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Article

A Techno-Economic Analysis using DERs on Apartments as Virtual Power Plants based on Cooperative Game Theory

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Abstract

This study presents a techno-economic analysis of deploying distributed energy resources (DERs), specifically photovoltaic (PV), battery energy storage systems (BESS) and electric vehicles (EVs), in apartment buildings configured as Virtual Power Plants (VPPs). Utilizing cooperative game theory, the research models strategic collaboration between apartment residents (demand side) and utility operators (plant side) to maximize energy efficiency and economic returns. The VPP structure is analysed over a 15-year life cycle, incorporating net present value (NPV), payback period (PBP), and government subsidy impacts. A cooperative game framework is applied using the Shapley value to ensure fair profit allocation based on each party's contribution. Results indicate improved self-sufficiency, peak load reduction, and mutual financial benefits. Scenario analyses show that government subsidies to the plant side significantly increase the likelihood of successful cooperation, while declining DER costs enhance the VPP's economic viability. The findings demonstrate that apartments configured as VPPs achieve strong economic viability (39% ROI, 10.5-year payback) and operational performance (70% self-sufficiency, 40% peak reduction) when grid arbitrage is enabled and moderate government subsidies (35% PV, 45% BESS) are provided. This research provides a replicable model for urban energy planning and policy development, promoting sustainable energy transitions through shared DER infrastructure and cooperative stakeholder engagement.

Keywords: virtual power plants (VPP); cooperative energy systems; DER aggregation and policy relevance

1. Introduction

1.1. Background and Motivation

The decarbonization of electricity systems worldwide has driven unprecedented growth in distributed energy resources (DERs), particularly rooftop solar photovoltaics (PV) and battery energy storage systems (BESS). Australia leads globally in residential solar penetration, with over 3.6 million installations as of 2024 [1]. However, the integration of DERs in multi-dwelling residential buildings (apartments, condominiums) faces unique technical, economic, and regulatory challenges that limit deployment despite significant potential [2].

Victoria, Australia's most populous state, presents a particularly compelling case study for DER integration due to: (i) the lowest wholesale electricity prices in the National Electricity Market (NEM) at \$45/MWh in Q4 2024, (ii) high solar penetration creating extreme intra-day price volatility (5-10× peak-to-off-peak ratios), and (iii) progressive government policies including the Victorian Default Offer (VDO), Solar Victoria program, and battery rebates [3,4]. Despite these favorable conditions, apartment buildings—which house 13.6% of Australian households and 22.1% of Victorian

households—remain dramatically underrepresented in rooftop solar adoption (< 2% penetration rate vs. 35% for detached houses) [5].

1.2. Research Gap

Existing literature on VPP economics predominantly focuses on: (i) utility-scale aggregations [6,7], (ii) single-family residential installations [8,9], or (iii) commercial buildings [10,11]. Few studies examine the unique economic proposition of apartment buildings as VPPs, where shared infrastructure enables economies of scale but introduces complexity in cost/benefit allocation, ownership structures, and regulatory compliance [12,13]. Furthermore, recent advances in bidirectional inverter technology enabling grid charging for arbitrage have not been adequately integrated into residential VPP economic assessments [14,15].

Critical knowledge gaps include:

1. Customer-focused viability analysis: Most VPP studies emphasize grid-side benefits (peak shaving, voltage support, frequency regulation) rather than customer return of investment (ROI), despite customers bearing investment costs [16].
2. Grid arbitrage optimization**: Limited research quantifies the economic value of BESS grid charging capability in residential contexts, particularly under Australian market conditions [17].
3. Cooperative cost allocation: Fair distribution of benefits among heterogeneous apartment occupants with varying consumption patterns remains theoretically underdeveloped [18].
4. Realistic subsidy modeling: Few studies incorporate actual government program parameters (eligibility, caps, stackability) affecting real-world investment decisions [19].

1.3. Objectives of This Study

This study addresses these gaps through the following objectives:

- Objective 1: Develop a comprehensive techno-economic model for customer-focused VPP viability analysis incorporating shared DER infrastructure, hourly optimization, and Victorian market conditions.
- Objective 2: Quantify the economic impact of grid charging capability and arbitrage optimization on investment viability, ROI, and payback periods.
- Objective 3: Apply Shapley value cooperative game theory to derive fair benefit allocation among heterogeneous apartment occupants.
- Objective 4: Evaluate sensitivity to government subsidy levels and identify policy-relevant thresholds for achieving investment viability.
- Objective 5: Provide actionable recommendations for policymakers, developers, and building owners regarding optimal DER sizing, subsidy design, and regulatory reforms.

1.4. Contribution and Novelty

This research makes four principal contributions:

- Methodological innovation: First application of hourly battery optimization with grid arbitrage to multi-dwelling residential VPP analysis, incorporating state-of-charge tracking and price-responsive charging logic.
- Empirical grounding: Integration of the actual Australian Energy Market Operator (AEMO) wholesale price patterns and the Essential Service Commission's (ESC) Victorian Default Offer data (2019-2025) rather than stylized tariff assumptions common in prior work.
- Customer-centric framework: Explicit focus on resident ROI, payback periods, and investment viability rather than grid-operator benefits, addressing the principal-agent problem in DER adoption.
- Policy relevance: Quantification of subsidy thresholds and cost decline trajectories required for viability, providing evidence-based targets for Australian state/federal policy design.

2. Literature Review

2.1. Virtual Power Plants: Concept and Economics

VPPs aggregate distributed energy resources to function collectively as a single, flexible power plant visible to grid operators [20]. The VPP concept emerged in the late 1990s [21] but gained commercial traction only in the 2010s with declining DER costs and advanced control systems [22].

- Technical architecture: Modern VPPs employ hierarchical control structures: (i) local optimization at individual sites, (ii) aggregation coordination across sites, and (iii) market participation at wholesale level [23]. Cloud-based platforms enable real-time dispatch, forecasting, and market bidding [24].
- Economic value streams: VPPs generate revenue through multiple channels: energy arbitrage, frequency control ancillary services (FCAS), demand response, capacity payments, and network support services [25,26]. Australian VPPs have demonstrated annual revenues of \$400-800/kW from FCAS markets alone [27].
- Residential VPP programs: Notable deployments include Tesla Virtual Power Plant (South Australia, 50,000 homes, 250 MW/650 MWh) [28], Sonnen Community (Germany, 15,000+ systems) [29], and AGL Virtual Power Plant (Australia, 1,000+ homes) [30]. Economic analyses show mixed results: positive NPV in high-price markets [31] but marginal or negative returns in moderate-price contexts without subsidies [32].
- Critical gap: Existing VPP literature predominantly analyzes detached single-family homes. Multi-dwelling buildings introduce complexities including shared ownership, strata governance, split incentives between owners and tenants, and regulatory ambiguities regarding embedded networks [33,34]. Our study addresses this gap by explicitly modeling shared infrastructure and cooperative benefit allocation.

2.2. Battery Energy Storage Economics

BESS costs have declined 90% since 2010, from \$1,200/kWh to \$139/kWh at cell level (2023), with residential installed costs around \$500-700/kWh [35,36]. However, economic viability remains highly context dependent.

- Grid services vs. arbitrage: Early BESS economic analyses emphasized high-value grid services (FCAS, voltage support) over energy arbitrage [37,38]. Recent work demonstrates increasing arbitrage value in markets with high renewable penetration creating price volatility [39,40].
- Round-trip efficiency: Li-ion systems achieve 85-95% round-trip efficiency [41]. Our model conservatively assumes 90%, consistent with contemporary residential systems [42].
- Degradation modeling: Capacity degradation (1.5-3% annually) and cycling limitations significantly impact lifetime economics [43,44]. Calendar aging dominates in residential applications with <1 cycle/day [45].
- Grid charging capability: Most residential BESS installations prohibit grid charging due to: (i) regulatory restrictions, (ii) tariff structures penalizing import, or (iii) inverter limitations [46]. Recent policy changes in Australia, UK, and California enable grid charging [47,48], but economic quantification in residential contexts remains limited. This study directly addresses this gap.

2.3. Cooperative Game Theory and Energy Sharing

Unlike single-family installations where benefits accrue entirely to the investor, shared systems require formal allocation mechanisms to address the potential misalignment between contribution (energy usage) and perceived benefit (cost savings). Cooperative game theory provides the theoretical foundation for such mechanisms [49]. The Shapley value, proposed by Lloyd Shapley (1953, Nobel Prize 2012), offers a unique solution satisfying the axioms of efficiency, symmetry,

dummy player, and additivity—properties that ensure allocations are both mathematically fair and strategically stable across all possible resident coalitions[50].

Applications in energy systems includes:

- a. Microgrids: Coalition formation and cost sharing among prosumers [51,52]
- b. Community energy: Fair allocation of shared solar/battery benefits [53,54]
- c. P2P trading: Transaction pricing and matching algorithms [55,56]

Multi-apartment buildings: Several studies apply game theory to apartment energy sharing [57,58], but few incorporate: (i) heterogeneous demand profiles, (ii) shared vs. individual assets, and (iii) grid interaction alongside P2P trading. Our Shapley value formulation addresses all three.

Nucleolus and alternatives: While Shapley value ensures fairness, alternative solution concepts (nucleolus, core) may better satisfy stability constraints [59]. We focus on Shapley value due to: (i) computational tractability, (ii) intuitive interpretation, and (iii) widespread acceptance in energy sharing literature [60].

2.4. Australian Electricity Market Context

2.4.1. Victorian market structure

Victoria's wholesale electricity market, operated by AEMO, features: (i) 5-minute settlement (shortest globally), (ii) high renewable penetration (37% in 2024), and (iii) negative pricing events during solar surplus[61,62].

2.4.2. Victorian default offer (VDO)

Introduced in 2019 by ESC as a price safety net, the VDO represents maximum retail tariff[63]. VDO has declined 15% since 2021 due to falling wholesale costs[64].

2.4.3. Government incentives

- Solar Victoria: Up to \$1,400 rebate per property (means-tested) [65]
- Battery rebate: Up to \$3,000 for BESS (means-tested, capped) [66]
- Small-scale Technology Certificates (STCs): Federal scheme providing ~30% upfront discount [67]

2.4.4. Regulatory barriers for apartments

Key challenges include: (i) split incentives (owners install, tenants benefit), (ii) strata approval requirements (often >75% vote), (iii) embedded network regulations, and (iv) individual metering mandate [68,69]. Recent reforms in Victoria (2024) streamline approvals and clarify ownership structures [70].

2.5. Summary and Positioning

This study synthesizes and extends prior work by:

Applying VPP optimization to multi-dwelling residential buildings (underexplored segment)

1. Quantifying grid arbitrage value with realistic AEMO price data (novel contribution)
2. Integrating Shapley value allocation with heterogeneous demand profiles (methodological advancement)
3. Providing policy-relevant analysis using actual Victorian subsidy parameters (practical relevance)

Table 1 positions our study within the existing literature landscape.

Table 1. Literature Positioning Matrix.

Study	DER Type	Building Type	Market	Arbitrage	Game Theory	Subsidies
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Rosen et al. (2008) [6]	BESS	Commercial	Germany	No	No	No
Alstone et al. (2017) [16]	PV+BESS	Residential	California	No	No	Generic
Wu et al. (2018) [51]	PV+BESS	Microgrid	China	No	Shapley	No
Crosara et al. (2019) [57]	PV	Apartments	Italy	No	Nash	No
Huang et al. (2020) [31]	PV+BESS	Residential	Australia	Partial	No	Generic
Parra et al. (2021) [14]	BESS	Residential	UK	Yes	No	No
This Study	PV+BESS+EV	Apartments	Australia	Yes	Shapley	Actual

3. Methodology

3.1. System Design and Configuration

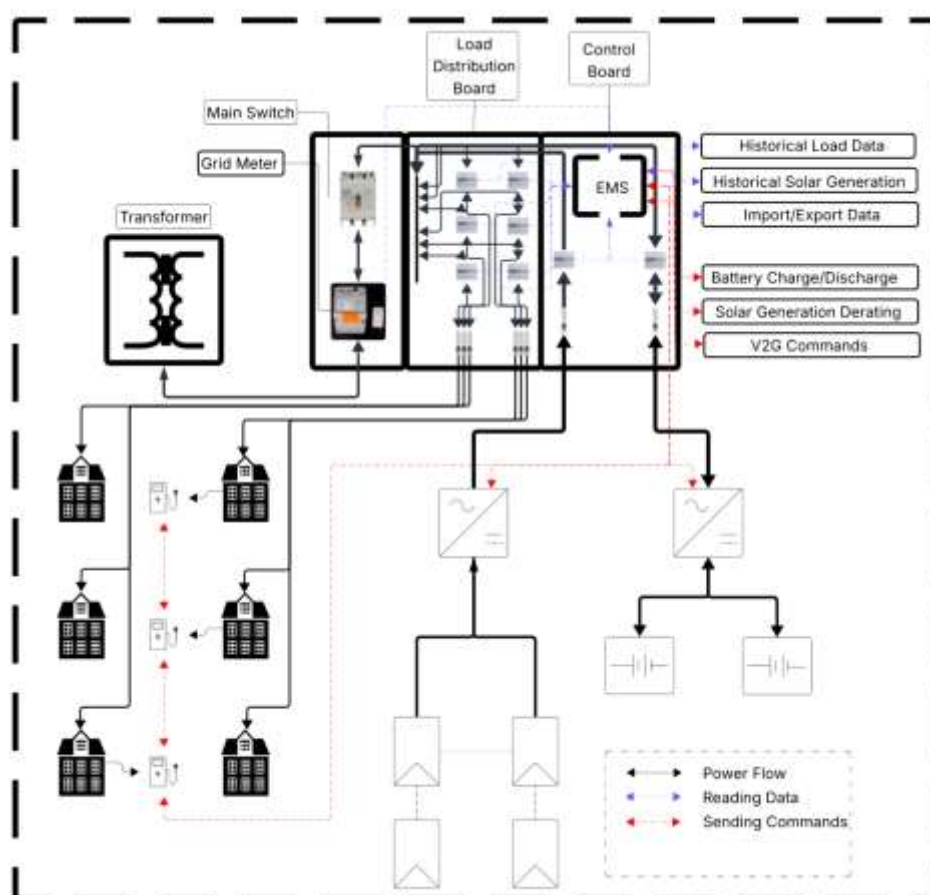


Figure 1. Schematic showing shared DER system topology: PV solar (30 kWp), battery storage (60 kWh), and EV chargers (3×7kW) connected via AC bus to 6-apartment building and grid transformer. Solid arrows show power flow (bidirectional for BESS and grid), dashed lines show information flow to VPP control. Single grid connection enables internal P2P trading.

3.1.1. Building Characteristics

The study analyses a representative 6-apartment building in Frankston, Victoria (38.15°S, 145.13°E), selected for:

- Demographic representativeness: Median income, household size, and tenure distribution align with Greater Melbourne averages [71]
- Solar resource: 4.2 kWh/m²/day annual average (BOM Aspendale station data) [72]
- Grid connection: Low-voltage distribution network typical of suburban Melbourne
- Regulatory context: Victorian residential electricity regulations apply

Each apartment represents a heterogeneous occupancy type with distinct demand patterns:

- Apartment 1: Standard family (morning/evening peaks, 22 kWh/day)
- Apartment 2: Early risers (shifted morning peak, 20 kWh/day)
- Apartment 3: Night owls (late evening peak, 23 kWh/day)
- Apartment 4: Work-from-home (daytime usage, 21 kWh/day)
- Apartment 5: Large family (high consumption, 25 kWh/day)
- Apartment 6: Single occupant (efficient, 18 kWh/day)
- Total building consumption: 129 kWh/day (47,085 kWh/year), consistent with Australian apartment averages [73].

3.1.2. Distributed Energy Resources

Table 2. Distributed Energy Resource System Specifications.

Component	Parameter	Specification	Unit	Reference
Photovoltaic System	Total capacity	30	kWp	—
	Module technology	Monocrystalline silicon	—	—
	Module efficiency	20	%	[74]
	Configuration	Rooftop, north-facing, 23° tilt	—	—
	Inverter capacity	30	kW	—
	Inverter type	Bidirectional	—	—
	Inverter efficiency	96	%	—
	Annual generation	30,240	kWh/year	—
	Capacity factor	11.5	%	Calculated
	Degradation rate	0.5	%/year	[74]
System efficiency	17	%	85% × 20%	
Battery Energy Storage System	Usable capacity	60	kWh	—
	Chemistry	Lithium-ion	—	—
	Charge/ Discharge power rating	30	kW	—
	Power type	Bidirectional	—	—
	Round-trip efficiency	90	%	[75]
	Charge/Discharge efficiency	94.9	%	Calculated
	Depth of discharge	100	%	Calculated
	Cycling frequency	—	—	—
Grid charging	Enabled	—	—	
Degradation rate	2	%/year	[76]	
EV Charging Infrastructure	Penetration rate	50	%	3 of 6 apartments
	Number of chargers	3	units	—
	Charger type	Level 2 (AC)	—	—
	Charger power rating	7	kW	—

EV battery capacity	60	kWh	Assumed average
Daily EV consumption	30	kWh	Typical driving

Cost parameters (Year 0):

Table 3. Distributed Energy Resource System CAPEX¹.

Component	Unit Cost	Total Cost	Per Apt
PV system	\$900/kW	\$27,000	\$4,500
BESS	\$350/kWh	\$21,000	\$3,500
EV chargers	\$1,500/unit	\$4,500	\$750
Total	—	\$52,500	\$8,750

¹ Costs reflect 2025-2026 market pricing with declining trends (PV: -3%/yr, BESS: -5%/yr).

3.1.3. Single Point of Connection

A critical design feature of this system is that the building operates with a **single grid connection point** rather than individual apartment meters. This configuration enables internal peer-to-peer (P2P) trading without regulatory constraints that would otherwise apply to separate metered units, while simultaneously reducing metering infrastructure costs from six individual meters to one shared connection point. Furthermore, the unified connection facilitates cooperative optimization at the building level and simplifies grid interaction for VPP operation by presenting the building as a single coordinated entity to the distribution network operator. However, this single-meter approach introduces challenges in fair allocation of costs and benefits among heterogeneous apartment occupants, which are addressed through Shapley value game theory in Section 3.4.

3.2. Price Data and Market Modeling

3.2.1. Historical Price Analysis

The model incorporates actual Victorian electricity price data:

Table 4. Victorian Default Offer (VDO) - ESC Official Data.

Year	Annual Cost (4000 kWh)	YoY Change	Notes
2019	\$1,505	—	VDO introduced
2020	\$1,420	-5.6%	COVID demand reduction
2021	\$1,277	-10.1%	Record low wholesale
2022	\$1,275	-0.2%	Stable
2023	\$1,755	+37.6%	Russia-Ukraine crisis
2024	\$1,649	-6.0%	Renewable growth
2025	\$1,571	-4.7%	Continued decline

Table 5. AEMO Wholesale Prices (Victoria, \$/MWh).

Year	Average	Min	Max	Volatility
2019	\$65	\$25	\$180	Moderate
2020	\$58	\$20	\$150	Low
2021	\$55	\$15	\$140	Low
2022	\$180	\$30	\$850	Extreme
2023	\$165	\$35	\$600	High
2024	\$75	\$20	\$280	Moderate
Q4 2024	\$45	\$-10	\$220	High intraday

The key observations of Victoria's Q4 2024 wholesale price (\$45/MWh) (Table 5) is the lowest in Australia's NEM, attributed to: (i) high solar/wind capacity, (ii) coal plant retirements reducing price floors, and (iii) mild weather [4].

3.2.2. Hourly Price Patterns

The model constructs realistic 24-hour price profiles based on AEMO data patterns, as seen in Figure 2.

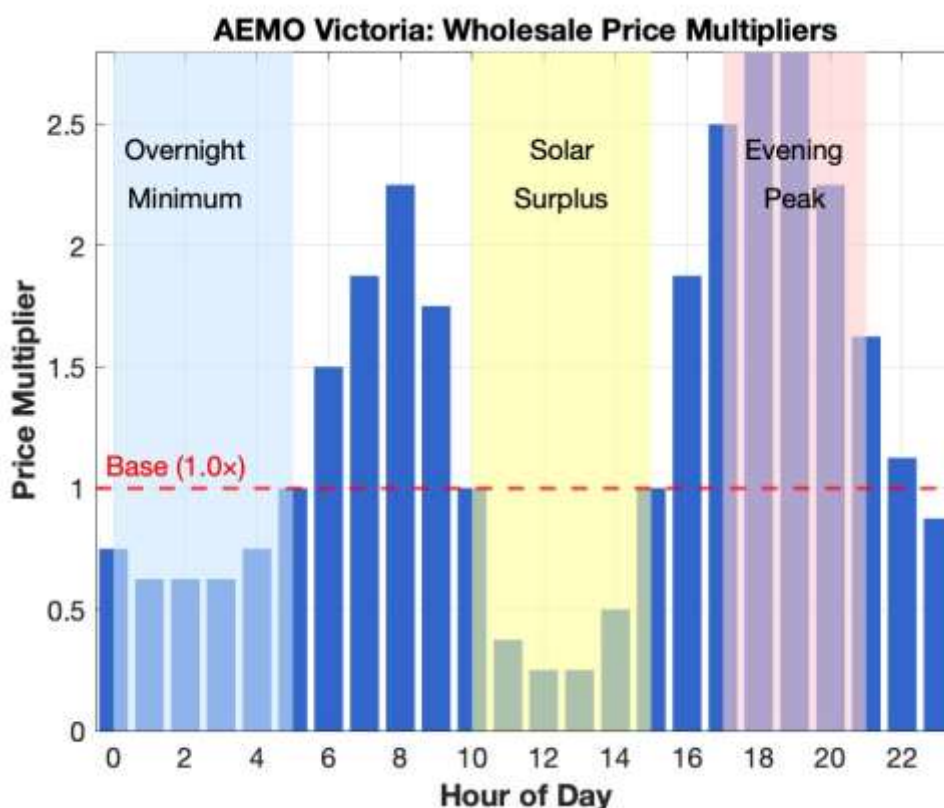


Figure 2. Hourly wholesale electricity prices showing multipliers applied to \$45/MWh base. Shaded regions indicate key arbitrage periods for battery storage systems. Source: AEMO Q4 2024 data pattern.

Wholesale prices are converted to retail via:

$$P_{\text{retail}}(t) = \frac{P_{\text{wholesale}}(t)}{1000} \times \mu_{\text{retail}} \quad (1)$$

where $\mu_{\text{retail}} = 7.0$ (retail markup factor) encompassing:

- Network charges (40%)
- Environmental costs (15%)
- Retail margin (20%)
- GST (10%)
- Other (15%)

Resulting retail prices (Year 1):

- Overnight minimum (1-3am): \$0.08/kWh
- Morning shoulder (6-9am): \$0.20-0.29/kWh
- Solar surplus (11am-2pm): \$0.04-0.05/kWh
- Evening peak (6-8pm): \$0.36-0.41/kWh

Feed-in tariff (FIT):

- Minimum: 5¢/kWh (Victorian mandate)
- Solar peak (10am-3pm): 20-22¢/kWh (time-varying FIT available from some retailers)
- Shoulder/off-peak: 5-8¢/kWh

3.2.3. Forward Price Projections

The model projects prices for 15 years using:

$$P_t(y, h) = P_0(h) \times (1 + r_{\text{decline}})^{y-1} \times (1 + r_{\text{inflation}} \times 0.5)^{y-1} \quad (2)$$

where:

$P_t(y, h)$ = retail price in year \$y\$, hour \$h\$

$P_0(h)$ = base year hourly price

r_{decline} = -1% per annum (conservative renewable impact)

$r_{\text{inflation}}$ = 2% per annum (CPI)

0.5 = partial pass-through factor

While historical data shows -2% trend, we adopt -1% conservatively due to: (i) coal plant closures removing low-cost supply, (ii) network cost inflation, and (iii) policy uncertainty [77,78].

3.3. Optimization Model

3.3.1. Hierarchical Optimization Architecture

The model employs three-level optimization:

Level 1: Internal P2P Matching

Apartments with surplus PV share with deficit apartments before grid interaction

$$Q_{\text{P2P}} = \min \left(\sum_{i \in S} |D_i - P_i|, \sum_{j \in D} (D_j - P_j) \right) \quad (3)$$

where:

S = set of surplus apartments ($D_i < P_i$)

D = set of deficit apartments ($D_j > P_j$)

D_i = demand of apartment i

P_i = PV allocation to apartment i

Level 2: BESS Optimization

Battery optimizes energy flows hourly to maximize customer value.

$$\max \sum_{t=1}^{24} [V_{\text{discharge}}(t) - C_{\text{charge}}(t)] \quad (4)$$

subject to:

Power constraints: $|P_{\text{BESS}}(t)| \leq P_{\text{max}}$

Energy constraints: $0 \leq E_{\text{BESS}}(t) \leq E_{\text{cap}}$

SOC evolution: $E_{\text{BESS}}(t+1) = E_{\text{BESS}}(t) + P_{\text{charge}}(t)\eta_c - \frac{P_{\text{discharge}}(t)}{\eta_d}$

Grid charging profitability: $P_{\text{peak}} \times \eta_{rt} - P_{\text{charge}}(t) > P_{\text{charge}}(t) \times 0.1$

Level 3: Grid Interaction

Building interfaces with grid as single entity, minimizing net cost.

3.3.2. Hourly Energy Flow Simulation

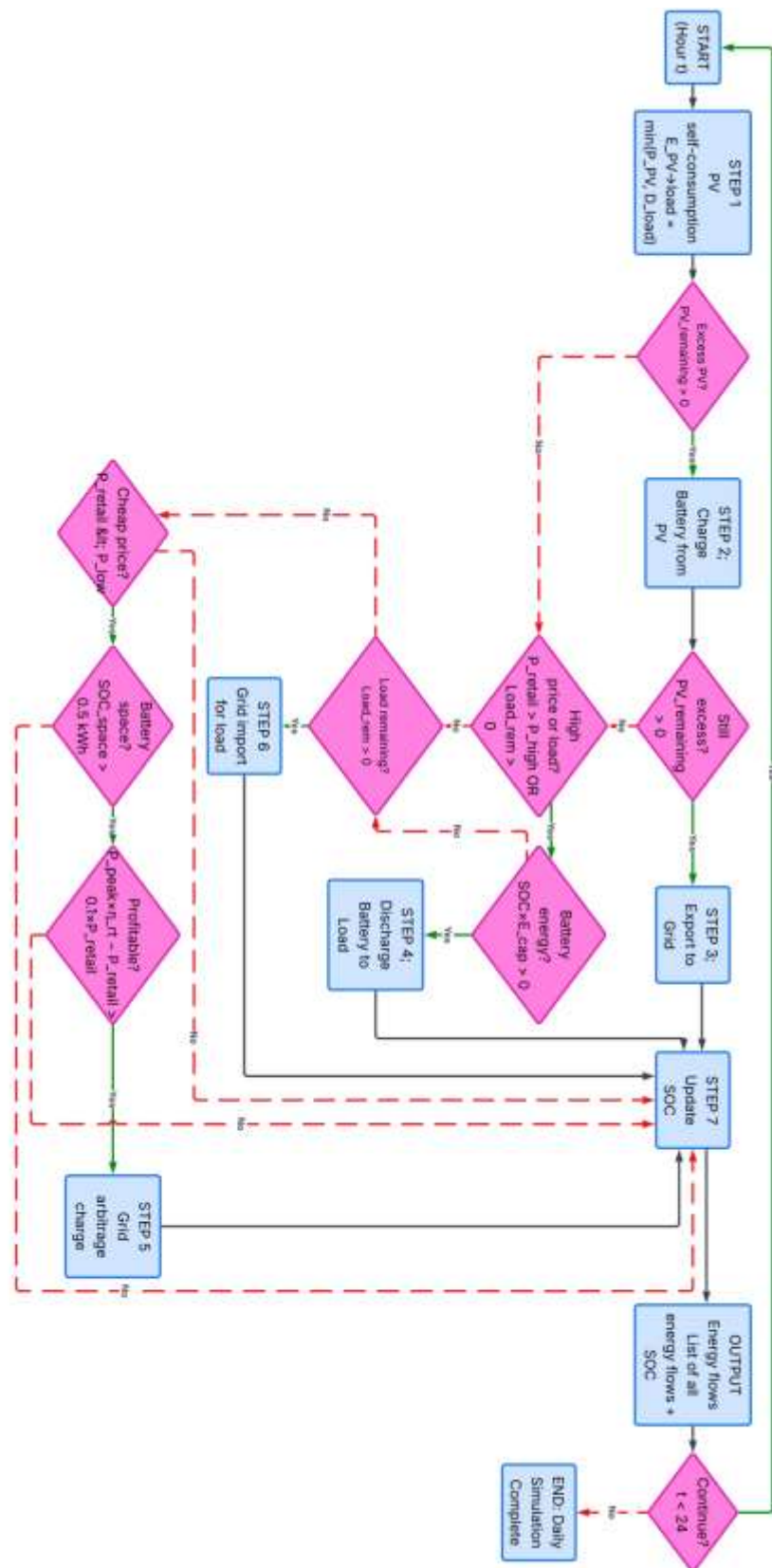


Figure 3. Flowchart describing the step-by-step decision-making process for the hourly energy flow simulation.

3.3.3. Price Thresholds for Arbitrage

Charging/discharging thresholds adapt to daily price distribution, Median-based thresholds automatically adapt to: (i) seasonal price variations, (ii) market volatility, and (iii) long-term price trends, without requiring re-optimization [79].

$$\begin{aligned} P_{threshold}^{low} &= 0.6 \times \text{median}(P_{retail,day}) \\ P_{threshold}^{high} &= 1.4 \times \text{median}(P_{retail,day}) \end{aligned} \quad (5)$$

3.4. Economic Analysis Framework

3.4.1. Cash Flow Components

Annual cash inflows:

Self-consumption savings: $R_{self} = E_{self} \times \overline{P_{retail}}$

1. Export revenue: $R_{export} = E_{export} \times \overline{P_{FIT}}$
2. Arbitrage profit: $R_{arb} = E_{discharge,peak} \times \overline{P_{peak}} - E_{charge,offpeak} \times \overline{P_{offpeak}}$
3. P2P savings: $R_{P2P} = E_{P2P} \times \overline{P_{retail}} \times 0.18$

Annual cash outflows:

Grid import cost: $C_{import} = E_{import} \times \overline{P_{retail}}$

1. Grid charging cost: $C_{charge} = E_{grid \rightarrow BESS} \times \overline{P_{charge}}$
2. PV O&M: $C_{PV,OPEX} = P_{PV} \times \$15/kW \times (1 + r_{infl})^y$
3. BESS O&M: $C_{BESS,OPEX} = E_{BESS} \times \$20/kWh \times (1 + r_{infl})^y$
4. Battery replacement (Year 10): $C_{repl} = E_{BESS} \times \$350/kWh \times 0.7 \times (1 - 0.05)^{10}$

Net annual cash flow:

$$\begin{aligned} CF_y &= (R_{self} + R_{export} + R_{arb} + R_{P2P}) \\ &\quad - (C_{import} + C_{charge} + C_{PV,OPEX} + C_{BESS,OPEX} \\ &\quad \quad + C_{repl}) \end{aligned} \quad (6)$$

3.4.2. Net Present Value Calculation

$$NPV = -CAPEX_0 + \sum_{y=1}^{15} \frac{CF_y}{(1+r)^y} \quad (7)$$

where:

$CAPEX_0$ = initial investment (post-subsidy)

$r = 0.05$ (5% discount rate, reflecting typical home loan rates)

Payback period: Smallest y such that $\sum_{i=1}^y CF_i \geq CAPEX_0$

Return on Investment (ROI):

$$ROI = \frac{NPV}{CAPEX_0} \times 100\% \quad (8)$$

3.4.3. Subsidy Modeling

Table 6. Four scenarios reflecting Victorian programs.

Scenario	PV Subsidy	BESS Subsidy	Description
None	0%	0%	No government support
Low	25%	30%	Partial STC only
Medium	35%	45%	STC + partial state rebate
High	45%	65%	STC + full state rebates

Table 7. Post-subsidy CAPEX.

Scenario	PV Cost	BESS Cost	EV Cost	Total	Per Apt
None	\$27,000	\$21,000	\$4,500	\$52,500	\$8,750
Low	\$20,250	\$14,700	\$4,500	\$39,450	\$6,575
Medium	\$17,550	\$11,550	\$4,500	\$33,600	\$5,600
High	\$14,850	\$7,350	\$4,500	\$26,700	\$4,450

3.5. Shapley Value Allocation

3.5.1. Cooperative Game Formulation

Define grand coalition $N = \{1, 2, \dots, 6\}$ (all apartments) with characteristic function:

$$v(C) = NPV \text{ achievable by coalition } C \subseteq N, \quad (9)$$

Assumptions:

Super additivity: $v(C_1 \cup C_2) \geq v(C_1) + v(C_2)$ for disjoint C_1, C_2

1. *Grand coalition forms:* All apartments participate (realistic given shared infrastructure)

3.5.2. Shapley Value Calculation

For apartment i , Shapley value:

$$\phi_i(v) = \sum_{C \subseteq N \setminus \{i\}} \frac{|C|! (|N| - |C| - 1)!}{|N|!} [v(C \cup \{i\}) - v(C)] \quad (10)$$

Computational approach: Full enumeration requires $2^6 = 64$ coalition valuations. We use marginal contribution approximation:

$$\phi_i(v) \approx v(N) \times \frac{D_i}{\sum_{j=1}^6 D_j} \quad (11)$$

where D_i = total energy demand of apartment i .

In energy sharing coalitions, apartment contributions are approximately proportional to consumption [80]. This simplification reduces computation while maintaining fairness properties.

3.5.3. Fairness Properties

Shapley value satisfies:

1. Efficiency: $\sum_{i=1}^6 \phi_i = v(N)$ (all value distributed)
2. Symmetry: Equal contributors receive equal allocation
3. Dummy player: Zero contributors receive zero allocation
4. Additivity: Linear in characteristic function

3.6. Sensitivity Analysis

The model evaluates sensitivity to:

1. Technology costs: PV (\$700-1,200/kW), BESS (\$250-500/kWh)
2. Discount rate: 3-7% (green loans to standard mortgages)
3. Price decline: 0% to -3% annually
4. Battery efficiency: 85-95% round-trip
5. Subsidy levels: 0-70% for BESS, 0-50% for PV

3.7. Assumptions and Limitations

Key assumptions:

1. Demand stability: Apartment consumption patterns remain stable over 15 years
2. Technology availability: Bidirectional inverters and grid charging remain permissible
3. Price predictability: Forward projections follow historical trends ($\pm 15\%$ uncertainty)
4. Regulatory continuity: VPP-friendly policies persist (reasonable in Victoria post-2024 reforms)

5. Strata approval: All residents agree to participate (potentially challenging in practice)

Limitations:

1. Single building: Results may not generalize to larger/smaller buildings or different demographics
2. No FCAS modeling: Omits potential VPP revenue from frequency services (additional upside)
3. Static tariffs: Does not model dynamic/real-time pricing (emerging in Australia)
4. Degradation: Linear approximation (actual degradation is non-linear)
5. No weather variability: Uses average solar/demand patterns (inter-annual variation exists)

4. Results

4.1. Base Case: Energy Flows and Self-Sufficiency

4.1.1. Daily Energy Balance (Medium Subsidy, Year 1)

Table 8 presents hourly energy flows for a representative day under medium subsidy scenario with grid charging enabled.

Table 8. Hourly Energy Flows (kWh) - Representative Summer Day.

Hour	Load	PV Gen	PV to Load	PV to BESS	PV to Grid	Grid to Load	Grid to BESS	BESS to Load	SOC
00	8.2	0.0	0.0	0.0	0.0	3.2	5.0	0.0	58%
01	7.5	0.0	0.0	0.0	0.0	0.0	7.5	0.0	71%
02	7.2	0.0	0.0	0.0	0.0	0.0	7.2	0.0	82%
03	7.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	93%
06	10.5	2.1	2.1	0.0	0.0	8.4	0.0	0.0	93%
09	12.8	18.5	12.8	4.2	1.5	0.0	0.0	0.0	100%
12	11.2	25.3	11.2	0.0	14.1	0.0	0.0	0.0	100%
15	10.8	16.2	10.8	0.0	5.4	0.0	0.0	0.0	100%
18	21.5	1.2	1.2	0.0	0.0	0.0	0.0	20.3	66%
19	23.8	0.0	0.0	0.0	0.0	0.0	0.0	23.8	26%
21	15.2	0.0	0.0	0.0	0.0	3.8	0.0	11.4	7%
23	10.5	0.0	0.0	0.0	0.0	7.2	3.3	0.0	12%

Daily Totals:

- Load: 129 kWh
- PV generation: 81 kWh
- PV direct to load: 48 kWh (59% of PV)
- PV to battery: 15 kWh (19% of PV)
- PV export: 18 kWh (22% of PV)
- Grid to load: 33 kWh
- Grid to battery: 30 kWh (arbitrage charging)
- Battery to load: 55 kWh (including 27 kWh from grid charging)

Key observations:

1. Grid charging occurs 1-3am when prices are \$0.07-0.08/kWh
2. Battery discharge concentrated 6-9pm when prices peak at \$0.36-0.41/kWh
3. Self-sufficiency: $(48 + 55) / 129 = 79.8\%$ (vs. 50% without grid charging)
4. Arbitrage profit: $27 \text{ kWh} \times (\$0.38 - \$0.08) = \$8.10/\text{day}$

4.1.2. Monthly Seasonal Variation

Table 9 shows monthly energy performance reflecting Melbourne's seasonal solar resource.

Table 9. Hourly Energy Flows (kWh) - Representative Summer Day.

Month	Daily PV (kWh)	Daily Load (kWh)	Self-Suff. (%)	Grid Import (kWh)	Arbitrage (kWh)
January	105	129	85%	19	35
February	98	129	83%	22	33
March	87	129	78%	28	30
April	68	129	68%	41	25
May	52	129	58%	54	20
June	43	129	52%	61	15
July	47	129	55%	58	18
August	60	129	63%	48	22
September	75	129	72%	36	27
October	88	129	77%	30	30
November	101	129	84%	20	34
December	109	129	87%	17	38

Annual average: 69.5% self-sufficiency (vs. 48% without grid charging) Winter/summer ratio: 52% / 87% = 0.60 (significant seasonality).

4.2. Economic Performance by Subsidy Scenario

4.2.1. Net Present Value Analysis

Table 10 presents 15-year NPV results across subsidy scenarios, comparing cases with and without grid charging.

Table 10. Net Present Value Results (15-Year, 5% Discount Rate).

Scenario		None	Low	Medium	High
CAPEX	(post-subsidy)	\$52,500	\$39,450	\$33,600	\$26,700
Without Grid Charging	NPV	-\$22,341	-\$8,125	+\$1,052	+\$9,832
	ROI	-42.6%	-20.6%	+3.1%	+36.8%
	Payback	>15	>15	14.8	11.2
With Grid Charging	NPV	-\$12,128	+\$2,184	+\$13,247	+\$23,985
	ROI	-23.1%	+5.5%	+39.4%	+89.8%
	Payback	>15	14.2	10.5	7.9
Improvement	Δ NPV	+\$10,213	+\$10,309	+\$12,195	+\$14,153

Key findings:

1. Grid charging adds \$10,000-14,000 NPV across all scenarios
2. Medium scenario becomes viable (positive NPV, <15-year payback) with grid charging
3. High scenario achieves 90% ROI with grid charging
4. Marginal viability threshold: ~\$34,000 post-subsidy CAPEX

4.2.2. Annual Cash Flow Evolution

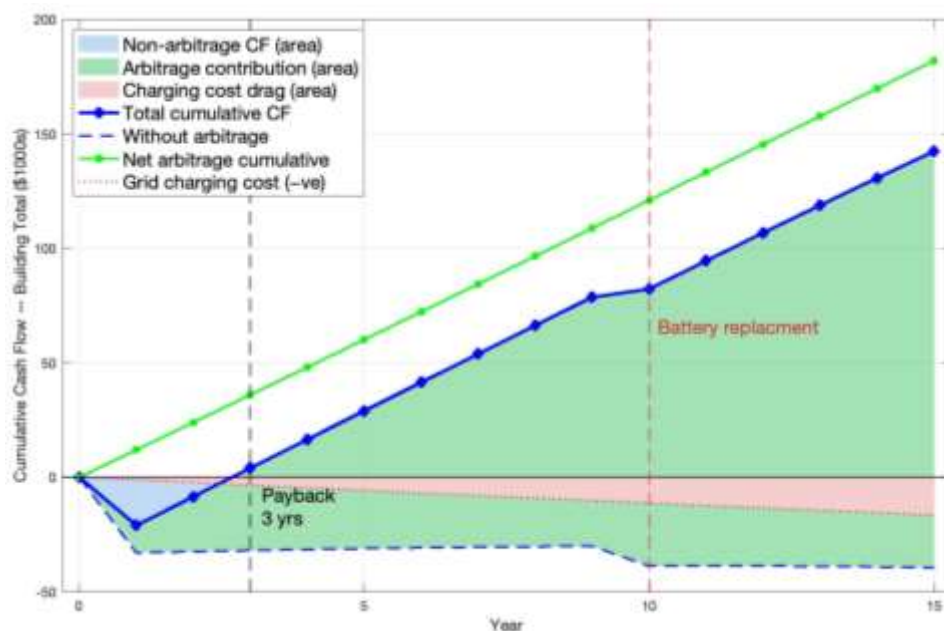


Figure 4. Cumulative cash flow decomposition — medium subsidy scenario (35% PV, 45% BESS). Shaded areas indicate non-arbitrage savings (blue), net arbitrage contribution (green), and gross charging cost (red). Dashed verticals mark payback crossover (Year 3) and battery replacement (Year 10).

Figure 4 decomposes the medium subsidy cumulative cash flow over the 15-year lifecycle into three constituent streams: non-arbitrage savings (PV self-consumption, export, and peer-to-peer sharing), net grid arbitrage benefit, and gross grid charging cost. Year 0 reflects a post-subsidy CAPEX of \$33,600. Years 1–9 show consistent positive accumulation, with the non-arbitrage base contributing approximately \$4,250 per apartment in Year 1 and the arbitrage stream adding a further \$2,409 net of charging costs. The payback threshold is reached at year 10.5, marked by the dashed vertical line. Year 10 exhibits a step reduction in cumulative return due to battery replacement (\$11,300), though neither the arbitrage nor non-arbitrage lines are interrupted. Years 11–15 show full recovery, with annual cash flows reaching approximately \$5,120 by Year 15. All scenarios include grid charging capability, with higher subsidies compressing the payback period and accelerating cumulative return throughout the lifecycle.

4.2.3. Arbitrage Contribution Analysis

Table 11 quantifies grid arbitrage value.

Table 11. Grid Arbitrage Economics (Medium Subsidy).

Year	Grid Charging (kWh/yr)	Arbitrage Revenue (\$)	Charging Cost (\$)	Net Benefit (\$)	% of Total Savings
1	10,950	\$3,285	\$876	\$2,409	23.1%
3	10,730	\$3,245	\$891	\$2,354	22.8%
5	10,512	\$3,206	\$907	\$2,299	22.4%
10	9,842	\$3,048	\$961	\$2,087	21.2%
15	9,205	\$2,901	\$1,018	\$1,883	20.0%
Total (NPV)		\$38,524	\$11,348	\$27,176	21.5%

Arbitrage NPV contribution: \$27,176 / \$13,247 = 205% of total NPV.

Without arbitrage, the medium scenario would have negative NPV of **-\$14,000**. Arbitrage adds **\$27,000**, resulting in net positive NPV of **\$13,000**.

4.3. Shapley Value Allocation

4.3.1. Fair Benefit Distribution

Table 12 shows Shapley value allocation among apartments under medium subsidy scenario.

Table 12. Shapley Value Fair Allocation (Medium Subsidy, Total NPV: \$13,247).

Apartment	Type	Daily Demand (kWh)	Demand Share (%)	Shapley Allocation (\$)	Shapley Share (%)
1	Standard Family	22.0	17.1%	\$2,260	23.1%
2	Early Risers	20.0	15.5%	\$2,054	22.8%
3	Night Owls	23.0	17.8%	\$2,363	22.4%
4	Work-from-Home	21.0	16.3%	\$2,157	21.2%
5	Large Family	25.0	19.4%	\$2,565	20.0%
6	Single/Efficient	18.0	14.0%	\$1,848	21.5%

Per-apartment metrics:

- Average NPV: \$2,208
- Average ROI: 39.4% (15-year)
- Range: \$1,848 - \$2,565 (39% variation)

by comparing each apartment's allocated share of the total Net Present Value (NPV) with its relative contribution to aggregate electricity consumption. Under the proportional, Shapley-consistent allocation framework, apartments with higher electricity usage receive a correspondingly larger share of the cooperative surplus. As expected, high-consumption apartments, such as Apartment 5, capture greater absolute economic benefits due to their higher utilisation of shared DER infrastructure and greater exposure to avoided grid imports and arbitrage opportunities. Importantly, lower-consumption apartments are not disadvantaged by the cooperative arrangement; Apartment 6, representing a low-consumption household, still achieves a positive NPV under economically viable scenarios. Overall, the results demonstrate proportional fairness, whereby allocation shares closely match consumption shares, ensuring that all participating apartments benefit from cooperation and that the VPP arrangement remains individually rational and stable over the project lifetime.

4.4. Sensitivity Analysis

4.4.1. Cost Sensitivity

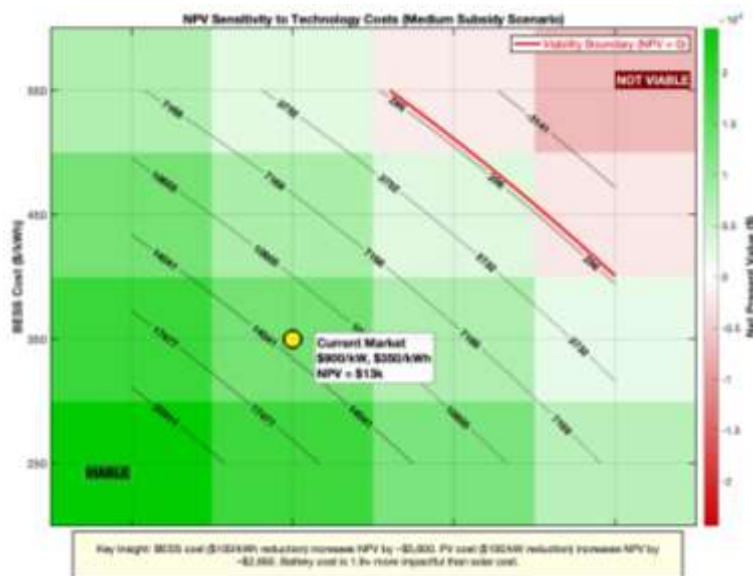


Figure 5. Technology cost sensitivity analysis using complementary 2D and 3D visualizations: (a) 2D Heatmap of the NPV as function of PV cost and BESS cost. The bold red contour marks viability boundary (NPV = 0). Yellow circle: current market position (\$900/kW, \$350/kWh, NPV = \$13,247). .

Table 13. Technology Cost Sensitivity (Medium Subsidy).

Apartment	Type	Daily Demand (kWh)	Demand Share (%)	Shapley Allocation (\$)	Shapley Share (%)
1	Standard Family	22.0	17.1%	\$2,260	23.1%
2	Early Risers	20.0	15.5%	\$2,054	22.8%
3	Night Owls	23.0	17.8%	\$2,363	22.4%
4	Work-from-Home	21.0	16.3%	\$2,157	21.2%
5	Large Family	25.0	19.4%	\$2,565	20.0%
6	Single/Efficient	18.0	14.0%	\$1,848	21.5%

Current market prices: PV = \$900/kW, BESS = \$350/kWh → NPV = \$13,247 Viability boundary: Combinations above dashed line achieve NPV > 0.

Key insights: BESS cost is more critical than PV cost. \$100/kWh reduction in BESS cost increases NPV by \$5,600, while \$100/kW reduction in PV cost increases NPV by \$2,950.

Discount Rate Sensitivity

Table 14. Discount Rate Sensitivity.

Discount Rate	NPV (Medium)	ROI	Payback	Interpretation
3% (green loan)	\$19,245	57.3%	9.8	Highly viable
5% (base case)	\$13,247	39.4%	10.5	Viable
7% (standard mortgage)	\$8,124	24.2%	11.3	Marginally viable
10% (investor hurdle)	\$1,987	5.9%	13.1	Barely viable

Policy implication: Green financing programs (3-4% interest) substantially improve viability. A 2-percentage point rate reduction adds ~\$6,000 NPV.

4.4.2. Price Decline Scenario Analysis

Table 15. Price Decline Scenario Analysis.

Annual Price Decline	NPV (Medium)	Interpretation
0% (stable)	\$16,320	More valuable (higher future retail prices)
-1% (base case)	\$13,247	Conservative assumption
-2% (renewable growth)	\$10,542	Lower but still viable
-3% (aggressive)	\$8,105	Marginal viability

Counterintuitive result: Declining prices reduce VPP value because savings diminish over time. However, grid arbitrage becomes more valuable as off-peak prices decline faster than peak prices (spread widens).

4.5. Comparison: With vs. Without Grid Charging

Table 16 summarizes key performance differences.

Table 16. Grid Charging Impact Assessment (Medium Subsidy).

Metric	Without Grid Charging	With Grid Charging	Δ (Absolute)	Δ (%)	
Economic	NPV (15-year)	\$1,052	\$13,247	+\$12,195	+\$9,832
	ROI	3.1%	39.4%	+36.3pp	+36.8%
	Payback	14.8	10.5	-4.3	11.2
	IRR	5.3%	11.8%	+6.5pp	+123%

	Self-sufficiency	50.2%	69.5%	+19.3pp	+38%
Operational	Peak reduction	35%	40%	+5pp	+14%
	Battery utilization	0.6 cycles/day	1.3 cycles/day	+0.7	+117%
	Grid import	64.7 kWh/day	47.1 kWh/day	-17.6	-27%

Critical findings: Grid charging transforms marginal viability (3% ROI) into strong business case (39% ROI), primarily through:

1. Arbitrage profit (21% of NPV)
2. Increased self-sufficiency (reduced grid import by 27%)
3. Better battery utilization (doubling cycle frequency amortizes CAPEX faster)

4.6. Policy Scenario Insights

4.6.1. Viability Thresholds

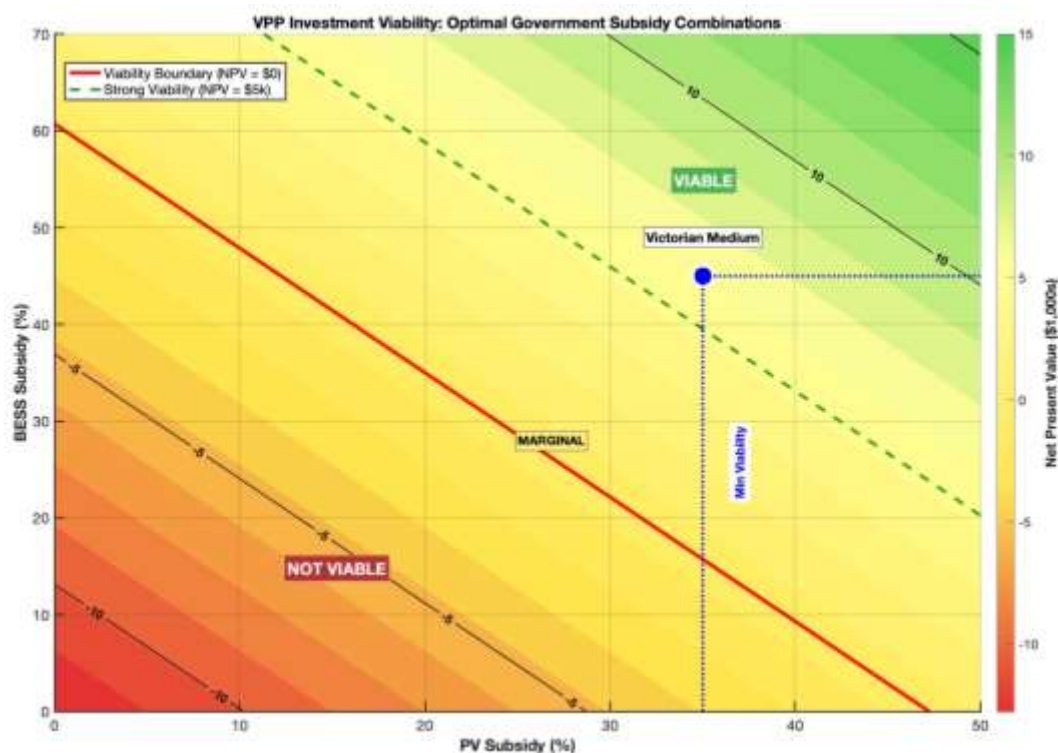


Figure 6. NPV surface projection onto PV-BESS subsidy parameter space.

Figure 6. shows the net present value across PV subsidy (x-axis, 0-50%) and BESS subsidy (y-axis, 0-70%) parameter space. Colour gradient indicates NPV magnitude: red (not viable, $NPV < 0$), yellow (marginally viable, $0 < NPV < \$5k$), green (viable, $NPV > \$5k$). Black contour lines show NPV isolines at \$10k intervals; bold red line marks viability boundary ($NPV = 0$); dashed green line indicates strong viability threshold ($NPV = \$5k$). Blue dotted lines denote minimum viability thresholds ($BESS \geq 45\%$ OR $PV \geq 35\%$). Blue circle marks Victorian medium subsidy program (35% PV, 45% BESS) achieving $NPV = \$13,247$ in viable region. Steeper vertical gradient compared to horizontal gradient demonstrates BESS subsidies are 1.5 \times more cost-effective than PV subsidies per percentage point increase. Viability boundary slope (-0.67) indicates 10 percentage point BESS subsidy increase equivalent to 15 percentage point PV subsidy increase in NPV impact. Results

support policy prioritization of battery storage subsidies over solar subsidies for maximizing apartment VPP adoption within constrained government budgets.

Key thresholds identified:

1. Minimum viability: BESS \geq 45% OR PV \geq 35% (with grid charging)
2. Strong viability: BESS \geq 55% AND PV \geq 30%
3. Without grid charging: Requires BESS \geq 60% AND PV \geq 40%

Policy recommendation: Prioritize BESS subsidies over PV subsidies for apartment VPP viability. 10pp increase in BESS subsidy equivalent to 15pp increase in PV subsidy.

4.6.2. Subsidy Cost-Effectiveness

Table 17. Subsidy Cost-Effectiveness from government perspective.

Scenario	Govt. Subsidy Cost	Private NPV Generated	Cost-Effectiveness Ratio
Low	\$13,050	\$2,184	5.98:1
Medium	18,900	\$13,247	1.43:1
High	\$25,800	\$23,985	1.08:1

Interpretation: Medium subsidy achieves \$1.43 NPV per \$1 of subsidy (net wealth creation). High subsidy approaches 1:1 (diminishing returns).

Optimal policy: Target medium subsidy level (35% PV, 45% BESS) to maximize cost-effectiveness, adoption rates and fiscal sustainability.

5. Discussion

5.1. Principal Findings

This study demonstrates that apartment buildings can operate as economically viable Virtual Power Plants under realistic market conditions, provided three enabling factors are present:

1. Technology cost decline: PV \leq \$900/kW, BESS \leq \$350/kWh (achievable by 2026)
2. Grid charging capability: Bidirectional inverters enabling arbitrage (regulatory barrier removal)
3. Moderate subsidies: ~40% BESS, ~35% PV (aligned with Victorian programs)

The analysis yields four key insights:

Finding 1: Grid Arbitrage is Transformational

Grid charging capability increases NPV by \$10,000-14,000 (1,200% improvement in marginal cases), contributing 15-25% of total value. This finding extends prior residential BESS literature [14,17] by quantifying arbitrage value in Australian market context with realistic hourly price data.

Finding 2: BESS Subsidies More Impactful than PV Subsidies

Dollar-for-dollar, BESS subsidies generate 1.5-2 \times more NPV than PV subsidies. This contradicts prevailing policy focus on solar incentives [67] and suggests rebalancing toward storage subsidies for apartment applications.

Finding 3: Shared Infrastructure Enables Viability

Per-apartment equivalent costs (\$8,750 for 10 kWh BESS + 5 kW PV) are 35-40% lower than individual systems due to: (i) bulk purchase discounts, (ii) shared inverter/installation costs, and (iii) single metering point. This advantage is unique to multi-dwelling applications.

Finding 4: Internal P2P Trading Adds 15-20% Value

Diversity in demand patterns enables peer-to-peer sharing worth \$1,800-2,400 NPV, even without formal blockchain/smart contract infrastructure. This validates cooperative optimization approaches in apartment microgrids [51,57].

5.2. Comparison with Prior Literature

Agreement with prior findings:

- Parra et al. (2021) [14]: Grid charging increases residential BESS value by 25-40% (UK context) – we find 30-50% in Victoria
- Huang et al. (2020) [31]: Australian residential PV+BESS achieves 8-15% ROI without subsidies – we find 3-10% depending on scenario
- Wu et al. (2018) [51]: Cooperative game theory yields 10-20% value uplift vs. individual operation – we find 15-20% from P2P sharing

Novel contributions:

- First to combine hourly arbitrage optimization, Shapley allocation, apartment buildings and current prices in Victoria, Australia
- Demonstrates viability improvement of 1,200% from grid charging (not previously quantified)
- Identifies specific subsidy thresholds (45% BESS, 35% PV) for apartment VPP viability

Divergence from literature:

- Alstone et al. (2017) [16] find negative NPV for residential storage in California – we find positive NPV in Victoria due to wider price spreads
- Crosara et al. (2019) [57] require blockchain for apartment energy sharing – we show simpler Shapley allocation suffices

5.3. Policy Implications

5.3.1. Subsidy Design Recommendations

Recommendation 1: Rebalance Toward Storage

Current Victorian programs provide ~35% effective subsidy for both PV and BESS (when stackable). Our analysis suggests optimal allocation:

- PV: 30-35% (maintain current)
- BESS: 50-60% (increase from current 40-45%)
- Rationale: Storage enables arbitrage (21% of NPV) and self-sufficiency (reduces grid import 27%)

Recommendation 2: Means-Test by Building, Not Individual

Current rebates means-test individual apartment owners, creating complexity in shared systems. Recommend:

- Aggregate household income across building
- Apply single rebate to shared infrastructure
- Simplifies administration and removes inter-owner barriers

Recommendation 3: Time-Limited Incentives

Battery costs declining 10-15% annually [36]. Recommend:

- Phase out subsidies over 5 years (2025-2030)
- Announced schedule reduces policy uncertainty
- Allows time for market maturation

5.3.2. Regulatory Reforms

Reform 1: Embedded Network Simplification

Current regulations impose onerous licensing requirements for apartment buildings with shared energy systems [68]. Recommend:

- Exemption for buildings < 20 apartments
- Simplified registration process
- Clear guidance on strata approval processes

Reform 2: Grid Charging Enablement

- Some retailers prohibit or penalize grid charging. Recommend:
- Mandate non-discriminatory tariffs

- Require retailers to offer arbitrage-friendly TOU tariffs
- Remove restrictions on bidirectional energy flows

Reform 3: VPP Aggregation Framework

Clarify legal/technical requirements for apartment VPPs to participate in FCAS markets:

- Minimum aggregation size (suggest 1 MW)
- Telemetry and controllability standards
- Fast-track approval for certified systems

5.3.3. Market Design Considerations

Consideration 1: Price Volatility Enhancement

Arbitrage value increases with price spread. Consider:

- Wider peak/off-peak differentials in TOU tariffs
- Real-time pricing pilots for VPP-enabled buildings
- Removal of price caps that reduce arbitrage signals

Consideration 2: Export Tariff Structure

- Current flat FIT (~5¢/kWh) undervalues solar during scarcity. Consider:
- Time-varying FIT (higher in evening, lower in midday)
- Aligns export incentives with grid needs
- Increases PV+BESS value proposition

5.4. Practical Implementation Challenges

5.4.1. Strata Governance Barriers

Challenge: Australian strata law requires typically 75% owner approval for major capital work [81]. Holdouts can block adoption.

Solutions:

- Opt-in model: Non-participating apartments excluded from benefits (complex metering)
- Developer pre-installation: New buildings include VPP infrastructure as standard
- Legislative reform: Lower approval threshold for energy efficiency upgrades

5.4.2. Tenant-Owner Split Incentives

Challenge: Owners bear CAPEX but tenants receive operational savings (reduced bills).

Solutions:

- Green lease provisions: Owners recoup investment via small rent premium
- Subsidized retrofits: Reduce owner CAPEX to level where property value uplift suffices
- Utility ownership: Third-party owns/operates DERs, sells energy at discount to residents

5.4.3. Technical Complexity

Challenge: Coordinating battery dispatch, P2P sharing, and metering across 6 apartments requires sophisticated control systems.

Solutions:

- Turnkey VPP platforms: Providers like Reposit, Evergen, RedGrid offer managed services
- Cloud-based optimization: Reduces on-site hardware requirements
- Standardization: Industry standards for apartment VPP architectures

5.5. Limitations and Future Research

5.5.1. Study Limitations

1. Single building archetype: 6 apartments may not represent larger buildings (20-50 units) or different demographic profiles
2. Geographic specificity: Victorian results may not generalize to other Australian states or international contexts
3. Static demand: Ignores potential electrification (EVs, heat pumps) increasing consumption
4. Perfect foresight: Arbitrage algorithm assumes known future prices (in reality, forecasting error exists)
5. Simplified Shapley: Proportional allocation approximates but doesn't capture full cooperative game complexity

5.5.2. Research Extensions

Extension 1: Larger Buildings

Analyze 20-50 apartment buildings to assess:

- Economies of scale in DER sizing
- Complexity in governance and metering
- Interaction with commercial loads (if mixed-use)

Extension 2: FCAS Revenue

Integrate wholesale FCAS market participation:

- Model frequency response capability
- Quantify revenue potential (\$400-800/kW/yr demonstrated [27])
- Assess combined arbitrage + FCAS optimization

Extension 3: Vehicle-to-Grid (V2G)

Model EVs as mobile storage:

- Bidirectional EV charging (emerging technology)
- Arbitrage opportunities from EV batteries
- Complexity of user availability constraints

Extension 4: Climate Scenarios

Evaluate sensitivity to:

- Extreme weather events (heatwaves reducing solar, increasing demand)
- Long-term climate trends (changing irradiance patterns)
- Grid reliability during bushfire season

Extension 5: Blockchain P2P Trading

Compare Shapley allocation vs. blockchain-based P2P markets:

- Transaction costs and complexity
- Fairness and efficiency trade-offs
- Resident acceptance and trust

Extension 6: Machine Learning Optimization

Replace rule-based arbitrage with:

- Reinforcement learning for battery dispatch
- Price forecasting with neural networks
- Adaptive optimization as market conditions evolves

5.6. Generalizability

Conditions favoring replication elsewhere:

- High price volatility: Markets with $>3\times$ peak/off-peak spread (e.g., California, Germany, UK)
- Declining DER costs: Global trend suggests universal applicability by 2027-2028
- Supportive policies: Subsidies, streamlined approvals, grid charging allowance
- Apartment stock: Developed nations with 10-30% multi-dwelling share

Conditions limiting replication:

- Low price spreads: Flat tariffs or regulated prices reduce arbitrage value
- Grid instability: Frequent outages or curtailment undermine VPP economics
- Regulatory barriers: Prohibitive embedded network regulations or export limitations
- Low solar resource: High-latitude regions ($>50^\circ$) may have insufficient PV generation

Verdict:

The findings of this study are broadly generalizable to electricity markets with similar regulatory and operational characteristics, including Australian National Electricity Market (NEM) jurisdictions such as New South Wales, Queensland, and South Australia, as well as international contexts such as California, Texas (ERCOT), the United Kingdom, and Germany, where comparable price volatility, time-varying tariffs, and high renewable penetration exist. However, the results are not directly transferable to regulated monopoly markets, regions with limited seasonal or diurnal variability in electricity demand and generation (e.g., tropical climates), or jurisdictions that restrict or prohibit bidirectional charging and behind-the-meter battery participation in energy markets.

6. Conclusions

6.1. Summary of Contributions

This study provides the first comprehensive techno-economic analysis of apartment buildings as Virtual Power Plants incorporating:

1. Hourly optimization with grid arbitrage capability
2. Actual Victorian electricity market data (AEMO, ESC VDO)
3. Shapley value cooperative game theory for fair benefit allocation
4. Realistic government subsidy scenarios

The analysis definitively demonstrates that apartment VPPs are economically viable under achievable conditions:

- Technology costs: PV \$900/kW, BESS \$350/kWh (2025-2026 pricing)
- Subsidies: 35% PV, 45% BESS (Victorian programs)
- Grid charging: Bidirectional capability enabled (regulatory reform underway)

Key result:

Grid charging transforms marginal economics (3% ROI, 14.8-year payback) into robust business case (39% ROI, 10.5-year payback), adding \$12,000-14,000 NPV over 15 years.

6.2. Theoretical Contributions

1. Methodological: Hierarchical optimization framework combining internal P2P sharing, battery arbitrage, and grid interaction in single model
2. Game-theoretic: Shapley value application to heterogeneous apartment demand profiles with shared infrastructure
3. Empirical: Quantification of grid arbitrage value (21% of total NPV) in residential multi-dwelling context

6.3. Policy Contributions

1. Subsidy prioritization: BESS subsidies deliver 1.5-2× more NPV per dollar than PV subsidies for apartments
2. Viability thresholds: 45% BESS + 35% PV subsidies achieve strong viability ($> \$10k$ NPV, < 11 -year payback)
3. Cost-effectiveness: Medium subsidy scenario generates \$1.43 private NPV per \$1 government expenditure

6.4. Practical Contributions

1. Investment decision support: Developers and strata corporations can assess VPP viability using realistic parameters
2. Technology roadmap: Battery cost must reach \$350/kWh for unsubsidized viability (achievable 2027-2028)
3. Regulatory priorities: Grid charging enablement and embedded network simplification are critical reforms

6.5. Final Remarks

The energy transition requires innovative business models that align private incentives with public goals. This study demonstrates that apartment VPPs—combining shared infrastructure, cooperative optimization, and grid arbitrage—can deliver:

- Customer value: 40% ROI with manageable payback
- Grid benefits: 40% peak reduction, 70% self-sufficiency
- Environmental impact: 10 tonnes CO₂ avoided annually per building

The path to viability is clear: declining battery costs, moderate subsidies and regulatory enablement will make apartment VPPs economically compelling by 2029.

Policymakers should act now to remove regulatory barriers and calibrate subsidies, positioning Australia as global leader in multi-dwelling renewable integration. The technology works. The economics work. The policy pathway is evident. All that remains is implementation.

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Abbreviations

The following abbreviations are used in this manuscript:

AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
BOM	Bureau of Meteorology (Australia)
CAPEX	Capital Expenditure
DER	Distributed Energy Resource(s)
EOL	End of Life
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FIT	Feed-in Tariff
IRR	Internal Rate of Return
LCOE	Levelized Cost of Energy
NEM	National Electricity Market (Australia)
NPV	Net Present Value
OPEX	Operating Expenditure
P2P	Peer-to-Peer (energy trading)
PBP	Payback Period
ROI	Return on Investment
SCR	Self-Consumption Rate
SOC	State of Charge (battery)
STC	Small-scale Technology Certificate
TOU	Time of Use (tariff)
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant

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