Energy Expenditure Incidence in the Presence of Prosumers: Can a Fixed Charge Lead Us to the Promised Land?

Yihsu Chen, *Senior Member, IEEE*, Makoto Tanaka, *Member, IEEE*, and Ryuta Takashima, *Member, IEEE*

***Abstract*—Distributed renewable resources owned by prosumers have been viewed as an effective way of fortifying grid resilience and enhancing sustainability. However, prosumers serve their own interests, and their objective is unlikely to align with that of society. Their growing presence in the market may negatively affect less affluent consumers who are financially unable to adopt new technologies. We compare the energy expenditure incidence among different income groups when prosumers are subject to a net-metering and a net-billing policy considering both the wholesale and retail markets. We demonstrate that policies exclusively based on volumetric consumption for recovering fixed costs are likely to favor the affluent income group. Among the two policies, net-metering is more regressive than net-billing under the volumetric tariff when prosumers are selling power into the grid. A hybrid policy, which also features an income-based fixed charge and an annual (re)connection fee or a grid access fee on prosumers, may potentially improve energy equity by leveling the energy expenditure incidence. Due to its revenue certainty, such policy is also more acceptable by and appealing to the utilities; however, it may reduce the incentive for conserving energy.**

***Index Terms*—Prosumers, energy expenditure incidence, retail and wholesale market, net-metering, net-billing, fixed cost recovery, linear complementarity problem.**

I. Introduction

CONCERNS about climate change, reliable power supply, and sustainability have shifted the electric power sector in the U.S. and elsewhere toward a more demand-side engagement to harness flexible distributed renewable energy resources (DERs) owned by prosumers. This change not only unleashes the opportunities for rethinking market design for the power sector but also challenges the conventional, top-down power grid architecture based on the supply side.

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Yihsu Chen is with the Technology Management in Sustainability, Electrical and Computer Engineering, Environmental Studies, University of California Santa Cruz, Santa Cruz, CA 95064 USA (e-mail: yihsuchen@ucsc.edu).

Makoto Tanaka is with the National Graduate Institute for Policy Studies, Tokyo 106-8677, Japan (e-mail: mtanaka@grips.ac.jp).

Ryuta Takashima is with the Tokyo University of Science, Chiba 278 8510, Japan (e-mail: takashima@rs.tus.ac.jp).

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More recently, the U.S. Federal Energy and Regulatory Commission (FERC) issued a landmark order, FERC Order 2222, that removes barriers for the entries of emerging technologies, thereby breaking new ground toward creating the grid of the future [1]. More specifically, the ruling allows the integration of multiple DERs owned by different entities with different sizes and diverse technologies to participate in the regional organized wholesale capacity, energy, and ancillary services markets alongside traditional resources. This will allow homeowners to "value-stack" their DERs by providing energy and various types of services to the grid. Already, we are witnessing some activities in the marketplace in response to or anticipation of the order. For instance, OhmConnect recently announced a plan to link homes dispersed in California to form a 550-MW virtual power plant (VPP) of distributed energy resources [2].

More frequent occurrences of hazardous events, in part induced by warming climate, also force utilities to develop better monitoring and contingency plans to protect their assets and reduce their liability had any damage occurred to their customers.[1] In particular, the Public Safety Power Shutoff (PSPS) programs implemented by three investor-owned utilities (IOU) in California are designed to shut off power to areas where the weather conditions are favorable to creating various hazards, such as wildfires, to prevent their electric systems from becoming the source of ignition [3]. Over the past few years, customers in California have experienced an increasing number of PSPS events and are increasingly frustrated by the resulting inconvenience. Consequently, those financially more capable households self-sort to become prosumers by investing in new technologies, such as rooftop solar panels coupled with on-site backup generators or storage. This allows them to operate their homes in an island model, shielding any service disruption from the main grid during PSPS.

Meanwhile, how to compensate energy produced by prosumers has emerged as a critical issue that may facilitate or impair the deployment of DERs and is currently subject to contentious debates [4]–[6]. For example, Chakraborty *et al.* [6] apply cooperative game theory to examine cooperation and cost allocation among participants within a community that shares their DERs under various pricing schemes. The situation has also been dubbed "revenue erosion" or "network defection"; utilities are forced to raise the grid tariff to compensate for the revenue

[1]The recent rolling black-out occurred in Texas is a testament of the extent of damage that could be resulting from correlated hazards induced by warming climate.

deficiency, further exacerbating the situation and leading to a downward spiral [7]–[11]. Within this context, Darghouth *et al.* [11] argue that there are two competing effects. While the effect of avoiding fixed-cost payment encourages consumers to become prosumers, the time-varying rate feedback that lowers power prices during peak hours discourages the adoption of DERs. There is some empirical evidence documenting the fixed-cost effect. For instance, using data from three IOUs in California, Wolak [12] finds that two-thirds of the increases in the residential distribution prices can be attributed to the growing solar capacity. Thus, while self-reliance is appealing to affluent customers, it may result in some unintended consequences that directly affect less affluent customers whose only energy source is the main grid. That is, less affluent customers are expected to shoulder more energy-unrelated cost [4], [13].[2] In fact, even in the absence of significant amounts of distributed energy, there are already concerns about energy inequality inherent in different income groups [15]. For instance, the U.S. EIA's Residential Energy Consumption Survey (RECS) reports that while the highest income group uses 25% more electricity than the lowest income group, the latter's energy incidence, gauged by the energy expenditure as a percentage of their income, is more than five times larger than that of the former [16].[3] Finally, the fact that the FERC requires rates to be "just and reasonable" in the wholesale market naturally leaves the concern about energy inequality to be addressed by the state government, such as the California Alternate Rates for Energy (CARE) program.

Fixed or non-convex cost recovery is a thorny political-economic issue. In principle, utilities prefer to recover their fixed costs through monthly fixed charge as it does not tie to customers' consumption level, rendering a significant revenue certainty. However, the fact that consumers face a lower volumetric retail price implies that they have less incentive to conserve energy. To what extent the growing presence of prosumers may worsen energy inequality depends on how energy produced by prosumers is priced and how utilities allocate their fixed costs to the retail rates. A number of recent studies have addressed issues related to pricing power from prosumers [17]–[19]. Using stylized models, Gautier [17] concludes that net-metering decreases the payment of prosumers, which is cross-subsidized by the higher bills of conventional consumers. The system also leads to too many prosumers and provides no incentive to synchronize local production and consumption. Abada *et al.* [18] apply cooperative game theory to examine an individual's incentive to participate in energy communities. The study finds the willingness to join depends on installation costs, magnitude of aggregated benefits, coordination costs, and energy share rule, as well as network tariff. Clastres *et al.* [19] estimate the extent of cross-subsidies between prosumers and conventional consumers in France. The authors also conclude that a demand charge may alleviate the network defection or death spiral problem facing distributed system operators. More recently, Gorman *et al.* [20] compare grid costs to off-grid costs of more than 2000 utilities in the U.S. and find that network defection could increase from 1% to 7%, with 3% in the southwest region and California and 7% in Hawaii.

Other studies focus on cost allocations for transmission and/or distribution expansion when the system is subject to uncertain renewables or load growth. The models developed in these studies typically have multiple levels because they are interested in the effects of transmission planning and cost allocation on capacity expansion and generation operations. Examples include [21], who proposes a multistage expansion planning problem jointly considering investment in distribution network and generation in distribution. Another study explores this issue using a tri-level model, where the first level represents transmission planning, the second is renewable energy expansion, and the third is operations [22]. Different from the aforementioned studies, Kristiansen [23] apply a cooperative-game-theoretical approach based on the Sharpley value to allocating the benefits and costs of international transmission investments, focusing on wind energy in the North Sea Offshore Grid. Other similar studies include [24], [25].

Other relevant work also examines issues on recovering or incorporating fixed costs in pricing electricity. However, their focus is on the wholesale market. For instance, Gribik [26] studies pricing rules that involve uplifts or make-whole payments to induce generators desirable market outcomes defined by unit commitment models. More recently, Mays [27] investigates the impact of different pricing schemes can have on generator entry-and-exit decisions. The study finds that despite the presence of fixed production cost elements, prices derived from marginal costs support the optimal capacity mix.

The current study extends our previous work [28] to examine the effects of the growing presence of prosumers on the energy expenditure incidence facing different income groups.[4] We consider a situation in which the utility's fixed costs need to be recovered from either a volumetric charge or a hybrid system that entails an additional income-based fixed charge while power sales from prosumers are subject to a net-metering or a net-billing policy. Although each prosumer may be relatively small, possessing limited ability to engage in the bulk energy market, we assume that an entity integrates a large number of prosumers and participates in the bulk energy market on their behalf, consistent with FERC Order 2222. The prosumers are endowed with renewables and are assumed to decide the amounts of self-consumption, dispatchable energy, for example, storage, to produce, and energy to sell into or buy from the bulk energy market to maximize its net private benefit, which is characterized by its "retail" inverse demand function. The independent system operator (ISO) maximizes the social surplus based on the "wholesale" inverse demand while treating the sales or purchases by the prosumers as fixed variables.

To the best of our knowledge, this is the first study that explicitly distinguishes the retail electricity demand from the wholesale demand when investigating energy expenditure incidence in the presence of prosumers, thereby contributing

[2] At least in California, the Public Utility Commission (PUC) has included a torrent of policy goals into electricity retail rate making, e.g., subsidies for rooftop solar and electrical vehicle charging stations, discount for low-income customers, energy efficiency programs, school water quality, and more recently, wildfire mitigation and compensation [14].

[3] The 2015 RECS also indicates that, in the Pacific region, around 15% of respondents in the highest income class own rooftop solar panels compared to 0% or less than 2% in the lowest three income classes.

[4] Raymar *et al.* [28] examine the extent of prosumers' market power potential in the wholesale market. Thus, it differs significantly from the current work as there is no representation of retail market and fixed-cost recovery. In other words, neither a net-metering or a net billing policy was considered.

to advancing the modeling approach in addition to its policy implication. In reality, any changes to the retail tariff needs a lengthy legal process, unlikely to be socially optimal, but is undoubtedly subject to various inputs from stakeholders with competing interests, e.g., utilities, the PUC, and consumer advocates. Thus, our intention herein is to understand how an income-based fixed charge may improve the equity in energy expenditure among different income groups. Our work is closely related to [17][19] but is different in significant ways. First, we consider the transmission network and market details, e.g., pool-type market settlement, capacity ownership, generation and transmission capacity constraints, retail-wholesale market linkage, which are crucial in determining realistic electricity market outcomes. Second, compared to [19], we explicitly benchmark the case to 2015's RECS data by assuming an energy incidence of 1.5% in order to discover income level by different groups and solve prosumers' load endogenously to examine its impact on energy incidence. In particular, we are interested in how an income-based fixed-charge policy can lead to a market outcome that deviates relatively from or "restore" the benchmark case. Third, we note that the size of the prosumers is exogenous since our interest is not the optimal proportion of prosumers.

The rest of this paper is organized as follows. Section II formulates the simulation models. A numerical case study is presented in section III. Finally, concluding remarks are provided in section IV.

II. MODEL

This section proceeds as follows. First, we introduce the optimization problem faced by each entity in the market, including, prosumers and the ISO, under a net-metering and a net-billing system. Second, we derive the Karush-Kuhn-Tucker (KKT) conditions associated with each variable in the optimization problems. Third, the collection of KKT conditions together with the condition for fixed cost recovery defines a market equilibrium problem, which can then be solved using complementarity solvers, such as PATH.[5]

A. Consumers

Consumers are grouped into two types, including conventional consumers and prosumers, whose marginal benefit functions in node i, p_i^{con} and p_i^{pro}, are respectively represented by the following linear inverse demand functions:

$$p_i^{con}(d_i) = P_i^0 - \left(P_i^0/\left((1-\alpha_i)Q_i^0\right)\right) d_i, \forall i \qquad (1)$$

$$p_i^{pro}(l_i) = P_i^0 - \left(P_i^0/\left(\alpha_i Q_i^0\right)\right) l_i, \forall i \qquad (2)$$

where P_i^0 and Q_i^0 respectively represent the vertical and horizontal intercepts of the "horizontally aggregated" retail inverse demand function, $p_i^r(d_i+l_i) = P_i^0 - (P_i^0/Q_i^0)(d_i+l_i)$, as illustrated in Fig. 1. The quantities demanded by conventional consumers and prosumers are denoted by d_i and l_i, respectively. The parameter α_i is the fraction of prosumers at node i. Note that while α_i varies between 0 and 1, the aggregated demand does not change. The term τ denotes a volumetric charge for whole

[5]The theoretical properties of the model, including the existence and uniqueness of the solutions, are documented in [28].

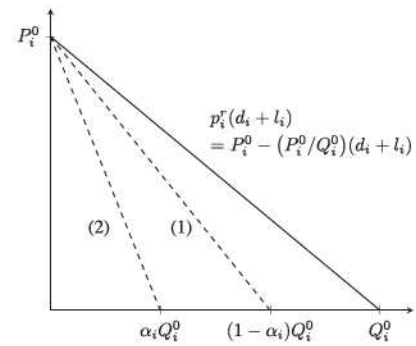

Fig. 1. An illustration of retail demand curves.

consumers, based on the fixed network or other types of stranded costs, such as renewable contracts, that need to be recovered. Thus, $p_i = p_i^{con} - \tau$ holds, where p_i is the wholesale power price in node i. In addition to a volumetric charge τ, customers in node i are subject to an income-dependent fixed charge ϕ_i, of which $(1-\alpha_i)\phi_i$ and $\alpha_i\phi_i$ are borne by conventional consumers and prosumers, respectively.

B. Prosumers

We posit that a prosumer maximizes its profit by deciding i) power to buy from or sell to the grid through node i, ii) consumption l_i given renewable output $K_i > 0$, and iii) generation g_i from the backup dispatchable technology with a cost $C_i^g(g_i)$.[6]

Net Metering: Under a net-metering system, there can be one meter recording the power injection ($z_i > 0$) and withdrawal ($z_i < 0$). Both types of transactions are subject to τ, which is regarded as a "subsidy" for sale ($z_i > 0$) or an end-user transmission tariff for purchase ($z_i < 0$). The optimization problem faced by the prosumer at node i under a net-metering system is displayed as follows:

$$\underset{l_i, g_i \geq 0, z_i}{\text{maximize}} (p_i + \tau) z_i + \int_0^{l_i} p_i^{pro}(m_i) dm_i - C_i^g(g_i) - \alpha_i \phi_i \qquad (3a)$$

subject to

$$z_i + l_i - K_i - g_i \leq 0 \quad (\delta_i), \qquad (3b)$$

$$g_i \leq G_i \quad (\kappa_i) \qquad (3c)$$

The corresponding KKT conditions of the prosumers' problem at node i under the net-metering system are collected for all nodes as in (4a)–(4e).

$$p_i + \tau - \delta_i = 0, \forall i \qquad (4a)$$

$$0 \leq l_i \perp P_i^0 - \frac{P_i^0}{\alpha_i Q_i^0} l_i - \delta_i \leq 0, \forall i \qquad (4b)$$

$$0 \leq g_i \perp -C_i^{g\prime}(g_i) + \delta_i - \kappa_i \leq 0, \forall i \qquad (4c)$$

$$0 \leq \delta_i \perp z_i + l_i - K_i - g_i \leq 0, \forall i \qquad (4d)$$

[6]One example is a company that acts as an aggregator managing more than 280 commercial, industrial, and residential customers operating in CAISO (California Independent System Operator) to provide energy and frequency regulation among other services [29].

$$0 \le \kappa_i \perp g_i - G_i \le 0, \forall i \tag{4e}$$

Net Billing: Under a net-billing system, two meters are implemented recording two quantities: power withdrawn from (z_i^b) and power injected into (z_i^s) the grid through node i, respectively. The power withdrawn from the grid is priced at $p_i + \tau^b$, where τ^b is always positive as a usual transmission tariff for end-users. The power injected into the grid is compensated by $p_i + \tau^s$, where τ^s can be either positive or negative. When $\tau^s > 0$, the prosumers effectively receive a "subsidy" in addition to the wholesale price. In the case when $\tau^s < 0$, it means that the prosumers are subject to a "tax" when selling power into the grid.[7] The optimization problem faced by the prosumer at node i is written as follows.

$$\underset{z_i^b, z_i^s, l_i, g_i \ge 0}{\text{maximize}} \, (p_i + \tau^s) z_i^s - \left(p_i + \tau^b\right) z_i^b + \int_0^{l_i} p_i^{pro}(m_i) dm_i - C_i^g(g_i) - \alpha_i \phi_i \tag{5a}$$

subject to

$$z_i^s - z_i^b + l_i - K_i - g_i \le 0 \quad (\delta_i), \tag{5b}$$

$$g_i \le G_i \quad (\kappa_i) \tag{5c}$$

Eq. (5b) makes sure that the net demand, $z_i^s - z_i^b + l_i$, is balanced with the sum of renewable and backup outputs. Eq. (5c) limits the backup output to be less than its capacity G_i. The corresponding KKT conditions of the prosumers' problem at node i under the net-billing system are collected for all nodes as in (6a)–(6f).

$$0 \le z_i^s \perp p_i + \tau^s - \delta_i \le 0, \forall i \tag{6a}$$

$$0 \le z_i^b \perp -p_i - \tau^b + \delta_i \le 0, \forall i \tag{6b}$$

$$0 \le l_i \perp P_i^0 - \frac{P_i^0}{\alpha_i Q_i^0} l_i - \delta_i \le 0, \forall i \tag{6c}$$

$$0 \le g_i \perp -C_i^{g\prime}(g_i) + \delta_i - \kappa_i \le 0, \forall i \tag{6d}$$

$$0 \le \delta_i \perp z_i^s - z_i^b + l_i - K_i - g_i \le 0, \forall i \tag{6e}$$

$$0 \le \kappa_i \perp g_i - G_i \le 0, \forall i \tag{6f}$$

C. The Independent System Operator

We assume that an ISO collects offers from producers and bids from utilities and maximizes the wholesale social surplus by deciding generation x_{ih} from power plant h in node i ($h \in H_i$) with a cost $C_{ih}(x_{ih})$, quantities demanded, d_i, and net injection to or withdrawal from the grid, y_i. Eq. (7b) limits the output x_{ih} to be less than its capacity X_{ih}. Eq. (7c) ensures that the total net injection/withdrawal in the system equals zero. Eqs. (7d)–(7e) describe that flow in link k is less than its transmission limit T_k. The term $PTDF_{ki}$ represents the power transfer distribution factors based on linearized-DC flows, similar to [30].

$$\underset{d_i, x_{ih} \ge 0, y_i}{\text{maximize}} \sum_i \int_0^{d_i} p_i(n_i)\, dn_i - \sum_{i, h \in H_i} C_{ih}(x_{ih}) \tag{7a}$$

subject to

$$x_{ih} - X_{ih} \le 0 \quad (\rho_{ih}), \ \forall i, h \in H_i, \tag{7b}$$

$$\sum_i y_i = 0 \quad (\theta), \tag{7c}$$

$$\sum_i PTDF_{ki} y_i \le T_k \quad (\lambda_k^+), \ \forall k, \tag{7d}$$

$$-\sum_i PTDF_{ki} y_i \le T_k \quad (\lambda_k^-), \ \forall k, \tag{7e}$$

The final constraint defines the nodal balance in each node with its dual variable giving the nodal power prices. This constraint is case-dependent, that is, (8) and (8*), representing the net-metering and the net-billing case, respectively.

$$y_i - \sum_{h \in H_i} x_{ih} - z_i + d_i = 0 \quad (p_i), \ \forall i, \tag{8}$$

$$y_i - \sum_{h \in H_i} x_{ih} - (z_i^s - z_i^b) + d_i = 0 \quad (p_i), \ \forall i \tag{8*}$$

These two conditions shift the demand by conventional consumers in the wholesale market operated by the ISO, given the decision of the prosumers. For example, if the prosumers sell $z_i > 0$ in node i, the effective "wholesale" demand is then reduced or shifts to the left by z_i through (8). Similarly, if the prosumers purchase $z_i < 0$ from the grid, the wholesale demand increases or shifts to the right by z_i, reflecting the demand from both the conventional consumers and the prosumers. The ISO's KKT conditions are then given as follows:

$$0 \le d_i \perp P_i^0 - \frac{P_i^0}{(1-\alpha_i) Q_i^0} d_i - (p_i + \tau) \le 0, \forall i \tag{9a}$$

$$0 \le d_i \perp P_i^0 - \frac{P_i^0}{(1-\alpha_i) Q_i^0} d_i - (p_i + \tau^b) \le 0, \forall i \tag{9a*}$$

$$0 \le x_{ih} \perp -C_{ih}'(x_{ih}) - \rho_{ih} + p_i \le 0, \forall i, h \in H_i \tag{9b}$$

$$-\theta + \sum_k PTDF_{ki}(\lambda_k^- - \lambda_k^+) - p_i = 0, \forall i \tag{9c}$$

$$0 \le \rho_{ih} \perp x_{ih} - X_{ih} \le 0, \forall i, h \in H_i \tag{9d}$$

$$\sum_i y_i = 0 \tag{9e}$$

$$0 \le \lambda_k^+ \perp \sum_i PTDF_{ki} y_i - T_k \le 0, \forall k \tag{9f}$$

$$0 \le \lambda_k^- \perp -\sum_i PTDF_{ki} y_i - T_k \le 0, \forall k \tag{9g}$$

$$(8) \quad \text{or} \quad (8^*).$$

Eqs. (9a) and (9a*) state that conventional consumers evaluate its marginal benefit against the retail price, that is, the wholesale price p_i and the transmission charge τ or τ^b, when deciding their quantity demand, d_i.

[7] It could also be other types of fixed or sunk costs that a utility attempts to recover, e.g., renewable procurement cost, those associated with discounts to low-income households, legacy stranded costs, or even drinking water related projects.

D. Fixed Cost Recovery

While each participant's optimization problem represents its behavior in the power market, (10) and (10*) help determine the transmission charge to reimburse to the transmission owners for their revenue adequacy T for net-billing and net-metering, respectively. Note that T is a parameter, a similar setup as in [31].

$$\sum_i (-z_i + d_i)\,\tau + \sum_i \phi_i = \mathrm{T} \tag{10}$$

$$\sum_i \left(-z_i^s \tau^s + z_i^b \tau^b + d_i \tau^b\right) + \sum_i \phi_i = \mathrm{T} \tag{10*}$$

The entire problem is then solved by the collection of KKT conditions and the condition for revenue adequacy. For the net-metering case, they include (4a)–(4e), (8), (9a)–(9g), and (10). For the net-billing case, they constitute (6a)–(6f), (8*), (9a*)–(9g), and (10*).

E. Energy Expenditure Incidence

The energy expenditure incidence in the current context is defined as the proportion of a consumer's income that is used to pay for electricity. (11) and (12) define the incidence for conventional consumers and prosumers in location i, respectively:

$$incidence_i^{con} = \frac{p_i^r d_i + (1-\alpha_i)\phi_i}{I_i^{con}} \tag{11}$$

where $p_i^r d_i$ and $(1-\alpha_i)\phi_i$ denote the retail load payment and the fixed charge borne by conventional consumers, respectively. The denominator I_i^{con} gives the total incomes of those consumers. The incidence for prosumers in node i is defined as follows:

$$incidence_i^{pro} = \frac{p_i^r z_i^* + \alpha_i \phi_i + C_i(g_i)}{I_i^{pro}} \tag{12}$$

where $z_i^* = -z_i$ and $z_i < 0$, that is, purchase from the grid, for net metering and $z_i^* = z_i^b$ for net-billing case, respectively. The terms, $\alpha_i\phi_i$, $C_i(g_i)$, and I_i^{pro} represent prosumers' fixed charge, costs of self-generation, and total incomes, respectively.

III. Numerical Case Study

A. Setup

To illustrate the effects of different pricing schemes, we apply the models developed in section II to a case study considering a three-node network with three firms, ten generating units, and three transmission lines. The data used in the case study is indicated in the appendix. This setup is sufficiently general because it allows firms to own facilities and to compete across different locations.[8] Our analysis assumes that a daily fixed cost of \$100 k needs to be reimbursed to the utility. For a meaningful comparison, we first establish the baseline by solving a cost-minimizing problem subject to fixed demand, assuming a demand elasticity equal to 0.05 to recover P_i^0 and Q_i^0. The

TABLE I
DEMOGRAPHIC DATA

Node	Income[i] [\$/year]	Households[i] []	Prosumers[ii] [%]	Daily Demand[ii] [kWh]
A	106,113	15,333	20	30
B	76,109	22,400	0	25
C	51,032	23,000	0	20

[i]: Authors' calculation; [ii]: Based on 2015 RECS data.

consumers are grouped into three income levels, that is, high, medium, and low, residing in nodes A, B, and C, respectively.[9] The baseline daily demand of the low-income group is assumed to be 20 kWh. The daily demand of the medium- and high-income groups are assumed to be 25% and 50% larger than the low-income group, broadly consistent with the data from the 2015 RECS survey. Given the assumed fixed demand in each node, we then recover the number of households in each income group. (Proportion of households among income groups are also compatible with the 2015 RECS results.) The income level is obtained by assuming that electricity expenditure is 1.5% of the income in each group.[10] Finally, based on RECS 2015, we assume that 20% of the households in high-income group own rooftop solar energy with a capacity of 8 KW each household or 25 MW in total. A backup or on-site generator or an energy storage of 25 MW is assumed.

The analysis first focuses only on volumetric charges. We then examine a hybrid system with both income-based and volumetric charge to recover the utility's fixed costs. Of course, utilities prefer to recover their fixed costs through a fixed charge as it does not tie to customers' consumption level, rendering significant revenue certainty. Under the net-billing case, we also posit that $\tau^s = -0.5\tau^b < 0$. Thus, selling back to the grid by prosumers is subject to a fee, contributing to the fixed cost recovery in (10*). Since the prosumer's net position is affected by the intermittency and uncertainty of renewable outputs, we consider two scenarios with aggregated DERs outputs from prosumers equal to 25 MW and 150 MW, representing the cases that prosumers are in a "buying" and "selling" position, respectively.[11] Note that our intent for the case study is mailnly to illustrate the impacts on the energy expenditure, focusing on the qualitative and meaningful aspect/direction of changes rather than the magnitude of the effects.

B. Results: Volumetric Charge

Results of a volumetric charge for the case with renewable output equal to 25 MWh and 150 MWh are reported in Tables II and III, respectively. Each table includes three parts related to

[8]The three-node network is the simplest that allows for looped flows, which is crucial in the electric power sector. Our intention is to analyze the impacts of different pricing policies on the energy expenditure incidence. Thus, we believe that this setup is reasonable and sufficient for our purposes.

[9]While there is income heterogeneity among consumers who live in the same state, state-level median incomes and average power prices are highly correlated as consumers who cannot afford high energy prices (and other expenses) would move somewhere more affordable [15].

[10]This represents the "energy equity" case at the baseline. The 1.5% is at the lower end based on 2015 RECS. However, our interest lies on the relative changes of the energy incidence when the power sales by prosumers are subject to different tariff designs. We believe that this assumption is not essential.

[11]Each scenario was solved less than 1 s using a MacBook Pro with a 2.8 GHz Intel Core i7 CPU and 16 GB RAM. Thus, scaling up to solve a larger case study, e.g., IEEE 118-bus system, is unlikely an issue, but will make exposition less explicable as it will require arbitrarily grouping nodes and assigning income levels, possibly ending up with too many income groups.

TABLE II
RESULTS OF 20% PROSUMERS AND 25 MWH RENEWABLE CASE WITH A VOLUMETRIC TARIFF

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [$/MWh]			70.01			70.01 (-35.01)
Prosumer's sale(+)/buy(-) [MWh]			-41.8			-41.8
Prosumer's load [MWh]			91.9			91.9
Backup generation [MWh]			25.0			25.0
Prosumer surplus [$K]			77.3			77.3
Prosumer incidence [%]			0.85			0.85
Variables\Nodes	A	B	C	A	B	C
Conventional demand [MWh]	367.5	558.9	458.4	367.5	558.9	458.4
Power price [$/MWh]	77.5	57.4	37.3	77.5	57.4	37.3
Consumer surplus [$K]	285.5	321.0	170.4	285.5	321.0	170.4
Consumer incidence [%]	1.52	1.53	1.53	1.52	1.53	1.53
Conventional generation [MWh]			1,384.8			1,384.8
Total consumer surplus [$K]			776.9			776.9
Producer surplus [$K]			13.6			13.6
ISO's revenue [$K]			1.8			1.8
Wholesale surplus [$K]			792.3			792.3
Total social surplus [$K]			869.7			869.7

TABLE III
RESULTS OF 20% PROSUMERS AND 150 MWH RENEWABLE CASE WITH A VOLUMETRIC TARIFF

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [$/MWh]			77.39			70.92 (-35.46)
Prosumer's sale(+)/buy(-) [MWh]			83.5			51.8
Prosumer's load [MWh]			91.5			98.2
Backup generation [MWh]			25.0			0.0
Prosumer surplus [$K]			96.3			87.7
Prosumer incidence [%]			0.16			0.00
Variables\Nodes	A	B	C	A	B	C
Conventional demand [MWh]	366.0	555.6	454.0	367.5	558.7	457.9
Power price [$/MWh]	76.3	56.8	37.2	76.6	56.9	37.2
Consumer surplus [$K]	283.3	317.2	167.1	285.5	320.7	170.1
Consumer incidence [%]	1.57	1.60	1.62	1.52	1.53	1.54
Conventional generation [MWh]			1375.6			1,332.3
Total consumer surplus [$K]			767.6			776.3
Producer surplus [$K]			12.9			13.1
ISO's revenue [$K]			1.8			1.8
Wholesale surplus [$K]			782.3			791.2
Total social surplus [$K]			878.6			878.8

prosumers, the wholesale market, and the distribution of economic rent in the upper, middle, and lower panels, respectively. Table II indicates that prosumers are in a buying position when renewable output is 25 MWh, purchasing 41.8 MWh from the main grid, together with their self-generation of 25 MWh to satisfy its load of 91.9 MWh. Thus, self-supply accounts for roughly 50%, effectively lowering its energy incidence to 0.85%. The generation from the wholesale market is 1384.8 MWh, of which 1292.9 MWh is supplied to conventional consumers. The decline in prosumers' dependence on the main grid shifts the burden of recovering fixed costs to consumers, leading to an increase of the energy incidence of low-, medium-, and high-income groups from 1.5% to 1.53%, 1.52%, and 1.52%, respectively. Note that as the prosumers act as a buyer, both net-billing and net metering cases produce the same outcomes.

Turning to the case of renewable output equal to 150 MWh in Table III under the net-metering case. The solutions suggest that prosumers become a seller in this situation; along with 25 MWh of self-production, they sell 91.5 MWh into the grid, reducing their energy incidence to 0.16%.[12] This is in contrast to the net-billing case, where the incidence of prosumers drops to zero.[13] The reason is that being able to sell energy at the retail rate under the net-metering case incites prosumers to produce more (25 MWh vs 0 MWh) from backup units (either on-site or storage), and sell more 31.7 MWh (=83.5-51.8), and consume less (91.5 MWh vs 98.2 MWh). On the other hand, selling into the grid under the net-billing case obtains a price that is less than the retail rate, thereby discouraging self-generation and encouraging self-consumption.

[12]Self-generation also incurs costs so that the energy incidence does not drop to zero even they do not rely on the grid at all.

[13]Had the revenue from selling power to the grid been allowed to offset expenses in (12), the incidence could actually be negative.

TABLE IV
RESULTS OF 20% PROSUMERS AND 25 MWH RENEWABLE CASE WITH A HYBRID POLICY OF 50% INCOME-BASED AND 50% VOLUMETRIC CHARGE

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [$/MWh]			33.85			33.85 (-16.92)
Prosumer's sale(+)/buy(-) [MWh]			-44.0			-44.0
Prosumer's load [MWh]			94.0			94.0
Backup generation [MWh]			25.0			25.0
Prosumer surplus [$K]			74.3			74.3
Prosumer incidence [%]			1.21			1.21
Variables\Nodes	A	B	C	A	B	C
Fixed Charge [$/household.day]	1.48	0.73	0.48	1.48	0.73	0.48
Conventional demand [MWh]	376.0	576.4	480.6	376.0	576.4	480.6
Power price [$/MWh]	77.7	57.6	37.6	77.7	57.6	37.6
Consumer surplus [$K]	280.7	325.0	176.4	280.7	325.0	176.4
Consumer incidence [%]	1.69	1.48	1.41	1.69	1.48	1.41
Conventional generation [MWh]			1,433.0			1,433.0
Total consumer surplus [$K]			782.1			782.1
Producer surplus [$K]			14.0			14.0
ISO's revenue [$K]			1.8			1.8
Wholesale surplus [$K]			797.9			797.9
Total social surplus [$K]			872.3			872.3

However, the profits earned by the prosumers remain higher under the net-metering case due to a larger size of financial reward when selling power into the grid. Overall, the energy incidence of all the income groups under the net-billing scheme is lower than that of the net-metering scheme. In other words, selling power at the prevailing retail rate, as in the case of net-metering, effectively increases the energy procurement costs for consumers who can only rely on the grid as the energy source, leading to higher incidences across all income groups. Finally, while the prosumer's surplus is lower under the net-billing case, it is more than offset by the increase in the consumers surplus due to lower volumetric charge and the retail rate, leading to a higher social surplus.

C. Results: Hybrid Policy

We now focus on the cases with policies entailing both income-based fixed and volumetric charges. We concentrate our discussions on the impacts of hybrid policies on the consumers and prosumers energy expenditure incidence. With an income-based fixed charge to recover 50% of the fixed costs when renewable output equals 25 MWh, the volumetric charge drops from $70.01/MWh in Table II to $33.85/MWh in Table IV. Since the income-based charge favors less affluent groups, it reduces the energy incidence of both medium- and low-income groups from 1.53% to 1.48% and from 1.53% to 1.41%, respectively. However, given that income of the consumers who reside in node A is on par with the prosumers, their energy incidence increases from 1.52% to 1.69%, a fairly significant increase. For prosumers, the energy incidence increases from 0.85% to 1.21% as they bear larger fixed costs due to their income level.

Impacts on the economic rent distribution are also noteworthy. While producers' profit is directly tied to power prices at the wholesale market, consumers are instead impacted by the retail power prices. The "retail power price" entails two parts: volumetric tariff and (wholesale) power price. Volumetric tariff declines under the hybrid policy with an income-based fixed change of 50%.. This decline is more than offset by an increase in wholesale power price induced by increased power purchase of prosumers from the grid: 41.8 MWh in Table II and

TABLE V
RESULTS OF 20% PROSUMERS AND 150 MWH RENEWABLE CASE WITH A HYBRID POLICY OF 50% INCOME-BASED AND 50% VOLUMETRIC CHARGE

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [\$/MWh]			37.01			34.03 (-17.01)
Prosumer's sale(+)/buy(-) [MWh]			81.1			72.0
Prosumer's load [MWh]			93.9			97.1
Backup generation [MWh]			25.0			19.1
Prosumer surplus [\$K]			88.4			84.2
Prosumer incidence [%]			0.67			0.63
Variables\Nodes	A	B	C	A	B	C
Fixed Charge [\$/household.day]	1.48	0.73	0.48	1.48	0.73	0.48
Conventional demand [MWh]	375.5	575.1	478.6	376.2	576.6	480.5
Power price [\$/MWh]	76.5	57.0	37.6	76.6	57.1	37.6
Consumer surplus [\$K]	279.9	323.6	174.8	281.0	325.3	176.3
Consumer incidence [%]	1.71	1.51	1.45	1.68	1.47	1.41
Conventional generation [MWh]			1,429.3			1,361.3
Total consumer surplus [\$K]			778.3			782.6
Producer surplus [\$K]			13.3			13.3
ISO's revenue [\$K]			1.8			1.8
Wholesale surplus [\$K]			793.3			797.7
Total social surplus [\$K]			881.8			881.9

TABLE VI
RESULTS OF 20% PROSUMERS AND 25 MWH RENEWABLE CASE WITH A HYBRID POLICY OF 80% INCOME-BASED AND 20% VOLUMETRIC CHARGE

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [\$/MWh]			13.28			13.28 (-6.64)
Prosumer's sale(+)/buy(-) [MWh]			-45.2			-45.2
Prosumer's load [MWh]			95.2			95.2
Backup generation [MWh]			25.0			25.0
Prosumer surplus [\$K]			72.5			72.5
Prosumer incidence [%]			1.43			1.43
Variables\Nodes	A	B	C	A	B	C
Fixed Charge [\$/household.day]	2.37	1.17	0.76	2.37	1.17	0.76
Conventional demand [MWh]	389.8	586.3	493.2	389.8	586.3	493.2
Power price [\$/MWh]	77.9	57.8	37.8	77.9	57.8	37.8
Consumer surplus [\$K]	277.5	327.1	179.7	277.5	327.1	179.7
Consumer incidence [%]	1.79	1.45	1.32	1.79	1.45	1.32
Conventional generation [MWh]			1,460.3			1,460.3
Total consumer surplus [\$K]			784.3			784.3
Producer surplus [\$K]			14.3			14.3
ISO's revenue [\$K]			1.8			1.8
Wholesale surplus [\$K]			800.4			800.4
Total social surplus [\$K]			873.0			873.0

TABLE VII
RESULTS OF 20% PROSUMERS AND 150 MWH RENEWABLE CASE WITH A HYBRID POLICY OF 80% INCOME-BASED AND 20% VOLUMETRIC CHARGE

Variables\Policies	Net-metering			Net-billing		
Volumetric charge [\$/MWh]			14.50			13.33 (-6.67)
Prosumer's sale(+)/buy(-) [MWh]			79.8			78.5
Prosumer's load [MWh]			95.2			96.5
Backup generation [MWh]			25.0			25.0
Prosumer surplus [\$K]			83.9			82.2
Prosumer incidence [%]			0.97			0.97
Variables\Nodes	A	B	C	A	B	C
Fixed Charge [\$/household.day]	2.37	1.17	0.76	2.37	1.17	0.76
Conventional demand [MWh]	380.8	586.0	492.4	381.1	586.6	493.2
Power price [\$/MWh]	76.6	57.2	37.8	76.6	57.2	37.8
Consumer surplus [\$K]	277.5	326.8	179.1	278.0	327.5	179.7
Consumer incidence [%]	1.79	1.46	1.34	1.78	1.44	1.33
Conventional generation [MWh]			1,459.2			1,382.3
Total consumer surplus [\$K]			783.4			785.1
Producer surplus [\$K]			13.5			13.5
ISO's revenue [\$K]			1.7			1.7
Wholesale surplus [\$K]			798.7			800.4
Total social surplus [\$K]			882.6			882.6

44.0 MWh in Table IV, leading to a decline in retail power prices in Table IV. The higher wholesale prices in Table IV benefit producers whose surplus increases by \$0.4 k (=\$14.0k–\$13.6 k). On the other hand, the consumers' surplus is jointly affected by the retail power prices and the income-base fixed charge. While the consumer surplus increases as a result of lower retail power prices, it is then negatively affected by the income-based fixed charge. Overall, the high-income consumers in node A become worse-off, while the medium- and low-income groups in nodes B and C are better-off in Table IV. The changes in energy expenditure incidence could also lead to the same conclusion. A similar observation also emerges when comparing Table III to Table V.

Outcomes when renewable output increases to 150 MWh under 50% between both income-based and volumetric charges are reported in Table V. The results from two pricing schemes diverge as the prosumers are now selling power to the grid. The decline in the volumetric charge for prosumers under the net-billing case benefits prosumers since their sales are tied to $p_i + \tau^s$ with $\tau^s < 0$. They increase their sales to the grid from 51.8 MWh in Table III to 72.0 MWh in Table V. On the other hand, the prosumers reduce their power sales into the grid under the net-metering case as their sales are priced to $p_i + \tau$.

Turning to the energy incidence of prosumers. It is 0.67% and 0.63% for net-metering and net-billing, respectively, higher than that of 0.16% and 0.00% in Table III as now a 50% of fixed cost is allocated based on income. A larger incidence facing the prosumers under these pricing schemes is due to cost associated with backup generators or storage, where it produces 25 MWh and 19.1 MWh of power, respectively. Given that output from the backup generator or storage under the net-billing case is less than that of the net-metering case, its energy incidence is also lower compared to the net-metering case. Taking advantage of the retail tariff when selling power to the grid, the prosumers' surplus of \$88.4 K is higher than the net-billing case of \$84.2K. Overall, allocating more fixed cost recovery to the income-based fixed costs worsens the energy incidence the high-income group face in node A as they are treated equivalently as the prosumers. Their energy incidence increases from 1.57% and 1.52% under the volumetric charge in Table III to 1.71% and 1.68% under the hybrid policy in Table V.

We next examine a more extreme case where 80% of fixed-cost recovery is based on an income-based fixed charge. Increasing the fixed charge to 80% of the fixed costs in Tables VI–VII further tilts the energy incidence favoring medium- and low-income customers. Under this pricing scheme, the volumetric charge drops significantly to \$13.28/MWh in Table VI compared to \$33.85/MWh under the equal allocation case in Table IV. Compared to Table IV, the prosumers' energy incidence increases from 1.21% to 1.43% in Table VI. The energy incidence of both medium- and low-income groups reduces accordingly, and is more discernible for the low-income group by 0.9% from 1.41% to 1.32%. As expected, the high-income group in node A is negatively impacted, leading to an increase of the incidence from 1.69% to 1.79%.

Table VII reports the last scenario when the renewable output equals 150 MWh under 80% of income-based fixed costs allocated. This represents the most extreme case where the high-income group, including both prosumers and consumers in node A, are responsible for a large share of fixed costs. The energy incidence facing prosumers increases from 0.67% and 0.63% in Table V under net-metering and net-billing cases to 0.97% for both cases in Table VII. Not surprisingly, the pricing scheme further benefits low- and medium-income customers as their incidences reduce from 1.45% (1.41%) and 1.51% (1.47%) in Table V under net-metering (net-billing) to 1.34% (1.33%) and 1.46% (1.44%) in Table VII, respectively. Finally, the worst impacts occur in the high-income customers in node A whose

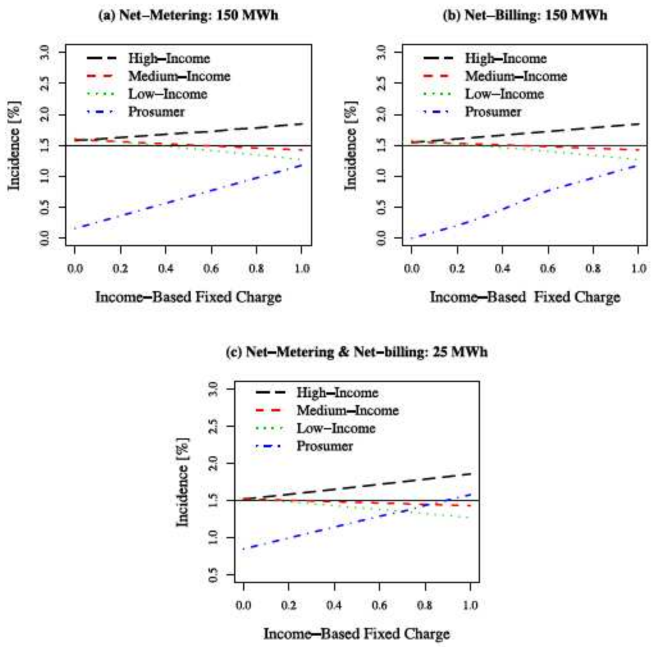

Fig. 2. Plots of customers' energy expenditure incidence against the fraction of income-based allocation.

incidence increases to 1.79% and 1.78% under net-metering and net-billing case, respectively.

D. Results: Sensitivity Analysis

In this section, we report the results from a sensitivity analysis that changes the fraction of income-based allocation from 0% to 100%. Figs. 2(a)-(b) and (c) illustrate the cases of 150 MWh and 25 MWh cases, respectively. Given Fig. 2(c) (both net-metering and net-billing case produce the same outcomes), and the fact that Figs. 2(a) and 2(b) are not discernible, it suggests that impact on the energy incidence is compatible or only marginally different between the two pricing schemes under the scenarios that we considered. Not surprisingly, an increase in x-axis or the fraction of income-based allocation benefits low- and medium-income groups as their incidences decline accordingly. Interestingly, not until a full income-based allocation, prosumers' incidence remains below the baseline of 1.5% under 150 MWh case. This demonstrates the prosumers' advantage to shield themselves when there are abundant renewables. Under the 25 MWh case, the prosumers act as a buyer, purchasing energy from the main grid, and are thus exposed to the market prices. When the income-based fraction is more than 0.2, the incidence of low- and medium-income groups decline to below the baseline of 1.5%. Among all the groups, the high-income group experiences the worst impact as its incidence stays above the baseline as long as certain income-based fixed cost is applied. This suggests that to level the impact among all the groups, a (re)connection or a grid access fee can be administrated by the utilities to the prosumers, which can be used to offset the cost incurred by the high-income group.

IV. Conclusion

Recovering non-convex cost has historically presented a significant regulatory challenge for utilities in designing an electricity tariff. While most concerns are typically placed on economic efficiency and incentive for energy conservation, an equally important aspect is their impacts on the energy expenditure incidence among different income groups. The situation is further exacerbated by the presence of prosumers who are among most affluent income groups, taking advantage of electricity tariff, adopting new technologies, and optimizing their self-interests.

This study analyzes the energy incidence under a volumetric charge and a hybrid scheme, which also includes an income-based fixed charge when considering a net-metering and a net-billing system. We demonstrate that a volumetric approach to recover fixed costs based on power consumption is likely to be regressive. Among the two pricing schemes, the net-metering scheme is more regressive than net-billing case. More specifically, under the net-metering policy, prosumers act as producers selling energy into the grid at the prevailing "retail price." This effectively increases the retail and wholesale energy prices, making consumers worse-off relative to the net-billing case. On the contrary, under the net-billing policy, prosumers sell into the grid at a price lower than the prevailing wholesale price (by a difference equal to 0.5τ), thereby shifting the market supply curve to the right and lowering the power prices. Moreover, when prosumers are penalized to over-contribute to fixed cost recovery in net-billing policy, it can incidentally encourage prosumers' over-self-consumption, thereby leading to lower total social surplus, similar to the finding in [31].

Whether the FERC 2222 can lead to more efficient resource allocation and make the society better off is an empirical question that will take years to answer. For the type of the fixed charge considered herein, it may improve the energy equity facing medium- or low- income groups, unfortunately, at the expense of high-income conventional consumers. Yet, a fine-tuned policy that also features an annual (re)connection or grid access fees for prosumers, one type of cross-subsidy from prosumers to the high-income group or to the group sharing a similar trait (e.g., income) as the prosumers to which the fixed charge is applied, may be able to improve overall energy equity.

Since we focus on a short-run analysis, which does not consider the interaction between power system operation and expansion decisions, e.g., [30], it is subject to several limitations. Specifically, the second feedback or time-varying rate feedback discussed in [11] is not considered in our paper. However, if the second effect offsets the benefit of avoiding fixed-cost payment, we believe that it can further reduce the economic incentive of marginal consumers in the high-income group to convert to prosumers under our proposed fine-tuned policy. That is, while the policy is expected to improve conventional consumers' energy incidence, it may offset their economic incentive to adopt DERs, slowing the development of non-utility DERs. Moreover, the impact on incidence can also be affected by the price elasticity of demand. When demand is less price-responsive, consumers cannot forego consumption in response to higher power prices, leading to higher consumption with a lower volumetric tariff and incidence. Finally, the conclusion herein can be applied to the context of other emerging technologies, such as electric vehicle recharging stations.

TABLE A1
INTERCEPTS OF INVERSE DEMAND FUNCTIONS OF THE THREE-NODE EXAMPLE

Node	P_i^0 (\$/MWh)	Q_i^0 (MWh)
A	228	1,080
B	170	660
C	112	1,146

TABLE A2
GENERATOR DATA OF THE THREE-NODE EXAMPLE

Plant	Intercept (\$/MWh)	Slope (\$/MWh^2)	Capacity (MW)	Node (unitless)
1	38	0.02	250	A
2	35.72	0.03	200	A
3	36.8	0.04	450	A
4	15.52	0.01	150	B
5	16.2	0.02	200	B
6	0	0.001	200	B
7	17.6	0.02	400	C
8	16.64	0.01	400	C
9	19.4	0.01	450	C
10	18.6	0.02	200	C

APPENDIX A
DATA

We document the data used in the analysis, particularly regarding demand and generators in Tables A1–A2, respectively. We assume linear demand and linear marginal costs. As in [32], node A is designed to resemble a power system mainly comprising natural gas plants, while node B includes a hydropower with almost zero variable production cost, and node C consists of coal plants with low production costs.

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Yihsu Chen (Senior Member, IEEE) is a Professor of Technology Management with the Department of Electrical and Computer Engineering, Baskin School of Engineering, the University of California Santa Cruz (UCSC). He is also affiliated with Department of Environmental Studies, Social Sciences Division, UCSC.

Makoto Tanaka is a Professor with the National Graduate Institute for Policy Studies (GRIPS) in Japan. He gained industrial experience working with Tokyo Electric Power Co. (TEPCO) before getting into academia. He focuses on the interdisciplinary fields of operations research and economic analysis with special interests in the energy and environmental policy issues.

Ryuta Takashima received the Ph.D. degree in quantum engineering and systems science from the University of Tokyo, Japan. He is currently a Professor of engineering economics with the Department of Industrial Administration, Tokyo University of Science, Japan. His research interests include energy economics, especially the application of operations research, finance and economics methods to enable the investment and operation of power generations, and energy and environmental policy.