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On the utility death spiral and the impact of utility rate structures on the adoption of residential solar photovoltaics and energy storage

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HIGHLIGHTS

- A death spiral occurs only with both high PV adoption rates and high utility costs.
- Community solar and rental property PV adoption increase risk of a death spiral.
- The net metering pricing structure both rewards DG and reduces grid defection.
- Our novel system dynamics model is available open-source for the research community.

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ABSTRACT

Today, many electric utilities are changing their pricing structures to address the rapidly-growing market for residential photovoltaic (PV) and electricity storage technologies. Little is known about how the new utility pricing structures will affect the adoption rates of these technologies, as well as the ability of utilities to prevent widespread grid defection. We present a system dynamics model that predicts the retail price of electricity and the adoption rates of residential solar photovoltaic and energy storage systems. Simulations are run from the present day to the year 2050 using three different utility business models: net metering, wholesale compensation, and demand charge. Validation results, initialized with historical data for three different cities, agree well with expert forecasts for the retail price of electricity. Sensitivity analyses are conducted to investigate the likelihood of a "utility death spiral", which is a catastrophic loss of business due to widespread grid-defection. Results indicate that a utility death spiral requires a perfect storm of high intrinsic adoption rates, rising utility costs, and favorable customer financials. Interestingly, the model indicates that pricing structures that reduce distributed generation compensation support grid defection, whereas pricing structures that reward distributed generation (such as net metering) also reduce grid defection and the risk of a death spiral.

1. Introduction

The 'utility death spiral' is a positive feedback loop, in which electric utility customers switch to distributed-generation and/or make efficiency improvements, causing a steep decline in electricity demand, in turn causing increased retail electric prices, driving more customers to reduce their demand, and so on until the utility becomes an unsustainable business. The first threat of a death spiral arose after the 1973 Arab Oil Embargo, when rising fuel prices and efficiency measures cut into utility profits [1]. However, these fears were found to be based on unrealistic conditions, and the conclusion was that if utilities, customers, and regulators behaved rationally, the death spiral would not happen [2].

Utility Concerns

Recently, concern of a utility death spiral has found new legs, because of the growing adoption of distributed energy generation systems, especially solar photovoltaics (PV) [3–6]. Solar PV is growing faster than any other distributed generation (DG) technology [7], and installed PV costs are dropping rapidly [8–10]. Furthermore, financial incentives such as net-metering make distributed generation (DG) systems more attractive to consumers while simultaneously reducing utility revenues [11,12]. Additionally, utility fixed costs are rising due to several factors: modernizing measures such as smart-grid technologies, maintenance of aging transmission and distribution infrastructure, environmental regulations, and rising costs of fossil fuels [8,13]. These factors combine to raise volume-based prices, which in turn encourage more customers to adopt DG systems and reduce their demand to save money. If these trends continue, US utilities could lose from \$18 to \$48 billion per year over the next decade [14].

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Nomenclature

DG	Distributed Generation (n/a)
PV	Photovoltaic (n/a)
ELCC	Effective Load Carrying Capability (n/a)
FCI	Fixed Capital Investment ($)
NPV	Net Present Value ($)
RoR	Required Rate of Return (unitless)
$F(t)$	installed base fraction (unitless)
$f(t)$	rate of change of the installed base fraction (time^{-1})
p	coefficient of innovation (unitless)
q	coefficient of imitation (unitless)
C_v	variable cost ($)
C_f	fixed cost ($)
D	cumulative electricity demand (kW h)
L	limit function for homes with PV systems (unitless)
N_{reg}	number of regular households (homes)
N_{PV}	number of PV households (homes)
N_{def}	number of defected households (homes)
d	drain-slowing function (unitless)
h	households adopting a technology per unit time (homes/time)
k	innovation/imitation rate scaling factor (unitless)
R	adoption rate (Note: h, k, and R use the following 6 subscripts to distinguish between the 6 adoption pathways) (% homes/time)
PN	photovoltaic innovation (n/a)
PM	photovoltaic imitation (n/a)
BN	battery innovation (n/a)
BM	battery imitation (n/a)
DN	direct defection innovation (n/a)
DM	direct defection imitation (n/a)

Today, a new threat to the traditional utility business model is emerging: energy storage combined with affordable PV systems raises the prospect of consumer grid defection [8]. Battery technology is an extremely active field of research (for example [15–17]) and battery prices are expected to drop significantly in the near future [8,18]. Combined, PV and battery systems could create disruptive competition for utilities [4].

Of course, other businesses in the energy supply chain are likely to be affected as the residential PV market share increases. For example, many utility-scale generation plants, including coal and natural gas generators as well as wind farms, will see a decrease in demand [19]. However, recent work by Cole et al. [20] indicates that distributed PV systems may be competing only with utility-scale PV systems.

While there is disagreement on the root cause of a potential death spiral, there is a consensus that utilities must adapt [21,11,4,22,1]. Raskin [11] argues that by the time DG is a real threat to utilities, a solution will have been found via the "regulatory compact": an unspoken relationship between utilities and regulators that allows utilities to attract investments that are necessary to maintain reliable service and meet regulatory requirements. Many agree, including Raskin, that net-metering is an unfair and unsustainable subsidy for DG systems that will not be allowed to persist, which will reduce the risk of a death spiral [1,22]. Graffy and Kihm [4] argue that protecting utilities through regulation might not be able to sustain utilities through the disruptive competition created by a myriad of factors, including improving DG technologies, expanding renewable portfolio standards, morphing consumer preferences and practices, and innovative businesses providing more attractive options than utilities currently offer. Felder and Athawale [1] suggest that a death spiral will not be the result of disruptive competition, but rather rate design. They argue that the current volumetric rate design, which spreads the utility's cost equally across most customers, is not viable for recovering utility fixed costs.

Few groups have attempted to model the complex interactions between the adoption of PV and storage systems, utility costs, and retail rate design. To the authors' knowledge, our model is the first to capture these complex feedback loops, as well as the potential for grid defection. Darghouth et al. [23] found that PV adoption rates are very sensitive to utility rate structures. Their results indicate that if utilities employ time-of-use rates they can offset the economic losses from net-metering pricing structures, thus damping the positive feedback loop between escalating retail prices and the number of distributed PV systems. However, Darghouth et al. did not include the option for utility customers to use batteries to flatten their demand curve and therefore take advantage of time-of-use rates or defect from the grid. Satchwell et al. [24] modeled the effects of increasing PV adoption on the profitability of electric utilities and the retail price of electricity; they found that as the PV adoption level increases, the utilities' costs increase faster than revenues, leading to greater average retail prices and reduced utility profits. Sigrin et al. [25] (of the U.S. National Renewable Energy Laboratory) are currently adding a storage adoption model to their existing dGen model, which forecasts the adoption of distributed energy resources for residential, commercial, and industrial customers in the U.S.

1.1. Scope of this article

This article presents a novel system dynamics model that captures the feedback loops required for a utility death spiral, namely the nonlinear interactions between utility costs, utility business model, the retail price of electricity, adoption rates of solar photovoltaics and energy storage technologies, and grid defection. Prior models have attempted to predict distributed generation (DG) adoption rates using fixed retail price forecasts, which do not take into account the impact that greater market penetration of DG technologies has on the electricity retail price. Our electricity retail price model captures the complex, nonlinear feedback between the electricity retail price and the number of homes with and without PV systems, as well many other market factors. Our model is implemented in Stella and is available open-source, in order to provide a platform for industry, policy makers, and researchers to rapidly evaluate the effects of different technologies, utility pricing structures, and government incentives on the impacts of integrating distributed-generation systems into the residential electric grid.

This article presents the modeling methodology as well as three case studies. We simulate the effects of residential PV and storage adoption on the retail price of electricity, and vice versa, out to 2050. As three example cases, we simulate residential Los Angeles, California; Sydney, Australia; and Boulder, Colorado. For each of these three locations, three different utility business models (i.e. pricing structures for the compensation of DG customers) are compared.

Los Angeles (LA) was chosen for this study for a combination of reasons: high retail prices (currently $\approx 40\%$ greater than the national average [10,8]), high solar potential [26], and the rapidly growing number of installed solar photovoltaic (PV) (see Fig. 1). Similar to LA, Sydney has seen rapid growth in residential PV systems in recent years and represents a large metropolis with high solar potential. Sydney was also chosen for analysis to explore the potential for a death spiral outside of the US, where energy consumption is generally less. Boulder was selected due to recent developments there regarding the development of a municipal electric utility. The citizens of Boulder have voted to create a municipal utility if the current utility cannot meet their requirements for increased service and decreased environmental impact [27]. The city of Boulder is currently attempting to purchase the transmission and distribution infrastructure from the incumbent utility. A summary of the model inputs used for each city are given in Table 1.

Our analysis focuses on residential PV systems (without and with battery storage) due to their rapidly declining costs and high resource availability. For example, if the retail price of electricity continues to grow at 3% (the average growth rate in LA over the last three years), parity between the retail price of electricity and the levelized cost of energy (LCOE) of a typical 5 kW PV system in LA will occur as early as 2018. Furthermore, the LCOE for a 10 kW PV + 65 kW h battery system in LA will be the same as the retail price of electricity as early as 2037 [8]. This article ignores other residential DG options such as wind, since typically their cost is higher and resource is lower; therefore, wind and other DG options would have muted results compared to solar PV systems. Also, the model does not distinguish between sources of electricity for the utility. The utility could buy electricity from coal plants, wind farms, or wherever, but regardless of source, the utility then sells the electricity to its residential customers. Our model focuses on the relationship between the electric utility and its residential customers.

In summary, the main contributions of this article include:

- novel system dynamics model that captures the nonlinear interactions between utility costs, utility business model, the retail price of electricity, adoption rates of solar photovoltaics and energy storage technologies, and grid defection;
- model results showing fraction of households who are regular customers, PV customers, and grid defectors, as well as retail price of electricity;
- sensitivity analysis, showing the most sensitive parameters are the efficiency improvement of customers, growth rates of utility costs, customer's required rate of return, and the customer's innovation scale factor, in addition to the utility pricing structure and the model limit on the number of PV households;

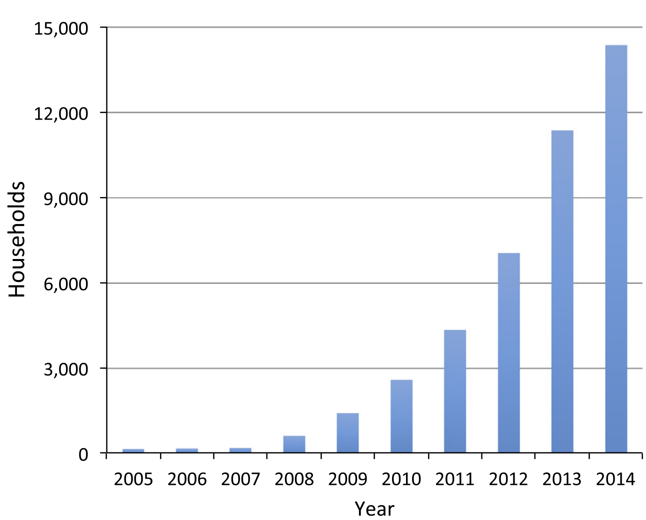


Fig. 1. Cumulative households with PV systems in LA. Estimate constructed using data from [28,29].

Table 1
Model inputs for each city. Most values are 2015 or 2014 averages. Each city was initialized with 1 defector household. All monetary values in USD.

Variable	LA	Boulder	Sydney
Regular customers (non-DG households)	3,361,031	45,674	1,448,848
Customers with PV	14,344	1674	153,571
Annual base demand	16,648 kW h	19,721 kW h	7000 kW h
Annual PV production	12,469 kW h	19,202 kW h	5694 kW h
Direct PV use	6211 kW h	7007 kW h	2848 kW h
Baseline retail price	20.9¢/kW h	12.5¢/kW h	20.7¢/kW h

- assessment of the scenarios that might cause a utility death spiral; and
- evidence that a utility death spiral can be avoided by using a net metering pricing structure.

This article is organized as follows: Section 2 details the system dynamics modeling methods; Section 3 presents model results, including sensitivity analysis in Section 3.2 and death spiral scenarios in Section 3.3; and Section 4 provides further discussion and conclusions.

2. Method

Fig. 2 provides a schematic diagram of the overall model, and Figs. 3–7 detail several subsmodels. The overall model consists of three primary components:

1. The adoption of PV and battery systems, resulting in three types of households: regular homes, PV homes, and defectors (see Section 2.1). A population growth model (Section 2.5) also accounts for the possible adoption of PV and battery systems during new home construction.
2. The traditional utility business model, which determines the retail price of electricity (see Section 2.2). We assume that the utility is vertically integrated.
3. The net present value (NPV) of a customer purchasing a PV and/or storage system versus doing business as usual (BAU) (see Section 2.3). This calculation is informed by the utility pricing structure (Section 2.4).

The model is initialized with the most accurate data available for each location in 2015. For example, the initial number of homes with and without PV systems was determined using data from the latest census and permit data for installed home PV systems. It was assumed that each location begins with one defected household. Historical data for the number of commissioned residential PV systems over time also provided an estimate for the initial adoption rates of PV systems. Current retail prices for electricity, as well as the breakdown of fixed versus variable utility costs, was determined from local utility information and used to initialize the retail price component of the model. Also, expert forecasts for the price of PV and battery systems were used in the NPV module.

The primary outputs of the model are (i) the number of each of the three types of households and (ii) the retail price of electricity, which are calculated at each time step in the simulation.

2.1. Adoption rates

The flows of technology adopters were represented using the Bass diffusion model [30]. The Bass diffusion model is a differential equation that describes how new products are adopted. Adoption rates are a function of both early adopters and late adopters, presented as innovation and imitation flows respectively [31]. Eq. (2.1) represents the Bass model for the adoption of a single

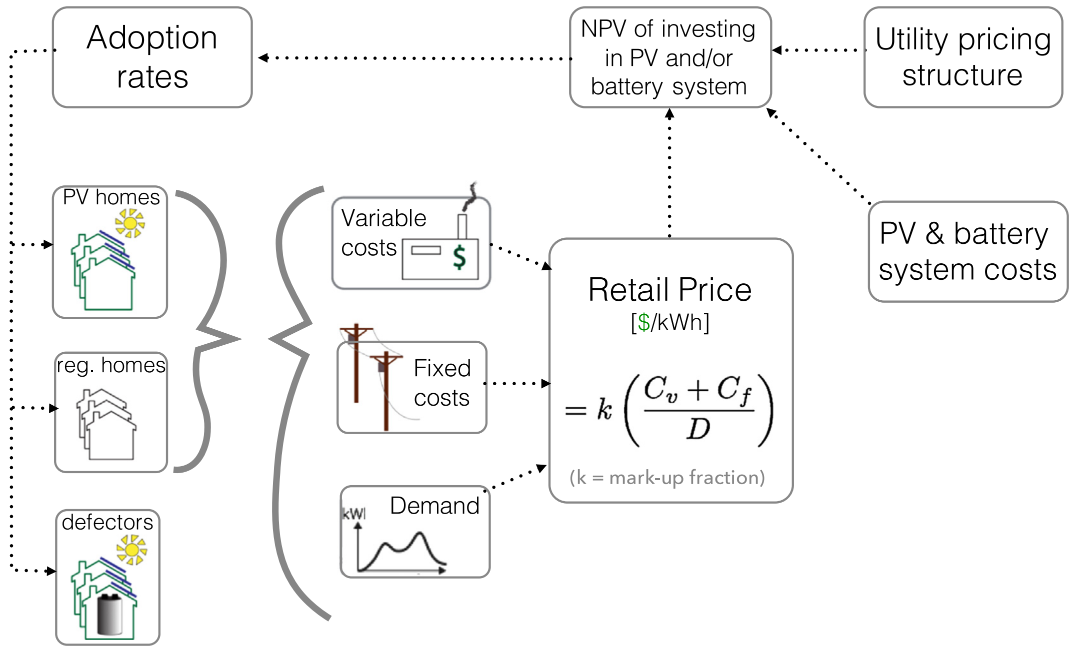


Fig. 2. Overall model schematic diagram. See text for variable definitions.

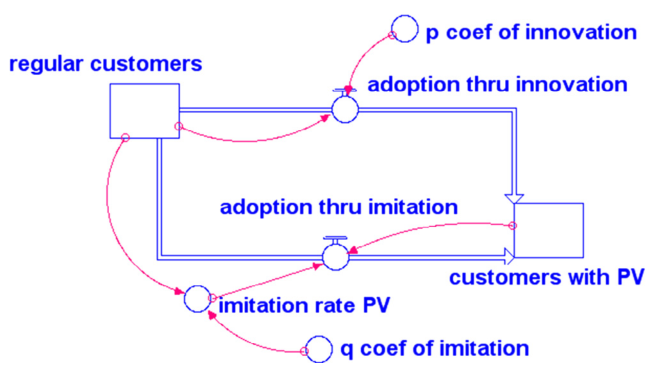


Fig. 3. A simple Bass diffusion model in Stella. Boxes represent state variables, directed pipes represent flows over time, circles represent constant or instantaneous calculations, arrows represent information linkages.

technology, where $F(t)$ is the installed base fraction (unitless) and t is time.

$$\frac{dF}{dt} = (p + qF(t))(1 - F(t)) \quad (2.1)$$

Here, p is the coefficient of innovation (unitless) and q is the coefficient of imitation (unitless). $F(t)$ asymptotically approaches one from zero. Fig. 3 shows an example how Eq. (2.1) can be implemented in a model.

Our model was constructed in Stella® [32], a system dynamics software that allows for rapidly creating and varying the parameters of differential equations via a graphical interface. As seen in Fig. 3, state variables (called stocks) are represented by squares; exchange variables (called flows) are represented by double-line arrows with circular valves in their centers; and auxiliary variables are represented by circles. Single-line arrows allow definition of relationships between variables via equations or graphical lookup functions.

Fig. 4 shows the more sophisticated adoption model used for the work herein. At the broad level, the overall model consists of three simple Bass diffusion models nested within each other. However, instead of constant coefficients of innovation and imitation, the adoption rates are determined using net present value criteria (described in Section 2.3).

Six adoption flow rates are computed in the model

$$h_{PN} = k_{PN}\ R_{PN}\ N_{reg}\ L\ d \quad (2.2)$$

$$h_{PM} = k_{PM}\ R_{PM}\ N_{PV}\ \rho\ L\ d \quad (2.3)$$

$$h_{BN} = k_{BN}\ R_{BN}\ N_{PV}\ d \quad (2.4)$$

$$h_{BM} = k_{BM}\ R_{BM}\ N_{def}\ d \quad (2.5)$$

$$h_{DN} = k_{DN}\ R_{DN}\ N_{reg}\ L\ d \quad (2.6)$$

$$h_{DM} = k_{DM}\ R_{DM}\ N_{def}\ L\ d \quad (2.7)$$

where the symbol definitions are as follows:

- h is the number of households adopting the technology per year.
- k is a unitless constant of proportionality (used for sensitivity analyses).
- R is the adoption rate (units: percentage of total households/time).
- L is a limit function (unitless) that prevents every household from owning a PV system.
- N is the number of households, where the subscripts *reg*, *PV*, and *def* represent respectively: regular households, photovoltaic households, and defector households.
- d is a drain-slowing function (unitless), that prevents the pool of adopters from draining unrealistically fast.

The subscripts on h, k and R distinguish the six different adoption flows, with

- *PN* for photovoltaic innovation,
- *PM* for photovoltaic imitation,
- *BN* for battery innovation,
- *BM* for battery imitation,
- *DN* for direct defection innovation, and
- *DM* for direct defection imitation.

Lastly, ρ is a photovoltaic density factor that has no effect (equal to one) when there are no photovoltaic households, and effectively

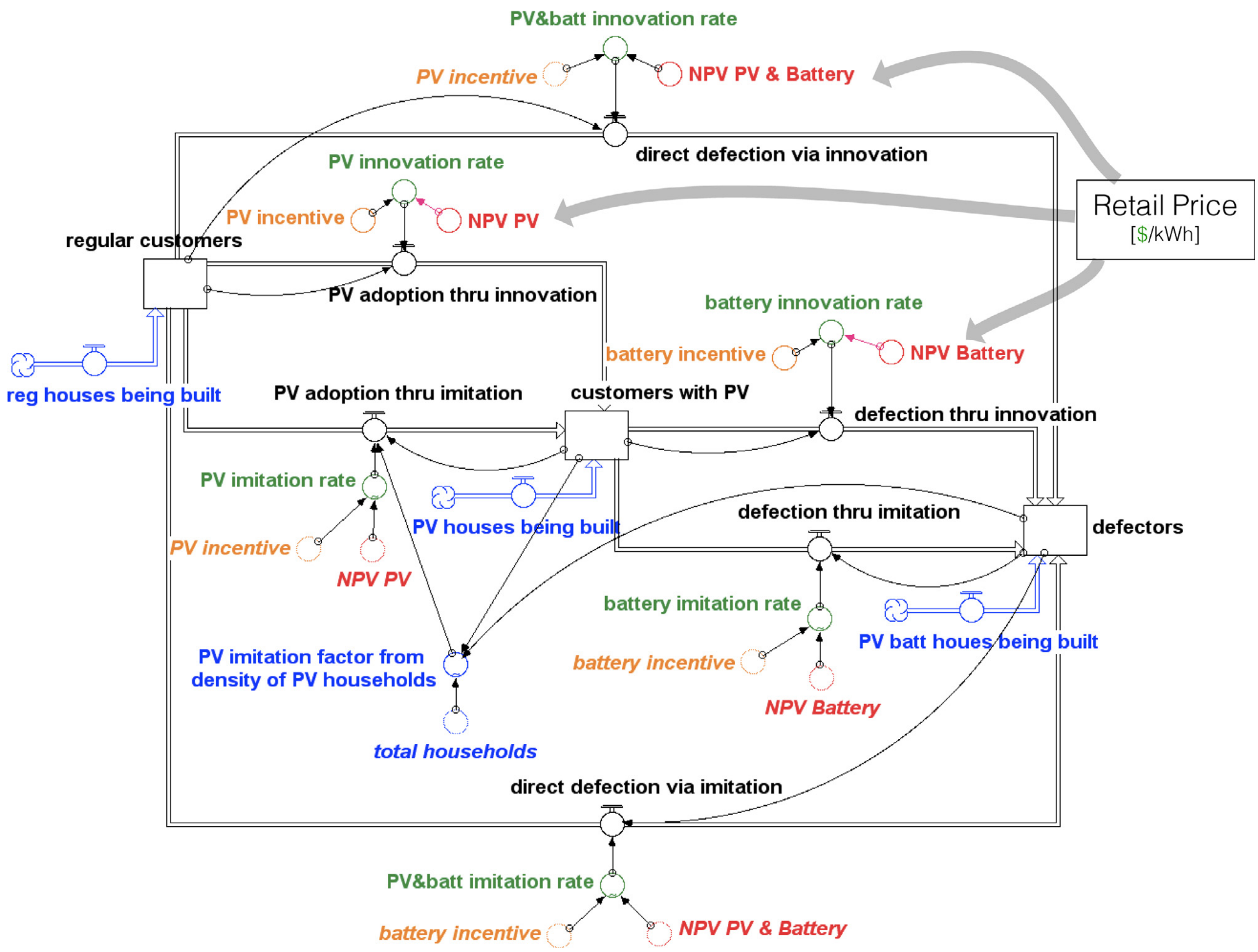


Fig. 4. Bass diffusion flows from Stella model. Light gray arrows are indicative of the links between the model components described in other sections. (The following components have been removed for clarity: flow rate scaling factors *k*, which are set equal to one in baseline model; limit on the ratio of PV customers to regular customers; and drain slowing function *d*.)

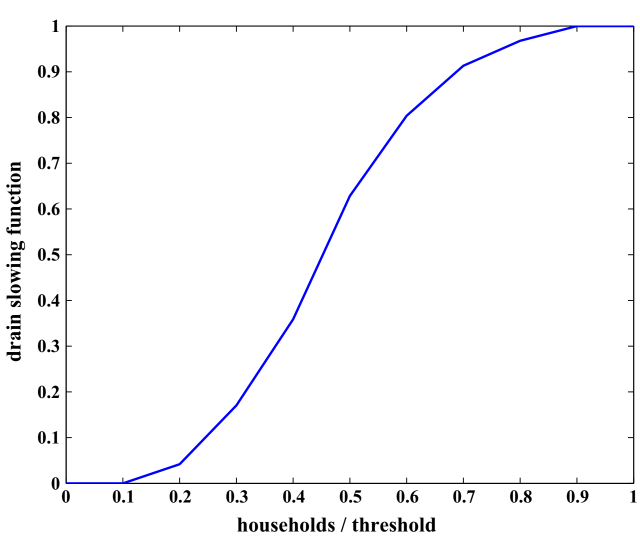


Fig. 5. Representative drain slowing function. Implemented as a lookup function in the model.

doubles the imitation flow rate (equal to two) when the number of homes with photovoltaic panels (including defectors) is equal to the number of regular households. No density factor is used for battery system imitation since they are presumed to be installed indoors and therefore do not have the “keeping up with the Jones” effect that highly visible photovoltaic panels can affect.

The imitation and innovation rates, represented by *R*, are lookup functions that vary linearly with the net present value (NPV) of each technology (described in Section 2.3). All imitation rates are zero when the NPV is zero (break even point) and grow linearly to 0.4% (of the total households/year) when the NPV reaches $10,000. This implies that imitators do not adopt the technology until it is financially beneficial.

Innovators, however, have a positive adoption rate for a zero NPV. A positive adoption rate for a zero NPV assumes that innovators are willing to except a negative NPV to be the first in the neighborhood to have the latest technology. Innovators may also be willing to accept a negative NPV because they value reducing greenhouse gas emissions, among other non-financial factors not considered in this analysis. (For example, see [33] for a detailed discussion of the financial and environmental costs of PV and battery systems in Australia.)

The adoption rate for PV innovators is the only adoption rate for which historical data is available. Surprisingly, the PV adoption rate of all three cities was approximately 0.5% of total homes in 2014. We assumed that the PV innovation rate will grow linearly to 5% per year when the NPV equals $10,000 (i.e. the innovator adoption rate grows with the financial benefit). For all the other innovator adoption rates we assumed an initial value of 0.1% of the potential

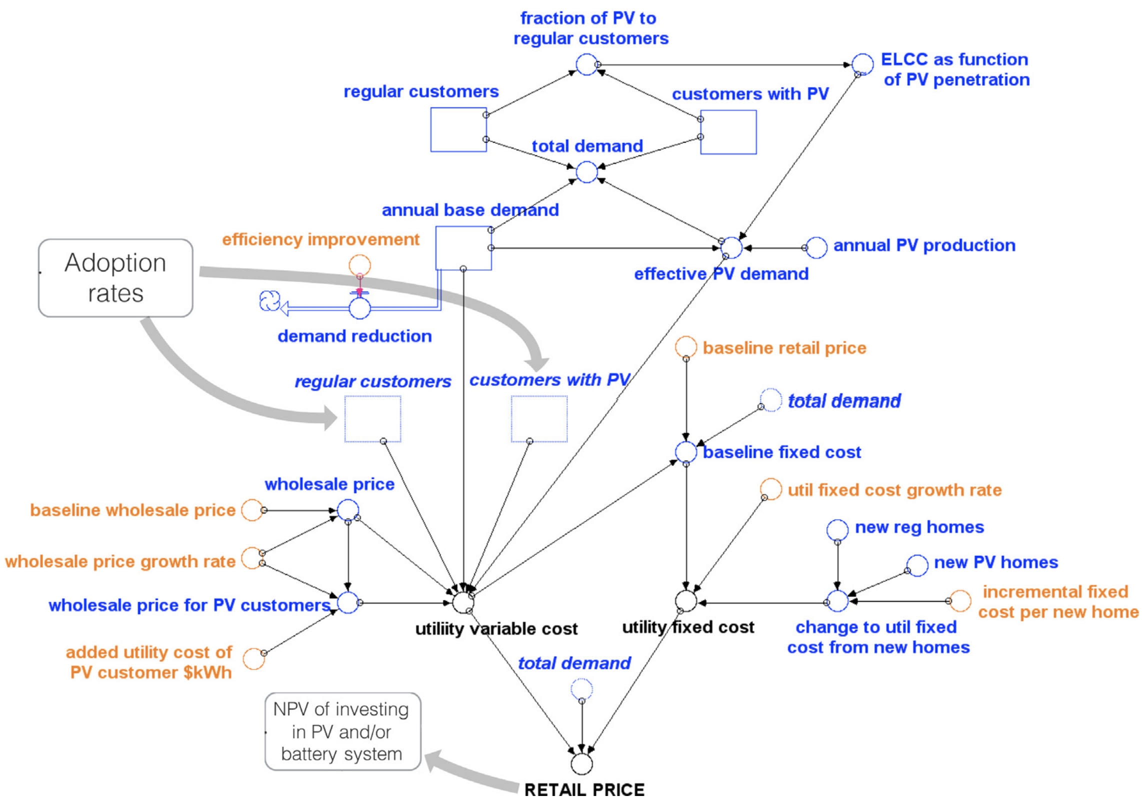


Fig. 6. Retail price formulation via the traditional utility business model. Light gray arrows are indicative of the links between the model components described in other sections.

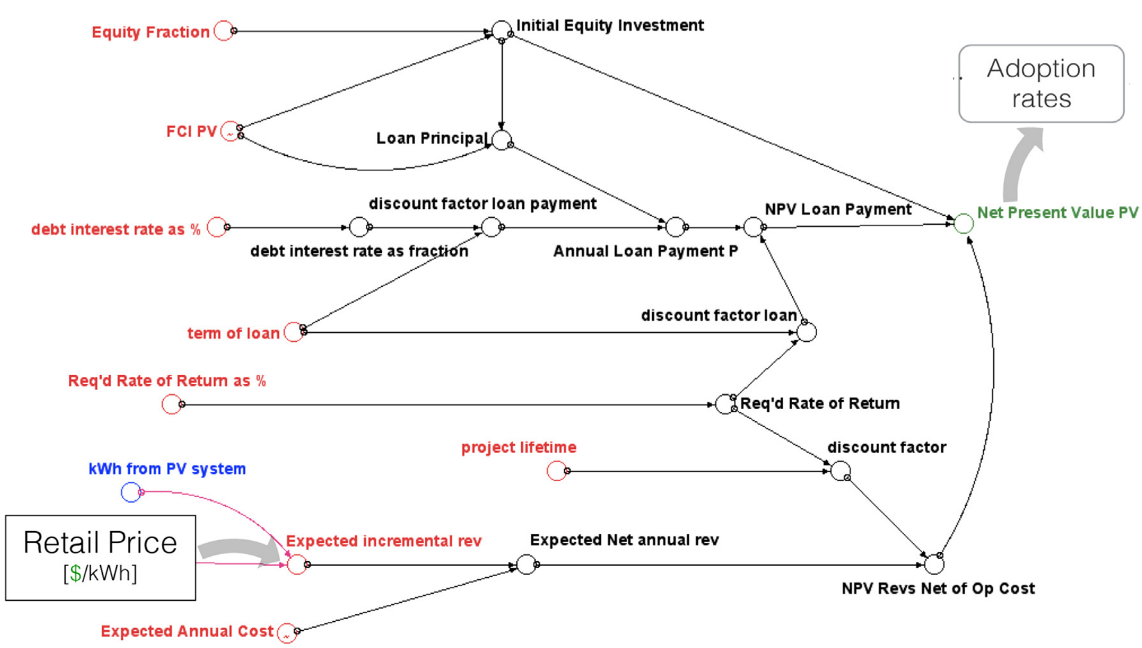


Fig. 7. Net Present Value model for PV system. Light gray arrows are indicative of the links between the model components described in other sections.

base per year for a zero NPV, with growth to 0.5% for NPV equal to $10,000. These upper and lower bounds were selected as reasonable estimates given the known PV adoption rate of 0.5%.

The limit function, *L*, places a cap on the fraction of the total households that can adopt a PV system. We chose to limit the number of homes with PV systems because rental residences, which represent a large fraction of the stock in many cities, have very little financial incentive to install a PV system [34]. The rental fraction in LA was assumed to be 50% on average from 2015 to 2050 (based off of 46% in 2015 with a growth rate of 1.85% every three years [35]). For ease of comparison the rental fraction was assumed to be 50% in Boulder and Sydney as well.

Lastly, we introduced a first-order drain-slowing function, *d*, for each adoption flow. The purpose of this function is to create more realistic (lower) adoption rates as the number of potential households approach zero. Once the number of potential households drops below a certain threshold, the drain-slowing function reduces the adoption rate using an 'S' curve - shown in Fig. 5. The thresholds for drain-slowing were found through trial-and-error such that a smooth transition to a zero adoption rate occurred as the number of households approached zero. Without the drain-slowing function the adoption rates would be unrealistically high for small numbers of potential adopters.

2.2. Traditional utility business model

The traditional utility business model consists of a volumetric rate design. The retail price [$/kW h] is simply the utility's variable costs C_v plus fixed costs C_f [$], divided by the total demand D [kW h] and multiplied by some mark-up factor k:

$$\text{Retail Price} = k\frac{C_v + C_f}{D} \tag{2.8}$$

The variable costs C_v, which are the generation costs, are computed as the number of customers times the demand per customer times the cost of generating power (or purchasing power from a third-party). The fixed costs C_f model transmission and distribution.

As Fig. 6 demonstrates, our pricing model is much more complicated than Eq. (2.8) indicates. In order to capture the potential for a utility death spiral, we had to include the reduced energy demand from utility customers with PV systems. Also, customers with PV generally produce less revenue for utilities than regular customers, and customers with PV systems can create higher energy production costs due to the variability that grid-connected PV systems introduce.[1] We captured these costs in the model by including the reduced demand of PV customers and an inflated wholesale price for meeting the energy needs of PV customers.

The pricing model also captures the potential for electricity customers to become more efficient in the future. To capture the improving efficiency of retail customers, lighting systems, and home appliances, the model includes a reduction in the baseline demand as a percentage of the total per year (baseline value of 0.5%).

Annual energy usages for single family homes in LA and Boulder were modeled after the US Department of Energy's residential reference buildings [38]; the average annual demand for Sydney was found in [39]. Furthermore, the energy required from the utility by homes with PV systems was determined using hourly resolution irradiance data from the National Solar Radiation Database [26] and the Australian Bureau of Meteorology [40], with system sizes equal to local averages. Estimates for the electricity directly used by a household from a PV system are summarized in Table 1.

In order to determine realistic demand values from customers with grid connected PV systems, we used estimates of their Effective Load Carrying Capability (ELCC) [41]. ELCC is a measure of how effective a generation system is at reducing the demand on the grid without decreasing the grid's reliability in meeting demand. Here we use the percentage definition of ELCC. For example, a 1 MW rated power plant with a 50% ELCC effectively provides 0.5 MW to the grid. The ELCC of PV systems declines with increasing penetration of PV systems. Therefore, our model estimates a PV household's demand with Eq. (2.9). Here, ELCC is a function of the ratio (PV homes)/(total homes) [41].

$$PV_{demand} = \text{Baseline}_{demand} - ELCC * PV_{production} \tag{2.9}$$

Each location was initialized with the latest average retail price of electricity (see Table 1). Furthermore, the initial wholesale price of electricity was determined with estimates of each utility's fraction of costs from generation (summarized in Table 2). To simplify the model all cost values implicitly include the utility's mark-up.

The wholesale price calibration also included an inflated wholesale price for PV customers. The added cost of electricity generation due to distributed PV systems is an open question in the literature. However, from a survey of the few studies that exist on this topic we concluded that an additional 1¢/kW h was a reasonable starting point [36,42,43]. The wholesale price is assumed to grow 1% per year in the baseline model, which is based on an average of the US annual average retail price from 2001 to 2014 [10].

The last pricing component is the utility's fixed cost. This was straightforward to determine given that we have an initial retail price. From Eq. (2.8) the baseline fixed cost is simply the initial retail price times the total initial demand minus the initial variable costs. The baseline fixed cost is allowed to change via two pathways: (i) population growth (see Section 2.5); and (ii) a growth rate, set to a small value for the baseline model (1% growth per year).

2.3. Net present value

Fig. 7 shows the submodel used to determine the Net Present Value (NPV). The NPV criterion is the most widely accepted metric for determining the worth of investing in a project. The cash inflows of investing in a PV system include the electricity produced by the panels (valued at the current retail price in a net metering business model), and the cash outflows include the cost of purchasing the system, or fixed capital investment (FCI), as well as the operation and maintenance costs. Using forecasts from [8] we determined the FCIs for installed PV systems and battery systems. The key assumptions in the NPV formulation were:

- investment is financed with 80% of debt
- debt interest rate is 10% throughout the 20-year lifetime of the system, with a 10-year term of loan
- required rate of return is 10%
- annual operation and maintenance costs of the PV, battery, and PV-battery systems are $60/kW, $1.54/kW h ($100), and $70/kW respectively

Note that the expected incremental revenue and FCI depend on the size of the installed PV system. The PV systems without batteries in each location are sized using a local average (5 kW for LA and Sydney, 9.3 kW for Boulder). For offgrid systems with batteries, the PV system size is increased such that the excess production (i.e. the

Table 2
Model inputs for retail price formulation.

Variable	Initial value	Source and/or assumption
Incremental fixed cost per new home	$200/kW with 5 kW peak consumption = $1000/house	[44]
Wholesale price growth rate	1%	[45] Apr 2009 - Dec 2013 average 0.8%
Fraction of utility costs from generation	LA: 56%; Boulder: 50%; Sydney: 45%	LA [46]; Boulder: estimate; Sydney [47]
Annual reduction in demand	0.5%	[48] conservative estimate

[1] The extent and existence of the added cost of distributed generation for utilities is up for debate. Estimates are few and vary widely (see [36] for examples). Ref. [37] enumerates some of the added costs for energy generators, such as *part-load penalty*, *min-gen penalty*, and *cycling cost*.

production that is stored in batteries) is approximately twice the unmet demand without batteries - thus providing a margin of safety of two.

2.4. Pricing structures

Three different pricing structures were used for comparison in the net present value formulation: *net metering*, *wholesale compensation*, and *demand charge*. In the *net metering* structure, customers producing excess power with PV are compensated with the current retail price of electricity. Therefore, for a regular customer that does not own a PV system, the expected incremental revenue is equal to the potential panel production in kW h times the retail price of electricity in $/kW h. However, for a regular customer considering an off-grid PV *and* battery system the expected incremental revenue is the customer's entire annual demand time the retail price of electricity (which is the same for all three pricing structures). The model also accounts for customers that already own a PV system and are considering purchasing an off-grid battery system. For these customers, considering grid defection, the expected incremental revenue of adding batteries to their PV system is the difference of their total demand and the electricity that they use directly from their PV panels, multiplied by the retail rate (see Table 3 for summary).

The *wholesale compensation* structure is similar to net metering, but customers producing excess power are only compensated with the current wholesale price of electricity, rather than the retail price as in net metering. The wholesale compensation structure is built around the premise that the wholesale price is a more fair market price for the utility to pay. Therefore, for a regular customer purchasing a home PV system the expected incremental revenue is the savings from not paying retail price for the electricity directly used from the panels, plus an income from excess production, which is compensated with the current wholesale price. And for a PV customer adding batteries the expected incremental revenue includes the benefit of no longer paying the utility for the difference of the electricity that the customer cannot directly use from their PV system subtracted by the lost income from excess generation.

In the *demand charge* structure, the customer pays one fee for access to the grid (with this fee related to the customer's peak demand during the pay period) plus another fee accounting for the net amount of energy consumed during that pay period. This model is an approximation of a pricing structure that already exists in many places, including Boulder, as an alternative to net metering. If we assume that the regular and PV customers have the same peak demand (true for LA and very close for Boulder - data not available for Sydney), then the expected incremental revenue from purchasing a PV system is only a lower energy charge (because the demand charge is unchanged). The lower energy charge for a PV customer compared to a regular customer will therefore be approximately the retail price times the direct PV electricity use (all other electricity generated is wasted because it is not stored nor put into the grid). Thus, under the demand charge pricing structure, a customer with a PV system that is considering purchasing a battery system has an expected incremental revenue of the retail price times the difference of their demand and their direct PV use (see Table 3 for summary).

2.5. Population growth

In addition to the adoption flows of households, the model includes an influx of households via population growth (illustrated in Fig. 4 as "houses being built"). For LA the initial value of population growth is set to the value in 2014 (0.6% annual change from 2013 [49]), and then tapers off to half of the initial value in 2050 (assuming that LA will not grow indefinitely). For Boulder and Sydney constant population growth rates of 0.8%/year [50] and 1.8%/year [51] respectively were used.

Which type of house people choose to build is determined by the attractiveness of each type of house, formulated in a *logit choice* model [52]. The logit function, expressed in Eq. (2.10), provides the probability P of a homebuilder choosing alternative i from the set of J choices with an attractiveness x.

$$P_i = \frac{e^{(k_i+x_i)}}{\sum_{j=1}^{J} e^{(k_j+x_j)}} \tag{2.10}$$

We determined the relative attractiveness of a house using the cost of adding a PV or PV/battery system to a new home. Furthermore, given that the construction of many new houses will not be paid for by the same people that will pay the utility bill, we gave regular households an additional higher weighting than houses with DG systems. We achieved this weighting for regular households by doubling the unexplained utility factor, k, relative to households with DG.

As more homes are added to the system the utility's fixed cost will increase. This is because new neighborhoods will require extension of the existing transmission and distribution system, in addition to increasing the load placed on existing infrastructure. We modeled the added cost by adding a flat amount per household to the utility's baseline fixed cost using estimates from [44].

2.6. Model validation

Our model is centered around the prediction of the retail price of electricity. The retail price, and its components, determine the NPV of purchasing a PV and/or battery system, which in turn affects the adoption rates of the technologies, (which in turn affects the retail price). Therefore, in considering if our baseline model results were reasonable we compared our predicted retail price with historical numbers and expert forecasts.

The retail price of electricity in the US has grown by an annual average of 1% per year since 2001 [10]. However, in some areas, including California, the retail price of electricity has grown by nearly 3% per year for the last three years. Our baseline model predicts an average annual growth rate of 1.5–1.6% out to 2050 for all cities and pricing structures. These values are reasonable given that forecasts range from 0.1% to 3% growth in retail prices [8] and that the US Energy Information Administration's *Annual Energy Outlook 2015* forecasts a 0.5% to 1.0% growth rate in electricity retail prices for the US out to 2040 (depending on scenario) [53].

For Sydney, the percent change in the retail price between 2015 and 2040 predicted by the model was compared to forecasts from the Australian Energy Market Operator. From 2015 to 2040 (after a short drop in retail prices due to the withdrawal of the carbon price) retail prices are projected to grow approximately 30% for

Table 3
Expected incremental revenue for each combination of pricing model and technology adoption pathway. Abbreviations: RP ≡ Retail Price, WP ≡ Wholesale Price, PVp ≡ PV production, PVu ≡ PV direct use, D ≡ annual demand.

	Net metering	Wholesale compensation	Demand charge
Customer buying PV system	RP * PVp	RP * PVu + WP * (PVp − PVu)	RP * PVu
PV customer buying battery system	RP * (D − PVp)	RP * (D − PVu) − WP * (PVp − PVu)	RP * (D − PVu)
Customer buying PV and battery system	RP * D	RP * D	RP * D

the medium demand case and 58% for the low demand case [54]. Our model predicts a growth of 51% for the same time period in the baseline case.

3. Results

The primary outputs of the model are the retail price of electricity and the number of each type of household at every time step. For the purposes of this discussion, we define a death spiral as a scenario in which the number defectors exceeds the number grid-connected customers at any time step within the simulation time. Although there are other ways to define a death spiral, we chose this metric for its simplicity, in order to facilitate analysis of over 10,000 cases.

An overview of this section is as follows: Baseline results for the nine combinations of three cities and three pricing structures are presented in Section 3.1. The baseline values for each variable are summarized in Table 4. Justification for the baseline values was given in the previous sections. Sensitivity analyses for the variables in Table 4 is presented in Section 3.2. Finally, we discuss model results with the limit on the number of PV households removed in Section 3.4.

3.1. Baseline model

The baseline results for each city are as expected: in each location, the PV market will saturate within the next 30 years, and the number of grid-defected homes will grow slowly over time. These baseline results indicate that a death spiral is unlikely.

Fig. 8 shows that the number of households with PV systems will grow significantly in Boulder and LA for all pricing structures until the PV market saturates by 2030. Note that the fraction of PV homes asymptotically approaches 50% of the total homes because of the rental-fraction limit function (see Section 2.1). The number of offgrid customers is insignificant compared to the number of grid-connected customers in Boulder and LA.

For Sydney the results are slightly different, but a death spiral is also unlikely. Sydney exhibits a more steady growth in PV households than the US cities, with PV market saturation occurring between 2030 and 2040. Sydney's lower PV adoption rate may be due to its greater initial fraction of PV customers. Compared to the other two cities, Sydney has a greater rate of offgrid technology adoption. If a death spiral were indicated one would see a rapid growth in the off-grid households coupled with comparable drops in regular and PV customers.

Comparing across cities, from left to right in Fig. 8, we see that Sydney has the greatest fraction of defectors and that Boulder and LA have very similar fractions of all three households. Note that LA lags Boulder by approximately 3 years and therefore LA has slightly less defectors (and more PV customers) than Boulder in 2050.

Comparing across pricing structures, from top to bottom in Fig. 8, we see a slight increase in the number of PV customers. This trend makes sense given that each pricing structure progressively compensates PV customers more as one trends from *demand charge* to *wholesale compensation* to *net metering*.

Table 4
Summary of baseline values and sensitivity variables.

Variable	Baseline value	Sensitivity value	Note
PV incentive	Zero	\$5000 per year	Addition to NPV
Battery incentive	Zero	\$5000 per year	Addition to NPV
Imitation scale factor	1	5	Section 2.1
Innovation scale factor	1	5	Section 2.1
Utility fixed cost growth rate	1% per year	5% per year	Section 2.2
Wholesale price growth rate	1% per year	5% per year	Section 2.2
Debt interest rate	10% per year	1% per year	Section 2.3
Equity fraction	0.1	0.8	Section 2.3
Required rate of return	10% per year	1% per year	Section 2.3
Efficiency improvement of customers	0.5% per year	2% per year	Section 2.2
Limit function	Local rental fraction	No limit	Section 2.1

3.2. Sensitivity analyses

Sensitivity analyses were conducted for ten different model parameters, summarized in Table 4. Also, the impact of the limit function is analyzed in Section 3.4. With two values for ten parameters and nine different scenarios (three pricing structures times three cities) over 18,000 cases were generated. In order to make the analysis tractable the impacts of varying the parameters were measured in terms of the percentage change in the four primary output variables in year 2050. Overall, the items with the most individual impact were:

- *efficiency improvement of customers* (annual reduction in customer demand)
- *utility fixed cost growth rate*
- *required rate of return* (return on investment required by consumer to decide to purchase a DG system)
- *innovation scale factor* (constant of proportionality k in Eqs. (2.2), (2.4), and (2.6))

A greater *efficiency improvement of customers* results in a lower demand for electricity, leading to higher retail prices (see Eq. (2.8)). Indeed, among all the sensitivity parameters, efficiency improvement had the largest impact on the retail price of electricity. When higher retail prices are combined with high adoption rates and high utility costs, the results are tipped in favor of PV customers as compared to defectors. However, the same combinations with a low efficiency improvement increases the number of defectors significantly. These effects are illustrated in Fig. 9, where the high adoption rates are evident in the initial sharp increase in PV customers compared to the baseline case. These trends are common across the three cities for the demand charge and wholesale compensation pricing structures, but less prevalent under the net metering structure.

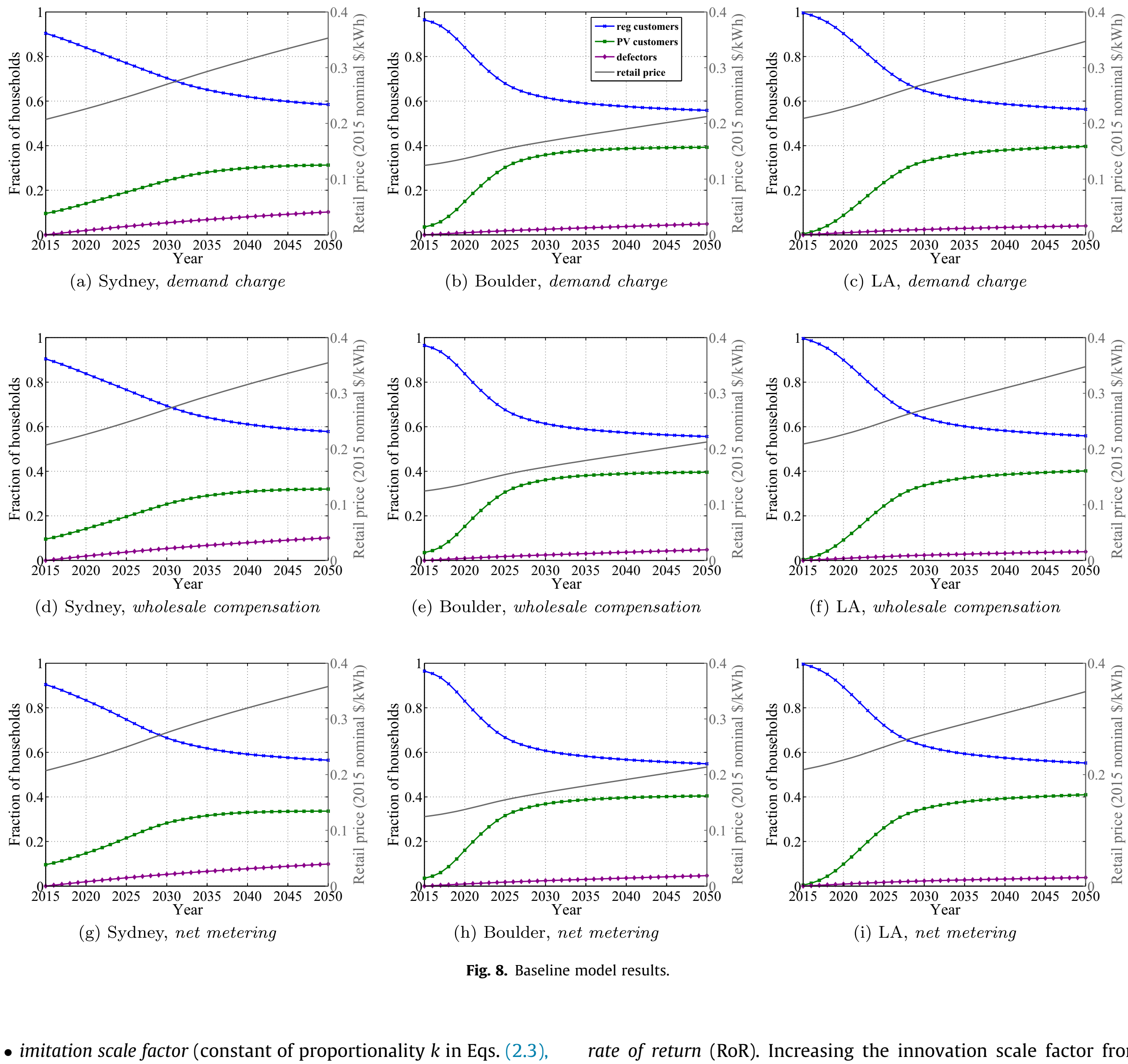
As expected, higher *utility fixed costs* increased the retail price. On average, greater utility fixed costs also lead to more PV customers converting to defectors, as shown in Fig. 10. Exaggerated results similar to those shown in Fig. 10 occur for all cities under the demand charge and wholesale compensation pricing structures. The effect of greater utility fixed costs on the number of defectors is muted for Boulder and Sydney under the net metering pricing structure.

Unlike the higher efficiency improvement or utility costs, a lower *required rate of return* (RoR) creates more defectors without the accompaniment of higher retail prices. The results for these scenarios look similar to those in Figs. 9 and 10 in that an increase in defectors comes with a decrease in PV customers, which indicates that direct defection from regular customers is rare. Although a lower RoR decreases the amount PV customers in 2050 over all cities and pricing structures on average, the combination of a lower RoR and the net metering pricing structure results in a *higher* number of PV customers on average across scenarios.

A higher *innovation rate* also significantly increases the number of defectors (and decreases the number of PV customers) when comparing cases with the innovation rate as the sole difference.

Overall, the parameters with the least individual impact were:

- *PV incentive* (modeled as an addition to the net present value of a technology)



(a) Sydney, *demand charge* (b) Boulder, *demand charge* (c) LA, *demand charge*

(d) Sydney, *wholesale compensation* (e) Boulder, *wholesale compensation* (f) LA, *wholesale compensation*

(g) Sydney, *net metering* (h) Boulder, *net metering* (i) LA, *net metering*

Fig. 8. Baseline model results.

- *imitation scale factor* (constant of proportionality k in Eqs. (2.3), (2.5), and (2.7))
- *equity fraction* (down payment on purchase of DG system, expressed as fraction of total cost)

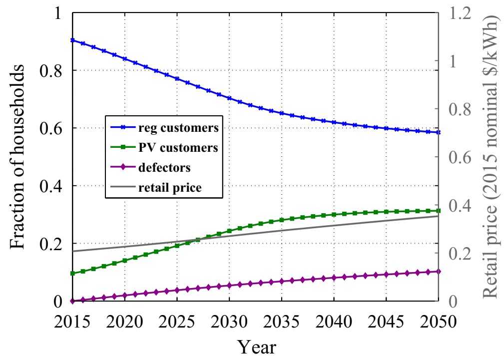
Surprisingly, *incentives* generally had a small impact on the results. Their affect is to shift the PV and Battery cost curves down slightly and therefore only shift the "fraction of households" results slightly to the left (i.e. to earlier times). Due to the complexity and variability of renewable energy incentives, the incentives were modeled as simple reductions in the fixed capital investment (FCI) required to purchase a PV and/or battery system. The amount of the incentive was determined as approximately 25% of the cost of a PV system in 2014. Many other (especially higher) values were evaluated in initial sensitivity analyses, with the result that the incentives had very little impact on the results unless they were unrealistically high values (i.e. higher than the actual FCI).

3.2.1. Impact of sensitivity variables on household type

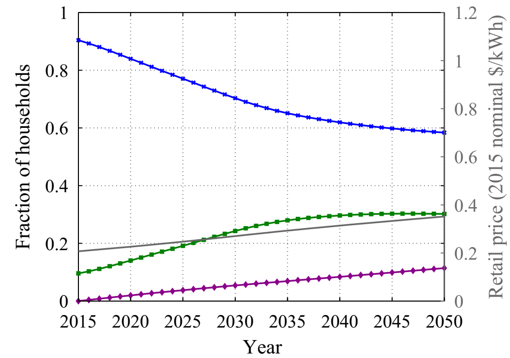
The most influential variables on the number of *regular customers* were a higher *innovation scale factor* and a lower *required rate of return* (RoR). Increasing the innovation scale factor from one to five, (i.e. increasing the innovator's adoption rate fivefold), decreased the number of regular customers by an average of 6% across pricing structures and cities. A lower RoR resulted in an average 3.5% decrease in the regular customers in 2050. The impact of the other sensitivity variables on the number of regular customers in 2050 were on the order of two percent or less.

The number of *PV customers* in 2050 were significantly increased by a higher *efficiency improvement*, with an average increase in PV customers of 34%. PV customers were impacted negatively by a number of factors: a lower RoR reduced PV customers by 12%; higher *utility fixed costs* resulted in the number of PV customers in 2050 being reduced by 8%; and the higher *wholesale price* growth rate reduced PV customers by 7%.

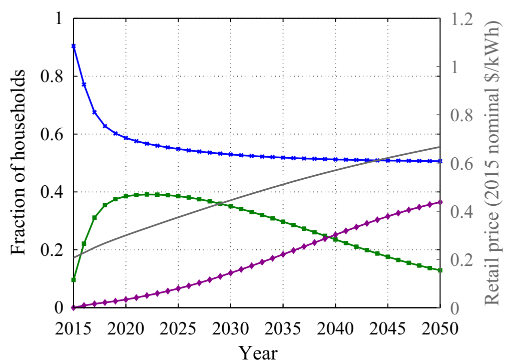
The reductions in PV customers due to higher utility fixed costs and wholesale price growth rates were accompanied by increases in the number of *defectors* on the order of 30%. In fact, the impacts of the utility fixed costs and wholesale price growth rates were similar across all scenarios. Defectors were also increased by approximately 30% by a greater *innovation scale factor* and nearly 70% by the lower RoR. A higher *efficiency improvement* value is



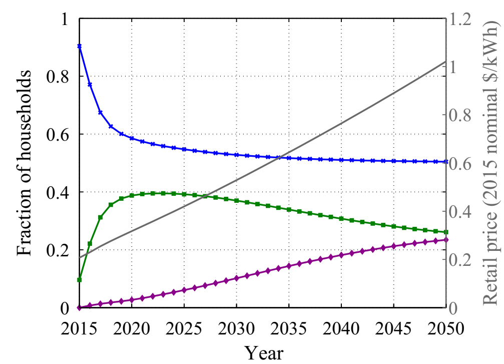
(a) Sydney demand charge, Base Case values (*0.5% efficiency improvement)*



(b) Sydney demand charge, Base Case values except *2.0% efficiency improvement*



(c) Sydney demand charge, with PV and battery incentives, 5x adoption rates, *0.5% efficiency improvement*, high utility cost growth rates, 1% debt interest, 0.1 equity fraction, 10% RoR, PV limit on



(d) Sydney demand charge, with PV and battery incentives, 5x adoption rates, *2.0% efficiency improvement*, high utility cost growth rates, 1% debt interest, 0.1 equity fraction, 10% RoR, PV limit on

Fig. 9. Impact of efficiency improvement.

the only parameter that had a significant negative impact on the number of defectors, which was a decrease in defectors in 2050 of 27%.

As expected there were no parameters that had a significant negative impact on the *retail price*. However, both higher *utility fixed cost* and *wholesale price* growth rates increased the retail price by more than 40% in 2050. Also, the higher *efficiency improvement* increased the retail price by more than 50%.

3.3. Death spiral scenarios (in cases with a limit on the number of PV households)

The scenarios with the highest fractions of defectors are those in which the four aforementioned, high-impact factors combine:

(i) lower *efficiency improvement of customers*;
(ii) higher *utility cost growth rates*;
(iii) lower *required rate of return*;
(iv) and high *innovation scale factor*.

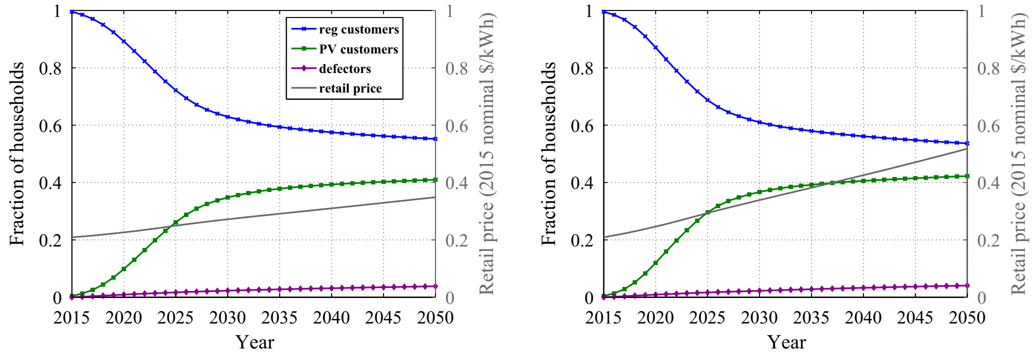
Comparing across all cities and pricing structures, the most likely candidate for a death spiral is the combination of LA under the demand charge pricing structure. Only LA has cases in which defectors are greater than 80% of the households in any year. There are 16 cases for the LA demand charge model and 2 cases for the LA wholesale compensation model that have more than 80% defectors. All 18 cases share these four high-impact factors. These cases highlight the fact that a utility death spiral will require compound factors working against the utility.

In these high-defector cases, changing the pricing structure either to net metering or to wholesale compensation would help prevent the death spiral. Fig. 11 compares the effect of changing the pricing structure in LA for one of the high-defector LA demand charge cases. The effect of the net metering pricing structure on the number of PV customers is apparent in Fig. 11.

3.4. Cases with no limit on number of PV households

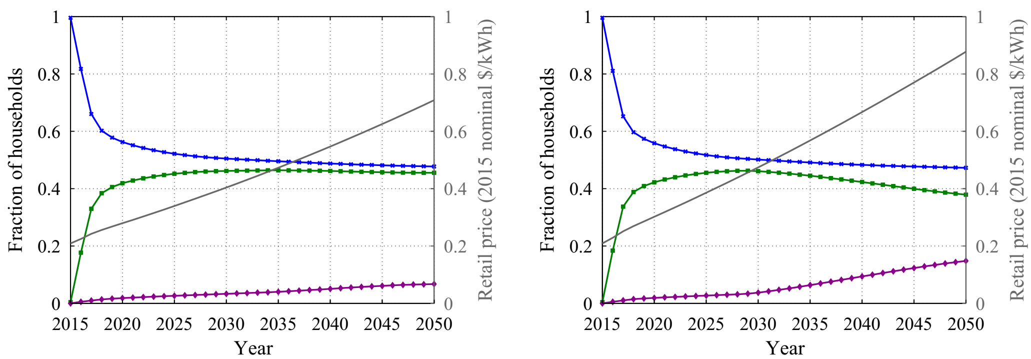
It is interesting to explore scenarios in which the number of PV households is not limited by the rental fraction. With the recent advent of community owned solar projects and virtual power purchase agreements, it is easy to imagine scenarios in which the number of residences powered by PV systems exceeds the rental fraction. In fact, community-owned solar projects can make powering homes with PV more economically viable than individual home systems, by reducing the volatility in solar energy production [55]. Shakouri et al. [55] present a decision-support model that applies Markowitz Portfolio Theory [56] to determine the optimum portfolio of PV panel sizes and locations to minimize hourly volatility and maximize electricity output. One main result is that while individual home systems experience large volatility (due to spatial factors such as shading and roof slope), the community as a whole experiences less volatility.

Returning to the our model, Fig. 12 shows the baseline cases for each city and pricing structure with the limit on the number of PV households removed. As expected, we see the number of PV households grow to much higher fractions when compared to the base cases with the limit function on (Fig. 8). In LA and Boulder we



(a) LA net metering, Base Case values (*1% utility fixed cost growth rate*)

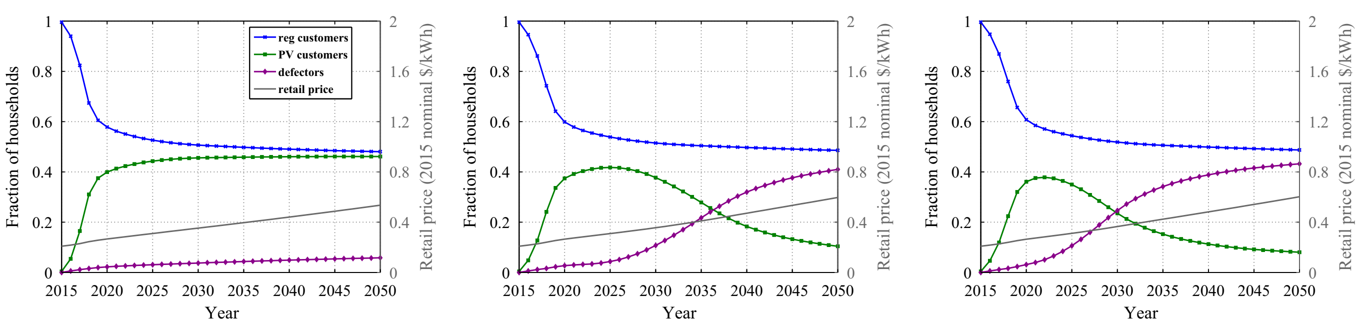
(b) LA net metering, Base Case values except *5% utility fixed cost growth rate*



(c) LA net metering, with PV and battery incentives, 5x innovation rate, 1x imitation rate, 2.0% efficiency improvement, *1% utility fixed cost growth rate*, 5% wholesale price growth rate, 1% debt interest, 0.8 equity fraction, 1% RoR, PV limit on

(d) LA net metering, with PV and battery incentives, 5x innovation rate, 1x imitation rate, 2.0% efficiency improvement, *5% utility fixed cost growth rate*, 5% wholesale price growth rate, 1% debt interest, 0.8 equity fraction, 1% RoR, PV limit on

Fig. 10. Impact of utility fixed cost growth rate.



(a) LA, *net metering* (b) LA, *wholesale compensation* (c) LA, *demand charge*

Fig. 11. One of the 16 cases (with the PV limit on) in which the LA demand charge model results in more than 80% defectors in 2050. The following parameters were used with all three pricing structures: no incentives, 5× adoption rates, 0.5% efficiency improvement, 5% utility fixed cost growth rate, 1% wholesale price growth rate, 1% debt interest, 0.1 equity fraction, 1% RoR, PV limit on.

can see the that system appears to be approaching a steady state of PV and regular customers. This trend is most likely due to the leveling out of the PV price forecast in the future.

The slower uptake in PV technology in Sydney (Fig. 12a, d, and g) is most likely due to the lower demand and direct PV use in Sydney compared to LA and Boulder (see Table 1). The lower demand and direct PV use values in Sydney produce lower net present values and therefore lower financial incentive for PV adoption in Sydney.

Interestingly, the net metering pricing structure resulted in the fewest number of death spiral cases. Compared to the other pricing structures, the net metering pricing structure creates a greater financial incentive for PV customers to stay connected to the grid, and therefore the flow from PV customers to defectors is retarded under the net metering pricing structure. In fact, LA was the only city with death spiral cases under the net metering pricing structure with the PV limit off.

The demand charge pricing structure produced the greatest number of death spirals. The demand charge pricing structure has the opposite effect of the net metering structure: when retail price and adoption rates rise, the demand charge pricing structure makes the prospect of going off-grid more financially attractive than staying grid-connected.

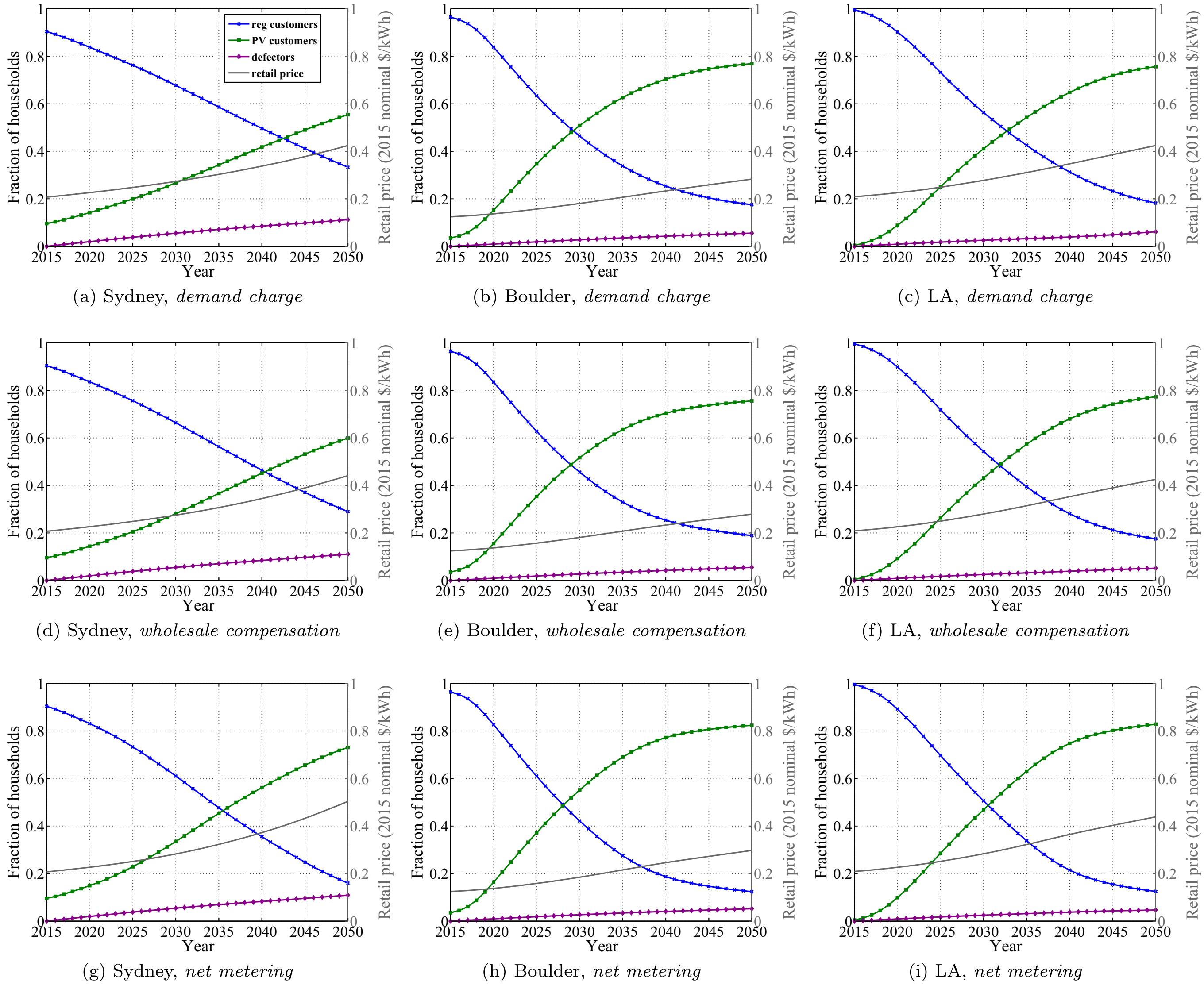


Fig. 12. Baseline model results with no limit on the number of PV households.

Comparing across cities, LA was the most likely to have a death spiral, and Sydney was the least likely candidate. A case for each city with the demand charge pricing structure is shown in Fig. 13.

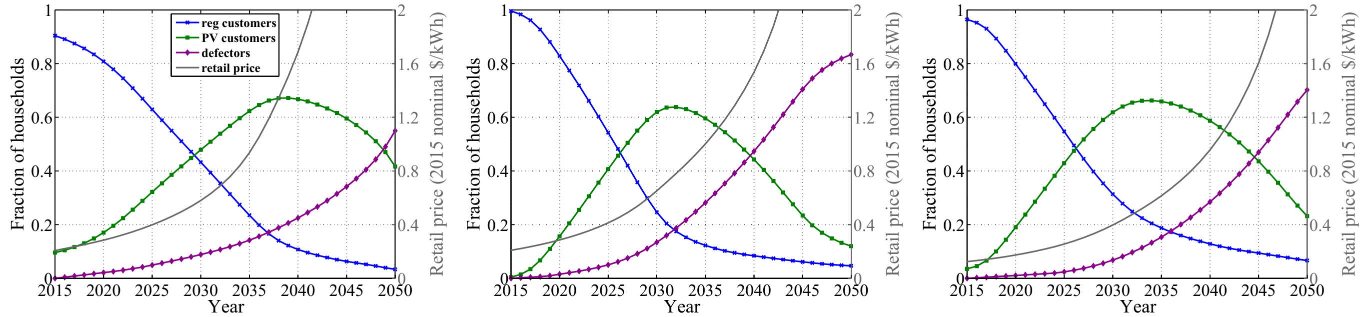
4. Discussion and conclusions

A utility death spiral due to solar photovoltaic and battery systems is highly unlikely. The model only indicated a utility death spiral, in which the number of defectors is greater than the number of grid-connected customers, for scenarios with combinations of high adoption rates, high utility costs, and favorable customer financial parameters such as the customer's required rate of return.

Pricing structure can have a significant impact on a utility's customer retention. The net metering pricing structure resulted in the fewest number of grid defectors. Low defectors, however, came with high PV market penetration. It is well known that the net metering pricing structure creates an imbalance of costs and revenues between the utility and customers. However, utilities will most likely have ample time to adjust their business model and pricing structures to maintain profits and prevent grid-defection. Many utilities are already adopting alternative pricing structures, indicating that they are adapting to the rapidly changing market.

Among the most influential parameters explored in the sensitivity analyses, three out of four are outside of a utility's control: the efficiency improvement of customers, the required rate of return of customers, and the rate of adoption by innovators. Of these three, the efficiency results were the most interesting. The results indicated that a greater efficiency improvement of utility customers would reduce the number of defectors, while increasing the number of PV customers and the retail price significantly. Demand reduction through customer efficiency improvements can create stranded costs for utilities, which could further increase the retail price. Furthermore, seasonal variations in demand and PV production (see for example [57]) can also require utilities to maintain expensive energy infrastructure that is only profitable for a fraction of a year, further raising costs. All of these factors could combine to cause retail prices to balloon in the future, making grid defection more likely.

On the other hand, time-of-use rate structures designed to recover utility costs can mute the positive feedback effects between PV adoption and the retail price of electricity [23]. But, as residential battery systems become more affordable, consumers could use optimally dispatched storage systems [58] to take advantage of time-of-use rate structures and increase the economic gains of their PV system.



(a) Sydney, *demand charge* (b) LA, *demand charge* (c) Boulder, *demand charge*

Fig. 13. Comparison of cases with no limit on PV households. All cases have the same parameters: No incentives, high efficiency improvement, high utility costs, high equity fraction, and low values for debt interest rate and RoR.

While utilities may not be able to impact consumer efficiency improvements and other market factors, they can control the pricing structure. As distributed generation and battery system costs come down in the near future, utilities may have to strike a balance between maintaining profits while providing distributed generation customers with reasonable compensation for excess generation. It will be interesting to see how the quantity and shape of customer demand will influence the utility of the future.

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