Power Purchase Agreements and Solar Securitization: Modelling Risk Factors and Returns

Stephen L.I. James

A thesis presented for the degree of
Masters of Research

Principal Supervisor: Professor Stefan Trück

Associate Supervisor: Dr Rohan Best

Department of Applied Finance

Faculty of Business and Economics

Macquarie University

15 October 2018

ACKNOWLEDGEMENTS

I would like to express great appreciation to my principal supervisor, Professor Stefan Trück and my associate supervisor, Dr Rohan Best for their guidance, and insightful advice right from the beginning, when discussing viable topics, through to the very final draft of the thesis.

Thanks also go to the Faculty of Business and Economics at Macquarie University for their valuable assistance and administration. The editorial assistance of Dr Bradley Smith and Vanessa Lesnie is also acknowledged.

To my wife Vanessa who made it possible to have two years of full-time study, and for her patience, unconditional love, and support. And special acknowledgement to my fantastic children, Sam and Sophie, who are now only 8 and 6, yet have the maturity to understand the importance of this thesis to their father.

DECLARATION

I **Stephen L. I. James**, certify that the work in this thesis entitled "**Power Purchase Agreements and Solar Securitization: Modelling Risk Factors and Returns"** has not been submitted for a higher degree to any university or institution other than Macquarie University.

I also certify that the thesis is an original piece of research and it has been written by me. Any help and assistance that I have received has been acknowledged.

In addition, I certify that all information sources and literature used are indicated in the thesis.

Stephen L.I. James

Student Number 45009147

14 October 2018

SUMMARY

The number of small-scale photovoltatic system installations has risen dramatically in the last ten years due, in part, to the introduction of government subsidies. However, the capital expenditure and complex investment decisions imposed on households limit the growth potential. This thesis examines an alternative way of funding the growth of solar installations on rooftops: Power Purchase Agreements (PPA) financed by Asset Backed Securities (ABS).

The thesis enhances and expands the foundational PPA ABS model developed in Alafita and Pearce (2014), to respond to the literature and technological developments. The model is enhanced by: introducing three investment tranches to the ABS, applying a sequential collateralised debt obligation (CDO) structure; discounting the PPA electricity price to below the retail grid price; using real customer production and consumption data; incorporating a Feed-in-Tariff (FiT); and adding a lithium-ion battery to the model, which allows for consumption under the PPA during the evening. To the best of the author's knowledge, this is the first time in the literature that these attributes have been considered in a solar PPA ABS model, in the literature.

The thesis demonstrates the viability of a PPA ABS, by finding that there are conditions under which PPA electricity customers, investors in the ABS, and PPA providers can all achieve financial benefits. The paper discusses the benefits of introducing PPA ABS into the Australian renewables and financial markets, and proposes avenues for future development.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 1: INTRODUCTION

1.1 The Australian electricity market is shifting towards renewables

It is well understood that, in Australia, electricity production is going through a significant period of change. Between 2008 and 2017 there was a 20% reduction in coal generation and a 325% increase in wind power (Australian Energy Market Operator (AEMO) 2017, p. 7). In 2008, there were just 14,000 residential solar panels; by 2017 there were 1.69 million (Australian Energy Market Operator (AEMO) 2017, p. 8). These changes have been driven by a need to reduce the greenhouse gas emissions generated by human activity, which have significantly grown since 1750, when burning fossil fuels became the norm for power production (BOM and CSIRO 2016). Currently, one-third of Australia's greenhouse emissions come from electricity production (Department of Industry and Science 2015).

Australian governments have been active in creating policy designed to reduce the burning of fossil fuels, with one of the key events being the signing of the Paris Agreement in 2016. Since 2001, Australia's national-level policy for promoting renewable energy and reducing greenhouse gas emissions has involved a Renewable Energy Target (RET). The overall RET was subsequently split into large-scale and small-scale components. The small-scale Renewable Energy Scheme provides an upfront subsidy for panel installation by households and small business, with the amount of the subsidy linked to the magnitude of the solar resource in particular geographical areas.

Government rebates in Australia have increased the incentive for householders to install solar photovoltaic systems (solar PV) on rooftops. In the state of NSW, household solar PV systems rated as a 4KW generation receive a rebate of AUD 2,500[1] (Clean Energy Regulator 2018; SolarMarket 2018). Rooftop solar installations grew rapidly after state governments implemented feed-in tariffs (FiT) in 2008. In 2016, 16.5% of Australians had rooftop solar PV systems - one of the highest proportions in the world (Bruce and MacGill 2016). Nonetheless, the significant upfront capital outlay required, and the complex decision processes involved in purchasing and installing

[1] Hereinafter, all references to dollar ($) amounts are references to AUD, unless otherwise stated.

solar PV systems, is a clear barrier to the ongoing growth of the residential solar PV market.

1.2 Power Purchase Agreements address a key barrier to growth in the residential solar PV market

The cost for a residential solar PV unit of 4kW capacity in 2012 averaged $9,600. By 2018, the price had come down significantly, to $5,600, including the government rebate (SolarChoice 2018). This price reduction has also been seen in the United States (which also provides tax credits), with a 4kW system costing USD 17,900 in 2012 and USD 11,200 in 2017 (Fu et al. 2017). However, even with the estimated $2,500 in Australian government concessions, installing solar PV requires 7% of the median family disposable income ($44,356) (Australian Bureau of Statistics 2017) – a significant proportion of a family budget. This financial burden on household budgets has been alleviated in the United States by using PPAs. This thesis explores the potential application of PPAs in Australia as a means to remove barriers to growth in the Australian residential solar PV market.

The Australian Energy Market Operator defines a PPA as a “contract between two parties, one who generates (electricity…) and one who purchases” (Australian Energy Market Operator (AEMO) 2018, p. 9). In the United States, PPA customers use solar panels which are installed on their rooftops by a third party (the aggregator), and pay the aggregator for electricity as they consume it, without owning the solar panels. The solar panels and inverter are owned and maintained by an aggregator, with the installation situated on the resident's rooftop.

For the homeowner, the key benefit of a PPA is access to clean energy at an agreed lower cost than the retail grid price with no upfront capital, installation or maintenance costs. A PPA also eliminates the complexity involved in assessing and comparing solar PV brands and installation companies, and passes the risk of hardware decisions on to the aggregator (Rai, Reeves and Margolis 2016)

Under PPAs, the capital requirements are shifted from homeowners to the aggregators. This imposes a significant capital-raising burden on the aggregator, well in advance of the revenue stream generated by the purchase of power. Hyde and Komor (2014) note that securitization is one method whereby aggregators may be able to access relatively cheap funds from large pools of money in pension funds and other investment products.

1.3 Motivation: exploring finance options designed to increase rooftop solar and batteries in the retail market

The key purpose of this thesis is to identify whether the introduction of PPAs as a financing mechanism for rooftop solar and batteries in the Australian residential market is economically viable.

1.4 There is limited research on the role of securitized PPAs

Securitization is the process of transferring an illiquid asset (such as car payments, mortgages or solar PPA payments) into a standardised, tradeable instrument. The security issuer (the PPA aggregator) sells the rights of the future payments on these assets (the PPA electricity contract), which allows the issuer to raise capital for further business operations (Lowder and Mendelsohn 2013). Securitization allows the aggregator to raise capital to expand the installation base without having to wait for a revenue stream to complete. Securitization also allows the aggregator to reduce the cost of capital down to the rate of an investment-grade asset (Liu, Mao and Nini 2018)

While there is a large body of research regarding the securitization of assets in the general sense, the relatively recent introduction of small scale PPAs into the electricity market has meant that there has been little exploration in the literature of the potential role of securitization in incentivising the uptake of renewable energy in the retail consumer market. The key paper connecting the concepts was published in 2012 when Joshi (2012) proposed that solar PPAs could be used in the securitization market. Joshi documents the basic structure of the product, the current tax benefits in the US, and the risks involved with securitization. Joshi also highlights that securitization provides the investment community with alternative avenues to invest in the renewable energy sector. Subsequent papers discuss some of the risks associated with solar securitization, including: insolation risk (solar risk); property transfer risk; grid price risk; credit risk; sponsor risk; counterparty risk; and technology risk (Joshi 2012, 2013b; Lowder and Mendelsohn 2013; Matsui and Malaya 2014; Gabig, Cohen and Kapoor 2015; Mendelsohn et al. 2015).

The US National Renewable Energy Lab (NREL) brought together in 2015 various stakeholders including aggregators, accounting firms, investment banks, and risk rating agencies to document the process of developing an investment-grade securitization of PPAs (Mendelsohn et al. 2015). The purpose was to align the stakeholders on the methods, and technicalities, involved in creating a securitized solar PPA deemed to be an investment-grade asset by the rating agencies. NREL examined the business model used, technical aspects of solar technology, real or perceived risk variables affecting repayments, availability of performance data, regulatory issues, legal structures, and cash flow analytics required to establish an investment-grade asset (Mendelsohn et al. 2015).

Alafita and Pearce (2014, p. 488) propose a basic solar PPA securitization finance model and suggest that “securitization of solar power purchase agreements (PPA) can significantly reduce project finance costs, suggesting that securitization is a viable mechanism for improving the financing of PV projects”.

Mendelsohn et al. (2015) recommend that PPA securities should be shorter than the 20-year bond period discussed in earlier literature, in order to increase acceptance by capital markets.

Kulatilaka, Santiago and Vakili (2014) suggest that PPAs should be designed to avoid the possibility that PPA customers will default on their contracts and return to the retail market, if they enter a long-term contract and the retail price drops below the contracted PPA price.

The literature does not currently incorporate an examination of the impact of lithium-ion batteries on the viability of PPAs. With lithium-ion batteries becoming mainstream (both in terms of pricing and acceptance), an aggregator can bundle batteries and solar PV panels into the customer offering. This bundling will allow customers to use the energy that is produced on their rooftops during the day, throughout the evening. A fleet of lithium-ion batteries will also allow aggregators to control the input and output of the batteries to the grid, providing an opportunity for the aggregator to participate in the wholesale market and thus operate as a virtual power plant (VPP). The opportunities associated with a VPP have the potential to significantly contribute to an aggregator’s business model. However, the key focus of this thesis is to examine whether the securitization of basic PPAs is sufficient to support the business model of an aggregator, in the absence of a VPP.

The literature has not examined the possibility that the introduction of securitized PPAs may offer a cheaper, and more effective, alternative to government subsidies for incentivising the take-up of solar resources on the rooftops of households and small businesses.

1.5 Contributions to the literature made by this thesis

This thesis will examine the financial benefits generated by a PPA financed through securitization for: power consumers; PPA service-providers and the purchasers of the securitized assets (bondholders), and examine whether this approach is a viable alternative to government rebates.

If residential and small business power consumers, PPA aggregators and capital providers can all enjoy financial benefits through the securitization of PPAs, the introduction of this financing mechanism has the potential to significantly increase rooftop solar power generation in Australia. This thesis therefore expands on the only empirical model currently in the literature - the model produced by Alafita and Pearce (2014) - to address the following questions:

1) Are consumers financially better off purchasing solar power via a PPA than they would be if they purchased power from the grid? If so, by how much? What is the range of the benefit?
2) Can a PPA aggregator generate a positive financial return by selling the PPAs onwards to the investment community through securitization? If so, how much?
3) Can capital market investors make a positive financial return through the purchase of PPA securities? If so, at what rate?
4) What is the impact of PPA payment defaults on investors? How are different investment tranches impacted by defaults?
5) Is it financially viable to include lithium-ion batteries into the PPA package?

To answer these questions, this thesis expands the Alafita and Pearce (2014) model by including multiple investment tranches in the securitization. The inclusion of multiple tranches can reduce the total financing cost by offering different risk profiles at different interest rates (prices) in order to produce a lower weighted average cost of capital than is feasible in a single tranche. The inclusion of multiple investment tranches also reflects more closely the range of investor appetites in capital markets and therefore makes the investment attractive to a broader range of investors. The model developed in this thesis includes three investment tranches, with the first two tranches being an investment-grade asset, and the third tranche representing the aggregator's investment into the bond, at a junk bond rating.

The weather experienced in the different seasons of the year affects both the amount of electricity consumed and the amount produced. This is of particular importance in a securitization model which is based on revenues generated by consumption, rather than underlying capital. Since the variance across the seasons of the year impacts on both revenues and cash flow, the I incorporate seasonality into the data.

Currently in the NSW electricity jurisdiction, there is a single, fixed, Feed-in Tariff (FiT), which differs from the price at which power is purchased from the grid. Recently, the Independent Pricing and Regulatory Tribunal recommended that there be different daytime and evening FiT rates, to acknowledge the difference in supply and demand in the early evening (Independent Pricing and Regulatory Tribunal 2018). Therefore, I include both a daytime and an evening FiT rate.

The model also introduces lithium-ion batteries into the solar package offered by aggregators. Agnew and Dargusch (2017) and Yu (2018) suggest that lithium-ion batteries will come down significantly in price in the near future, due to the current economies of scale. Given the practicality of facilitating the storage of excess daytime power generation for evening usage, I tests the viability of including batteries into the PPA package

This study will also add to the literature on distributed energy methods and business models and provide a platform for further insights into energy portfolio design. The study will support possible avenues for implementing solar PV and battery distributed energy options for low-cost housing, rental properties and for body corporate (co-op) housing. Household renters have no option of purchasing solar PV, and property investors have no economic incentive to fund the installation of rooftop solar panels as they will not enjoy the cost savings generated. This ‘split incentive’ experienced by property investors has slowed the uptake of solar PV and has left significant amounts of rooftop real estate dormant. The study will also demonstrate the potential for small-medium sized businesses to access renewable electricity without coming into conflict with alternative business investment decisions. This thesis suggests that PPAs increase the likelihood of using the rooftops of investment properties, strata buildings and small-medium business properties by passing the capital cost from the rooftop owners to the aggregator.

Further, the development of an enhanced PPA securitization bond model with multiple investment tranches opens up additional portfolio options for green bonds, amongst other renewable energy investments, and allows for the assessment of risks associated with this type of bond.

1.6 Key results

The model developed in this thesis demonstrates the viability of using securitization to finance solar PV PPAs. The PPA customers, bondholders and aggregator can all achieve financial benefits under a variety of scenarios. The modelling demonstrates a capacity to absorb the application of discounts on the grid electricity prices, customer default rates, increasing interest rates, and a bond period less than 20 years, under certain conditions. While the current lithium-ion battery prices make the model uneconomical, the expected reduction in battery prices suggest that in the future the inclusion of batteries can also be supported under a securitized PPA model.

The results of the modelling suggest that the introduction into Australia of PPAs financed through securitization could open up a range of new options for the private and public sector to incentivise the uptake of residential rooftop solar PV.

1.7 Thesis structure

The remainder of the thesis is structured as follows.

Chapter 2 presents a review of related literature and provides further discussion regarding existing research on solar PPA securitization.

Chapter 3 outlines the design of the model.

Chapter 4 documents the data used in the model and Chapter 5 provides the results generated by the model under two different scenarios.

Chapter 6 discusses the implication of the results generated by the model, highlights some of the limitations of the approach in this thesis, and raises issues relevant for future research.

Chapter 7 offers a conclusion based on the results of the modelling.

CHAPTER 2: LITERATURE REVIEW

While there are many studies on the use of solar rooftop and battery technologies for electricity and storage, these studies typically focus on: which consumers have chosen to buy solar and or batteries for their household, and why they made that choice (Agnew and Dargusch 2017; Sommerfeld, Buys and Vine 2017; Bondio, Shahnazari and McHugh 2018); using a battery to optimise use of power from the grid (Sani Hassan, Cipcigan and Jenkins 2017; Alramlawi et al. 2018; Reniers et al. 2018); FiT design and effects on the market (Zahedi 2009; Tveten et al. 2013; Chapman, McLellan and Tezuka 2016; Ossenbrink 2017; Martin and Rice 2018); the effect of government policy incentives on small-scale renewables (Bauner and Crago 2015; Dusonchet and Telaretti 2015; Outhred and Retnanestri 2015); and the effect of renewables on the merit order in the wholesale market (Tveten et al. 2013). The literature review revealed a body of research considering the return on investment for institutional investors for energy efficient office buildings see for example, Newell, Macfarlane and Walker (2014). There is also research exploring the benefits of state based investment banking to the renewable energy sector as a financing mechanism see for example Geddes, Schmidt and Steffen (2018). Further, the literature considers the impact of government environmental policy on return on equity in capital markets see for example, Ramiah, Martin and Moosa (2013); Ramiah et al. (2016);Pham et al. (2017); Han et al. (2019); McIver (2019)

The present study focuses on the literature regarding the role of PPAs in increasing the uptake of rooftop solar. It highlights that current government incentives are primarily used by higher income householders, and that PPAs can unlock the rooftops of a much broader range of property owners and give access to clean and cheaper power to people in all income brackets. This section also examines literature regarding securitization as a method of accessing lower cost capital, and the role that securitization plays in funding large-scale investments for solar PV on rooftops. In particular, this study investigates the first and, to the author's knowledge, the only empirical solar PPA securitization model in the literature, by Alafita and Pearce (2014). The section also highlights the known critiques of solar PPA securitization and how the model in this thesis responds to those critiques.

2.1 PPAs can incentivise increased uptake of rooftop solar

Government subsidies have encouraged rooftop solar installations by households; however, the large capital outlays required to install these solar PV systems mean that these incentives have primarily gone to higher income households (Kwan 2012; De Groote, Pepermans and Verboven 2016). Solar PPAs, which may include lithium-ion batteries, facilitate the installation of solar on a broader range of household rooftops, because users pay as they consume electricity and do not require upfront capital. If PPAs provide power prices that are lower than the grid price and eliminate the need to have access to capital, low-income households will be better able to participate in the rooftop solar electricity market.

Power purchase agreements are already common in the industry sector. In the United States, they became popular after the introduction of the Public Utility Regulation Policy Act (PURPA) in 1978 which required electric utilities to purchase electricity from independent power producers (Burger, Graeber and Schindlmayr 2014). In Australia, PPAs have been established between wholesalers and retailers, and are also used between wholesalers, distributors and large industry. PPAs for retail consumers were introduced on a small scale in 2009, with the establishment of a company called Solar Finance Solution.

In 2006, US companies SolarEdison and Renewable Ventures developed PPAs to pay for distributed generation, including household solar PV systems, on a large scale (Kollins 2010).

2.2 Securitization of PPAs may support a viable business model

Aggregators will need to access significant amounts of upfront capital at rates that are serviceable within their business model, in order to service the PPA market. One way for aggregators to access this capital for a household solar PV and battery roll out is through securitization of the revenue obtained by PPA contracts.

The opportunity to fund residential solar PPAs through securitization was initially discussed by Joshi (2012), who highlighted the risks and benefits of the PPA solar securitization market. Jacoby (2013); Joshi (2013a, 2013b); Lowder and Mendelsohn (2013) outline the risks and opportunities of securitization, but do not provide any financial models.

The risks for solar PPA securities have been identified (Jacoby 2013; Joshi 2013b; Hyde and Komor 2014; Matsui and Malaya 2014) to include the following:

- Credit risk: the homeowner's, or business's, ability to pay the bill.
- Counterparty risk: the aggregator and the hardware providers (battery, solar panels and inverter) as well as the installers and maintenance providers.
- Insolation risk: this eventuates when there is low production (such as on rainy days), which risk is dramatically increased with no counter days of high discount rateadiance, thus reducing the amount of power from the solar cells.
- Transfer risk: where the building on which the equipment is installed is sold or foreclosed.
- Grid price risk: if the retail, small-business electricity prices reduce significantly below current rates, the assets will not pay for themselves and the investors will make a loss.

Hyde and Komor (2014), Matsui and Malaya (2014), and Joshi (2013) examine these risks and discuss mitigation strategies including: installation insurance; matching warranties to the length of time of the deal on equipment; and robust credit checking policies with adequate credit risk scoring (commonly known as FICO score). Risks such as insolation risk and grid pricing risk could be hedged, and may be borne by the investor.

2.3 Foundational financial model for securitization of PPAs

Solar PPA securities obtain their income through the contract with consumers to pay for the power that they consume; which is unlike other Asset-Backed Securities (ABS). For example, automobile ABS generate revenue through the predetermined monthly repayments of the capital cost of the car, not the variable number of kilometres travelled during the month.

The foundational model developed by Alafita and Pearce (2014) seeks to document the cash flows generated by PPAs and securitization with a set number of customers, and assumes that solar production is exactly equal to the customer's consumption. The model incorporates discounts on a customer's early termination (for example due to defaults or moving premises), and takes account of power degradation of the solar output. The model also assumes that the consumption of electricity from the cells is uniform. The model allows for a set power price with standard increases over the duration of the 20-year term (not a variable), and assumes that the interest paid has a risk-free component and a risk-premium component. It includes a securitization fee for the agents that administer the bond. The model allows for the over-collateralization of the security, which is a common method in ABS to meet the investor's obligation. The model assesses the PPA securitization based on the internal rate of return. The model does not include a set up for different investment tranches, where senior and subordinate tranches have a different risk profile and therefore different rates of return.

2.4 The foundational model can be expanded and enhanced

This thesis builds upon the Alafita and Pearce (2014) model, taking into account: recommendations and developments described in the literature; technological advancements; and applications of current practices.

The literature on PPAs and ABS helps to inform how the Alafita and Pearce (2014) model might be enhanced and extended.

Discussion of PPAs in the literature can be dated back to 1913, in an article regarding electricity-powering coal collieries in Pittsburgh PA and the agreements with a central power plant. The purchase agreement discussed in that paper has details on the price, maintenance schedules, and penalties due to outages (Beers and Eddy 1913).

While reducing financial and technology risks is a key advantage of PPAs for the consumer (Drury et al. 2012), with their design of increasing prices annually there is no mechanism to adjust to lower prices in the PPA in the event of a fall in market electricity prices. Thus, if retail electricity prices fall, the PPA does not provide a financial benefit to the consumer (Kulatilaka, Santiago and Vakili 2014). Kulatilaka et al. suggest that designing a PPA to discount the retail price would remove market risk from the consumer and shift it to the aggregator. The aggregator can then manage this risk through financial instruments.

ABS were first introduced by First Boston in 1985, and seven years later in the US had a cumulative volume of USD 200 billion (Lockwood, Rutherford and Herrera 1996). According to Fender and Mitchell (2009, p. 29) ABS have "…three distinct characteristics: 1) [A] pooling of [eligible] assets (either cash-based or synthetically created); 2) Delinking of the credit risk of the collateral asset pool from that of the originator, usually through the transfer of the underlying asset, to a finite-lived, stand alone special purpose vehicle (SPV); 3) Tranching of liabilities, (ie issue of claims with different levels of seniority) that are backed by the asset pool."

"[H]igh-growth firms mainly use ABS to finance acquisition while low-growth firms spend ABS proceeds to increase both investments and stock repurchases…" (Riachi and Schwienbacher 2015, p. 17). ABS can help the issuing business access debt at rates cheaper than standard financing channels. Securitization also allows the separation of classes of debt into tranches, with the low-risk tranches attracting investors who have a mandate to invest in higher-grade investments. Securitization in tranches can allow a speculative-grade company to source a proportion of funding at an investment-grade level (Lemmon et al. 2014).

While the early work of Lockwood, Rutherford and Herrera (1996) suggests that shareholders in automobile companies issuing ABS did not experience wealth benefits, this is perhaps because at the time of the research these automobile companies could access borrowings at or near to A to AAA+ rates. This is discussed in the research of of Lemmon et al. (2014) which suggests that shareholders in companies who are not otherwise able to access debt at ‘A-grade’ rates will benefit from ABS. Thomas (1999) also demonstrates that ABS could bring wealth to shareholders, without negatively impacting on bondholders. Additionally, ABS securities can be bundled together or pooled from multiple issuers, reducing the risks associated with a single aggregator, and removing geographic or other firm-based bias.

One of the ways to evaluate the risk of a security is to examine when repayments are made, and this depends on the structure of the security. Alafita and Pearce (2014) modelled securitization using the simplest method – ‘the pass-through’ - where “…all assets classes receive a pro-rata share of any of the cash flow (both interest and in the principal) from the underlying pool of assets”.(Singer 2001, p. 13) The alternative to this approach is the ‘multi-class collateralized obligations’ approach where a collateralized debt obligation (CDO) takes on multiple class attributes including risk, returns and cash flow structures (Singer 2001).

Securitization engages not only credit risk - the end customer not paying their obligation - but prepayment risk - where the mortgage or asset holder repays the debt early; which can lead to “contraction risk” which creates “liquidation” of the asset, or “extension risk”, which results in “curtailment” of the asset (Lyuu 2004, p. 423). In the case of PPAs, this prepayment risk occurs when a customer chooses to purchase the equipment from the aggregator. A way of decreasing this prepayment risk is through a planned amortization class (PAC) of the CDO (Fabozzi 2001). PACs guarantee the repayment schedule, with protection from contraction and extension risks (Lyuu 2004). “The most important consideration for investors in senior tranches is their return of principal – the sooner the better” (Chasen 2009, p. 26). One method for reducing the time range for the payment on principal is through a sequential method, which pays the lowest-risk-priced bond first, and once the principle for the first tranche is paid, then the following tranche is paid and so forth. This method reduces the payment risks to the primary bond (Lyuu 2004). The PAC sequential method makes the primary debt less risky, as the payment terms are known and the time shortens: the risk is passed to other, higher-risk tranches in the deal.

The literature on ABS helps to inform the modelling of securitized PPAs. Many recent studies on securitization have focussed on the significant detrimental impact those financial instruments have had in the context of the global financial crisis (GFC), see, e.g., Gorton (2009); Gorton and Metrick (2012); Krishnamurthy, Nagel and Orlov (2014); Beltran, Cordell and Thomas (2017) These articles emphasise the risk of moral hazard where securitization risks are not managed In the case of this model there is a moral hazard risk thatthe originator who signs on the PPA customer gathers private information on the customer which is not passed on to the investor. This asymmetrical information ownership can lead to a moral hazard and puts the investor at some risk. To address this moral hazard risk, "..originators may signal positive information via junior retentions…" of the bonds in all the tranches (Chemla and Hennessy 2014, p. 1597). This method of removing asymmetrical risk has "…led the sponsoring bank to take the off-balance sheet [Structured Investment Vehicles] SIVs back onto their balance sheets, when there was no explicit obligation to do so" (Gorton 2009, p. 41). If the originator also invests in the different tranches, this diminishes the likelihood of a moral hazard and demonstrates that the information is reliable: the originator has 'skin in the game'.

From a technological perspective, the cost and availability of lithium-ion batteries have advanced greatly since the Alafita and Pearce model. The facility to store power and use it at times when it is not possible to generate solar energy significantly impacts on the value proposition for the consumer, and potentially of the aggregator (in the form of VPPs). The literature to date has not considered or modelled PPA solar rooftop and lithium-ion battery bundles for household consumption.

This thesis enhances and expands the model developed in Alafita and Pearce (2014) to reflect the above literature, technological advancements and market settings in the following ways: increasing the number of tranches in the security to reflect different investor risk categories; decreasing the term length to replicate the market demand; using a collateralized debt obligation (CDO) structure of sequential PAC tranches; identifying the aggregator as the owner of the highest risk investment tranche; ensuring that the price paid by the customer is lower than the retail price; acknowledging the difference in consumption vs production; incorporating a market FiT; and adding a lithium-ion battery to the model for consumption during the evening.

The following chapter discusses the enhanced model in more detail.

CHAPTER 3: THE ECONOMETRIC FRAMEWORK

There are two major components to the modelling framework developed in this thesis. The first component is the solar PPA which generates the revenue, or cashflow, to pay for securitization by selling electricity generated by the solar panels installed on rooftops[2]. The second major component is the mechanics of the CDO, which determines how the cashflow will be used to pay the investment tranches. Each of those components engage a range of interacting inputs.

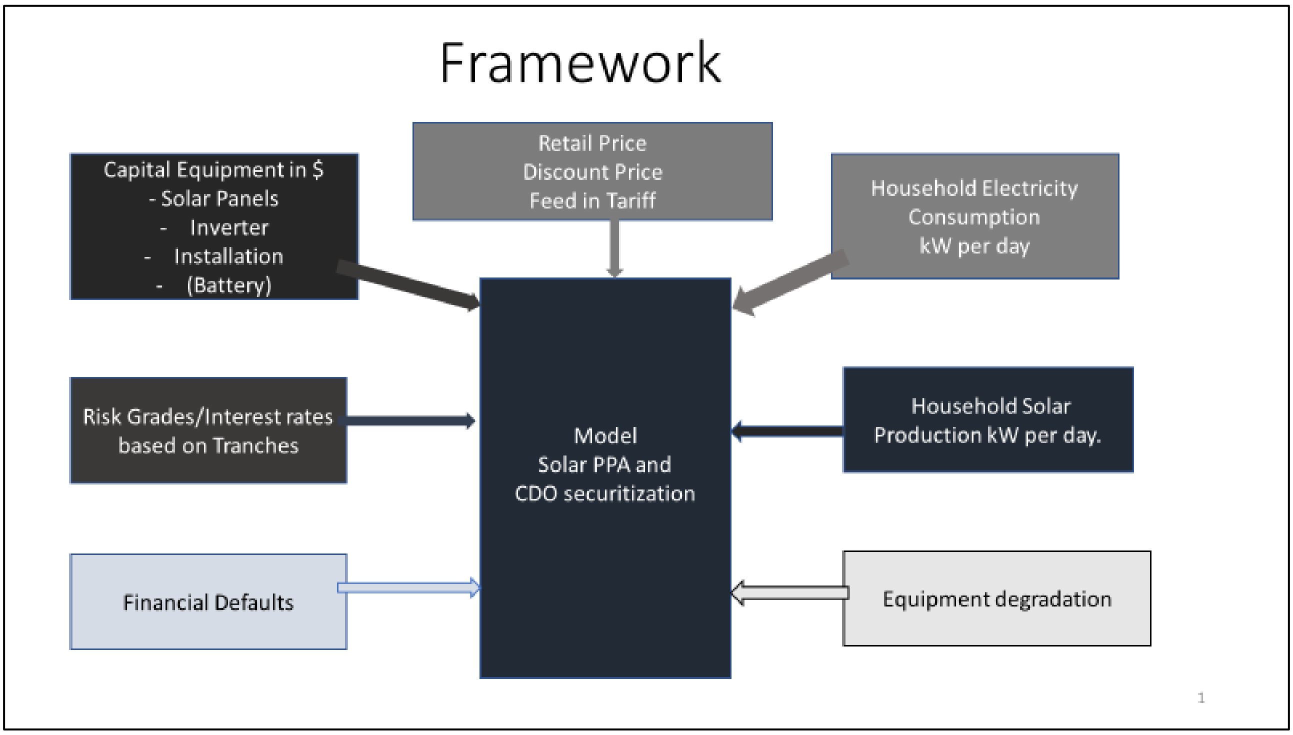


Figure 1 The econometric framework and major inputs

The framework inputs include: capital equipment prices; electricity prices - including average retail prices, PPA discount prices and FiT rates; household electricity consumption; household electricity production from the solar panels; electricity storage (where there is a battery); solar and battery equipment degradation; financial default rates; and interest rates, depending on the risk grade for each of the investment tranches.

[2] In this study we assume that the building owner owns the solar cells installed on the roof after the term of the contract. An alternative approach could be that the building owner receives a rental payment from the aggregator for use of the rooftop for a period of time. It is also assumed that any maintenance of the roof is at cost of the owner, rather than the aggregator.

3.1 Capital Equipment Costs

The costs borne by the aggregator are assumed to include the cost of installing the relevant equipment in each customer household, as shown in equation (1).

$$\mathrm{c} = c^s + c^b \qquad (1)$$

c = total cost of the installation of capital equipment including installation per customer where:

c^s = Cost of the solar panels and the inverter, installed for one customer.

c^b = Cost of the battery and the inverter, installed for one customer.

The total cost of capital is the cost of capital equipment per customer, times the number of customers. The number of customers at the beginning of the bond period is zero.

$$\mathrm{K} = \mathrm{c} \times \mathrm{n}_{\mathrm{m}=0} \qquad (2)$$

K is the total cost of capital

$n_{m=0}$ is the number of customers at the beginning of the contract, where *m* is month.

The model assumes that all customers will have 5kW rated solar panels installed and, where batteries are included, the battery will be a Tesla Powerwall2, a 13.5kWh battery. It is assumed that all equipment is purchased at wholesale prices, as discussed in Chapter 4. All warranties for solar PV and inverters are assumed to be extended for the life of the bond. For the batteries, it is assumed that the warranty covers 38,700kWh, except where explicitly stated otherwise.

3.2 Electricity Production and Solar PV Degradation

This framework employs data regarding consumption and production which can be found in Ausgrid's (Ausgrid 2014) Solar Home Electricity Dataset. These data points represent the real power consumption and solar production of 300 homes over the period July 2010 - June 2013, at half hour intervals. These homes are in the Ausgrid catchment area of the electricity grid service, which covers Sydney coastal, Inner West, and North Shore suburbs as well as part of the Hunter region. The data in this model removes any assumption around consumption in any particular hour, and allows for differences between power consumption and solar production depending on the time of day and time of year. The equations discussed below and in the following sections allow, therefore, for electricity consumption and production inputs in terms of half-hour intervals, days and months, which are abbreviated as follows:

$h = \ represents\ half\ hour\ interval. d = \ represents\ day.\ \ m = represents\ month$

As the Ausgrid data collection started over 8 years ago when solar panels were higher in price than they are now, 73% of the 300 customers have only 1kW to 2kW panels, with 98% of the customers having less than 5kW installations. This framework models a base standard implementation of 5kW production to reflect the reality that, in NSW, 54% of solar panel installations under 14kW in the period April 2017 to March 2018 were between 4.5kW and 6.5kW (Australian PV Institute (APVI) 2018). Production data is therefore normalised to replicate 5kW production.

The power produced by solar panels degrades over time. Manufacturers state the degradation rates on the product specification documentation. Unlike Alafita and Pearce (2014), this model uses the two-step degradation rate of solar output specified by solar manufacturer Winaico, namely a 3% degradation in Year 1, and a 0.7% linear degradation for the next 24 years, with a 15 year warranty (Winaico 2018).

The first-year degradation rate is expressed in equation (3), where DS stands for Degradation of Solar and DS_m represents the degradation of the production of solar power at month *m*.

$$DS_m \ = \ DS_{(m-1)} \times (1 - \ \lambda^F), \text{ for m=1,..,12} \qquad (3)$$

λ^F is the degradation rate in months, for the first year. Hereby, $DS_{m=0}$ =1 (i.e. no degradation on commencement).

The degradation rate from the commencement of Year 2 until the end of the bond period of *m* months is similar to equation (3) but applies a slower degradation rate.

$$DS_{m(13:Term)} \ = \ DS_{(m-1)} - \lambda^{s} \tag{4}$$

$\lambda^{s}$is the degradation rate in months, after the first year of installation.

A degradation rate has not been applied to the Ausgrid (2014) retrospective data, as the data does not include the solar degradation rate of the 300 different installations in the production figures, nor the length of time the panels have been installed. Instead, the model assumes that the solar production from Ausgrid for January, although a median over 3 years, will represent the first month of production, i.e. no degradation rate has been applied to the original data. This is in contrast to Alafita and Pearce (2014) who use expected production across the year, based on the size of the panels.

To calculate electricity production in a given month and half hour period ($P_{m\,h}$), the model uses the median production from the 300 Ausgrid customers for the relevant half-hour period over a month, multiplied by solar degradation formula (3) or (4), depending on whether or not the relevant time period falls inside Year 1 (Equation (5)). The model uses the median rather than the mean, to reduce the influence of the tail skew: the left tail in production and the right tail in consumption (see further in Chapter 4).

$$P_{m\,h} \ = \ \omega_{mh} \times DS_{m} \tag{5}$$

ω_{mh} is the median production of electricity in kW for the half-hour time period *h* in the day, in a particular month *m*. For example, $\omega_{12\,18}$ represents the median production for December (month 12), at 9am~9:30am (18th half hour of the day).

Equation (6) describes the median production for a relevant half-hour period, per day, in a particular month.

$$P_{mhd} \; = \frac{\omega_{mh} \; \times DS_m}{number\ of\ days\ in\ the\ month} \tag{6}$$

For simplicity, the modelling assumes a simultaneous commencement date of 1 January for both the production and consumption of electricity, in order to remove any lag time between installation and power production.

3.3 Electricity Consumption

As discussed further in Chapter 4, to calculate electricity consumption in a given month and half hour period ($Z_{m\,h}$), the model uses the median consumption data over three years, from 300 Ausgrid customers, for the relevant half-hour period over a month (Ausgrid 2014).

$Z_{m\,h}$ = median electricity consumption in the relevant month and half-hour time period from the Ausgrid dataset (Ausgrid 2014)

The key difference between the way that Alafita and Pearce (2014) treats electricity consumption and the model in this thesis, is that Alafita and Pearce use net consumption and thus assume that total production of the solar cells is consumed. The model in this thesis offset production against consumption, and applies a feed in tarrif which is lower than consumption.

3.4 Battery Storage, Battery Degradation and Feed-in-Tariffs

Where there is no battery in the solar PPA package, the consumption input per half hour is aggregated to a median monthly value. Where a battery is included in the PPA package, and FiT are variably applied during the evening and daytime periods, the model uses daily calculations rather than monthly calculations, as they are time and volume critical. The model breaks the median half-hour rate down into a daily rate, based on the month in question, with the median divided by the number of days in the month.

Like solar panels, battery operation also degrades over time. There is an assumption that, once the battery has reached the maximum throughput of 37.8MWh, the battery will cease to function. However, the model assumes that the battery will work past its warranty of 10 years and will operate beyond the retention of 70% (Tesla 2017).

Equation (7) represents battery degradation, where $B_{m=0}$ is the maximum rated capacity in kW at month 0.

$B_m = B_{(m-1)} \times (1 - \lambda^b)$, for m = 1,…,to the end of battery life (7)
in months.

λ^b is the degradation rate of the lithium-ion battery.

Combining the data on battery capacity, and the production and consumption of the median household, the model can determine whether there is a surplus of electricity during a particular half-hour period. This surplus can then be used to charge the battery, or it can be sold into the grid.

Equation (8) calculates the existence of surplus electricity production in each half-hour period over a month ($S_{m\,h}$), by subtracting consumption from production.

$$S_{m\,h} = P_{m\,h} - Z_{m\,h} \tag{8}$$

where:

$Z_{m\,h}$ = median monthly consumption in the month and half-hour time period from the Ausgrid dataset (Ausgrid 2014)
$P_{m\,h}$ = median monthly production in the month and half-hour time period from the Ausgrid dataset (Ausgrid 2014)

The surplus per day for the time period, given the month, is described in (9), the consumption per day is described in (10), and the production per day is described in (11).

$$S_{mdh} \frac{S_{m\,h}}{number\ \ of\ days\ in\ the\ month} \tag{9}$$

$$Z_{mdh} = \frac{Z_{m\,h}}{number\ \ of\ days\ in\ the\ month} \tag{10}$$

$$P_{mdh} = \frac{P_{m\,h}}{number\ \ of\ days\ in\ the\ month} \tag{11}$$

Once the surplus production and the battery degradation is known, it is possible to calculate how much electricity is stored in the battery at a given time (β_{mh}) (12). Since the median monthly figure is used, the surplus for any given month will be the same for each day in that month. However, the values for that month over the bond term will reduce due to the production and battery degradation rates.

$$\beta_{m\,h} \ = \ \beta_{(m\,h-1\,)} + S_{mdh} \ \text{ for } \ \beta_{mh} \ \ \leq B_m \tag{12}$$

β_{mh} = represents the amount of energy stored in the battery in month *m*, and time h.

The model assumes that any surplus production will first be used to fill the battery but, if there is still excess power production in the half-hour window (ψ_{mh}), after this has occurred, then this power can be sold into the grid to earn a FiT (13).

$$\psi_{mh} \ = \beta_{(mh-1\,)} + S_{\,mdh} \ - \ B_m \ \text{ for } \ \psi_{mh} \ \geq 0 \tag{13}$$

ψ_{mh} = is the excess electricity at time interval *h*.

To determine the capacity to sell excess power at a FiT, the model uses a naive approach to forecasting the battery usage, illustrated in Figure 2. It takes the maximum and the minimum amounts of power stored in the battery on the previous day to approximate how much excess power can be sold to the grid in the event that there is an evening FiT premium, and leaves 2kWh in the battery as reserve. The model assumes that the aggregator has an opportunity to sell electricity in the evening and that, by the next day, solar production will top up the battery.

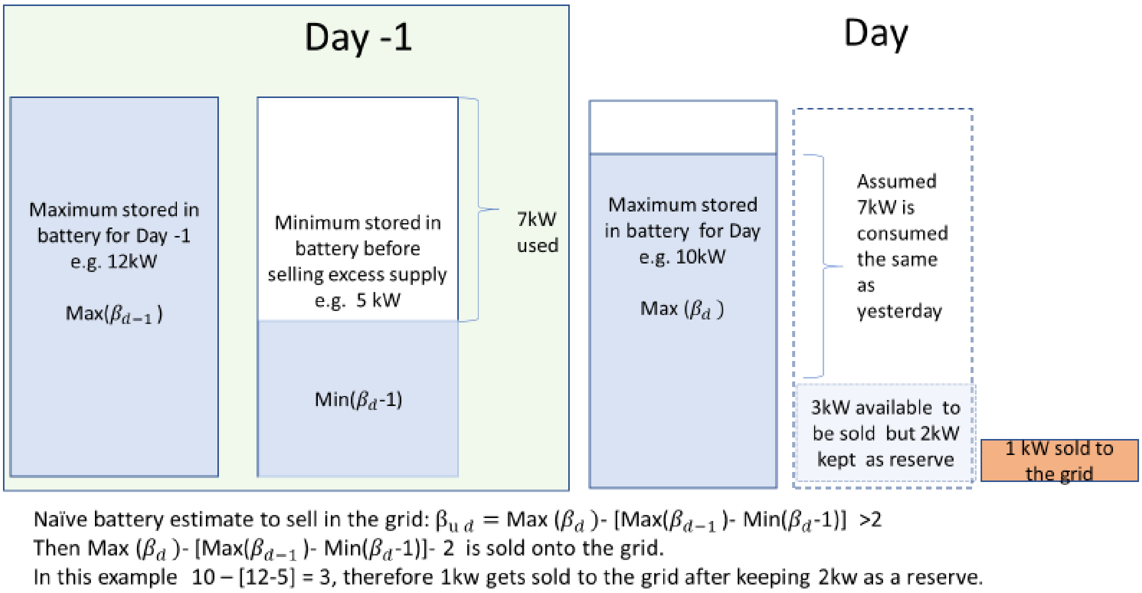


Figure 2 Naive approach to calculating surplus power available to sell for evening FiT.

Equation (14) calculates the expected unused power in the battery for the day (β_{ud}), which is available to be sold in the evening.

$$\beta_{ud} = max(\beta_{(d)}) - [max(\beta_{(d-1)}) - min(\beta_{(d-1)})] \tag{14}$$

For $\beta_u \geq 2,$ then $\beta_{sd} = |2 - \beta_u|$ For $\beta_u < 2$ then $\beta_{sd} = 0$

β_{sd} is the surplus power sold in the evening of the relevant day after ensuring a 2kWh buffer, using the naive approach to predicting surplus electricity in the battery, with a 2kWh buffer.

Using the excess electricity from a surplus during the day (ψ_{mh}) ((13) and the surplus from the battery in the evening (β_{sd}) (14), the value of the excess electricity sold to the grid at FiT rates is (gr_m) where g_d represents the FiT rate during the day, and g_n is the premium FiT rate for the evening (15).

$$gr_m = \begin{cases} \sum_{1}^{48} \psi_{mh} \times g_d + \beta_{sd} \times g_n, \; for\; g_n > g_d \\ \sum_{1}^{48} \psi_{mh} \times g_d, \quad for\; g_d \geq g_n \end{cases} \tag{15}$$

The model assumes that, if the evening FiT rate is not greater than the daytime FiT rate, then no excess electricity would be sold from the battery, as the limited battery cycles would be wasted if no extra income is earned.

There is also an option to sell into the grid in the absence of a battery. In these circumstances, the electricity surplus must be generated and sold during the day, as there is no capacity to store the electricity at evening prices. In Equation (14), the value for β_{sd} , which describes the electricity available to be sold from the battery, will be zero and there will therefore be no application of g_n, the premium evening FiT rate.

Figure 3 below illustrates production and consumption from 10am to 3pm, with the plot line showing the amount of kW sold into the grid in the absence of a battery.

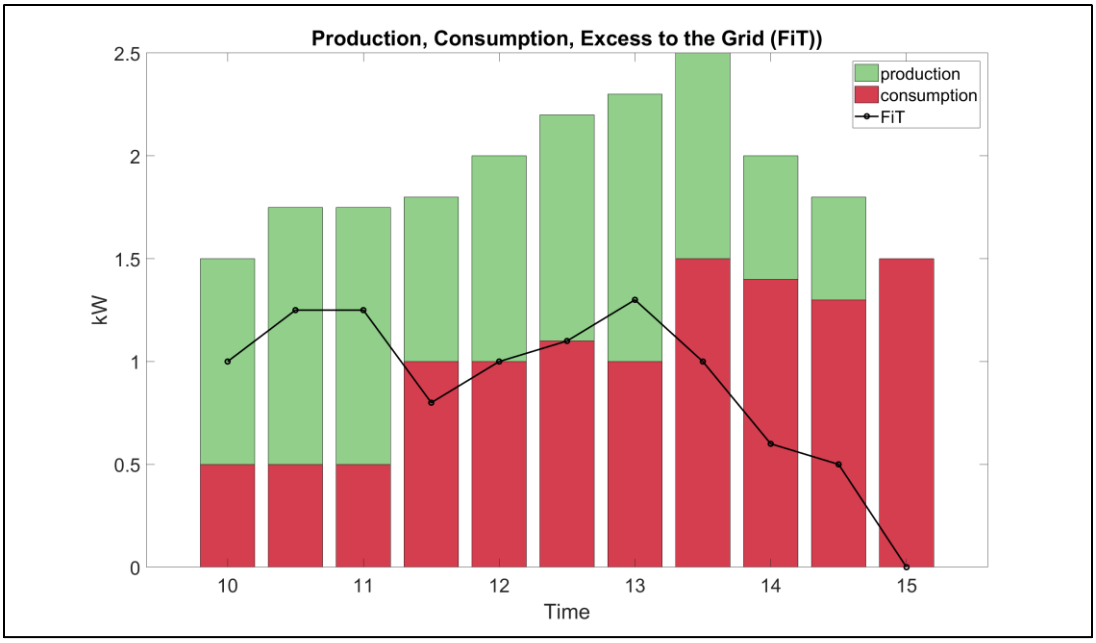


Figure 3 Illustrative electricity production, consumption and surplus sold to the grid for FiT, in the absence of a battery (10am-3pm)

Figure 4 illustrates production, consumption and export to the gird in the presence of the battery. This example assumes that, at 10am, the battery already has 4kWh stored, and then builds up till 2pm when the battery is full at 12kW, at which point the excess begins to be exported to the grid to receive the FiT.

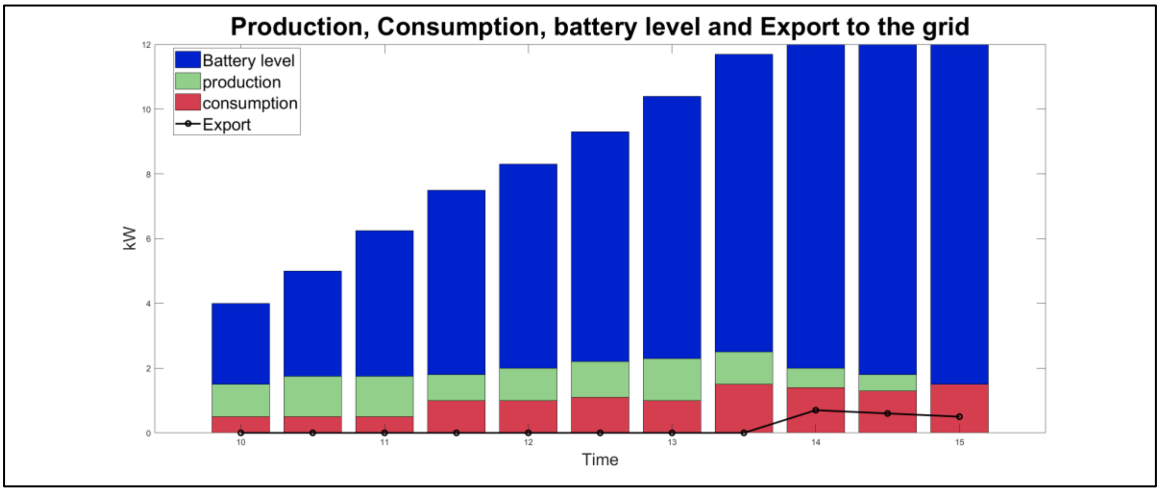


Figure 4 Illustrative electricity production, consumption and surplus sold to the grid for FiT, with a battery (10am-3pm), assuming 4kW at 10am, maximum battery capacity of 12kW.

Together, these two Figures illustrate that, with a battery, access to FiT rates begins at 2pm with the potential to continue into the premium evening FiT rate periods, whereas in the absence of a battery only daytime FiT rates will be available.

3.5 Calculating the payments made by the PPA customer to the aggregator

PPA customers will purchase some electricity through the PPA contract, and some electricity from the grid. The electricity purchased through the PPA contract is the electricity sourced from the solar PV, and battery where relevant, and translates into revenue earned by the aggregator. It is, therefore, necessary to determine how much electricity is produced and stored by the aggregator's assets in any given time period (ϕ_{mh}), to understand how much the customer owes to the aggregator under the PPA (16).

$$\phi_{mh} = \begin{cases} z_{mh} \\ P_{mh} + \beta_{mh} \end{cases} \quad \text{for} \begin{cases} & P_{mh} \geq z_{mh} \\ P_{mh} < z_{mh}, & 0 \leq \beta_{mh} \leq (z_{mh} - P_{mh}) \end{cases} \tag{16}$$

ϕ_{mh} is the consumption of electricity from the aggregator's assets. When electricity production from the aggregator's assets is greater than consumption ($P_{mh} \geq z_{mh}$) in a certain half-hour period and month, then the customer's total consumption (z_{mh}) is the same value as the consumption from the aggregator's assets. Where the customer's electricity consumption is greater than the production of power from the aggregator's assets ($P_{mh} < z_{mh}$), then consumption from the aggregator's assets equals production plus any electricity available in the battery ($P_{mh} + \beta_{mh}$), to make up the gap ($0 \leq \beta_{mh} \leq (z_{mh} - P_{mh})$). The revenue to the aggregator for that consumption (ar_{mh}), is described in equation (17), where p^a is the price per kWh the customer pays for electricity supplied by the aggregator.

$$ar_{mh} = \phi_{mh} \times \; p^a \tag{17}$$

The model assumes that the retail grid power prices and PPA prices remain constant over the term of the PPA security, and that the PPA prices are always lower than the retail price. For simplicity, it is further assumed that PPA customers will either pay on time or they will default: there is no allocation for late payment or delayed payment in the model. If the real estate on which the solar PV is installed is sold, it is assumed that the new owner continues with the PPA contract.[3]

The basic model also assumes that there are no prepayments in the CDO, as, unlike the situation in other ABS, there are fewer incentives for the power consumers to make advance payments, as they are paying based on consumption rather than on ownership of an asset.

3.6 Modelling Customer Default Rates

Payment default rates change over time due to economic conditions, both for the customers and the economy more generally. Alafita and Pearce (2014) use a simple discount factor on customers defaulting, whereas this thesismodels the default of PPA customers by applying a Large Pool Gaussian Copula (LPGC) approach (Li, Mikusiński and Taylor 1998; Clemen and Reilly 1999). Unlike Alafita and Pearce (2014), who simply assume a constant annual default rate among customers, the LPGC model allows for correlated defaults among customers as well as defaults being dependent on a systematic risk factor. Therefore, the model offers a more flexible and

[3] The salvage value of solar PV may be an additional revenue stream, especially for defaulting customers. However, it may be more economical for the aggregator to continue to earn revenue from the FiT. For example, in the Scenario 1 Base Case 5.1, FiT revenue amounts to an average $420pa. If a customer defaults after 12 years, the NPV to year 18 would be approx. $1,970. This amount may be greater than the resale value once collection and electrician costs are considered. To be on the conservative side, the model does not include this revenue when the customer defaults.

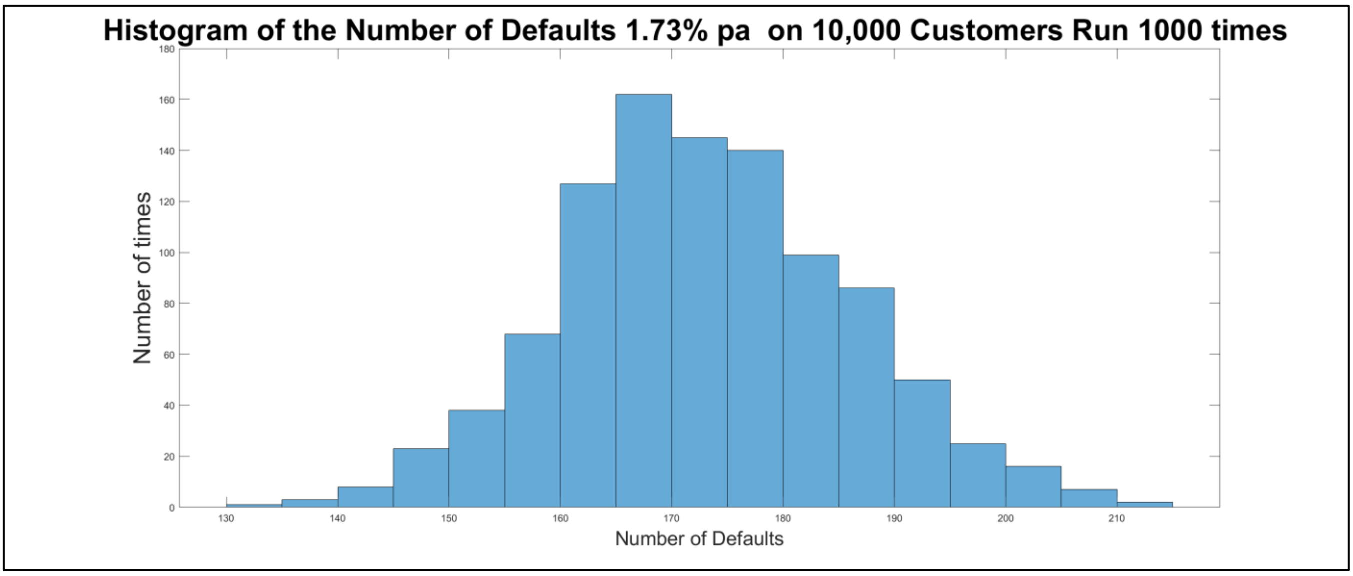
realistic approach to modelling the number of PPA customers that fail to fulfil the PPA contract throughout the lifetime of the solar ABS.

Following the typical specification in the LPGC model, it is assumed that all PPA customers have the same unconditional average probability of default p. Defaults among customers are then correlated based on a specified copula correlation parameter ξ. Furthermore, the conditional probability of default for each customer $p(Y)$ is dependent on the outcome of a systematic risk factor Y that has an impact on all customers. The systematic risk factor can be interpreted, for example, as an indicator of the overall state of the economy. Thus, the LPGC model introduces default correlation among customers through the joint dependence on the systematic risk factor.

$$\begin{aligned} p(Y) &= \left[\frac{N^{-1}p - \sqrt{\xi}Y}{\sqrt{1-\xi}}\right] \\ n_m &= B(n_{m-1,}\, cdf(p(Y))) \end{aligned} \tag{18}$$

This model is based on annual default rates, but the number of defaults on a monthly basis is simulated, such that the default rate is divided by 12. In Equation (18), N^{-1} represents the inverse of the standard normal cumulative distribution function (*cdf*). The parameter for default correlation is set as $\xi = 3\%$. Firstly, an outcome for the systematic risk factor is simulated. This then yields the conditional default probability for each PPA customer, see Equation (18). The number of defaults produced is random around the normal distribution, as illustrated in the two graphs shown in Figure 5.

Finally, using the Binomial distribution, the number of PPA customer defaults in a particular month can then be simulated. Note that, in this framework, it is assumed that, once a customer defaults, no revenue will come from that customer. This generates a more conservative result than is likely to occur in reality, as the solar assets relating to a defaulting customer could still feed the grid with electricity and command the daytime FiT tariff, and possibly even the evening FiT revenue, depending on the controlling mechanism and the existence of a battery package, as well as the salvage value of removing the asset and selling it on the open market. The model in this thesis also assumes that, once the customer exits the PPA, there is no settlement or part payment.



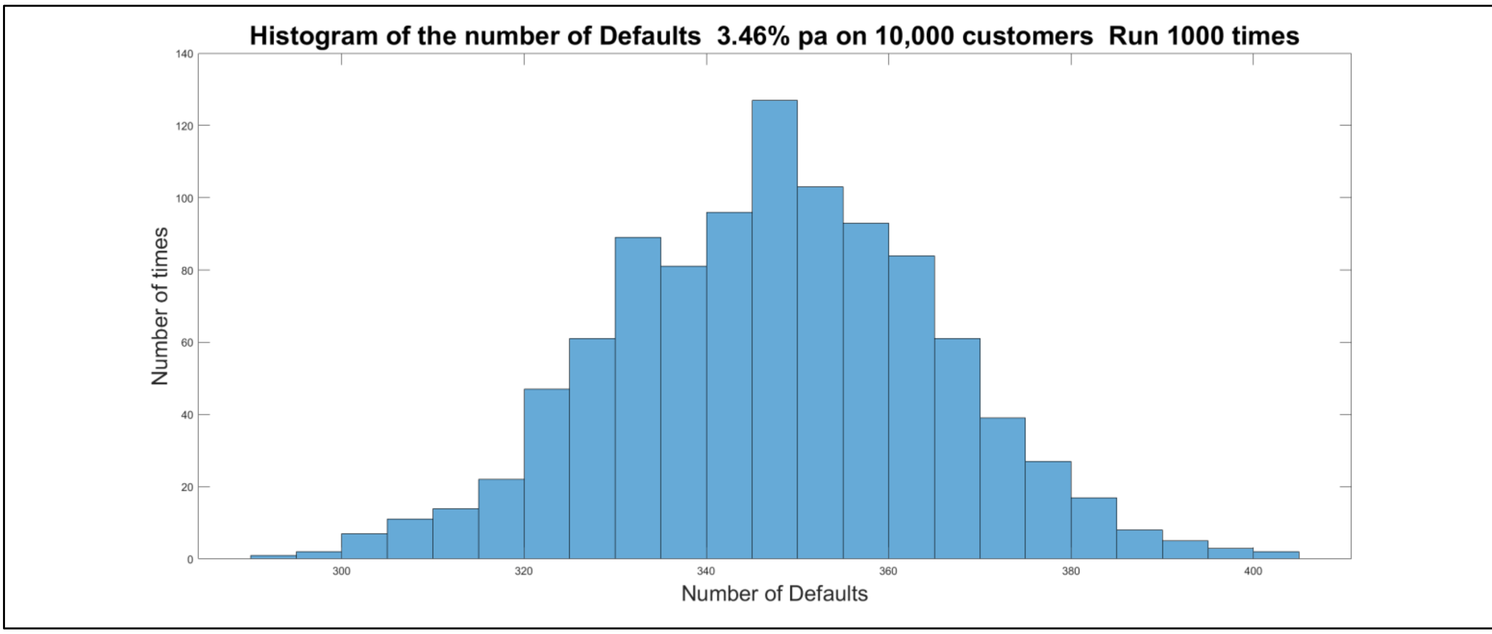


Figure 5 Histograms illustrating the number of defaults, at two different default rates - 1.73% pa and 3.46% pa. Run 1000 times.

3.7 Modelling total aggregator revenue and securitization payments

The total revenue earned by the aggregator per month is the revenue per time period from power consumption by the PPA customer (17), plus revenue earned by selling excess power to the grid at FiT (15) for the number of customers in term *m* (19).

$$R_m = \left(\sum_{h=1}^{48} \mathrm{ar}_{\mathrm{m\,h}} + \mathrm{gr}_{\mathrm{m}}\right) \times ND_m \times \mathrm{n}_{\mathrm{m}} \qquad (19)$$

where ND_m is the number of days in the month *m*.

Figure 6 shows a schematic representation of the cash flows of the sequential ABS CDO. As discussed in Chapter 2, sequential CDO structures reduce the time for repayment of the principal in the senior tranche - tranche A – so that the lowest-risk-priced bond is paid first. Once the principal for the first tranche is paid, the following tranche is paid and so forth. The inclusion of this repayment structure in the model permits the possibility of issuing an investment-grade security. The mechanics is that tranche A, starting at time period 1, immediately receives repayments of the principal, plus interest. At the same time, interest is also being paid to the mezzanine tranche (tranche B) and the subordinate tranche (tranche C). Once tranche A principal is paid off, payment of the principal for tranche B commences, and thus the interest payments for tranche B become smaller. While the principal for tranche B is being paid, the interest for tranche C is also being paid. The last month of each tranche payment will be a transition period such that the balance of the principal for the higher-rated tranche will be paid first, and any remaining amounts will contribute to the principal of the next tranche.

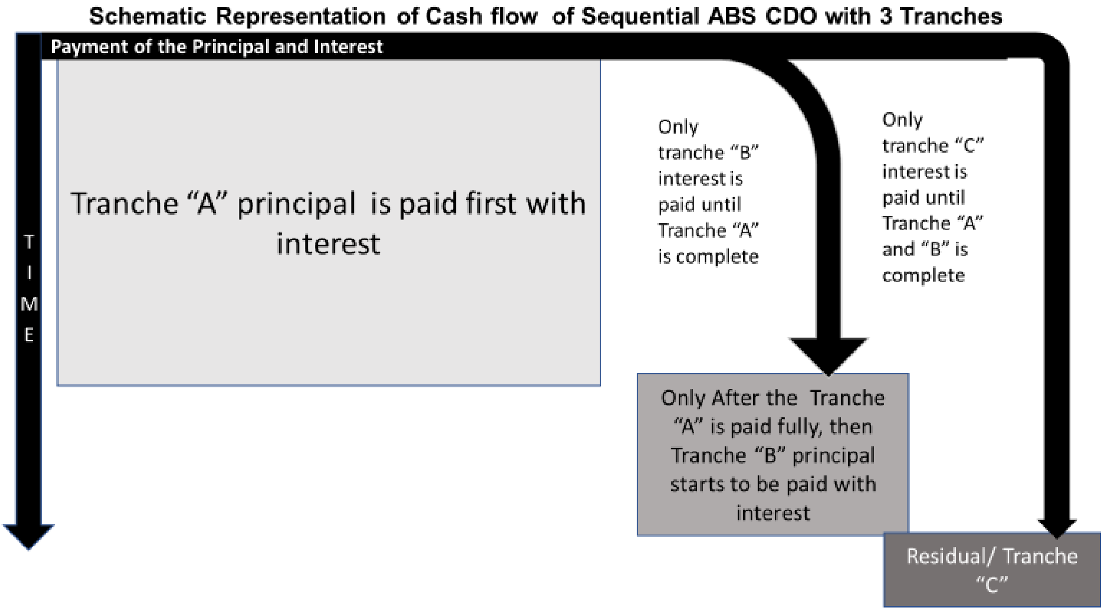


Figure 6 Schematic representation of the sequential ABS CDO cashflows, with 3 tranches – A, B and C.

In order to calculate the principal and interest payments, the model employs a technique which assumes no prepayments on the sequential CDO, and the absence of any tranches. Instead, the model uses the weighted average coupon rate across all the tranches and creates an amortized loan balance based on the term length, as a fraction of par value (The Bond Market Association 1999). Understanding that the par value is the total capital borrowed for all the tranches, and assuming that par is one, Equation (20) represents this approach.

$$p_{\mathrm{m}} = 1 - \frac{1-(1+\frac{C}{12})^{-m}}{1-\left(1+\frac{C}{12}\right)^{(-m_0)}}\text{, for all } m \qquad (20)$$

p_{m} represents the principal to be paid in any month, as a ratio. *C* is the total of the weighted coupon rates + fee rates, where *C* is made up of r_A, r_B, r_C, r_f, and *r* represents the interest rates which apply to investment tranches A,B,C and the fees (f) payble as weighted average.

$$i_m = \left(\frac{1-(1+\frac{C}{12})^{-(M_{-1})}}{1-\left(1+\frac{C}{12}\right)^{(-M_0)}} \right) \times \; C/12 \quad \text{, for all } m \tag{21}$$

i_m represents the interest to be paid in any month, as a ratio.

The sequential payments are then made up of the following, where each tranche is being paid off, as suggested in Equation (22).

$$T_{pm} = \; p_{\mathrm{mt}} \times \; \mathrm{K}\,,\, till \; \sum T_{pm} = tranche\; principal\; (TP^x) \tag{22}$$

TP^x *is the principal paid out by tranche* x *at time* 0

T_{pm} *represents tranche payments* per month

p_{mt} *is the principal payment ratio see*(20)

$T^{it}_m = \left(TP^x - \sum_0^t T_{pm}\right) \times \; r_x$

T^{it}_m *is the interest component of tranche payment in month* m.

$T^{it} = (TP^x) \times r_x$ while $T_{pm} = 0$

The creation of a special purpose vehicle to protect the investors from the aggregator’s bankruptcy imposes a range of fees including the costs of setting up and administering a trust structure, “selling” the ABS, and billings costs. The fees are calculated as a percentage rate on the capital outstanding (23).

$$f_m = \left(k - \sum_0^m T_{pm} \;\; for\; all\; TP^x \right) \times r_f \tag{23}$$

The Net Revenue amount (NR_m) is the gross revenue to the aggregator, less all payments to the bondholders (24). The amount is calculated by taking the revenue (19) and subtracting the interest (21), the principal payments (20), and all fees (23).

$$NR_m = R_m - \;\; \sum_1^{\max m} T_{pm} \text{-} \sum_t^{\max t} T^{it}_m \text{-} \sum_{tm}^{\max m} f_m \tag{24}$$

Due to the seasonality of solar production, and the inverse relationship with consumption and production over the seasons (consumption is greatest in the winter and production is greatest in summer), there is an assumption that, when the revenue yield to the aggregator is greater than the coupon payments and fees on the bond, this surplus amount will act as a reserve against any losses in the winter as well as for any degradation of the power plant, and customer defaults (Singer 2001).

$$NR_{mi} = \left(\sum_{m=1}^{m-1} NR_{m-1} \times i^{cr}\right) + R_m \tag{25}$$

$$i^{cr} = monthly\ cash\ rate, NR_{mi} = interest\ earned + Current\ \ Net\ Revenue$$

To calculate the aggregator's profitability at the end of the bond period, the model uses the net present value (NPV) of the aggregator's monthly net revenue stream (26), where *n* is the number of months in the bond period, and d^r is the discount rate in each month over this time period.

$$NPVAgg = \sum_{t=m}^{n} \frac{NR_{mi}}{(1 + d^r)^{tm}} \tag{26}$$

3.8 A conservative approach

When applying any of these equations, this thesis employs the accounting principle of conservatism whereby, "under uncertainty, assets, revenues and profit should not be overstated" (Trotman and Gibbins 1998, p. 355). Therefore, where data is unavailable, or where there is contention of the value, there is a preference towards less favourable terms for the aggregator and the investor.

CHAPTER 4: DATA

4.1 Solar Production and Consumer Consumption

As noted in Chapter 3, the data regarding electricity consumption and solar production has been sourced from Ausgrid's Solar Home Electricity Dataset (Ausgrid 2014), and represents the real consumption and solar production of 300 homes over the period July 2010 - June 2013, at half-hour intervals. Using this dataset permits the model to allow for differences between power consumption and solar production at different times of the day and during different seasons of the year. The live nature of the dataset also allows for weather effects, possible shadowing, and directional installation settings. For example, Figure 7 shows the generation of solar energy for the three days July 4-6, 2012, where there was 4mL rain on 5 July and 19mL rain on 6 July (Bureau of Meteorology 2018).

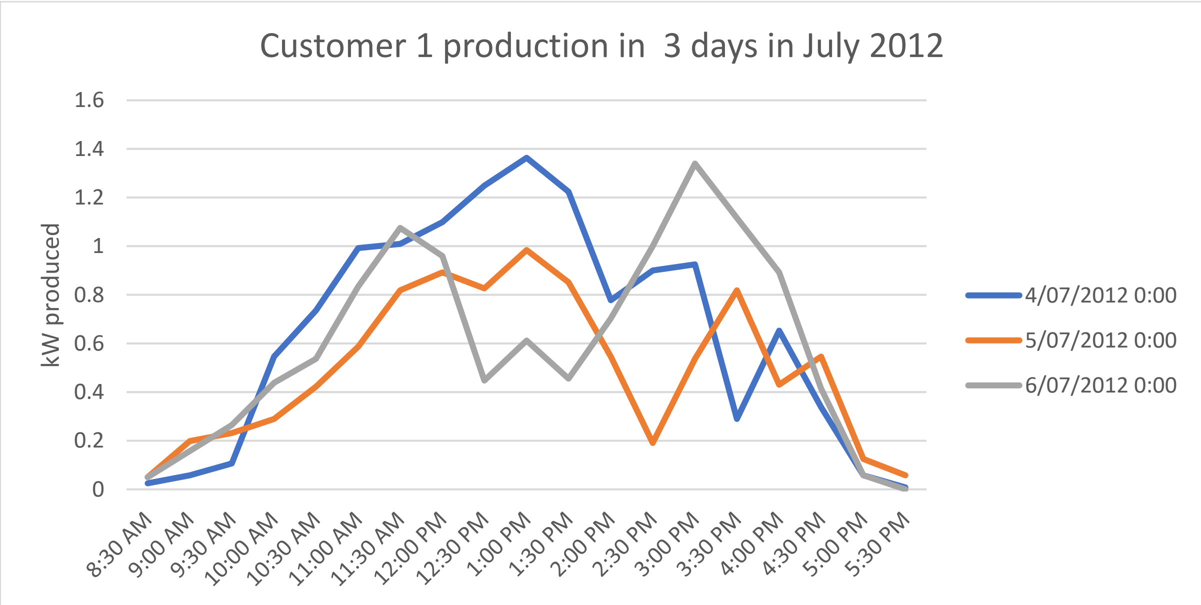


Figure 7 Example: Solar production by one customer for 3 days in winter with patchy rain

As noted in Chapter 3, the Ausgrid dataset solar production numbers reflect the fact that, in 2010, 98% of customers had installations generating less than 5kW due to the high price of solar installations. Currently in NSW, 54% of solar panel installations under 14kW in the period April 2017 to March 2018 were between 4.5kW and 6.5kW (Australian PV Institute (APVI) 2018). Production data has thus been normalised to replicate 5kW production.

Each customer's data for consumption and production has been summarised by taking the average across three years, for each half-hour period in each month. Thus, the model uses average values for 48 time periods per day, for 300 customers, for a period of 12 months.

The solar production figures, by season and by month, are shown in Table 1. Table 1 illustrates that summer, followed by spring, are the two most productive periods for generating electricity. There is a slight left skew in production data, which may be explained by the number of production days which are recorded as zero.

	Monthly kWh Produced Distribution of 300 homes on Ausgrid Network Normalized to 5kWh										
Year Part	Mean	Median	Std.Dev	Variance	Min	Max	Range	95% Percentile	75% Percentile	25% Percentile	5% Percentile
AllYear	524.96	545.23	139.89	19570.34	86.04	1065.27	979.23	715.74	629.58	433.21	270.73
Summer	618.31	623.80	101.60	10322.90	253.50	1065.27	811.77	759.93	688.59	548.71	460.61
Autumn	483.62	491.44	103.14	10637.62	93.67	861.33	767.66	639.46	556.93	423.80	293.82
Winter	393.86	382.29	126.61	16031.14	86.04	716.17	630.13	614.02	483.84	305.80	186.13
Spring	604.07	615.76	86.30	7448.43	170.34	995.82	825.48	714.21	659.57	559.73	449.00
Jan	664.52	673.78	90.81	8245.70	287.15	1065.27	778.12	780.03	713.06	620.14	510.29
Feb	540.54	547.09	74.77	5590.12	264.58	850.99	586.41	642.52	584.70	495.74	411.73
Mar	558.46	565.90	79.71	6353.53	267.16	861.33	594.17	666.47	613.35	503.87	420.99
Apr	465.92	477.11	81.08	6574.71	178.47	676.01	497.55	570.90	525.28	418.57	320.58
May	426.48	441.79	99.23	9846.35	93.67	676.74	583.08	554.98	502.88	361.26	250.98
Jun	302.63	310.84	79.88	6380.09	86.04	515.53	429.49	414.64	364.64	251.78	151.59
Jul	364.07	374.00	87.91	7727.97	89.16	525.96	436.81	483.53	432.97	305.66	199.56
Aug	514.87	527.74	100.79	10159.23	131.90	716.17	584.27	649.94	591.60	455.74	331.72
Sep	592.13	604.00	89.38	7989.66	170.34	792.11	621.78	702.99	659.57	547.08	420.28
Oct	622.02	634.43	84.24	7095.68	179.57	967.53	787.96	725.64	673.42	582.80	477.38
Nov	598.05	609.57	82.51	6807.10	208.14	995.82	787.67	697.52	644.53	558.85	454.85
Dec	649.87	659.77	89.39	7990.79	253.50	1035.14	781.64	760.13	699.37	604.20	488.42

Table 1 Ausgrid data normalized to 5kWh, solar production in kWh. 3-year average of 300 homes in Ausgrid catchment including seasonal and monthly mean, median, standard deviation, minimum, maximum, 95, 75, 25 and 5 percentiles.

Figure 8 demonstrates the distribution and the range of solar production by season. The data shows that the daily power production period is longest in summer (6.30am to 8pm, with a peak at 2pm). The daily median average in summer is above 20.55kWh, with just over 0.7333 kWh, per half hour, for 90 days, well below the full potential of 2.5kWh per half hour. The maximum production rate is in January at

34.36kWh, which represents 1.22kWh per half hour, just half the theoretical maximum production rate of 2.5kWh.

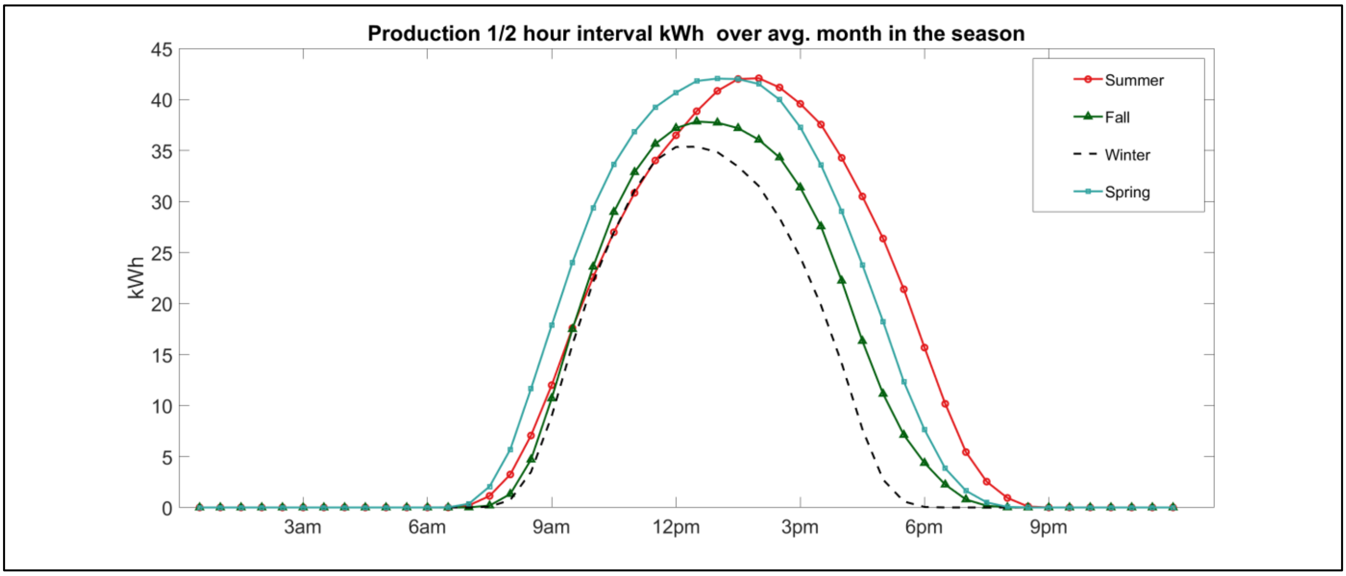


Figure 8 Median solar production by season, represented as average monthly production, by the time of day (half-hour intervals).

Table 2 represents the descriptive consumption data for all 300 customers. Unlike the production data, this dataset has not been adjusted, as the model assumes that consumption has not changed over the last 8 years. Each monthly period represents the individual customer average for that period over 3 years. This distribution represents the total average monthly consumption data per customer, using the average accumulated consumption over 48 time periods per day (half-hour periods in a day).

	Monthly kWh Consumed of 300 homes on Ausgrid Network										
Year Part	Mean	Median	Std.Dev	Variance	Min	Max	Range	95% Percentile	75% Percentile	25% Percentile	5% Percentile
AllYear	554.51	501.67	257.78	66449.50	64.68	1978.05	1913.37	1033.79	702.83	352.84	239.53
Summer	511.82	470.65	227.87	51925.46	64.68	1523.50	1458.82	939.10	660.22	326.94	219.34
Autumn	515.94	470.07	219.74	48286.46	149.14	1586.44	1437.30	918.78	653.55	346.06	233.75
Winter	693.03	625.80	308.21	94996.00	91.56	1978.05	1886.49	1261.68	893.11	462.67	304.91
Spring	497.27	451.22	212.15	45009.04	87.22	1257.01	1169.80	890.57	642.46	324.61	232.88
Jan	543.42	500.28	246.97	60995.14	169.60	1523.50	1353.90	1007.64	694.77	338.04	235.73
Feb	488.31	435.66	211.76	44843.14	64.68	1088.24	1023.56	886.91	633.68	314.31	208.35
Mar	487.37	444.03	206.00	42437.11	153.28	1071.08	917.80	872.28	627.67	330.39	217.80
Apr	476.55	438.52	196.12	38463.11	149.14	1049.85	900.71	857.78	612.01	321.78	223.69
May	583.91	527.67	239.31	57271.43	160.00	1586.44	1426.44	1029.48	755.05	406.53	262.51
Jun	677.12	608.16	299.67	89800.01	105.78	1972.92	1867.14	1219.16	850.42	463.04	284.42
Jul	740.03	675.03	329.32	108449.74	93.60	1978.05	1884.45	1316.24	946.16	487.61	312.16
Aug	661.93	598.00	289.71	83932.75	91.56	1840.89	1749.33	1168.73	822.48	439.82	309.46
Sep	515.16	465.90	219.93	48370.76	87.22	1148.49	1061.27	922.61	663.81	331.00	250.22
Oct	494.44	449.26	209.32	43816.88	138.99	1257.01	1118.03	868.57	638.86	324.81	240.39
Nov	482.20	441.08	206.36	42583.50	116.28	1238.95	1122.68	871.71	609.44	321.77	219.47
Dec	503.72	455.83	220.60	48662.82	159.91	1162.24	1002.33	915.09	666.42	331.43	222.63

Table 2 Ausgrid data showing consumption in kWh. 3-year average of 300 homes in Ausgrid catchment including seasonal and monthly mean, median, standard deviation, variance, minimum, maximum, 95, 75, 25 and 5 percentiles.

Table 3 focuses on the average consumption for each time period, which generates different results than focussing on the average consumption per customer. Whereas the mean consumption is the same, the median consumption is 80-100 kWh less than the mean during each time period, making the data right skewed for consumption. The data also illustrates that consumption is greatest in the winter months (June, July and August in the southern hemisphere). This can be clearly seen in Figure 9 which shows median consumption as a line graph. Further analysis of average monthly median consumption by time period, and by season, is shown in Figure 10, which illustrates significant differences in winter consumption in the morning and evening as compared to the other seasons, whereas early morning and pre-dawn show the least difference when compared to other seasons.

Monthly kWh Consumption based on timeperiod consumed in 48 time periods 300 Homes in 3 Year Period.											
	Mean	Median	Std.Dev	Variance	Min	Max	Range	95% Percentile	75% Percentile	25% Percentile	5% Percentile
Jan	543.42	440.85	363.82	3261.95	109.46	2454.69	2454.69	1287.81	663.76	304.96	185.97
Feb	488.31	404.82	321.63	2518.30	60.04	2217.27	2217.27	1130.01	594.37	278.00	168.06
Mar	487.37	394.49	333.34	2801.84	88.95	2332.47	2332.47	1151.65	585.96	280.38	173.93
Apr	476.55	383.71	318.83	2687.76	95.51	2189.39	2189.39	1136.26	571.46	274.87	171.48
May	583.91	465.40	410.88	4297.09	93.52	2679.55	2679.55	1433.07	700.40	319.91	188.84
Jun	677.12	533.18	485.09	5624.69	31.02	2998.19	2998.19	1680.77	839.01	353.34	195.56
Jul	740.03	589.31	529.96	6654.77	29.48	3274.43	3274.43	1810.41	930.63	380.99	210.90
Aug	661.93	516.95	478.30	5544.61	27.59	3052.39	3052.39	1652.12	817.47	347.20	200.14
Sep	515.16	407.95	364.99	3487.78	24.88	2386.10	2386.10	1259.70	621.38	283.19	172.98
Oct	494.44	399.79	334.71	2948.10	89.87	2287.61	2287.61	1175.45	592.71	281.35	176.41
Nov	482.20	394.35	329.30	2831.36	90.34	2217.82	2217.82	1136.67	579.96	271.07	167.66
Dec	503.72	404.89	341.69	2996.04	94.15	2307.35	2307.35	1199.32	607.18	285.02	176.48

Table 3 Monthly consumption based on 48 time periods in the day on 300 homes over 3 years by month in kWh

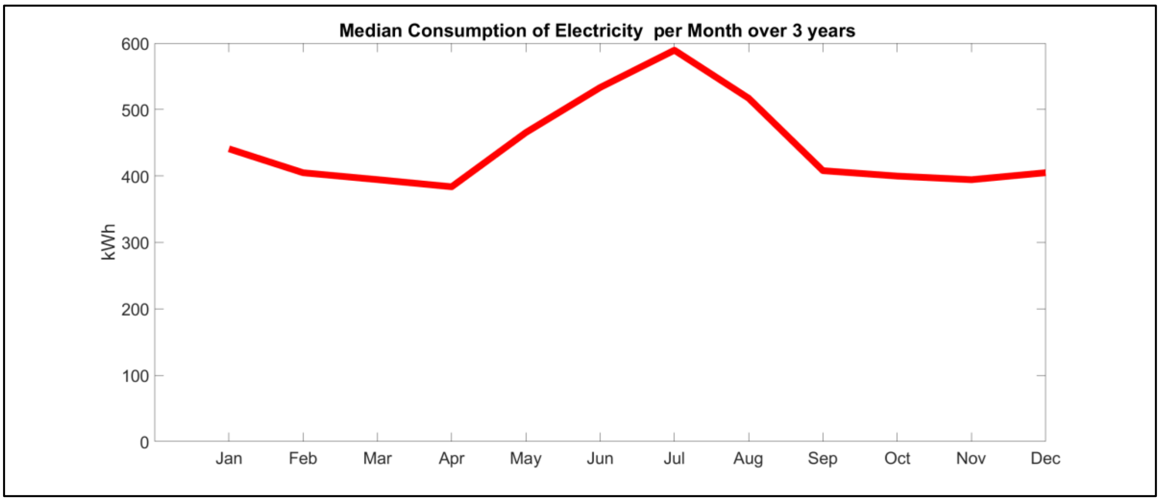


Figure 9 Median electricity consumption, by month, over a 3-year period. Consumption is highest in winter months.

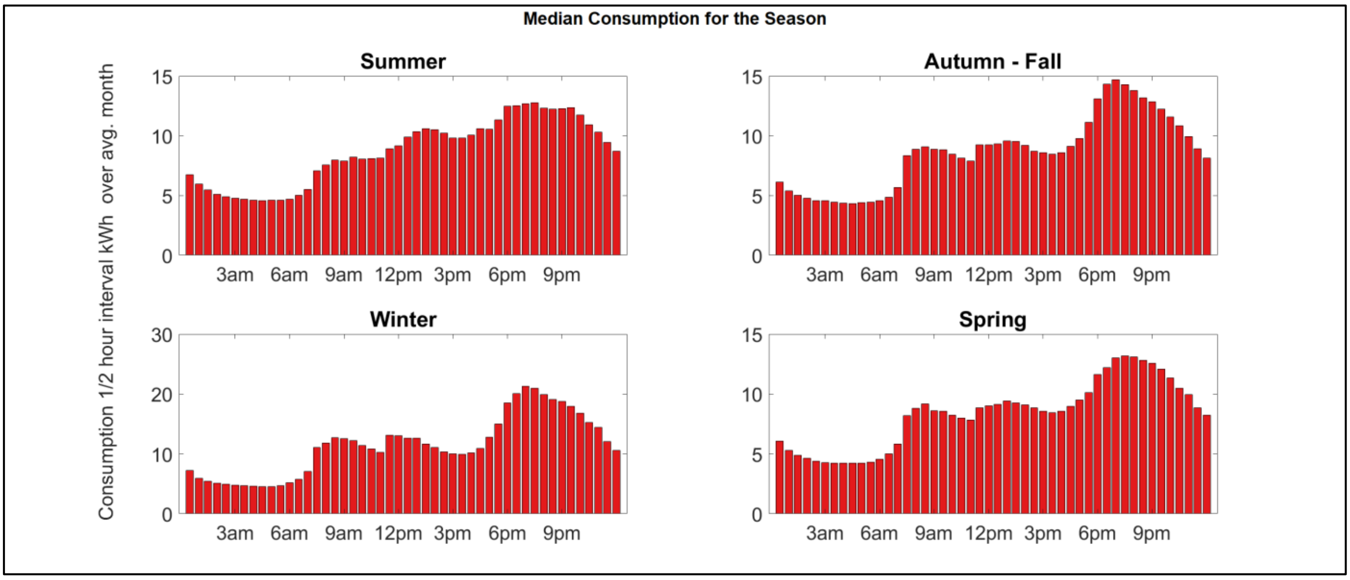


Figure 10 Seasonal average median consumption during the day. Winter 'y' axis altered to represent greater consumption.

In the original Ausgrid data set, some customers had controlled consumption for off-peak usage in order to incentivise those customers to use electricity when it is cheap for the supplier. Prior to the installation of solar cells, this period generally occurred during the early morning period between 1am and 4am. The model in this thesis shifts this known controlled data by 12 hours, to the afternoon period, so that the controlled consumption is during the period when solar electricity is produced and prices paid by the PPA aggregator are lower than the grid prices. *Figure* 11 illustrates the impact of the four seasons of the year on net production, and in particular, the negative effects of winter.

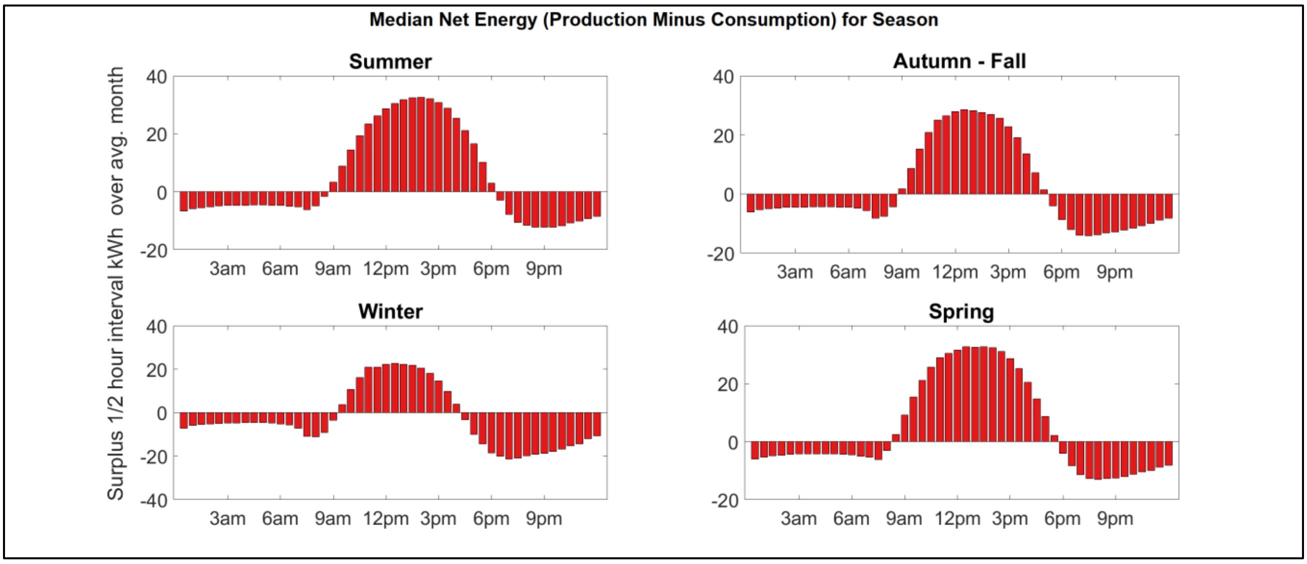


Figure 11 Daily median net production of electricity (half-hourly median solar production – half-hourly median total consumption), by season. Daytime net production is positive in all seasons, but weakest in winter.

The effect of winter on production and consumption is also shown in Figure 12 which highlights that consumption is far greater than production and that households are dependent on the grid for their total consumption.

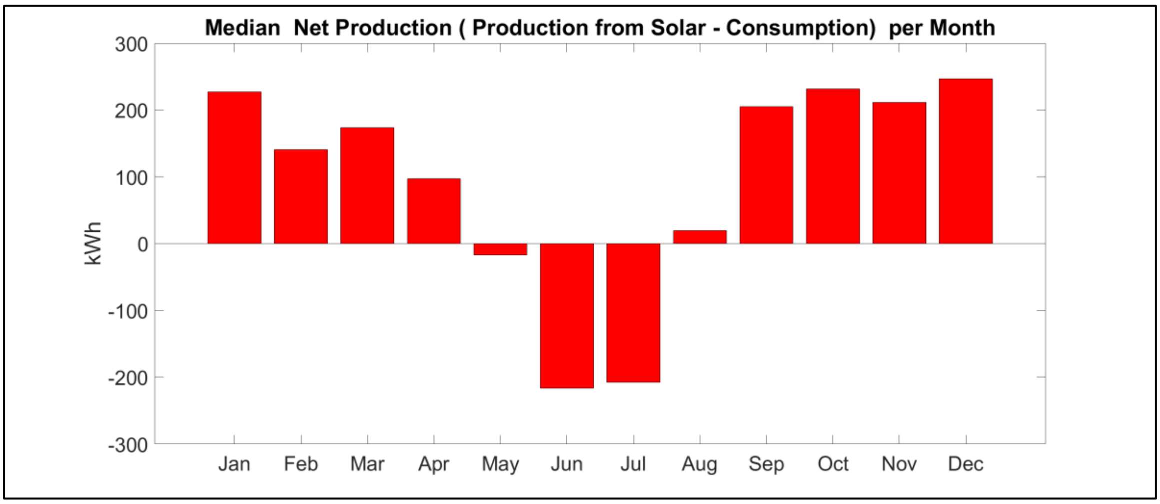


Figure 12 Monthly median net production of electricity (monthly median solar production – monthly median total consumption)

The time-of-day and seasonal differences also demonstrate the opportunities created by adding a battery package to the model simulation. The consumption and production data demonstrate that Ausgrid customers consume greater amounts of electricity in the winter, with the peak consumption time being in the early evening; and that solar production is greatest in the summer and during the early part of the afternoon. While neither of these observations are surprising, the data clearly demonstrates the lost revenue opportunities for the aggregator if they cannot supply electricity in the evening. Using a battery to transfer the daytime “overproduction” to consumption in the evening is highly beneficial to the aggregator, and if the price is lower than the grid price, then the consumer also benefits.

4.2 Controlling Variables.

Table 4 represents the controlling variables and assumptions used in the model to evaluate the viability of PPAs. They are based on current values in the marketplace. However, the values of each variable can be altered to assess different scenarios. The first six variables in Table 4 (bond term, electricity price discounts, default rates and interest rates) are the key elements tested in the two Scenarios explored in Chapter 5.

In Scenario 1, the base case bond term of 18 years is utilised, as the expected life of solar PV cells is 25 years (Winaico 2018). In Scenario 2, the base case bond term is reduced to 13 years to reflect expected battery life (Tesla 2017).

The retail electricity price has been obtained from the Australian Competition and Consumer Commission (2018, p. 8 and p15) as the average price in NSW for 2017-18. The base case discount rate of 20% on that retail price is used, as it is assumed that consumers are unlikely to take up a PPA at lower discount rates given that power consumers tend to be static in nature: “approximately 37% of retail Australian electricity customers have not searched for a better offer in the last 5 years” (Australian Competition and Consumer Commission 2018, p. 236)

The customer default rates are based on a conservative approach to credit ratings, which employs a disconnection rate of 0.9% and assumes the number of customers in NSW on debt Hardship Programs to be 0.83% (Australian Energy Regulator 2017, p. 35 and p 44); which brings with it an assumed default rate of 1.73%. When conducting stress testing on the security, the model doubles the default rate to 3.46% and assumes that the correlation of the defaulting customer to other customers on the PPA is 3%. It applies this high default rate in order to test the viability of the product for a low-income customer market which may engage a high credit risk.

The base case interest rate on each of the three investment tranches is based on the Bank Bill Swap Rate (BBSW), which has a similar market function in Australia to LIBOR in other markets and was obtained from the ASX (2018). The BBSW has been adjusted for each tranche to reflect the assumption that tranche A has an AA rating, tranche B has a BBB rating, and tranche C – the aggregator's own investment – has a B rating, based on the Standard and Poor's Rating index. This means that tranches A and B are investment-grade, while tranche C is junk bond quality. The model assumes that the rates are fixed throughout the bond term.

Variables and Assumptions	Values
Term in Years of Bond and PPA Contract	18
Discount % to Retail Electricity Price	20%
Customer Default Rate p.a	1.73%
Tranche A Basis Points above BBSW6	200
Tranche B Basis Points above BBSW6	400
Tranche C Basis Points above BBSW6	600
Cost of 5kWh Solar PPV with Inverter	$5,000
Cost of Battery with Inverter (Tesla PowerWall2), assumed 25% discount	$6,525
Retail Electricity Price, excl GST	$0.2852
Feed-in-Tariff – Day	$0.0720
Feed-in-Tariff - Evening	$0.2090
Tranche A % of the Deal	80%
Tranche B % of the Deal	15%
Tranche C % of the Deal	5%
Reinvestment Rate of Net Revenue - Cash Rate	1.5%
Customer Correlation to Defaulting Customer	3.00%
Solar Degradation Rate - Year 1, per month	0.21%
Solar Degradation Rate - Year 2 onwards, per month	0.06%
Battery Degradation, per month	0.29%
Fee Rate p.a.	0.50%
Bank Bill Swap Rate 6mths (BBSW6)	2.12%
Battery Capacity, kWh	13.5
Number of Customers	10,000
Maximum Battery Throughput Cycles, kWh	37,800

Table 4 Variables and assumptions applied in the model.

In NSW, depending on the service provider, the FiT rates during the day range from $0.1190 to $0.15 per kWh (Australian Competition and Consumer Commission 2018, p. 214). The model employs the rates recommended by the Independent Pricing and Regulatory Tribunal (2018, p. 6) to apply $0.072 per kWh from sunrise to 6pm, and $0.2090 per kWh in the early evening, and assumes a gross measurement method in calculations. Currently, the FiT during the day is between $0.08 and $0.15 but, as IPART suggests, the wholesale price during the day has decreased due to the impact of increases in solar production. In relation to evening rate, the model uses the rate suggested by IPART; however, it is noted that the recommended FiT in the state of Victoria is $0.29 (Department of Environment Land Water and Planning 2018). The model uses the more conservative values.

The model assumes that an aggregator purchasing 10,000 solar PV units in the Australian market would obtain a wholesale price, representing a significant discount from retail prices. The wholesale spot price for solar panels has been sourced from (PVinsights 2018), which suggests that the cost for the solar panels, inverter and installation is approximately $5,000.[4] The battery/inverter price has been obtained from Tesla (2018), as Tesla is currently the dominant player in the market. For the Tesla battery and battery inverter, the model assumes a wholesale price of 25% discount on the retail prices.

Solar panels and batteries have a degradation rate which results in a gradual reduction in the amount of electricity that can be produced and stored over time. The degradation rates used in the model have been sourced from the product warranties of solar panels sold by Winaico (2018) and battery products sold by Tesla (2017). The model also uses the Tesla PowerWall2 battery throughput life-cycle limit (Tesla 2017).

---

[4] Costs are based on the spot price of USD 0.294 per watt for high quality panel solar panels landed in Australia (including China VAT of 17%, shipping USD 0.015 per watt, and exchange rate AUD/USD 0.71), bringing the AUD amount to approx. $0.5056. When a wholesale margin of 10% is added, the assumed price per watt is $0.5562, and 5KW is $2,781. Inverter costs of $1000, and estimated warehousing, transport and installation costs of $1,200, result in a total price of approx. $4,981.

CHAPTER 5: RESULTS BY SCENARIOS

This chapter tests the financial viability of the securitization of a solar PV-only PPA securitization (Scenario 1) and a solar PV plus battery PPA securitization (Scenario 2). Each of these scenarios interrogates the following three questions:

1) *Are PPA consumers better off* purchasing electricity via a PPA than they are purchasing power off the grid? If so, by how much? What is the range of the benefit?
2) *Can a PPA aggregator generate a positive return* by selling the PPAs onwards to the investment community through securitization? If so, by how much?
3) *Can capital market investors generate a positive return* through the purchase of PPA securities? If so, at what rate?

To answer these questions, each scenario uses the variables discussed in Chapter 4 and shown in Table 4 as the base case, and manipulates the controlling scenario variables included in Table 5 below, namely: percentage discounts on the retail electricity price; the customer default rates; the interest rates applied to each investment tranche; and the term in years of the bond.

Key Scenario Variables.
Aggregator's Price Discount on Retail as %
Customer Default Rate as %
Interest Rate above BBSW6, Applied to Each Tranche
Term in Years of the Bond

Table 5 Variables tested in Scenarios 1 and 2

A successful outcome in the two scenarios will generate financial benefits for the PPA customer, aggregator and bondholder. A successful outcome for the PPA customer will be in terms of electricity billing savings. A successful outcome for the aggregator will be in terms of a positive net revenue after the bondholders have been repaid. For the bondholders, the key concern is that tranche A is fully repaid, in order to justify the "AA" rating; however, an overall successful outcome will have all bondholders being fully repaid.

A summary of all results can be found in Appendix A.

5.1 Scenario 1: Solar-only PPA Securitization

5.1.1 Base Case

The Scenario 1 Base Case uses the standard price discount, default rates, interest rates and bond terms set out in Table 4, in Chapter 4, which are applied and extracted below.

Scenario 1 Base Case Variables			
Tranche A Investment	$40,000,000	Tranche A Interest Rate	4.1214%
Tranche B Investment	$7,500,000	Tranche B Interest Rate	6.1214%
Tranche C Investment	$2,500,000	Tranche C Interest Rate	8.1214%
Gross Interest Rate	5.1214%	Fee	0.5%
Cash Rate	1.50%	NPV rate	10.0%
Discount to Retail Price		20%	
Default Rate		1.73%	
Term		18 Years	

Table 6 Scenario 1 Solar-only PPA, base-case variables

The results generated by the model demonstrate that all three bond tranches can be easily repaid. Customers will achieve 7.2% overall savings on their electricity bills and, over a period of 18 years, an NPV saving of nearly $900. Figure 13 illustrates that the customer is, on average, better off by $110 over the first year, as compared to accessing power solely from the grid. The relatively low savings can be explained by the high power consumption in the early morning and in the evening where there is little, or no, solar power generated - requiring customers to source their power from the grid (see Chapter 4 for further details).

Scenario 1 Base Case Results	
NPV savings for consumer over 18 years	$896
Overall consumer bill savings	7.20%
NPV revenue for the aggregator	$17,503,527
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Table 7 Scenario 1 Base Case results show strong return for the aggregator after all tranches fully repaid.

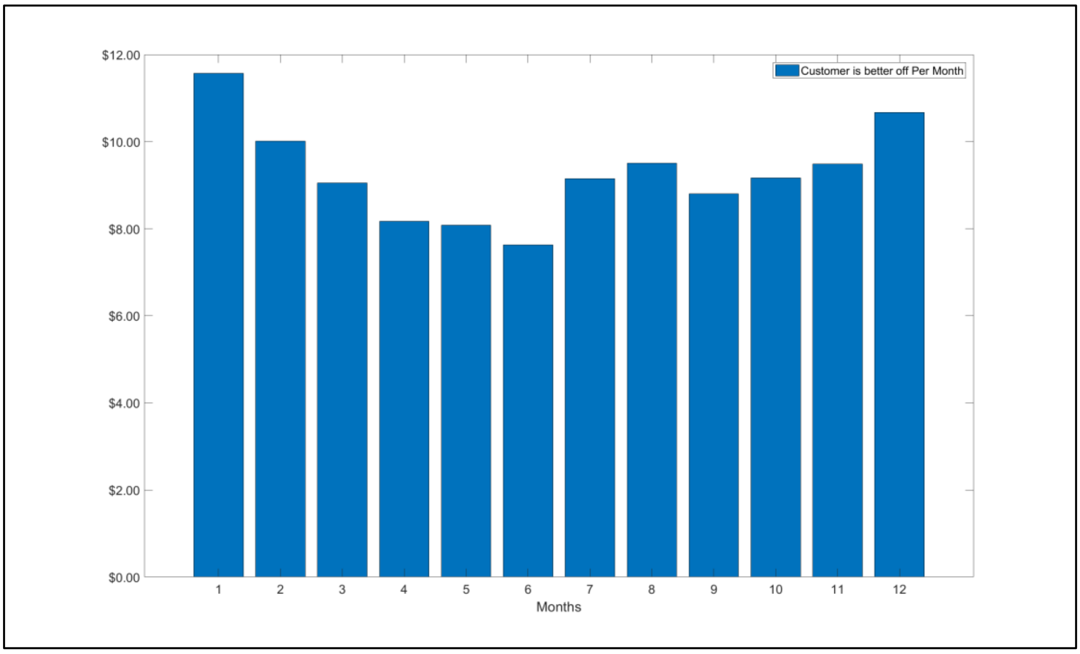


Figure 13 Savings for consumers, per month, in Year 1, Base Case (20% price discount). Average savings of $110 over the year.

Figure 14 shows that the bond repayments placed no pressure on the aggregator, which accumulates an NPV revenue of $17.5 million with a 10% return, excluding the interest earned on the principal of tranche C. The aggregator is therefore in a position to offer further price discounts to the customer.

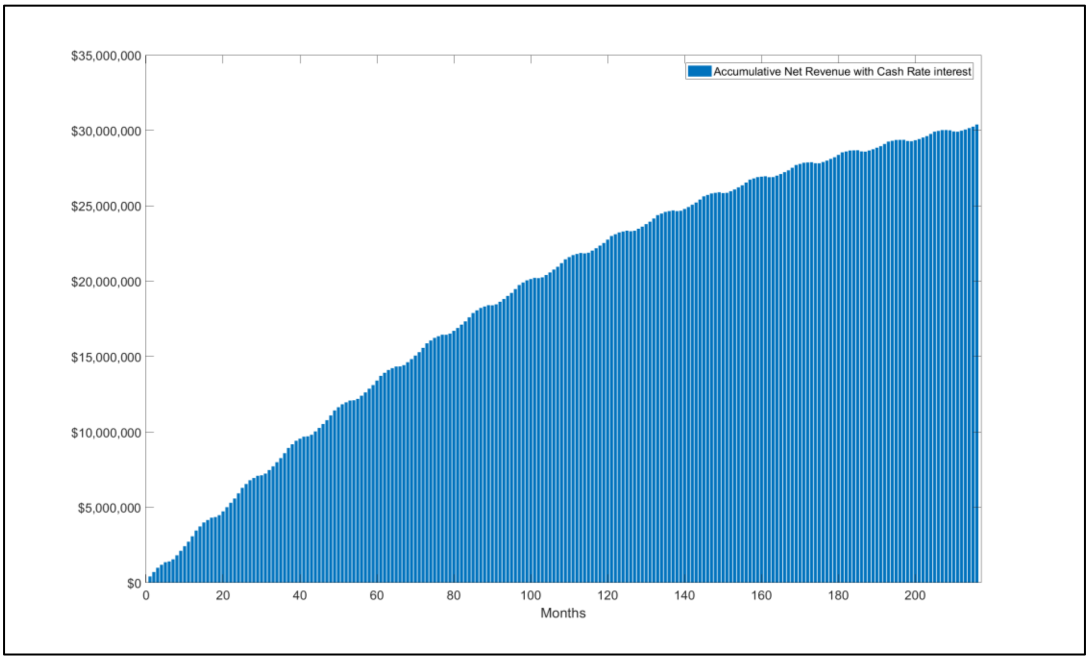


Figure 14 Accumulative Net Revenue with Cash Rate interest. Scenario 1 Base Case.

5.1.2 Increased Power Price Discounts

Kulatilaka, Santiago and Vakili (2014) highlight the importance of offering PPA customers prices significantly lower than the retail power price in order to prevent customers defaulting on the PPA and moving back to the grid. The purpose of case 5.1.2 is to establish the maximum viable discount on retail electricity prices that can be offered to consumers under the PPA.

The base case results in section 5.1.1 demonstrated that a 20% discount on retail prices for power supplied by the solar panels resulted in overall customer savings of just 7.2%. This level of savings may not be sufficient to incentivise a switch to PPAs, given that power consumers tend to be static in nature, as discussed in Chapter 4.

Case 5.1.2 tests whether the price discount on the power supplied under the PPA can be increased beyond 20% given that the overall discount experienced by the customer is low at just 7.2%, and the aggregator receives a large NPV of $17.5 million. The discount is increased significantly due to the substantial cushion provided by the large NPV at a 20% discount. Thus the next discount rate tested is 45%, and given the positive results at 45%, a further discount of 55% is then tested to explore at what point the bond can be repaid and the aggregator’s NPV revenue remains positive.

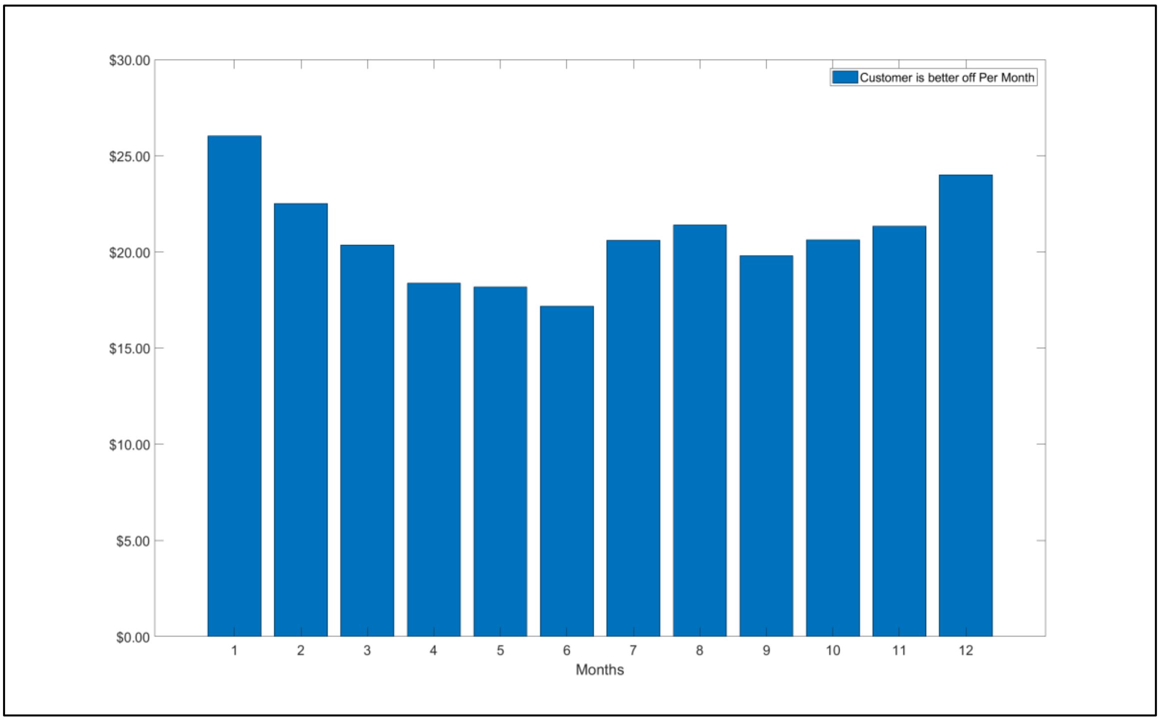
The results of this scenario have generated a successful outcome for all parties. The investors of all tranches are fully repaid under both discounts, the customer is better off, and the aggregator achieves positive revenues.

Scenario 1 Results – 45% Retail Price Discount	
NPV savings for consumer over 18 years	$2,016
Overall consumer bill savings	16.20%
NPV revenue for the aggregator	$7,209,400
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Scenario 1 Results – 55% Price Discount	
NPV savings for consumer over 18 years	$2,464
Overall consumer bill savings	19.80%
NPV revenue for the Aggregator	$2,943,100
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Table 8 Scenario 1 Increase retail price discounts to 45% and 55%. NPV consumer savings of $2,000-2,500 (17~19% off prior bills). All tranches fully repaid. Positive NPV revenue for the aggregator.

Table 8 and Figure 15 illustrate that a 45% discount on the power supplied under the PPA results in an average $245 savings for the customer in the first year of the PPA, or an NPV over 18 years of $2,016, compared to retail electricity supply, which is equivalent to an average 16.2% discount per annum. A 55% retail price discount results in the customer being better off by an average $299 in the first year, or an NPV over 18 years of $2,464, which amounts to 19.8% savings on average.



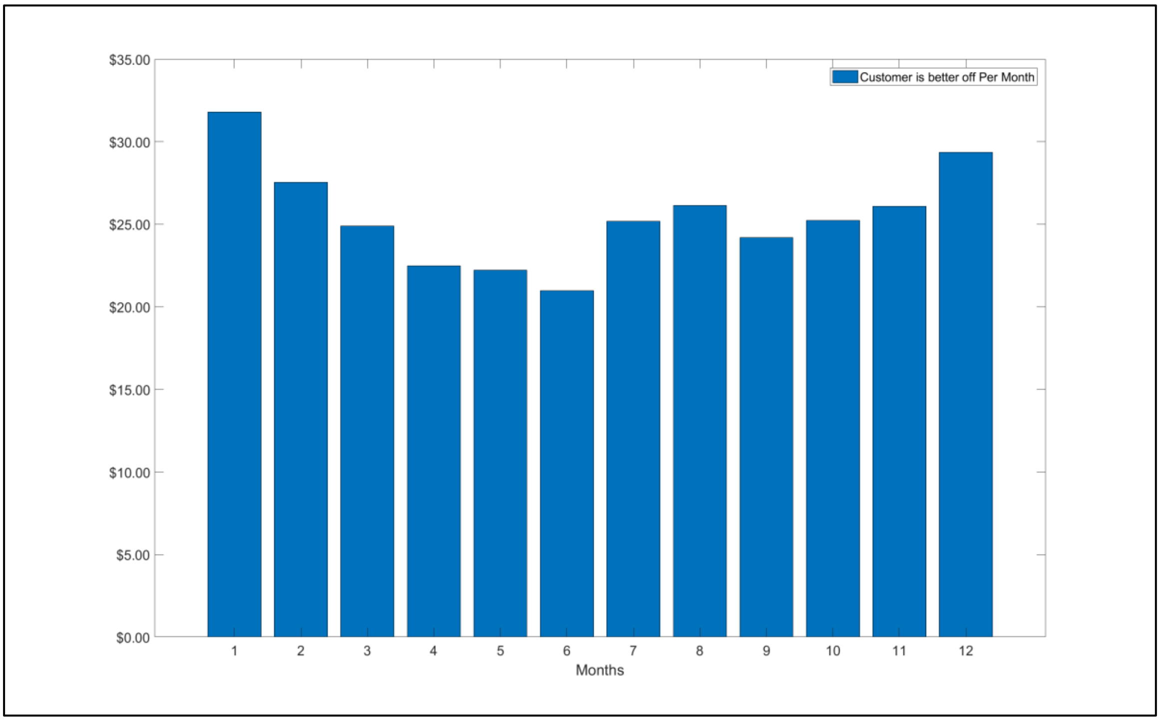
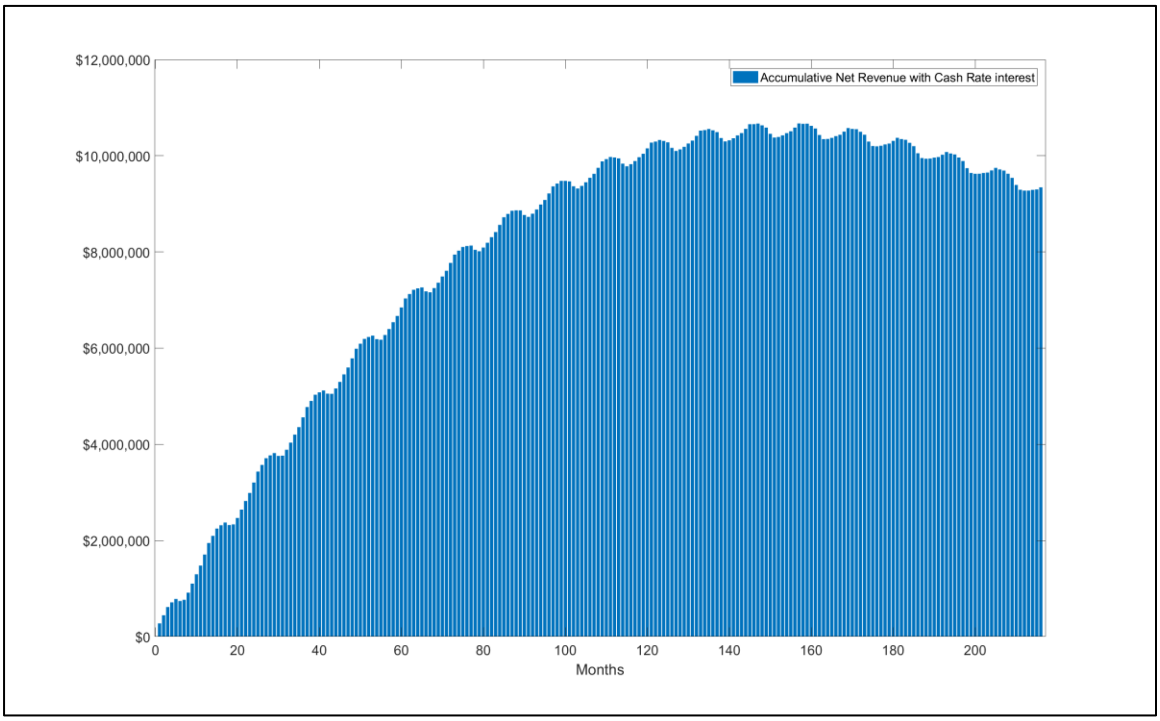


Figure 15 Savings for consumers per month, for the first year, 45% and 55% price discount. Average savings of $245 at 45% and $299 at 55%, over the year.

Figure 16 and Table 8 illustrate that the aggregator can offer a 45% discount to households and still achieve a 10% internal rate of return, amounting to an NPV return of $7.2 million dollars after 18 years. If the discount is increased to 55%, the aggregator can earn net revenue of $2.94 million, after all investment tranches are fully paid.



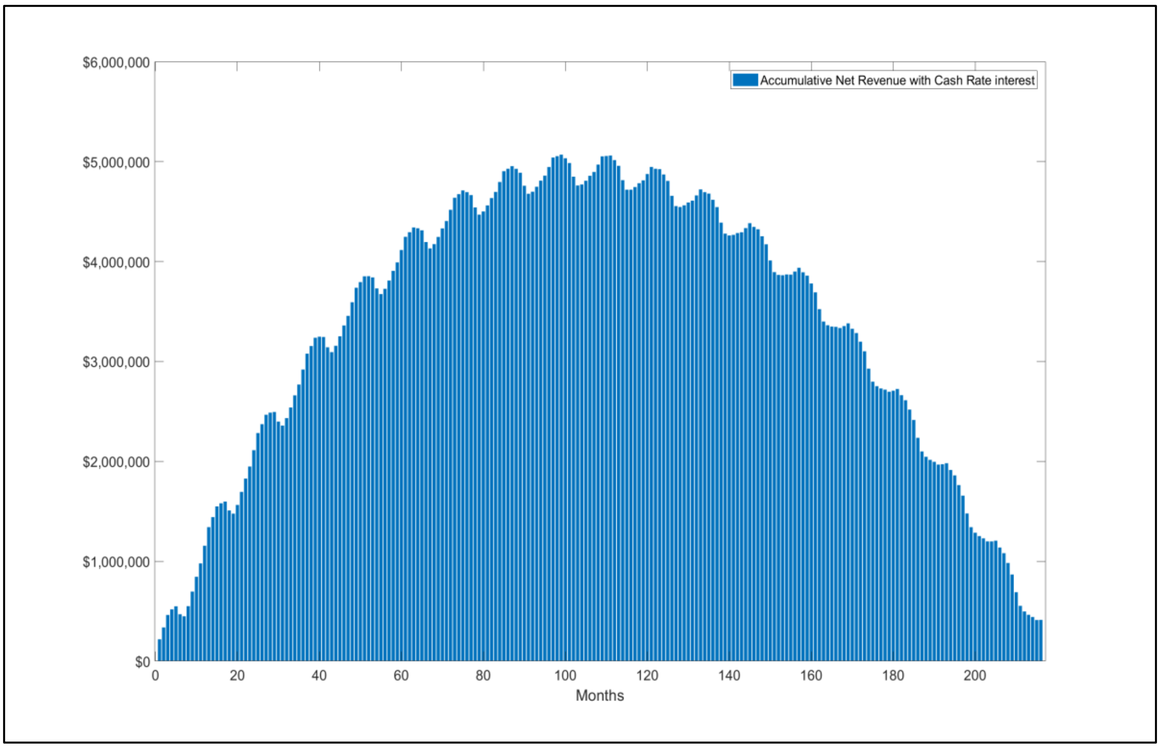


Figure 16 Accumulative Net Revenue with Cash Rate interest, 45% and 55% price discount.

5.1.3 Increased Default Rates

As discussed further in Chapter 6, one of the key benefits of a PPA is its capacity to open up the solar energy market to low-income consumers. It is, therefore, important to test the impact of engaging customers with lower quality credit ratings. Case 5.1.3 thus applies a strong stress test to the model by doubling the default rate to 3.46%.

The very high revenues earned by the aggregator in the base case make it clear that the increased default rates will not impact on the ability to repay all bond holders. However, the base case results also demonstrate that the 20% price discount did not generate significant benefits for the consumer, something that low-income customers are likely to seek. Thus, this case tests the impact of increasing default rates to 3.46%, at a 45% discount on the retail price.

Scenario 1 Results – 3.46% Default Rate, 45% Price Discount	
NPV savings for consumer over 18 years	$2,016
Overall consumer bill savings	16.20%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	Yes
Tranche B successfully paid	No
Tranche C successfully paid	No

Table 9 Scenario 1 Increase default rates to 3.46%, 45% price discount. Tranche A fully repaid, tranches B and C default.

Table 9 and Figure 17 highlight the effect of doubling the default rate and applying a 45% discount in price. The accumulative net revenue with interest earned by the aggregator is positive for 198 months of the 216-month term. This permits tranche A to be fully paid in month 186. However, tranche B defaults with 48.46% of the principal ($3.635 million) and 1.46%% of the interest ($110,500) unpaid. 100% of tranche C principal is unpaid and 7.01% of interest ($252,499) is unpaid before default.

Given that tranche B and C cannot be paid when a 45% discount is applied, this case is not tested at a 55% price discount, where a higher level of default could be expected.

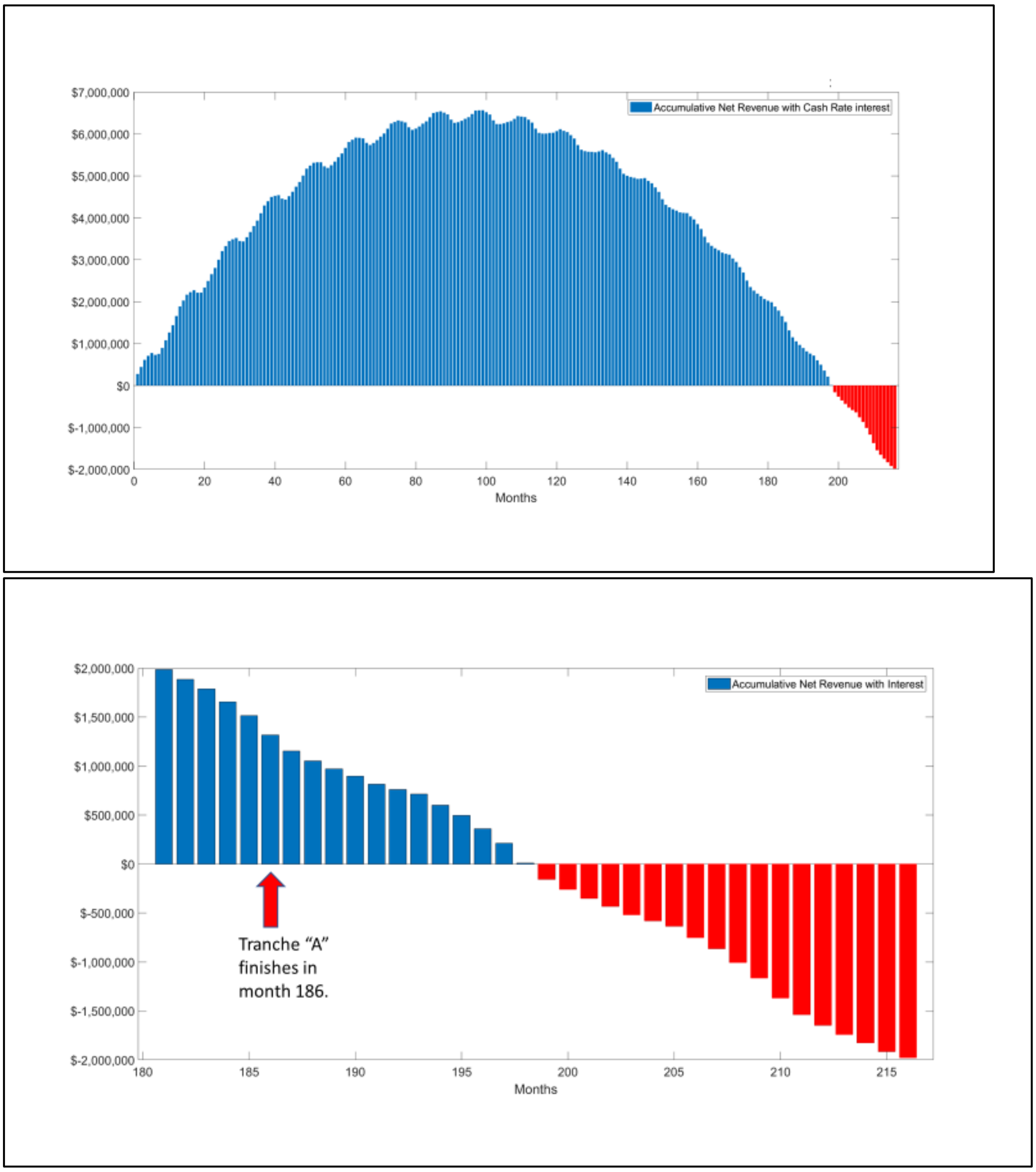


Figure 17 Accumulative Net Revenue with Cash Rate interest, 45% price discount, 3.46% default rate. Negative in month 199, after tranche A is fully paid.

5.1.4 Increased Interest Rates

Increasing interest rates could impact significantly on the aggregator's repayment costs and the ability of the bondholders to recoup their investment. Case 5.1.4 tests the impact of an increase of 150 and 200 basis points on the base case interest rates for each tranche. For the reasons set out in case 5.1.3 above, this case tests the impact of interest rate rises after a 45% retail price discount has been applied.

Results – 150 Basis Points Increase on all Tranches, 45% Price Discount	
NPV savings for consumer over 18 years	$2,016
Overall consumer bill savings	16.20%
NPV revenue for the aggregator	$2,930,000
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes
Results – 200 Basis Points Increase on all Tranches, 45% Price Discount	
NPV savings for consumer over 18 years	$2,016
Overall consumer bill savings	16.20%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	No
Tranche B successfully paid	No
Tranche C successfully paid	No

Table 10 Scenario 1 Increase interest rates by 150 basis points, 45% price discount - all tranches fully repaid. Increase by 200 basis points, 45% price discount – all tranches default.

Table 10 highlights that all investors are paid successfully upon an increase of 150 basis points for each of the tranches. However, the 150 basis points interest rate increase has a significant impact on the aggregator's earnings, which come down to $2.93 million. This is $4.27 million less than the $7.20 million earned when the 45% price discount was applied to the base case interest rate scenario in case 5.1.2 (Table 8).

When the interest is increased by another 50 basis points to 200 (or 2%), with a gross interest rate of 7.1%, Table 10 and Figure 18 illustrate that all tranches default, with tranche A defaulting in month 186 of the 190 month repayment period.

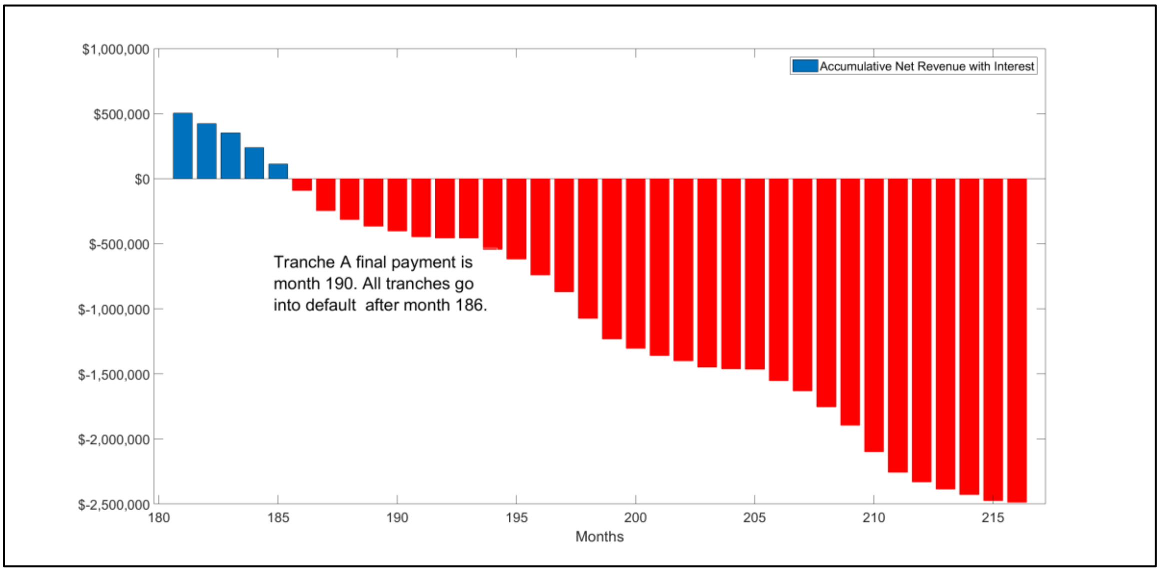


Figure 18 Accumulative Net Revenue with Cash Rate interest, 45% price discount, 200 basis points interest increase. All tranches default.

5.1.5 Reduced Bond Term

Case 5.1.5 tests whether it is financially viable to sell bonds with an 11-year term, rather than the base case of 18 years, with a view to attracting a broader range of investors, as suggested by Mendelsohn et al. (2015).

Case 5.1.5 therefore alters the base case bond term to 11 years. It then tests whether that bond term is viable when: (i) the price discount is increased to 30%; (ii) the default rate is doubled to 3.46%; and (iii) the interest rates are increased by 150 and 200 basis points.

Figure 19 demonstrates that, when an 11-year term is applied to the base case, tranche A can successfully mature in under 10 years - in this case at 111 months (9 and a quarter years) – and tranche B will mature at the end of 127 months. Table 11 shows that all tranches can be repaid and that the aggregator can earn an NPV revenue of $4.2 million. This suggests that an investment-grade security can be designed to address the concern of Mendelsohn et al. (2015).

Results – 11-year Term	
NPV savings for consumer over 11 years	$712
Overall consumer bill savings	7.20%
NPV revenue for the aggregator	$4,191,600
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Table 11 Scenario 1 Reduce bond term to 11 years. All tranches are paid.

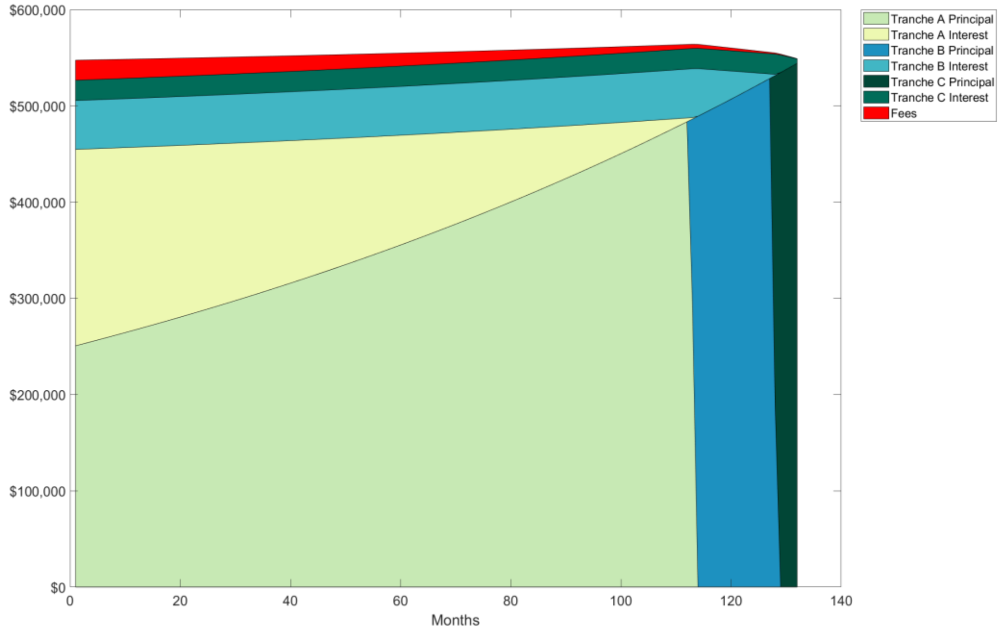


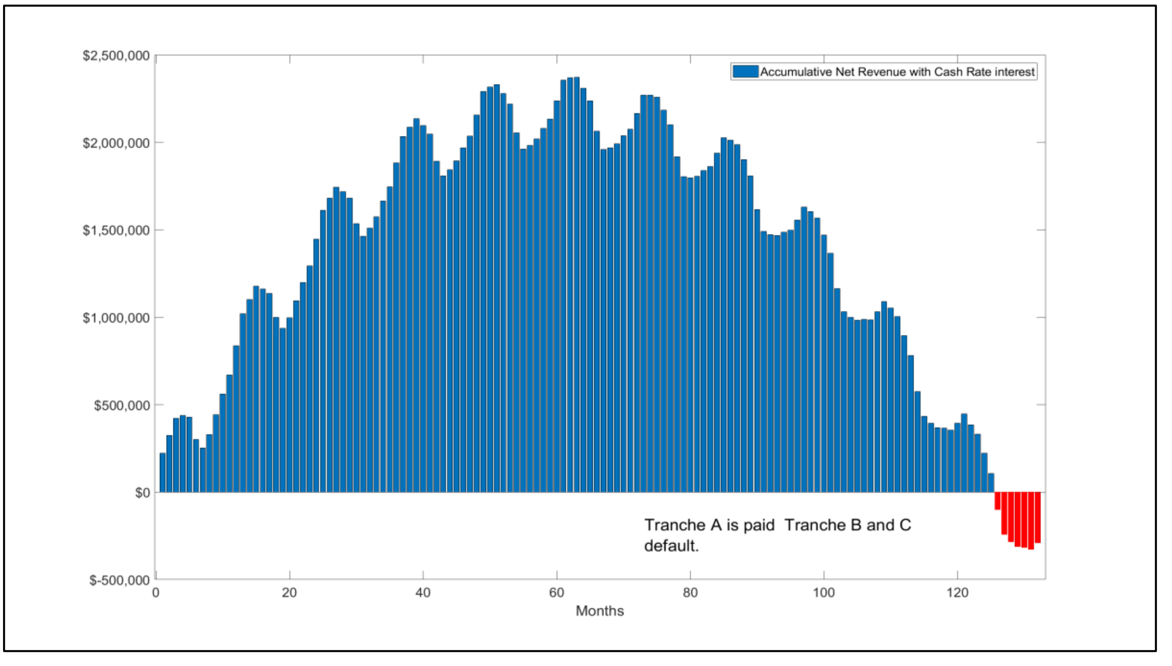
Figure 19 Payment of investment tranches, 11-year term. Tranche A paid in less than 120 months (i.e. under 10 years)

(i) Increasing the price discount on an 11-year bond term

As with base case 5.1.1, customers only achieve a 7.2% discount on their overall electricity bills when a 20% price discount is applied, and their NPV savings are reduced by $184, due to the shorter term. Table 12 demonstrates that, when a price discount of 30% is applied, the customer achieves 10.86% savings over the 11-year period. However, under these conditions only tranche A can be paid successfully, with tranche B and tranche C being in default, as illustrated in Figure 20.

Results – 11-Year Term, 30% Price Discount	
NPV savings for consumer over 11 years	$1,061
Overall consumer bill savings	10.86%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	Yes
Tranche B successfully paid	No
Tranche C successfully paid	No

Table 12 Scenario1 Reduce bond term to 11 years, 30% Price Discount. Tranches B and C default.



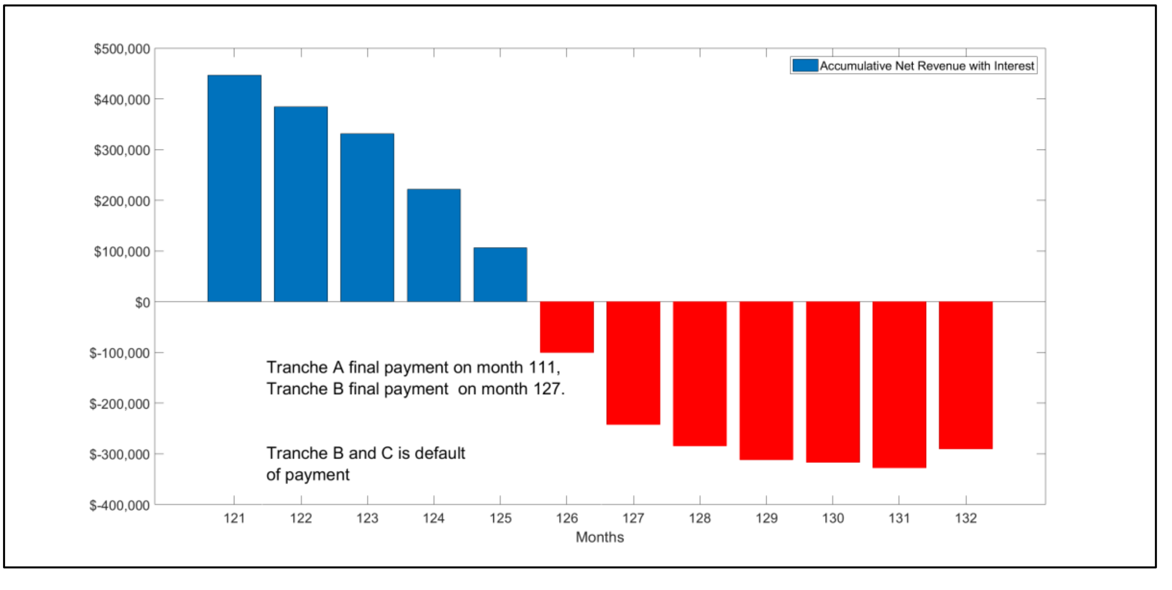


Figure 20 Accumulative Net Revenue with Cash Rate interest, 11-year term, 30% price discount. Tranches B and C default.

(ii) Increasing the default rate on an 11-year bond term

Table 13 and Figure 21 illustrate that, when the default rate is doubled to 3.46%, tranche A can be repaid by month 111 (i.e. in under 10 years). However, Figure 21 also illustrates that the aggregator's accumulative net revenue goes negative after month 123 and both tranche B and C go into default, with tranche B's final payment due in month 126.

Results – 11-Year Term, Default Rate of 3.46%	
NPV savings for consumer over 11 years	$712
Overall consumer bill savings	7.20%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	Yes
Tranche B successfully paid	No
Tranche C successfully paid	No

Table 13 Scenario 1 Reduce bond term to 11 years, 3.46% default rate. Tranches B and C default.

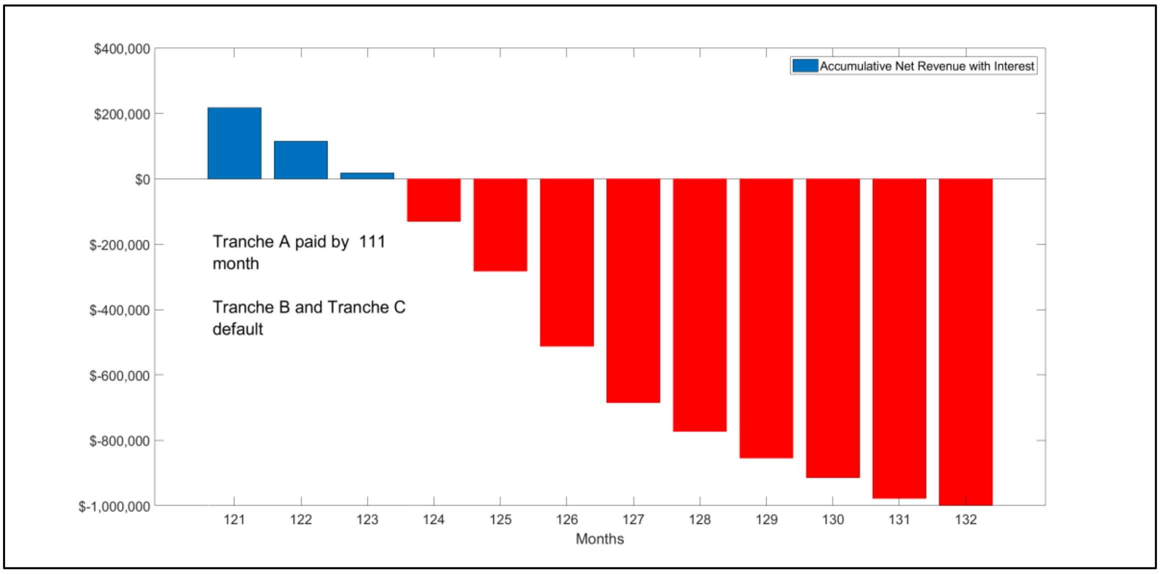


Figure 21 Accumulative Net Revenue in final year of 11-year term, 3.46% default rate. Tranches B and C default.

(iii) Increasing the interest rates on an 11-year bond term

Table 14 shows that all tranches can be repaid on an 11-year bond term in the event of a 150 basis points interest rate increase. However, Figure 22 illustrates the accumulative net revenue for the aggregator rapidly approaching zero in the last year of the bond term, suggesting that the viability of the bond under this scenario is marginal and any further increase in interest rates will lead to default.

Results – 11-year bond term, 150 basis points interest rate increase	
NPV savings for consumer over 11 years	$712
Overall consumer bill savings	7.20%
NPV revenue for the aggregator	$1,136,200
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Table 14 Scenario 1 Reduce bond term to 11 years, 150 basis points interest rate increase. All tranches fully repaid. Low NPV revenue.

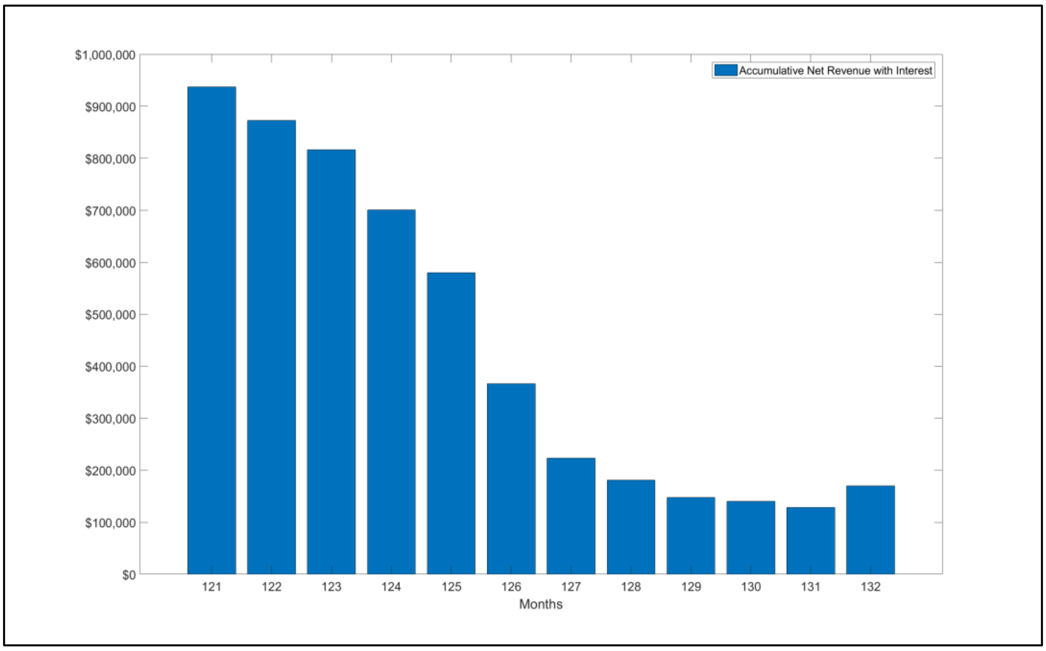


Figure 22 Accumulative Net Revenue with Cash Rate interest in final year of 11-year term, 150 basis point increase. Marginal business case.

Figure 23 illustrates that, when a 200 basis points increase is applied, the final payment for tranche A, due in month 113, can only be paid if the first principal payment owing to tranche B is sacrificed, as is required under a sequential CDO (see Chapter 2). This results in a 98.43% principal default of tranche B and 100% principal default for tranche C.

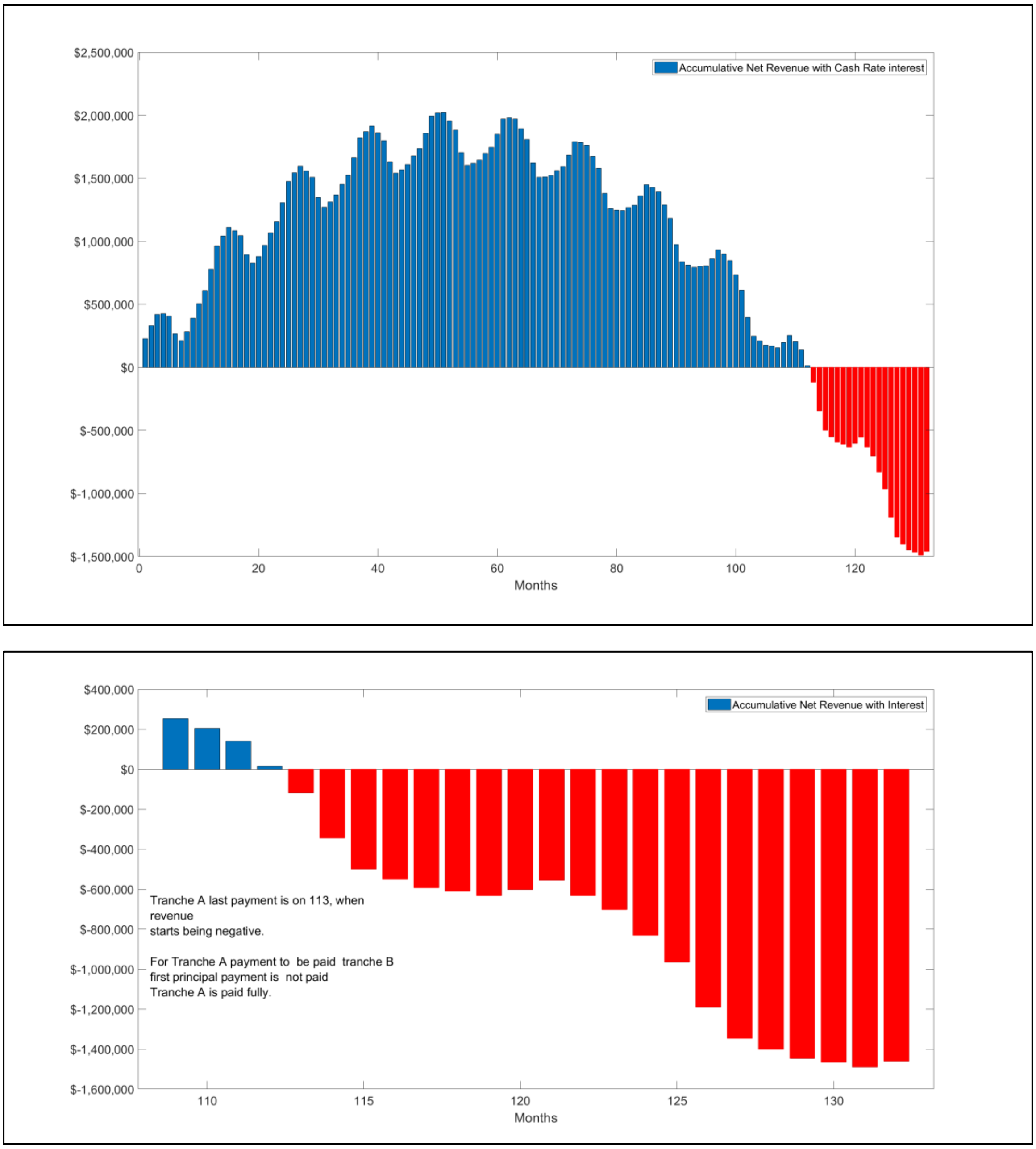


Figure 23 Accumulative Net Revenue with Cash Rate interest, 11-year term, 200 basis point increase. Tranche A paid out of tranche B principal payment sacrifice. Tranches B and C default.

5.2. Scenario 2: Solar plus battery PPA Securitization

Given the increasing prevalence of lithium-ion batteries in the marketplace, the significant impact that batteries can have in extending the period over which solar-generated power can be used, and the increased capacity to sell power back into the grid, it is important to test the feasibility and impact of including batteries in a PPA offering.

Under this Scenario 2, the investment capital to be raised under the bond increases by $65.25 million to cover the costs of the batteries and inverters for the assumed 10,000 customers. Table 15 reflects the increased amounts in each of the investment tranches.

5.2.1 Base Case

As illustrated in Table 15, the Scenario 2 Base Case uses the standard price discount, default rates, and interest terms applied in Scenario 1. The base case bond term has reduced from 18 years to 13 years to reflect the fact that the life of the battery is about half the life of the solar panels. The model takes a conservative approach by assuming that the battery expires after 38,700khW cycles as per the Tesla warranty, thereby limiting the bond period to 13 years.

Table 15 also notes the base case battery cost of $6,525 per customer, as this is an additional variable tested in this Scenario in case 5.2.3.

Scenario 2 Base Case Variables			
Tranche A Investment	$92,200,000	Tranche A Interest Rate	4.1214%
Tranche B Investment	$17,287,500	Tranche B Interest Rate	6.1214%
Tranche C Investment	$5,762,500	Tranche C Interest Rate	8.1214%
Gross Interest Rate	5.1214%	Fee	0.5%
Cash Rate	1.50%	NPV rate	10.0%
Discount to Retail Price		20%	
Default Rate		1.73%	
Term		13 years	
Battery Cost (Tesla PowerWall2)		$6,525	

Table 15 Scenario 2 Solar and Battery PPA, base-case variables.

The base case results set out in Table 16 illustrate failed outcomes for all parties other than the consumer, who achieves an overall bill of 17.7% despite the base case retail price discount being just 20%. This savings level is similar to case 5.1.2 in Scenario 1, where a 45% price discount on the solar-only PPA achieved a 16.2% customer saving and repaid all tranches.

Scenario 2 Results – Base Case	
NPV savings for consumer over 13 years	$1,913
Overall consumer bill savings	17.77%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	No
Tranche B successfully paid	No
Tranche C successfully paid	No

Table 16 Scenario 2 Base Case results. All tranches default.

The base case results demonstrate that the additional revenue generated by supplying electricity to the customer in the evening, and earning the evening FiT, cannot cover the additional capital required to purchase batteries at current prices. Figure 24 illustrates that the aggregator's net accumulative revenue is negative in month 98, with payments due to tranche A bondholders until month 133.

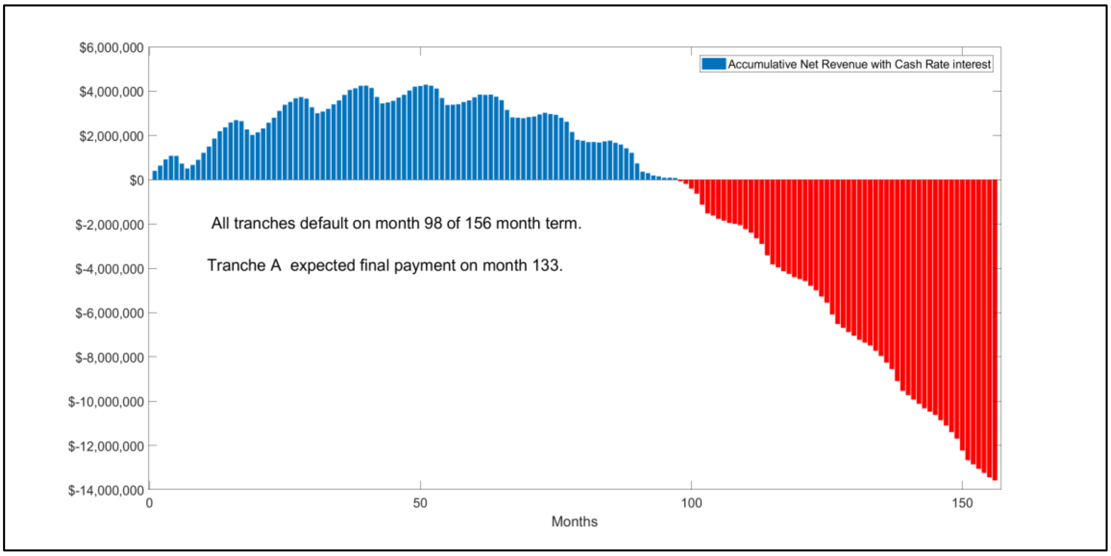


Figure 24 Accumulative Net Revenue with Cash Rate interest. Scenario 2 Base Case. All tranches default.

Figure 25 illustrates the impact of winter on the gross and net revenue earned by the aggregator. The bond is assumed to commence on 1 January, and the sharp dips in gross revenue occur in the winter months (June-August). When Figure 25 is read together with Figure 24, it can be seen that, during the first 97 months of the bond term, there is sufficient revenue to cover the tranche payments. However, the summer months in Year 8 (months 96-98) are no longer capable of generating a positive net revenue, as the customer default rate of 1.73% has resulted in the loss of more than 10% of the customers, leaving just 8,904 customers as a revenue source.

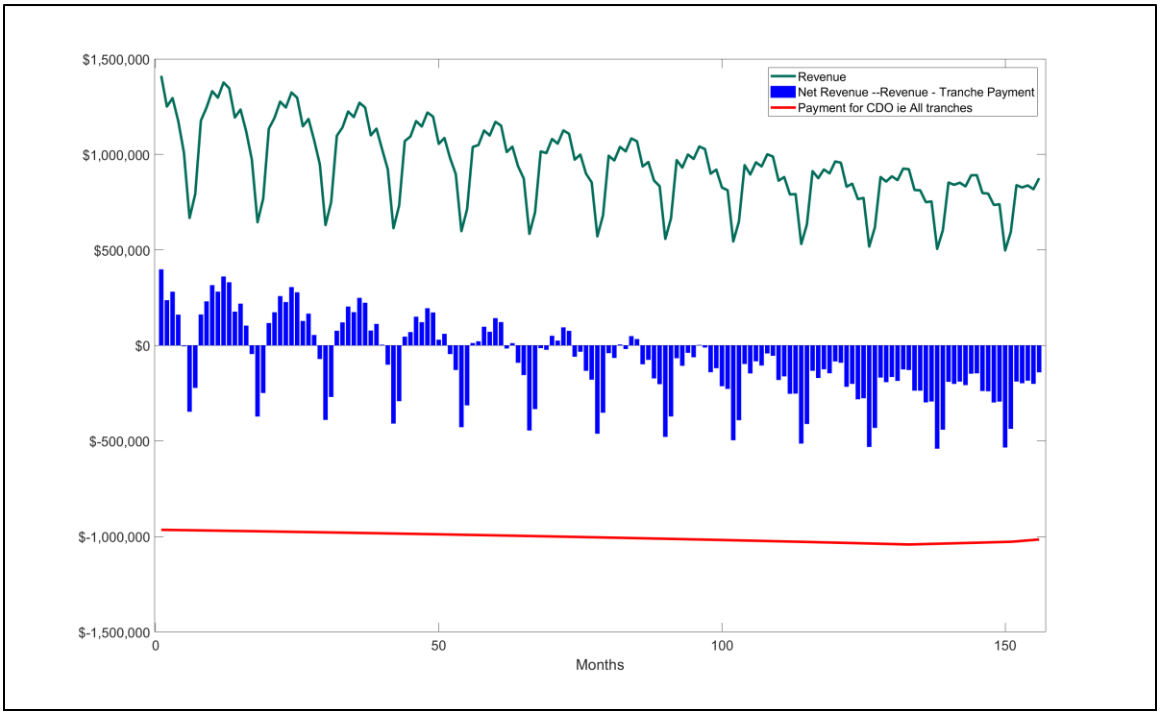


Figure 25 Revenue flows for Scenario 2 Base Case.

5.2.2 Decreased Default Rates

Due to the base case failure when a 1.73% default rate was applied, it is not relevant to test the impact of doubling the default rate to 3.46%, as occurred in Scenario 1. Instead, case 5.2.2 tests the impact of halving the default rate to 0.865% (which would exclude PPA customers with low credit ratings).

Figure 26 illustrates, however, that the application of this lower default rate is insufficient to prevent default of all three tranches, albeit that the tranche A bondholders would receive a greater proportion of the principal with default occurring at month 123 (10 year and 3 months), rather than at month 98 (8 years and 2 months) when the standard default rate is applied.

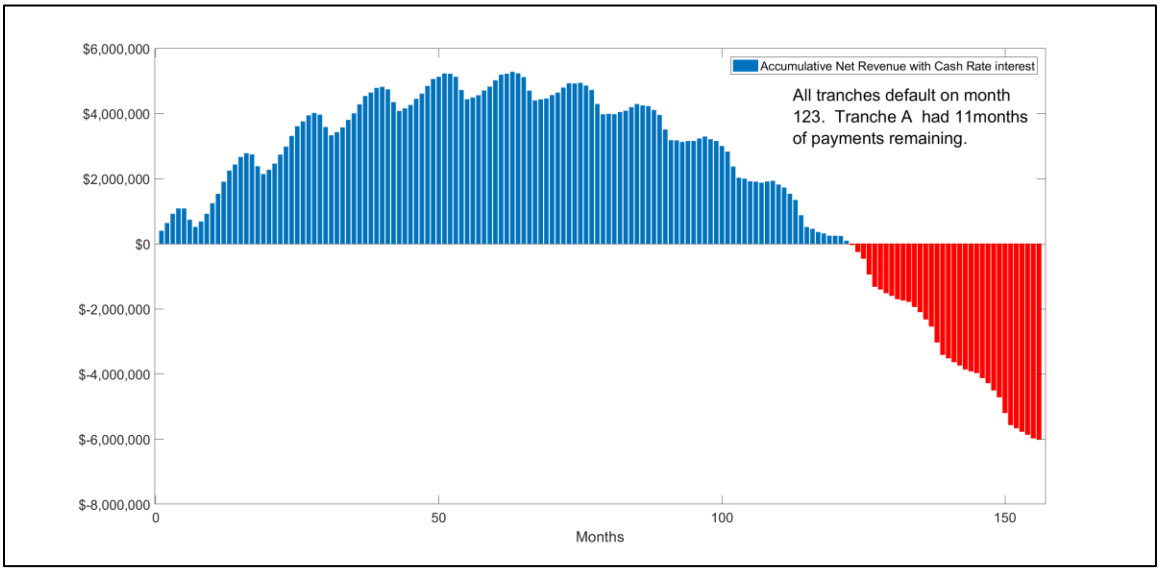


Figure 26 Accumulative Net Revenue with Cash Rate interest, 0.865% default rate. All tranches default.

Given that the bond is not viable upon the application of lower default rates, it is not relevant to test the impact of increased retail price discounts or increased interest rates, as both these circumstances would further weaken the business model. It is, therefore, clear that, given current battery prices and battery life, a solar PV and battery PPA is uneconomic.

5.2.3 Reduced Battery Costs

Case 5.2.3 tests the potential impact of anticipated reductions in battery costs. It applies a 1/3 decrease in battery price based on Yu (2018), which highlights that lithium-ion batteries are expected to decrease in price from $500 per kW in 2015, to $200 per kW around 2020~2025, and $150 per kW in 2030. When the 1/3 reduction in price is applied to the model, the battery cost per customer down to $4,350 and reducing the total capital required from $115.25 million in the base case to $93.5 million, as shown in Table 17.

The results in Table 17 demonstrate that these decreased capital costs generate a viable PPA. All investment tranches can be paid, the customer achieves savings of 17.77%, and the aggregator earns a NPV revenue of $13.76 million. It is, therefore, relevant to test the impact of changes to price discounts, default rates and interest rates.

Scenario 2 Variables and Results – 1/3 Decrease in Battery Price			
Tranche A Investment	$74,800,000	Tranche A Interest Rate	4.1214%
Tranche B Investment	$14,025,000	Tranche B Interest Rate	6.1214%
Tranche C Investment	$4,675,000	Tranche C Interest Rate	8.1214%
Gross Interest Rate	5.1214%	Fee	0.5%
Cash Rate	1.50%	NPV rate	10.0%
Discount to Retail Price		20%	
Default Rate		1.73%	
Term		13 years	
NPV savings for consumer over 13 years		$1,913	
Overall consumer bill savings		17.77%	
NPV revenue for the aggregator		$13,758,000	
Tranche A successfully paid		Yes	
Tranche B successfully paid		Yes	
Tranche C successfully paid		Yes	

Table 17 Scenario 2 Decrease battery price by one third. All tranches fully repaid. Aggregator NPV revenue produces large reserves.

(i) Increasing the electricity price discount to 25%

The bond remains viable upon application of a 25% discount to the retail power price. The results in Table 18 show that all investment tranches can be paid, the aggregator earns an NPV revenue of $8.7 million, and the customer bill savings are 22.21%, representing an NPV saving of $2,391 dollars over 13 years.

Scenario 2 Results - 1/3 Battery Price Decrease, Increased Price Discount of 25%	
NPV savings for consumer over 13 years	$2,391
Overall consumer bill savings	22.21%
NPV revenue for the aggregator	$8,690,700
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes
Tranche C successfully paid	Yes

Table 18 Scenario 2 Decrease battery price by one third, 25% price discount. All tranches fully repaid. Substantial savings for customer. Strong NPV revenue for aggregator.

Figure 27 illustrates that, in the first year of the PPA, the customer will save an average of $335, with the greatest savings being in August and May, where there is high supply of sunshine but cold weather. These results can be compared to those in Scenario 1, case 5.1.2 where prices discounts of 45% and 55% are applied generating annual savings of $245 and $299, respectively, and savings are greatest in January and December, when solar production is high, the days are long and there is less dependence on the grid.

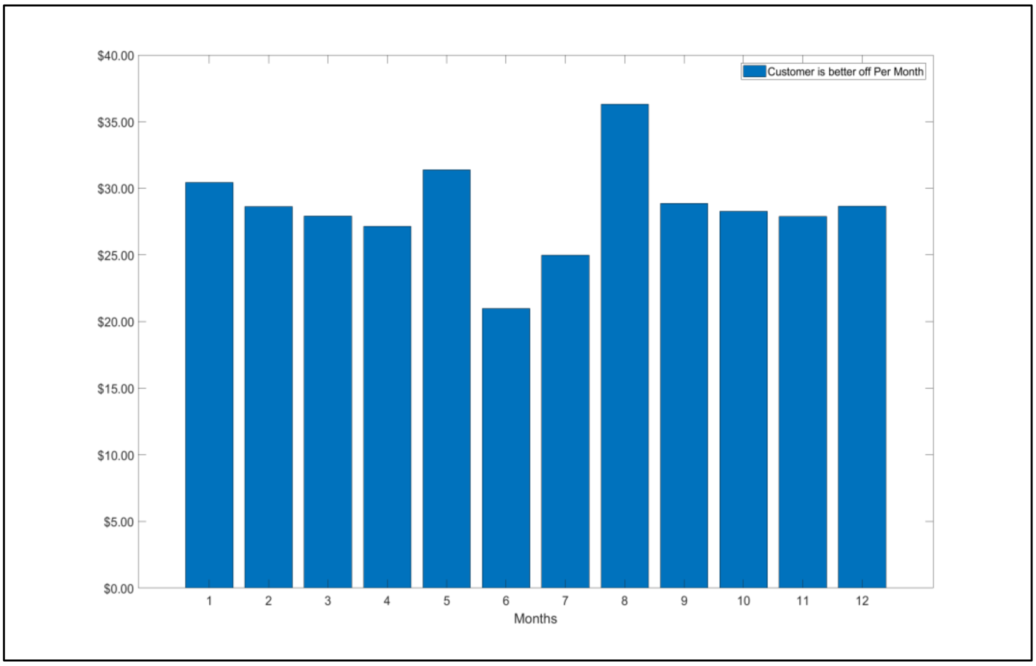


Figure 27 Savings for consumers, per month, in Year 1, 1/3 battery price decrease, 25% price discount. Average savings of $335 over year.

(ii) Increasing the default rate to 3.46%, price discount of 25%

The $13.7 milllion NPV revenue achieved by the aggregator under reduced battery prices and a price discount of 20% will be sufficient to ensure the viability of the bond upon the application of a 3.46% default rate. However, if a default rate of 3.46% is applied with a price discount of 25%, Figure 28 illustrates that the Accumulative Net Revenue of the aggregator is negative at month 136 of the 156-month term, with the result that tranche A can be fully paid at month 133, but tranche B and tranche C will default. For tranche B, $11.8 million of principal and $0.49 million of interest remains unpaid at default. For tranche C, 100% of the $4.675 million principal, and $0.589 million in interest, is unpaid.

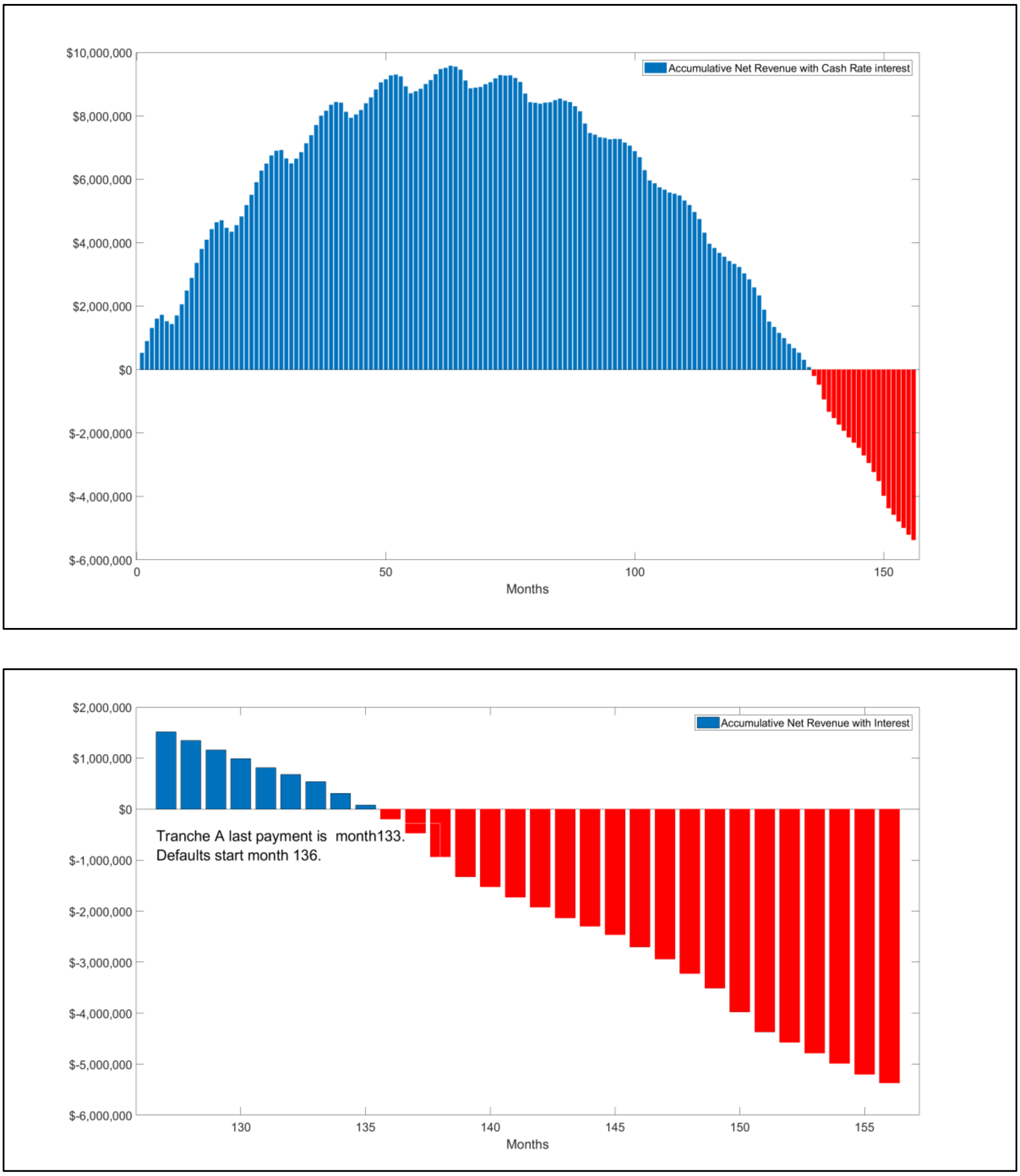


Figure 28 Accumulative Net Revenue with Cash Rate interest, 1/3 battery price decrease, 25% price discount, 3.46% default rate. Tranches B and C default.

(iii) Increasing the interest rate by 125 basis points, price discount of 25%

The $13.7 milllion NPV revenue of the aggregator under reduced battery prices and a 20% price discount will also be sufficient to support an interest rate rise of 125 basis points. However, Table 19 illustrates that, when the interest rate increases 125 basis points and a 25% price discounted is applied, tranche B will default with 2 payments remaining. As with scenario 5.1.5(iii), the sequential CDO requires tranche

C to sacrifice payments in order to satisfy the tranche B principal and interest obligations. These results suggest that any increase in interest beyond 125 basis points, where a price discount of 25% is applied, will put tranche B into default.

Scenario 2 Results - 1/3 Battery Price Decrease, 25% Price Discount, 125 basis point rate increase	
NPV savings for consumer over 13 years	$2,391
Overall consumer bill savings	22.21%
NPV revenue for the aggregator	Tranche default
Tranche A successfully paid	Yes
Tranche B successfully paid	Yes (final 2 payments from tranche C sacrifice)
Tranche C successfully paid	No

Table 19 Scenario 2 Decrease battery price by one third, 25% price discount, interest increase of 125 basis points. Tranche C defaults, tranche B repayment relies on tranche C payment sacrifice.

CHAPTER 6: DISCUSSION AND FUTURE DIRECTIONS

This chapter provides an overarching summary of the results generated by the two scenarios discussed in Chapter 5, and explores the policy implications of these results in the context of the financial and renewables markets. It also discusses some opportunities for further model adjustment and investigation.

6.1 Results Overview

The results in Chapter 5 demonstrate that there are circumstances in each of the two scenarios which generate positive economic outcomes for PPA power customers, PPA aggregators and PPA bondholders. These results suggest that, depending on the conditions, it is viable to use an ABS which securitizes a consumption-based revenue stream in order to fund the expansion of solar PV and battery packages in the residential and small-business market.

In the case of a solar-only PPA, Scenario 1 results demonstrate that the base case scenario, which applies a 20% price discount, generates a discounted revenue to the aggregator of $17.5 million over 18 years after repaying all bondholders. All bondholders can also be repaid if the base case is adjusted to an 11-year bond term, although the discounted revenue earned by the aggregator falls to $4.19 million. When the base case is adjusted to apply a 45% price discount, rather than a 20% price discount, all bondholders can be fully repaid even when interest rates increase by 150 basis points, but if the default rate is then doubled, only tranche A can be fully repaid.

Scenario 2 results demonstrate that the bond defaults for all bondholders under the base case battery prices, price discounts and interest rates, even when default rates are cut in half. However, when the battery price is decreased by one third, as is expected in the market, the aggregator achieves a discounted revenue of $13.76 million after repaying all investment tranches. All bondholders are repaid when price discounts are increased to 25%. Tranche A and B bondholders are repaid when a 25% price discount is combined with an interest increase of 125 basis points. Only tranche A bondholders are repaid when a 25% price discount is combined with double the default rates.

Customers in all scenarios are in a financially superior position under a PPA than they would be if they sourced 100% of their power from the grid. In the solar-only PPA tested in Scenario 1, customers can achieve 16.2% overall bill savings when a 45% price discount is applied, which amounts to discounted savings of $2,016 over 18 years. In the solar and battery PPA tested in Scenario 2, customers can achieve 22.2% overall bill savings when a 25% grid price discount is applied, which amounts to discounted savings of $2,391 over 13 years.

The variables tested within and between each of the scenarios – the grid price discount, the customer default rates, the interest rates on the bond, the length of the bond term and PPA contract, and the inclusion of lithium-ion batteries – are designed to test the impact on each of the stakeholders (bondholders, aggregators and customers) of key concerns in the literature and technological developments relating to the financial and renewables market. The following discusses the strengths and weaknesses of using those variables in the model, the policy implications, and the opportunities for further development in the literature.

6.2 Strengths and weaknesses of model variables

In Scenario 1, case 5.1.5 focusses on testing whether bondholders can achieve a return on investment in under ten years, in response to recommendations by Mendelsohn et al. (2015). While the results in case 5.1.5 demonstrate that it is possible to achieve this objective in principle, it is suggested that this scenario is unlikely to occur in practice, as it only generates an overall 7.2% bill discount for consumers. In the context of the Australian retail power market, where customers are complacent about changing their energy providers (Australian Competition and Consumer Commission 2018), it is unlikely that the offer will be sufficiently attractive to convince an adequate number of customers to switch to a PPA. Recent developments in financial market behaviour suggest that the absence of a shorter term bond offering is unlikely to be a significant barrier to investment in a solar PPA ABS, as was originally raised by Mendelsohn et al. (2015). For example, recently in the United States, Vivint Solar successfully issued a 240-month ABS bond (Kroll Bond Rating Agency 2018). This change in financial market behaviour is likely to be related to an increased understanding of solar technology since Mendelsohn et al. (2015), in particular that the expected life of solar energy products is approximately 20-25 years.

Once the pressure of ensuring the repayment of an investment within 10 years is relieved, it becomes feasible to test the financial viability of a longer term ABS for the PPA contracts. Increasing the bond period and PPA contract length to 18 years permits a focus on how to repay bondholders whilst maximising savings for customers, in order to incentivise greater uptake of the PPA offering, and absorbing payment default by those PPA customers. Therefore, the key variables in Scenario 5.1 are the price discount offered to customers and the expected default rate of those customers. The results demonstrate that, at a 45% price discount, all bondholders can be repaid under base case default rates, but when default rates are doubled, only tranche A bondholders are repaid. Thus, the model settles on a maximum 45% retail price discount for this scenario. As noted above, a 45% retail discount on power supplied under the PPA translates into significant customer savings over 18 years and, at base case default rates, permits the aggregator to earn an NPV revenue of $7.2 million after 18 years, at a 10% internal rate of return. If the interest rates payable under the bond are increased by 150 basis points, all tranches remain viable and the aggregator earns a discounted revenue of $2.93 million. However, once the interest rates are increased by 200 basis points, tranche A defaults with five payments remaining.

When a high customer default rate of 3.46% is applied to the 45% discount, only tranche A can be repaid. This is an unsurprising result, as this rate of default reduces the customer base by more than 40% by the end of the 18-year term. A weakness of the model is that this high default rate is applied evenly across the full bond term, despite the fact that Australia's history of economic cycles suggests that it is highly unlikely to experience such consistently poor economic conditions over a period of 18 years.[5] Nevertheless, the positive results generated in spite of this conservative application of the default rate also demonstrates this scenario's underlying viability. Firstly, despite the unrealistically high default rate, tranche A with a credit rating of AA was fully repaid, meeting the rating guidelines requiring an ability to withstand economic adversity; and while tranche B could not be fully paid out (Figure 17 and Figure 28), this is also consistent with a BBB rating under adverse economic

[5] It is important to recall that the application of the 3.46% customer default rate is an extreme scenario designed to test the viability of the product in the context of an intentional strategy to engage a large proportion of low-income households who are more likely to have lower credit ratings. However even the standard default rate of 1.72% incorporates almost 50% of hardship customers. Under both scenarios low income customers are a key market.

conditions. Secondly, the bond's ability to withstand high default rates highlights the possibility of targeting lower income customers for the PPA market. This may be particularly important in a policy setting trying to address the fact that electricity bills represent 5.2% of the disposable income of low income earners (Australian Energy Regulator 2017, p. 11). The model could be further enhanced by a closer study of the default behaviour of this cohort and the broader customer market.

6.3 Policy implications

It is relevant to note that the capital cost calculations in the model assume that the government rebates designed to incentivise residential uptake of solar PV, valued at $2,500 per installation, are not taken up by the PPA aggregator. Rather, the model applies wholesale pricing to arrive at a capital cost of $5,000 per solar PV installation, which is not significantly different to the current price of $4,800 which is expected to be paid by residential customers after rebates (SolarChoice 2018).

While the absence of rebates does not make any significant difference to the model results, the 'savings' generated for government by shifting the pricing 'discount' from the government rebate budget to the solar PV wholesalers highlights a policy opportunity. The PPA model in this study assumes 10,000 customers. If those 10,000 customers accessed the government's rebate, at $2,500 per installation, the government rebate owing would be $25 million. In a policy environment whereby government seeks to encourage the uptake of solar PV and reduce household power bills, an alternative approach would be to invest a portion of those rebate 'savings' in tranche B of the security, on the condition that the price charged to the consumer is suitably discounted (as per scenario 5.1.2).

For example, if the government invested $7.5 million into tranche B (100% of tranche B or 15% of the $50 million bond) and customer defaults were incurred at the base case rate of 1.73%, the government would achieve the same policy objectives as the rebate, whilst saving $17.5 million at the outset and receiving the remaining $7.5 million back with a return of 6.12% over 18 years (Table 6 and Table 8). If the customer default rate increased to 3.46% pa (perhaps because there was a deliberate strategy to attract lower income customers), the results set out in Table 9 suggest that tranche B would default; and section 5.1.3 highlights that, at the time of default, approximately 48% (or $3.635 million) of the principal, plus interest, would have been owing on the $7.5 million invested. However, even on default, the government would be more than $21.365 million better off than if it had paid out the rebates, and the tranche C losses would remain with the aggregator.

Furthermore, because the PPA structure may diminish the split incentive problem faced by renters by relieving homeowners from 100% of solar capital costs, a government investment into a PPA security may be more effective than a government rebate policy in increasing access to cleaner, cheaper power for lower income earners. This proposition would be a valuable avenue for further exploration in the literature.

In addition, as discussed above, the results demonstrate that current lithium-ion battery prices make the model uneconomical but that battery prices are expected to significantly reduce in price and, when that occurs, customers will experience greater price discounts. The inclusion of batteries also opens up options for the establishment of VPPs. It may therefore be relevant for government to consider subsidising battery prices to facilitate its renewable energy policy agenda.

6.4 Future directions for researchScenario 2 introduces lithium-ion batteries into the solar PPA package at current battery prices and applies an expected battery life of 13 years to adjust the bond term. This scenario produces high savings for the customer (17.8% bill savings), but the increase in capital costs and shorter bond period cause tranche A to default with 18 months remaining, even when half of the standard default rate is applied.

Scenario 2 could produce stronger results if the customer base was increased from 10,000 to 100,000, so as to facilitate the operation of a Virtual Power Plant (VPP) by the aggregator. If each of the 100,000 customers had, on average, 1kW spare electricity stored in the battery, the aggregator could act as 100MW power plant, which is the same size as the largest battery currently found in the world - the Hornsdale Power Reserve Battery Energy Storage System. The Hornsdale battery has been profitable on various wholesale markets (Parkinson 2018). If the aggregator had control of a sufficient number of batteries and could operate a VPP, the bond capital could be repaid from the extra revenue stream coming from the wholesale markets (electricity supply, frequency control, and ancillary service markets), which would relieve the default rate and interest rate sensitivities. The introduction of a VPP facility would require an expansion of the capability and dynamics of the model presented in this thesis, as the aggregator operating on the wholesale market would have the capacity to ‘fill up’ the batteries from the grid when power prices were low and sell the power back to the grid when the power prices were high. For example time of day, day of week and bidding behaviour can generate spikes in wholesale electricity pricing (Thomas et al. 2011) which can be capitalised upon by a VPP. Distributed energy systems, like VPPs, are an important development in the Australian energy market. The model in this thesis provides an initial framework within which these emerging market opportunities can be further explored.

The results in Scenario 2, section 5.2.3, anticipate a one-third reduction in battery prices and an increase in battery life, as suggested, for example, by (Chediak 2017 ; Reniers et al. 2018; Yu 2018). As noted above, under these circumstances, customers will achieve a 22.2% overall bill discount - the largest discount among all scenarios. At the base case default rate of 1.73%, and a 25% price discount, all bond tranches can be paid and the aggregator generates a discounted revenue of $8.69 million. When the default rate is doubled, tranche A is repaid but tranches B and C are not.

As suggested above, there is an opportunity for the government to invest in tranche B to facilitate the purchase of solar PV and battery packages, rather than providing rebates for solar PV only, in order to increase access to cleaner, cheaper power. Even under high default conditions (3.46%), the government expenditure would be $11.8 million (see 5.2.3(ii)) rather than $25 million. It is also feasible to consider the impact of the government participating in the ABS as the guarantor of last resort. While a thorough investigation of this issue is beyond the scope of this study, this highlights the opportunity to further examine alternatives to rebates as an incentive mechanism and to explore the impact of government participation on bond pricing, risk and public and private investment in social goods.The results of this thesis also point towards several additional directions for research, including: how the actual life of commercial batteries will impact on the results; whether the batteries do in fact stop working after the stated warranty period and cycle limits expire; how much it might cost to replenish the battery; and the impact of replenishment on the potential bond term. It is also noted that the modelling of battery utilisation in this thesis uses a naïve approach as described in equation (14). An optimisation and probability of need approach for home batteries was outside the scope of the present study, as was an analysis of the relative benefits to the consumer and aggregator of selling electricity into the grid or keeping it for household consumption. Further enhancements to this model could include a battery optimisation algorithm that incorporates the constraints of battery degradation, limited battery cycles, household needs and revenue maximisation from FiT. Enhancements such as these would assist in evaluating the financial benefits of PPAs for customers, and enhance an assessment of the value of engaging in a VPP operation.

An enhanced version of the model might also include the dynamic effect of grid price changes. The current model assumes that grid prices remain static over the term of the PPA contract, and therefore that the discounted price under the PPA also remains static. A PPA model linking the PPA price discount to a floating grid price could generate different results in the event of significant price changes. However, in the more plausible scenario that the PPA charges a fixed power price representing a discount from the grid price at the commencement of the contract, a change in the grid price will primarily impact on the overall savings enjoyed by the PPA customer, and therefore on the incentives to enter and remain on PPA contracts. For example, a significant increase in the grid price would have a substantial impact on the overall savings enjoyed by the solar-only PPA customers, who depend on power from the grid every day after sunset. It would impact on the solar plus battery PPA customers most greatly in the winter months of June and July when solar production is low and consumption is high. A change in grid price will not impact on the results for the bondholder and aggregator, unless the customers default because they can get a cheaper price from the grid.

A further avenue for exploration is an assessment of how a significant increase in solar PV production might cause a change in the market grid prices, which then has flow-on impacts for the savings enjoyed by the PPA customer under the model. Similarly, it is relevant to consider the role that an increase in energy efficient appliances and practices might have on the market, and whether those products might be bundled into a PPA.

The model in this study assumes that there are no prepayments of the PPA contracts. If prepayments were incorporated into the model, the turnover rate of 6% in the housing market (Leal et al. 2017) may be an appropriate rate to apply.

There are some capital costs which have not been included in the current PPA model. As discussed in Chapter 1, one of the key advantages of the PPA model is shifting the capital costs from the property owner to the aggregator, thereby removing the split incentive experienced by body corporates, private rental housing, public housing and small businesses. However, in the context of apartment and other shared buildings, there would need to be purchases of switching and metering hardware and software (Vorrath 2018). The costs of that equipment have not been included.

An expanded model might also apply different default rates to different customer segments, namely, household consumers, business consumers and body corporates. Similarly, there may be different energy consumption profiles to consider for different customer segments; and the results of this investigation may generate different decisions regarding the inclusion of a battery. For example, most businesses conduct their main activities during the daytime, making a battery package less advantageous for those customers. For body corporates managing buildings with a lift, it may be necessary to investigate the lift's energy consumption and usage timing.

Finally, from a capital markets perspective, further investigation could be made regarding pricing and credit ratings applied to a PPA ABS in the context of other wholesale investment products.

CHAPTER 7: CONCLUSION

7.1 Summary

This thesis explores new ways to increase the uptake of rooftop solar PV and batteries in Australia. It explores the introduction of PPAs to the Australian electricity market in order to address the barriers created by high solar PV and battery capital costs for household and small business consumers. It also examines the viability of securitization as a means for PPA aggregators to access the capital they require.

The key research questions posed in Chapter 1 can be answered as follows:

1) Consumers are financially better off purchasing solar power via a PPA offering grid price discounts, even when they continue to purchase some power from the grid. While the quantum of savings depends on the discounts offered and the contract length, the model demonstrates that a grid price discount of 55% can be offered to consumers under an 18 year solar-only PPA, leaving those customers 19.8% per annum better off.
2) A PPA aggregator can generate a positive financial return by selling the PPAs onwards to the investment community through securitization under circumstances where: (a) grid price discounts are offered to consumers; (b) there is a high customer default rate; and/or (c) interest rates increase. The results demonstrate that the aggregator can generate a NPV revenue (at 10% return) under a solar-only PPA of between \$2.9 million to \$17.5 million depending on the variables applied to the scenario.
3) Capital market investors can make a positive financial return through the purchase of PPA securities. The results demonstrate that under certain circumstances, owners of all three investment tranches can be fully repaid.
4) PPA customer default rates impact on investors, particularly those owning the subordinate investment tranches. The highest rated investment tranche developed in this model (tranche A rated at AA) can be repaid in the event of extreme default rates of 3.46% combined with interest rate increases. Tranche B (rated at BBB) can only be paid in the event of increased customer default rates *or* increased interest rates. Tranche C (junk bond rating) can support

'normal' default rates of 1.76% and interest rate increases upto 150 basis points, but will not be repaid at higher customer default rates.

5) Including lithium-ion batteries into the PPA package is uneconomical at current battery prices. However, it is expected that battery prices will significantly decrease over time and when this occurs, the inclusion of lithium-ion batteries will generate greater returns for all parties than under a solar-only scenario.

7.2 Key contributions to literature

This paper confirms empirical research that the securitization of PPAs for household rooftop solar PV supports economically viable results in a range of different environments. The model developed in this thesis enhances and expands Alafita and Pearce (2014) by: increasing the number of tranches in the security to reflect different investor risk categories, using a collateralized debt obligation (CDO) structure of sequential tranches; ensuring that the price paid by the customer under the PPA is always lower than the retail grid price; acknowledging differences in electricity consumption and production by using real customer production and consumption data; incorporating a market FiT; and adding a lithium-ion battery to the model which allows for consumption under the PPA during the evening. It also applies real data to the enhanced Alafita and Pearce model to explore the relevance and viabilility of PPAs to households in the Australian market.

The results demonstrate the viability of using an ABS to finance solar PV PPAs. The PPA customers, bondholders and aggregator can all achieve financial benefits under a scenario, which assumes a 20% discount on the grid price, a customer default rate reflecting current electricity market conditions, risk-adjusted interest rates, and an 18-year bond term. The modelling tests the effects of adjusting any one or more of those variables and demonstrates a capacity to absorb the application of higher price discounts, higher default rates, increased interest rates, and shorter bond terms under certain conditions.

The findings demonstrate that, when lithum-ion batteries are packaged into the PPA, the ABS security is only viable under the considered base case scenario if battery prices come down from the current market prices. When the battery price is reduced by one third, it is possible for all parties to make financial gains, and it is particularly beneficial for customers, who can achieve more than 22% savings on their electricity bills over a 13-year bond period, when a 25% retail price discount is applied.

I also discusse the various benefits of introducing PPA ABS into the Australian renewables and financial markets. In particular, the study highlights the role that PPAs can play in releasing currently dormant rooftop real estate by shifting the solar PV and battery capital requirements to the PPA aggregator from homeowners, body corporates and small businesses, and decreasing the split incentive experienced by property investors.

I highlight how a PPA ABS can faciliate opportunities for the government to engage in private-public partnerships designed to improve access to cheaper, distributed energy systems for lower-income households.

This thesis also suggests several directions for future research. In particular, there is potential to expand the model in order to explore the dynamics of a VPP and examine the impact of such a distributed energy system in wholesale and retail electricity markets.

REFERENCES

Agnew, S. and Dargusch, P. 2017, 'Consumer preferences for household-level battery energy storage', *Renewable and Sustainable Energy Reviews*, vol. 75, pp. 609-17.

Alafita, T. and Pearce, J.M. 2014, 'Securitization of residential solar photovoltaic assets: Costs, risks and uncertainty', *Energy Policy*, vol. 67, pp. 488-98.

Alramlawi, M., Gabash, A., Mohagheghi, E. and Li, P. 2018, 'Optimal operation of hybrid PV-battery system considering grid scheduled blackouts and battery lifetime', *Solar Energy*, vol. 161, pp. 125-37.

ASX 2018, *Bank Bill Swap Rates (Mid) - 10 Day History*, ASX, Sydney Australia, viewed 12 September 2018 2018, <https://www.asx.com.au/data/benchmarks/bbsw-10-day-rolling-history.pdf>.

Ausgrid 2014, 'Solar Home Electricity Data - Solar home half-hour data', in Ausgrid (ed.)Sydney, Australia, viewed 5 July 2018, <https://www.ausgrid.com.au/Common/About-us/Corporate-information/Data-to-share/Solar-home-electricity-data.aspx>.

Australian Bureau of Statistics 2017, *6523.0 - Household Income and Wealth, Australia, 2015-16*, ABS, Canberra, viewed 28/4/10/2018, <http://abs.gov.au/ausstats/abs@.nsf/Lookup/by%20Subject/6523.0~2015-16~Main%20Features~Key%20Findings~1>.

Australian Competition and Consumer Commission 2018, *Restoring electricity affordability and Australia's competitive advantage*, Canberra, <https://www.accc.gov.au/publications/restoring-electricity-affordability-australias-competitive-advantage>.

Australian Energy Market Operator (AEMO) 2017, *Annual Report 2017*.

Australian Energy Market Operator (AEMO) 2018, *AEMO Insights Quartley Energy Dynamics Q4 2017*, viewed 4th April 2018, <https://www.aemo.com.au/-/media/Files/Media_Centre/2018/QED-Q4-2017.pdf>.

Australian Energy Regulator 2017, *Annual Report on Compliance & Performance of Retail Energy Market 2016-2017*, Commonwealth Government, Melbourne Victoria, Australia, <https://www.aer.gov.au/system/files/AER%20Performance%20Report%20on%20Compliance%20%26%20Performance%20of%20the%20retail%20energy%20market%202016%E2%80%9317.pdf>.

Australian PV Institute (APVI) 2018, 'Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 9 August 2018.', <http://pv-map.apvi.org.au/postcode>.

Bauner, C. and Crago, C.L. 2015, 'Adoption of residential solar power under uncertainty: Implications for renewable energy incentives', *Energy Policy*, vol. 86, pp. 27-35.

Beers, C.W. and Eddy, H.C. 1913, 'Discussion On " Purchased Power In Coal Mines" (Eddy) and " Central Station Power For Coal Mines" (Beers), Pittsburgh, PA., April 18, 1913.', *Proceedings of the American Institute of Electrical Engineers*, vol. 32, no. 12, pp. 2206-13.

Beltran, D.O., Cordell, L. and Thomas, C.P. 2017, 'Asymmetric information and the death of ABS CDOs', *Journal of Banking & Finance*, vol. 76, pp. 1-14.

BOM and CSIRO 2016, *State of the Climate 2016*, Canberra.

Bondio, S., Shahnazari, M. and McHugh, A. 2018, 'The technology of the middle class: Understanding the fulfilment of adoption intentions in Queensland's rapid uptake residential solar photovoltaics market', *Renewable and Sustainable Energy Reviews*, vol. 93, pp. 642-51.

Bruce, A. and MacGill, I. 2016, *FactCheck Q & A: is Australia the world leader in household solar power?* , viewed 26 April 2018, <https://theconversation.com/factcheck-qanda-is-australia-the-world-leader-in-household-solar-power-56670>.

Bureau of Meteorology 2018, *Daily Rainfall Sydney (Observatory Hill)* viewed 9th August 2018 2018, <http://www.bom.gov.au/jsp/ncc/cdio/weatherData/av?p_nccObsCode=136&p_display_type=dailyDataFile&p_startYear=2012&p_c=-872921770&p_stn_num=066062>.

Burger, M., Graeber, B. and Schindlmayr, G. 2014, *Managing Energy Risk: An Integrated View on Power and Other Energy Markets, 2nd Edition*, 2nd edn, John Wiley and Sons.

Chapman, A.J., McLellan, B. and Tezuka, T. 2016, 'Residential solar PV policy: An analysis of impacts, successes and failures in the Australian case', *Renewable Energy*, vol. 86, pp. 1265-79.

Chasen, A. 2009, 'The Impact of Structure on the Value of CM0 Bonds', *Journal of Structured Finance*, vol. 15, no. 3, pp. 26-31.

Chediak, M. 2017 'The Latest Bull Case for Electric Cars: the cheapest Batteries Ever', *Bloomberg Technology*, 6th December 2017.

Chemla, G. and Hennessy, C.A. 2014, 'Skin in the Game and Moral Hazard', *The Journal of Finance*, vol. 69, no. 4, pp. 1597-641.

Clean Energy Regulator 2018, *Small Generation unit STC Calculator* Canberra, ACT Australia, viewed 28/04/2018, <https://www.rec-registry.gov.au/rec-registry/app/calculators/sgu-stc-calculator>.

Clemen, R. and Reilly, T. 1999, 'Correlations and Copulas for Decision and Risk Analysis', *Management Science*, vol. 45, no. 2, pp. 208-24.

De Groote, O., Pepermans, G. and Verboven, F. 2016, 'Heterogeneity in the adoption of photovoltaic systems in Flanders', *Energy Economics*, vol. 59, pp. 45-57.

Department of Environment Land Water and Planning 2018, *Victorian Feed in Tariff*, Victorian State Government, Melbourne, viewed 9 Oct 2018 2018, <https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff>.

Department of Industry and Science 2015, *2015 Energy White Paper*, Canberra Act

Drury, E., Miller, M., Macal, C.M., Graziano, D.J., Heimiller, D., Ozik, J. and Perry Iv, T.D. 2012, 'The transformation of southern California's residential photovoltaics market through third-party ownership', *Energy Policy*, vol. 42, pp. 681-90.

Dusonchet, L. and Telaretti, E. 2015, 'Comparative economic analysis of support policies for solar PV in the most representative EU countries', *Renewable and Sustainable Energy Reviews*, vol. 42, pp. 986-98.

Fabozzi, F.J. 2001, *Accessing Capital Markets Through Securitization* Kindle, Fran J Fabozzi Associates, viewed 11 June 2018.

Fender, I. and Mitchell, J. 2009, 'The Future of Securitisation How to Align Incentives?', *BIS Quarterly Review : International Banking and Financial Market Developments*, vol. 2009, no. September 2009, pp. 27–43.

Fu, R., Feldman, D., Margolis, R., Woodhouse, M. and Ardani, K. 2017, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Lab. (NREL), Golden, CO (United States), NREL/TP-6A20-68925.

Gabig, N., Cohen, B. and Kapoor, M. 2015, 'Solar ABS: Understanding Market Potential', *Journal of Structured Finance*, vol. 21, no. 1, pp. 105-10.

Geddes, A., Schmidt, T.S. and Steffen, B. 2018, 'The multiple roles of state investment banks in low-carbon energy finance: An analysis of Australia, the UK and Germany', *Energy Policy*, vol. 115, pp. 158-70.

Gorton, G. 2009, 'The Subprime Panic', *European Financial Management*, vol. 15, no. 1, pp. 10-46.

Gorton, G. and Metrick, A. 2012, 'Securitized banking and the run on repo', *Journal of Financial Economics*, vol. 104, no. 3, pp. 425-51.

Han, J., Linnenluecke, M.K., Pan, Z. and Smith, T. 2019, 'The wealth effects of the announcement of the Australian carbon pricing scheme', *Pacific-Basin Finance Journal*, vol. 53, pp. 399-409.

Hyde, D. and Komor, P. 2014, 'Distributed PV and Securitization: Made for Each Other?', *The Electricity Journal*, vol. 27, no. 5, pp. 63-70.

Independent Pricing and Regulatory Tribunal 2018, *Solar Feed in Tariffs the value of electricity from small-scale solar panels in 2018-19 Draft Report*, Independent Pricing and Regulatory Tribunal, NSW.

Jacoby, S. 2013, 'Solar-Backed Securities Opportunities, Risks, and the Specter of the Subprime Mortgage Crisis. ', *University of Pennsylvania Law Review*, vol. 162, no. 1, pp. 203-40.

Joshi, J. 2012, 'Creating a Market for Solar Securitization', *Journal of Structured Finance*, vol. 18, no. 2, pp. 82-8.

Joshi, J. 2013a, 'Renewable Energy Finance and Securitization', *Journal of Structured Finance*, vol. 18, no. 4, pp. 215-9.

Joshi, J. 2013b, 'Solar Securitization: Understanding the Risks of Residential Solar Energy-Backed Securities from an Investor Perspective', *Journal of Structured Finance*, vol. 19, no. 2, pp. 64-70.

Kollins, K., Speer,B.,Cory,K., 2010, *Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners*, <https://www.nrel.gov/docs/fy10osti/46723.pdf>.

Krishnamurthy, A., Nagel, S. and Orlov, D. 2014, 'Sizing Up Repo', *Journal of Finance*, vol. 69, no. 6, pp. 2381-417.

Kroll Bond Rating Agency 2018, *Structured Finace ABS New Issue Report Vivint Solar Financeing V, LLC, Series 2018-1*, ABS New Issue Report, KBRA, NY,NY, USA.

Kulatilaka, N., Santiago, L. and Vakili, P. 2014, 'Reallocating risks and returns to scale up adoption of distributed electricity resources', *Energy Policy*, vol. 69, pp. 566-74.

Kwan, C.L. 2012, 'Influence of local environmental, social, economic and political variables on the spatial distribution of residential solar PV arrays across the United States', *Energy Policy*, vol. 47, pp. 332-44.

Leal, H., Parsons, S., White, G. and Zurawski, A. 2017, 'Housing Market Turnover', *The Bulletin* vol. 0317, no. March Quarter, pp. 21-8.

Lemmon, M., Liu, L.X., Mao, M.Q. and Nini, G. 2014, 'Securitization and Capital Structure in Nonfinancial Firms: An Empirical Investigation', *The Journal of Finance*, vol. 69, no. 4, pp. 1787-825.

Li, X., Mikusiński, P. and Taylor, M.D. 1998, 'Strong Approximation of Copulas', *Journal of Mathematical Analysis and Applications*, vol. 225, no. 2, pp. 608-23.

Liu, L.X., Mao, M.Q. and Nini, G. 2018, 'Customer risk and corporate financial policy: Evidence from receivables securitization', *Journal of Corporate Finance*, vol. 50, pp. 453-67.

Lockwood, L.J., Rutherford, R.C. and Herrera, M.J. 1996, 'Wealth effects of asset securitization', *Journal of Banking & Finance*, vol. 20, no. 1, pp. 151-64.

Lowder, T. and Mendelsohn, M. 2013, *The Potential of Securitization in Solar PV Finance.*, Technical, NREL/TP-6A20-6023, National Renewable Energy Laboratory, Golden CO, USA, NREL/TP-6A20-60230.

Lyuu, Y.-D. 2004, *Financial Engineering and Computation Principles, Mathematics, Algorithms*, VitalSource Bookshelf, Cambridge University Press, viewed 10 June 2018.

Martin, N. and Rice, J. 2018, 'Solar Feed-In Tariffs: Examining fair and reasonable retail rates using cost avoidance estimates', *Energy Policy*, vol. 112, pp. 19-28.

Matsui, R. and Malaya, N. 2014, 'A Primer of Collateral-Related Risks Associated with Solar ABS', *Journal of Structured Finance*, vol. 20, no. 1, pp. 59-63.

McIver, R. 2019, 'The Effects of Environmental Announcements on Exchange Traded Funds AU - Wallace, Damien', *Emerging Markets Finance and Trade*, vol. 55, no. 2, pp. 289-307.

Mendelsohn, M., Lowder, T., Rottman, M., Borod, R., Gabig, N., Henne, S., Caplin, C. and Notte, Q. 2015, *Solar Access to Public Capital (SAPC) Mock Securitization Project*, NREL/TP-6A20-64347 United States 10.2172/1233704 NREL English, National Renewable Energy Lab. (NREL), Golden, CO (United States).

Newell, G., Macfarlane, J. and Walker, R. 2014, 'Assessing energy rating premiums in the performance of green office buildings in Australia', *Journal of Property Investment & Finance*, vol. 32, no. 4, pp. 352-70.

Ossenbrink, J. 2017, 'How feed-in remuneration design shapes residential PV prosumer paradigms', *Energy Policy*, vol. 108, pp. 239-55.

Outhred, H. and Retnanestri, M. 2015, 'Insights from the Experience with Solar Photovoltaic Systems in Australia and Indonesia', *Energy Procedia*, vol. 65, pp. 121-30.

Parkinson, G. 2018, 'Tesla big battery defies skeptics, sends industry bananas over performance', *Renew Economy*, 27 September 2018, viewed 29 September 2018, <https://reneweconomy.com.au/tesla-big-battery-defies-skeptics-sends-industry-bananas-over-performance-38273/>.

Pham, H.N.A., Wang, I., Dang, V.N.T., Veron, J.F. and Duong, H. 2017, 'The financial consequences of abolishing a carbon trading system AU - Ramiah, Vikash', *Applied Economics Letters*, vol. 24, no. 13, pp. 936-9.

PVinsights 2018, *Solar PV Module Weekly Spot Price*, PVInsights, viewed 9 Oct 2018 2018, <http://pvinsights.com/index.php>.

Rai, V., Reeves, D.C. and Margolis, R. 2016, 'Overcoming barriers and uncertainties in the adoption of residential solar PV', *Renewable Energy*, vol. 89, pp. 498-505.

Ramiah, V., Martin, B. and Moosa, I. 2013, 'How does the stock market react to the announcement of green policies?', *Journal of Banking and Finance*, vol. 37, no. 5, pp. 1747-58.

Ramiah, V., Morris, T., Moosa, I., Gangemi, M. and Puican, L. 2016, 'The effects of announcement of green policies on equity portfolios', *Managerial Auditing Journal*, vol. 31, no. 2, pp. 138-55.

Reniers, J.M., Mulder, G., Ober-Blöbaum, S. and Howey, D.A. 2018, 'Improving optimal control of grid-connected lithium-ion batteries through more accurate battery and degradation modelling', *Journal of Power Sources*, vol. 379, pp. 91-102.

Riachi, I. and Schwienbacher, A. 2015, 'Investment, firm performance and securitization: Evidence from industrial companies', *Finance Research Letters*, vol. 13, pp. 17-28.

Sani Hassan, A., Cipcigan, L. and Jenkins, N. 2017, 'Optimal battery storage operation for PV systems with tariff incentives', *Applied Energy*, vol. 203, pp. 422-41.

Singer, D. 2001, 'Securitization Basics', in F.J. Fabozzi (ed.), *Accessing Capital Markets through Securitization* Fank J Fabozzin and Associates, New Hope PA, USA, pp. 13-24, viewed 7 September 2018.

SolarChoice 2018, 'Current solar power system prices: Residential and Commercial', *Current solar power system prices: Residential and Commercial*, weblog, Solar Choice, Manly, Australia, <https://www.solarchoice.net.au/blog/solar-power-system-prices?nabe=4658498117042176:0>.

SolarMarket 2018, *Rebates Still available in 2018*, The Quote Company Perth, WA Australia <https://lp.solarmarket.com.au/national/with-healthy-rebates-still-available-2018-is-great-time-to-go-solar/?type=rebates&state=nsw&size=5kW&geo=NSW&gclid=EAIaIQobChMIgaC5kqHe2gIVl5K9Ch21iwlfEAAYASAAEgIQcvD_BwE>.

Sommerfeld, J., Buys, L. and Vine, D. 2017, 'Residential consumers' experiences in the adoption and use of solar PV', *Energy Policy*, vol. 105, pp. 10-6.

Tesla 2017, 'Tesla POWERWALL Warranty (Australia and New Zealand)', May 24th 2017, <https://www.tesla.com/sites/default/files/pdfs/powerwall/powerwall_2_ac_warranty_au-nz_1-5.pdf?>.

Tesla 2018, *Powerwall*, Tesla, viewed 13 Sept 2018 2018, <https://www.tesla.com/en_AU/powerwall?redirect=no>.

The Bond Market Association 1999, *Chapter SF Standard Formulas for the Analysis of Mortgage-Backed Securities and Other Related Securities*, The Bond Market Association, USA.

Thomas, H. 1999, 'A preliminary look at gains from asset securitization', *Journal of International Financial Markets, Institutions and Money*, vol. 9, no. 3, pp. 321-33.

Thomas, S., Ramiah, V., Mitchell, H. and Heaney, R. 2011, 'Seasonal factors and outlier effects in rate of return on electricity spot prices in Australia's National Electricity Market', *Applied Economics*, vol. 43, no. 3, pp. 355-69.

Trotman, K. and Gibbins, M. 1998, *Financial Accounting: An integrated approach* Nelson ITP, Ontario, Canada.

Tveten, Å.G., Bolkesjø, T.F., Martinsen, T. and Hvarnes, H. 2013, 'Solar feed-in tariffs and the merit order effect: A study of the German electricity market', *Energy Policy*, vol. 61, no. Supplement C, pp. 761-70.

Vorrath, S. 2018, 'Melbourne apartment complex switches on shared solar system', *One Step Off The Grid*, Magazine Report, Mullumbimby. NSW. 2482., <https://onestepoffthegrid.com.au/melbourne-apartment-complex-switches-shared-solar-system/>.

Winaico 2018, *Our Performace Features stand for quality*, Degration rate, Winaico, Taiwan, viewed 08 August 2018 2018, <http://www.winaico.com/index.php?id=93&L=1>.

Yu, H.J.J. 2018, 'A prospective economic assessment of residential PV self-consumption with batteries and its systemic effects: The French case in 2030', *Energy Policy*, vol. 113, pp. 673-87.

Zahedi, A. 2009, 'Development of an economical model to determine an appropriate feed-in tariff for grid-connected solar PV electricity in all states of Australia', *Renewable and Sustainable Energy Reviews*, vol. 13, no. 4, pp. 871-8.

APPENDIX A: SUMMARY OF RESULTS

Scenario 1 Results

Scenario	5.1.1 (Base Case 1)	5.1.2 (45%)	5.1.2 (55%)	5.1.3 (45%, 3.46%)	5.1.4 (45%, 150bp)	5.1.4 (45%, 200bp)
Tranche A Investment	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000
Tranche B Investment	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$7,500,000
Tranche C Investment	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
Total Investment	$50,000,000	$50,000,000	$50,000,000	$50,000,000	$50,000,000	$50,000,000
Tranche A Interest Rate	4.1214%	4.1214%	4.1214%	4.1214%	5.6214%	6.1214%
Tranche B Interest Rate	6.1214%	6.1214%	6.1214%	6.1214%	7.6214%	8.1214%
Tranche C Interest Rate	8.1214%	8.1214%	8.1214%	8.1214%	9.6214%	10.1214%
Gross Interest Rate (Including fees 0.5%)	5.1214%	5.1214%	5.1214%	5.1214%	6.6214%	7.1214%
Discount % To Retail Electricity Price	20%	45%	55%	45%	45%	45%
Discounted Price (Retail Price = $0.283)	$0.2264	$0.1557	$0.1274	$0.1557	$0.1557	$0.1557
Term Length	18 Years	18 Years	18 Years	18 Years	18 Years	18 Years
Customer Default Rate p.a	1.73%	1.73%	1.73%	3.46%	1.73%	1.73%
			Results			
Tranche A Successfully Paid	Yes	Yes	Yes	Yes	Yes	No
Tranche B Successfully Paid	Yes	Yes	Yes	No	Yes	No
Tranche C Successfully Paid	Yes	Yes	Yes	No	Yes	No
NPV (10%) Revenue For Aggregator (If All Tranches Paid).	$17.50 M	$7.20 M	$2.94 M	-	$2.93 M	-
NPV (10%) Savings for Customer	$896	$2,016	$2,464	$2,016	$2,016	$2,016
Overall Consumer Bill Savings	7.20%	16.20%	19.80%	16.20%	16.20%	16.20%
Tranche Default Information	-	-	-	Acc Net Rev -ve at month 199/216. TrancheA paid month 186/216; TrancheB 48.46% ($3.635M) principal & 1.46% ($110,500) interest unpaid; TrancheC 100% ($2.5M) principal & 7.01% ($252,499) interest unpaid.	-	Acc Net Rev -ve at month 186/216. TrancheA 4.037% ($1.615M) principal & 0.1% ($23,622) interest unpaid; TrancheB 100% ($7.5M) principal & 7.697% ($783,047) interest unpaid; TrancheC 100% ($2.5M) principal & 13.31% ($598,871) interest unpaid.

Scenario	5.1.5 (11 yrs)	5.1.5(i) (11yrs, 30%)	5.1.5(ii) (11yrs, 3.46%)	5.1.5(iii) (11 yrs, 150bp)	5.1.5(iii) (11yrs, 200bp)
Tranche A Investment	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000
Tranche B Investment	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$7,500,000
Tranche C Investment	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
Total Investment	$50,000,000	$50,000,000	$50,000,000	$50,000,000	$50,000,000
Tranche A Interest Rate	4.1214%	4.1214%	4.1214%	5.6214%	6.1214%
Tranche B Interest Rate	6.1214%	6.1214%	6.1214%	7.6214%	8.1214%
Tranche C Interest Rate	8.1214%	8.1214%	8.1214%	9.6214%	10.1214%
Gross Interest Rate (Including fees 0.5%)	5.1214%	5.1214%	5.1214%	6.6214%	7.1214%
Discount % To Retail Electricity Price	20%	30%	20%	20%	20%
Discounted Price (Retail Price = $0.283)	$0.2264	$0.1981	$0.2264	$0.2264	$0.2264
Term Length	11 Years	11 Years	11 Years	11 years	11 Years
Customer Default Rate p.a	1.73%	1.73%	3.46%	1.73%	1.73%
Results					
Tranche A Successfully Paid	Yes	Yes	Yes	Yes	Yes (with tranche B sacrifice)
Tranche B Successfully Paid	Yes	No	No	Yes	No
Tranche C Successfully Paid	Yes	No	No	Yes	No
NPV (10%) Revenue For Aggregator (If All Tranches Paid).	$4.1916M	-	-	$1.1362M	-
NPV (10%) Savings for Customer	$712	$1,061	$712	$712	$712
Overall Consumer Bill Savings	7.20%	10.86%	7.20%	7.20%	7.20%
Tranche Default Information	-	Acc Net Rev -ve at month 126/132. Tranche A paid month 111/132; TrancheB 12.2% ($915,102) principal & 0.15% ($6,879) interest unpaid; TrancheC 100% ($2.5M) principal & 3.81% ($83,718) interest unpaid.	Acc Net Rev -ve at month 124/132. TrancheA paid month 111/132; TrancheB 24.96% ($1.872M) principal & 0.52% ($23,545) interest unpaid; TrancheC 100% ($2.5M) principal & 5.35% ($117,558) interest unpaid.	-	Acc Net Rev -ve at month 113/132. TrancheA paid month 113 through TrancheB sacrifice; TrancheB 98.43% ($7.382M) principal & 0.69% ($41,936) interest unpaid; TrancheC 100% ($2.5M) principal & 5.50% ($151,058) interest unpaid.

Scenario 2 Results

Scenario	5.2.1 (Base Case 2)	5.2.2 (0.865%)	5.2.3 (1/3 Price)	5.2.3(i) (1/3 Price, 25%)	5.2.3(ii) (1/3 Price, 25%, 3.46%)	5.2.3(iii) (1/3 Price, 25%, 125bp)
Tranche A Investment	$92,200,000	$92,200,000	$74,800,000	$74,800,000	$74,800,000	$74,800,000
Tranche B Investment	$17,287,500	$17,287,500	$14,025,000	$14,025,000	$14,025,000	$14,025,000
Tranche C Investment	$5,762,500	$5,762,500	$4,675,000	$4,675,000	$4,675,000	$4,675,000
Total Investment	$115,250,000	$115,250,000	$93,500,000	$93,500,000	$93,500,000	$93,500,000
Tranche A Interest Rate	4.1214%	4.1214%	4.1214%	4.1214%	4.1214%	5.3714%
Tranche B Interest Rate	6.1214%	6.1214%	6.1214%	6.1214%	6.1214%	7.3714%
Tranche C Interest Rate	8.1214%	8.1214%	8.1214%	8.1214%	8.1214%	9.3714%
Gross Interest Rate (Including fees 0.5%)	5.1214%	5.1214%	5.1214%	5.1214%	5.1214%	6.3714%
Discount % To Retail Electricity Price	20%	20%	20%	25%	25%	25%
Discounted Price (Retail Price = $0.283)	$0.2264	$0.2264	$0.2264	$0.2123	$0.2123	$0.2123
Term Length	13 Years	13 Years	13 Years	13 Years	13 Years	13 Years
Customer Default Rate p.a	1.73%	0.87%	1.73%	1.73%	3.46%	1.73%
Results						
Tranche A Successfully Paid	No	No	Yes	Yes	Yes	Yes
Tranche B Successfully Paid	No	No	Yes	Yes	No	Yes (with tranche C sacrifice)
Tranche C Successfully Paid	No	No	Yes	Yes	No	No
NPV (10%) Revenue For Aggregator (If All Tranches Paid).	-	-	$13.758M	$8.6907M	-	-
NPV (10%) Savings for Customer	$1,913	$1,913	$1,913	$2,391	$2,391	$2,391
Overall Consumer Bill Savings	17.77%	17.77%	17.77%	22.21%	22.21%	22.21%
Tranche Default Information	Acc Net Rev -ve at month 98/156. TrancheA 32.22% ($29.704M) principal & 8.18% ($1.882M) interest unpaid; TrancheB 100% ($17,287,500) principal & 31.57% ($3.946M) interest unpaid; TrancheC 100% ($5.763M) principal & 36.85% ($2.208M) interest unpaid.	Acc Net Rev -ve at month 123/156. TrancheA 9.71% ($8.957M) principal & 0.74% ($170,626) interest unpaid; TrancheB 100% ($17,287,500) principal & 13.93% ($1.741M) interest unpaid; TrancheC 100% ($5.763M) principal & 20.58% ($1.233M) interest unpaid.	-	-	Acc Net Rev -ve at month 136/156. Tranche A paid month 133/156; TrancheB 84.17% ($11.804M) principal & 4.87% ($493,973) interest unpaid; TrancheC 100% ($4.675M) principal & 12.12% ($588,866) interest unpaid.	Acc Net Rev -ve at month 150/156. TrancheA paid month 134/156; TrancheB paid month 151/156; TrancheC 100% ($4.675M) principal & 3.12% ($0.1752M) interest unpaid.