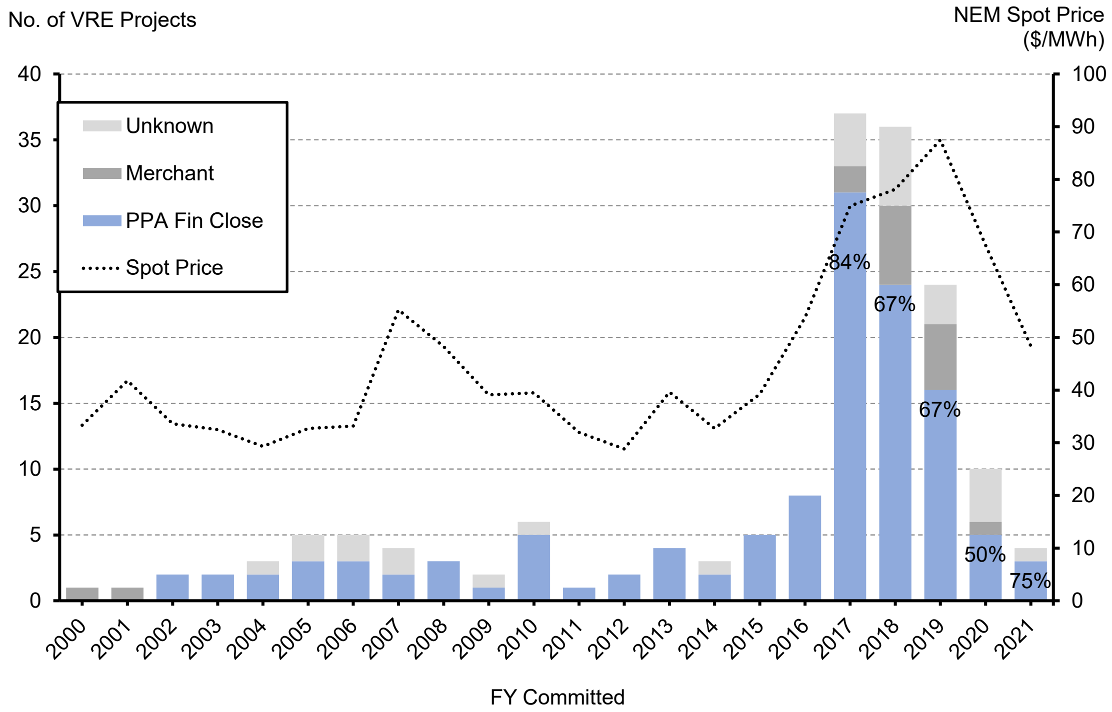
2.3 The NEM: a market in transition

As with other energy markets, the NEM is transitioning towards rising levels of VRE (Newbery, 2016; Pollitt and Anaya, 2016; de Atholia, Flannigan and Lai, 2020; Simshauser and Gilmore, 2022). However, over the past decade investors in Australian VRE projects have been forced to contend with considerable policy uncertainty (Nelson et al, 2018; Nelson et al., 2022). Policy uncertainty is naturally internalised by market participants, and may result in investment hesitation, entry lags and elevated costs for VRE projects due to fear of capital loss. Extended periods of policy discontinuity persisted across a series of key climate change initiatives, including VRE, arising from a policy war between Australia's two main political parties (Byrnes *et al.*, 2013; Molyneaux *et al.*, 2013; Nelson *et al.*, 2013; Freebairn, 2014; Garnaut, 2014; Apergis and Lau, 2015; Nelson, 2015; Simshauser and

Tiernan, 2019). Indeed, Australia's 2020 Renewable Energy Target or 'RET' was subject to six major reviews between 2004 and 2015 whilst the implementation of an emissions trading policy was attempted on seven separate occasions (Garnaut, 2014; Wild, Bell and Forster, 2015; Simshauser and Tiernan, 2019). Byrnes et al. (2013), Nelson et al. (2013) and Molyneaux et al. (2013) all detail similar risks associated with uncertain policy changes.

Yet once Australia's two parties settled on a revised RET policy in 2015, record investment commitments in Australian VRE projects would follow. As noted in Section 1, from 2016-2021 investors committed to 135 VRE projects totalling 16,000MW of generation capacity worth ~$26.5 billion (Simshauser and Gilmore, 2022). de Atholia et al. (2020) distinguish this recent period from the past decade, noting significant investment increases in large-scale VRE projects primarily driven by the private sector.[5] 80% of new VRE projects initiated during the period were underwritten by a PPA – with the 80% 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, surprisingly, 'merchant' (Simshauser, 2020). Figure 2 illustrates PPA vs merchant transactions for our generation dataset over the period 2000-2021, with the y-axis recording the number of projects reaching financial close.

Figure 2: VRE projects with a PPA



Sources: 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 a dynamic, multi-year, integrated power project finance model designed to simulate the parameters of a typical Australian VRE project. In the present analysis, we focus on wind. The PF model is set up to produce outputs when applying the technical and cost data presented in Table 1, which vary according to PPA contract conditions set out in Table 2. In each instance, the model iterates and solves for a minimum VRE plant entry cost in year one, which is then CPI adjusted in future years. Binding financial constraints of the model relate to project

[5] Investment followed surging forward electricity price levels, however the central driver of the investment bubble is primarily attributed to lags in achieving Australia's 20% renewable portfolio standard. The final revision of the target occurred between 2015/2016, leaving only 4 years for retailers to adjust in order to avoid financial penalties (Nelson et al. 2013).

financing parameters and expected equity returns. Estimates are synonymous with an approximation of the entry cost, or Long Run Marginal Cost (LRMC) of wind generation on a post-tax, post-financing basis. Simulating entry costs across each PPA scenario allows for an effective comparative analysis. Model details appear in Appendix A.

Our analysis in the PF Model assumes a 150MW onshore wind farm. Table 1 details the cost, financial and engineering parameters used as model inputs. We focus on the post-commissioning period, which in practice typically follows an 18-month construction period and an intensive 2-year development period. The assumption of 'post-commissioning' is adopted to remove the complexity of construction and development-related risks and cashflows.

Table 1. *Model inputs and assumptions*[6]

Assumptions for 150MW Wind Farm aquired in 2020					
Generation			**Inflation**		
Plant size	(MW)	150	CPI	(%)	2.00
Annual capacity factor	(%)	40.0	Electricity prices	(%)	2.00
MLF	(%)	91.0			
Auxillary Load	(%)	3.0	**Taxation**		
Forced Outage Rate	(%)	3.0	Tax rate	(%)	30.0
Technical Life	(Years)	30	Useful plant life	(Years)	30
			Turbine Depreciation	(Years)	20
Plant costs					
Construction cost	($/kw)	1,800	**Financing details**		
Connection Cost	($/kw)	100	Debt tenor	(Years)	25
Turbine Cost	(% of Capex)	60%	Refinancing fee	(%)	0.8
Acquisition price	($M)	285	Refinance frequency	(Years)	5
Variable O&M	($/MWh)	2.67	BBSW	(%)	0.89
Fixed O&M	($/MW p.a.)	36,020	Yeild curve	(%)	0.69
Ancillary Services Cost	($/MWh)	1.00	Lock up Covenant	(DSCR Multiple)	1.05x
Maintenance Capex	($M p.a.)	1.43			

Our inflation assumption of 2.0% in line with the lower bound of the Reserve Bank of Australia's 2-3% inflation target. The project is assumed to be depreciated over 20 years for tax purposes consistent with Australian Taxation Office rulings, although note the assumed useful life of 30 years (and financing life / debt tenor of 25 years). Generation plant specifications and costs are sourced from the 2019 Costs and Technical Parameter Review published by the Australian Energy Market Operator (AEMO). Inputs from AEMO's 2018 report is used are where insufficient granularity exists in the 2019 report.[7] We assume the plant is located in New South Wales (NSW) and therefore apply a marginal loss factor of 0.91, consistent with the average of all NSW wind generators in 2021.

Financing costs are calculated through a single annuity operating between year 1 and year 25 of the project. Payments include principal and interest, with the latter based on *credit spread* plus the *Bank Bill Swap rate* (BBSW). The applied BBSW is derived using the methodology of Simshauser and Gilmore (2020), where rates are calculated through averaging returns of current bond issues. To account for missing refinancing costs, an additional fee is applied on a 5-yearly basis equal to 0.8% of outstanding debt. Finally, a 0.69% premium is applied to interest rates, in line with current 10- vs. 2-year spreads on Commonwealth Government bonds. This is included to account for future changes in prevailing interest rates, given the tenor of the annuity.

[6] MLF refers to Marginal Loss Factor, a coefficient determined by AEMO annually, which represents plant marginal losses. BBSW is the Bank Bill Swap Rate.
[7] Both reports are available on AEMO's website. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf and; https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Aurecon-2019-Cost-and-Technical-Parameters-Review-Draft-Report.PDF

Two financing constraints are applied within the PF model. The first constraint involves a lock-up covenant, set at 1.05 times Cash Flows Available for Debt Servicing or 'CFADS' (noting that initial debt sizing ranges from 1.25x – 2.2x). This restriction stipulates dividends to equity cease during periods where CFADS persists below the lockup value in order 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 in order to provide lenders with additional security. Both constraints are established to mimic a simplified version of commonplace cash flow restrictions placed on project financed plant. All financing assumptions and calculations were adopted following consultation with project financing experts currently operating in Australia's energy industry.

3.1 Lender and investor survey and NEM generation dataset

One of the primary difficulties regarding the calculation of VRE entry costs is accurate estimation of the cost of capital. In order to obtain results that are current and novel, a direct survey of active VRE equity investor and project lending participants was conducted. The developed questions were geared towards identifying accurate model inputs. The 14 respondents sampled are characterised as either i). principal investor or ii). project financier of VRE projects. All participants were deemed to be highly active in VRE financings, with considerable expertise in the field, ensuring results were well informed as at 2021. Anonymity was ensured for all participants in order to allow for results with minimum bias. Data inputs concerning credit spreads, debt/gearing ratios and expected returns to equity were derived from survey results. The mean value of survey results appear in Table 2, with the survey range presented in Appendix B. We note ~93% of responses fell within one standard deviation of the average across all input related questions. The homogeneity of data implies a reasonably cohesive view of Australia's energy market VRE financings has been garnered from respondents.

Table 2. *Survey results*

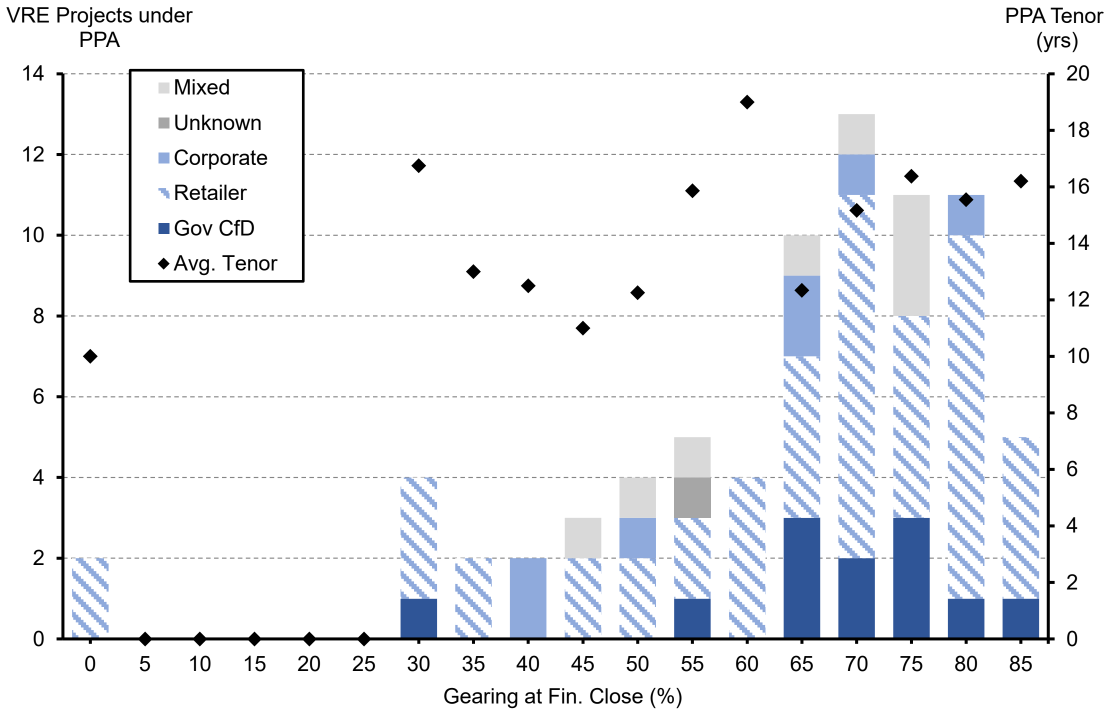
Scenario	Equity Return	Credit Spread	Gearing Ratio	Historical Gearing*
Merchant	12.25%	260bp	40.75%	48.0%
Partial. Corporate	9.75%	200bp	56.75%	54.0%
Full Corporate	8.00%	180bp	69.25%	61.0%
Partial Retail	9.75%	200bp	57.5%	57.5%
Full Retail	8.00%	180bp	67.5%	63.5%
Partial Govt. CfD	7.75%	180bp	64.25%	N/A
Full Govt. CfD	6.25%	140bp	72.5%	71.8%

*Not survey data. Taken from average historical gearing rates derived from NEM Generation Dataset

In addition to the survey data, a comprehensive VRE dataset was developed and used to further inform model inputs. The dataset was established to provide details on the different types of VRE projects in the NEM. Data on each plant covers project specification, key dates, project financing details, capital costs and PPA information. In order to compile a comprehensive source relating to NEM generation, information was consolidated from a variety of authorities.[8] Figure 3 presents summary level data on the tenor of PPAs, counterparty category and gearing levels of VRE projects at financial close.

[8] Existing datasets were acquired from private energy information databases, such as the Australian Energy Council, Rystad Energy, Bloomberg, Inframation, AEMO as well as news reports and investor announcements. Datasets were checked and verified against one another to create a comprehensive and robust picture of the NEM's generation.

Figure 3: VRE PPA vs project gearing at financial close



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

4 Results

Results are organised around the two central research questions. First, we examine the impact of PPAs by comparing full volume coverage with partial volume coverage and merchant plant ('Average Scenarios'). Second, we examine the impact of PPA counterparty credit quality ('Counterparty Scenarios'). Our inputs to be applied across the scenarios derived from the survey results appear in Tab.3.

Table 3. PPA scenario inputs

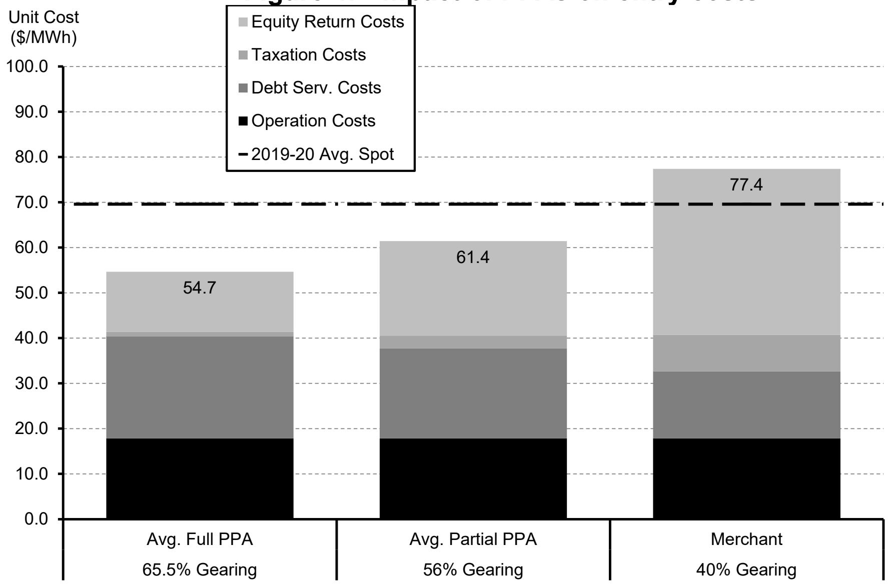
Average Scenarios	**Equity Return***	**Credit Spread***	**Gearing****
Avg. Full PPA	7.25%	170bp	65.5%
Avg. Partial PPA	9.00%	200bp	56.0%
Merchant	12.25%	260bp	40.0%
Counterparty Scenarios	**Equity Return***	**Credit Spread***	**Gearing*****
Partial Corporate	9.75%	200bp	55.0%
Full Corporate	8.00%	180bp	67.0%
Partial Retail	9.75%	200bp	57.5%
Full Retail	8.00%	180bp	67.5%
Partial Government CfD	7.75%	180bp	64.0%
Full Government CfD	6.25%	140bp	72.0%

*input taken from survey results
**input taken from historical NEM data
***input derived from both survey and historical data

4.1 Impact of PPAs

Here, we simulate three distinct scenarios for a wind farm, with full PPA cover (100% run-of-plant), partial PPA cover (50% of run-of-plant) and merchant (i.e. no contractual cover). With 100% PPA coverage, our model applies gearing of 65.5% which aligns with historical NEM averages derived from our broader generation dataset. As outlined in Tab.3, credit spreads were set to 170 basis points (bps) and expected equity returns at 7.25%. The partial PPA scenario applies a 56% gearing ratio, 200bps credit spread and an equity return of 9.0% from the same sources. The merchant scenario applies a balance sheet financed structure, with variable parameters described in Tab.3. These were 40%, 260bps and 12.25% for gearing, credit spreads, and equity returns respectively. Model results are presented in Fig.4.

Figure 4: Impact of PPAs on entry costs



In Fig.4, the breakdown of the wind project across scenarios comprises cost elements for operations, debt servicing, taxation and expected equity returns. Each are calculated as the minimum required whilst meeting all financial commitments. The totality of these costs ($/MWh) is synonymous with the new entrant cost associated with wind generation, or the minimum average PPA sale price per MWh required for wind generators to meet expected financial obligations. The average FY2020 electricity spot price is overlayed for reference, noting wind generation in the NEM typically trades at a ~10-15% discount to baseload prices. This (ex-carbon) spot price is not necessarily a commentary on the viability of new entrant merchant wind.

Note plant output and operating costs do not deviate between scenarios, with O&M expenses calculated at ~$18/MWh. Cost discrepancies exist exclusively within the cost of capital calculated for each scenario. Debt financing costs under a PPA exceed those of a fully merchant plant due to servicing larger quantities of debt on an absolute basis. However, the cost of equity associated with merchant plant more than outweighs any savings made in debt obligations.

Results in Fig.4 confirm that, on average, VRE projects with PPAs enjoy a lower cost of capital than those reliant on merchant markets. This relationship is monotonic under conditions of strict cost recovery with results of $54.7MWh, $61.4/MWh and $77.4/MWh, respectively. Accordingly, and consistent with prior work in the field, model results confirm the extent of PPA coverage is important vis-à-vis entry costs. Sensitivity analyses for these results are included in Appendix B.

The importance of these cost of capital variations are also consistent with our survey results. Respondents were asked to assign numeric values to project variables that were likely to alter risks for project investors and lenders. Variables included marginal loss factors, construction, the existence and specifications of PPAs, amongst others. Based on responses given, the presence of a PPA was labelled as the most meaningful risk-reducing factor for the average Australian VRE project. Closely following were the specifications of the PPA (i.e. term, volume, price) and creditworthiness of the counterparty. This means that a project's PPA and its associated characteristics were consistently ranked higher than other variables regarding their ability to reduce overall project risk for lenders. Full results for the ranking of risk factors is presented in Table 4.

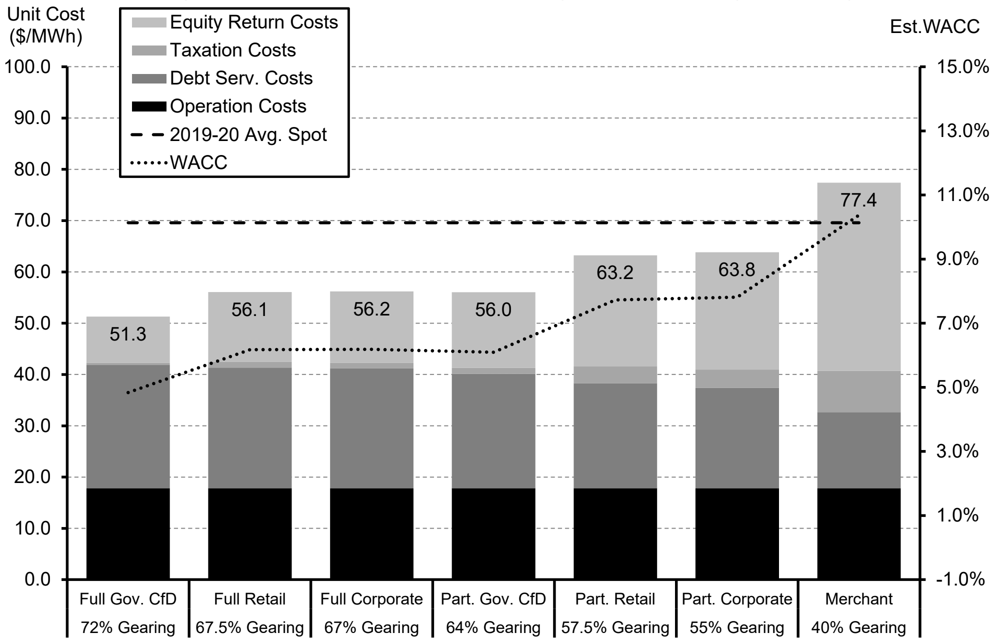
Table 4. Risk factors impacting VRE projects (rank order)

Rank	Risk Factor
1st	The existence of a PPA
2nd	The details (term, volume, price) of the PPA
3rd	The credit-worthiness of the offtaker
4th	Anticipated MLF risk
5th	Construction contractor's experience in the sector
6th	Financial health of the construction contractor
7th	Performance warranty period
8th	The source/supplier of plant components

4.2 Counterparty credit quality

Results in Section 5.1 were, by and large, axiomatic. Perhaps more interesting is the impact of PPA counterparty credit quality. As outlined in Section 2.2, there are three broad PPA counterparties in the NEM, viz. i). retailers, ii). corporates, iii). state governments. A primary difference between such parties exists in their credit ratings. In order to distinguish between counterparties, data was compiled from our survey and from historic data contained in our generation database. Using this, average gearing levels, credit spreads and expected equity returns were compiled for each counterparty category. Distinctions were then made between full volume coverage, and partial volume coverage. Our final data inputs are presented in Tab.3 with model results displayed in Fig.5.

Figure 5: Impact of counterparty credit quality on entry costs



In Fig.5, all seven scenarios are simulated for costs (bar series, LHS axis) and estimated WACC (dotted line series, RHS axis). These scenarios capture a more diverse range of PPA-contracted project financings with gearing levels ranging from 55-72%, and expected equity returns ranging from 6.25-9.75%, consistent with the data presented in Tab.3. Note the merchant plant result in Fig.3 has been reproduced from Fig.2.

Model outputs demonstrate the lowest cost scenario ($51.3/MWh) is the VRE plant with a state-backed CfD, which covers 100% of plant capacity. Following this are the retailer-backed and corporate PPAs (100% coverage), and government-backed CfDs with partial coverage, with entry costs of ~$56/MWh. Conversely, partial PPA coverage underwritten by retailers or corporates rises to ~$63/MWh. And as expected, the merchant scenario remains the most expensive, at $77.50/MWh, given the assumption of a balance sheet financing.

4.3 Discussion

Perhaps among the most noteworthy of results from Fig.3 is the similarity in the estimated entry cost for the 'Partial Government CfD', and the 'Full Retail' and 'Full Corporate' PPA scenarios. Based on model outputs, it appears security provided by a 'AA+ rated' sovereign CfD with only 50% volume coverage can rival 100% volume cover from a 'BBB rated' counterparty. While the split between debt and equity costs vary amongst these three scenarios, the total cost of capital is calculated to be virtually the same, at ~$37/MWh.

Differences between retailer and corporate PPAs do not appear to be significant. We had wondered whether retailers may have been viewed by capital providers as being better equipped to understand, manage and withstand residual exposures generated by entering into PPAs as a buyer[9]. Conversely, we also considered it plausible that any specialisation advantages of retailers would be offset by higher general exposures to energy market fluctuations, as distinct from deriving ordinary profits from exogenous market sectors. The evidence from our survey and mode is that both full (100%) and partial (50%) PPAs generated similar capital costs at ~$37/MWh and $42/MWh, respectively. It therefore appears, in aggregate, that investors and lenders view the security of BBB retailers and BBB corporates as comparable, with both groups considered to hold similar propensities for contract default in the real world.

In aggregate, there appears to be measurable cost advantages in new entrant VRE plant securing PPAs relative to merchant exposures, with our estimations being ~$10-20/MWh depending on run-of-plant volume cover. But expected equity returns are commensurately diminished, reducing by ~2-4% across simulated scenarios. Fig.5 results also confirm state-backed CfDs provide even greater advantages in reducing entry costs. According to the survey data, both investors and lenders adopt different return expectations when prices are secured by a government CfD. Project financiers allow higher gearing ratios with lower credit spreads, while equity investors demand lower expected returns on capital invested, with equity IRRs as low as 6.25% - roughly half the 12.25% expected return from merchant projects.

To generalise, financial economics takes issue with injecting unconstrained levels of debt into a project to take advantage of the apparently lower cost of capital – a theory which dates back to Modigliani and Miller (1958), Sharpe (1964) Lintner (1965) and others. In equilibrium, financial economics assumes expected returns to equity will rise as leverage is increased due to the amplification of dividend returns and potential bankruptcy costs. This in turn is thought to erode any positive impact derived from a lower cost of debt and associated tax shields. Prima facie, our survey evidence, broader generation dataset, and

[9] One reviewer also noted it could be that through market power, they shadow price Corporate PPAs (ie when on the sell-side).

modelling results, seem to collide with theory. VRE generators evidently place a premium on PPAs *and* counterparty credit quality, which collectively we define as *'revenue quality'*. Rather than witness an increase in expected returns to equity (ke) as debt levels increased, VRE projects demand lower returns with the quality of revenue providing a 'counter-balance' to higher gearing. Investors and financiers seem to accept materially lower rates of returns as both price uncertainty and counterparty credit risk exposure reduces. The implication of this result is counterparty credit quality impacts the cost of debt *and equity*. Intriguingly, Australia has no history of BBB-rated retailer counterparty failures or defaults on PPAs. Financial institutions and equity investors seem to be value government CfDs more than we had anticipated.

A valuation and sale process of two otherwise identical wind farms would produce interesting results. The cost of developing two x 150MW wind farms, one with a corporate PPA, and the other with a state government CfD – both covering 100% of output - is likely to be similar. But when offered for sale on completion, one will attract bidders with a WACC of ~6% and the other ~5% based on Fig.5 results, and holding all other variables constant. In this instance, it would seem leverage has altered the value of a company (albeit a project financed SPV). In practice, our evidence does not necessarily collide with financial economic theory. Ultimately the revenue quality which drives the WACC differential is not *'a magic pudding'*. What is evidently occurring is a reallocation of residual risks of the CfD, shifting incremental exposures away from VRE investors and (in this example) the corporate PPA counterparty, to taxpayers.

5 Policy considerations

Section 6 results warrant discussion on the implications for renewable policy construction. Unlike other cost elements, PPA liquidity represents an area where policymakers can wield considerable influence and materially reduce entry costs, and therefore consumer prices. If our PF Model outputs are accepted, greater PPA counterparty liquidity may facilitate VRE entry cost reductions of \$10-\$20/MWh below merchant rates. Consequently, policies that drive PPA activity such as renewable targets are to be encouraged. Whether policymakers should seek to extract the final \$4-5/MWh benefit (see Fig.5) associated with government-initiated CfDs is, we believe, more nuanced.

5.1 Government CfD Auctions

Following the 2014 review of Australia's Renewable Energy Target, numerous state governments hosted auctions for CfDs in an attempt to fill a gap created by the Commonwealth Government vis-à-vis climate change policy discontinuity (Simshauser, 2019; Nelson, Nolan and Gilmore, 2022). Participating state governments included most NEM jurisdictions, viz. Australian Capital Territory, Queensland, South Australia, Victoria and the New South Wales. Auction events reported successful outcomes with regards to meeting policy objectives. Lessons learnt along the way served to improve results on subsequent auction rounds.

Government coordination of VRE projects through CfD auctions forms a legitimate role in dealing with transient energy market and/or climate change policy failures, or as a means by which to deliver plant capacity that the market is otherwise failing to deliver. To this end, CfD auctions have, on-balance, been helpful developments in the NEM - particularly in an environment of climate change policy discontinuity.

Once a government program has initiated a market, in our view, it is desirable to facilitate ongoing investments through markets and progressively withdraw taxpayer exposures.[10] The marginal CfD savings in WACC (~1.2%) and entry costs (~\$4.75/MWh) outlined in Fig.5 are *not sufficiently material* relative to PPAs in our view (noting that if this differential

[10] There are also material risks to the functioning of the forward markets. See Simshauser, (2019).

'blew out' due to changes in market conditions, a re-assessment of this view would be required). The complexity is how to avoid a perpetual cycle of state-participation once markets have been primed, due to residual taxpayer risks.

The approach adopted by the Queensland Government with their 150MW solar CfDs in 2017 followed this path. The CfD auction sparked a further 3000 MW of market-based solar investments over the ensuing four-year period. It is not entirely clear to us that the large sophisticated VRE developers and utilities that developed the subsequent market-based projects required (or deserved) what amounts to a taxpayer funded credit-wrap. Viewing the *marginal* savings of $4.75/MWh from CfDs (cf. PPAs) as a direct financial subsidy from state governments may not be perfectly apt. But at the same time, the incremental reduction in costs (i.e. 0.5c/kWh on a headline retail price of ~23c/kWh) is only achieved when taxpayers absorb spot price risks, and these risks seem disproportionate relative to the *marginal* gain in final consumer prices contained in our modelling results.

If governments and central planners were capable of consistently picking optimal projects, at optimal intervals, and pre-empt changes in technology costs over time, then nothing further need be said. Ongoing government CfD auctions may well represent an optimal policy response to capture the gains in the cost of capital. But evidence in support of governments and planners consistently picking optimal projects tends to collide with the basis of market reforms across the US, Great Britain, Australia and others during the 1990s, where power systems were marked by capital misallocation, overcapacity and rising prices (Pierce, 1984; Hoecker, 1987; Joskow, 1987; Kellow, 1996; Newbery and Pollitt, 1997).

It is to be acknowledged that a cost of capital arbitrage does exist based on the evidence in Fig.5. Such gains would exist with any capital-heavy product. However, in Australia we do not observe widespread government investments in the workable markets for airlines, airports, gas supply, power supply, telecommunications or large shopping centres merely to reduce consumer prices through a cost of capital arbitrage, because there are limits to the scarce fiscal and balance sheet resources of governments. On the contrary, competitive neutrality taxes apply to government trading business so as to avoid distorting markets.

5.2 Managing taxpayer risk

In stalled markets for VRE entry, locking in low prices for VRE capacity by way of government-initiated CfDs has benefits for the broader energy market, ex ante. CfDs are ultimately speculative derivative instruments, and when written by a state government they do not change form. CfDs thus create new upside risks to taxpayers when in-the-money, and downside financial risks to government fiscal positions when *out-of-the-money*.

In the case of NSW, CfDs are to be structured as one-way swaptions in which the VRE proponent decides whether to exercise a CfD in any given year, or remain exposed to market prices (Nelson, Nolan and Gilmore, 2022). Such instruments will only be exercised by VRE proponents when instruments are out-of-the-money. Consequential losses arising from out-of-the-money CfDs can be funded by levying charges onto regulated network tariffs, as is done in Great Britain. The ACT government is currently following this path with their out-of-the-money CfD commitments made in prior periods. [11]

[11] 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 (see Hartmann, 2021). The CfDs were extremely low cost at the time (i.e. ~$70/MWh during 2016-2017) but changes in costs and market prices have 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.

If hypothecated taxes are strictly organised with accompanying legislation, international ratings agencies are likely to treat CfDs as 'funded' and prima facie be neutral to the fiscal position and credit rating of government. However, if commensurate legislation does not exist, CfD price exposures are likely to be considered as 'housed' on the government's fiscal accounts, and may absorb scarce government balance sheet capacity.

6 Conclusions

Unlike traditional fossil fuel technologies, VRE is not exposed to fuel costs and this heightens the focus on upfront construction costs and the cost of capital. The central goal of this article has been to analyse the latter and in particular, the implications of PPAs and counterparty credit (collectively, 'revenue quality') on the cost of capital of new VRE projects.

The cost of capital secured by an incumbent VRE plant is a critical variable in the relevant cost of entry. Our analysis revealed that VRE projects with higher levels of PPA volume cover demonstrate an entry cost advantage via higher levels of debt, and at lower credit spreads. Equity investors evidently also trade-off lower expected returns on invested capital when future revenues are secured through PPAs.

What our analysis also revealed is that the credit rating of counterparties is equally important to the cost of entry. PPA counterparties with higher credit ratings are preferred by financiers, who offer commensurately higher gearing levels and lower credit spreads. Equity investors also appear to moderate their expected returns.

What our analysis did not investigate was post contract revenue assumptions. In our analysis, we assumed levelized costs form the efficient price. Varying this assumption can (and does) impact upfront PPA and CfD prices. Some research on this exists in the field (see for example Jenkin *et al.*, 2019; Simshauser and Gilmore, 2020) but further research seems warranted.

7 References

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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.

$$\pi_t = \left[1 + \left(\frac{CPI}{100}\right)\right]^t, \tag{1}$$

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.

$$q_t = \frac{CF \cdot k \cdot MLF_t \cdot (1 - Aux) \cdot YrHrs_t}{1000}, \tag{2}$$

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

$$YrHrs_t = \left(YearDays_t \cdot (1 - FO)\right) \times 24 \tag{3}$$

The convergent price of electricity PPA_t^p for the p^{th} scenario is calculated for year one and escalated per eq. (1). Period one pricing is synonymous with project entry costs allowing the model to solve for minimum PPA_t^p or price under given equity return constraints.

$$PPA_t^p = LRMC \cdot \pi_t, \tag{4}$$

plant revenue is therefore:

$$R_t^p = PPA_t^p \cdot q_t, \tag{5}$$

where R_t^p is revenue at time t.[12] 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.

$$FOM_t = \frac{FC \cdot k \cdot \pi_t}{1000} \tag{6}$$

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

$$VOM_t = VC \cdot q_t \cdot \pi_t \tag{7}$$

Ancillary services cost AC_t is calculated as the product of q_t and an assumed cost per MWh denoted as $ASer$ scaled at π_t.

$$AC_t = q_t \cdot ASer \cdot \pi_t, \tag{8}$$

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

$$EBITDA_t^p = R_t^p - FOM_t - VOM_t - AC_t, \tag{10}$$

[12] For the purposes of this model, no revenues were simulated from hypothetical hedge contracts or ancillary services. Whilst debate exists over the capacity of VREs to provide ancillary services, this model views such services exclusively as a cost.

Capital expenditure
Capital investment and ongoing capital works include capex cost of plant acquisition ($285M) 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:

$$if\ t\begin{cases} = 1,\ X_t = Capex + x_t \cdot \pi_t \\ \neq 1,\ X_t = x_t \cdot \pi_t \end{cases}, \quad (11)$$

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 ($1,800/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.

$$DS_t = \left(\frac{Capex - T}{oL}\right) + \left(\frac{T}{tL}\right) \quad (12)$$

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

$$\tau_t = \left(EBITDA_t^p - I_t - DS_t - L_t\right) \cdot \tau_c, \quad (13)$$

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

$$L_t = Min(0, \tau_{t-1}), \quad (14)$$

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 $EBITDA_t^p$.

$$CAFDS_t^p = EBITDA_t^p - X_t - \tau_t, \quad (17)$$

Debt parameters
Appropriate modelling granularity vis-à-vis financing life, debt tranches, refinancing expenses and yield curve adjustments are not necessarily obvious when identifying broad economic averages. Ordinarily, multiple debt tranches may exist for VRE projects, incorporating a mix of bullet (i.e. interest-only) and semi-permanent amortising (i.e. principal & interest) facilities with semi-regular re-financings[13]. For the purposes of simplification and generalisation, s debt was adopted in the form of a single facility running the full financing life of the project (i.e. 25 years). Ordinary refinancing expenses are acknowledged by charging 0.8% of outstanding debt as an independent fee on a 5-yearly basis. Interest rates are held steady for the full loan tenor. However, a 0.69% premium is applied to reflect anticipated rate increases materialised by the existing yield curve. These underlying assumptions are held constant across all scenarios and in a low rate environment, were intended to be conservative in the context of our analysis.

[13] 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

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

$$if\ t\begin{cases}= 1, & B_t = D \\ \neq 1, & B_t = B_{t-1} - \left(\frac{B_{t-1}}{\left[\frac{1-(1+i)^{-n}}{i}\right]} - I_{t-1}\right)\end{cases}, \tag{18}$$

where n depicts the debt term and total debt D is the product of the scenario p gearing capacity G^p and $Capex$.

$$D = G^p \cdot Capex \tag{19}$$

The applied interest rate i is calculated as the sum of BBSW, the credit spread $CS^p$for scenario p and yield curve premium yP.

$$i = CS^p + BBSW + yP \tag{20}$$

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

$$I_t = B_t \cdot i \tag{21}$$

Refinancing fee DF_t is identified using the following decision rule:

$$if\ t\begin{cases}= Refi, & DF_t = B_t \cdot RF \cdot \pi_t \\ \neq Refi, & DF_t = 0\end{cases}, \tag{22}$$

where $Refi$ is a set of values arranged in intervals of 5, representing the periods in which debt is assumed to be refinanced throughout the life of the project. RF represents the service fee charged when refinancing outstanding debt.

A lockup covenant of 1.05x is applied to the project cash flows, thereby pausing dividend payments following two consecutive periods of insufficient debt service coverage ratios (DSCR).

$$DSCR_t = \frac{CAFDS_t^p}{(I_t + DF_t + [B_t - B_{t-1}])} \tag{23}$$

Dividends and Entry Cost / LRMC

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

$$Div_t = CAFDS_t^p - DP_t, \tag{24}$$

$$DP_t = I_t + DF_t + (B_t - B_{t-1}) \tag{25}$$

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

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

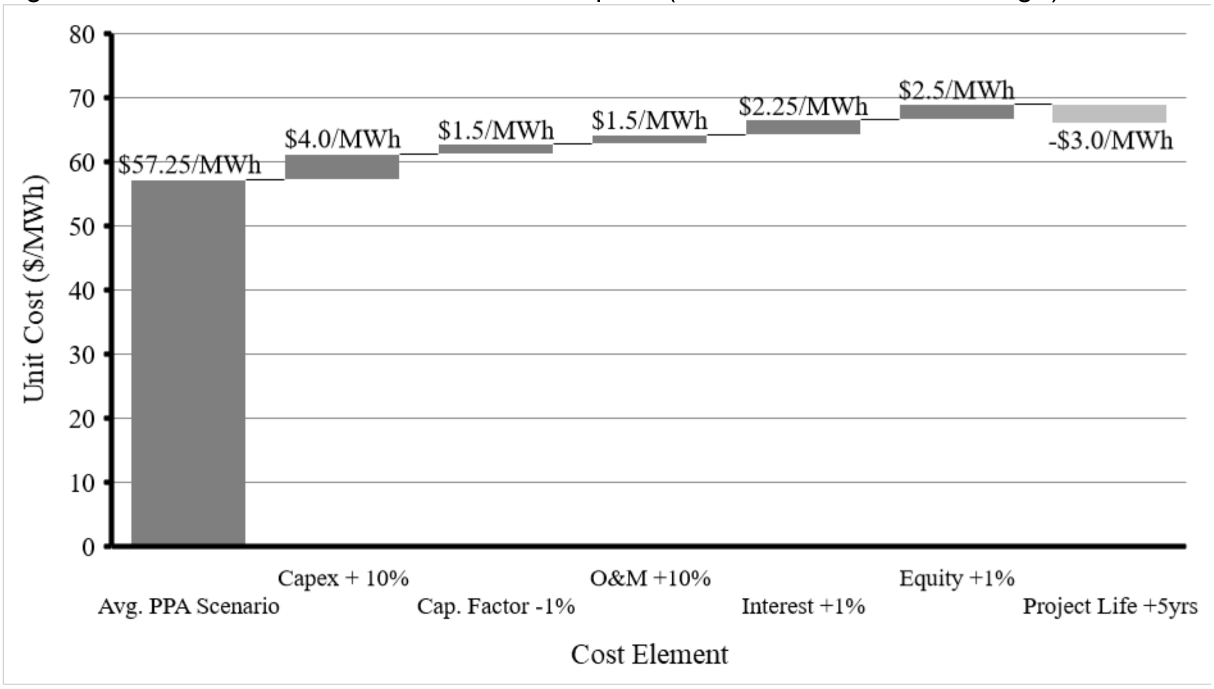
$$0 = -Capex + \textstyle\sum_{t=1}^{N} Div_t \cdot \left(1 + k_e^p\right)^{-t} \tag{26}$$

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

Appendix B – Model Sensitivity Results

In order to ensure that model outputs are reasonable, a sensitivity analysis was conducted on the results. The PF model was stress-tested by relaxing key assumptions and applying inflated cost inputs. Figure A1 displays the impacts of changes to entry costs.

Figure B1. Cost element sensitivities for VRE plant (PPA 100% volume coverage)



The most sensitive adjustments are changes to capex and project useful life. The clustering of survey responses and lack of outliers also contributes to confidence in model results as illustrated by the box plots in Figures B2, B3 and B4. It is probable that any discrepancy in entry cost between merchant and PPA scenarios is largely attributable to the 'revenue quality'.

Figure B2. Survey results – equity returns

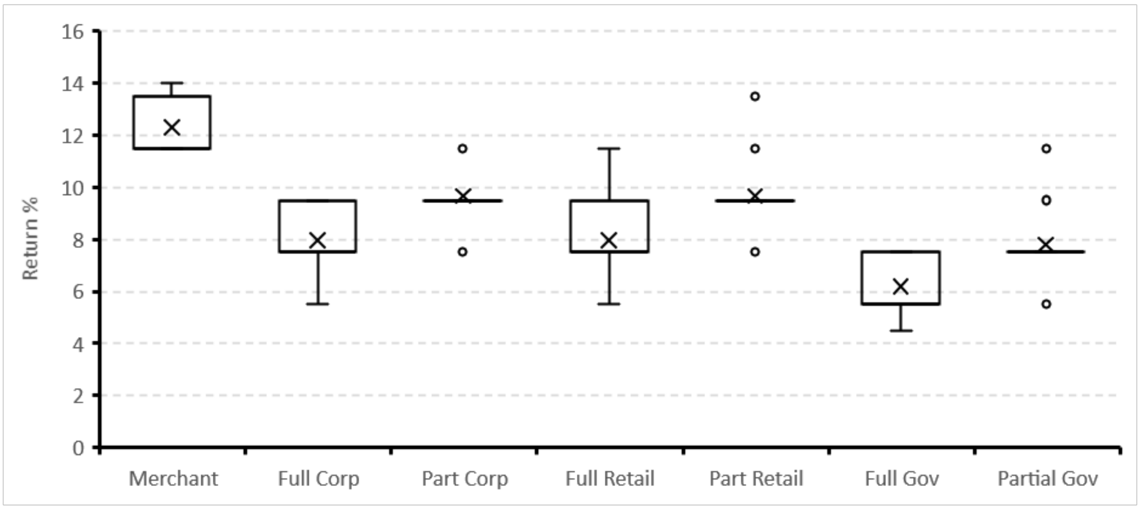


Figure B3. Survey results – credit spreads

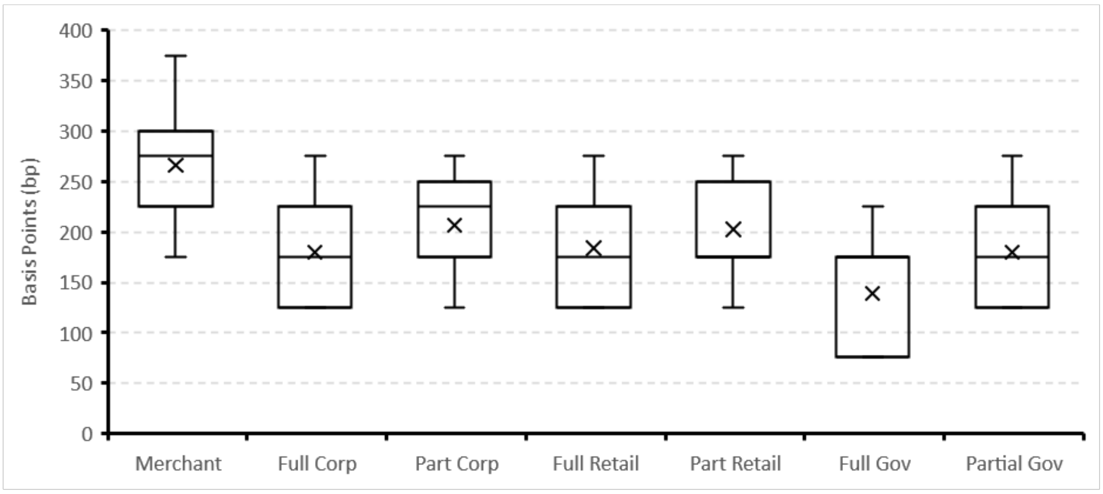


Figure B4. Survey results – gearing level