

Ellabban, Omar; Alassi, Abdulrahman

## Article

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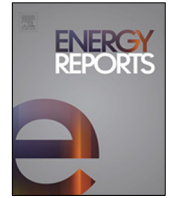
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## Research paper

# Integrated Economic Adoption Model for residential grid-connected photovoltaic systems: An Australian case study



Omar Ellabban\*, Abdulrahman Alassi

Iberdrola Innovation Middle East, Qatar Science &amp; Technology Park, Tech 1 Building, Office 204, PO Box 210177, Doha, Qatar

## HIGHLIGHTS

- EAM for distributed PV systems has been implemented based on real data.
- ToU-NB-BB scheme achieves the maximum saving compared with other metering schemes.
- 89% probability of getting PV-LCOE less than the retail rate has been achieved.

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## ABSTRACT

Photovoltaic (PV) systems, like most renewable energy resources, are characterized by large initial capital investments by the energy user. The high upfront cost (for which many residential customers are unwilling to take risks) is and will remain one of the main obstacles that need to be tackled in order to achieve a faster and a greater deployment of the distributed PV technology in the residential sector as a local generation source. Understanding the economics of the residential PV installation is a key aspect to determine whether the financial investment in this sector is economically feasible and reasonable or not. Thus, it is essential to conduct a comprehensive economic analysis to encourage residential consumers to be PV adopters. The main purpose of this work is to present an Integrated Economic Adoption Model (IEAM) for distributed PV systems. This IEAM is composed of four modules: (1) economic assessment of four different proposed electricity retail tariff structures; (2) profitability analysis of these proposed electricity retail tariff structures based on the most common economic indicators: Net Present Value (NPV), Internal Rate of Return (IRR), Discounted Payback Period (DPBP), and Profitability Index (PI); (3) sensitivity analysis of different variables which strongly affect the PV system profitability; and finally, (4) Levelized Cost of Electricity (LCOE) probability distribution based on the Monte Carlo Analysis (MCA). The model is implemented using Microsoft Excel spreadsheet based on a real dataset for one year of PV generation and residential load consumption for 54 customers in the Ausgrid's electricity network, New South Wales (NSW), Australia (as case study) under the current market arrangements and PV support policies. The model can be easily adapted to any location by changing the generation and load profiles and the relevant economic assumptions and electricity regulatory policies. The outcomes of this IEAM should guide the decision makers in different distribution networks in designing their retail tariff structure and PV support policies and to conduct economic feasibility analysis for residential and commercial PV projects with different sizes in different locations within their networks. Also, the IEAM answers the investment profitability questions for the household owners under real integrated system uncertainty.

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## 1. Introduction

Energy is no longer a luxury but a necessary commodity for the modern life. The global economic growth coupled with population increase, mainly in developing countries; require more

energy to drive up the predicted global energy demand by about 25% by the year 2040. The electricity demand is expected to increase by 60% between 2015 and 2040, representing 55% of the global energy demand growth. Therefore, the global electricity generation capacity is expected to increase by 93% between 2010 and 2040 (Anon, 2018b). Shifting to renewable energy resources can help the globe to meet the dual goals of reducing greenhouse gas (GHG) emissions, thereby limiting future extreme weather

\* Corresponding author.

E-mail addresses: [oellabban@iberdrola.com](mailto:oellabban@iberdrola.com) (O. Ellabban), [aalassi@iberdrola.com](mailto:aalassi@iberdrola.com) (A. Alassi).

## Abbreviations

|           |                                       |
|-----------|---------------------------------------|
| BN-S      | Net Billing Simple                    |
| DPBP      | Discounted Payback Period             |
| DPPs      | Dynamic Pricing Plans                 |
| FiT       | feed-in tariff                        |
| FR        | Flat Rate                             |
| FR-NB-BB  | Flat Rate-Net Billing with Buy Back   |
| FR-NB-S   | Flat Rate-Net Billing Simple          |
| GHG       | Greenhouse Gas                        |
| IEAM      | Integrated Economic Adoption Model    |
| IRR       | Internal Rate of Return               |
| LCOE      | Levelized Cost Of Electricity         |
| MCA       | Monte Carlo Analysis                  |
| NB        | Net Billing                           |
| NB-BB     | Net Billing with Buy Back             |
| NM        | Net Metering                          |
| NPV       | Net Present Value                     |
| NSW       | New South Wales                       |
| PI        | Profitability Index                   |
| PR        | Performance Ratio                     |
| PV        | Photovoltaic                          |
| RET       | Renewable Energy Target               |
| SBS       | Solar Bonus Scheme                    |
| ToU       | Time of Use                           |
| ToU-NB-BB | Time of Use-Net Billing with Buy Back |
| ToU-NB-S  | Time of Use-Net Billing Simple        |

and climate impacts, and ensuring reliable, timely, and cost-efficient delivery of energy, therefore, investing in renewable energies can have significant advantages for world future energy security, (Ellabban et al., 2014).

The global renewable energies consumption is expected to increase annually by 2.3% between 2015 and 2040 representing (under most optimistic predictions) 50%–60% of global electricity consumption by 2050 (Kuo and Pan, 2018). Solar Photovoltaic (PV) power is surging on the back of scaled-up production and continuously falling costs. The amount of new solar power capacity has experienced remarkable growth across the globe, led by China, the United States and Japan. Technological learning as well as economics of scale have reduced costs throughout the PV value chain. Prices continue to fall; meaning power from new solar plants is now cheaper than new coal plants in several locations. During 2016, at least 75 GW of solar PV capacity was added worldwide, making the global solar PV capacity at least 303 GW, (Anon, 2017b) and (Anon, 2017c). The PV market was multiplied by almost 40 in 10 years and the solar PV capacity which has been installed in 2016 (up 48% over 2015) is more than the cumulative world capacity five years earlier. Solar energy costs have fallen 58% in five years (2010–2015) and are expected to continue to fall by additional 40%–70% by 2040, (IRENA, 2016) and (International Energy Agency, 2016). Furthermore, in 2016, the global investment in solar energy was USD 112.4 billion, down about a third compared to 2015 investment in large part due to falling costs of production. Investment in solar energy made up about 46% of all investment in renewable energies for 2016 (Frankfurt School-UNEP Centre/BNEF, 2017).

Investigating the economics of the distributed PV system is a highly complex exercise given the intermittent nature of PV generation, location and generation and consumption behavior, in addition to a wide range of economic variables, a variety of support policies and different metering arrangements. Adding to

that, the costs and benefits of the PV systems are distributed among different industry participants including customers (PV owners), retailers and network service providers. Furthermore, PV based energy trading may as well add considerable complexity in financial transfers between industry participants.

In the literature, many authors have explored the techno-economic feasibility analysis for a PV system. Therefore, different techno-economic feasibility studies for a variety of solar PV systems had been conducted in different regions and countries (Pillaia and Naserb, 2018; Audenaert et al., 2010; Camilo et al., 2017; Lomas et al., 2018; Lee et al., 2017; Haegermark et al., 2017; Li et al., 2017; Okoye and Oranekwu-Okoye, 2018; Ayadi et al., 2018; Tarigan et al., 2015; Kazem et al., 2017; Edalati et al., 2016; Kumar, 2015; Koumparou et al., 2017; Honrubia-Escribano et al., 2018; Akter et al., 2017; Chapman et al., 2016). These studies tackled the economic assessment analysis of PV systems from various viewpoints such as, profitability analysis, metering and feed-in tariffs (FiTs) schemes and PV support policies.

In Pillaia and Naserb (2018), the economic performance of a 1 MW grid-connected PV system is analyzed based on the levelized cost of electricity (LCOE), net present value (NPV), payback period (PBP) and energy payback time (EPBT) calculations with a conclusion that the LCOE for the PV system was 43% less than the present actual cost of a kWh in Bahrain. In Audenaert et al. (2010), using a cash flow projection method, the economic evaluation of a grid connected PV systems (GCPVS) in Flanders is analyzed based on NPV, internal rate of return (IRR), PBP, discounted payback period (DPBP), profitability index (PI), yield unit cost, yield unit return and break-even turnkey cost with a conclusion that, it is financially responsible to invest in a GCPVS for a Flemish company. In Camilo et al. (2017), an economic assessment of residential PV systems with different configuration in Portugal is made using the NPV, IRR, PI and DPBP and the LCOE is calculated in each case. And if the results point to non-profitable solutions, the required reduction in the investment cost to make the project a viable one is computed. Lomas et al. (2018) undertakes a detailed analysis of the energy and economic performance of a PV plant in Spain (based on NPV and IRR) in order to assess the influence of the promotion policies on the profitability of this investment. The conclusion of this work is, although the project is economically viable; it is financially unfeasible due to a negative cumulative annual liquidity as a result of the recent governmental actions. In Lee et al. (2017), a life cycle cost analysis of a residential PV system in the U.S is conducted to establish the minimum rate for purchasing electricity generated from a PV system to achieve the target payback period and to improve the solar incentives policies. Haegermark et al. (2017) presents an economic feasibility study (based on NPV and PI) of PV systems in Swedish multifamily buildings including, a tax rebate and an investment subsidy. The study showed that both the investment subsidy and tax rebate have a large effect on profitability and sizing of PV systems. Furthermore, the current Swedish incentives make the viability of PV rooftop systems difficult to predict. Li et al. (2017) presents a techno-economic assessment model (based on LCOE, PBP and PI) of grid-connected PV systems at Northeast England for different PV technologies (monocrystalline (s-Si), polycrystalline (p-Si) and Cadmium telluride (CdTe)). The study concludes that, the p-Si system has the best performance. In Okoye and Oranekwu-Okoye (2018), a generalized economic model (based on NPV) is developed to assess the cost-benefit of an off-grid PV system in Sub-Saharan Africa. The study concludes that, the PV technology is eligible for project financing as it can repay its loan within the specified time under the current energy policies in Nigeria. In Ayadi et al. (2018), an economic assessment (based on IRR and PBP) is carried out for a proposed 15 MW grid-connected PV system at a University of Jordan to

cover the institute electricity needs, the IRR for this choice was 32% and the payback period is 3 years. [Tarigan et al. \(2015\)](#) simulates a techno-economic feasibility study of installing a grid-connected PV system in a typical residential in Surabaya. This study concludes that, without any financial support from the government, a grid-connected PV system is not financially viable to meet the entire electrical need of a typical residential house in Surabaya. In [Kazem et al. \(2017\)](#), a techno-economic feasibility analysis of 1 MW PV grid-connected system in Oman is presented. The assessment results show that, the PV system is economically feasible and shows great promise for the city of Adam. In [Edalati et al. \(2016\)](#), a technical and economic assessments (based on NPV, PBP, IRR and LCOE) of grid-connected PV power plants in Iran has been conducted based on recent a statistical data and not on real nor experimental projects. The study concludes that, the LCOE for PV power plants is higher than the average selling price of the electricity; therefore, the solar PV systems may reach the grid-parity only for peak prices. In [Kumar \(2015\)](#), an economic assessment models (based on NPV, PBP and IRR) for a residential PV system is conducted. The result of the assessment screens the economic feasibility of PV systems. [Koumparou et al. \(2017\)](#), present a methodology to identify the appropriate net-metering scheme for the Mediterranean region (Cyprus, Greece, Spain, Slovenia, Portugal and France) given the particularities and local conditions and real system where flat rate electricity tariffs is only considered. The main conclusion of this work is that, for the time being, net-metering schemes should be considered as a transition policy from the FIT schemes towards policies closer to the market involving dynamic cost-reflective pricing. [Honrubia-Escribano et al. \(2018\)](#) performs a comprehensive assessment of the economic performance of a PV system (based on NPV, IRR and PBP) with different topologies in seven EU countries with the largest PV development. The main conclusion of this work is that, the direct replication of PV systems that were successful in a particular country should be avoided due to the large amount of parameters involved in the economic performance assessment. [Akter et al. \(2017\)](#), proposes the inclusion of a generalized tariff structure in its economic evaluations of a residential building with solar photovoltaic and battery energy storage systems, which allow residential consumers to choose the right one based on their different perspectives of the investments. [Chapman et al. \(2016\)](#) discusses the successes, failures and impacts of Australian residential solar PV policy from 2001 to 2012 specially the different FIT levels, across two distinct types; gross and net, with a conclusion that this potential inequity of these policies warrants further research. Net metering (NM) allows the PV system owners to offset their energy consumed within their premises with energy produced from their locally installed PV system and to sell surplus electricity to their electricity service provider at a rate equal, less or greater than the retail rate according to the country and network operator policy. Different net metering (fully or partially) and Net Billing (NB) policies has been discussed in [Christoforidis et al. \(2016\)](#), [Dufo-López and Bernal-Agustín \(2015\)](#) and [Comello and Reichelstein \(2017\)](#).

These studies addressed the profitability analysis of a PV system during its lifetime based on the common economic indicators (NPV, PBP, DPBP, IRR and PI) based on estimated or average operating values, mostly without considering the real generation and consumption data, real market economic parameters, different financing mechanisms, different tax schemes, the effect of variation of different system parameters, different metering and retail tariffs schemes, in addition to the associated investment risk and the expected monthly saving from such investment. Furthermore, in order to understand the cost distribution and the cost outlook of the different components of a distributed PV system in different countries, a generic market-based cost

prediction methodology has been developed and tested on the Australian market by the authors of this work In [Alassi et al. \(2018\)](#). The cost distributions and outlook of a distributed PV system are mainly attributed to country-specific developments such as local demand, local economy indicators (such as: nominal discount rate, interest rate and inflation rate), the level of market maturity and local experience and incentives (subsidy increment/decrement). Therefore, it is very difficult to give a value range of the used economic indicators.

On the other hand, by reviewing the literature, one can find many similar techno-economic studies, based on the similar economic indicators used in this study with similar methodology, which has been conducted for a variety of energy resources and energy storage devices, such as: tidal energy, wind energy, nuclear energy, fuel cells and batteries, ([Segura et al., 2017](#); [Cali et al., 2018](#); [Kharitonov and Kosterin, 2017](#); [Nelson et al., 2005](#); [Löbberding and Madlener, 2019](#)) and ([Masebinu et al., 2017](#)). [Segura et al. \(2017\)](#) presents an economic assessment for tidal energy technologies based on NPV, IRR, DPBP and LCOE. [Cali et al. \(2018\)](#), implements a techno-economic analysis for an offshore wind farm based on NPV, LCOE, DPBP, and IRR. [Kharitonov and Kosterin \(2017\)](#) investigates the investment performance criteria (NPV, LCOE, IRR, DPPB and basic engineering-economic parameters of nuclear reactors characterizing a Nuclear Power Plant profitability and competitiveness at the microeconomic level. An assessment of the economic benefits of using grid-connected Fuel-Cell Systems is presented in [Nelson et al. \(2005\)](#) and [Löbberding and Madlener \(2019\)](#) based on NPV, payback period, benefit-to-cost ratio and the cost of electricity. A techno-economic viability and environmental benefits of using Battery Energy Storage (BES) with three different technologies (lithium ion, lead acid and sodium sulfur) has been implemented based on NPV, LCOE, IRR and payback period in [Masebinu et al. \(2017\)](#).

Like other countries around the world, the international and domestic concerns regarding GHG emissions and energy security have encouraged the successive Australian governments to increase the renewable energies share in the Australian power generation mix replacing fossil fuel based generation. Since, the electricity generation accounting for 33% of Australia's GHG emissions, Australia has committed to a Renewable Energy Target (RET) that delivers 20% of Australia's energy needs by 2020. The RET aims to reduce GHG emissions from electricity generation by providing certificates for renewable energy generation. Small systems (<100 kW) are provided with upfront payment deductions, while large systems are provided with certificates based on MWh generated. The RET has played a key role in facilitating Australia's renewable energy deployment, it fueled the rapid deployment of household rooftop PV system installations across Australia, ([Byrnes and Brown, 2015](#)) and ([Commonwealth Government of Australia, 2015](#)). Additionally, feed-in tariffs (FiT) were introduced in 2008 by most Australian state governments to encourage residential sector and small businesses (<10 kW) to install solar PV technology, where, a household gets a premium payment for the electricity supplied to the electricity grid, this FiT can be a gross or a net FiT, ([Zahedi, 2010](#)) and ([Poruschi et al., 2018](#)). Moreover, Australia has the highest average solar radiation per square meter of any continent in the world ranging from 1500 to 1900 kWh/m<sup>2</sup>/yr and more hours of sunlight per day, ([Geoscience Australia and BREE, 2014](#)), which leads to high PV electricity yield ranging from 1200–1600 kWh/kWp/yr (with an average 1460 kWh/kWp/yr) at Australia compared with other countries, ([Talavera et al., 2010](#)). As a result, Australia became one of the top ten countries for total solar installed capacity in 2015 and this continued in 2016, ([Anon, 2017c](#)). By the end of 2017, Australia's total solar PV capacity exceeded 6.4 GW with close to 1.8 million installations, the amount of rooftop PV capacity



installed during 2017 is estimated to have reached over 1 GW, (Anon, 2018a). The Australasian cumulative installed PV power, from 2006–2016, is distributed among four sub-markets, where, almost 90% of the cumulative installed capacity by 2016 comes from the residential sector, (IEA-PVPS, 2017). The average number of Australian households with solar PV systems reached 18.7%, and exceed 30% in some states, (Stock et al., 2017). Solar PV electricity systems produced about 2.6% of Australia's total electricity generation in 2016, while renewable electricity represents 16.3% of the Australian total electricity generation (Jaeger-Waldau, 2017). Moreover, the small scale PV installed capacity is expected to surge to 44 GW by 2040 representing 31% of the Australian power mix and the Australia's electricity system will become one of the most decentralized in the world, with around 45% of power generating capacity located behind the meter (BNEF, 2017). Therefore, Australia has been selected to validate the developed IEAM for distributed PV systems.

To the best authors' knowledge, no integrated economic assessment study of the distributed PV system is presented in the literature, which takes into account all the variables around the PV system (technical, economic, financial and environmental) based on real market conditions and derived from real generation and consumption data. In addition, the sensitivity of different system variables affecting its profitability and the variability distribution of the system inputs and outputs has not been thoroughly investigated yet.

The main contribution of this paper is to develop an Integrated Economic Adaption Model (IEAM), which provides a holistic economic assessment framework for distributed PV systems under real integrated uncertainty and can be used by both the household and the utility decision makers. The developed model is easy to use, modify, adapt to different operating conditions, policy and regulatory variations. The proposed IEAM is developed and validated based on real PV generation and consumption data from a real distribution network to serve as a full economic assessment framework for distributed PV systems covering all the aspects of a PV system (technical, environmental, economic and financial). The IEAM considers all the policy and regulatory issues in any distribution network through its four modules; economic assessment of different retail tariff structures as the first module, profitability analysis as the second module, sensitivity analysis as the third module and probability distribution analysis based on Monte Carlo Analysis (MCA) as the fourth module. The proposed IEAM can be used by the household to economically assess the different metering schemes offered by the distribution network operator, to financially optimize the installed PV system size according to the desired monthly saving, export rate and the pay-back period and to estimate the effects of varying the different PV system variables based on its profitability under real integrated uncertainty. Also, the IEAM can be used by utility decision makers to design their retail tariffs, to conduct profitability analysis for different residential and commercial PV projects with different sizes and to estimate the effect of different incentives on the PV system profitability under real integrated uncertainty.

This paper is organized as follows; Section 2 presents a detailed description for the proposed IEAM and its four different modules. Section 3 presents the model validation based on the Australian case study of the Ausgrid's electricity distribution network, New South Wales (NSW), Australia. Where the input parameters for the four different modules of the IEAM are defined based on: the Ausgrid's customer load and generation profiles, retail and FIT tariff structures, PV support policies and current market arrangements. Then, the results of this IEAM are presented and discussed in Section 4. Finally, Section 5 presents the main conclusion of this study.

## 2. Model description

This section contains a detailed description for the proposed IEAM to provide an integrated residential PV system economic adoption model. The model should be able to: economically evaluate different retail tariffs under different metering schemes by computing the PV system monthly saving for different tariff scenarios; calculate the life time profitability of the residential PV system based on the traditional financial indicators (NPV, IRR, PI and DPBP); compute the LCOE of the PV system; conduct a sensitivity analysis for the variables affecting the PV system profitability the most, considering all the policy and regulatory issues in the distribution network and produce probabilistic distribution of its profitability based on MCA. The proposed IEAM is structured into four different modules; Fig. 1 illustrates the structure and the different modules of the proposed IEAM. This model is implemented using Microsoft Excel Spreadsheet based of real data for a complete year of PV generation and residential load consumption for 54 customers in the Ausgrid's electricity network, NSW, Australia. However, the model can be easily adapted for any location by updating the PV system parameters (technical, economic, financial and environmental), generation and load profiles and retail tariffs and metering schemes (distribution network regulations). These four different modules are described as follows:

### 2.1. Economical assessment of different electricity retail tariff structures

Electric utility companies have developed exciting Dynamic Pricing Plans (DPPs) to encourage consumers to change their consumption patterns. In many regions, consumers can choose between different electricity pricing schemes such as Time of Use (ToU) and Flat Rate (FR). Through DPPs, the consumers are encouraged to efficiently manage their energy consumption while attempting to flatten the overall load profile. Thus, DPPs are beneficial for both consumers and utilities through saving costs and reducing peak-to-average ratio, respectively. Therefore, it is essential to consider all possible tariff structures in order to conduct the cost-benefit analysis (Pillaia and Naserb, 2018).

Furthermore, in order to encourage households and small business owners to install PV systems in their premises, different countries had implemented FIT for paying a premium price for the generated electricity from PV systems in residential and commercial sectors under different Net Metering (NM) policies. The output of a PV system can be recorded into two different configurations, as illustrated in Fig. 2 (Zahedi, 2010), known as; Net Billing (NB) and Net Metering (NM). In case of NB, the PV system owner, which has two meters installed at his premises, injects all his PV system generated electricity into the grid and gets  $FiT_{NB}$  ( $FiT_{NB}$  can be equal to, below or above the retail tariff) and imports his local electricity consumption from the grid with the retail tariff. In NB, the balance (imported electricity minus exported electricity) is done in monetary terms. However, in case of NM, the PV system owner, which has one bidirectional meter installed at his premises, injects the surplus PV generated electricity (the PV system generated electricity minus the local consumed electricity) into the grid and gets  $FiT_{NM}$  ( $FiT_{NM}$  is normally equal to the retail tariff) and the balance (imported electricity minus exported electricity) is done in energy terms (kWh), this exported energy typically varies from 10% to 50% of the total production of the PV system and depends on the local consumption profile and the installed PV system capacity, (Poruschi et al., 2018). The NB will be used in this study; however, there are many NB and NM (fully or partially) policies used by different countries which have different economic impact on the PV system profitability, the following two approaches will be used in this study, (Dufo-López and Bernal-Agustín, 2015):

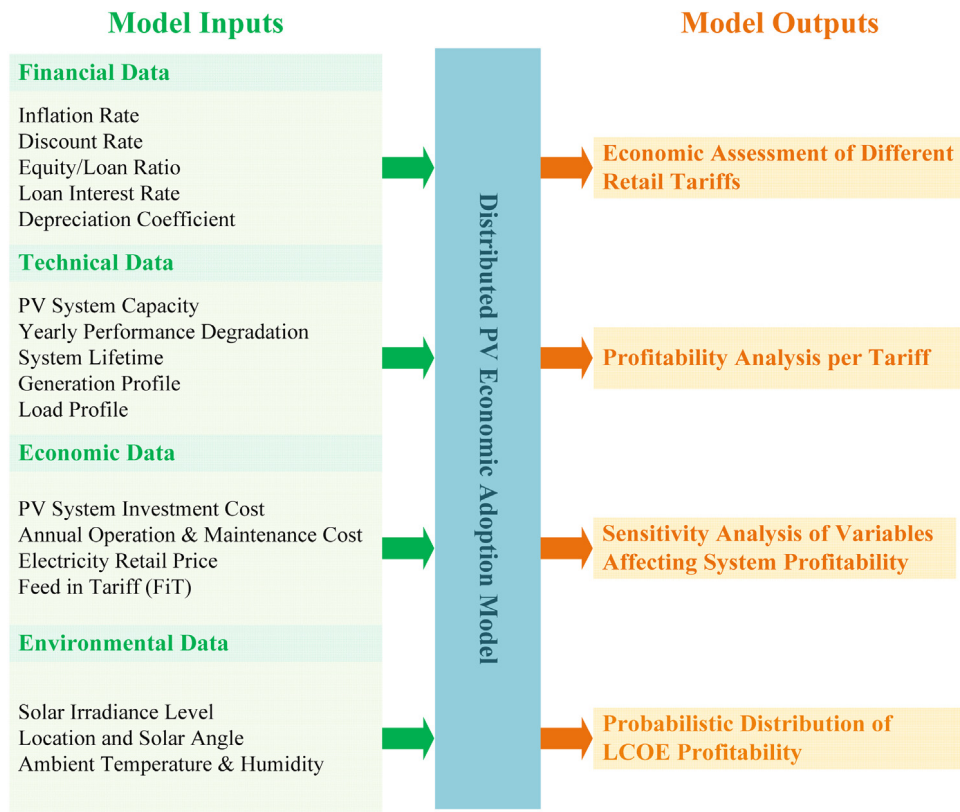


Fig. 1. Structure of the developed Integrated Economic Adoption Model for a distributed PV system.

- Net Billing Simple (BN-S): at the end of the billing period, if the imported electricity cost is higher than the exported electricity cost, the PV system owner must pay the grid operator for the difference between the two terms. If the cost of the energy imported is higher than cost of energy exported, the PV owner receives no compensation.
- Net Billing with Buy Back (NB-BB): at the end of each billing period, the PV system owner pays the grid operator for all imported electricity (at retail rate) and the grid operator purchases any exported electricity at a certain FiT rate using a buy-back scheme.

In both cases, the PV system owner may be required to pay the daily supply charges for grid connectivity according to Ausgrid's electricity network operator.

In this IEAM, the two different retail tariff structures, which are the FR and ToU tariffs, are combined with two different NB schemes, which are NB-S and NB-BB, to propose four different retail tariff structures: (i) Flat Rate-Net Billing Simple (FR-NB-S), (ii) Flat Rate-Net Billing with Buy Back (FR-NB-BB), (iii) Time of Use-Net Billing Simple (ToU-NB-S), (iv) Time of Use-Net Billing with Buy Back (ToU-NB-BB). Collectively, and based on the real PV generation and load profiles, the cost balance between the imported and exported electricity is calculated on hourly basis to compute the monthly saving in the electricity bill (as percentage) for the four proposed retail tariff structures for a household with PV system compared with normal household.

## 2.2. Profitability analysis of different electricity tariff structures

While costs of PV systems have declined rapidly, it is still difficult to determine the economic benefits of making an installation especially for the household owner who will personally finance his rooftop PV insulation. With the majority of costs being born

with the initial installation, payback times tend to be relatively long depending on the local tariff rates and incentives. Therefore, the objective of this module is to provide the reader with a comprehensive understanding of the profitability analysis for the PV investment throughout its lifetime. The economic assessment is made using traditional economic indicators based on discounted cash flows analysis, such as NPV, IRR, PI and DPBP. In addition, the LCOE is also computed. These economic indicators will be calculated for the four proposed retail tariff structures from the previous module to benchmark their profitability. The different economic indicators are explained as follows.

*Net Present Value (NPV)* is a very important parameter in determining the economic feasibility of an investment as it represents the net profit generated. A project is economically viable if the NPV is positive, therefore, the project is economically justified if its  $NPV > 0$  and rejected if its  $NPV < 0$ . When comparing multiple projects, the one with the highest NPV is the best option to make the investment decision. The NPV calculation relies on the initial investment, the total accumulated cash flow and the discount rate. The NPV is the sum of present values of all cash inflows (revenues) and outflows (costs) related to the investment (discounted cash flow over the lifetime of the project), thus accounting for the time value of money and the NPV is given by, Caamaio and Lorenzo (1996), Nofuentes et al. (2002) and Talavera et al. (2007):

$$NPV = \sum_{t=0}^L (I_t - O_t) \quad (1)$$

Where,  $I$  represents the discounted cash inflows,  $O$  represents the discounted cash outflows, and  $L$  is the lifetime of the project. The project inflows (revenues) are the direct economic benefits of the project; in case of a subsidized PV system, it consists of a onetime capital subsidy ( $S_0$ ), that may be provided by the

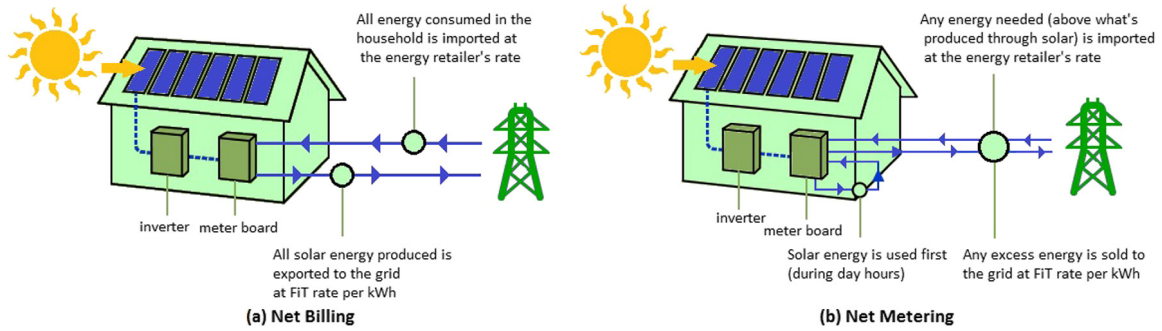


Fig. 2. Net Billing and Net Metering scheme for residential sector (Camilo et al., 2017).

government to promote renewable energy installation, and two operational components; savings from deferring purchases of grid electricity ( $Q_d$ ) at the retail price ( $P_r$ ) and sales of surplus electricity to the grid ( $Q_e$ ) at the FIT ( $P_{FIT}$ ), as represented by:

$$I = S_0 + \sum_{t=1}^L \frac{Q_d P_r + Q_e P_{FIT}}{(1 + d_a)^t} \quad (2)$$

Where,  $d_a$  is the actual discount rate, which is derived from the nominal discount rate ( $d_n$ ) and the annual inflation rate ( $g$ ) by:

$$d_a = (d_n - g)/(1 + g) \quad (3)$$

Most of PV system revenue depends on its energy delivery,  $E_{pv}$ . The useful energy generated by a PV system is a function of many parameters, such as: the nominal power of the PV system, the average global solar irradiance at the installation location, the PV array orientation, the environmental conditions (possible shadowing, temperature, soiling, snow, etc.) and the different system components efficiencies (i.e. PV array and inverter). The effects of all these parameters are combined into one variable called the Performance Ratio ( $PR$ ), (Chabot, 1998). The  $PR$  is a measure for the degree of PV system utilization, it describes the relationship between the actual and theoretical energy output of a PV system. Typical ranges of the  $PR$  have evolved from 50%–75% in the late 1980s, via 70%–80% in the 1990s, to >80% nowadays, with some systems reaching 90%, (van Sark et al., 2012; de Lima et al., 2017) and (Cherfa et al., 2015). Therefore, the PV system output can be given by:

$$E_{pv} = P_{nom} \cdot \frac{G_{dt(\beta_0)}}{G_{stc}} \cdot PR \quad (4)$$

where  $P_{nom}$  is the nominal installed power of the PV system,  $G_{stc}$  is the solar irradiance under standard test conditions ( $1 \text{ kW/m}^2$ ) and  $G_{dt(\beta_0)}$  is the solar irradiance at optimum position and is typically available from the Solar Radiation Atlas.

The project outflows (costs) can be divided into one-time and recurring costs. The one-time costs include the PV system installation  $I_0 = C_{kWp} \cdot P_{nom}$ , (where,  $C_{kWp}$  is the system initial cost per kWp), while recurring costs include operations and maintenance ( $OM_t$ ) and financing ( $F_t$ ). A one-time VAT tax on the system ( $T_0$ ) may be included depending on the installation area, as well as the required payment of VAT on income from oversold electricity ( $T_t$ ). The discounted lifetime cost (outflows) for a PV system is given by:

$$O = I_0 + T_0 + \sum_{t=1}^L \frac{OM_t + F_t + T_t}{(1 + d_a)^t} \quad (5)$$

The annual  $OM_t$  cost is normally given as a percentage of the PV system initial cost, this percentage depends on PV system

size, used technology, market maturity level and other conditions, typically ranging from 1%–5%.

Annual financing cost ( $F_t$ ) refers to the reimbursement of the PV system installation loan, if there is one. The house owner may decide to get a loan to finance the PV system installation partially or in total, which is incorporated by Equity and debt ratios in this study, therefore, the annual loan payment should be included in the system costs (outflows). For each year, the loan payment will consist of some principal  $P(t)$  and interest on this principal for  $t$  years at specified interest rate  $i_i$ . The amount of the  $n$ th year principle  $P(t)$  and interest  $I(t)$  can be given by, Singh and Singh (2010):

$$P(t) = \frac{P_1(t)}{(1 + i_i)^t} \quad (6)$$

$$I(t) = P_1(t) - P(t) \quad (7)$$

where,  $P_1(nt)$  is the value of  $t$ th loan payment, which is given by:

$$P_1(t) = P_1(1)(1 + e)^{t-1}, \text{ for } t = 1 \text{ to } N \quad (8)$$

where,  $e$  is escalation in the annual loan installment (%) and  $N$  is the loan repayment period (years). It has been assumed that the annual loan payment is due at the end of each year; therefore, the household can do the loan payment from the earning of selling surplus PV electricity to the grid. Therefore, the financing cost can be giving by:

$$F_t = \begin{cases} P_1(t), & t = 1 \text{ to } N \\ 0, & t = N + 1 \text{ to } L \end{cases} \quad (9)$$

Typically, in most countries with active distributed PV grid integration, the PV systems installed at domestic sites are considered non-taxable (for personal use/hobby) as they are not in the nature of a business or profit making scheme.

Finally, as the PV system owner is supplied in part by the PV system and in part by the distribution network, the NPV must take into account the respective payments (supply charge cost or grid connection cost) for the distribution network operator and this cost should be part of the retail tariff. This supply charge cost may vary depending on the tariff scheme and the user consumption level, (Vilaça Gomes et al., 2018).

The Profitability Index ( $PI$ ) is an investment assessment technique which is defined as the ratio between its net present value and its initial investment cost (benefit cost/ratio) and is given by:

$$PI = \frac{NPV}{I_0} \quad (10)$$

The NPV is an absolute measurement in cash while the  $PI$  is a relative measurement, which can be used to compare several investments with different cost and to rank the relative returns.



The investment breakeven point is when the PI is equal to one, therefore, a PI greater than one indicates a profitable investment, and when a PI is equal to two the investment is doubled, etc. (Drury et al., 2011).

*Discounted Payback Period (DPBP)* is the required number of years to recover the initial investment made on a project by considering the discount rate. Therefore, the present values of the net cash flows (cash inflows minus cash outflows) are summed year by year until the total equals zero to get the DPBP, which can be represented by:

$$DPBP = T \begin{cases} \sum_{t=0}^T (I_t - O_t) = 0 \\ d_n > 0 \end{cases} \quad (11)$$

Obviously, the profitability means that the DPBP should be shorter than the serviceable life of the system; otherwise, the initial investment cannot be recovered within the project's lifetime.

*Internal Rate of Return (IRR)* of an investment project is the value of the discount rate that leads to zero NPV. In general, no analytical solution can be found for the equation  $NPV=0$ , so the value of IRR can be determined by iteration numerical calculation and it can be given by:

$$0 = \sum_{t=0}^L (I_t - O_t), \quad \text{where } d_n = IRR \quad (12)$$

The higher the value of IRR, the more positive the value of NPV appears to be and the more stable is the project (less risks), (No-fuentes et al., 2003).

*The Levelized Cost of Electricity (LCOE)* is a measure for defining the cost of electrical energy generated from a PV system; it is the net present value of the unit-cost of electricity. The LCOE calculation is defined as the discounted production cost of installing and operating a project divided by the energy generated from this project over its lifetime, as given by:

$$LCOE = \frac{\text{Lifecycle cost}}{\text{Lifetime energy production}} \quad (13)$$

$$LCOE = \frac{\sum_{t=0}^L O_t}{\sum_{t=0}^L E_t / (1 + d_n)^t} \quad (14)$$

Where,  $E_t$  is the energy yield in year  $t$ . As the solar PV technology becomes more mature, the economic feasibility of PV projects is evaluated using the LCOE generation to compare it with other electricity generation technologies, (Branker et al., 2011) and (Hernández-Moro and Martínez-Duart, 2013).

Finally, this module presented the methodology for performing the profitability assessment for the distributed PV adoption. Based on the PV system technical, environmental, economic and financial parameters, the NPV, IRR, PI, DPBP and LCOE are calculated and compared for the four proposed retail tariff structures.

### 2.3. Sensitivity analysis for a distributed photovoltaic grid connected system

There is a wide range of inputs that go into the PV system profitability analysis and their values may change according to government policies, technology used, location, country economic conditions, etc. The objective of this module is to demonstrate the influence of certain PV system variables on its profitability; therefore, a sensitivity analysis is performed mainly on the NPV

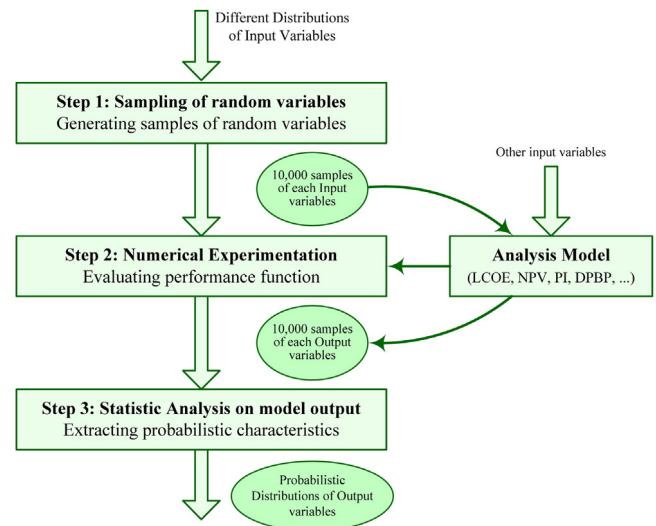


Fig. 3. Monte Carlo Analysis outline.

and LCOE by varying a selection of major input parameters by  $\pm 10\%$ . Furthermore, this sensitivity analysis demonstrates the robustness of the economic analysis and gives solidity to the obtained results. This sensitivity analysis is considered as an important tool for gauging the importance of different factors in driving the overall financial result of the PV system. The four most influential input variables (combining technical, economic and financial inputs) are the solar irradiance, initial investment cost, the operation and maintenance cost and the electricity retail tariff (the discount rate has been considered in (Audenaert et al., 2010)). The impact of varying each variable will be graphically visualized on both the NPV and LCOE, (Ren et al., 2009) and (Cucchiella et al., 2016). Collectively, this module highlights the most significant variables impacting the NPV and the LCOE of the PV system while varying a selection of major PV system input parameters by predefined percentage.

### 2.4. Levelized Cost of Electricity (LCOE) probability distribution

Sensitivity analysis can help to determine a reasonable range of outcomes, or identifying most critical factors, but cannot provide insight into the probability of such outcomes taking place. However, Monte Carlo Analysis (MCA) is a more valuable platform for assessing long term uncertainties in deregulated markets since it can quantify risk and present it in a way that is easy for non-professional investors to understand, (Sommerfeldt and Madani, 2017). In MCA, a calculation is performed many times, and each set of parameters is chosen randomly from predefined distributions for each input, creating thousands of possible scenarios. The choice of probability distributions of the inputs and their limits are very important for accurate MCA results, since, inappropriate choices may lead to mistaken decisions. Inputs can be completely independent or linked, allowing causal relationships that better represent real world conditions (e.g. a reduction in electricity usage due to high prices). MCA results are presented as a probability distribution to show the occurrence possibility of a certain situation rather than a point value. The outline of MCA is illustrated in Fig. 3. Three steps are required in the simulation process: (1) sampling on random input variables, (2) evaluating model output, and (3) statistical analysis on model output. In this work, the MCA is also implemented using Microsoft Excel.

This is particularly valuable for PV investment, which are subject to many unforeseen negative events to occur during its



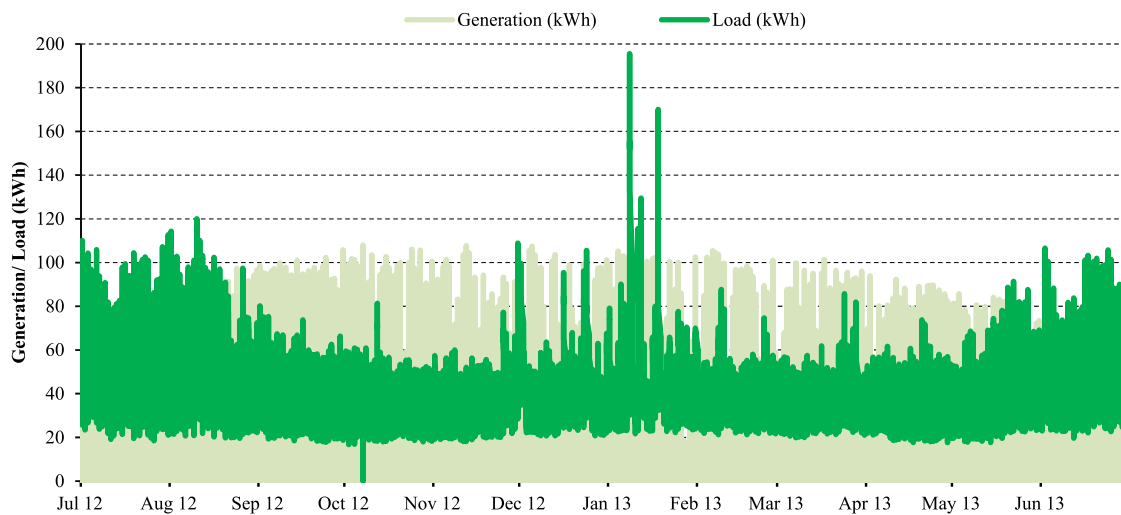


Fig. 4. Aggregated generation and load of 54 customers at Ausgrid distribution network, July 2012 to June 2013.

long lifetime and payback period. MCA produces a probability distribution of different outcomes for the main economic performance indicators (such as the LCOE) providing a more accurate projection as a result (Jeon and Shin, 2014) and (da Silva Pereira et al., 2014). The purpose of this module is to demonstrate a complete MCA for a residential PV system owner given the current market conditions and support policies under real integrated system uncertainty. MCA answers the question: “what is the probability of getting a LCOE (for the local installed PV system) that is less than the current electricity retail rate?”. Therefore, five input variables have been selected which exhibit random variability and represented with probability distributions, these variables are; PV system installation cost, operation and maintenance annual cost, average annual solar irradiance, electricity retail price and FiT. Other studies has considered other variables such as: tax refund rate, market risk premium, risk free rate and foreign exchange rate, which are not affecting the distributed PV system in the Australian market, (Jeon and Shin, 2014). Applying all the possible probability distribution for these five variables and running the MCA for ten thousand iterations, the probability distribution of the LCOE, which is cheaper than the current electricity retail price, can be obtained. Eventually, this module produces the probability distribution of the LCOE (or any other economic indicator) due to randomly varying a selection of PV system input parameters by using MCA.

### 3. Model verification—Australian case study

Following the description of the proposed IEAM and the determination of the main inputs and outputs of its four different modules in the previous section, this section presents the application of the proposed IEAM for the Ausgrid’s electricity distribution network, NSW, Australia, under the current market arrangements and PV support policies. Ausgrid’s network supplies electricity to more than 1.7 million customers and covers an area of 22,275 km<sup>2</sup> which includes some of the most densely populated and fastest growing areas in NSW. Ausgrid supports the installation and connection of small scale PV systems. As of 2017, around 108,000 solar customers are connected to its network. The following subsections include the technical, environmental, economic and financial parameters of a residential PV system connected to the Ausgrid’s network under the current market arrangements and PV support policies, (Ausgrid, 2017).

#### 3.1. Load and generation profiles

Ausgrid provides a free dataset called “Solar home electricity data”, which can be used by organizations and individuals for a variety of purposes, including research, policy-making and providing information about solar PV system performance. This data has been sourced from 300 randomly selected solar customers in Ausgrid’s electricity network area that were billed on a domestic tariff based on net-billing scheme for the period from 1 July 2010 to 30 June 2013. The chosen customers had a full set of actual data (collected every half-hour), which went through some data quality checking and resulting in excluding customers on the high and low ends of household consumption and solar generation performance, (Anon, 2013). The Ausgrid dataset includes: the installed PV capacity (kWp), the solar PV generation (kWh) and the residential energy consumption (kWh) recorded every half hour for each of the 300 customers. Out of these 300 customers, a clean dataset for 54 customers without any load and/or generation abnormalities as described in Ratnam et al. (2015). Fig. 4 shows the aggregated PV generation and load of these 54 customers over a one year period based on half-hour intervals daily real measurements from July 2012 to June 2013. The peak load occurred on 12 January 2013, which was recorded as the hottest day in summer 2013 in NSW as recorded by the bureau of meteorology, also, the observed zero load point corresponds to changes in daylight saving time on 3 October. Fig. 5 illustrates the average monthly PV generation and load, shown by season over the day based on half-hour generation and consumption measurements. This dataset has been used in this work to provide the average PV system installed capacity, the average hourly, weekly, monthly and yearly load and PV generation profiles for a typical Ausgrid residential customer.

#### 3.2. Tariff structures

The Australian electricity retailers provide different DPP options to the consumers. These DPPs include three different tariffs such as ToU, FR and FiT. Figure 6 shows the three different tariff structures; the FR and FiT which are constant though the day and the latter is negative as the consumers are paid, while the third structure, which is the ToU scheme is divided into three different rates: peak, shoulder and off-peak. Table 1 illustrates the NSW residential energy price, in Ausgrid Distribution Zone (Anon, 2017a). Through these DPPs, the customers are encouraged to achieve financial benefits by utilizing the offered incentives.

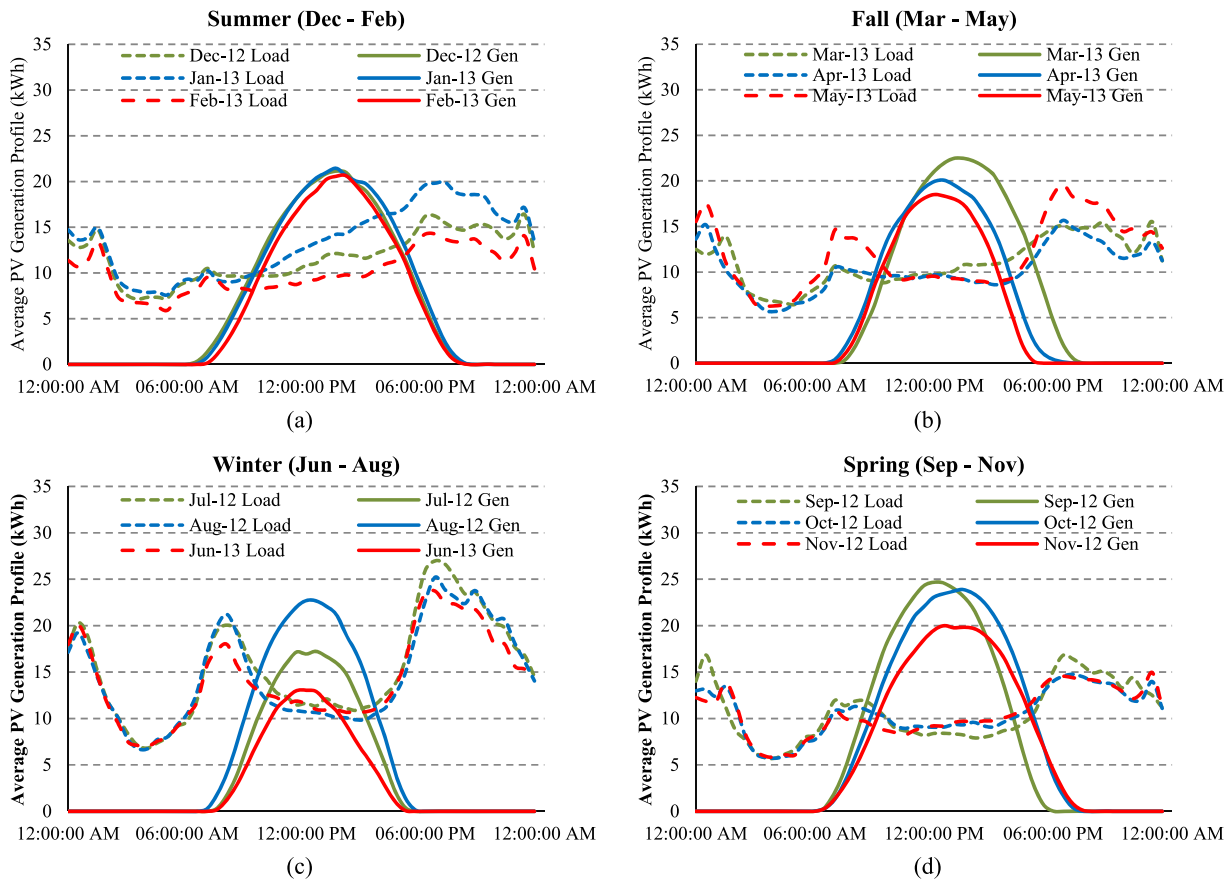


Fig. 5. Ausgrid average monthly PV generation and load per customer during the day, July 2012 to June 2013.

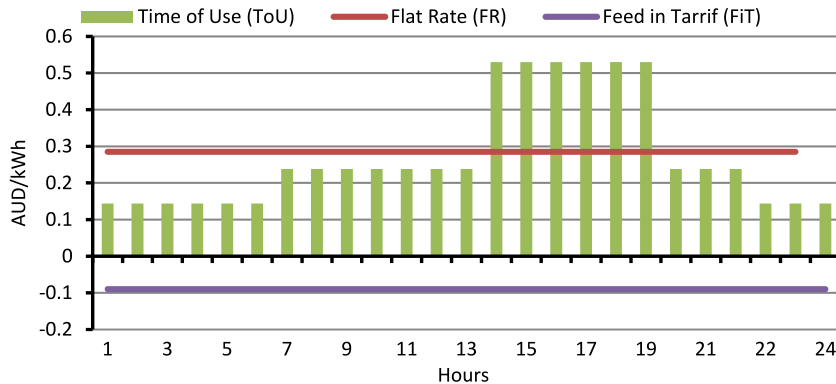


Fig. 6. Different retail electricity tariffs, NSW 2017.

The NSW Solar Bonus Scheme (SBS) began in 2009 initially offering a FiT to eligible customers for all PV generation (based on net-billing scheme) at a rate of a 60 Australian cent/kWh with NB, reduced to 20 c/kWh after October 2010. The SBS 60 and SBS 20 schemes ended on December 2016. From April 2011, all generation received an amount set by electricity retailer in the range of 6–12c/kWh and it is not compulsory for retailers to offer this FiT, (Anon, 2017d) and (Jacobs, 2017). The current study is using a FiT of 9 Australian cent/kWh and this FiT is applied only in the retail tariff structures with buy back, as indicated in Table 1. There is no grid costs associated with the existence of the PV system, however, there is daily supply charge for every customer based on his tariff scheme, and in this work the daily supply charge is included in the tariff calculation.

### 3.3. PV system technical parameters

The PV technical system parameters include, the peak installed capacity (kWp), the expected life time of the PV system and the annual system degradation rate. In the current study, the peak installed capacity is the average installed PV system capacity for the 54 customers at Ausgrid distribution network. Most solar panels manufacturers offer a standard 25-year warranty, guaranteeing that their energy output will remain at 80% of capacity for 25 years. Moreover, recent solar inverters carry 10–15 year warranty, which means that the solar inverter should be replaced once during the lifetime of the PV system and the replacement cost is normally included in the annual system operation and maintenance cost. The PV system degradation rate defines the percentage of system output reduction from year to year and

**Table 1**

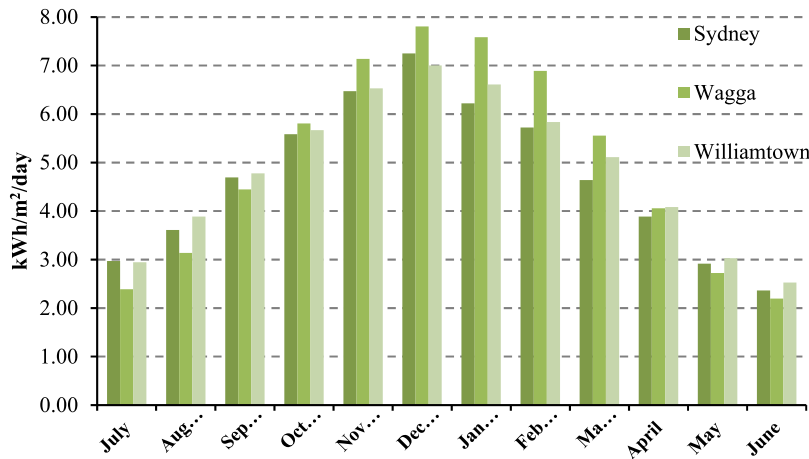
NSW residential energy price, AusGrid distribution zone, September 2017, (Anon, 2017a).

| Tariffs               | Time periods of the day | Electricity prices (Australian Cents/kWh)                                  | Daily supply charge (Australian Cents/Day) |
|-----------------------|-------------------------|--|--|
| Flat rate             | 24 h                    | 28.52  | 83.39                                      |
| Time of Use (ToU)     | Peak                    | 2pm–8pm on working weekdays  | 53.01                                      |
|                       | Shoulder                | 7am–2pm, 8pm–10pm working weekdays, 7am–10pm on weekends & public holidays | 23.79                                      |
|                       | Off peak                | All other times  | 14.42                                      |
| Solar feed-in tariffs | 24 h                    | 9  | –  |

**Table 2**

Technical, economic and financial parameters for the average residential PV system at Ausgrid.

| Parameter                                | Value                                     | Dimension       |
|--|---|-----------------|
| PV system technical information          |   |                 |
| Peak installed capacity                  | 2.45                                      | kW <sub>p</sub> |
| PV system life time                      | 25  | year            |
| PV system degradation rate               | 0.5                                       | %/year          |
| PV system economical information         |   |                 |
| Cost/W <sub>p</sub>                      | 1.72                                      | AUD             |
| O&M cost/W <sub>p</sub> /year            | 1% of the capital cost per W <sub>p</sub> | AUD             |
| PV system financial information          |   |                 |
| Annual inflation rate                    | 2.5                                       | %               |
| Nominal discount rate                    | 10.29                                     | %               |
| Electricity and O&M cost escalation rate | 2.5                                       | %               |
| Loan interest                            | 8.5                                       | %               |
| Loan period                              | 15  | Year            |
| Equity and debt ratio                    | 50% to 50%                                | %               |
| Amortization period                      | 5   | Year            |
| Tax                                      | 0   | %               |

**Fig. 7.** Solar Global Horizontal Irradiation (GHI) in three different cites at NSW, Jul 12–Jun 13.

it is approximately range from 0.1%–1% depending on the solar panel technology. The Australian Energy Council has used 0.5% as a constant degradation rate, (IEA-PVPS, 2017).

### 3.4. PV system economic parameters

The PV system economic parameters include the capital expenditures (CAPEX), which is the installing cost of the PV system per watt ( $I_0$ ) and the operating expenses (OPEX) which is the operation and maintenance cost ( $OM_t$ ) of the PV system per watt per year. The best-practices for O&M cost are generally around 0.5% of system initial cost per year for large systems and 1% for small systems. In this work, the O&M costs are assumed to be 1% of total system costs, (NREL, 2016) and (IRENA, 2017). According to Australian PV institute, the average price per watt is 2.42 Australian Dollar (AUD), March 2017, this price is exclusive

of incentives which reduce the price to consumers by a further 60–70c/W<sub>p</sub>, depending on installation area, therefore, the average watt cost is considered as 1.72 AUD/W<sub>p</sub>, (Anon, 2017d).

### 3.5. PV system financial parameters

The PV system financial data includes the annual inflation rate, the nominal discount rate, electricity and O&M cost escalation rate, the loan interest rate, the loan period, the equity to loan ratio, the depreciation period and the income taxation. These parameters are market dependent and vary from one country or investment sector to another. In the case of Ausgrid, these financial and other technical and economic parameters are given in Table 2, (Mills et al., 2011; Oliva et al., 2013) and (Yu and Halog, 2015).

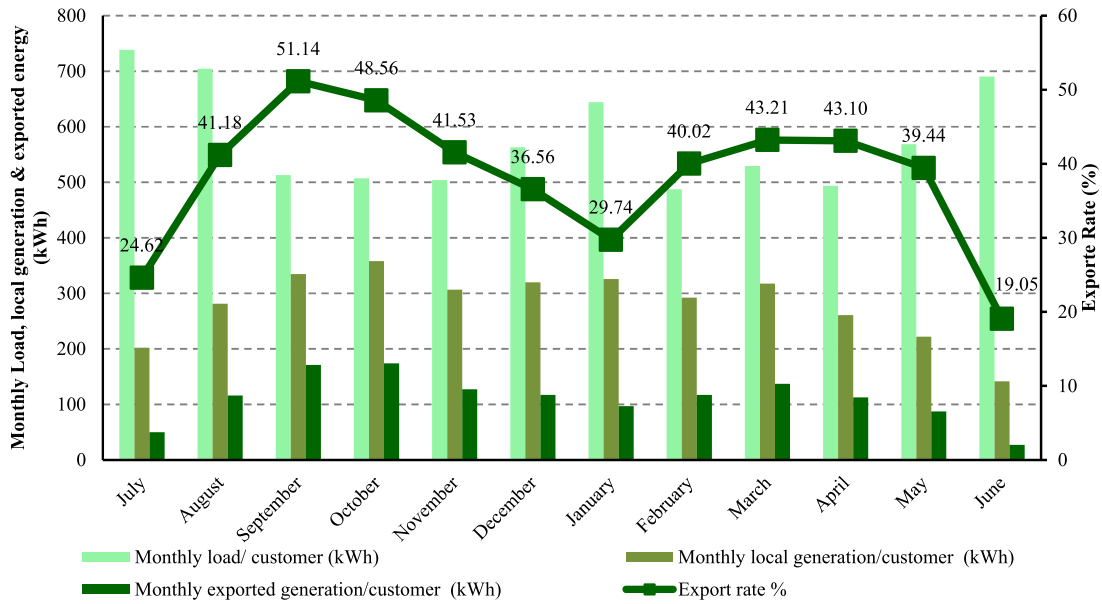


Fig. 8. Average monthly load, local generation, exported energy and exported rate per each of the dataset Ausgrid's customers.

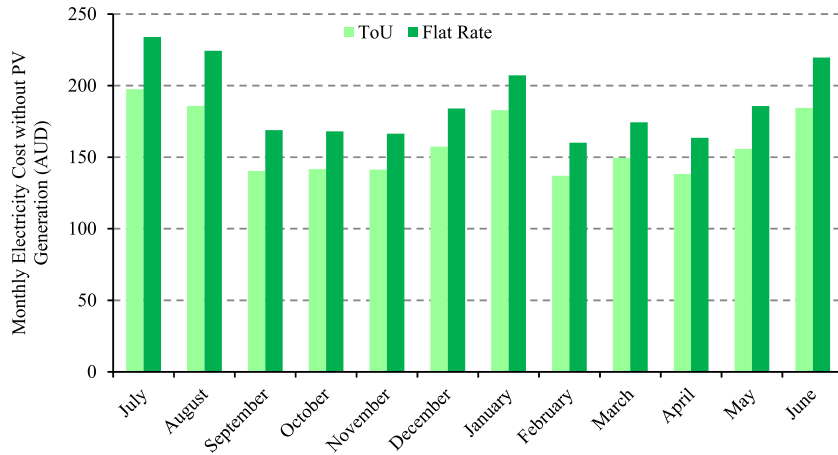


Fig. 9. Average monthly electricity cost without local PV generation (Ausgrid).

3.6. PV system environmental parameters

The PV system environmental parameters include solar irradiance level, location and tilt angle and temperature. The combination of Australia's dry climate and latitude gives it high benefits and potential for solar PV energy production. The Solar Global Horizontal Irradiation (GHI) is the most important parameter in calculating PV system generated electricity, Fig. 7 shows the average monthly solar irradiance all over a year in different cities at NSW, (Morrison and Litvak, 000).

4. Results

This section details the results of applying the proposed IEAM under current prices, regulation and irradiation conditions throughout Austgrid distribution network, NSW, Australia. The results of the different four modules of the IEAM will be presented and discussed as follows.

4.1. First module

Using the annual generation and consumption real data represented in Figs. 4 and 5 and the retail prices and tariff schemes

represented in Fig. 6 and Table 1 for the AusGrid distribution network service provider in NSW, Australia, an economic assessment of the four proposed retail tariff structures (FR-NB-S, FR-NB-BB, ToU-NB-S and ToU-NB-BB) has been conducted with the results illustrated in Figs. 8 to 11.

Fig. 8 illustrates the total monthly average customer load, local generation, exported energy and the export rate, where the exported energy is the local generated energy which is not used locally and exported into the distribution network and the export rate is the ratio between the exported energy and the local consumed energy from the local generated energy. The average annual local load and generation are 6944 and 3363 kWh/customer, respectively. The average PV yield is 1373 kWh/kWp which is in agreement with average PV yield in Australia (1400 kWh/kWp), (Anon, 2017d). The export rate changes monthly ranging from 20%–50%, however, the average annual export rate is 39%. Thus, almost two thirds of the local generated energy (based on 2.45 kWp average PV system size for the given data) is consumed locally. Fig. 9 shows the average monthly electricity cost per customer without local PV generation for ToU and FR schemes, respectively.

Fig. 10 shows the average monthly saving for the four proposed scenarios, where the saving is high during the summer



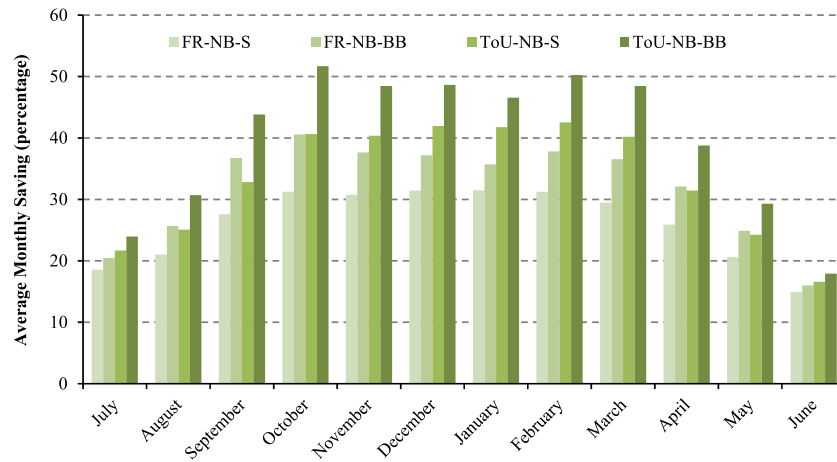


Fig. 10. Percentage average monthly saving for different scenarios (Ausgrid).

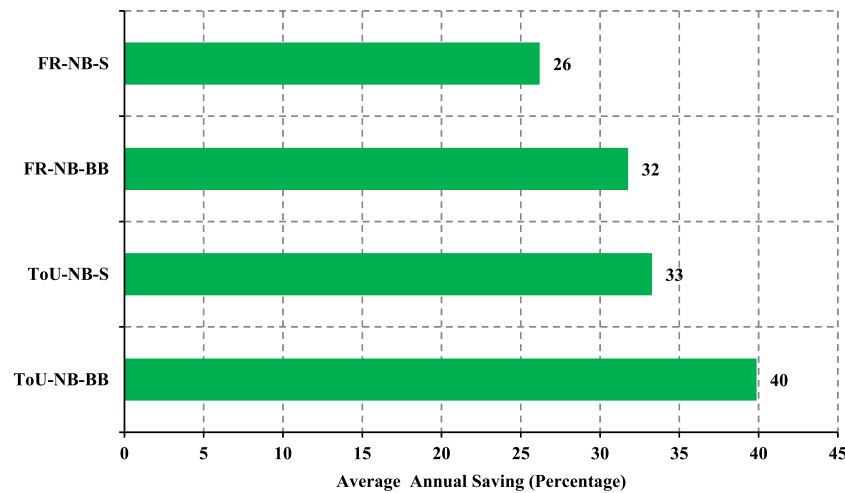


Fig. 11. Percentage average annual saving for different scenarios (Ausgrid).

**Table 3**  
Summary of economic indicators value for profitability analysis of the residential PV system.

| Economic indicator  | Proposed retail tariff scenarios |          |          |           |
|---------------------|----------------------------------|----------|----------|-----------|
|                     | FR-NB-S                          | FR-NB-BB | ToU-NB-S | ToU-NB-BB |
| NPV (AUD)           | 2842.39                          | 4419.88  | 3421.33  | 4998.83   |
| Project IRR (%)     | 14                               | 17       | 15       | 18        |
| Equity IRR (%)      | 17                               | 23       | 19       | 25        |
| PI (Unitless Ratio) | 1.68                             | 2.05     | 1.82     | 2.19      |
| DPBP (years)        | 10.75                            | 8.28     | 9.67     | 7.61      |

months (December, January and February) and low in winter months (June, July and August), where the weather is cold and the energy consumption is high, which is line with the solar radiation illustrated in Fig. 7. Fig. 11 illustrates the average annual saving for the four different presented electricity retail tariff scenarios, where the ToU-NB-BB achieves the maximum saving and FR-NB-S achieves the minimum saving; getting financing compensated for the exported electricity to the grid will increase the saving by 21.3% and 19.8% for the FR and ToU schemes respectively.

4.2. Second module

The profitability analysis resulted in LCOE equal to 0.1959 AUD/kWh which is less than the flat rate at AusGrid (28.52 Australian Cents/kWh), the payback period results of the PV system

are varied from 7.6 to 10.75 years depending of the proposed retail tariff scenarios, with the ToU-NB-BB scheme giving the highest NPV, project and Equity IRR, profitability index and shortest payback period. It is noted that, all schemes are profitable within the Ausgrid network and the details of the different economic indicator for the different proposed retail pricing schemes are illustrated in Fig. 12 and summarized in Table 3.

4.3. Third module

Fig. 13 and Fig. 14 show the impact of the variation of key parameters by ± 10% on the LOCE and NPV ranking the inputs from the ones with the highest impact to the least, respectively. Fig. 13 shows the impact of the four inputs on the NPV output, as shown the solar irradiance and tariff rate have the highest impact on the NPV change followed by the initial cost. The O&M cost has very low impact that is almost insignificant. As noticed from Fig. 14, the most significant variables impacting the LCOE are the solar irradiance and the system initial cost, therefore, an extended evaluation is carried out to investigate the mutual initial cost and solar irradiance effect beyond the 10% variations as illustrated in Fig. 15, where, average values' boundaries are marked by orange, encircling LCOE value around the current: 0.1959 AUD/kWh.

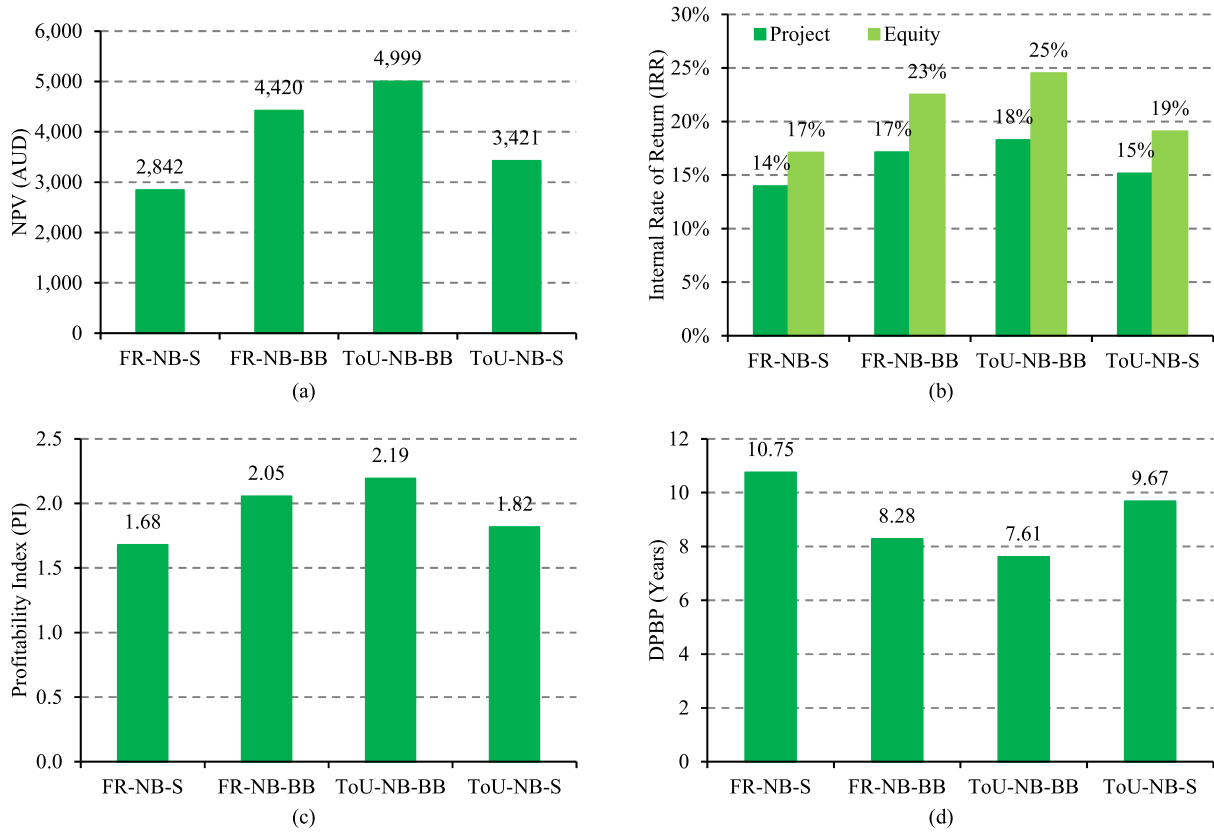


Fig. 12. Economic indicators for the profitability analysis of a residential PV system: (a) net present value; (b) project and equity internal rate of return; (c) profitability index and (d) discounted payback period.

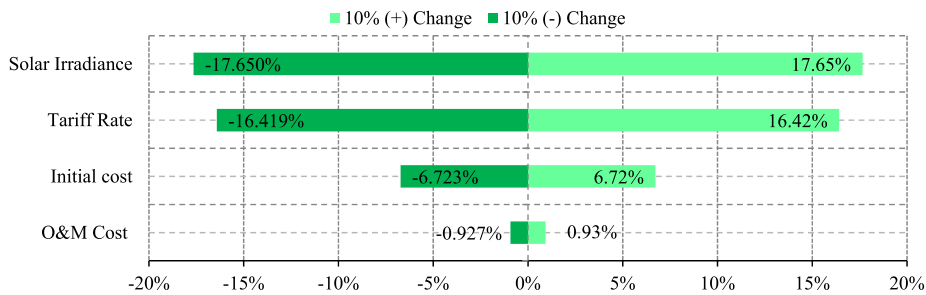


Fig. 13. Impact on the Net Present Value associated with variation of key parameters  $\pm 10\%$ , ranking the inputs from the highest significant impact to the least.

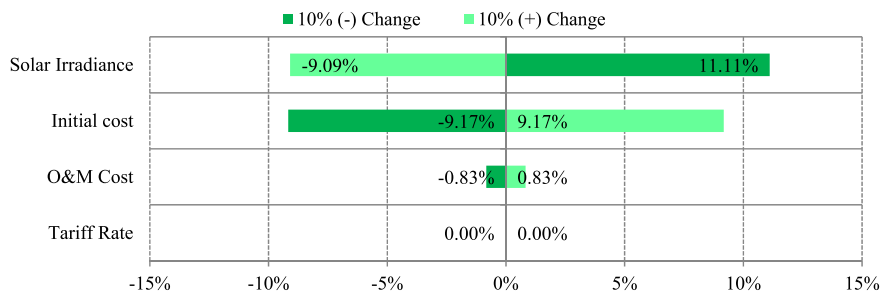


Fig. 14. Impact on LCOE with variation of key parameters  $\pm 10\%$ , ranking the inputs from the highest significant impact to the least.

| LCOE < Flat Rate 0.285 AUD/kWh<br>TOU with 9 C/kWh |   |       |       |       |       |       |       |       |       |       |       |       |       |
|--|---|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| LCOE   | Average annual solar radiation (kWh/m <sup>2</sup> /year) |       |       |       |       |       |       |       |       |       |       |       |       |
|  | 1200  | 1300  | 1400  | 1500  | 1600  | 1700  | 1800  | 1900  | 2000  | 2100  | 2200  | 2300  |       |
| Cost (AUD/W)                                       | 1.2   | 0.246 | 0.227 | 0.210 | 0.196 | 0.184 | 0.173 | 0.164 | 0.155 | 0.147 | 0.140 | 0.134 | 0.128 |
|  | 1.3   | 0.266 | 0.246 | 0.228 | 0.213 | 0.200 | 0.188 | 0.177 | 0.168 | 0.160 | 0.152 | 0.145 | 0.139 |
|  | 1.4   | 0.286 | 0.264 | 0.246 | 0.229 | 0.216 | 0.202 | 0.191 | 0.181 | 0.172 | 0.164 | 0.156 | 0.149 |
|  | 1.5   | 0.307 | 0.283 | 0.263 | 0.246 | 0.230 | 0.217 | 0.205 | 0.194 | 0.184 | 0.175 | 0.167 | 0.160 |
|  | 1.6   | 0.327 | 0.302 | 0.281 | 0.262 | 0.246 | 0.231 | 0.218 | 0.207 | 0.196 | 0.187 | 0.179 | 0.171 |
|  | 1.7   | 0.348 | 0.321 | 0.298 | 0.278 | 0.261 | 0.246 | 0.232 | 0.220 | 0.209 | 0.199 | 0.190 | 0.182 |
|  | 1.8   | 0.368 | 0.340 | 0.316 | 0.295 | 0.276 | 0.260 | 0.246 | 0.233 | 0.221 | 0.210 | 0.201 | 0.192 |
|  | 1.9   | 0.389 | 0.359 | 0.333 | 0.311 | 0.292 | 0.274 | 0.259 | 0.246 | 0.231 | 0.222 | 0.212 | 0.203 |
|  | 2   | 0.409 | 0.378 | 0.351 | 0.327 | 0.307 | 0.289 | 0.273 | 0.258 | 0.246 | 0.234 | 0.223 | 0.214 |
|  | 2.1   | 0.430 | 0.397 | 0.368 | 0.344 | 0.322 | 0.303 | 0.286 | 0.271 | 0.258 | 0.246 | 0.234 | 0.224 |
|  | 2.2   | 0.450 | 0.416 | 0.386 | 0.360 | 0.338 | 0.318 | 0.300 | 0.284 | 0.270 | 0.257 | 0.246 | 0.235 |
|  | 2.3   | 0.471 | 0.434 | 0.403 | 0.377 | 0.353 | 0.332 | 0.314 | 0.297 | 0.282 | 0.269 | 0.257 | 0.246 |
|  | 2.4   | 0.491 | 0.453 | 0.421 | 0.393 | 0.368 | 0.347 | 0.327 | 0.310 | 0.295 | 0.281 | 0.268 | 0.256 |
|  | 2.5   | 0.512 | 0.472 | 0.439 | 0.409 | 0.384 | 0.361 | 0.341 | 0.323 | 0.307 | 0.292 | 0.279 | 0.267 |

Fig. 15. Levelized cost of electricity sensitivity with variation of average annual solar irradiance and initial investment cost per watt.

#### 4.4. Fourth module

The LCOE calculation is highly sensitive to the following five variables: installation cost, O&M cost, average annual solar irradiance, electricity retail price and FiT. Therefore, these variables have been modeled to have random variability with different probability distributions as follows. Anon (2018a) and IEA-PVPS (2017). Also, Table 4 summarizes the assumed probability distributions for these five variables.

- A wide variety of factors can influence the installation cost, such as; equipment quality, installer experience, and roofing conditions. Therefore, in this study, the installation cost per kW is assumed to be randomly linearly varied, from 500–2500 AUD.
- Solar irradiance is subjected to many changes daily, monthly, seasonally and annually due to different climatic conditions and sun related conditions. Therefore, the average annual solar irradiance is represented by normal distribution, with 2000 (kWh/m<sup>2</sup>/year) as mean and 150 as standard deviation (STD) to cover all the possible variations in solar irradiance across NSW.
- The annual O&M cost per kW/year is assumed to be randomly linearly varied between 1%–5% of the total initial cost of a PV system.
- The residential retail tariff is assumed to randomly vary linearly from 0.1–0.35 AUD/kWh.
- The FiT is assumed to linearly vary from 0–0.15 AUD/kWh.

Applying all the possible probability distribution for the five variables and running the MCA for ten thousand iterations following the steps illustrated in Fig. 3 using Microsoft Excel, the probability distribution of the LCOE can be obtained as illustrated in Fig. 16, where for 89.19% of the probability distribution, a LCOE less than the current retail rate can be achieved under the wide range of variation in the five selected input variables which proves the system profitability under real integrated system uncertainty. Also, MCA has been conducted to other output variables NPV, PI and DPBP The results mean values are presented here, respectively, to provide the reader with additional analytic insights: 4,724.7253 AUD, 1.7683 and 9.6237 year.

#### 5. Discussion and conclusions

Due to falling PV systems cost and rising electricity tariff rates, it is becoming increasingly attractive for residential consumers to

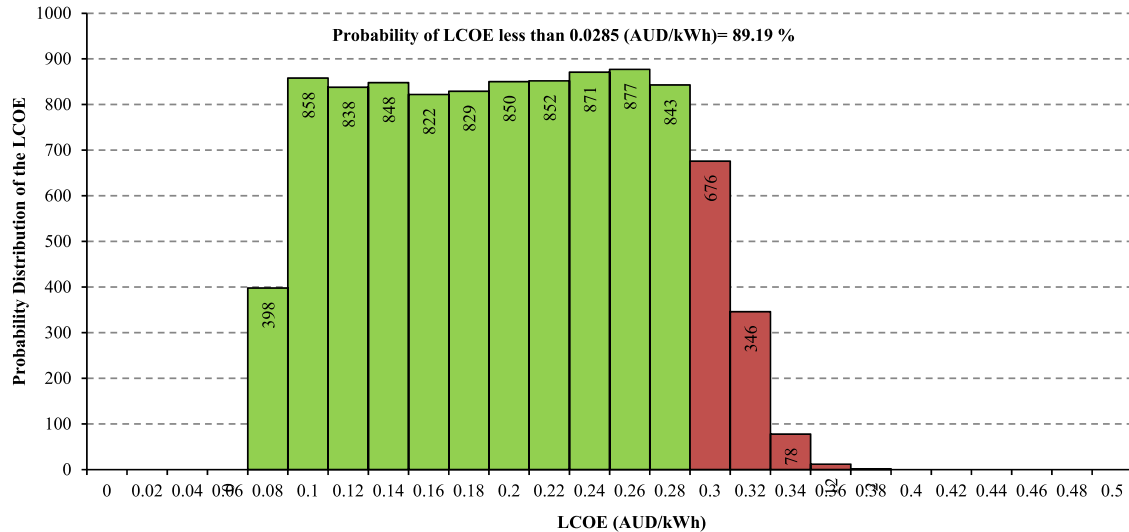
install PV systems and reduce their electricity purchases from the distribution network. However, the payback from PV system is realized over a long term and PV system owners could be uncertain about many factors that impact the system payback over such a long period. Therefore, the main objective of this study is to develop an intensive IEAM for distributed photovoltaic systems. The model is implemented using MS Excel Spreadsheet based on a real case study with one year real load and generation data from Ausgrid distribution network (NSW, Australia). The developed IEAM is composed of four modules: economic assessment of four different proposed electricity retail tariff schemes; profitability analysis of these proposed tariffs schemes; sensitivity analysis of different variables which strongly affect the distributed PV system profitability; and finally, LCOE probability distribution based on MCA due to random variations of a certain set of the distributed PV system input variables.

The following findings have been obtained (based on Ausgrid cleaned dataset with the current retail and FiT tariffs, 2.45 kWp average PV system size and 39% average annual export rate):

- ToU-NB-BB achieves the maximum saving (40%) and FR-NB-S achieves the minimum saving (26%) out of the four proposed retail tariff scenarios; getting financing compensated for the exported electricity to the grid will increase the saving by 21.3% and 19.8% for the FR and ToU schemes, respectively.
- All retail tariff scenarios are profitable, and the ToU-NB-BB achieves the highest NPV, project and equity IRR and PI, and shortest payback period. The profitability analysis resulted in LCOE equal to 0.1959 AUD/kWh which is 31% less than the flat rate at Ausgrid (28.52 Australian Cents/kWh), the payback period of the PV system is varied from 7.6 to 10.75 year depending of the proposed retail tariff scenarios.
- The NPV of a PV system is very sensitive to the variation on the solar irradiance and the initial cost; while, the LCOE is very sensitive to solar irradiance and retail tariff. Therefore, the extended sensitivity analysis using main influencing parameters is important to predict the market behavior corresponding to potential climatic and/or economical variations.
- Taking all the possible probability distribution into account: PV system installation cost, operation and maintenance annual cost, average annual solar irradiance, electricity retail price and FiT simultaneously, the probability distribution of getting a LCOE from the local installed PV

**Table 4**  
MCA inputs variation range and their recommended probability distribution functions.

| Parameter                             | Distributions method | Variability range    | Units                     |
|---------------------------------------|----------------------|----------------------|---------------------------|
| Solar irradiance                      | Random (Gaussian)    | Mean: 2000, STD: 150 | kWh/m <sup>2</sup> /Year  |
| Installation costs                    | Linear               | 0.5–2.5              | AUD/Wp                    |
| Annual operation and maintenance cost | Linear               | 1%–5%                | % of initial cost/Wp/year |
| Electricity retail Tariff             | Linear               | 0.1–0.35             | AUD/kWh                   |
| Feed in Tariff                        | Linear               | 0.05–0.15            | AUD/kWh                   |



**Fig. 16.** Probability distribution of getting levelized cost of electricity less than the current retail rate.

system less than the current retail rate is 89.19%, which validates the system profitability under real integrated uncertainty.

The presented analysis in this paper mainly target standalone PV systems, which are widely used on a global scale. Though, an emerging trend for distributed scale consumers in some countries (e.g. in USA and Australia) is to increase their PV system size (the 2017 average residential PV system size in Australia increased to 6 kW), to and couple it with distributed energy storage units to increase their PV self-consumption and minimize export to the grid. This trend is a result of lowering the FIT for the exported energy by some distribution network operators, which makes it more economically attractive for customers to maximize their self-consumption rate rather than exporting their surplus PV energy at lower rates. For such systems, an extended version of the presented IEAM could be developed to take into account different energy storage integration scenarios.

Collectively, the developed IEAM is of primordial importance for understanding and implementing the economic feasibility study for any residential PV system under real integrated uncertainty. In addition, the IEAM can be applied to a variety of electricity market designs, retail rate structures, and PV compensation mechanisms by changing the generation and load profiles and relevant economic and financial parameters. The outcomes of this IEAM (based on retrospective scenario) will guide different utility, in emerging countries where PV technology is becoming a reality in their energy generation mix, by offering some useful lessons learned to design their time-varying rates and policies for billing residential electricity customers (net-billing policy, net-metering policy, FR tariffs and ToU tariffs) and to conduct profitability analysis for residential and commercial PV projects with different sizes in different locations within their networks to estimate the adoption rate of residential and commercial solar PV systems. Adding to that, the IEAM gives a clear answer for the PV investment profitability question for the house owner

and evaluates the investment risk (through the sensitivity and the probability distribution modules under real integrated uncertainty). This in turn encourages further distributed PV penetration level in the distribution network, which result in different benefits for the network operator such as reduce the severity of peak electricity demand, reduce network distribution losses, reduce CO<sub>2</sub> emissions, provide firm capacity to the distribution network with high degree of reliability at a high level of penetration and reduce the length of peak electricity demand which in turn will reduce the stress in the distribution network and wholesale prices.

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