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TITLE: Towards net-zero energy neighbourhoods utilising high rates of residential photovoltaics with battery storage: a techno-economic analysis

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Declaration of interests

None

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Abstract

This paper aims to evaluate the role of residential battery storage in addressing network barriers to the further adoption of household photovoltaics. By presenting a unique perspective combining a housing and network techno-economic evaluation. Stochasticity in demand and weather inputs to PV generation are modelled using Monte Carlo methodology and a power flow model is constructed of a test area of the Low-Voltage network. Findings of the paper include: that batteries address voltage drop issues on low voltage networks at PV penetration rates of 50% and over and can mitigate voltage rise issues at PV penetration rates up to 75%. Economically, under Queensland conditions, the household gains are marginal with optimal results provided by charging batteries from PV generation only and a minimum array size of 5kW. The most significant potential economic gains are at the network level through the deferral of network augmentation spending.

Index Terms

Photovoltaics, residential battery storage, economic assessment, low voltage network, renewable energy

1. Introduction

Initially generous subsidy schemes have resulted in Australia having one of the highest rates of PV installations with 2 million (19%) households adopting PV. Australian households have installed over 8 GW of PV generation, with some regions over 40% PV penetration (APVI, 2018), with forecasts rising to 12.6 GW in 2037 (Australian Energy Regulator, 2017). With over seven million privately owned fully-detached dwellings in Australia (ABS, 2017) there is tremendous scope for household PV to contribute further to the shift to a low-carbon energy sector.

The move to higher levels of PV, however, must address the challenges presented by their impact on distribution networks. The intermittency of PV generation can affect frequency and voltage management. Research has indicated that PV penetration rates on the Low Voltage (LV) network can reach up to 20-40% before voltage management issues arise (Chiandone et al., 2014; Gaunt et al., 2017;

Thomson and Infield, 2007; Tonkoski et al., 2012). Traditional network responses have tended towards further network augmentation spending, driving price prices, and curtailment of generation.

Quantifying the costs of incorporating further levels of PV have been difficult due to complex system-wide interactions; a recent review by Horowitz et al. found that costs can vary widely due to location, clustering and feeder characteristics and that studies suffer from inconsistencies of terminology, proprietary information and methodologies (Horowitz et al., 2018). Such a lack of clarity can contribute to network operator's reluctance to encourage change on the network. A study by Simpson found, through a series of interviews with market participants in Western Australia, that network operators were perceived to be blocking further moves to decentralise the network (Simpson, 2017). Such resistance, as identified in submissions to regulators regarding rule changes and tariffs not conducive to decentralisation, was found to be due primarily to risk-averse tendencies, a lack of clarity of costs as well as an unwillingness to encourage actions that would result in reduced revenue.

Battery Energy Storage Systems (BESS) technology has advanced rapidly (Darcovich et al., 2013; Diouf and Podo, 2015); it has the potential to address the voltage regulation challenges present in moving to greater levels of PV adoption (Divya and Østergaard, 2009; Medina et al., 2014; Tant et al., 2013). An increasing range of residential battery offerings are becoming available to householders, and whilst the private business case can be marginal at today's prices ((Naumann et al., 2015; Shaw-Williams et al., 2018), BESS are forecast to undergo a similar rate of cost reduction as PV as production ramps up (Schmidt et al., 2017). The potential benefits arising from the use of BESS stored energy to meet household load during times of network congestion, and regulating surplus PV generation, mean that network impacts must be considered when considering the economic case for PV and BESS (Gast et al., 2014; Jayasekara et al., 2014; Mohammad Taufiqul et al., 2013).

While the generation profile of PV matches well with industrial use, it does not address network evening peak demand which is largely driven by the residential use. In Australia household energy consumption accounts for only a quarter of all electricity consumed and yet it is the primary driver of network peak demand. Addressing the residential evening peak, while maintaining reliability standards, are the key

challenges of network planning and the potential of residential BESS are being evaluated in this light (Dunn et al., 2011; Hashemi et al., 2014; Hoff et al., 2007).

Prior research at the household economic benefits of PV and batteries has found that they vary widely depending on national conditions in terms of electricity prices and subsidies. Potential gains arise through peak energy reduction, self-consumption and energy sales revenue (Allan et al., 2015). Cucchinella et al. found that positive returns from PV and BESS are most associated with a significant increase in the amount of self-consumption (Cucchiella et al., 2016). Similarly, Neuman et al. found that the profitability of PV & BESS was dependant on self-consumption and large loads, however found that the Powerwall 1 capacity of 6.4 kWh was likely to be over capacity for the average German household in 2016 (Naumann et al., 2016).

Conversely, Camillo et al. in a Portuguese study showed that despite self-consumption no installation was profitable with BESS pricing at current levels (Camillo et al., 2017). Under Australian conditions Khalilpour and Vassallo similarly suggested that neither the retail electricity price nor the FiT were independently significant in the determination of profitability and that PV only installations were consistently profitable (Khalilpour and Vassallo, 2016). Our previous research on this point concurs, our study of a test area in New South Wales, Australia found that PV&BESS was economically marginal except at larger PV configurations with self-consumption (Shaw-Williams et al., 2018).

The literature to date provides extensive analysis of the technical challenges presented by higher PV penetration rates, the potential of optimised behaviour and household economics. However, the work does not provide an integrated and comparative view of the economic impacts for both households and network operators from investment in PV and BESS on LV networks.

This paper provides a novel approach of incorporating a housing and network sectoral analysis and presents a series of value measures detailing economic outcomes. With this unique perspective the investments of householders can be evaluated not just against private benefit but also the effect on network value when considering the role of BESS in enabling higher rates of distributed generation to achieve net zero neighbourhoods.

This paper is organised as follows: Section 2 presents the model and methodology, Section 3 the results and discussion and Section 4 presents the paper’s conclusions.

2. Model and Methodology

Using a section of the network, with load data and network structure obtained from Energex Ltd, a Distribution Network Service Provider (DNSP) covering the urbanised south-east of Queensland Australia, of the suburb of Newmarket, a representative model will be built and serve as the basis for this study across a range of scenarios. The variability in weather and demand will be modelled by adopting a Monte Carlo methodology; commonly used for modelling uncertainty across scenarios by normally distributed random sampling (Duenas et al., 2011; Modassar et al., 2013).

The model will be constructed modularly in MATLAB. It is comprised of: a simulation model of weather, demand and grid prices, household PV production, BESS operations, LV Network Power flow and Economic modules as shown in Figure 1, with each component detailed in the following correspondingly numbered sections.

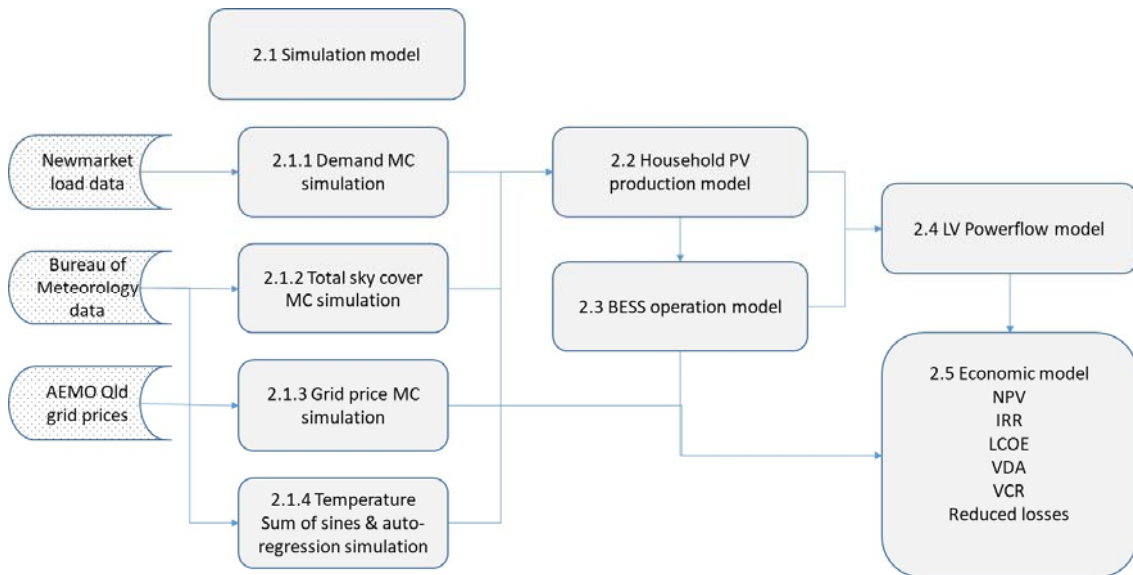


Figure 1. Model architecture.

2.1 Simulation model

Given the seasonal yet short-term stochastic nature of the demand, price and weather variables simulation methodologies have been adopted to reflect these characteristics where appropriate. To derive input variables, historical data for 2012-2013 was analysed at the half hour level to provide per period inputs for Monte Carlo simulation. Temperature, total sky cover (TSC) and global insolation data were sourced from Exemplary Energy and the Australian Bureau of Statistics (Exemplary Energy and Australian Bureau of Statistics, 2014). Demand from the Newmarket test area and grid prices from the Australian Energy Market Operator (AEMO, 2017).

For more detail the simulation data sources and methodology are outlined in our previous paper of 2018 (Shaw-Williams et al., 2018). Concurrent data sets were utilised to preserve temperature and demand/price correlations.

2.2 Household PV production model

PV generation is derived through the regression analysis of global insolation to levels of Total Sky Cover (TSC) at the test area and extra-terrestrial insolation (ETI) for each half hourly period. The regression analysis results are shown in Table 1; returning an R^2 of 89.34%.

Table 1. Global Irradiation to Extra-Terrestrial by TSC octas.

TSC	Mean Global/ETI	SD Global/ETI
0	0.6498	0.2854
1	0.6713	0.2494
2	0.7066	0.1890
3	0.6962	0.1753
4	0.6046	0.1819
5	0.5315	0.1942
6	0.4671	0.2175
7	0.4289	0.2149
8	0.2448	0.1507

Source: Brisbane 7am-6pm (Exemplary Energy and Australian Bureau of Statistics, 2014).

Simulations were performed using Monte Carlo based on regression output parameters on PV generation of a panel at latitude -27.437, longitude 153.007, incorporating temperature related performance degradation. In Australia a north facing orientation is optimal and the optimal tilt is

generally that of the region's latitude (Liu et al.,2018), in this case 27.5 degrees which is used for this study. Then insolation falling on a tilted surface and the output of a photovoltaic panel is calculated. The equations for location and time dependent ETI (equations 1 & 2) in addition to PV generation (equations 3 & 4) (Duffie and Beckman, 2013). are listed below:

$$I_o = \frac{12*3600}{\pi} G_{sc} \left(1 + 0.033 \cos \frac{360n}{365} \right) * \left[\cos \phi \cos \delta (\sin \omega_2 - \sin \omega_1) + \frac{\pi(\omega_2 - \omega_1)}{180} \sin \phi \sin \delta \right] \quad (1)$$

Where I_o = extra-terrestrial radiation on a horizontal surface; ϕ = latitude; δ = declination and ω_1 = time period.

$$I_T = I_b R_b + I_d + \frac{(1 + \cos \beta)}{2} I_g + I_g \frac{(1 - \cos \beta)}{2} \quad (2)$$

Where I_T = isotropic diffuse insolation falling on a tilted surface; I_b = beam insolation; R_b = ratio of beam insolation on tilted surface; I_d = diffuse insolation; β = slope of tilted surface; ρ_g = diffuse reflectance of surroundings.

Generation - PV generation simulations will be based on manufacturer specifications, local solar resource and temperature to incorporate degradation of PV output at higher temperatures than rated conditions.

$$\eta = \eta_r \left[1 - 0.9 \beta \frac{I_{array}}{I_{array,NOCT}} (T_{c,NOCT} - T_{a,NOCT}) - \beta (T_a - T_r) \right] \quad (3)$$

Where η = photovoltaic array efficiency; η_r = array efficiency at reference cell temp; β = temperature coefficient; I_{array} = insolation on the array per unit area; $T_{c,NOCT}$ = cell temp; T_a = ambient temp; T_r = reference cell temp and NOCT = Nominal operating cell temperature.

$$Q_c = \eta A I_{array} \quad (4)$$

Where Q_c = PV output; A = area and I_{array} = irradiation on the array. PV performance will be degraded at a rate of 0.5% per year (Jordan and Kurtz, 2013).

2.3 Battery model

The BESS module incorporates performance specifications such as: power rating, storage capacity, depth of discharge and round-trip efficiency (Bortolini et al., 2014). The degradation of BESS performance is based on Tesla warranty conditions of 70% performance after ten years use, calculated to 3.5% per year (Tesla Inc, 2017). Battery performance life is measured in cycles (Jayasekara et al., 2014), which is given by:

$$Cycles = \frac{1}{2} \frac{\sum_{h=1}^H |SOC_h - SOC_{h-1}|}{DoD_{avg} \cdot K_b} \quad (5)$$

Where SOC = state of charge, DoD = depth of discharge and K_b = BESS capacity.

Charging regimes of PV only and PV and offpeak BESS charging will be compared. A reference diagram for battery operations is presented in Figure 2.

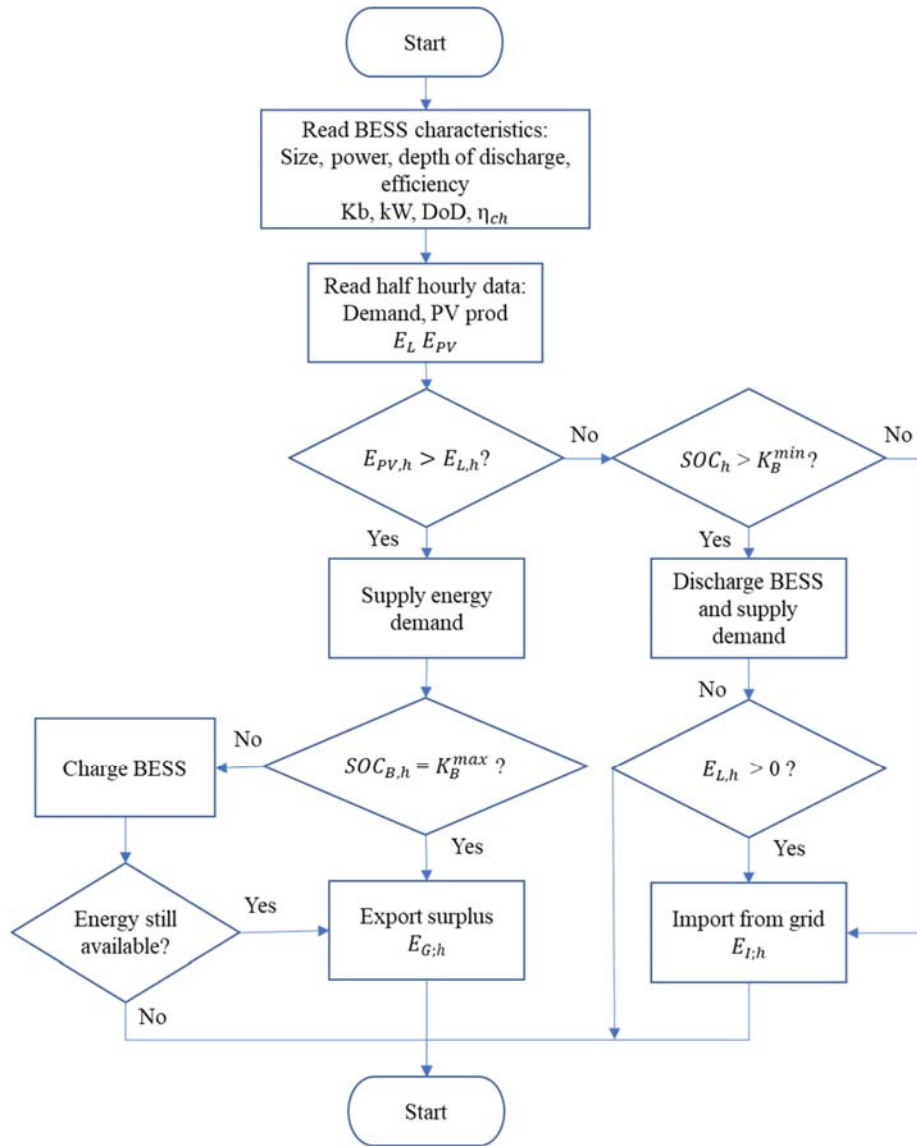


Figure 2. Energy flow control chart for each half-hourly period.

where SOC = State of Charge, K_B = BESS capacity in kWh, $E_{G,h}$ = energy exported, and $E_{I,h}$ = energy imported from grid.

2.4 Network model

To analyse the impacts of household investment in energy infrastructure on the LV network a network model developed to reflect Australian Electrical Engineering standards was selected (Varendorff et al., 2017). The model verified against South East Queensland DNSP Energex, feeder level data, has been adapted for the purposes of this research to identify voltage regulation impacts of household PV, the

operational issues they present to DSNPs and the degree to which they are mitigated by the addition of BESS.

The trial area, shown in Figure 3, was chosen as it is composed of primarily fully detached houses and had low initial PV penetration. Meters were installed on customers' premises and on the distribution transformer to record voltage, current and phase data. Under current regulatory standards EnergeX is required to maintain voltage at customer terminals to $240V \pm 6\%$, with the transition to $230V +10\% - 6\%$ by 2020 (Counsel, 2018).

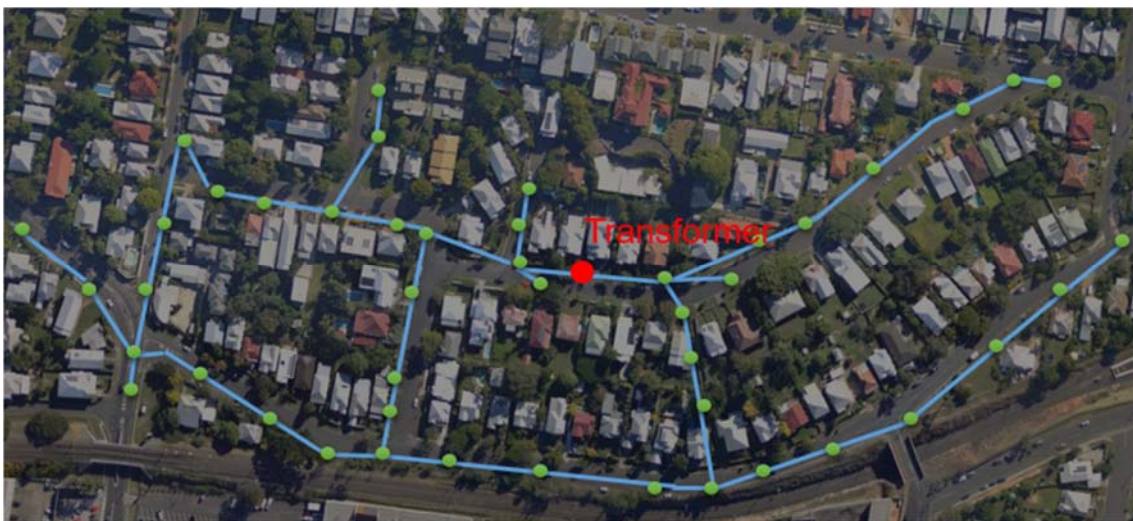


Figure 3. LV Network trial area and customer connections snapshot.

The load flow technique outlined in Teng (Teng, 2003) detailing a three-phase power flow methodology has been implemented in MATLAB. This method defines two matrices, the bus-injection to branch current (BIBC) matrix and the branch current to bus-voltage (BCBV) matrix. Multiplication of these two matrices leads to the load flow solution and is outlined in Figure 4. The advantages of this methodology lie in its use the topological features of the network examined to solve the distribution load flow directly thus reducing the complexity and resources required to run compared to traditional Newton Raphson and Gauss implicit Z matrix algorithms.

The network connection matrix (NCM) contains information on each conductor span including length, connections and conductor type. The algorithm produces the BCBV and BIBC matrices containing 3

phase element data; Kron's reduction is used to incorporate the neutral conductor impedance (Caliskan and Tabuada, 2014). The resulting matrices are multiplied together to provide the distribution load flow (DLF) matrix.

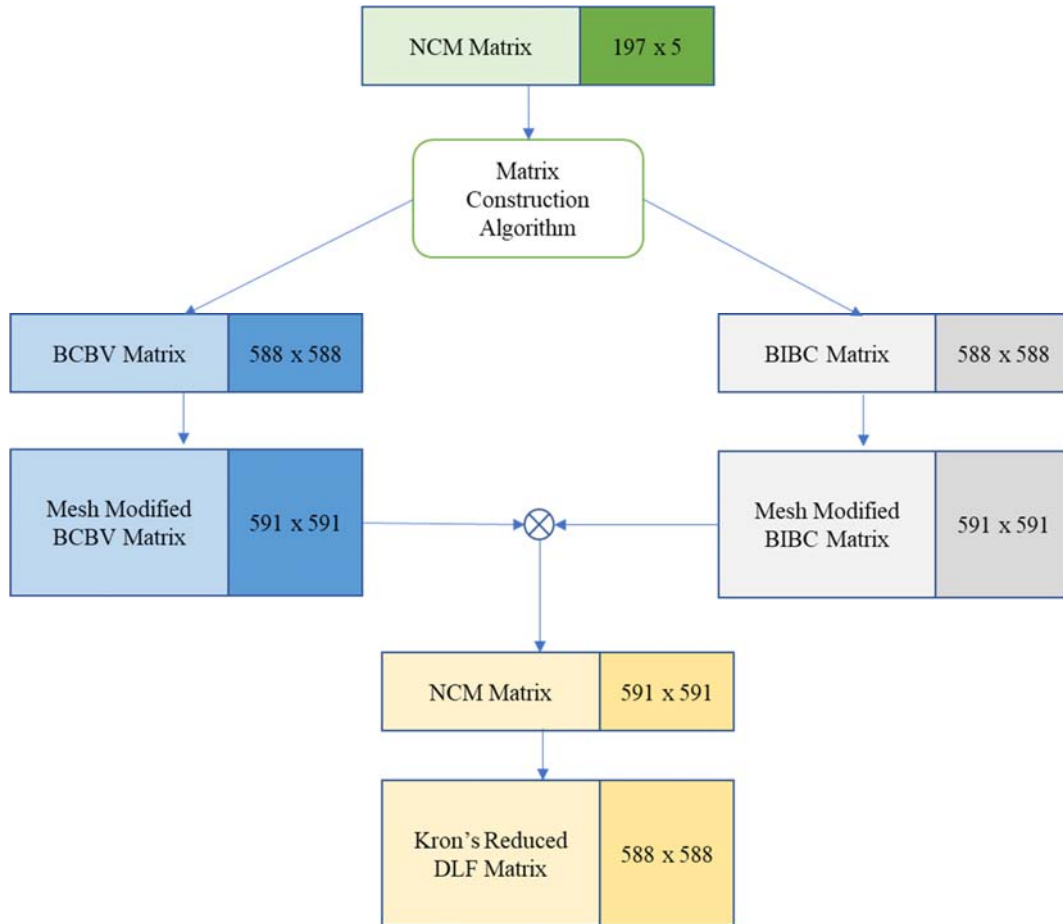


Figure 4. Network model structure: Matrix construction

The second modelling stage involves the load flow algorithm and is outlined in Figure 5. The inputs to the algorithm are comprised of the DLF matrix, PQ (containing customer demand data) matrix from which a PV (PV or PV+BESS data) matrix is subtracted and the voltage at each customer's meter and each pole is solved iteratively. Noting that PV and batteries are allocated randomly to households per PV penetration scenario, at higher levels of PV penetration any imbalance of allocation will be minimised.

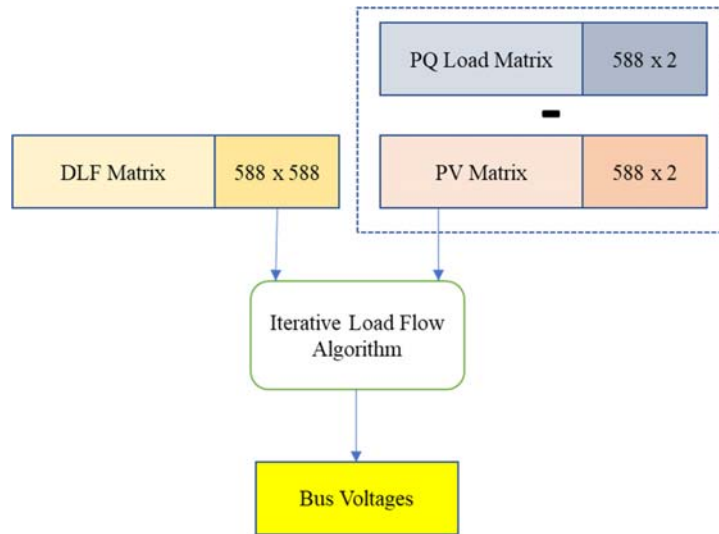


Figure 5. Network modelling structure: Load flow

The model was verified by comparing the output voltages from the load flow solution to the recorded data voltages at each customer connection point. The validation period from 8:00 pm - 4:00 am on the 13th January 2013 was selected to avoid influence from PV. The verification results returned errors less than 1.5% through 8:00pm – 4:00am evaluation periods.

2.5 Economic model

The economic evaluation is based on the changes to energy profiles across a range of financial metrics. Through analysis of changes in energy volumes and maximum demand the economic network impacts can be evaluated in terms of capital spending, losses, energy not served and changes in reliability. Household economics are based on commonly used metrics such as: energy self-consumed, energy export sales at FiT and equipment lifecycle costs. Economic Inputs to model include:

Capex – PV units at three sizes typically installed in the Australian market are evaluated as presented in Table 2.

Table 2. PV system installed (including inverter) costs.

PV Input Parameters	PV1	PV2	PV3	Unit
Size	1.5	3	5	kW
Cost	2100	5000	7500	\$AUD
Lifespan	25	25	25	year
Degradation/year	0.5	0.5	0.5	%
Panel yield	15	15	15	%

Source: SolarQuotes 2017 (SolarQuotes, 2017).

The BESS products considered are shown in Table 3. The installed costs include inverters. Replacement BESS units are to the same specifications. Stationary BESS units' costs are forecast to reduce, however, given uncertainty regarding the reduction in BESS costs, a 5% reduction per year is used for this paper. For the household analysis operational and maintenance spending is assumed to be \$0 for PV & BESS kit (Schmidt et al., 2017).

Table 3. BESS product range.

BESS Specifications	Sonnen Battery	Fronius Battery	Tesla Powerwall	Units
Cost	8900	12,250	10,350	\$AUD
Capacity	4	9	13.5	kWh
Cost per kWh	2225	1361	767	\$/kWh
Capex reduction/year	5	5	5	%
Efficiency	86%	90%	90%	%
Power	2	4.8	7	kW
Degradation/year	3.5	3.5	3.5	%
Cycles	10,000/10 years	20 years	5000/10 years	-
DoD	100%	80%	100%	%

Source: (Enphase.AC, 2016; Fronius, 2016; SolarQuotes, 2017; Tesla Inc, 2017)

Retail electricity prices and Feed-in-tariffs (FiT) – Sample market pricing was sourced from AGL Ltd. in Queensland for 2017 as shown in Table 4 will be used to both provide the baseline energy

cost and cost of energy imports where demand is not met by PV. Prices will be escalated at an annual CPI of 2.5%.

Table 4. AGL Queensland Standard Retail Contracts.

Cost component	Flat	Peak+ Controlled Load	ToU	Demand	Basis
Flat	31.04			14.74	kWh
Peak (14:00-20:00 weekdays)		28.6	59.4		kWh
Shoulder (07:00 – 14:00 and 20:00 – 22:00)			25.3		
Controlled load (22:00-07:00)		18.7	16.5		kWh
Demand (max demand in billing period)				33	c/kWh/day
Daily charge	92.4	110	105.6	104.61	day
FiT	10.6	10.6	10.6	10.6	kWh

Source: AGL 2017 (AGL Ltd, 2017).

Net Present Value (NPV) – Discounted cash flow analysis will be undertaken on the operational cash flows and investment capex and replacement cycles. The Weighted Average Cost of Capital (WACC) is the hurdle rate that must be covered to provide that return. A WACC of 4% is used in this analysis,

$$NPV = \sum_{j=1}^n \frac{RL_j}{(1+a)^j} - \sum_{j=0}^{n-1} \frac{I_j}{(1+a)^j}. \quad (6)$$

Value of Deferred Augmentation (VDA) – A measure of network investment that is deferred or avoided expressed as the value per kVa or kW of capacity displaced (Coles et al., 1995; Gil et al., 2008; Peterson et al., 2010; Piccolo and Siano, 2009), the figure of AUD \$916 (in 2017 \$) from the AEMC 2012 Power of Choice report is used in this paper (AEMC, 2012). Network maximum demand is a key driver of network planning. In this study VDA is apportioned to households based on the Postage Stamp (PS) methodology whereby benefits, or costs, are allocated based on changes to their contribution to demand at network peak demand (Abdelmoteleb et al., 2016). Benefits of this method include its simplicity and focus on maximum demand as the key driver of network spending.

Value of Customer Reliability (VCR) – The VCR, as compiled by the Australian Energy Regulator (AER), calculation is utilised by network operators to prioritise network planning and address potential constraints (AEMO, 2014). The VCR represents, in \$/kWh, the value of the reliable supply of

electricity per sector, as shown in Table 5. Residential VCR will be used in this analysis to measure changes in a household’s value of reliability based on its average BESS State of Charge (SOC) as the measure of its self-sufficiency in the event of an outage.

Table 5. NEM level VCR \$/kWh.

Customer class	Residential	Agriculture	Commercial	Industrial	Direct connect customers	Aggregate NEM value
VCR	25.95	47.67	44.72	44.06	6.05	33.46

Source: AEMO VCR Final Report 2014 (AEMO, 2014)

Reduced losses - An important network benefit of DG is the reduction in losses resulting from generation being sited close to demand (Chiandone et al., 2014; Chiradeja, 2005; Marinopoulos et al., 2011; Shaw-Williams et al., 2019). Queensland wholesale electricity prices will be used to value avoided energy losses.

Financial analysis of impacts attributable to household investment was performed both at the individual household level, aggregated household level and that of the network across scenarios. The evaluation is performed over the PV panel lifespan of 25-years; BESS replacements are determined by usage and manufacturer specifications. The comparison baseline is the present value of retail energy costs with an escalation at CPI of 2.5% and household load growth forecast at 2%.

3. Results and discussion

Utilising the QUT High Performance Computing (HPC) array, 200 simulations of demand, TSC, temperature and grid prices were run for one year at the half-hourly level. Local area solar resource was modelled, and PV generation derived for each household. Average scenario results were input into the LV network model and voltage impacts were analysed. The economic analysis is extended, on an annual basis subject to price escalations and performance degradations, to the 25-year lifespan of PV including BESS replacement cycles with a discount rate of 4%. The analysis was performed on the range of retail pricing structures available in the Australian market as at 2017. The results are presented in terms of

energy profiles and economic performance of individual equipment configurations and of the test area in aggregate.

3.1 Operational results

For equipment comparisons a baseline demand profile of 6,100 kWh was utilised and configurations, except for the uneconomic 1.5kW with larger battery sizes, evaluated, Table 6 presents resulting first year energy profiles. As shown, there are sizeable reductions in energy imports with all BESS sizes and that the 13.5kWh BESS, combined with 3kW PV and over, displaces virtually all imports. This has profound network spending implications both in terms of mitigating voltage rise and reducing peak demand. Further, exporting households can contribute to meeting area load which will be considered in the aggregated results in the next section. Results from the Peak and Controlled Load pricing structure, where batteries are charged overnight similarly to hot water and heat pump systems under the current tariff 33, have a higher rate of exports due to batteries not being empty at the beginning of the day. The PV only installation results and the high level of imports illustrate the mismatch in timing between solar generation and evening demand peak and illustrates the potential gains from the incorporation of batteries.

Table 6. Household energy profiles by equipment mix and pricing structure (kWh).

Equipment mix	kWh PV	Demand		Flat		Peak + CL		Time of Use	
		Export	Import	Export	Import	Export	Import	Export	Import
1. PV 3kW	4,719	2,680	4,061	2,678	4,062	2,679	4,067	2,666	4,073
2. PV 5kW	7,865	5,540	3,775	5,537	3,777	5,532	3,780	5,507	3,787
3. PV1.5kW, BESS4kWh	2,360	6	3,742	6	3,743	496	4,238	5	3,755
4. PV3kW, BESS4kWh	4,719	1,094	2,471	1,092	2,472	2,352	3,738	1,078	2,482
5. PV3kW, BESS9kWh	,719	151	1,525	147	1,524	2,354	3,742	147	1,548
6. PV3kW, BESS13.5kWh	4,719	37	1,408	35	1,408	2,354	3,742	35	1,433
7. PV5kW, BESS4kWh	7,865	3,912	2,143	3,907	2,142	5,287	3,532	3,872	2,147
8. PV5kW, BESS9kWh	7,865	2,329	557	2,320	553	5,290	3,536	2,291	563
9. PV5kW, BESS13.5kWh	7,865	1,923	151	1,913	146	5,290	3,537	1,884	157

While reductions in peak period energy volumes can potentially result in lower wholesale energy costs, it is the impacts on households' contribution to maximum demand that has the greatest significance for network planning.

3.1.1 Aggregated sector and scenario results

Scenarios were run at 10%, 25%, 50% and 75% PV and BESS penetration rates across the 148 test households with PV and BESS installations allocated randomly to households. For concision the results for 5kW PV and Tesla Powerwall battery configuration are presented. Aggregate energy profile results by scenario and pricing structure are presented in Table 7. The displacement of peak demand for the test area to offpeak periods are pronounced across all pricing structures. The significant increase in exports in the Peak and Controlled Load (BESS charging overnight) pricing results from starting each day with a full battery to cover morning peak energy use and reduced capacity to absorb PV generation.

Table 7. Aggregate energy results by pricing structure and scenario.

Annual Aggregates	Baseline	10%	25%	50%	75%
PV installed kW	-	70.00	185.00	375.00	590.00
BESS installed kWh	-	189.00	499.50	1,012.50	1,593.00
PV generation MWh	-	109.83	290.26	588.36	925.69
<u>Demand</u>					
Max Demand kW	387.29	356.27	306.21	261.89	201.35
Peak period energy MWh	612.98	518.67	365.56	114.20	- 173.24
OffPeak period energy MWh	210.72	195.10	167.60	120.47	70.19
Total Energy Served MWh	823.70	713.77	533.15	234.67	- 103.05
Exports MWh	-	44.45	109.72	197.03	314.45
<u>Flat</u>					
Max Demand kW	387.29	340.41	298.87	239.65	192.70
Peak period energy MWh	612.98	519.20	366.07	114.69	- 172.54
OffPeak period energy MWh	210.72	195.08	167.61	120.55	70.13
Total Energy Served MWh	823.70	714.28	533.68	235.25	- 102.40
Exports MWh	-	44.48	109.79	196.96	313.98
<u>Peak and Controlled Load</u>					
Max Demand kW	387.29	359.16	306.49	384.65	497.78
Peak period energy MWh	612.98	482.56	264.21	- 107.92	- 520.48
OffPeak period energy MWh	210.72	232.21	270.40	344.81	420.50
Total Energy Served MWh	823.70	714.78	534.61	236.89	- 99.98
Exports MWh	-	81.21	211.60	416.19	656.25

Time of Use

Max Demand kW	387.29	367.51	323.84	266.68	214.77
Peak period energy MWh	612.98	518.56	364.22	110.93	- 178.40
OffPeak period energy MWh	210.72	194.86	167.42	120.33	69.80
Total Energy Served MWh	823.70	713.42	531.64	231.26	- 108.60
Exports MWh	-	45.05	111.68	200.64	319.92

The resulting changes in maximum demand by period and PV and BESS penetration scenario is shown in Figure 6. From the 25% scenario it becomes apparent that households using a Controlled Load tariff to charge batteries overnight represents a significant source of demand as households commence charging from 10pm. Whilst this represents a significant shift of demand out of peak periods it can be seen that at 50% and higher that households acting in a manner logical at the individual level has a dramatic impact on local network area demand in the absence of more responsive pricing structures.

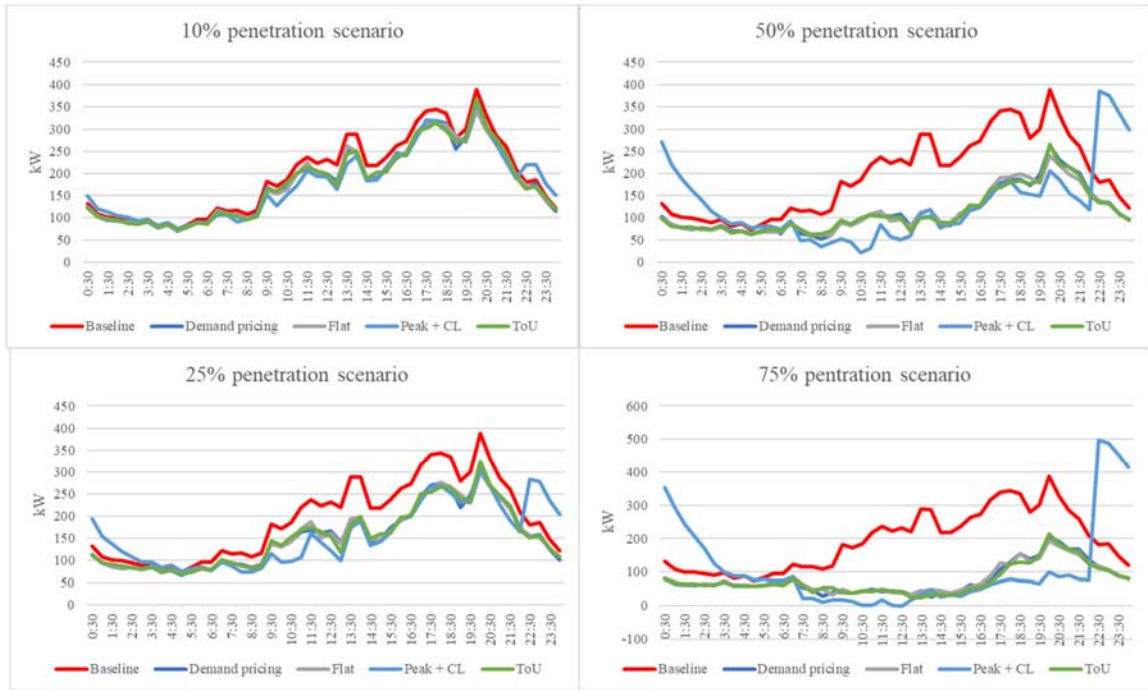


Figure 6. Area maximum demand by scenario and pricing structure per half hour period.

3.1.2 Network voltage impacts

The most quoted barrier to the further incorporation of PV into LV networks has been the impact on voltage regulation. To evaluate the extent of this issue a power flow model was constructed and verified based on a section of the LV network in the suburb of Newmarket in Queensland as representative of a typical urban area. The cost implications of reconductoring or other physical network enhancement

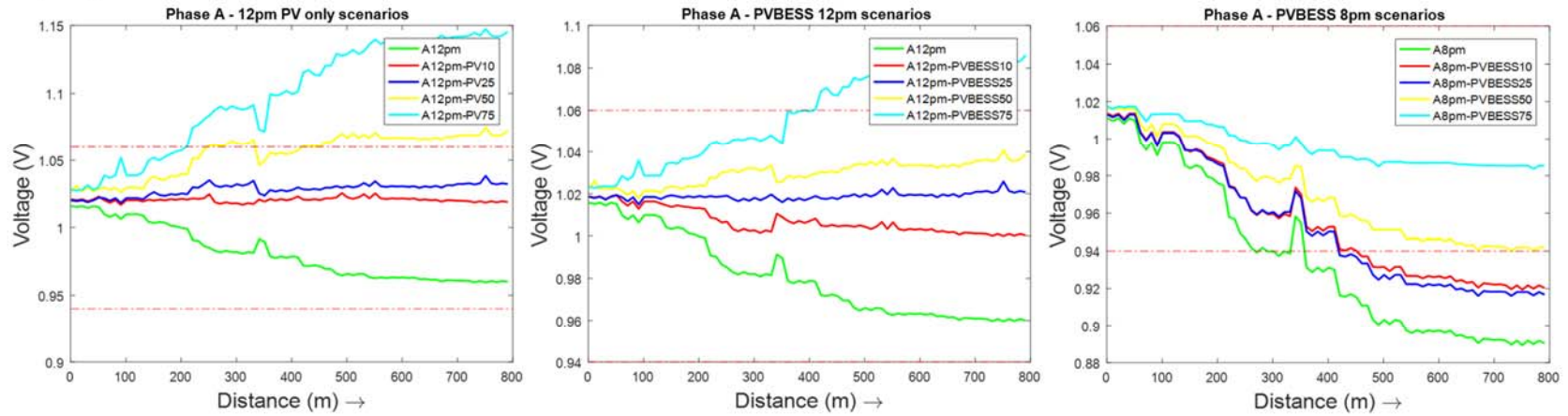
approaches are outside of the scope of this paper, rather, the aim is the exploration of the potential of independent household investment choices on current network limitations regarding the further incorporation of distributed generation. The PV & BESS units were allocated randomly to households with any initial allocation imbalances reduced at higher penetration rates due to saturation levels.

Voltage impact results are shown across PV and BESS penetration rates for the Demand and Peak + Controlled Load pricing structures to illustrate the differences arising from a PV only charging protocol to that utilising both PV and offpeak charging. The results are presented for 12pm for maximum PV production and evaluation of voltage rise as well as 8pm network peak periods to evaluate voltage drop across phase A, which is a single-phase service line in Figure 7.

On service line A there are notable reductions in voltage drop even at the 10% PV only scenario, this is less pronounced on other lines. At PV penetration of 75% surplus generation being fed into the grid leads to significant voltage rise across scenarios. Such results illustrate the potential problems posed for network operators in facilitating higher levels of PV on networks without additional measures of support. However, the potential for batteries to address these conditions are shown in their ability to bring voltage back within limits by the addition of batteries; as can be seen in the shift of the PV+BESS 50% scenario results to under upper network limits. The addition of batteries even without active coordination with network operators provide a significant benefit under these conditions. The 8pm scenarios show that the higher PV + BESS scenarios can provide significant support to the network through the reduction of voltage drop compared to the baseline case.

The effect of demand pricing can be seen by comparing the PV+BESS 50% scenario results. With demand pricing and PV only charging the batteries start the day empty resulting in a greater capacity to absorb PV generation resulting in a corresponding reduction in voltage rise. The reduction in arbitrage opportunities from utilising offpeak sourced energy at peak times is more than compensated for by maximising PV energy use.

Demand pricing



Peak and controlled load pricing

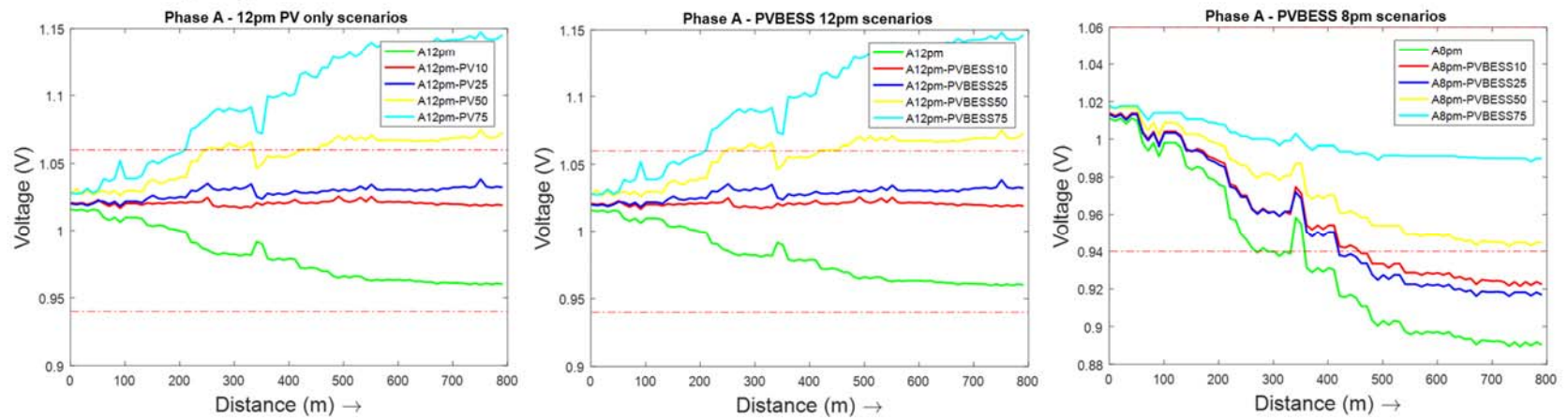


Figure 7. Phase A voltage impacts by case and penetration scenario.

3.2 Financial results

The results for the comparison of system configurations by pricing structure are presented in Figure 8. It is apparent that the Peak and Controlled Load pricing structure returns the worst household economic results and Demand pricing the highest under these conditions. This is primarily due to the low level of the FiT resulting in exported generation effectively being wasted compared to displacing further consumption. Similarly, to Cucchiella et al. our model finds residential PV&BESS profitability is related to larger capacity sizes combined with larger household demands as this provides for a greater degree of self-consumption (Cucchiella et al., 2016). The work of Camillo et al. under Peak and Offpeak pricing in Portugal, having an equivalence to the Peak and Controlled Load pricing structure in our study, similarly finds that the capital costs of BESS render all configurations uneconomic (Camillo et al., 2017). Further, our findings concur with those of Khalilpour and Vassalo regarding the consistent profitability of PV only installations under Australian conditions (Khalilpour and Vassallo, 2016).



Figure 8 Financial results by equipment mix and pricing structure

At current battery prices, the private economic business case is marginal except for under moving to demand pricing and or larger battery sizes. This presents social equity concerns for those households unable to afford the capital investments required to manage their energy price exposure.

3.2.1 Aggregate and scenario results

The aggregated sector financial results across pricing structures and PV&BESS penetration rates of 10%, 25%, 50% and 75% are shown in Figure 9. It can be noted that network benefits exceed private benefits in all cases. The negative impact of significant coincident battery charging load as seen in the Peak and Controlled Load pricing section, in the absence of other price signals to prevent it, results in adverse economic network impacts at high penetrations. Demand pricing provides the greater returns to households, with the exception of ToU pricing in the 50% scenario, whilst returning significant network benefits showing greater allocative efficiency in aligning benefits with beneficial network outcomes. Further, given the low level of FiT for PV exports there are no scenarios, under current retail offerings, that provide the opportunity for arbitrage benefits. As found in previous studies self-consumption is the primary determinant of household benefit, this is enhanced by the ability to maximise a greater proportion of PV generation afforded by the larger battery capacity. From this perspective any net area exports during peak PV production in terms of reverse power flows both causes issues with voltage regulation as well as representing the underutilisation of PV resource.

The impact on the area level reliability is also significant in terms of network reporting on energy supply security. The ability of households to operate in islanded mode in the case of energy supply outage enhances measures of network resilience. Given that reliability of supply is a major driver of network spending prioritisation; the ability of residential batteries to be enlisted to support area networks is an example of the value in cooperative arrangements between network operators and households.



Figure 9 Financial results 25 Years by pricing structure and penetration scenario

Another view of the aggregated household sector benefits compared with network outcomes across scenarios is illustrated in Figure 10. Particularly in the large equipment configuration results there are significant network benefits that can be unlocked from household installations and so household investment in energy infrastructure, and the incentivisation thereof, must be considered in network planning. Further economic benefits from reductions in wholesale energy prices and emissions reductions are outside the scope of this paper.

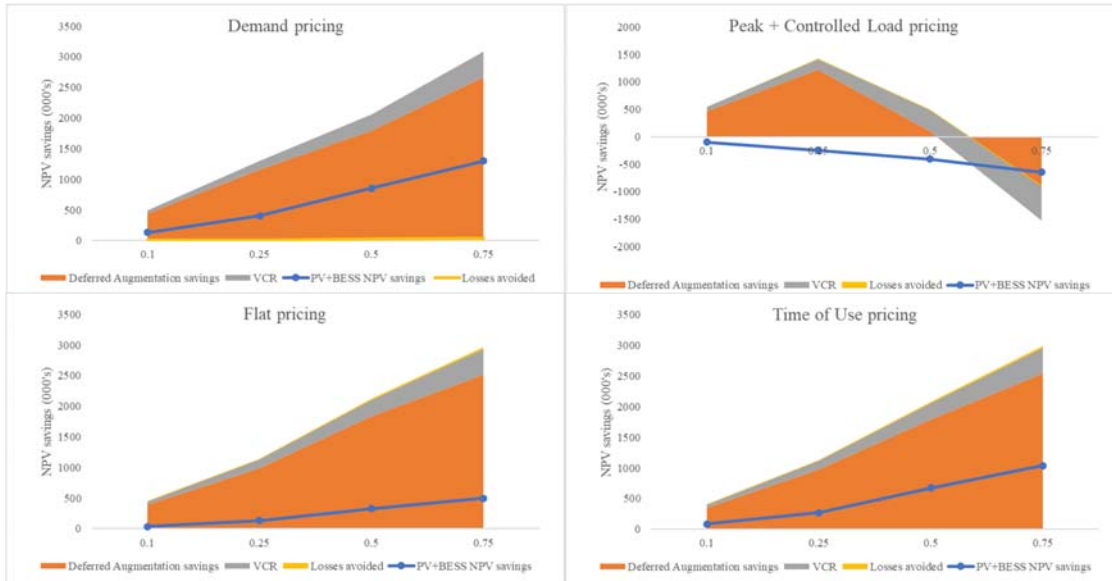


Figure 10. Private and network savings by scenario.

There is a growing range of batteries for residential storage coming to market and initial signs indicating a willingness on the part of households to adopt. The role of vendors to provide aggregation and optimisation of batteries to provide auxiliary services to networks will no doubt play a role, however, currently networks lack the data systems and two-way communications for widespread consumer interaction, and hence is outside the scope of this analysis.

This paper aimed to evaluate economic outcomes and the effectiveness of pricing signals to enable rates of distributed generation on LV networks sufficient to render urban areas effectively net zero energy. In the case of Energex Ltd, the DNSP considered in this study, up to 50% of its customer base – some one million households - is connected to the urban LV network, and is broadly representative of similar urban network areas, and this study indicates the potential for BESS to provide the means for both addressing the network issues arising from the current levels of PV in a meaningful way in advance of network operator advances.

4. Conclusions

This paper presented a techno-economic model to evaluate the feasibility for moving to higher levels of distributed generation in the housing sector with battery storage and so contribute further to the decarbonising of the energy sector in Australia. The model simulates household demand, weather

inputs, PV production, BESS operation and provides a power flow analysis to determine voltage impacts on a LV network. It provides an economic analysis both from the household perspective and the wider network in terms of deferred network spending, losses avoided and reliability.

The results of the analysis show that the addition of BESS enables the incorporation of higher levels of PV on LV networks through moderating voltage rise issues and assists in the operation of networks by alleviating voltage drop during periods of high demand.

This research can serve to inform policy discussions in determining strategies for increasing the contribution to decarbonisation of energy systems of retrofitting of existing housing stock with photovoltaics and storage. Further, it makes a significant contribution to policy deliberations in determining support or incentivisation of the adoption of battery storage. However, the scope of the current research does not consider carbon pricing in considering economic impacts of reducing carbon emissions due to the current lack of emissions pricing in Australia, nevertheless this would also be a natural extension of the model in future work.

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