Revenue Stream Analysis on Battery Storage within Volatile Market Prices

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Acronyms

AEMC Australian Energy Market Commission. 1

ARENA Australian Renewable Energy Agency. 8, 14

BESS battery storage energy systems. 1

DEIP Distributed Energy Integration Program. 15

DER distributed energy resources. 1

DNSP distribution network service provider. 5

ENA Energy Networks Australia. 5, 6

FCAS Frequency Control Ancillary Services. 6

NEM National Electricity Market. 4

NLCAS Network Loading Control Ancillary Services. 8

NOFB normal operating frequency band. 10, 28

NSCAS Network Support and Control Ancillary Services. 8

PV photovoltaic. 1

TOSAS Transient and Oscillatory Support Ancillary Services. 8

TOU time-of-use. 21

VCAS Voltage Control Ancillary Services. 8

VPP virtual power plant. 7

Abstract

The uptake of Distributed Energy Resources (DER) within Australia is one with many technical issues, as well as opportunities. With rooftop photovoltaics (PV) and residential battery energy storage systems (BESS) becoming more prevalent within Australia's National Electricity Market (NEM), coordination of these DERs is vital in deferring network investment and added costs on consumers. Virtual Power Plants (VPPs) are seen as an effective option. Prosumers with rooftop PV and BESS who participate in VPPs have the opportunity to participate in additional revenue streams other than PV self-consumption and feed-in tariff (FiT) revenue from PV exports. These are an increased PV self-consumption, provision within contingency frequency control ancillary services (FCAS), and participation within the wholesale energy spot market. Revenue implications of participating within these streams are assessed across 288 households over the July 2019 to June 2020 period, with households operating under either a flat tariff and time-of-use (TOU) tariff. Data and methodologies are adapted to the South Australian context, where wholesale prices are low, FCAS prices are high, and both being relatively volatile compared to historical trends. Compared to the base case with rooftop PV and BESS operating on a flat tariff, revenues under a TOU tariff across all streams were not seen as the economically attractive tariff. Revenues from participating in contingency FCAS were seen to be on average 5.3 times higher than the base case, with a minimal difference under the TOU tariff. On the other hand, energy market participation in the form of energy arbitrage was not financially beneficial, with revenues on average being 0.75 and 0.71 times that of the base case, on a flat tariff and TOU tariff respectively. Further opportunities and revenue gains are available through simultaneous multi-market participation, as well as other revenue streams such as demand response.

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Research Opportunity and Performance Evidence (ROPE)

Fortunately, the implications of COVID-19 has not affected my plans within completing this thesis, as it was initially planned to be modelling and simulation based.

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Chapter 1

Introduction

The economy and infrastructure driving Australia's electricity network is facing unparalleled change in response to increasing innovation and technological advancements. At the heart of this change is the consumer. By 2050, 45% of electricity across Australia will be generated by consumers(AEMC 2019*b*), who continue to play an increasingly active role within the adoption of distributed energy resources (DER).

DER takes the form of electricity generated behind-the-meter within homes or businesses, placing a higher stake on consumers within the distribution network. DER represents residential PV systems, battery storage energy systems (BESS), smart meters, and other energy management systems. With Australia having more rooftop solar installed per capita relative to the rest of the world (AEMO & Energy Networks Australia 2019), and with prices of energy storage forecasted to drop 50% over the next five years (ARENA 2019*a*), the significant increase of DER uptake is very likely to continue in the future. The Australian Energy Market Commission (AEMC) further predicts Australia to have one of the most decentralised electricity systems in the world by 2039 (AEMC 2019*b*). With a similar timeline, in CSIRO's projections for small scale technologies, Australia is forecasted to have (Graham et al. 2019):

- 16,000 MW of residential rooftop PV capacity
- 7,500 MW of residential BESS

Different scenarios are projected by CSIRO that have their economic and regulatory drivers at different levels. As seen in figures 1.1 and 1.2, DER uptake will still increase steadily into 2050 no matter the scenario.

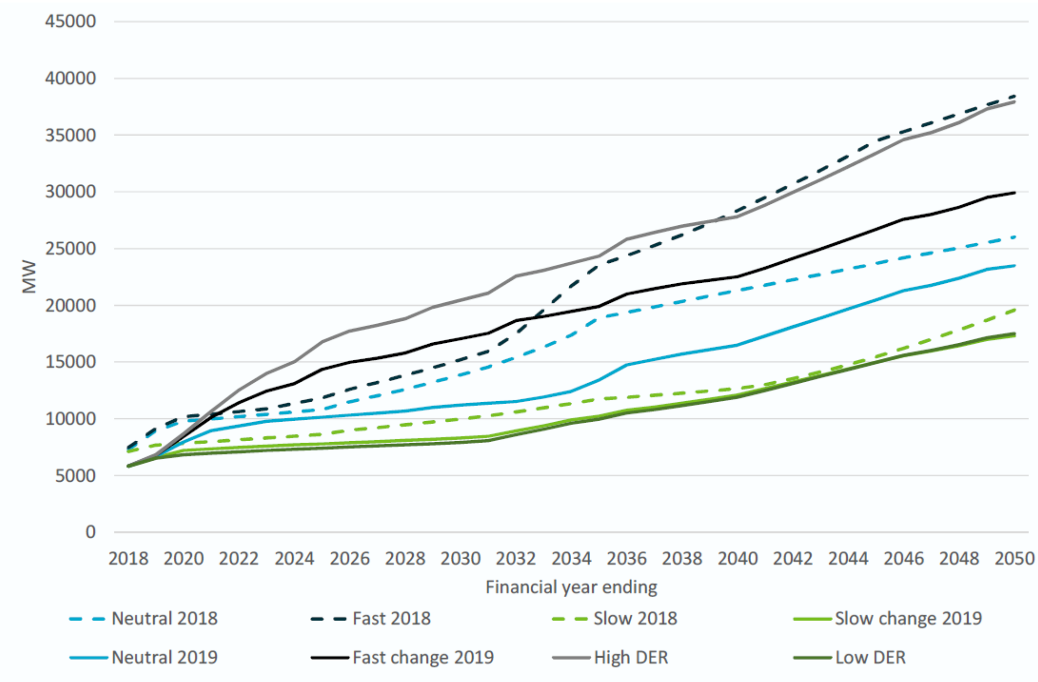


Figure 1.1: Different scenarios of residential rooftop PV capacity in Australia Graham et al. (2019)

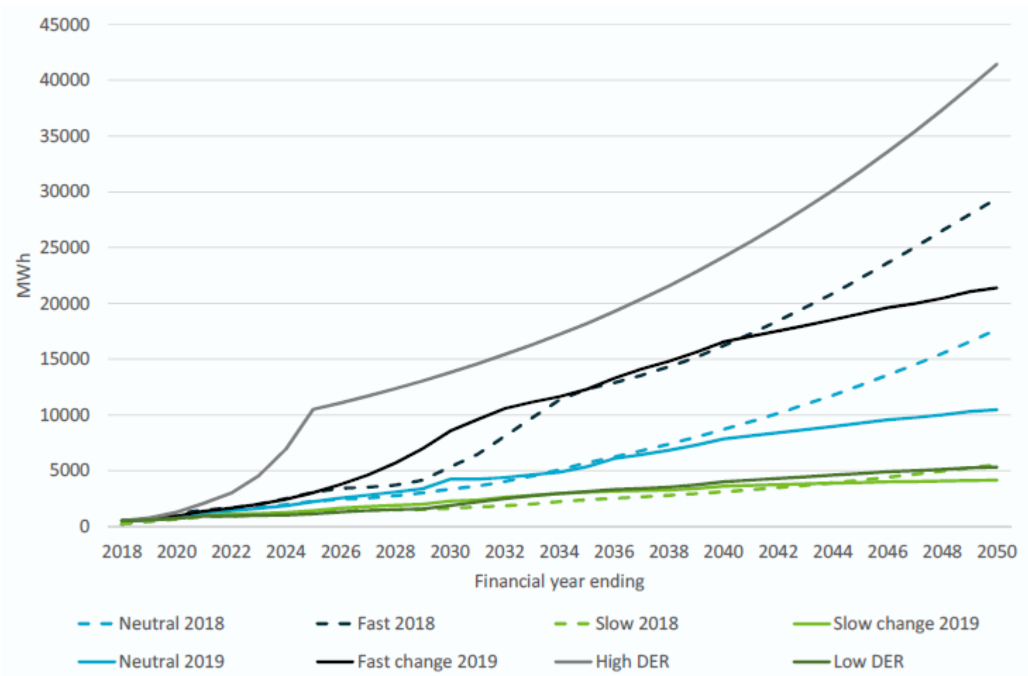


Figure 1.2: Different scenarios of residential BESS capacity in Australia (Graham et al. 2019)

1.1 Thesis Structure

Chapter 2 presents a literature review on the Australian National Electricity Market (NEM), the markets that the Australian Energy Market Operator (AEMO) operates, and the revenue streams that are available to prosumers through the medium of a VPP. At the end of this chapter, gaps, the problem statement and thesis aims are defined. Chapter 3 explores the methodology in simulating battery operation over 288 households, and why Python was chosen as the modelling language. Logic models for battery operation are provided, and limitations are discussed. Chapter 4 discusses the results of the modelling, and compares these results to real life applications and their implications on future outlooks. Finally, chapter 5 summarises the problem and key results, and concludes with future work and possibilities.

Chapter 2

Literature Review

2.1 Distributed Energy Resources

The National Electricity Market (NEM) of Australia was designed with a centralised model in mind, with large scale synchronous generators that send electricity one way through transmission and distribution networks. Consumers took a passive role within electricity consumption, and demand was relatively inelastic (AGL 2018).

DER may be thought of as three components: generation units, storage units and flexible loads (Ghavidel et al. 2016). Generation units can be seen as either dispatchable or non-dispatchable (also known as intermittent). Dispatchable generation units can dispatch power on command, with diesel generators, gas turbines or biomass powered generators being examples. Non-dispatchable generation cannot generate electricity on demand, and is often dependent on external factors beyond reasonable control. Renewable energy such as wind energy or solar are prime examples, as their power output is entirely dependent on the weather.

To support the intermittency of non-dispatchable generation, they are usually paired with storage units capable of storing the energy generated for dispatch during other periods of time. With this pairing, non-dispatchable units become "dispatchable". Storage units of note include hydraulic pumped energy storage (HPES), flywheel energy storage (FES), compressed air energy storage (CAES), and battery energy storage system (BESS) (Ghavidel et al. 2016).

Flexible loads are loads that are able to respond to grid conditions, price signals, or incentive payments through load consumption adjustment (Ghavidel et al. 2016). Like distributed generation, flexible loads may be utilised as a balancing resource, capable of supporting the distributed network (Taneja et al. 2013). For example, consumers may consider deferring the use of their HVAC system if the distributed network is overloaded. Like generation units and storage units, the optimal strategy in managing flexible loads may also be determined through control systems (Ghavidel et al. 2016).

Technical issues within high penetration DER has been passed on to the consumer due to these challenges and technical constraints. Figure 2.1 demonstrates the lack of visibility in tackling these challenges. When consumers export their rooftop solar into the distribution network, reverse power flow is apparent. These tend to raise the voltage, leading to a wider voltage range that existing equipment and infrastructure cannot safely handle. During periods of peak solar production, DERs across the distribution network will be exporting at the same time, potentially overloading the existing capacity constraints on distribution transformers. As a short term solution, distribution network service provider (DNSP)'s curtail solar exports from consumers (AEMC 2019*b*). With consumers driving the uptake of DERs, negative impacts, like the above, on their financial investments will discourage investment from other consumers.

With the growing shift towards RE and an increasing uptake of DER, the change in Australia's generation mix has posed several challenges on the electricity network. With consumers now taking a more active role in consumption and generation of electricity, distribution networks will now have to support bi-directional power flows within the network, something it was not originally designed to do.

Coordination of DER is crucial in alleviating these challenges, while also providing fruitful opportunities (AEMO & Energy Networks Australia 2018). If coordination is managed efficiently, the distribution network will evolve into a platform where consumers will be able to connect and perform transactions (AGL 2017). If not, systems costs could increase significantly.

The 2017 Electricity Network Transformation Roadmap, written by Energy Networks

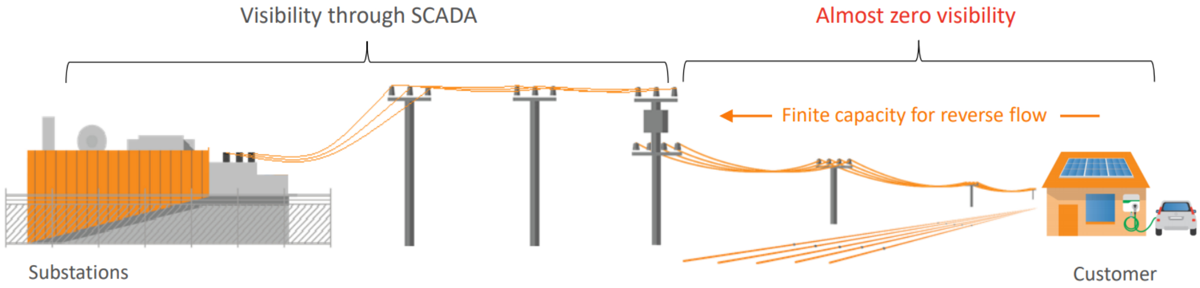


Figure 2.1: DER visibility on the distribution network level is integral in keeping balance in the system (SA Power Networks 2019)

Australia (ENA) and CSIRO, have estimated the following benefits as a result of effective DER coordination:

- Avoided network investment to the value of \$1.4 billion
- Household electricity bills lowered by \$414 a year
- Cumulative value of \$158 billion by 2027

Consumers currently receive value in their DER through self consumption and passive exports. Using rooftop solar as a primary example, consumers save money through consuming solar energy in place of purchasing electricity. When solar generation exceeds demand, solar is exported to the grid and the consumer is paid through a feed-tariff (FiT) rate. This type of DER release is known as *passive* DER (EA Technology 2019).

On the other hand, *active* DER release incorporates coordinated behaviour from an aggregator, retailer or a third party through through smart technologies (AEMO & Energy Networks Australia 2019). Active DER opens up new avenues for consumers to gain further value from their DER investment, as well as being able to provide value to the NEM. Through aggregators or retailers, effective coordination of DER will allow consumers to contribute in peak load reduction, participate in ancillary services such as Frequency Control Ancillary Services (FCAS), as well as network support. AEMC's Distribution Market Model report presented a cohesive list of value streams, shown in figure 2.2.

As ENA and AEMO described in their Open Energy Networks Interim Report, ineffective coordination will increase system costs. Coordinated control of DER could poten-

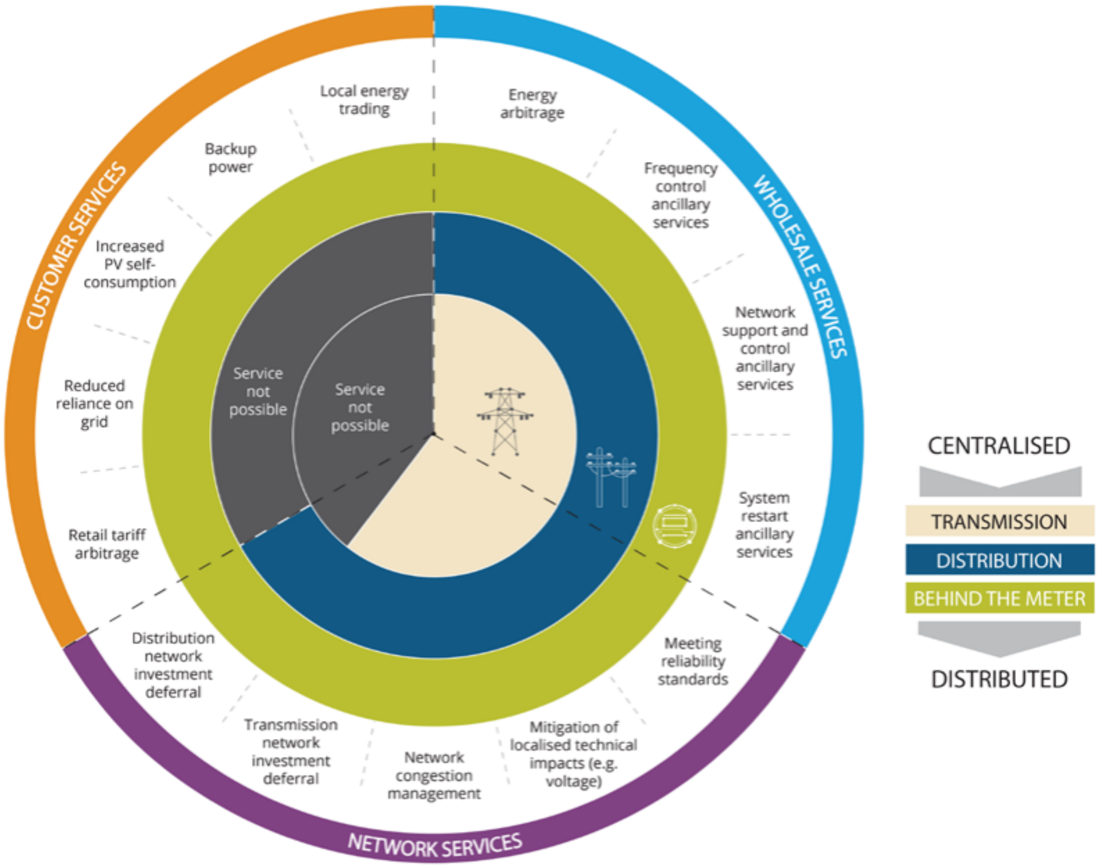


Figure 2.2: Value streams within DER (AEMC 2017)

tially operate without consideration of distribution network capacities, resulting in the need for local network investment upgrades where the costs are reflected onto consumers' electricity bills. Rapid ramping from DER in response to price signals or combined solar export may disrupt the frequency within the NEM, requiring frequency control reserve expansion.

2.2 Virtual Power Plants

A virtual power plant (VPP) is broadly defined as the linking of DER, coordinated through control systems to form a generating unit that delivers the same services as a conventional power plant. In the Australian context, grid-connected VPPs focus mainly on the coordination of rooftop PV and BESS (?).

VPPs are becoming more and more appealing to various electricity sector stakeholders as they leverage the sunk cost of existing systems to provide an additional revenue stream

(Maisch 2019). VPP uptake is forecasted to deliver up to 700 MW by 2022, driven by existing programs and funding (ARENA 2019*b*).

The term "value stack" is often used to describe the capabilities of VPPs, where VPPs may be able to deliver services within the energy markets, FCAS markets and through network support agreements. Without consumers registering as a "Market Customer", where they'll be able to participate in delivering these services, the full value stack is not possible through the current energy regulatory framework (AEMO 2018). Examples of how consumers may deliver these services through VPPs are described below:

- Energy markets - contributing to peak load reductions through generating and/or exporting electricity during energy price events, as well as revenue gains through energy arbitrage
- FCAS markets - delivering contingency FCAS during periods of unexpected frequency variations
- Network support - delivering ancillary services under Network Support and Control Ancillary Services (NSCAS): Voltage Control Ancillary Services (VCAS), Network Loading Control Ancillary Services (NLCAS), and Transient and Oscillatory Support Ancillary Services (TOSAS)

One of the key takeaways within Australian Renewable Energy Agency (ARENA)'s VPP Knowledge sharing workshop summary was the fact that VPPs are in its early stages of its technological lifecycle, and is still viewed as an industry with varying business models, incohesive policies and communication inefficiency. To realise the full benefit of coordinated DER, effective interoperability must be achieved through consistency in APIs and communications. The summary further enunciates a greater emphasis on the consumer journey.

2.3 Revenue Streams

To access the wholesale services and network services outlined in figure 2.2, in particular the energy and FCAS markets, households may do so through retailers who host the VPP, usually partnered with a technology vendor who manages the optimisation software and/or hardware. To limit the scope, revenue streams of interest are increased PV self consumption, contingency FCAS provision, and energy arbitrage through spot price exposure

The NEM operates as a spot market, managed by AEMO. Supply and demand is matched through the coordination of the dispatch process, whereby AEMO determines which generator is allowed to generate based on the power they can provide during set time periods (AEMO 2020*e*). Generator bids are collected and pooled every five minutes, and a dispatch price for that five minute period is determined by the marginal cost of electricity production (Wang et al. 2020). At the current time of writing, electricity trading is settled every thirty minutes at a "spot price", which is the average of six dispatch prices (AEMO 2020*e*). However, the settlement period is set to change from thirty minutes to five minutes based on the five-minute settlement rule change commissioned by the AEMC, effective from 1st July 2021 (AEMC 2020*a*).

From the July 2019 to June 2020 temporal scope in which this thesis simulates within, the maximum spot price for South Australia was $14,700/MWh and the minimum was $-1000/MWh. The maximum has been set at $15,000/MWh effective from 1st July 2020 (AEMO 2020*e*), which sits outside the scope.

2.3.1 Increased PV Self-Consumption

For a residential consumer, investments into rooftop PV allows for partial energy independence from the grid due in owning a non-dispatchable generating unit. The power generated from PV can be used to supply the load demand within the household, avoiding the costs associated with importing electricity from the grid. Excess PV generation can be exported into the grid valued at a feed-in tariff (FiT), decided upon by the retailer and their associated electricity plans. Return on investment on the rooftop PV comes in the form of avoided costs from self-consumption, and revenues from PV exports.

BESS paired with rooftop PV further unlocks the value within distributed generation, in providing the control and capability behind import and export timings. BESS can be used to store the excess PV generated within peak sun hours, and dispatched during non-sun hours to increase PV self-consumption.

2.3.2 Energy Arbitrage

When it comes to residential consumers of electricity, participation is facilitated through retailers. Interactions within the retail sector is highlighted on the top right of figure 2.3. Retailers purchase electricity at the spot price within the energy market, and resells it to consumers who then purchase the electricity under commercial tariffs. Retail markets are extremely competitive, with multiple retailers providing multiple electricity plans for consumers to choose from. Within each plan, however, are fixed charges and variable charges. Fixed charges come in the form of daily supply charges, where consumers pay for their connection to the grid. Variable charges are volumetric, and vary with electricity consumption (NREL 2015). As a whole, the final electricity bill that consumers are billed for a reflection of wholesale electricity costs, regulated network costs (transmission and distribution), environmental policy costs and retail costs (AEMC 2019*a*).

The determination of the spot price is dependent on the generation mix and physical infrastructure capabilities. Fluctuations are often seen between the maximum and minimum spot price caps, and each stakeholder that purchases electricity from the spot market carry risks inherent within price fluctuations. Retailers manage this risk through their analyses on market trends and statistics, setting firm prices for their customers that will ensure profits. However, through technology vendors that offer pass through tariffs, such as Amber Electric, prosumers are given the choice in purchasing and selling electricity through spot market exposure, rather than through defined prices. Prosumers now carry that risk, however financial gains are possible through arbitrage. That is, prosumers can manage their generation and consumption such that consumption occurs during periods of low or negative prices, and exports are saved for periods of high prices.

2.3.3 FCAS

Frequency Control Ancillary Services (FCAS) was established and maintained by AEMO to maintain the frequency within the NEM to close to 50 Hz, as per NEM frequency standards (AEMO 2015). To achieve this, generation or demand is altered. FCAS is divided into two segments, ”regulation” FCAS and ”contingency” FCAS. To keep the frequency within the normal operating frequency band (NOFB) of 49.85 Hz and 50.15 Hz (AEMC 2020*b*), regulation FCAS is deployed, responsible for correcting minor devi-

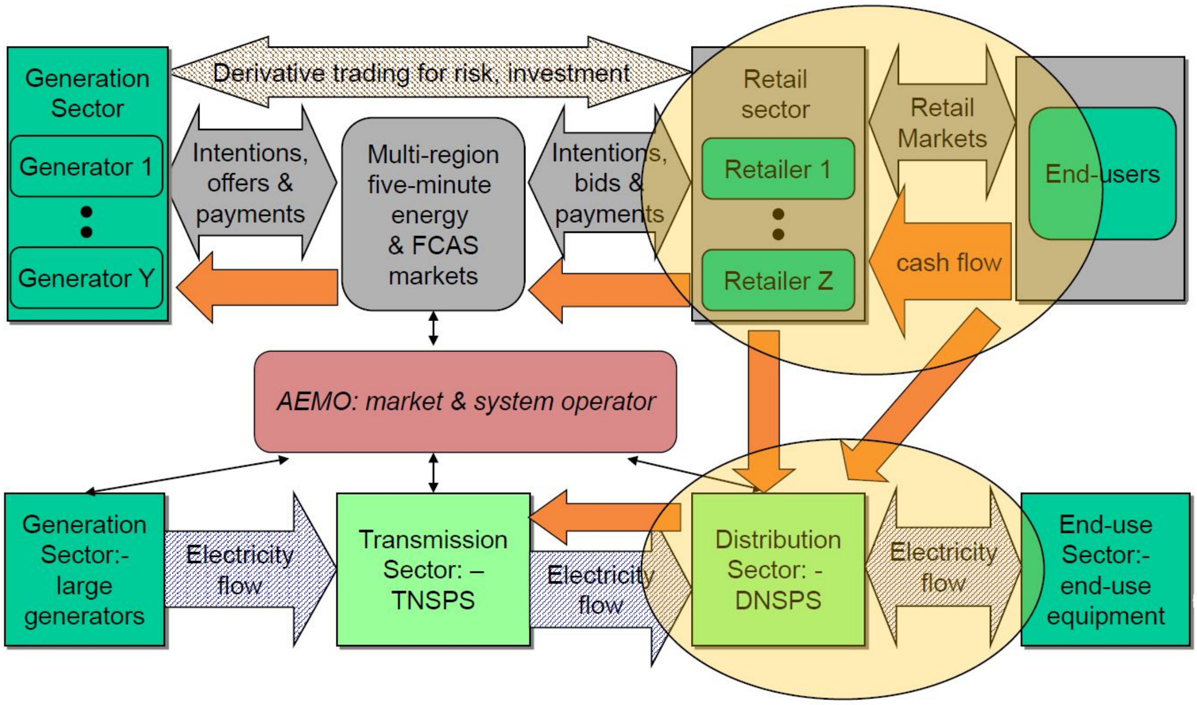


Figure 2.3: NEM market energy and cash flows (Outhred & Thorncraft 2010) (MacGill 2020)

ations in generation or load (AEMO 2015). If the frequency falls outside of the NOFB, contingency FCAS control is used to correct the frequency back in to the NOFB. As summarised in table 2.4, both regulation and contingency FCAS may be further categorised as "raise" or "lower" FCAS. Raise FCAS aims to raise the system frequency back into the NOFB through either increasing generation or decreasing system load. Lower FCAS aims to lower the frequency by decreasing generation or increasing system load (AEMO 2015) (Wang et al. 2020).

Within contingency FCAS, markets are divided based on how fast generators can respond to contingency events. Consequently, both raise and lower contingency FCAS are further divided into fast, slow and delayed FCAS. The response times in which determines a generator fit to participate in a market is defined in figure 2.4.

Contingency FCAS providers are paid based on the quantity of service they can provide within each dispatch interval. The payment is valued at the market clearing price, with each of the 6 contingency markets having their own price traces (AEMO 2020*d*). If the quantity of service FCAS providers can be sustained for greater than five minutes, prices across the fast, slow and delayed FCAS are stacked. With a certain capacity enabled and available for charge or discharge at the command of AEMO, providers are paid for their potential commitment, regardless of the need to provide a response (Wang et al. 2020).

FCAS services		Response time	Duration
Regulation	Raise/lower	Continuous	
Contingency	*Fast* raise/lower	Within 6 s *following a contingency event*	60 s
	Slow raise/lower	Within 60 s *following a contingency event*	5 min
	Delayed raise/lower	Within 5 min *following a contingency event*	Until notified by central dispatch (presumably within 10 min)

Figure 2.4: Overview of FCAS (Wang et al. 2020)

2.4 Literature on BESS and VPPs

There is no scarcity in literature that explores the revenue streams available to rooftop PV and BESS combined, for the objective in maximising the value of the storage.

Reference (Sani Hassan et al. 2017) engages with the techno-economic benefits of PV and BESS within the UK with FiT incentives, varying electricity prices and BESS unit cost. FiT revenue was maximised with an optimisation model, and TOU tariffs were found to offer similar revenue capabilities as wholesale energy market tariffs. The optimisation between the delivery of frequency control and peak shaving through BESS was explored in reference (Engels et al. 2019), with the revenue implications of frequency control earning much more than peak shaving. Peak shaving, along with primary control reserve (PCR) and energy arbitrage were also considered in reference (Braeuer et al. 2019). Profitability was only achieved when the three revenue streams were considered together, with peak shaving and PCR being the major revenue contributors. Reference (McMahon et al. 2019) discussed the economic feasibility of BESS through an analysis on typical domestic loads on top of two flexible loads, a heat pump and electric car. Cost effectiveness was not achieved on the basis of UK electricity tariffs, however the author(s) hypothesise sensible payback periods through aggregation and new revenue streams. Energy storage optimisation in the form of "energy shifting, ancillary services and electricity supply capacity" are considered for BESS's in reference (Yu & Foggo 2017). Frequency regulation services were seen to provide the majority of revenue. Similarly, the simulation of 5,000 system-aggregated batteries was performed within the scope of the UK electricity markets (Rappaport & Miles 2017), where energy arbitrage and frequency regulation services were provided by the BESS. Although rooftop PV was not considered within this study, the provision of frequency response proved to be financially valuable. In the same vein, another study on BESS in the UK were seen to have profits tripled from reserve market participation relative to arbitrage (Staffell & Rustomji 2016).

Literature on VPP and its frameworks, optimisation models, and participation strategies are also rich. Overviews on DER, VPP infrastructure and the integration of prosumers have been discussed (Mahmud et al. 2020, Ghavidel et al. 2016). Studies have taken into consideration other generating units, storage units and flexible loads, and have simulated bidding strategies within day-ahead, intra-day, real time, and reserve markets. Reference (Loßner et al. 2017) has shown that the optimisation of DER through a VPP interface yields higher trading revenues than when operated individually. Independent operation of DER is also unable to contribute towards distributed network support and stability (Naughton et al. 2020). Real time control of BESS based on spot prices and "rolling price predictions" was performed in (Xiao et al. 2019), with maximal revenue obtained when BESS acts as both a local generator and load, and an energy buyer and seller. Two-stage stochastic mixed-integer linear programming was used in (PandŽić et al. 2013) to maximise the profit gained by a VPP participating in the day-ahead and balancing markets. Multi-market co-optimisation, in which a VPP participates in the energy market, FCAS, demand response and hedging contract markets, are explored in reference (Wang et al. 2020). Multi-market participation was presented as a strong business case, with DER and VPP investments being paid back in less than 12 years. Without multi-market participation, however, DER investment would have a payback time greater than their lifespan.

Within literature, the economic field of game theory has been employed to ensure fair, efficient and equitable reward allocation. Cooperative game theory was considered to form an energy pricing structure that would serve as an alternative to feed-in tariffs, providing supply security as a benefit (Chalkiadakis et al. 2011). Non-cooperative game theory has also been considered to maximise financial benefits for each DER player through price bidding strategies (Marzband et al. 2016).

2.5 Programs

With the Australian Renewable Energy Agency (ARENA) funding $57 million into a total of 30 past and current DER projects (ARENA 2020*b*), many stakeholder groups are interested in driving projects and research studies to fully unlock the potential of DER and VPPs. Those of significance importance and capital investment are briefly summarised in this section. In looking into these programs, insights into the current Australian VPP landscape can be gained, and implications of further work may be extrapolated.

2.5.1 Ausgrid VPP

Ausgrid's VPP aims to explore demand management capabilities through residential batteries, connecting with BESS fleets managed by Reposit Power, Evergen and Shinehub. As at November 2020, Ausgrid's VPP network spans across 350 customers, with an average BESS capacity of 10 kWh and average maximum discharge power of 4.1 kW. Network support, in the form of peak load reduction on local feeders, were the main focus in their latest progress report (Ausgrid 2020). Along with the provision of peak shaving during hot and cold weather, voltage support and business case analysis were also discussed.

The 11kV feeder at the Kurri zone substation of the Hunter region was established as the reference feeder in which their findings and projections were based upon. Three dispatch days, two hot and one cold day, were highlighted for analysis. The battery dispatch profile in response to the peak load events were compared to the battery profile on a BAU case and to the feeder load profile. Among each dispatch day, the dispatch profiles were adjusted to simulate greater potential in VPP dispatch, and further findings were gathered as a result.

Based on the findings discussed in their latest progress report, VPP dispatch for the purpose of demand management was concluded as a viable option. The reduction in peak demand was seen to be one and a half to four times greater compared to the BESSs working independently. Coordination of the BESS was also seen to be imperative in aligning BESS dispatch closely to peak periods. The timing associated with BESS precharging in preparation for dispatch events are to be investigated further. Ausgrid also recognises a timing difference when comparing local network peaks, wider system peaks and energy and FCAS price signals. Consequently, further coordination and improved strategies are to be considered within further trials, in which literature has explored.

2.5.2 DEIP

The *Distributed Energy Integration Program (DEIP)* aims at providing the maximum value for all energy users with DER. As a collaboration between 13 stakeholder groups, input from various stakeholders into value exchange in markets and the efficient use of DER will span across government agencies and market authorities (ARENA 2020*a*). Within DEIP's mission and objectives, four "work streams" were established.

- Customers - recognising and understanding consumer expectations and preferences
- Markets - allowing for full value stacking of DER through multi-party exchange, while considering network constraints
- Frameworks - evaluating the optimal investment strategy between physical network infrastructure and non-network DER infrastructure
- Interoperability - normalising the communication and operation between distributed energy control systems

Four "work packages" have been released based on the objectives of the above work streams:

- DER Access and Pricing - developing pricing and access arrangements to support the higher penetration of DER and investment in DER services
- DER Interoperability - execution of a DER platform that could effectively manage the exchange of information
- DER Market Development - running trials of different market frameworks and assessing which could provide efficient, equitable and sustainable outcomes
- Electric vehicles

2.5.3 VPP Demonstrations

The VPP Demonstrations program was established through a collaboration with AEMO, AEMC, AER and DEIP. The program contributes towards all 4 work streams mentioned in the previous section (customers, markets, frameworks and interoperability). Through the management and integration of VPPs, the trials held within the program aims to (AEMO 2018):

- provide data and insights into the capability of VPPs in delivering the full value stack
- to assist AEMO and AEMC in generating frameworks to support the commercialisation of VPPs through operational visibility

Participation models within the VPP Demonstrations are visualised in figure 2.5. Prosumers with rooftop PV and BESS participate within VPPs through their retailer. Their retailer acts as the Financially Responsible Market Participant (FRMP), in which their responsibility is to pay the spot price for each of the customer loads. The left column showcases a retailer and VPP operator working together through a commercial agreement. In recent events, however, retailers are seen to move horizontally into VPP provision, and VPP operators are seen to provide retail plans. The second column encapsulates this. An example would be Tesla operating within the South Australia VPP (SAVPP). The third column describes a VPP operator acting as the Market Ancillary Services Provider (MASP), with provisions allowed in FCAS only.

2.5.4 South Australian VPP (SAVPP)

The South Australian VPP is a progressing initiative that aims to connect 50,000 customers on a VPP network. Phase 2 of the initiative was completed early 2020, with a total of approximately 1,100 connected systems currently on the network. Operating in conjunction is the South Australia Home Battery Scheme that provides subsidies and/or loans to assist in consumer investment within rooftop PV and/or BESS. The scheme acts as an incentive for consumers to participate in the VPP, lowering the barrier of high capital investment.

Upon deciding on participating within this initiative, consumers are presented with the choice of going with 1 of 7 VPP providers available within SA, established by energy

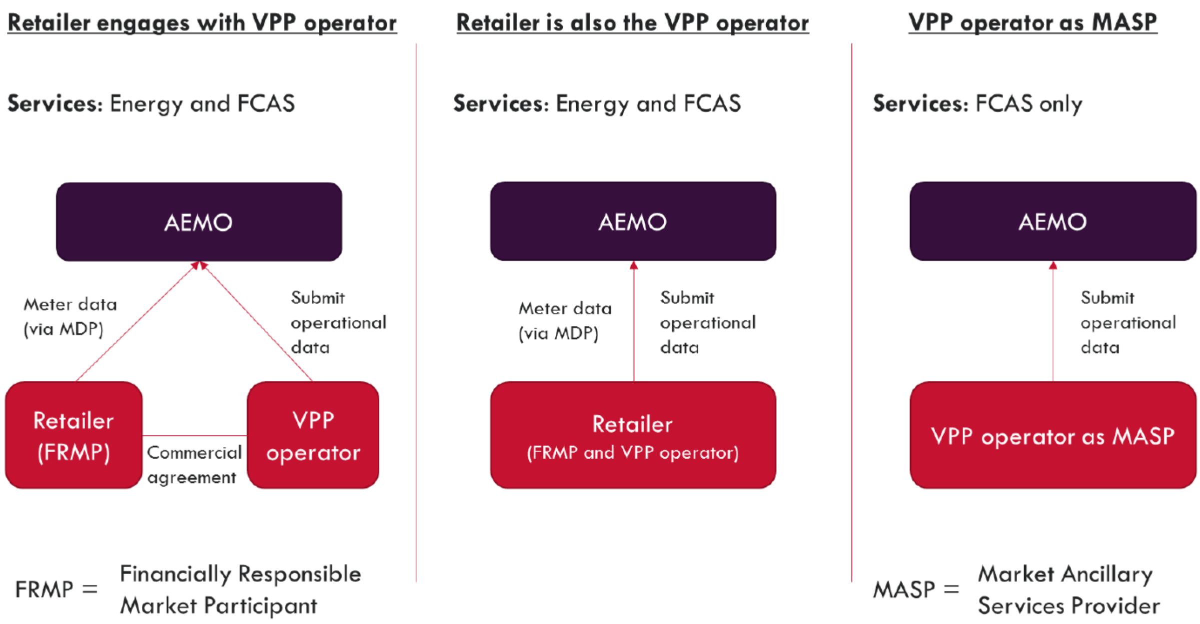


Figure 2.5: Participation models within the VPP Demonstrations

retailers and technology vendors. These are AGL VPP, Simply Energy VPP, Tesla Energy Plan, Shinehub Community, SonnenFlat, Discover Energy Smart Saver VPP, and Stoddart VPP. Within their plans are monetary incentives to attract consumers into joining their network. Examples include daily credits, sign-up bonuses, competitive electricity rates and reduced supply charges.

2.6 SA Context and Energy Landscape

South Australia stands at the forefront of renewables integration within the NEM, and within Australia. Across September 2020, SA has seen a 30.4% share of RE, and coal fired generation falling to a minimum of 65.4% (RenewEconomy 2020*c*). Further milestones were achieved during the months of October and November, with 73.3% of demand met by wind and solar in September (RenewEconomy 2020*e*). Rooftop solar was even seen to meet 100% of SA demand during October (RenewEconomy 2020*d*). Wholesale prices were also at a record low in September (RenewEconomy 2020*a*).

Throughout the second half of 2019 and first half of 2020, FCAS prices were seen to be extremely volatile (WattClarity 2020). FCAS provision has usually been the responsibility of coal-fired, fossil-fuelled or gas generators, due to the inertia and system strength they provide (RenewEconomy 2020*d*). In South Australia, a minimum of gas fired generation is required to provide these grid services, however the capability of BESS in providing synthetic inertia may reduce the need for gas generators. BESS has seen to provide exceptional responses to FCAS contingency events (AEMO 2020*c*), as seen in the VPP Demonstrations Program. With RE seeming to take larger shares within supplying demand, volatility in FCAS prices are arise with thermal power stations being called upon less. This has been a major shift relative to historic trends, as FCAS has only been "a few percent" of the energy price (WattClarity 2020).

2.7 Gaps in Literature

Although literature is rich within BESS contributing towards multiple revenue streams, and VPPs shown to financially favourable when operating DER, to the author's best knowledge, there is a gap within presenting a residential business case of rooftop PV and BESS working together within markets that have high renewable penetrations, relatively low wholesale energy prices and volatile FCAS prices. Within the literature explored in this thesis, the majority of the analyses performed were in markets which still had thermal powered generators taking the majority within the generation mix, hence relatively stable energy and FCAS prices. However, South Australia has seen changes to its energy landscape like no other electricity system in the world, starting with the largest capacity wise battery in the world at the time of construction, with new BESS entrants following suit. There is huge potential in discovering the financial impacts on prosumers participating in VPPs compared to other prosumers around the world, and how that may change moving forward into the future.

2.8 Problem Statement

Distribution networks are experiencing technical issues with uncoordinated DER across Australia, potentially resulting in further network infrastructure investments which adds costs to consumers. In coordinating DER through VPPs, there is immense opportunity within BESS contributing towards peak load reduction and network support, with additional revenue streams becoming available for prosumers.

2.9 Hypothesis and Aims

The aim is to explore the financial implications of prosumers, who own rooftop PV and BESS, in participating in additional revenue streams. The revenue streams in question are increased PV self-consumption, tariff arbitrage, feed-in tariffs, frequency control ancillary service (FCAS) market participation, and energy arbitrage through pass through tariffs. The analysis on multiple revenue stream participation will be performed within the context of SA, in particular the July 2019 to June 2020 period, where wholesale prices and FCAS prices are relatively more volatile than historical trends.

Tariff arbitrage in the form of TOU tariffs is hypothesised to be more financially attractive than customers on a flat tariff, as an optimally operated BESS can avoid peak and shoulder periods and only charge during off-peak hours. However, this impact is dependent on the size of the PV system relative to the load profile. With FCAS prices being extremely high, relative to historical prices, it is hypothesised that FCAS participation will yield the most revenue, averaging over triple the revenue on a business-as-usual case as seen in the above literature (Staffell & Rustomji 2016). However, the allocation of headroom to allow for FCAS commitments may decrease the revenue gained from self consumption and PV exports. Revenue gained through energy arbitrage is also hypothesised to be financially attractive with the low wholesale market prices.

Chapter 3

Methods

In order to perceive the additional amount of value from residential batteries accessing multiple revenue streams, models are generated to simulate the charging and discharging behaviour of a BESS with a given load profile and PV profile, across 288 prosumer profiles.

3.1 Instruments

Out of the revenue streams listed within figure 2.2, increased PV self-consumption, frequency control ancillary service (FCAS) market participation, and energy arbitrage through pass through tariffs are considered. Within every trading interval of 30 minutes, the BESS compares the multiple revenue streams available, and identifies which stream provides the most revenue. In order to simulate this behaviour, Python was chosen as the modelling tool.

Python is widely considered to be a tool fit for large amounts of data, suitable for automation, modelling or simulation purposes (Cambridge Spark 2019). With python having a relatively easier learning curve than other programming language alternatives, such as R, it was suitable for a preliminary data analysis for simulating the behaviour of a BESS. Furthermore, its expansive collection of libraries and wide user base allows for strong community support. Libraries of note are numpy and Pandas, which are commonly used within data science and visualisation purposes, and hence throughout this thesis.

NEMOSIS is an open source tool that supports the creation of data sets on the NEM. The downloadable software allows the user to access NEM data through an easy to use graphical user interface. As the BESS model requires price traces across revenue streams, NEMOSIS is used as the main data collection tool for NEM related data.

3.2 Data Collection

As the geographical scope within this study is South Australia (SA), where the majority of VPP research and trials are occurring, all data retrieved are based off current market prices and offers available to prosumers in SA.

To simulate charging and discharging behaviour of a residential BESS with rooftop PV and non-controllable loads, sample PV and load data sets and profiles are needed. Ausgrid Solar Homes data set was chosen to provide both of these sample profiles, with 300 unique consumers that had their PV export and load gross metered over the 2012-2013 calendar year. More specifically, data was available from July 2012 to June 2013 inclusive.

There were alternative data sets that were released closer to the temporal scope of this study, i.e. 2020, however they did not provide a cohesive set that included both PV and load profiles. One example is the data set associated with the Next Generation Energy Storage Program. The program supports the establishment of 36 MWh of BESS storage within the ACT region (ACT Government 2019), and has developed a portal in which researchers and other stakeholders may access the data. However, the data is seen to have major flaws within their timestamp variable, and was hence not considered within this thesis.

To perform revenue stream optimisation for a residential BESS with rooftop PV, price traces are to be retrieved for each respective revenue stream. As stated in section 3.1, the revenue streams available for the prosumer are self consumption, FCAS market participation, and wholesale energy market spot price exposure through feed-in tariffs. An electricity rate of 37.73 c/kWh is applied, based off AGL's retail electricity rates which are effective from July 2020. Time-of-use (TOU) rates and the feed-in tariff is similarly retrieved (AGL 2020). All prices are inclusive of the goods and services tax (GST), which is 10% in Australia. Electricity rates are summarised in table 3.1.

What may be unexpected from 3.1 are the TOU prices, especially the shoulder and off-peak rates. In other states within Australia, peak period rates are valued highest, with off-peak rates valued lowest. This valuation roughly aligns with broader system demand, whereby the peak periods are defined by the periods of highest demand, and vice versa. For SA, however, a "Solar Sponge" tariff is available for consumers with smart meters, and is applied within the shoulder period. The Solar Sponge tariff was established to encourage consumers to shift loads during the middle of the day (10am to 3pm), in hopes of consuming as much solar as possible produced during that period. The shoulder period is hence evaluated at 25% of the standard tariff, with peak periods at 125%, and off-peak at 50% (Solar Quotes 2019).

Supply charges are not considered within the revenue calculation, as it is a constant variable.

Table 3.1: Electricity rates for flat tariff and time of use plans, based off retail electricity rates from AGL

Rates	Time Period	Electricity Rate ($/kWh)
Flat tariff	All day	0.3773
TOU - peak	6am-10am and 3pm-1am	0.44539
TOU - shoulder	10am - 3pm	0.24431
TOU - off peak tariff	1am - 6am	0.30734
Feed-in tariff	All day	0.16

Market clearing prices, also known as ancillary service prices (AEMO 2020*d*) , across the 6 contingency FCAS markets and the wholesale energy market prices are retrieved through NEMOSIS for the time period starting 01/07/2019 and ending 30/07/2019 inclusive for a total of 365 days. Regulation FCAS is not considered within this thesis.

3.3 Data Analysis

3.3.1 Data Cleansing

Within the data analysis process, 11 customers out of the 300 were found to have data missing within some 30 minute time intervals. These were customers 2, 68, 95, 161, 187, 248, 272, 284, 289, 293, 294 and 300. Consequently, they are not considered within the results, and 288 customers are henceforth taken into account.

3.3.2 Setup

The model produced in python simulates a prosumer within a residential household, who has already invested and installed rooftop PV and a Tesla Powerwall 2 BESS. The Powerwall 2 and its corresponding technical specifications were utilised throughout the thesis as the reference residential BESS, as it is also prevalent within the South Australian BESS Scheme. From the Tesla Powerwall 2 Datasheet, its usable energy capacity is rated at 13.5 kWh, and the maximum rated charging and discharging capacity is 5 kW (Tesla 2019). The prosumer is assumed to have no controllable loads, hence the distributed energy resources relevant to the prosumer is only generation based, and not load based. That is, the prosumer is not modelled to induce savings from changes in consumption behaviour. All prosumers are also considered to be price takers, i.e. their participation within the FCAS and energy markets does not influence market prices.

As mentioned within the introduction and literature review, rooftop PV and BESS have developed substantially in regards to their performance, efficiencies and financial feasibilities. When comparing the PV generation profiles between 2013 and 2020, new and improved solar cell technologies have both increased the solar generation per square metre and also provided incentive for prosumers to install relatively more solar (AEC 2019). Hence, to adapt the PV generation profile from the Solar Homes data set, which was held in 2013, a scaling factor is to be applied to the 2013 PV profile to align with the typical performance seen within 2020.

A 6.6 kW PV system is assumed for each prosumer modelled. This variable is kept constant for simplicity, and is shown to be a popular and affordable choice among Australians (Martin 2020). The average solar generation per year for 6.6kW system in the South Australian region is taken to be 29.97 kWh (Energy SA 2020). Within the summary statistics, the 2012-13 average gross generation was recorded to be 2,181 kWh per year, which equates to 5.96 kWh generation per day. Hence, a scaling factor of 5.02 is applied such that each of the 300 prosumers generate approximately 29.97 kWh a day, to fit within the 2020 technological scope.

The load profile, on the other hand, did not have a scaling factor applied, and was left unchanged from the Solar Homes data set. The change in demand from household electricity consumption over the decade is seen to both increase and decrease depending on the consumer. While an overall scaling factor may have been applied on this basis, the change in weather and climate from 2013 to 2020 is the most significant factor in the shape of the load profiles.

To promote the longevity of the BESS and for safety concerns, the BESS was set to operate between an SOC cutoff of minimum 10% and maximum 90% (Li & Danzer 2014). As the maximum charging and discharging power of the BESS is rated at 5 kW, a maximum of 2.5 kWh is able to flow in and/or out of the BESS within a 30 minute period. However, this is not the maximum that the grid may see, as excess PV exports may assist in delivering further export capabilities.

The BESS is AC coupled, whereby a connection to a BESS inverter precedes the connection to the electricity grid. The PV arrays are connected to a PV inverter, which converts the DC power to AC. All conversion efficiencies within these power flows are assumed to be 100%.

3.3.3 Revenue Stream Analysis

The operation of rooftop PV and BESS across 288 households is assessed with the following cases:

Table 3.2: Participation Scenarios

Case number	Operating model
1	Base case, revenue earned from self consumption and PV exports only
2	Revenue earnt from FCAS contingency market participation, self consumption and PV exports
3	Revenue earnt from energy market, self consumption and PV exports

3.3.4 Case 1: Base case

In case 1, the household is not participating within a VPP and is hence unable to participate within FCAS markets and the energy market. Financial benefits gained from investing in rooftop PV and BESS would be through self consumption and PV exports. With self consumption in case 1, it is always beneficial for the prosumer to allow the PV generation to satisfy loads within the household, as the value within the alternative of exporting the PV (FiT at 16c/kWh) is less than deferring the cost of paying for those loads. If the BESS is full, and there is excess PV generation after satisfying loads, revenue is then gained through exports at the FiT price. The following logic models are adapted from literature (Young et al. 2019). The logic model for case 1 is shown in figure 3.1.

Under the flat tariff, the load and PV generation is compared. As self-consumption is more financially beneficial and hence prioritised over PV exports, PV generation will seek to satisfy loads whenever possible. When the load exceeds PV generation, the household will seek power from the BESS. If the BESS cannot fulfil the loads, electricity is imported from the grid under the flat tariff of 37.73 c/kWh. If there is an excess of PV power after all loads are fulfilled, the household will seek to store this excess within the BESS. If the BESS is full, the household then earns revenue at the FiT by exporting the excess PV to the grid.

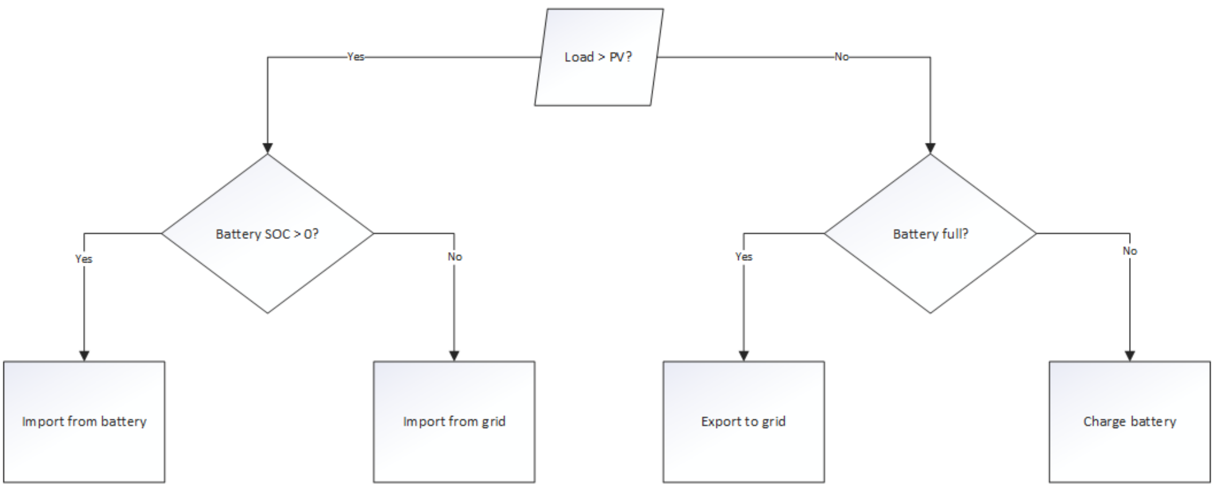


Figure 3.1: Case 1 logic model for a flat tariff

Under the TOU regime, the household gains the most value by avoiding electricity consumption during peak times, and charging the BESS during off-peak times when the rate is low. This is also known as tariff arbitrage. Energy from PV generation is most valuable during these peak times as the electricity rate is highest, hence the BESS will attempt to conserve its energy until peak times. When it is a peak period, the BESS will operate in a similar manner to a flat tariff, where load and PV generation is compared and decisions are made based on the BESS state of charge. During shoulder or off-peak periods, negative net loads are only fulfilled by grid imports, as the BESS saves its energy for peak periods. Otherwise, excess PV generation will either be stored or exported.

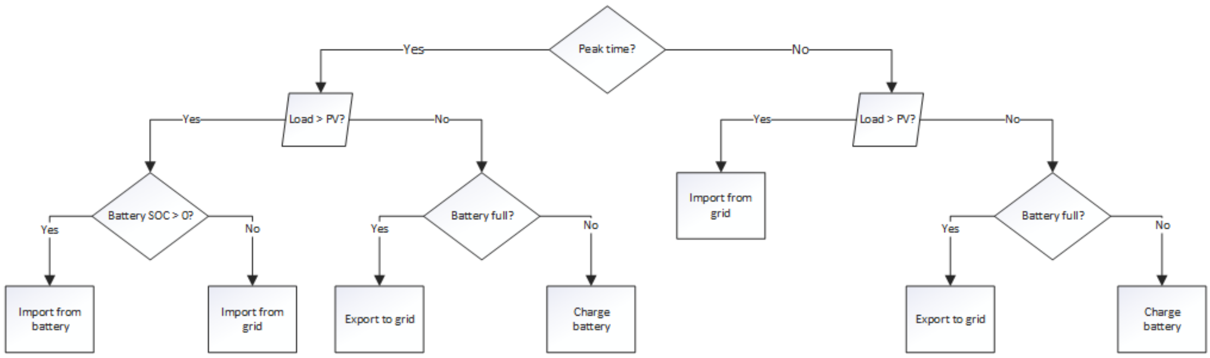


Figure 3.2: Case 1 logic model under TOU

3.3.5 Case 2: FCAS

Figures 3.3 and 3.4 represent case 2 under the flat tariff and TOU regimes respectively. The prosumer is rewarded within their participation in the contingency FCAS markets for being available in providing contingency services. That is, the prosumer would submit bids to AEMO through their retailer which indicate how much power the household could discharge during raise contingency and how much it could import during lower contingency. To allow each household to participate in all 6 markets, headroom is considered in the BESS such that it is always available to deliver its raise and lower commitments.

The BESS considered in this study (Tesla Powerwall 2) has a rated maximum charging and discharging power of 5 kW. At 5 kW, the maximum that the BESS can charge or discharge within a 30 minute interval is 2.5 kWh. If extra headroom of 2.5 kWh is provided for the BESS in regards to its minimum and maximum SOC cutoff, it is able to provide its raise and lower FCAS commitments year round, while simultaneously allowing for revenue gains through previous strategies of self consumption, PV exports and tariff arbitrage. In addition, the household will attract revenue from the prices across the 6 FCAS markets simultaneously. Hence, each household is simulated to bid 5 kW across raise and lower

FCAS. With this headroom of 2.5 kWh considered along with the 10% minimum and 90% maximum SOC cutoff, the BESS operates between 3.85 kWh and 9.65 kWh for case 2 only.

A summary of all FCAS contingency events within the July 2019 to June 2020 period inclusive are shown in table 3.3, with a total of 18 events (AEMO 2019*a*), (AEMO 2019*b*), (AEMO 2020*b*), (AEMO 2020*c*).

Table 3.3: All raise and lower FCAS contingency events from July 2019 to June 2020 inclusive

Date	**Time**	**Duration**	**Services Required**
3/09/2019	1:22:00	7 min 42 sec	All Lower Services
9/10/2019	8:00:00	3 min 33 sec	Fast Raise And Slow Raise
16/11/2019	18:00:00	15 min	All Lower Services
10/12/2019	13:46:00	2 min	Fast Lower And Slow Lower
10/12/2019	14:05:00	8 min	All Raise Services
2/01/2020	15:35:00	12 sec	Fast Raise
20/01/2020	12:59:00	13 min	All Raise Services
23/01/2020	11:26:00	> 5min and<15min	All Raise Services
28/01/2020	17:20:00	1 hr 10 min	All Lower Services
30/01/2020	17:23:00	> 5min and < 15min	Fast And Slow Raise
14/02/2020	10:02:00	> 5min and <15min	All Raise Services
5/04/2020	15:37:00	>5min and < 15min	All Raise Services
10/04/2020	17:05:00	> 5min	All Raise Services
16/04/2020	17:50:00	1 hr 5 min	All Raise Services
6/05/2020	16:44:00	> 5min and < 15min	Fast Raise And Slow Raise
12/05/2020	14:30:00	> 5min	All Raise Services
19/05/2020	14:52:00	> 5min and < 15min	All Raise Services
1/06/2020	12:56:00	9 min 57 sec	Fast Raise And Slow Raise

The optimal BESS strategy within case 2 is similar to case 1 with both flat and TOU tariffs, as the headroom given accounts for the raise and lower FCAS commitments. When contingency is not called, the BESS operates in its usual behaviour in prioritising self consumption, exporting excess PV generation and importing electricity from the grid during periods of negative net load.

As the BESS within the modelling operates within 30 minute intervals, the times at which contingency is called is rounded to the nearest 30 minute cutoff. For example on the 03/09/2019, contingency was called at 0122 hours. As the duration of the contingency event was roughly 8 minutes, the period in which the event is associated is 0100 to 0130. For the case of 01/06/2020, where the contingency event lies in between the 1230 to 0100 and 0100 to 0130 periods, the 1230 to 0100 is chosen as the highest prices are typically seen immediately after contingency is called, with prices dropping as the frequency returns within the NOFB. This is further explored and discussed within section 4.

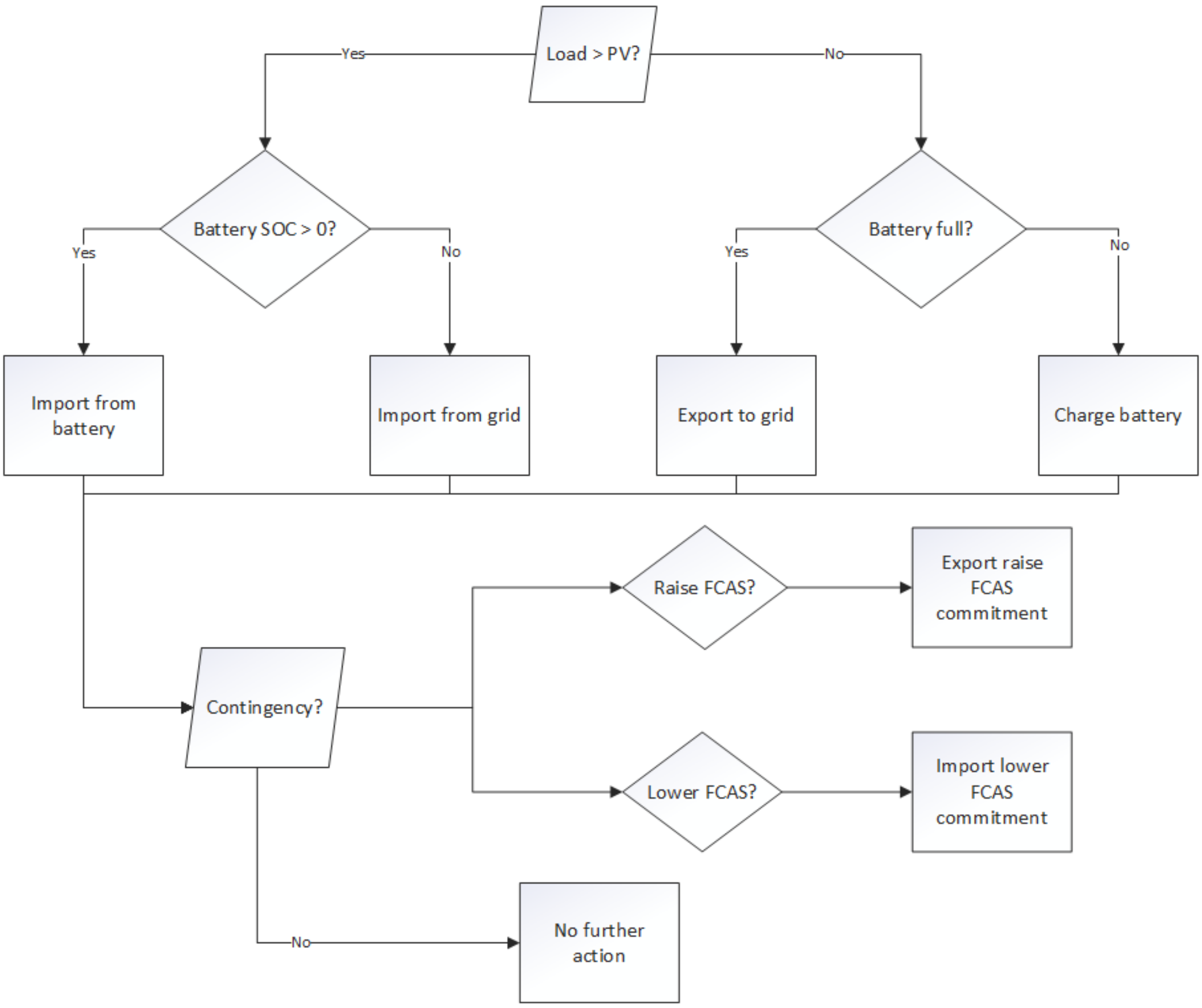


Figure 3.3: Case 2 logic model for a flat tariff

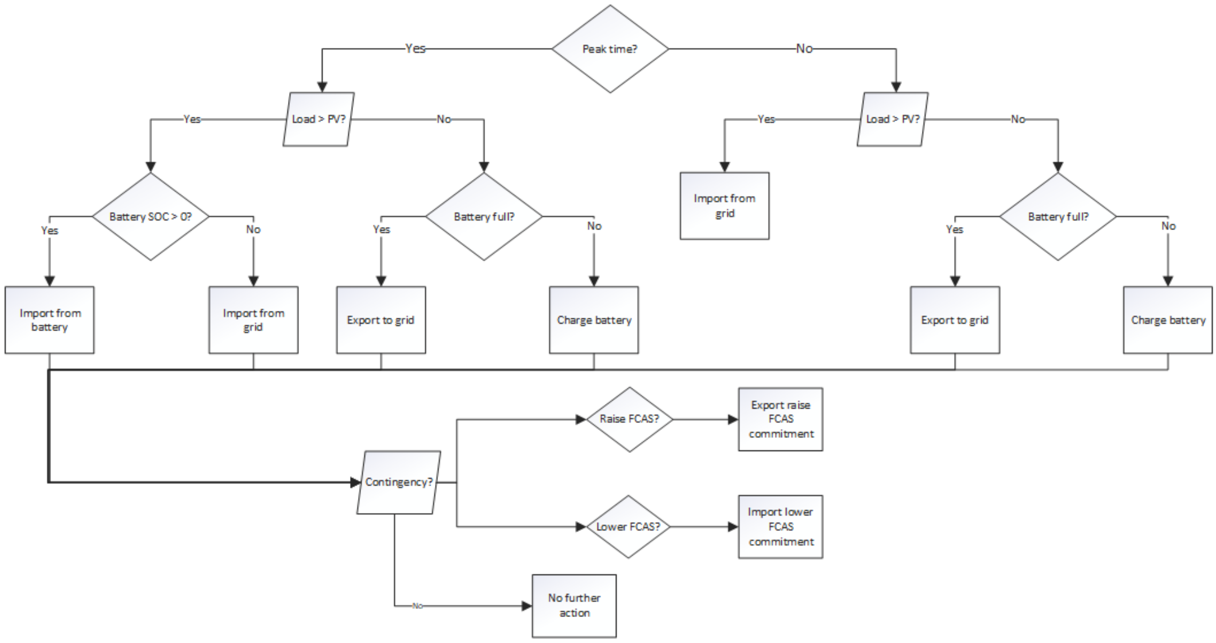


Figure 3.4: Case 2 logic model under TOU

3.3.6 Case 3: Energy Market

Spot price exposure for the prosumers are available with pass through tariffs. BESS behaviour is similarly modelled under flat and TOU tariff, figure 3.1 and figure 3.2 respectively. Instead of the household consuming electricity under a flat tariff or TOU rates, the wholesale market price, in addition to other costs, are paid instead. In the case of Amber Electric, these include metering costs, network charges, environmental costs and carbon offset costs. In considering these other costs, the pricing structure of Amber Electric is followed. Amber Electric provides the average price per month and the average FiT per month for a prosumer in SA(Amber Electric 2020*b*). The difference between the average wholesale market price and the Amber Electric average price (which includes the other costs) is calculated for each month. The average of these 12 values, calculated to be 21.68 c/kWh, is then taken as a constant value that encompasses the metering costs, network charges, environmental costs and carbon offset costs for all trading intervals. The FiT is calculated in a similar manner. It is paid to the prosumer at the wholesale market price on top of the market and environmental costs (Amber Electric 2020*c*). To determine a constant value for the market and environmental costs, the difference between the Amber Electric average FiT and average wholesale market price is calculated monthly. The average of the 12 values is calculated to be 3.31 c/kWh. Monthly values and calculated values are presented in the Appendix. A fee is also typically charged to the prosumer at

\$15 per month within their subscription model (Amber Electric 2020*a*). Hence, a yearly fee of \$180 is also added to the final revenue calculations for case 3.

3.4 Limitations

Simplifications and assumptions were made within this thesis due to the nature of the data collected. Scaling factors were applied to the PV profiles received from Ausgrid Solar Homes data set as the data must be adapted towards the temporal scope of 2019-2020. In the ideal situation, scaling factors would not be considered should there be data in the 2019-2020 period, in South Australia that records net consumption and generation, i.e. load and PV profiles separately. Formulating adapted PV profiles from the consideration of weather and climate changes from 2013 to 2020 is also ideal.

A singular flat tariff and TOU tariff is applied to all 288 prosumers and households. Competition within the retail electricity market in the NEM allows for prosumers to choose electricity plans that are most suited to their consumption and generation habits, often each with differing and competitive electricity rates. However, these electricity prices, along with supply charges, TOU windows, feed-in tariffs etc. are required to stay constant to measure the change in revenue between cases, with the only changes being the BESS participation behaviour.

In Case 3, section 3.3.6, the cost components within a variable electricity rate and FiT were discussed. Spot price exposure was simulated based on Amber Electric's pricing structures, however averages were considered to fill in gaps in data that Amber Electric did not provide, most likely to maintain a competitive edge.

Chapter 4

Results and Discussions

The base scenario within this thesis considers a prosumer who owns rooftop PV and a BESS on a flat tariff with no controllable loads. The financial gain for a prosumer participating within FCAS and the energy market will be measured using the revenue ratio, whereby revenues accumulated across all 3 cases will be assessed relative to this base scenario. Tariff arbitrage, in the form of TOU tariffs, will also be considered in these assessments.

Within each case, BESS operation and strategy will be visualised. Periods of time within the 2019 to 2020 temporal scope are chosen based on the impact it has on the decision making of the BESS. That is, periods of high prices are noted, and its impact on the charging and discharging behaviour of the BESS are shown. Customer 4 is randomly chosen as the reference household, and will be referred to throughout this section to explore BESS behaviour and reasons behind results.

4.1 Case 1

Case 1 considers a prosumer with rooftop PV and BESS operating under a flat tariff (base case) or TOU tariff. With the logic model shown in figure 3.2, tariff arbitrage could be achieved through TOU tariffs.

6 days of BESS operation, from 01/08/19 to 07/08/19, are shown in figure 4.1. Charging and discharging behaviour can be seen from the BESS; as PV starts generating during the day, the PV satisfies household load first, and the excess energy is stored in the BESS.

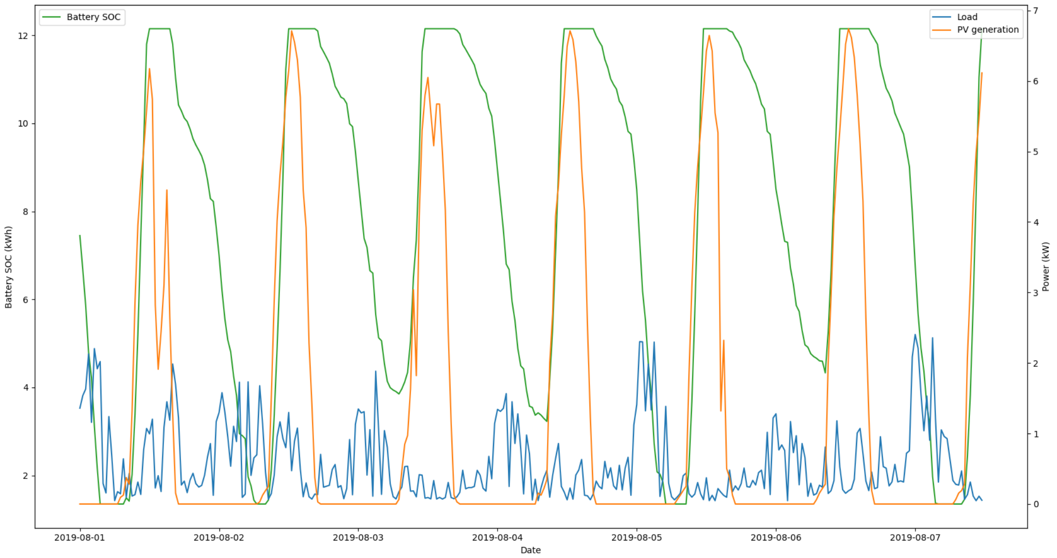


Figure 4.1: Case 1 - BESS behaviour under a flat tariff

The SOC hits a maximum of 90% of the BESS maximum rated capacity (13.5 kWh) for safety and BESS longevity purposes, as discussed in section 3.3.2. Excess energy beyond the maximum is exported to the grid, valued at the FiT. As PV generation ramps down towards the evening hours, the BESS can be seen to discharge its stored energy to supply the load demand, hitting a minimum of 10% of 13.5 kWh. Demand not fulfilled by the PV or BESS is supplied through electricity imported to the grid at the flat tariff rate.

Figure 4.2 demonstrates similar behaviour. However, the BESS is seen to continue storing energy during the night time, even when there are loads. As figure 3.2 defines, the BESS saves its energy for peak periods (15:00 - 24:00, 00:00 - 01:00, and 0600 - 10:00), as the electricity cost at those times are at their highest. Through a comparison of figures 4.1 and 4.2, the BESS is seen to discharge more often on the flat tariff. On the TOU tariff, this means that the energy generated from PV is being sold at the FiT more often self-consumption by the loads. As self-consumption is financially a better option, tariff arbitrage may be seen as a worse option compared to a flat tariff.

To capture the share between self-consumption and PV exports, the PV consumption ratio is introduced:

$$\text{PV consumption ratio} = \frac{\text{Self consumed PV}}{\text{Grid exported PV}}$$

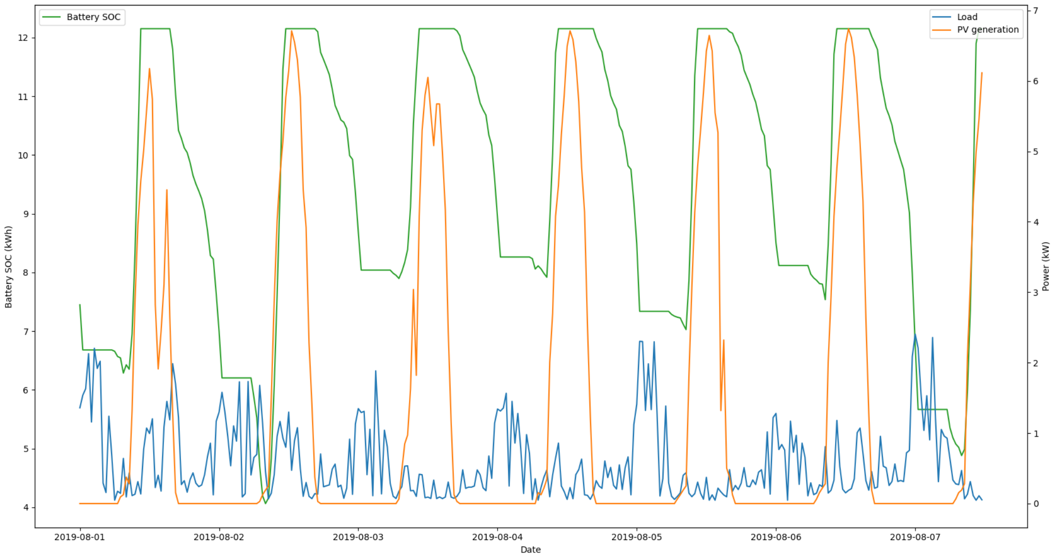
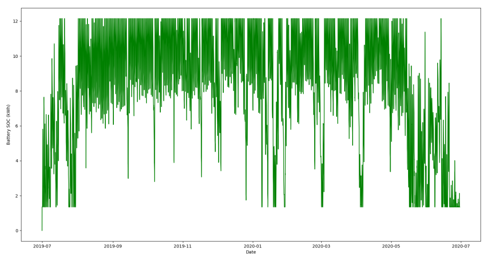
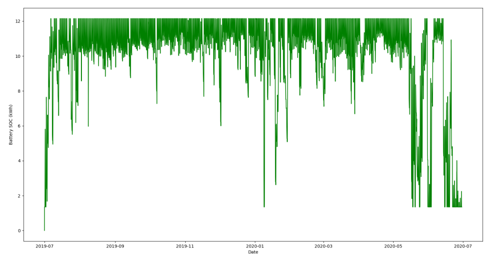


Figure 4.2: Case 1 - BESS behaviour under a TOU tariff

BESS SOC over the year is captured in figures 4.3a and 4.3b. Compared to the flat tariff, the SOC under TOU tariff is seen to remain at higher capacities more often, as the BESS is only allowed to discharged during peak periods.



(a) Case 1 - BESS SOC under flat tariff



(b) Case 1 - BESS SOC under TOU tariff

Table 4.1: Case 1 Customer 4 - Yearly costs and revenues

	Flat tariff	TOU tariff
Original bill	953.27	936.57
Case 1 bill	90.09	320.08
FiT revenue	166.25	288.64
Total revenue	1029.43	905.13

An analysis on customer 4's case 1 results is an example of the above hypothesis. Revenue under a TOU tariff is seen to be 11.6% lower than the revenue on a flat tariff.

In their original bill, TOU tariffs seemed to favour their consumption patterns, but was not the case with PV and BESS integrated. The case 1 bill for TOU was higher due to lower self consumption, which also resulted in higher FiT revenue for TOU in conjunction. This is also reflected in the PV consumption ratios, with 2.2 times as much PV being self-consumed over exports on the flat tariff, and 0.84 for TOU.

Running a simulation over 288 households reveal that this is the case for the slight majority of households. Figure 4.4 showcases the tariff arbitrage revenue ratio. If the revenue gained under a TOU tariff is greater than that of the flat tariff case, then the ratio of a particular household would be greater than 1. Outliers were also identified, with 1 household outside the boxplot maximum, and 9 outside the boxplot minimum. The mean is calculated to be 0.99, and median to be 0.99, meaning the share of households who benefit from a flat tariff over a TOU tariff is slightly larger than their counterparts.

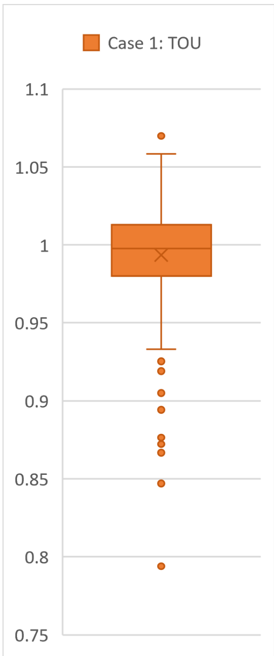


Figure 4.4: Case 1 TOU tariff revenue ratio relative to case 1 flat tariff

With BESS discharging less often on a TOU tariff, which increases the share of PV being exported, the PV consumption ratio on the flat tariff was always seen to be greater than the ratio on a TOU tariff, across all 288 households.

Prosumers with rooftop PV and BESS benefit from a TOU tariff if the BESS supplies a majority of the demand during peak periods, such that the grid imported electricity will be at the lower shoulder or off-peak rates. Hence, shifting loads within peak periods is seen to be the optimal strategy; a completely opposite approach for consumers without distributed generation or loads.

4.2 Case 2

On top of financial gains from self consumption and PV exports from Case 1, households participate in contingency FCAS markets. Market clearing prices across the 6 contingency markets are shown in figure 4.5 and figure 4.6. Figure 4.6 visualises the FCAS prices in SA without the price spikes, where it is clear that raise FCAS are valued higher than lower FCAS, across all fast, slow and delayed contingency services. However, figure 4.5 demonstrates that although lower FCAS is valued lower, lower FCAS is still seen to hit its market price cap as often as raise FCAS. That is, lower FCAS still provides the opportunity to reap substantial revenues during these opportune moments, given that BESS is available in delivering its commitment.

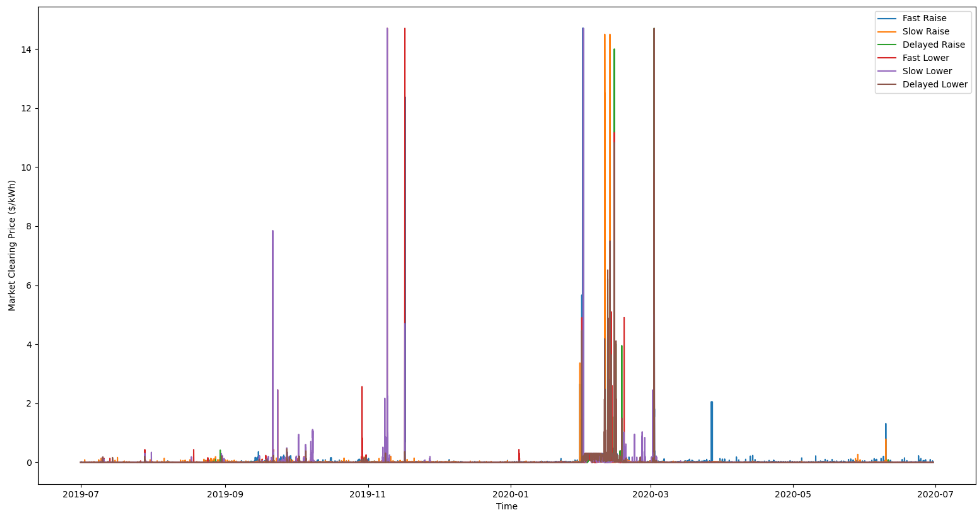


Figure 4.5: Case 2 - Market clearing prices across all 6 contingency FCAS markets

Prosumers are paid for their BESS being available to commit power when contingency is called. The behaviour of the BESS is analysed during periods of contingency through the following figures. Contingency events over the July 2019 to June 2020 year are sum-

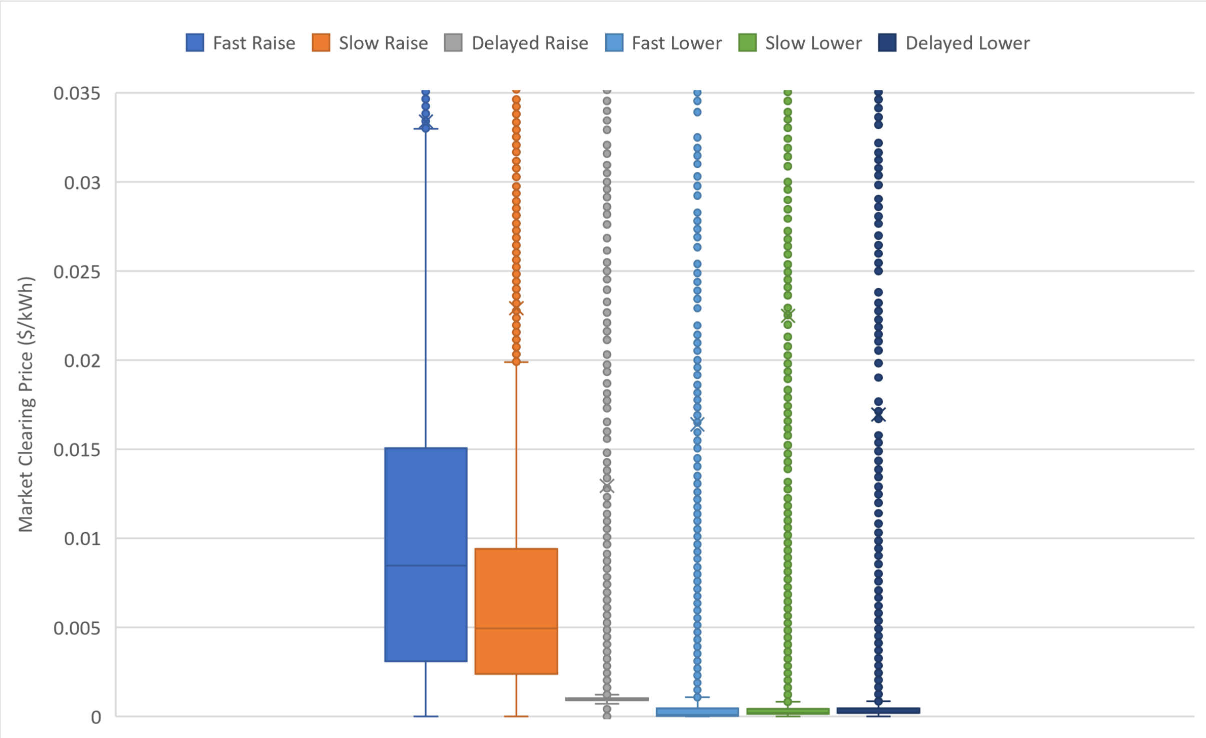


Figure 4.6: Case 2 - Boxplots of market clearing prices across all 6 contingency FCAS markets

marised in table 3.3.

BESS behaviour during the lower contingency event on the 03/09/19 01:22 (rounded to 01:00) that lasted approximately 8 minutes is shown in figure 4.7. As the bid for both raise and lower contingency was 5 kW, the amount charged during the 8 minute period was 0.67 kWh. However, there was a high load that coincided with the lower commitment. The 0.67 kWh charge was consumed by the loads, and hence a rise in the BESS SOC was not seen.

There are periods, however, when lower FCAS is called and a noticeable rise in SOC is seen. This was the case with the lower contingency event on the 16/11/19 18:00 that lasted 15 minutes. As the load was higher than the PV generation at the time, it is clear to see that the SOC rise was from the lower FCAS commitment and not PV, allowing for further self consumption through the evening. Headroom for raise FCAS commitment can also be seen within the 00:00 and 06:00 period. The BESS SOC does not go below 3.75 kWh (2.5 kWh above the 10% minimum capacity), in case raise FCAS is called and the 2.5 kWh would have to be committed.

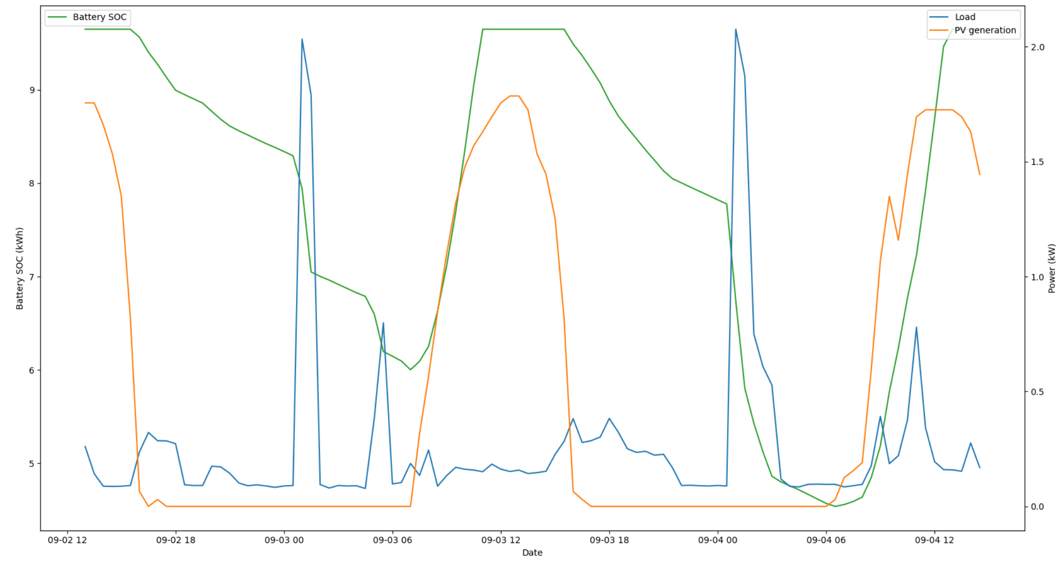


Figure 4.7: Case 2 - 03/09/2019 lower FCAS contingency event BESS behaviour

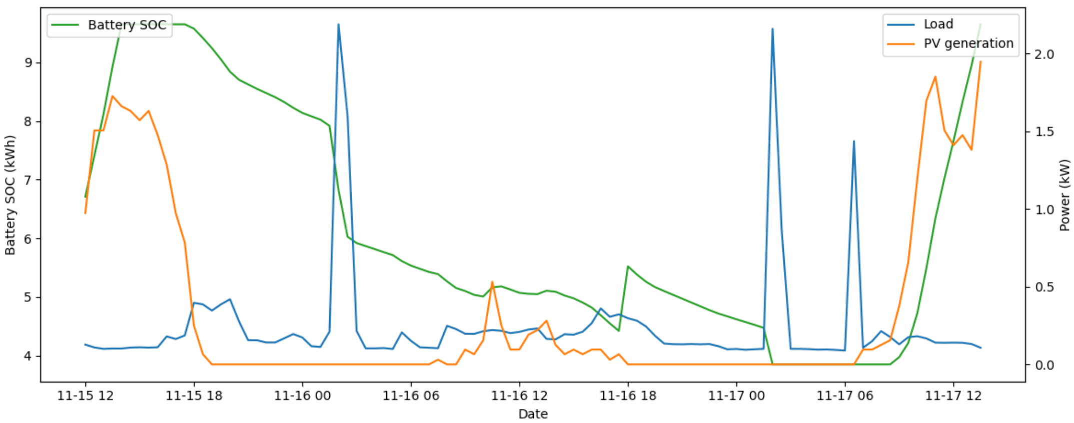


Figure 4.8: Case 2 - 16/11/2019 lower FCAS contingency event BESS behaviour, with a noticeable SOC rise from lower FCAS commitment

Figure 4.9 presents BESS behaviour during a raise contingency event, for the 16/04/20 17:50 (rounded to 18:00) event that lasted for 1hr and 5 min. The BESS SOC is seen to rise to its maximum capacity of 90% minus the 2.5 kWh headroom as it approaches 18:00, to potentially allow for the lower FCAS charging commitment. Once contingency is called, the BESS is seen to discharge continually for the next hour, while satisfying loads at the same time as it has the capacity to do so.

Revenue gains relative to the base case are calculated for Case 2, and summarised in

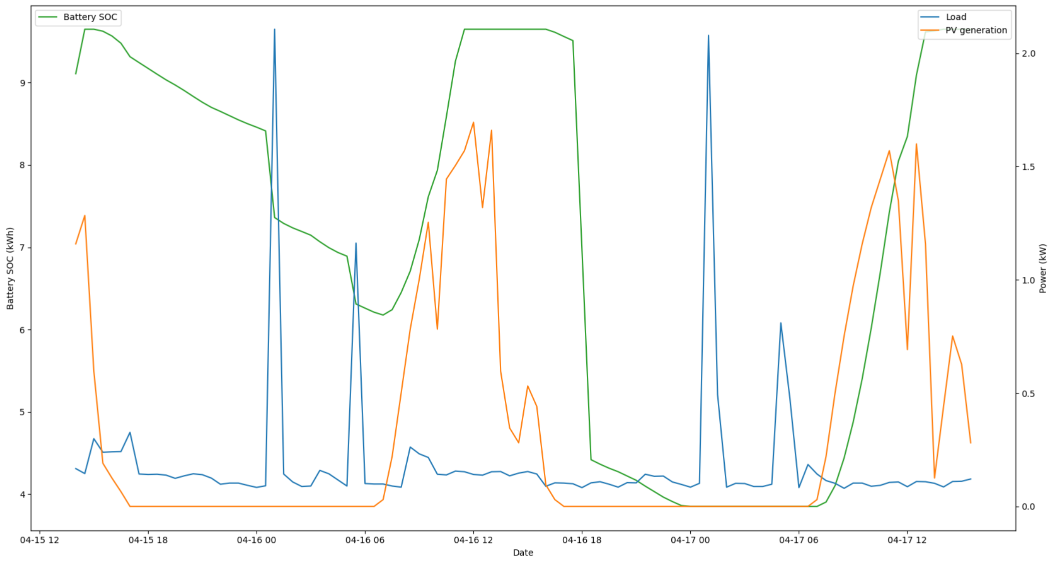


Figure 4.9: Case 2 - 16/04/2020 raise FCAS contingency event BESS behaviour

figure 4.11. The expenses and revenues for customer 4 is again provided as an example in table 4.2.

Table 4.2: Case 2 Customer 4 - Yearly costs and revenues

	Flat tariff	TOU tariff
Case 1 bill	953.27	936.57
Case 2 bill	133.74	338.51
FiT revenue	183.79	294.15
FCAS revenue	5475.55	5475.55
Total revenue	6478.86	6367.76

Yearly revenues attracted from the addition of FCAS contingency participation was seen to be substantially higher than that of the base case, with a mean of 5.38 as seen in figure 4.11. Across all 288 households, the majority of revenue came from the 5kW raise and lower FCAS contingency bids, with every household earning just under $5,500 per year just from FCAS.

To secure these earnings however, a headroom of 2.5 kWh was implemented at the minimum and maximum BESS capacity. With the headroom in place, self-consumption occurs less often, with more instances of electricity being imported from the grid and PV being exported relative to case 1. The impact of the headroom on self consumption and PV export earnings is explored with a comparison of case 1 and case 2. In case 1 for customer 4, these revenues were calculated as \$1,029 under a flat tariff, and \$905 for TOU. In case 2, it was \$1,003 and \$909 respectively when excluding FCAS revenue. Across the flat tariff, there was a decrease in revenue of approximately 2.6%. Interestingly, there was an increase of 0.4% with the TOU tariff. When considering all 288 households, all households exhibit the same pattern with the flat tariff, i.e. revenues from self-consumption and PV exports drop from case 1 to case 2. However, there are 18 households, including customer 4, that demonstrates an unexpected behaviour whereby revenue increases from case 1 to case 2.

This impact is visualised in figure 4.10 for all households. Although there are households that experience a gain in self-consumption and PV generation revenue, more households on a TOU tariff experience a decrease in this revenue compared to the flat tariff case. When considering the headroom that takes up 5 kWh out of the available 10.8 kWh, however, the impact is lower than expected.

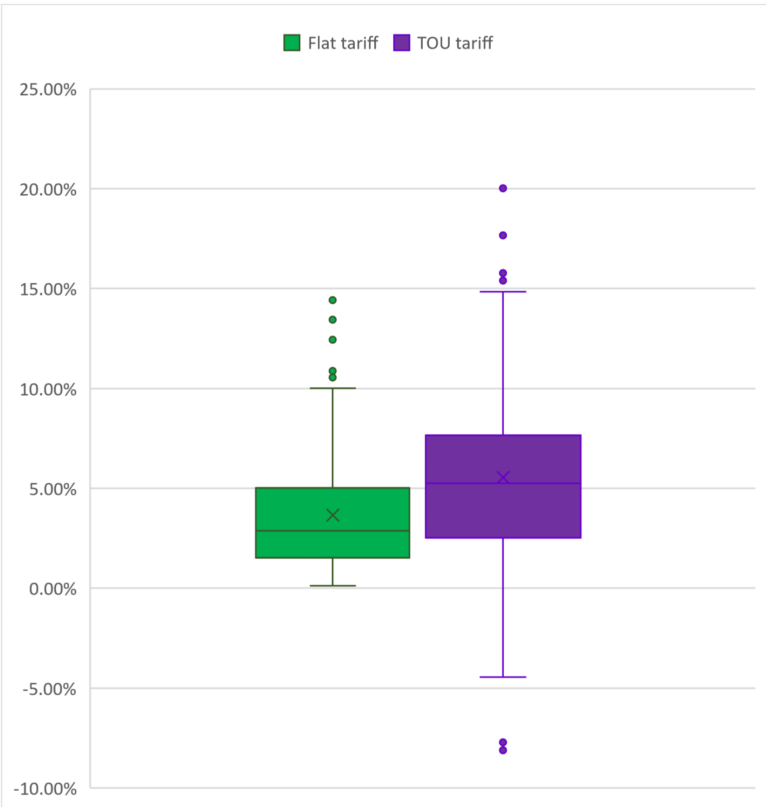


Figure 4.10: Percentage decrease in self consumption and PV export revenue from case 1 to case 2

The PV consumption ratio under a flat tariff was calculated to be 1.89, with 0.81 for TOU. Similar to case 1, every household had a higher ratio under a flat tariff. As discussed in section 4.1, BESS SOC remains at a higher capacity more often on TOU compared to a flat tariff. There is a often a higher decrease in revenue with the TOU case as the headroom further restricts households from self-consuming during peak periods when prices are highest. Households on TOU will have to import the electricity at the peak rate while households on the flat tariff import at the flat rate.

Revenue ratios for case 2 also appear to be extremely similar. Referring back to table 4.2, the case 2 bill and FiT revenue are both relatively higher for the TOU tariff, which results in a similar total revenue. It is suspected that the same pattern occurs for all customers in case 2.

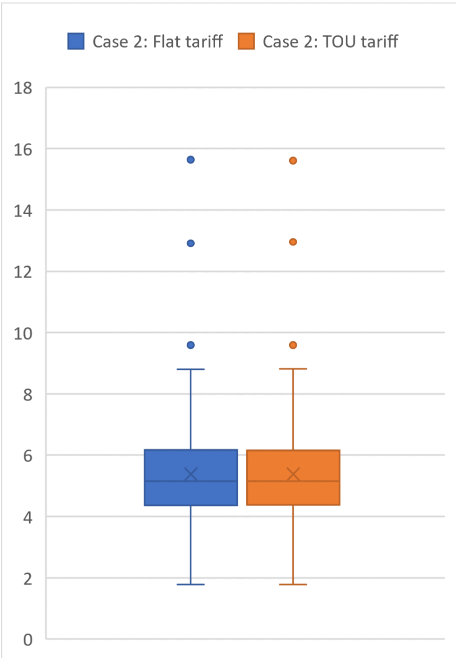


Figure 4.11: Case 2 -flat tariff and TOU tariff revenue ratio relative to case 1 flat tariff

4.3 Case 3

Spot price exposure is introduced in case 3 in place for flat tariffs, TOU tariffs and feed-in tariffs. Energy market prices are visualised in figure 4.12, with monthly averages included in A.1 in the appendix. Monthly averages average to around 3c/kWh, with price hitting the market price cap in December 2019, as well as prices regularly holding negative values.

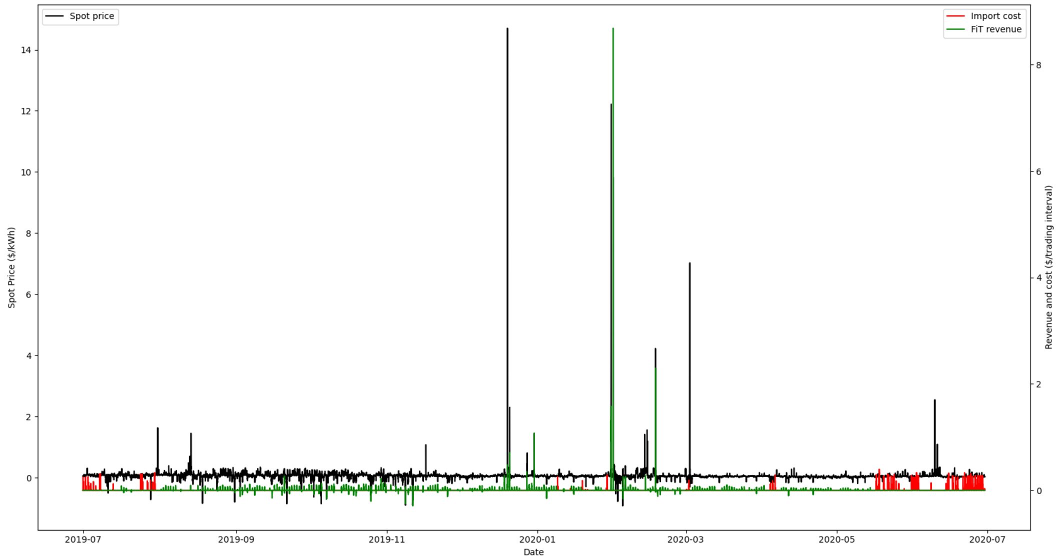


Figure 4.12: Case 3 - Spot prices over the year

Costs and revenues are calculated for customer 4 in table 4.3. Compared to table 4.1, the bill reduction and FiT revenue is seen to decrease, resulting in lower total revenues.

Table 4.3: Case 3 Customer 4 - Yearly costs and revenues

	Flat tariff	TOU tariff
Case 1 bill	953.27	936.57
Case 3 bill	242.42	447.13
FiT revenue	90.12	131.30
Total revenue	800.97	620.74

To visualise revenue inflows and outflows during a price spike, figure 4.13 presents the 19/12/2019 day as an example of substantial income. FiT revenue came to around $5 just within a singular training interval, which was 5.6% of the yearly FiT revenue for household 4 under a flat tariff. A day afterwards, revenue hits above $4 again on a much lower price spike, indicating that the excess of PV generation was greater than the previous price spike. However, being able to export solar at this price also indicates that importing electricity will occur at that price too. In having the price spike occur when PV is generating, the load is supplied by PV and no import costs are incurred.

With reference to figure 4.12, customer 4 fortunately does not incur extremely high

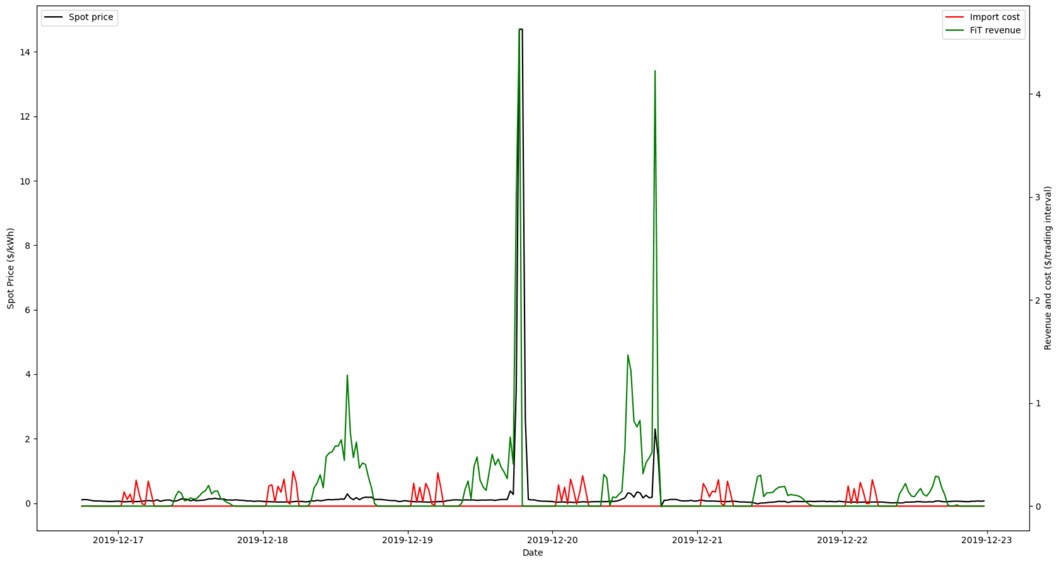


Figure 4.13: Case 3 - Spot price hitting the market ceiling on 19/12/2019

import costs in the same way for FiT exports. However, it seems that the majority of import costs come from the beginning and end of July 2019 to June 2020, with barely any costs incurred in between. Seasonal PV generation may be the reason. High SOCs are seen during the spring and summer periods in figures 4.3a and 4.3b, however during the winter, the SOC remains in the lower to middle level capacities. Self-consumption is achieved less often, and import costs are incurred more often.

Whenever costs are incurred, the prices are usually lower than the flat tariff in case 1, but the total revenue was still higher for case 1. The difference is close to the yearly subscription fee of $180 that Amber Electric customers are to pay to gain exposure to spot prices, which is implemented within the methodology. Optimisation and forecasting is essential in participating within the energy market, but however was not in the scope of this thesis. Implications are further discussed in section 4.4.

Solar feed-in without BESS suffers heavily under spot price exposure. All households are exporting PV at the same time, with utility PV generating in conjunction. Prices are hence extremely low, even negative at times. This provides the flat tariff case as the stronger case, as self-consumption occurs more often than PV exports. Storing as much solar in the BESS is also essential as the BESS will have more capacity in charging when prices are low and discharging when prices are high.

With all the above considered, spot price exposure was not economically attractive on average, as seen in figure 4.14. The revenue ratio relative to the base case was 0.75 and 0.71 for the flat tariff and TOU tariff respectively, with a few households sitting above 1 for both cases.

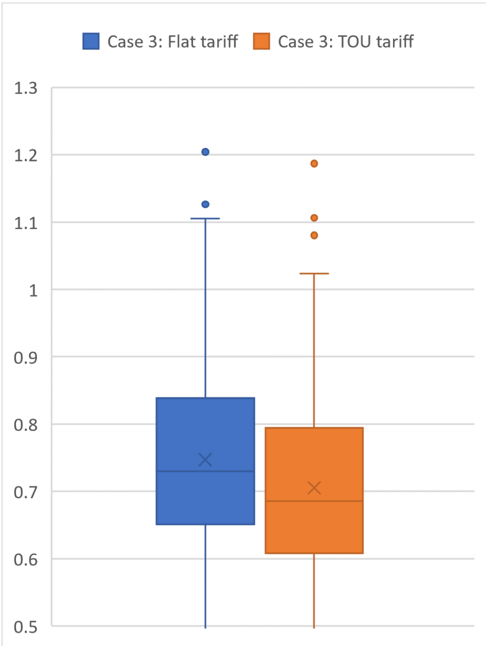


Figure 4.14: Case 3 flat tariff and TOU tariff revenue ratio relative to case 1 flat tariff

4.4 Implications

Value stacking has untapped potential that was not within the scope of this thesis. Revenue stream analysis was performed on a case by case basis, to individually and independently evaluate financial gains from each stream. However, as also discussed in literature, simultaneous multi-market participation has shown to be the most financially attractive, whereby BESS participates in increased PV self-consumption, FCAS provision and energy arbitrage at the same time.

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In case 1, it comes to no surprise that rooftop PV and BESS operating together provide substantial revenues, high enough to payback these DER investments during their lifetime. However, the PV consumption ratio (ratio of PV self consumed over PV exported) was much lower than expected relative to the ratio on a flat tariff. That is, during the summer, the BESS remained at a high SOC for the majority of the time. Instead of the BESS discharging during peak periods only, it would be interesting to explore see how revenue changes if BESS were to discharge during off-peak periods as well (as the shoulder period was the cheapest due to the solar sponge tariff). In doing so, the PV consumption ratio will increase, and further revenues may be realised. Further optimisation is possible through energy arbitrage, which is discussed later in this section.

The high revenue ratio for case 2 may be attributed to the elevated FCAS prices in SA, especially within Febrary and March as seen in figure 4.5. All raise and lower FCAS services were seen to settle above $25/MWh for more than 20% within February, compared to the typical 3%-10% for consecutive months (AEMO 2020*a*). Out of the $5,476 gained from FCAS commitments, $3,005 (55%) are from February alone. Moving forward into the near future, FCAS contingency prices are expected to decrease with more than a dozen new BESS market entrants (RenewEconomy 2020*b*). That is, the FCAS revenue ratios that were calculated within this thesis may become overestimated as FCAS provision becomes more saturated. However, there is capability for BESS to provide grid services within markets that have not been recognised yet, synthetic inertia being one of them (RenewEconomy 2020*d*). Hence, residential BESS potential remains extremely high, and the financial feasibility of BESS is only going to improve.

Only 4 out of the 18 contingency events during the July 2019 to June 2020 period required lower services, as shown in table 3.3. In the simulation, however, the same amount of headroom was provided for lower FCAS commitments and raise FCAS commitments. Lower FCAS prices across the fast, slow and delayed services were all seen to be valued lower than their raise counterparts. It may be argued providing more headroom for raise FCAS may be more beneficial. However, the headroom considered in the simulation was already at its maximum, for both lower and raise FCAS. The amount of possible headroom is determined by the nameplate maximum power input and output, which was 5kW. Over a 30 minute period, the maximum headroom would be 2.5 kWh. What was not considered, however, was the potential in PV assisting in raise FCAS commitments, as exports are only possible with PV. On top of the BESS discharging at 5kW, the PV can be optimised in discharging all of its power into raise FCAS. However, PV generation is not guaranteed, and submitting a guaranteed bid to AEMO would not be possible. As

FCAS prices continue dropping, it may be worth considering cutting down on the headroom, especially with lower FCAS.

As seen in case 3, energy arbitrage was not economically attractive, not without optimisation. In being exposed to spot prices without any demand response on the prosumer's end, the prosumer would not be taking full advantage of their BESS. While the BESS would still allow for self-consumption during periods of high energy prices, excess PV exports would always be sold at extremely low prices during the "solar sponge" period. Operating under the TOU logic model incorporates demand response to some extent, but was still seen to be least attractive option out of the tariffs. Predictive modelling, i.e. foresight, may be incorporated to bolster revenues. An example could be as follows. For simulation purposes, the BESS is provided with wholesale prices 24 hours in advance. If energy prices above $300/MWh were detected, the BESS will attempt to store as much energy prior to the high price event. If negative prices were detected outside of the solar sponge period (10am-3pm), the BESS will attempt to discharge as much as possible to store the energy for later use. There may be cases where, because of this, the BESS will be fully charged and PV was exporting at the same time. As import wholesale costs are higher, due to the addition of network charges compared to the wholesale FiT, there is less financial risk in having too much energy rather than having too little.

Chapter 5

Conclusion

Revenue stream analysis on 288 households with rooftop PV and BESS in the South Australia region was performed in this thesis. South Australia was considered due to its high renewable penetrations and battery uptake in SA over the past 2 years, resulting in decreased wholesale prices and higher FCAS prices that are also more volatile relative to historic trends. The July 2019 to June 2020 period was chosen to reflect these price trends. To bolster the financial feasibility of DER investment, the revenue streams of increased PV self-consumption (case 1), FCAS provision across contingency events (case 2), and energy arbitrage through spot price exposure (case 3) were considered. Across all 3 cases, households operating under a TOU tariff was seen to be the less economically attractive choice. Provision of contingency FCAS services, both raise and lower FCAS, was possible through partitioning headroom within the BESS. In securing 2.5 kWh headroom for both raise and lower FCAS based on the BESS' maximum rated charge and discharge power, households attained revenue that was approximately 5.3 times greater than the revenue received through self-consumption and FiT revenue only. Similar results were found under the TOU tariff. Spot price exposure under current market offers, Amber Electric's electricity plan in particular, was not economically attractive on average. Although there were households out of the 288 assessed that had revenues higher than the base case, the revenue ratio on average for the flat tariff and TOU tariff was 0.75 and 0.71 respectively. The loss in revenue was largely attributed to the $180 yearly subscription that Amber Electric customers pay, whereby case 3 revenues would be similar to case 1 revenues if ignored.

Incentives for SA residents to join the South Australian VPP have been substantial over the past 2 years, with subsidies available for the installation of rooftop PV and

BESS. Without the additional revenue streams through VPPs considered within this thesis, BESS is not often seen as financially feasible as it often struggles to pay itself back during its lifetime. However, communicating the immense value in owning residential BESS, gained through VPPs, has shown to be difficult, as there are informational barriers between industry and consumers. To continue realising this value within electricity market provision and network support, these barriers must be overcome.

5.1 Future Work

Optimisation within FCAS provision and energy arbitrage is essential within achieving effective coordination of DER, namely rooftop PV and BESS. Future work is apparent within optimising the amount of headroom that BESS can provide when committing to raise and lower FCAS contingency events, as this amount is heavily dependent on individual consumer load profiles. Optimisation is also imperative within spot price exposure to fully take advantage of high and low energy prices. Realising the full value stack, however, is only achieved in participating within both markets simultaneously.

Demand response (DR) is an additional revenue stream to be explored within the residential context. As no flexible loads were considered within this thesis, DR was not explored. Through shifting consumption in response to extreme price events, the business case for case 3, as well as multi-market participation, may be stronger.

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Appendix A

A.1

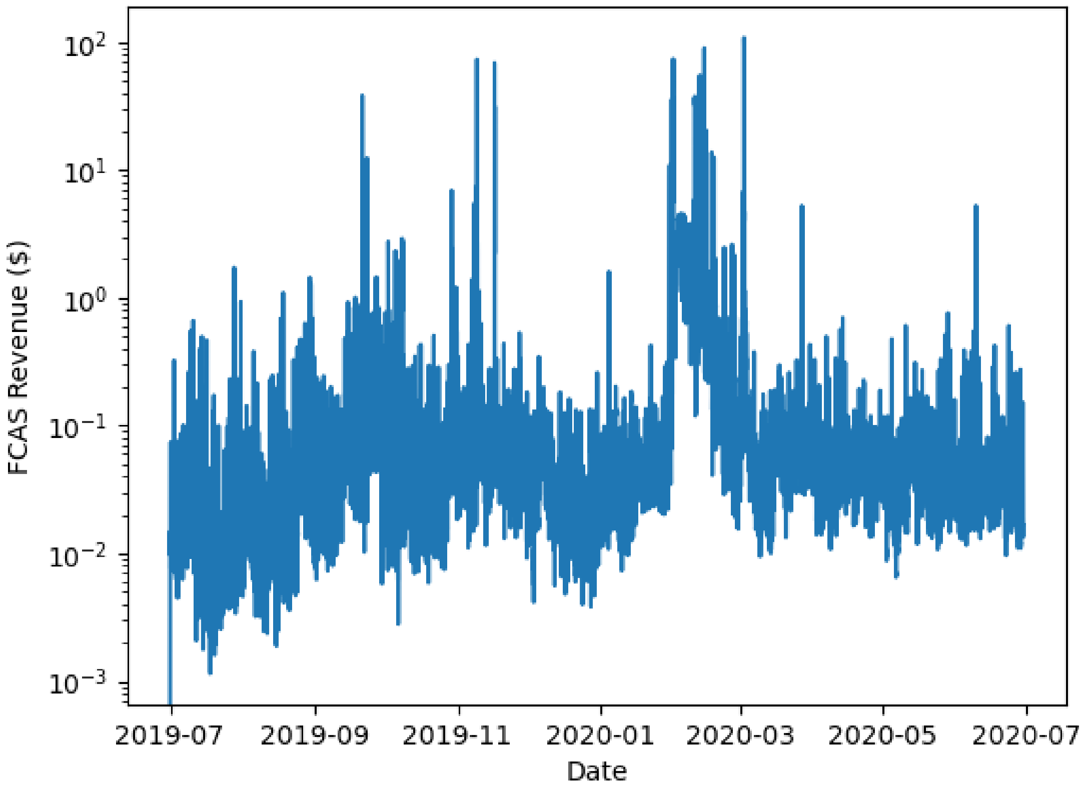

Figure A.1: Case 2 - Revenue earnt from raise and lower FCAS participation over a year on a log scale

Table A.1: Case 3 - Comparison between energy market prices and Amber Electric Prices

Month	Average wholesale market price (c/kWh)	Amber average wholesale price (c/kWh)	Difference between wholesale price and Amber price (c/kWh)	Amber average FiT price (c/kWh)	Difference between wholesale price and Amber FiT (c/kWh)
1	3.99	31.28	27.29	11.70	7.71
2	3.08	25.77	22.69	7.03	3.95
3	2.25	22.53	20.28	9.70	7.45
4	1.61	21.35	19.74	4.37	2.76
5	1.79	21.83	20.04	5.01	3.22
6	2.45	24.55	22.10	7.77	5.32
7	3.55	25.54	21.99	8.73	5.18
8	3.78	23.98	20.20	5.80	2.02
9	3.50	20.56	17.06	-1.26	-4.76
10	3.23	22.50	19.27	3.27	0.04
11	2.44	23.88	21.44	3.75	1.31
12	4.03	32.11	28.08	9.56	5.53
Average				21.68	3.31

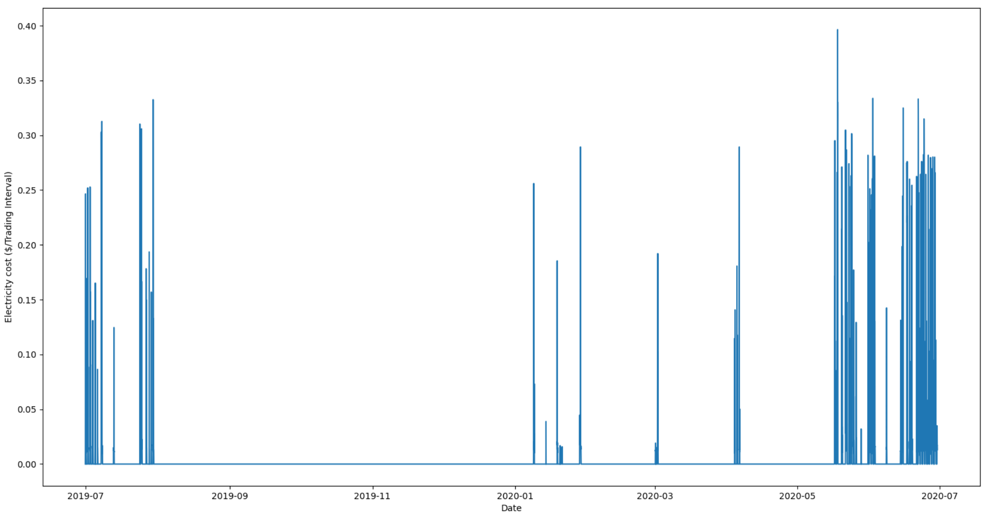

Figure A.2: Case 3 - Electricity import cost

A.2

Github link:

https://github.com/raymo-nd/undergrad-thesis

Includes code (that's also included below for reference), raw data and results.

```
import numpy as np
import pandas as pd
from datetime import datetime
from matplotlib import pyplot as plt
import pickle
import random
import time
import csv
from operator import add

start_time = time.time()

bess_max_capacity = 12.15 # powerwall specs
bess_min_capacity = 1.35
max_discharge_rate = 5 # kw
max_discharge = 2.5 # kWh
hours_in_day = 24

hour_diff = 0.5

peak = 0.44539
shoulder = 0.24431
off_peak = 0.30734

elec_rate = 0.3773 #$/kWh
fit = 0.16 #$/kWh

yearly_amber_fee = 180
other_bill_costs = 0.2168
market_env_costs = 0.031

load_scaling = 1
pv_scaling = 5.0156
```

```
pickle_in = open("time_single.pickle", "rb")
timestamp = pickle.load(pickle_in)

list_length = len(timestamp)

df = pd.read_csv('sa_ACTUAL.csv')

rrp= df.RRP.tolist()

raise6sec_price = df.RAISE6SECRRP.tolist()
raise60sec_price  = df.RAISE60SECRRP.tolist()
raise5min_price  = df.RAISE5MINRRP.tolist()
raisereg_price  = df.RAISEREGRRP.tolist()

lower6sec_price  = df.LOWER6SECRRP.tolist()
lower60sec_price  = df.LOWER60SECRRP.tolist()
lower5min_price  = df.LOWER5MINRRP.tolist()
lowerreg_price  = df.LOWERREGRRP.tolist()


global instant_bess, bess , import_grid, import_cost, export_grid ,
    fit_rev, FCAS_rev

instant_bess = [0]*list_length #battery SOC list at the given time
    period
bess = [0]*list_length #battery SOC list which accumulates overtime
import_grid = [0]*list_length
import_cost = [0]*list_length
export_grid = [0]*list_length
fit_rev = [0]*list_length
FCAS_rev = [0]*list_length

raise6sec = [0]*list_length
raise60sec = [0]*list_length
raise5min = [0]*list_length
raisereg = [0]*list_length
lower6sec = [0]*list_length
lower60sec = [0]*list_length
lower5min = [0]*list_length
```

```
lowerreg = [0]*list_length

FCAS_max_price_list = [0]*list_length

bess_raise_discharge = 5 * hour_diff # maximum discharging within 30 min period in kWh
bess_lower_charge = 5 * hour_diff # maximum charging within 30 min period in kWh
bess_FCAS_min = bess_min_capacity + (1 * bess_raise_discharge)
bess_FCAS_max = bess_max_capacity - (1 * bess_lower_charge)

pickle_in = open("solar_homes.pickle", "rb")
df = pickle.load(pickle_in)

column_len = len(df.columns)

row_len = len(df.index) # 268557

original_bill_flat = 0
original_bill_tou = 0

from_row=0
to_row=17520

array_rows, array_cols = (300, 22)
arr = [ [ 0 for i in range(array_cols) ] for j in range(array_rows) ]

CL = []
GC = []
GG = []

raise_commitment = 5
lower_commitment = 5

def bess_pv_load_plot():
    fig, ax1 = plt.subplots()

    color = 'tab:green'
    ax1.set_xlabel('Date')
    ax1.set_ylabel('Battery SOC (kWh)')
```

```
    ax1.plot(timestamp[from_row:to_row], bess[from_row:to_row],color=color, label = "Battery SOC")
    ax1.tick_params(axis='y')
    plt.legend(loc="upper left")

    ax2 = ax1.twinx()  # instantiate a second axes that shares the same x-axis

    ax2.set_ylabel('Power (kW)')  # we already handled the x-label with ax1
    ax2.plot(timestamp[from_row:to_row], load[from_row:to_row], label = "Load")
    ax2.plot(timestamp[from_row:to_row], pv[from_row:to_row], label = "PV generation")
    ax2.tick_params(axis='y')

    plt.legend(loc="upper right")

    fig.tight_layout()  # otherwise the right y-label is slightly clipped
    plt.show()

def plot_import_export():

    fig, ax1 = plt.subplots()

    ax1.set_xlabel('Date')
    ax1.set_ylabel('Spot Price ($/kWh)')
    ax1.plot(timestamp[from_row:to_row], rrp[from_row:to_row],color='k', label = "Spot price")
    ax1.tick_params(axis='y')
    plt.legend(loc="upper left")

    ax2 = ax1.twinx()  # instantiate a second axes that shares the same x-axis

    ax2.set_ylabel('Revenue and cost ($/trading interval)')  # we already handled the x-label with ax1
    ax2.plot(timestamp[from_row:to_row], import_cost[from_row:to_row], color = 'r', label = "Import cost")
```

```
    ax2.plot(timestamp[from_row:to_row], fit_rev[from_row:to_row], color = 'g', label = "FiT revenue")
    ax2.tick_params(axis='y')

    plt.legend(loc="upper right")

    fig.tight_layout()  # otherwise the right y-label is slightly clipped
    plt.show()

def plot_bess_only():
    plt.plot(timestamp[from_row:to_row], bess[from_row:to_row],color='g')

    plt.xlabel("Date")
    plt.ylabel("Battery SOC (kWh)")
    plt.show()

def raise_period(duration): # duration in minutes
    bess[i] = bess[i] - raise_commitment * (duration/60)
    if bess[i] < bess_min_capacity:
        bess[i] = bess_min_capacity

def lower_period(duration):
    bess[i] = bess[i] + lower_commitment * (duration/60)
    if bess[i] > bess_max_capacity:
        bess[i] = bess_max_capacity

def contingency():
    if (timestamp[i].day == 3 and timestamp[i].month == 9 and
        timestamp[i].hour == 1 and timestamp[i].minute == 0):
        # print ("1")
        lower_period(8)
    elif (timestamp[i].day == 9 and timestamp[i].month == 10 and
        timestamp[i].hour == 8 and timestamp[i].minute == 0):
        # print("2")
        raise_period(3)
    elif (timestamp[i].day == 16 and timestamp[i].month == 11 and
        timestamp[i].hour == 18 and timestamp[i].minute == 0):
        # print("3")
```

```
            lower_period(15)
        elif (timestamp[i].day == 10 and timestamp[i].month == 12 and
            timestamp[i].hour == 13 and timestamp[i].minute == 30):
            # print("4")
            lower_period(2)
        elif (timestamp[i].day == 10 and timestamp[i].month == 12 and
            timestamp[i].hour == 14 and timestamp[i].minute == 0):
            # print("5")
            raise_period(8)
        elif (timestamp[i].day == 2 and timestamp[i].month == 1 and
            timestamp[i].hour == 15 and timestamp[i].minute == 30):
            # print("6")
            raise_period(0.2)
        elif (timestamp[i].day == 20 and timestamp[i].month == 1 and
            timestamp[i].hour == 13 and timestamp[i].minute == 0):
            # print("7")
            raise_period(13)
        elif (timestamp[i].day == 23 and timestamp[i].month == 1 and
            timestamp[i].hour == 11 and timestamp[i].minute == 30):
            # print("8")
            raise_period(10)
        elif (timestamp[i].day == 28 and timestamp[i].month == 1 and
            timestamp[i].hour == 17 and timestamp[i].minute == 0):
            # print("9a")
            lower_period(30)
        elif (timestamp[i].day == 28 and timestamp[i].month == 1 and
            timestamp[i].hour == 17 and timestamp[i].minute == 30):
            # print("9b")
            lower_period(30)
        elif (timestamp[i].day == 30 and timestamp[i].month == 1 and
            timestamp[i].hour == 17 and timestamp[i].minute == 30):
            # print("10")
            raise_period(10)
        elif (timestamp[i].day == 14 and timestamp[i].month == 2 and
            timestamp[i].hour == 10 and timestamp[i].minute == 0):
            # print("11")
            raise_period(10)
        elif (timestamp[i].day == 5 and timestamp[i].month == 4 and
            timestamp[i].hour == 15 and timestamp[i].minute == 30):
            # print("12")
```

```
            raise_period(10)
        elif (timestamp[i].day == 10 and timestamp[i].month == 4 and
            timestamp[i].hour == 17 and timestamp[i].minute == 0):
            # print("13")
            raise_period(7)
        elif (timestamp[i].day == 16 and timestamp[i].month == 4 and
            timestamp[i].hour == 18 and timestamp[i].minute == 0):
            # print("14a")
            raise_period(30)
        elif (timestamp[i].day == 16 and timestamp[i].month == 4 and
            timestamp[i].hour == 18 and timestamp[i].minute == 30):
            # print("14b")
            raise_period(30)
        elif (timestamp[i].day == 6 and timestamp[i].month == 5 and
            timestamp[i].hour == 16 and timestamp[i].minute == 30):
            # print("15")
            raise_period(10)
        elif (timestamp[i].day == 12 and timestamp[i].month == 5 and
            timestamp[i].hour == 14 and timestamp[i].minute == 30):
            # print("16")
            raise_period(7)
        elif (timestamp[i].day == 19 and timestamp[i].month == 5 and
            timestamp[i].hour == 14 and timestamp[i].minute == 30):
            # print("17")
            raise_period(10)
        elif (timestamp[i].day == 1 and timestamp[i].month == 6 and
            timestamp[i].hour == 12 and timestamp[i].minute == 30):
            # print("18")
            raise_period(10)

def calc_pv_ratio():
    global pv_consumption_ratio
    pv_consumption_ratio = ((sum(load)*0.5) - sum(import_grid))/(sum(
        export_grid))

def empty_lists():
    global instant_bess, bess , import_grid, import_cost, export_grid ,
        fit_rev, FCAS_rev
    instant_bess = [0]*list_length #battery SOC list at the given time
        period
```

```
    bess = [0]*list_length #battery SOC list which accumulates overtime
    import_grid = [0]*list_length
    import_cost = [0]*list_length
    export_grid = [0]*list_length
    fit_rev = [0]*list_length
    FCAS_rev = [0]*list_length


row=0
check=0
customer_min = 4
customer_max = 4
while (row < row_len): #row_len
    if (df.iloc[row,0] >= customer_min and df.iloc[row,0] <= customer_max) :
        customer_no = df.iloc[row,0]
        temp_list = list(df.iloc[row,4:column_len])
        if df.iloc[row,2] == "CL":
            CL.extend(temp_list)
        if df.iloc[row,2] == "GC":
            GC.extend(temp_list)
        if df.iloc[row,2] == "GG":
            GG.extend(temp_list)

        if ( customer_no != 300 and (df.iloc[row+1,0] == customer_no+1)) : # once the list hits the full year mark, we move onto the next customer
            if (len(GG) == 17520 and len(GC) == 17520 and customer_no !=68 and customer_no!=95 and customer_no !=161 and customer_no != 187
                                            and customer_no != 248 and customer_no != 272 and customer_no!=284 and customer_no!=289 and customer_no!=293 and customer_no!=294):
                # check = check+1
                # print(len(GC), len(GG), customer_no)
                if not CL: # if CL list is empty, then the load list is just GC, general consumption
                    load = GC
                else: # otherwise, add CL (controlled load) and GC together
                    load = list(map(add,CL,GC))
```

```
load = [i*load_scaling for i in load]
pv = GG
pv = [i*pv_scaling for i in pv]

original_bill_flat = 0
original_bill_tou = 0

i=0
for times in timestamp:  # BASE FLAT
    if i>0:
        excess_in_kW = pv[i] - load[i]
        excess_in_kWh = excess_in_kW * (hour_diff)
        original_bill_flat = original_bill_flat + load[i]*hour_diff*elec_rate
        if excess_in_kWh > 0: #if PV is greater than load
            if bess[i-1] == bess_max_capacity:
                export_grid[i] =  excess_in_kWh
                fit_rev[i] = export_grid[i] * fit #paid at the feed in tariff price
                bess[i] = bess_max_capacity
            else:
                bess[i] = bess[i-1] + excess_in_kWh
                if bess[i] > bess_max_capacity:
                    export_grid[i] = bess[i] - bess_max_capacity
                    fit_rev[i] = export_grid[i] * fit
                    bess[i] = bess_max_capacity
        else: #if load is greater than PV
            if bess[i-1] > bess_min_capacity: #if the battery has charge
                bess[i] = bess[i-1] - abs(excess_in_kWh)
                if bess[i] < bess_min_capacity:
                    import_grid[i] =  bess_min_capacity-bess[i] #importing electricity from grid
                    import_cost[i] = import_grid[i] * elec_rate # paying for importing electricity
                    bess[i] = bess_min_capacity
            else:
                import_grid[i] = -excess_in_kWh
```

```
                        import_cost[i] = import_grid[i] * elec_rate
                        bess[i] = bess_min_capacity
            i = i + 1

        calc_pv_ratio()
        # print (pv_consumption_ratio)

        # customer_no - 1 because the 1st customer is in the 0th row
        arr[customer_no-1][0] = original_bill_flat
        arr[customer_no-1][1] = sum(import_cost)
        arr[customer_no-1][2] = sum(fit_rev)
        arr[customer_no-1][16] = pv_consumption_ratio

        # print(original_bill_flat,sum(import_cost), sum(fit_rev))

        # bess_pv_load_plot()
        # plot_bess_only()

        empty_lists()

        i=0
        for times in timestamp: # BASE TOU
            if i>0:
                excess_in_kW = pv[i] - load[i]
                excess_in_kWh = excess_in_kW * (hour_diff)

                # BASE TOU CODE
                if (timestamp[i].hour >= 15 and timestamp[i].hour < 24) or timestamp[i].hour == 0 or (timestamp[i].hour >= 6 and timestamp[i].hour < 10):
                    tou_elec_rate = peak
                if (timestamp[i].hour >= 10 and timestamp[i].hour < 15 ): # if shoulder period
                    tou_elec_rate = shoulder
                if (timestamp[i].hour >= 1 and timestamp[i].hour < 6): # if off peak
                    tou_elec_rate = off_peak
```

```

                    original_bill_tou = original_bill_tou + load[i]*hour_diff*tou_elec_rate # iterating to find the original bill without PV and battery

                    if (tou_elec_rate == peak): # if peak period
                        if excess_in_kWh > 0: #if PV is greater than load
                            if bess[i-1] == bess_max_capacity:
                                export_grid[i] =  excess_in_kWh
                                fit_rev[i] = export_grid[i] * fit # paid at the feed in tariff price
                                bess[i]=bess[i-1]
                            else:
                                bess[i] = bess[i-1] + excess_in_kWh
                                if bess[i] > bess_max_capacity:
                                    export_grid[i] = bess[i] - bess_max_capacity
                                    fit_rev[i] = export_grid[i] * fit
                                    bess[i] = bess_max_capacity
                        else: #if load is greater than PV

                            if bess[i-1] > bess_min_capacity: #if the battery has charge
                                bess[i] = bess[i-1] - abs(excess_in_kWh)
                                if bess[i] < bess_min_capacity:
                                    import_grid[i] = bess_min_capacity-bess[i] #importing electricity from grid
                                    import_cost[i] = import_grid[i] * tou_elec_rate # paying for importing electricity
                                    bess[i] = bess_min_capacity
                            else:
                                import_grid[i] = -excess_in_kWh
                                import_cost[i] = import_grid[i] * tou_elec_rate
                                bess[i] = bess_min_capacity

                    else: #if not peak time
```

```
                        if excess_in_kWh > 0: #if PV is greater than load
                            if bess[i-1] == bess_max_capacity:
                                export_grid[i] =  excess_in_kWh
                                fit_rev[i] = export_grid[i] * fit
                                bess[i]=bess[i-1]
                            else:
                                bess[i] = bess[i-1] + excess_in_kWh
                                if bess[i] > bess_max_capacity:
                                    export_grid[i] = bess[i] - bess_max_capacity
                                    fit_rev[i] = export_grid[i] * fit
                                    bess[i] = bess_max_capacity
                        else: #if load is greater than PV
                            if (tou_elec_rate == shoulder): # if shoulder period
                                import_grid[i] = -excess_in_kWh
                                import_cost[i] = import_grid[i] * tou_elec_rate
                                bess[i] = bess[i-1]
                            if (tou_elec_rate == off_peak): # if off peak
                                import_grid[i] = -excess_in_kWh
                                import_cost[i] = import_grid[i] * tou_elec_rate
                                bess[i] = bess[i-1]

                i=i+1

            calc_pv_ratio()
            # print (pv_consumption_ratio)

            arr[customer_no-1][3] = original_bill_tou
            arr[customer_no-1][4] = sum(import_cost)
            arr[customer_no-1][5] = sum(fit_rev)
            arr[customer_no-1][17] = pv_consumption_ratio

            # print(original_bill_tou,sum(import_cost), sum(fit_rev))
```

```
            # bess_pv_load_plot()
            # plot_bess_only()

            empty_lists()

            i=0
            for times in timestamp: #FCAS FLAT
                if i>0:
                    excess_in_kW = pv[i] - load[i]
                    excess_in_kWh = excess_in_kW * (hour_diff)

                    FCAS_rev[i] = ( (raise6sec_price[i] + raise60sec_price[i] + raise5min_price[i]) * bess_raise_discharge +
                                  (lower6sec_price[i] + lower60sec_price[i] + lower5min_price[i]) * bess_lower_charge )

                    if excess_in_kWh > 0: #if PV is greater than load
                        if bess[i-1] == bess_FCAS_max:
                            export_grid[i] =  excess_in_kWh
                            fit_rev[i] = export_grid[i] * fit #paid at the feed in tariff price
                            bess[i] = bess_FCAS_max
                        else:
                            bess[i] = bess[i-1] + excess_in_kWh
                            if bess[i] > bess_FCAS_max:
                                export_grid[i] = bess[i] - bess_FCAS_max
                                fit_rev[i] = export_grid[i] * fit
                                bess[i] = bess_FCAS_max
                    else: #if load is greater than PV
                        if bess[i-1] > bess_FCAS_min: #if the battery has charge
                            bess[i] = bess[i-1] - abs(excess_in_kWh)
                            if bess[i] < bess_FCAS_min:
                                import_grid[i] =  bess_FCAS_min-bess[i] #importing electricity from grid
                                import_cost[i] = import_grid[i] * elec_rate # paying for importing electricity
```

```
                                bess[i] = bess_FCAS_min
                        else:
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * elec_rate
                            bess[i] = bess_FCAS_min

                    contingency()
                i = i + 1

            calc_pv_ratio()
            # print (pv_consumption_ratio)

            arr[customer_no-1][6] = sum(import_cost)
            arr[customer_no-1][7] = sum(fit_rev)
            arr[customer_no-1][8] = sum(FCAS_rev)
            arr[customer_no-1][18] = pv_consumption_ratio

            # bess_pv_load_plot()

            # print(sum(import_cost), sum(fit_rev), sum(FCAS_rev))

            # plt.plot(timestamp[from_row:to_row], FCAS_rev[from_row:to_row])
            # plt.show()
            # print (sum(FCAS_rev[10320:11712])) # calculating revenue in Feb only

            empty_lists()

            i= 0
            for times in timestamp: #FCAS TOU
                if i>0:
                    excess_in_kW = pv[i] - load[i]
                    excess_in_kWh = excess_in_kW * (hour_diff)

                    FCAS_rev[i] = ( (raise6sec_price[i] + raise60sec_price[i] + raise5min_price[i]) * bess_raise_discharge +
                                (lower6sec_price[i] + lower60sec_price[i] + lower5min_price[i]) * bess_lower_charge )
```

```
                    
                    if (timestamp[i].hour >= 15 and timestamp[i].hour < 24) or timestamp[i].hour == 0 or (timestamp[i].hour >= 6 and timestamp[i].hour < 10):
                        tou_elec_rate = peak
                    if (timestamp[i].hour >= 10 and timestamp[i].hour < 15 ): # if shoulder period
                        tou_elec_rate = shoulder
                    if (timestamp[i].hour >= 1 and timestamp[i].hour < 6): # if off peak
                        tou_elec_rate = off_peak

                    if (tou_elec_rate == peak): # if peak period
                        if excess_in_kWh > 0: #if PV is greater than load
                            if bess[i-1] == bess_FCAS_max:
                                export_grid[i] =  excess_in_kWh
                                fit_rev[i] = export_grid[i] * fit # paid at the feed in tariff price
                                bess[i]=bess_FCAS_max
                            else:
                                bess[i] = bess[i-1] + excess_in_kWh
                                if bess[i] > bess_FCAS_max:
                                    export_grid[i] = bess[i] - bess_FCAS_max
                                    fit_rev[i] = export_grid[i] * fit
                                    bess[i] = bess_FCAS_max
                        else: #if load is greater than PV
                            if bess[i-1] > bess_FCAS_min: #if the battery has charge
                                bess[i] = bess[i-1] - abs(excess_in_kWh)
                                if bess[i] < bess_FCAS_min:
                                    import_grid[i] =  bess_FCAS_min-bess[i] #importing electricity from grid
                                    import_cost[i] = import_grid[i] * tou_elec_rate # paying for importing electricity
                                    bess[i] = bess_FCAS_min
                            else:
```

```
                                import_grid[i] = -excess_in_kWh
                                import_cost[i] = import_grid[i] * tou_elec_rate
                                bess[i] = bess_FCAS_min

                else: #if not peak time
                    if excess_in_kWh > 0: #if PV is greater than load
                        if bess[i-1] == bess_FCAS_max:
                            export_grid[i] =  excess_in_kWh
                            fit_rev[i] = export_grid[i] * fit
                            bess[i]=bess[i-1]
                        else:
                            bess[i] = bess[i-1] + excess_in_kWh
                            if bess[i] > bess_FCAS_max:
                                export_grid[i] = bess[i] - bess_FCAS_max
                                fit_rev[i] = export_grid[i] * fit
                                bess[i] = bess_FCAS_max
                    else: #if load is greater than PV
                        if (tou_elec_rate == shoulder): # if shoulder period
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * tou_elec_rate
                            bess[i] = bess[i-1]
                        if (tou_elec_rate == off_peak): # if off peak
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * tou_elec_rate
                            bess[i] = bess[i-1]

                contingency()
            i = i + 1


        calc_pv_ratio()
        # print (pv_consumption_ratio)
```

```
                arr[customer_no-1][9] = sum(import_cost)
                arr[customer_no-1][10] = sum(fit_rev)
                arr[customer_no-1][11] = sum(FCAS_rev)
                arr[customer_no-1][19] = pv_consumption_ratio

                # print(sum(import_cost), sum(fit_rev), sum(FCAS_rev))

                # bess_pv_load_plot()

                empty_lists()

                i= 0
                for times in timestamp: #ENERGY FLAT
                    if i>0:
                        excess_in_kW = pv[i] - load[i]
                        excess_in_kWh = excess_in_kW * (hour_diff)

                        if excess_in_kWh > 0: #if PV is greater than load
                            if bess[i-1] == bess_max_capacity:
                                export_grid[i] =  excess_in_kWh
                                fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs) #paid at the feed in tariff price
                                bess[i] = bess_max_capacity
                            else:
                                bess[i] = bess[i-1] + excess_in_kWh
                                if bess[i] > bess_max_capacity:
                                    export_grid[i] = bess[i] - bess_max_capacity
                                    fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs)
                                    bess[i] = bess_max_capacity
                        else: #if load is greater than PV
                            if bess[i-1] > bess_min_capacity: #if the battery has charge
                                bess[i] = bess[i-1] - abs(excess_in_kWh)
                                if bess[i] < bess_min_capacity:
                                    import_grid[i] =  bess_min_capacity-bess[i] #importing electricity from grid
```

```
                                    import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs)# paying for importing electricity
                                    bess[i] = bess_min_capacity
                        else:
                                import_grid[i] = -excess_in_kWh
                                import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs)
                                bess[i] = bess_min_capacity
                i=i+1

            calc_pv_ratio()
            # print (pv_consumption_ratio)

            arr[customer_no-1][12] = sum(import_cost) + yearly_amber_fee
            arr[customer_no-1][13] = sum(fit_rev)
            arr[customer_no-1][20] = pv_consumption_ratio

            # print(sum(import_cost), sum(fit_rev))

            # bess_pv_load_plot()
            # plot_bess_only()

            # print(max(rrp))

            # plot_import_export()

            plt.plot(timestamp, import_cost)
            plt.xlabel("Date")
            plt.ylabel("Electricity cost ($/Trading Interval)")
            plt.show()

            empty_lists()

            i=0
            for times in timestamp: # ENERGY TOU
                if i>0:
                    excess_in_kW = pv[i] - load[i]
                    excess_in_kWh = excess_in_kW * (hour_diff)

```

```
                    # BASE TOU CODE
                    if (timestamp[i].hour >= 15 and timestamp[i].hour < 24) or timestamp[i].hour == 0 or (timestamp[i].hour >= 6 and timestamp[i].hour < 10):
                        tou_elec_rate = peak
                    if (timestamp[i].hour >= 10 and timestamp[i].hour < 15 ): # if shoulder period
                        tou_elec_rate = shoulder
                    if (timestamp[i].hour >= 1 and timestamp[i].hour < 6): # if off peak
                        tou_elec_rate = off_peak

                    if (tou_elec_rate == peak): # if peak period
                        if excess_in_kWh > 0: #if PV is greater than load
                            if bess[i-1] == bess_max_capacity:
                                export_grid[i] =  excess_in_kWh
                                fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs) #paid at the feed in tariff price
                                bess[i]=bess[i-1]
                            else:
                                bess[i] = bess[i-1] + excess_in_kWh
                                if bess[i] > bess_max_capacity:
                                    export_grid[i] = bess[i] - bess_max_capacity
                                    fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs)
                                    bess[i] = bess_max_capacity
                        else: #if load is greater than PV

                            if bess[i-1] > bess_min_capacity: #if the battery has charge
                                bess[i] = bess[i-1] - abs(excess_in_kWh)
                                if bess[i] < bess_min_capacity:
                                    import_grid[i] = bess_min_capacity-bess[i] #importing electricity from grid
                                    import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs) # paying for importing electricity
                                    bess[i] = bess_min_capacity
```

```
                        else:
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs)
                            bess[i] = bess_min_capacity

                else: #if not peak time
                    if excess_in_kWh > 0: #if PV is greater than load
                        if bess[i-1] == bess_max_capacity:
                            export_grid[i] =  excess_in_kWh
                            fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs)
                            bess[i]=bess[i-1]
                        else:
                            bess[i] = bess[i-1] + excess_in_kWh
                            if bess[i] > bess_max_capacity:
                                export_grid[i] = bess[i] - bess_max_capacity
                                fit_rev[i] = export_grid[i] * (rrp[i]+market_env_costs)
                                bess[i] = bess_max_capacity
                    else: #if load is greater than PV
                        if (tou_elec_rate == shoulder): # if shoulder period
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs)
                            bess[i] = bess[i-1]
                        if (tou_elec_rate == off_peak): # if off peak
                            import_grid[i] = -excess_in_kWh
                            import_cost[i] = import_grid[i] * (rrp[i]+other_bill_costs)
                            bess[i] = bess[i-1]
            i=i+1

        calc_pv_ratio()
        # print (pv_consumption_ratio)

```

```
                arr[customer_no-1][14] = sum(import_cost) +
    yearly_amber_fee
                arr[customer_no-1][15] = sum(fit_rev)
                arr[customer_no-1][21] = pv_consumption_ratio

                # print(sum(import_cost), sum(fit_rev))

                # bess_pv_load_plot()
                # plot_bess_only()

                # plot_import_export()

                empty_lists()

                CL = []
                GC = []
                GG = []
            else :
                CL = []
                GC = []
                GG = []

    # where all the operations and number crunching finishes, lists get
    cleaned and ready for the next customer
    row=row+1


# with open("results.csv","w+") as my_csv:
#     csvWriter = csv.writer(my_csv,delimiter=',')
#     csvWriter.writerows(arr)


print("Process finished --- %s seconds ---" % (time.time() - start_time)
    )
```