On the Design of Distributed Generation Policies:
Are Common Net Metering Policies Optimal?

by

David P. Brown* and David E. M. Sappington**

Abstract

Electricity customers who install solar panels often are paid the prevailing retail price for the electricity they generate. We show that this rate of compensation typically is not optimal. A payment for distributed generation (w) that is below the retail price of electricity (r) often will induce the welfare-maximizing level of distributed generation (DG) when centralized generation and DG produce similar (pollution) externalities. However, w can optimally exceed r when DG entails a substantial reduction in externalities. We demonstrate that the optimal DG compensation policy varies considerably as industry conditions change, and that a requirement to equate w and r can reduce aggregate welfare substantially and can generate pronounced distributional effects.

Keywords: electricity pricing, distributed generation, net metering

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* Department of Economics, University of Alberta, Edmonton, Alberta T6G 2H4 Canada
   (dpbrown@ualberta.ca).

** Department of Economics, University of Florida, Gainesville, FL 32611 USA
   USA (sapping@ufl.edu).

1   Introduction

Distributed generation of electricity (i.e., the "generation of electricity from sources that are near the point of consumption, as opposed to centralized generation sources such as large utility-owned power plants")[1] is already pervasive in many countries and is expanding rapidly throughout the world.[2] Distributed generation (DG) is popular in part because it can reduce electricity distribution costs (by moving generation sites closer to final consumers), improve system reliability (by ensuring multiple production sources), limit the amount of capacity required at the primary production site, and reduce generation externalities (e.g., carbon emissions).[3] One popular form of DG involves the production of electricity from solar panels installed on the roofs of residential buildings.[4] Homeowners incur the expense of the panels in order to produce electricity which they either consume or sell to the electric utility.

More than four-fifths of U.S. states have implemented net metering policies to encourage DG in their electricity sectors.[5] Under net metering, the electric utility compensates a customer at the end of each billing period for the customer's net production of electricity (i.e., the difference between the customer's production and consumption of electricity) during the period. Compensation typically reflects the prevailing retail price of electricity,[6] although in principle it can be set at a different level.[7]

Some states have also adopted feed-in tariffs to promote DG.[8] Under feed-in tariffs, the

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[1]American Council for an Energy-Efficient Economy (2014).

[2]The World Alliance for Decentralized Energy (2014) summarizes the extent of distributed generation around the world.

[3]See Weissman and Johnson (2012), for example.

[4]The Solar Electric Power Association (2013) reports that "Between 2011 and 2012, the number of newly installed solar net metering systems [in the U.S.] increased from 61,400 to 89,620 – a 46% annual growth rate."

[5]See the American Public Power Association (2013), Linvill et al. (2013), and the Solar Electric Power Association (2013), for example.

[6]Under many net metering policies, positive net production of electricity in a given billing period is subtracted from electricity consumption in the next billing period, thereby effectively providing compensation for positive net production that reflects the prevailing retail price of electricity.

[7]For example, the DG compensation might reflect the utility's avoided cost of producing electricity. "Net purchase and sale" policies are similar to net metering policies, but allow for continual measurement of and compensation for any net production of electricity.

[8]Linvill et al. (2013).

utility compensates a customer at a specified rate for all of the electricity he generates. In particular, this rate of compensation – which can differ from the prevailing retail price of electricity – is paid even if a customer's consumption of electricity exceeds his production of electricity.[9]

Although many net metering and feed-in tariff policies have been implemented, controversy about the appropriate compensation for DG abounds.[10] Some contend that, in light of its many benefits, DG should be encouraged by providing compensation that exceeds the prevailing retail price of electricity. Others argue that compensation for DG at the prevailing retail price of electricity is unduly generous – and so compels customers who do not engage in DG to subsidize those who do – for at least three reasons. First, the prevailing retail price of electricity typically exceeds the system-wide cost saving that a unit of distributed electricity generation provides. This saving is the cost the primary production source (the utility) avoids when it is not required to produce the electricity generated by the distributed source.[11] Second, compensation at the retail rate does not charge customers who generate more electricity than they consume for the relevant cost of distributing the excess electricity to other consumers. Third, the electricity supply from several forms of DG (including solar and wind generation) is unreliable because the amount of electricity generated depends heavily on prevailing weather conditions.[12]

Despite the prevalence of DG compensation policies, the economic literature provides little guidance on their optimal design. Several studies (e.g., Couture and Gagnon, 2010)

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[9]Feed-in tariffs generally are set at a specified level for an extended period of time (e.g., ten to twenty years) and so do not change (explicitly or implicitly) as the retail price of electricity changes. The long duration of the specified compensation is intended to encourage investment in DG by guaranteeing the financial payoff from the investment for a long period of time. Yamamoto (2012) provides a useful discussion of net metering, feed-in tariff, and net purchase and sale policies.

[10]Cardwell (2012), Kind (2013), Raskin (2013), and Than (2013), among others, review the key arguments in the debate regarding the merits of these policies.

[11]Gordon et al. (2006, p. 28) observe that the proper DG "payment should be based on the wholesale power costs that the utility avoids as a result of the availability of power from the DG customer/generator."

[12]Consequently, such DG production may not permit the utility to reduce its generating capacity much, if at all. Furthermore, in light of DG "intermittency," the utility may employ a technology that generates substantial losses from environmental externalities to address the transient excess demand for electricity that arises when DG supply falls below its expected level.

discuss the strengths and weakness of different DG policies. Some studies (e.g., Darghouth et al., 2011, 2014; Poullikkas, 2013) simulate the effects of different DG policies. A few studies (e.g., Yamamoto, 2012) model some elements of the critical design problem, but do not fully characterize an optimal DG policy.[13]

The purpose of this research is to begin to fill this void in the literature by characterizing the optimal DG compensation policy in a simple setting where a regulator can set a unit retail price (r) for electricity purchased from the utility and the compensation (w) the utility must deliver to customers for each unit of electricity they generate.[14] The regulator may also be able to set a fixed retail charge (R) for the right to purchase electricity from the utility. Some customers ("D customers") can install DG capacity at their own expense while others ("N customers") do not have this opportunity (perhaps because of limited financial resources or local zoning ordinances that prohibit the installation of solar panels on residential roof tops, for example). Installed DG capacity produces a stochastic supply of electricity. The utility adjusts its electricity supply to meet market demand after observing the amount of electricity supplied via DG. The regulator chooses her policy instruments to maximize the difference between consumer welfare and social losses from environmental externalities (e.g., pollution and climate change) while ensuring non-negative (extranormal) profit for the utility.

We find that when the regulator can set w, r, and R, the optimal value of w ensures that the rate at which expected DG payments increase as DG capacity expands is equal to the sum of the corresponding rates at which: (i) the utility's generation, transmission, and distribution costs decline; and (ii) social losses from environmental externalities decline as

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[13]Yamamoto (2012) assumes the government first chooses a retail price for electricity and then sets the DG compensation rate to ensure a specified number of customers invest in a fixed level of DG capacity. Consumers do not consider the potential reduction in their electricity bills when they decide whether to install this capacity.

[14]Smart meters permit the separate measurement of a customer's consumption and generation of electricity (International Renewable Energy Agency, 2013). The Institute for Electric Efficiency (IEE, 2012) reports that 36 million smart meters had been installed as of 2012. The IEE also forecasts that 65 million U.S. households (more than half of all such households) will have smart meters by the end of 2015.

DG replaces centralized generation of electricity. r is optimally set to minimize expected weighted deviations between r and the utility's marginal cost of generating electricity.[15]

The optimal values of w and r typically differ. r optimally exceeds w, for example, when losses from environmental externalities associated the utility's electricity production are sufficiently limited and the utility's marginal cost of generating electricity is sufficiently insensitive to the scale of production. In contrast, w optimally exceeds r when, for instance, the utility primarily employs coal-powered units to produce electricity whereas D customers employ solar panels. In this case, production by the utility generates considerably greater losses from environmental externalities than does production by D customers. Consequently, the regulator often sets w above r to encourage D customers to expand their investment in DG capacity that will generate "clean energy."

Just as the properties of the optimal DG compensation policy can vary with environment in which the policy is implemented, so can the effects of a "net metering mandate" (that requires w and r to be identical). To illustrate, first consider a setting in which the optimal value of w (denoted w^*) is less than the optimal value of r (denoted r^*). A net metering mandate in this setting can produce a unit DG payment and retail price (r_n) that exceeds both w^* and r^*. Although the increase in r harms all customers, D customers can experience an overall increase in welfare due to the increased DG compensation they receive. The increase in w also can induce increased DG investment and output, with a corresponding reduction in losses from environmental externalities.

In contrast, when w^* exceeds r^*, a net metering mandate can result in an r_n below both w^* and r^*. The reduction in r benefits all customers. However, D customers can experience an overall reduction in welfare due to the reduced DG compensation they receive. The reduction in w also can discourage investment in DG capacity and result in increased social losses from environmental externalities.

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[15]The weights reflect the price elasticities of demand for D and N customers. If fixed retail charges (R) are not feasible and if the identified values of w and r generate negative expected profit for the utility, then r is increased and w is decreased to ensure the utility's solvency.

Thus, in contrast to popular claims during policy debates, one cannot state unequivocally that a net metering mandate always benefits D customers and harms N customers. One also cannot state conclusively that such a mandate will reduce social losses from environmental externalities. One can conclude, though, that a net metering mandate typically reduces aggregate expected welfare below the level that can be achieved in the absence of the mandate. Furthermore, the welfare reduction can be substantial, and the distributional effects of the mandate can be particularly pronounced.

We develop and explain these findings as follows. Section 2 describes our formal model. Section 3 characterizes the optimal policy in the benchmark setting where electricity production does not generate losses from externalities. Section 4 reviews the changes introduced by losses from externalities. Section 5 employs numerical solutions to illustrate how the optimal DG policy and the effects of a net metering mandate vary with the prevailing industry environment. Section 6 concludes and identifies directions for further research. The proofs of all formal conclusions are presented in the Appendix A. Appendix B provides details of the analyses that underlie the numerical solutions presented in section 5.

2 Model

A regulated vertically-integrated provider ("the VIP") produces and distributes electricity to its customers, consumer N and consumer D.[16] Each customer pays: (i) a fixed fee, R, for the right to purchase electricity from the VIP; and (ii) unit price r for each unit of electricity purchased from the VIP.[17]

Consumer N cannot generate electricity, so he purchases all of the electricity he consumes from the VIP.[18] Consumer D can produce electricity to supplement or replace electricity

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[16]Alternatively, the electricity supplier can be viewed as securing electricity via market transactions in a setting where a system operator dispatches supply in order of increasing cost. We assume there are only two consumers for expositional ease. Our qualitative conclusions are unchanged if there are multiple D consumers and multiple N consumers.

[17]We will analyze the optimal regulatory policy both when the regulator can set a fixed fee, R, and when she cannot set such a fee.

[18]A customer may be unable to generate electricity for a variety of reasons, which include local zoning regulations that prohibit the installation of solar panels, residence architecture or location that is not

purchased from the VIP. The distributed generation undertaken by consumer D might reflect the electricity produced by solar panels that he installs on the roof of his home, for example. The VIP is required to pay consumer D the amount w for each unit of electricity he produces. If $w = r$, then consumer D is paid exactly the retail price of electricity for each unit of electricity he produces, as is common under many net metering policies in practice.

After the regulator sets R, r, and w, consumer D determines the level of DG capacity (K^D) he will install. The cost of installing capacity K^D is $C_D^K(K^D)$, which is a strictly increasing, strictly convex function.[19] To capture the intermittency associated with many forms of DG, including solar and wind generation, we assume that each unit of DG capacity generates θ units of electricity, where $\theta \in [\underline{\theta}, \overline{\theta}]$ is the realization of a random state variable with distribution function $F(\theta)$. The corresponding density function, $f(\theta)$, has strictly positive support on $[\underline{\theta}, \overline{\theta}]$, where $0 \leq \underline{\theta} < \overline{\theta} \leq 1$. The expected value of θ is denoted θ^E.[20]

Consumer $j \in \{D, N\}$ derives value $V^j(x, \theta)$ from x units of electricity in state $\theta \in [\underline{\theta}, \overline{\theta}]$. This value is a strictly increasing, strictly concave function of x. The state variable θ can be viewed as a measure of the amount of sunshine that prevails at a specified time in the relevant period. Therefore, in hot climates, for example, higher realizations of θ often will be associated with higher total and marginal valuations of electricity (to power cooling units).[21] Consumer j's demand for electricity in state θ is $X^j(r, \theta)$. Aggregate consumer demand in state θ is $X(r, \theta) = X^D(r, \theta) + X^N(r, \theta) > 0$.

The VIP incurs both capacity costs and additional operating costs. The VIP's variable cost of generating Q^v units of electricity when it has K_G units of generating capacity is

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conducive to efficient solar generation, or limited access to financing of the up-front fixed costs of installing solar panels. We do not model these fixed costs explicitly, for expositional ease.

[19]The increasing marginal cost of generating capacity might reflect in part the limited surface available on a customer's roof. Less than ideal exposure to the sun reduces the electricity a solar panel generates.

[20]We assume consumer D always installs some DG capacity $(K^D > 0)$ but not enough to serve the entire realized demand for electricity. This will be the case if, for example, $\lim_{K^D \to 0} C_D^{K\prime}(K^D) = 0$ and $C_D^{K\prime}(K^D)$ increases sufficiently rapidly as K^D increases above 0.

[21]Formally, in hot climates, $\frac{\partial V^j(x, \theta)}{\partial \theta} \geq 0$ and $\frac{\partial^2 V^j(x, \theta)}{\partial \theta \partial x} \geq 0$ for all $x \geq 0$ and $\theta \in [\underline{\theta}, \overline{\theta}]$, for $j \in \{D, N\}$. These inequalities need not hold more generally. The findings reported below hold even if these inequalities do not hold.

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$C^G(Q^v, K_G)$. Increased generating capacity reduces at a diminishing rate the VIP's variable and marginal cost of generating electricity.[22] The VIP's cost of installing K_G units of generating capacity is $C^K(K_G)$, which is an increasing, convex function.[23]

The VIP also incurs transmission and distribution (T&D) costs $T(K_G, K_D)$ to support centralized and distributed generating capacities K_G and K_D.[24] For simplicity, we abstract from variable T&D costs associated with line losses that might arise even when adequate infrastructure is implemented to fully accommodate electricity produced by the installed generating capacity.[25]

Electricity production can generate social losses from externalities (due to pollution and associated climate change, for instance). $L(Q^v, Q^D)$ will denote the magnitude of the loss that arises when the VIP produces Q^v units of electricity and consumer D produces Q^D units of electricity. $L(\cdot)$ is a non-decreasing function of each of its arguments.

The regulator chooses her policy instruments to maximize the difference between expected consumer welfare and expected social losses from externalities, subject to ensuring non-negative expected profit for the VIP. The regulator's policy instruments are the retail charges for electricity (R and r), the unit compensation (w) the VIP must deliver to consumer D for the electricity he produces, and the VIP's generating capacity (K_G).

Consumer N's welfare ($U^N(\cdot)$) is the difference between the value he derives from the electricity he consumes and the amount he pays for the electricity. Formally, consumer N's expected welfare is:

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[22]Formally, $\frac{\partial C^G(Q^v, K_G)}{\partial K_G} < 0$, $\frac{\partial^2 C^G(Q^v, K_G)}{\partial Q^v \partial K_G} < 0$, and $\frac{\partial^3 C^G(Q^v, K_G)}{\partial Q^v \partial^2 K_G} > 0$ for all $Q^v > 0$.

[23]Formally, $C^{K\prime}(K_G) > 0$ and $C^{K\prime\prime}(K_G) > 0$. We also assume a strictly positive level of generating capacity is optimal. This will be the case if, for example, $\underset{K_G \to 0}{limit} \left| \frac{\partial C^G(Q^v, K_G)}{\partial K_G} \right| = \infty$ for all $Q^v > 0$ and $\underset{K_G \to 0}{limit} C^{K\prime}(K^G) = 0$.

[24]The ensuing discussion will emphasize the case in which $T(\cdot)$ is strictly increasing in each of its arguments. The analysis in Appendix B allows for the possibility that the VIP's (long run) T&D costs might decline as K_D increases (Cohen et al., 2015).

[25]These losses are relatively small in practice (Parsons and Brinckerhoff, 2012; U.S. Energy Information Administration (EIA), 2014b). Explicit accounting for these variable costs would not affect the key qualitative conclusions reported below.

$$E\{U^N(\cdot)\} \;=\; \int_{\underline{\theta}}^{\overline{\theta}} [\,V^N(X^N(r,\theta),\theta) - \; r\,X^N(\cdot)\,]\,dF(\theta) - R\,. \tag{1}$$

Consumer D's welfare $(U^D(\cdot))$ is the sum of the value he derives from the electricity he consumes and the compensation he receives for producing electricity, less the amount he pays for the electricity he purchases from the VIP and his DG capacity costs. Formally, consumer D's expected welfare is:

$$E\{U^D(\cdot)\} \;=\; \int_{\underline{\theta}}^{\overline{\theta}} [\,V^D(X^D(r,\theta),\theta) - r\,X^D(\cdot)\,]\,dF(\theta) - R + w\,\theta^E\,K_D - C_D^K(K_D)\,. \tag{2}$$

As reflected in equation (2), consumer D produces $\theta\,K_D$ units of electricity in state θ when he has installed K_D units of DG capacity. The VIP produces the residual demand for electricity. Therefore, expected losses from externalities are:

$$E\{L(\cdot)\} \;=\; \int_{\underline{\theta}}^{\overline{\theta}} L(\,X(r,\theta) - \theta\,K_D,\, \theta\,K_D\,)\,dF(\theta)\,. \tag{3}$$

The VIP's profit (π) is the revenue it secures from selling electricity to consumers D and N, less the sum of: (i) the DG compensation it pays to consumer D; (ii) the cost of its generating capacity; (iii) its variable cost of generating electricity; and (iv) its T&D costs. Formally, the VIP's expected profit is:

$$E\{\pi\} \;=\; \int_{\underline{\theta}}^{\overline{\theta}} \left[\, r\,X(\cdot) - w\,\theta\,K_D - C^G(Q^v(\cdot), K_G)\right] dF(\theta)$$
$$+\; 2\,R - C^K(K_G) - T(K_G, K_D)\,. \tag{4}$$

The regulator's problem, denoted [RP], is:

$$\underset{R,\,r,\,w,\,K_G}{Maximize} \;\; E\{U^D(\cdot) + U^N(\cdot)\} - E\{L(\cdot)\} \tag{5}$$

$$\text{subject to:} \;\; E\{\pi\} \;\geq\; 0\,. \tag{6}$$

The timing in the model is as follows. The regulator first sets her policy instruments. Consumer D then chooses his DG capacity investment. Finally, the state is realized, DG production occurs, and the VIP supplies the realized demand for electricity and provides all

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required T&D of electricity.

3 Benchmark Setting with No Losses from Externalities

The key features of the optimal regulatory policy are most transparent when there are no social losses from externalities. We analyze this benchmark setting here and then discuss in section 4 the changes that arise when electricity production generates losses from externalities.

A. No Restrictions on Policy Instruments.

Consider, first, the setting in which the regulator has access to her full set of policy instruments (R, r, w, and K_G). Her formal problem in this setting, denoted [RP-F], is problem [RP] with the exception that $L(Q^v, Q^D) = 0$ for all Q^v and Q^D. Proposition 1 identifies the key features of the optimal policy in this setting.

Proposition 1. *At the solution to [RP-F]:*

$$\int_{\underline{\theta}}^{\overline{\theta}} \left| \frac{\partial C^G(\cdot)}{\partial K_G} \right| dF(\theta) \;=\; C^{K\prime}(\cdot) + \frac{\partial T(\cdot)}{\partial K_G} \;; \tag{7}$$

$$w\,\theta^E \;=\; \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v}\, \theta\, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D} \;; \tag{8}$$

$$\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[r - \frac{\partial C^G(\cdot)}{\partial Q^v} \right] \frac{\partial X^j}{\partial r}\, dF(\theta) \;=\; 0\;; \quad and \tag{9}$$

$$R \;=\; \frac{1}{2}\left[\int_{\underline{\theta}}^{\overline{\theta}} \left[C^G(Q^v(\cdot), K_G) - r\,X(\cdot) \right] dF(\theta) + w\,\theta^E K_D \right.$$
$$\left. + \; C^K(K_G) + T(K_G, K_D) \right]. \tag{10}$$

Equation (7) indicates that the VIP's generating capacity (K_G) is optimally expanded to the point where its marginal benefit and full marginal cost are equated. The marginal benefit of K_G is the associated expected marginal reduction in the VIP's variable cost of generating electricity. The full marginal cost of K_G reflects both the marginal cost of securing capacity

and the associated marginal T&D costs.

Equation (8) indicates that the unit compensation for DG production (w) is optimally set to induce consumer D to install the efficient level of DG capacity (K_D). This outcome is achieved by equating the consumer's marginal expected return from increasing K_D (i.e., $w\,\theta^E$) with the marginal expected reduction in the VIP's costs from increasing K_D. This reduction is the difference between the marginal expected reduction in generation costs and the marginal increase in T&D costs.[26]

Equation (9) indicates that the regulator employs the unit retail price of electricity (r) to induce efficient consumption decisions. Specifically, r is set to ensure that the expected weighted deviations of prices from the incumbent's marginal cost of generating electricity are zero. As is standard under Ramsey pricing of this sort (Ramsey, 1927; Baumol and Bradford, 1970), deviations of price from marginal cost are weighted more heavily when consumer demand is more sensitive to price. Equation (10) indicates that the regulator employs the fixed retail charge to ensure the VIP earns exactly zero profit.[27]

Corollary 1 reports that in settings where the VIP operates with a constant marginal cost of generating electricity, the optimal unit price of electricity (r) exceeds the optimal unit payment for DG output (w), so net metering is not optimal.

Corollary 1. *Suppose $\frac{\partial^2 C^G(Q^v, K_G)}{\partial (Q^v)^2} = 0$ for all $Q^v \geq 0$ and $K_G > 0$. Then at the solution to [RP-F], $r = \frac{\partial C^G(Q^v, K_G)}{\partial Q^v} > w = \frac{\partial C^G(Q^v, K_G)}{\partial Q^v} - \frac{1}{\theta^E}\,\frac{\partial T(\cdot)}{\partial K_D}$.*

When the VIP experiences a constant marginal cost (c) of generating electricity, r is optimally set equal to c in order to induce efficient consumption decisions. w is set below c to equate consumer D's private marginal return to expanding K_D (i.e., $\theta^E w$) with the corresponding marginal social benefit. This benefit is the expected marginal reduction in the VIP's cost of generating electricity (i.e., $\theta^E c$) less the marginal increase in the VIP's

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[26]Observe that $\frac{\partial Q^v(\cdot)}{\partial K_D} = -\theta$ in state θ because $Q^v(\cdot) = X(\cdot) - \theta\,K_D$. Therefore, $\frac{\partial C^G(\cdot)}{\partial Q^v}\,\theta = \frac{\partial C^G(\cdot)}{\partial Q^v}\left|\frac{\partial Q^v(\cdot)}{\partial K_D}\right|$.

[27]It can be shown that when the regulator is able to set w, r, and R, her inability to dictate the DG capacity investment is not constraining.

T&D costs.[28]

More generally, if expanded DG capacity increases the VIP's T&D costs substantially, then w will optimally be set below r to avoid excessive investment in DG capacity.

Corollary 2. $r > w$ *at the solution to [RP-F] if* $T(K_G, K_D)$ *increases sufficiently rapidly with* K_D *for all* $K_G, K_D \geq 0$.

B. No Fixed Retail Charge is Permitted.

In practice, the fixed charge (R) imposed on consumers often is small relative to the average fixed cost of supplying electricity.[29] Limited fixed charges may reflect income distribution concerns, for example.[30] To illustrate the changes that arise when the regulator has limited ability to impose a fixed retail charge, Proposition 2 characterizes the solution to [RP-r], which is problem [RP-F] with the exception that R is constrained to be 0. The proposition refers to λ_r, which is the Lagrange multiplier associated with constraint (6).

Proposition 2. *Equation (7) holds at the solution to [RP-r]. Furthermore:*

$$w\,\theta^E \;=\; \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v}\, \theta\, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D} - \left[\frac{\lambda_r - 1}{\lambda_r}\right]\frac{\theta^E\, K_D}{\partial K_D/\partial w}\;; \tag{11}$$

$$\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[r - \frac{\partial C^G(\cdot)}{\partial Q^v}\right]\left|\frac{\partial X^j}{\partial r}\right| dF(\theta) \;=\; \left[\frac{\lambda_r - 1}{\lambda_r}\right]\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot)\, dF(\theta)\,; \tag{12}$$

and

$$r \;=\; \frac{w\,\theta^E\, K_D + \int_{\underline{\theta}}^{\overline{\theta}} C^G(Q^v(\cdot,\theta), K_G)\, dF(\theta) + C^K(K_G) + T(K_G, K_D)}{\int_{\underline{\theta}}^{\overline{\theta}} X(\cdot,\theta)\, dF(\theta)}\,. \tag{13}$$

Equations (11) and (12) reveal that when the values of r and w identified in Proposition

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[28] w would optimally exceed r in this setting if expanded DG capacity reduced the VIP's T&D costs.

[29] Borenstein (2014) reports that two of the three major electric utilities in California (Pacific Electric & Gas and San Diego Gas & Electric) impose no fixed retail charge. The third utility (Southern California Edison) imposes a monthly fixed charge of only $0.99.

[30] If all fixed costs of supplying electricity were recovered via fixed retail charges, customers who consume little electricity (perhaps because their limited income compels them to consume only minimal housing resources) would face large monthly charges for electricity.

1 would impose a loss on the VIP (so $E\{\pi\} < 0$), the regulator adjusts r and w to eliminate this loss. Specifically, when $\lambda_r > 1$ at the solution to [RP-r], the regulator increases r in order to enhance the VIP's revenue and reduces w in order to limit the DG payments the VIP must deliver to consumer D.[31] Equation (13) indicates that r is optimally set equal to the VIP's expected average cost to ensure zero expected profit for the VIP.

When the regulator is unable to set a fixed retail charge (R), she must employ r and w to both induce efficient consumption and investment decisions and secure nonnegative profit for the VIP. The multiple roles that r and w must play in this setting complicate attempts to systematically rank the optimal values of r and w. However, as Proposition 3 reports, r is optimally set above w when consumer demand for electricity is sufficiently price inelastic and the VIP's marginal cost of generating electricity is sufficiently insensitive to the level of generation. The proposition refers to Assumptions 1 and 2 which, for tractability, introduce an iso-elastic demand function and a polynomial cost function of degree $n \geq 2$.

Assumption 1. $X^j(r, \theta) = m_j\left[\beta_{0j} + \theta^{\beta_j}\right] r^{\alpha_j}$ for $j = D, N$, where $\alpha_j \leq 0$, $m_j > 0$, $\beta_{0j} > 0$, and β_j are parameters.

Assumption 2. $C^G(Q^v, K_G) = c(K_G)\, Q^v + \sum_{i=2}^{n} b_i\, [Q^v]^i$ where $b_2, ..., b_n$ are parameters.

Proposition 3. *$r > w$ at the solution to [RP-r] if Assumptions 1 and 2 hold, α_j is sufficiently close to zero for $j = D, N$, and either: (i) b_i is sufficiently close to zero for all $i = 2, .., n$; or (ii) the VIP's generation capacity costs $(C^K(K_G))$ and T&D costs $(T(K_G, K_D))$ are sufficiently large.*

When consumer demand for electricity is largely insensitive to its price, the regulator employs r primarily to hold the VIP to zero expected profit, and so sets r equal to the VIP's average cost of operation. The regulator employs w primarily to induce consumer

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[31] Additional restrictions on demand and cost functions are required to rule out the possibility that the regulator might increase w in order to reduce the VIP's costs by shifting electricity production from the VIP to consumer D.

D to install the efficient level of DG capacity (K_D). She does so by setting w below the VIP's (nearly constant) marginal cost of generating electricity, thereby accounting for the increase in T&D costs the VIP incurs as K_D increases. Consequently, r exceeds w under the optimal policy. The numerical solutions presented in section 5 and Appendix B indicate that r often exceeds w under the optimal policy even when the special conditions identified in Proposition 3 do not hold.

4 The Setting with Losses from Externalities

The conclusions reported in section 3 are modified in intuitive and straightforward fashion when electricity production generates social losses from externalities ($L(\cdot)$). To illustrate, consider the setting where the regulator can employ her full set of policy instruments (R, r, w, and K_G). The optimal policy in this setting is characterized in Proposition 4 and its corollaries.

Proposition 4. *Equations (7) and (10) hold at the solution to [RP]. Furthermore:*

$$w\,\theta^E \;=\; \int_{\underline{\theta}}^{\bar{\theta}} \left[\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right] \theta\, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D}\,, \quad and \qquad (14)$$

$$\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\bar{\theta}} \left[r - \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} \right) \right] \frac{\partial X^j}{\partial r}\, dF(\theta) \;=\; 0\,. \qquad (15)$$

Corollary 3. $r > w$ *at the solution to [RP] if* $T(K_G, K_D)$ *increases sufficiently rapidly with* K_D *for all* $K_G, K_D \geq 0$.

Corollary 4. *Suppose* $\frac{\partial^2 C^G(Q^v, K_G)}{\partial(Q^v)^2} = \frac{\partial^2 L(Q^v, Q^D)}{\partial(Q^v)^2} = \frac{\partial^2 L(Q^v, Q^D)}{\partial(Q^D)^2} = 0$ *for all* $Q^v \geq 0$, $Q^D \geq 0$, *and* $K_G > 0$. *Then at the solution to [RP]:*

$$r \;=\; \frac{\partial C^G(Q^v, K_G)}{\partial Q^v} + \frac{\partial L(Q^v, Q^D)}{\partial Q^v}$$

$$> \; w \;=\; \frac{\partial C^G(Q^v, K_G)}{\partial Q^v} + \frac{\partial L(Q^v, Q^D)}{\partial Q^v} - \frac{\partial L(Q^v, Q^D)}{\partial Q^D} - \frac{1}{\theta^E} \frac{\partial T(\cdot)}{\partial K_D}\,.$$

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Equation (14) indicates that in order to induce consumer D to install the efficient DG capacity (K_D), w is set to equate $w\theta^E$, the consumer's marginal expected financial return from K_D, and the associated marginal social benefit from K_D. This marginal social benefit is the sum of the marginal reduction in the VIP's costs and the marginal expected net reduction in losses from externalities as electricity generation is shifted from the VIP to consumer D.

Equation (15) indicates that in order to induce efficient electricity consumption, r is set to equate to 0 weighted deviations of r from the social marginal cost of electricity generation by the VIP. This social marginal cost is the sum of the VIP's marginal cost of generating electricity and the marginal social loss from externalities resulting from electricity generation by the VIP.

Corollary 3 reflects the fact that w is optimally reduced below r to avoid excessive investment in K_D when such investment increases T&D costs substantially. Corollary 4 reports that r also optimally exceeds w when the VIP operates with a constant marginal cost of generating electricity and where social losses from externalities increase linearly with electricity production. In this case, r is set equal to the social marginal cost of electricity production by the VIP ($\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v}$) in order to induce efficient consumption decisions. To induce efficient investment in K_D, w is set to equate consumer D's marginal expected return from K_D (i.e., $w\theta^E$) and the marginal social benefit of K_D. This benefit is the sum of the expected marginal reduction in the VIP's costs ($E\left\{\frac{\partial C^G(\cdot)}{\partial Q^v}\left|\frac{\partial Q^v}{\partial K_D}\right| - \frac{\partial T(\cdot)}{\partial K_D}\right\}$) and the expected marginal reduction in social losses from externalities as electricity production is shifted from the VIP to consumer D ($E\left\{\frac{\partial L(\cdot)}{\partial Q^v}\left|\frac{\partial Q^v}{\partial K_D}\right| - \frac{\partial L(\cdot)}{\partial Q^D}\frac{\partial Q^D}{\partial K_D}\right\}$).[32]

Conclusions analogous to those derived in section 3.B persist when the regulator cannot set a fixed retail charge for electricity in the presence of social losses from externalities ($L(\cdot)$). To illustrate, it is readily verified that r optimally exceeds w when the conditions specified in Proposition 3 hold and the rate at which $L(\cdot)$ increases with Q^v is not too much greater than

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[32] w could exceed r in the setting of Corollary 4 if expanded DG capacity reduced the VIP's T&D costs sufficiently rapidly.

the rate at which $L(\cdot)$ increases with Q^D.[33] The numerical solutions presented in section 5 and Appendix B indicate that r optimally exceeds w more generally (but not always) in this setting.

5 Numerical Solutions

We now present numerical solutions to further illustrate the properties of optimal DG policies and the impact of net metering mandates (which require w and r to be identical). We consider two settings. The VIP primarily employs non-coal resources to serve a relatively large market in the "baseline" setting. In contrast, the VIP primarily employs coal resources to serve a relatively small market in the "coal-intensive" setting. We begin by specifying tractable functional forms and representative parameter values for the baseline setting.

Recall that the distribution of the state variable (θ) reflects variation in the production of electricity from installed DG capacity. To specify this distribution, we first plot the ratio of the MW's of electricity produced by photo-voltaic (PV) panels to the year-end installed generating capacity ($\overline{K}_D = 3,254$ MW) of PV panels in California for each of the $8,760$ hours in 2014.[34] We then employ maximum likelihood estimation to fit a distribution to the 4,443 (49.4%) of the observations that are strictly positive. Standard tests reveal that the beta distribution with parameters $(1.165, 1.204855)$ fits the data well, so this distribution is employed as $f(\theta)$ in the ensuing analysis.[35]

Consumer demand for electricity is assumed to be iso-elastic. Specifically, $X^j(r, \theta) = m_j \left[1 + \theta^{\beta_j} \right] r^{\alpha_j}$ for $j \in \{D, N\}$, where $m_j > 0$, $\alpha_j < 0$, and β_j are parameters.[36] Reflecting

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[33]The regulator may set w above r if $\frac{\partial L(\cdot)}{\partial Q^v}$ substantially exceeds $\frac{\partial L(\cdot)}{\partial Q^D}$. A relatively high value of w can induce substantial investment in DG capacity which limits the VIP's expected electricity production.

[34]The data on PV output are derived from the California Independent System Operator (CAISO) (2015b). The statistic on PV capacity is drawn from California Solar Statistics (2015). The ensuing calculations are not intended to characterize actual or likely outcomes in California or any other specific jurisdiction However, the California data is useful in modeling a setting where a VIP generates a relatively large amount of electricity employing primarily non-coal resources.

[35]The tests are the chi-squared, Kolmogorov-Smirnov, and Anderson-Darling tests. These tests also reveal that the generalized extreme value (GEV) distribution with parameter values $(0.4827, 0.3088, -0.7135)$ fits the data reasonably well. Findings very similar to those reported below arise when this GEV distribution replaces the identified beta distribution.

[36]This relationship is assumed to hold for $r \leq r^m$. We assume $X^j(\cdot) = 0$ for $r > r^m$ to ensure finite values

estimates of the price elasticity of demand for electricity in the literature, we initially assume $\alpha_D = \alpha_N = -0.25$.[37] β_j can be viewed as a measure of the sensitivity of electricity demand to solar intensity. We initially set $\beta_D = \beta_N = 0$ in light of the fact that increased sunshine and associated higher temperatures can either increase the demand for electricity to power cooling units in summer months or reduce the demand for electricity to power heating units in winter months.

We set m_D and m_N in the baseline setting to equate the equilibrium expected demand in the model with $\overline{X} = 25,391$ (MWh), the average hourly consumption of electricity in California in 2014.[38] Formally, m_j is chosen to ensure $E\left\{m_j\left[1+\theta^{\beta_j}\right]\widetilde{r}^{\alpha_j}\right\} = \eta_j\overline{X}$ for $j \in \{D, N\}$, where η_D denotes the fraction of demand accounted for by customers who undertake some distributed generation of electricity, $\eta_N = 1 - \eta_D$, and $\widetilde{r} = 143.8165$ reflects the average unit retail price of electricity (\$/MWh) in California in 2014 (California Public Utilities Commission, 2015). We initially assume $\eta_D = 0.1$ to reflect the potential deployment of PV panels in the U.S. in the near future.[39]

The VIP's capacity costs are assumed to be quadratic, i.e., $C^K(K_G) = a_K K_G + b_K (K_G)^2$. Estimates of the cost of the generation capacity required to produce a MWh of electricity range from \$16.1/MWh for a conventional combined cycle natural gas unit to \$81.9/MWh

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for $E\{U^j\}$, $j \in \{D, N\}$. We set $r^m = 800$, reflecting particularly high estimates of customer valuations of lost load (London Economics International, 2013).

[37] Estimates of the short-run price elasticity of demand for electricity for residential consumers range from -0.13 (Paul et al., 2009) to -0.20 (Bohi and Zimmerman, 1984) to -0.24 (Bernstein and Griffen, 2006) to -0.26 (Narayan and Smyth, 2005), to -0.35 (Espey and Espey, 2004). King and Chatterjee (2003) and Wade (2003) report corresponding estimates in the ranges of $[-0.34, -0.13]$ and $[-0.34, -0.20]$, respectively. Corresponding long-run estimates reflect substantially more elastic demand (e.g., between -0.40 (Paul, 2009) and -0.85 (Espey and Espey, 2004)). Commercial and industrial customers typically exhibit less elastic demands for electricity (e.g., Wade, 2003; Taylor et al., 2005; Paul et al., 2009).

[38] $\overline{X}$ is the sum of: (i) $\overline{Q}_v = 24,577$ MWh, the average amount of electricity sold hourly by California utilities in 2014 (CAISO, 2015a); and (ii) the estimated average hourly electricity generated from solar DG in California in 2014. This latter estimate is 25.0% of $\overline{K}_D$, the $3,254$ MW of PV capacity installed in California at year end 2014. The 25.0% represents 49.4% of the mean of θ under the identified beta distribution. (Recall that 49.4% of the $8,760$ DG output observations in the sample were non-zero.)

[39] 10.6% of consumers undertook some DG of electricity in Hawaii in 2014. The corresponding percentages are 2% in California and 1.6% in Arizona (EIA, 2015b). Schneider and Sargent (2014) report rapid growth in the installation of solar panels in recent years. Borenstein (2015) reports that, on average, households that engage in the DG of electricity consume more electricity than do households that do not undertake DG.

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for a nuclear facility (EIA, 2015a). We initially set $a_K = 16.1$ to reflect the lower bound of this range. We also set $b_K = 0.00045$ to ensure that the marginal cost of capacity required to generate a MWh of electricity is \$81.9 at the observed level of centralized non-renewable generation capacity in California in 2014 ($\overline{K}_G = 72,926$ MW) (California Energy Commission, 2015).

For simplicity, the VIP's T&D costs are assumed to be linear, i.e., $T(K_G, K_D) = a_T^G K_G + a_T^D K_D$. Utility transmission capacity costs associated with generating a MWh of electricity are estimated to be between \$1.2 and \$3.5 for centralized, non-renewable generation and between \$4.1 and \$6.0 for PV generation (EIA, 2015a). To reflect these estimates, we initially assume $a_T^G = 2.35$ and $a_T^D = 5.05$.

We take the VIP's cost of generating Q^v units of electricity when it has K_G units of capacity to be $C^G(Q^v, K_G) = \left[a_v + \frac{c_v}{K_G} \right] Q^v + b_v (Q^v)^2$, where a_v, b_v, and c_v are positive constants. This formulation implies that increased capacity reduces the VIP's cost of generating electricity at a diminishing rate.[40] We initially set $b_v = 0.003$ and $a_v + \frac{c_v}{K_G} = 28.53$, reflecting Bushnell (2007)'s estimates.[41] The initial value of c_v is chosen to equate the observed marginal benefit ($\frac{c_v \overline{Q}^v}{(\overline{K}_G)^2}$) and marginal cost ($a_K + 2 b_K \overline{K}_G + a_T^G$) of VIP capacity.[42]

The cost of installing K_D units of DG capacity is assumed to be $C_D^K(K_D) = a_D K_D + b_D (K_D)^2$. Estimates of the unsubsidized cost of residential photo-voltaic (PV) capacity vary between \$100 and \$400/MWh (Branker et al., 2011; EIA, 2015a). Application of the 30 percent federal income tax credit (ITC) reduces these estimates to between \$70 and \$280/MWh. State subsidies further reduce these estimates to between \$45 and \$255/MWh (NCCETC, 2015a,b,c). We initially set $a_D = 150$, the midpoint of this lattermost range

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[40]Formally, $\frac{\partial C^G(\cdot)}{\partial K_G} = -\frac{c_v Q^v}{(K_G)^2} < 0$ and $\frac{\partial^2 C^G(\cdot)}{\partial (K_G)^2} = \frac{2 c_v Q^v}{(K_G)^3} > 0$, which implies $\frac{\partial}{\partial K_G} \left| \frac{\partial C^G(\cdot)}{\partial K_G} \right| < 0.$

[41]Employing a cost function of the form $C(Q^v) = a Q^v + b(Q^v)^2$, Bushnell (2007) estimates $a = 28.53$ and $b = 0.003$.

[42]Recall equation (7). Also recall $\overline{Q}^v = 24,577$ is the average MWh's of electricity sold daily by California utilities in 2014 and $\overline{K}_G = 72,926$ is the MW of centralized non-renewable generation capacity in California at year-end 2014. Thus, the initial value for c_v (and hence a_v) reflects the assumption that the welfare-maximizing level of capacity in the model is $\overline{K}_G$.

of cost estimates. We also set $b_D = 0.0038$ to ensure ensure that the marginal cost of DG capacity when $K_D = \overline{K}_D = 3,254$ (i.e., $a_D + 2\,b_D\,\overline{K}_D$) is 175, the midpoint of the range of estimated costs after applying the ITC.

Finally, we assume there are no social losses from externalities due to (solar) distributed generation of electricity. In addition, for simplicity, the corresponding losses are assumed to increase linearly with electricity produced by the VIP.[43] Specifically, we assume $L(Q^v, Q^D) = e_v\,Q^v$, where $e_v = \phi_c\,e_c + \phi_g\,e_g + \phi_o\,e_o$. ϕ_c, ϕ_g, and ϕ_o denote the fraction of the VIP's electricity production that is generated by coal, natural gas, and other units, respectively.[44] We initially set $e_c = 37.231$, $e_g = 21.029$, and $e_o = 0$. e_j, the estimated unit loss from environmental externalities for technology $j \in \{c, g, o\}$, is the product of \$38, the estimated social cost of a metric ton of CO_2 emissions (EPA, 2013), and the metric tons of CO_2 emissions that arise when technology j is employed to produce a MWh of electricity.[45] In the current baseline setting, we assume $\phi_c = 0.064$ and $\phi_g = 0.445$, reflecting the fraction of electricity generated by California utilities in 2014 using coal and natural gas generating units, respectively (California Energy Commission, 2015). Consequently, $e_v = 11.746$.

Using these parameter values, we solve numerically for the values of r, w, and K_G (and the associated equilibrium value of K_D) that solve problems [RPE-r] and [RPE-rNM].[46] The former problem is problem [RP] where fixed retail charges are not feasible (so $R = 0$). The latter problem is the same problem under the net metering ($w = r$) mandate. Table 1 records the key outcomes at the solutions to these problems in this baseline setting. $E\{W\}$ in the table denotes expected welfare, which is the regulator's objective function, as specified

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[43]In practice, social losses from externalities often increase with centralized electricity production nonlinearly. To illustrate, marginal social losses tend to be: (i) small when the utility employs renewable or hydro sources to generate small levels of electricity; (ii) high when the utility dispatches coal-fired units to produce moderate levels of electricity; and (iii) moderate when the utility dispatches natural gas units to serve peak demand.

[44]In practice, other units primarily reflect hydro and nuclear production. $\phi_o = 1 - \phi_c - \phi_g$.

[45]EIA (2014a) estimates that 2.16 pounds of CO_2 are emitted when a KWh of electricity is produced using a coal generating unit. The corresponding estimate is 1.22 pounds when a natural gas unit is employed. These estimates are multiplied by $1,000$ to convert KWhs to MWhs, and divided by $2,204.62$ to convert pounds to metric tons. Thus, $e_c = 38\,[\,2.16\,]\,\frac{1,000}{2,204.62} = 37.231$ and $e_g = 38\,[\,1.22\,]\,\frac{1,000}{2,204.62} = 21.029$.

[46]The solutions are generated using *Mathematica*, as explained more fully in Appendix B.

in equation (5).

Problem	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
[RPE-r]	272.8	187.6	$68,231$	$4,953$	$8,789$	999	240	$9,549$
[RPE-rNM]	313.7	313.7	$61,963$	$21,544$	$8,006$	$1,318$	184	$9,140$

Table 1. Outcomes in the Baseline Setting.[47]

Four elements of Table 1 warrant emphasis. First, net metering is not optimal. The unit retail price of electricity (r) is optimally set well (45%) above the unit DG payment (w). The relatively high value of r enables the VIP to secure the revenue required to offset capacity costs, generation costs, and DG payments. Second, a net metering mandate increases both r and w. The requirement to raise w to the level at which r is set increases the DG payments the VIP must make, *ceteris paribus*. r (and consequently w) must then be increased further to ensure non-negative expected profit for the VIP.

Third, the substantial (67%) increase in w under net metering induces a significant (35%) increase in DG capacity (K_D) and an associated (9%) reduction in centralized generation capacity (K_G). The resulting increase in the fraction of electricity derived from (solar) distributed generation reduces (by 23%) the social losses from externalities. Fourth, the increase in w under net metering causes consumer D's expected utility to increase by 32%. In contrast, the increase in r causes consumer N's expected utility to decline by 9%. On balance, the net metering mandate reduces expected welfare by 4.3%.[48]

To illustrate the different qualitative conclusions that can arise under other circumstances, consider a setting where the VIP primarily employs coal units to serve a smaller market. Specifically, suppose $\phi_c = 0.9$, $\phi_g = 0.1$, and the demand parameters (m_j) are chosen to

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[47]The values of $E\{U^N\}$, $E\{U^D\}$, $E\{L\}$, and $E\{W\}$ in Table 1 and in all successive tables are expressed in thousands. The entries in all tables are rounded to the nearest integer.

[48]The distributional and aggregate welfare effects of a net metering mandate are less pronounced in this baseline setting if the regulator can set both a unit (r) and a fixed (R) retail charge and if the latter does not affect the demand for electricity. w is optimally set closer to r in this case, which reduces the impact of a requirement to equate w and r. See Table B11 in Appendix B.

ensure $E\left\{m_j\left[1+\theta^{\beta_j}\right]\widetilde{r}^{\alpha_j}\right\} = \eta_j\,\widehat{X}$, where $\widehat{X} = 21,404$.[49] Further suppose the VIP's capacity parameters ($a_K = 16.1$, $b_K = 0.000674$) ensure that the marginal cost of capacity required to generate a MWh of electricity is approximately 60.4 when $K_G = \widehat{K}_G = 32,854$.[50,51] Table 2 presents the key elements of the solutions to problems [RPE-r] and [RPE-rNM] in this "coal-intensive" setting.

Problem	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
[RPE-r]	164.6	213.7	32,381	8,387	9,293	1,097	664	9,726
[RPE-rNM]	161.7	161.7	33,475	1,536	9,347	1,041	727	9,661

Table 2. Outcomes in the Coal-Intensive Setting.

Four elements of Table 2 warrant emphasis. First, net metering is not optimal. w optimally exceeds r in order to induce substantial investment in DG capacity, which permits reduced electricity production by the VIP's coal-powered generating units. Second, a net metering mandate reduces both r and w. The requirement to reduce w to the level at which r is set reduces the DG payments the VIP must make, *ceteris paribus*. r (and w) can then be lowered without reducing the VIP's expected profit below zero.

Third, the reduction in w under net metering reduces investment in DG capacity whereas the reduction in r increases electricity demand and associated investment in centralized capacity (K_G). The resulting reduction in the fraction of electricity derived from (solar) distributed generation causes the social losses from externalities to increase. Fourth, the reduction in w causes consumer D's expected utility to decline, whereas the reduction in r causes consumer N's expected utility to increase. On balance, expected welfare declines.

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[49]The smaller level of expected demand ($\widehat{X} < \overline{X}$) reflects the average daily consumption of electricity in Ohio in 2014 (EIA, 2015c). $e_v = 35.692$ when $\phi_c = 0.9$ and $\phi_g = 0.1$.

[50]$\widehat{K}_G = 32,854$ MW reflects the level of centralized non-renewable generation capacity in Ohio in 2013 (EIA, 2015c). The estimated cost of capacity required to produce a MWh of electricity using a coal generating unit is \$60.4 (EIA, 2015a).

[51]Much as in the baseline setting, we choose a_v, b_v, and c_v to reflect Bushnell (2007)'s estimates for the serving region of the PJM rgional transmission organization (i.e., $a = 0$ and $b = 0.0009$), assuming that the welfare-maximizing level of VIP capacity in the model is $\widehat{K}_G$.

Parameter values other than those considered here may well be plausible in relevant settings. Consequently, the entries in Tables 1 and 2 are merely illustrative. Nevertheless, these entries demonstrate that the distributional and the aggregate welfare effects of a net metering mandate can be pronounced and can vary substantially with the environment in which the mandate is imposed. Appendix B provides additional illustrations of how the optimal DG compensation policy and industry outcomes vary with prevailing industry conditions. These illustrations further support the key qualitative conclusions drawn above.

6   Conclusions

We have analyzed the optimal design of compensation for the distributed generation (DG) of electricity. We found that the optimal unit payment (w) for electricity produced via DG reflects the corresponding reductions in both the utility's generation, transmission, and distribution costs and the social losses from environmental externalities as DG replaces centralized generation of electricity. Furthermore, the optimal retail price of electricity (r) is set in Ramsey fashion to minimize expected weighted deviations between r and the utility's marginal cost of generating electricity.

These optimal values of w and r typically differ. r often exceeds w, for instance, when the marginal cost of centralized generation of electricity varies little with the scale of the utility's operation and when the social losses from environmental externalities vary little across generating technologies. In contrast, w can exceed r when losses from externalities are substantially lower under DG than under centralized distribution of electricity. Thus, there is no single DG compensation policy that is optimal in all settings. Indeed, the terms of an optimal DG policy, like the effects of a net metering ($w = r$) mandate, can vary substantially with the prevailing industry characteristics.

We found that as it reduces aggregate welfare, a net metering mandate can produce particularly pronounced distributional effects. Opponents of net metering often argue that a net metering mandate will benefit customers that undertake DG at the expense of those who do not. This may be the case if the relevant benchmark is a policy that provides no

compensation for DG production. However, we have shown that this is not necessarily the case if the relevant benchmark is the optimal DG policy. In particular, when the optimal DG policy sets w above r (to promote the production of "clean energy," for instance), a net metering mandate can cause both r and w to decline. The reduction in r increases the welfare of all consumers. However, the reduction in w can reduce the welfare of those that undertake DG to the point where their overall level of welfare declines. By discouraging investment in DG capacity, the reduction in w also can increase social losses from externalities.

A net metering policy can be a useful instrument to promote the distributed generation of electricity when it is not possible to monitor a customer's production and consumption of electricity separately. However, as smart meters are deployed more ubiquitously, DG policies that do not mandate net metering can enhance consumer welfare. Such policies have begun to emerge. To illustrate, the "value of solar" program in Minnesota (Farrell, 2014; Minnesota Department of Commerce, 2014) links DG payments to estimated reductions in social losses from environmental externalities and to associated reductions in the utility's generation, transmission, and distribution costs, as our analysis prescribes.

In concluding, we note three directions in which our analysis might be fruitfully extended. First, alternative DG technologies should be considered. The amount of electricity produced by a non-solar DG source typically is not entirely beyond the producer's control. The ability to control DG output can engender contracting opportunities that facilitate a utility's load management activities. Because the nature and extent of DG intermittency varies by production technology, the presence of multiple distinct DG technologies may also facilitate load management. Just as the optimal DG policy varies with the characteristics of the single DG source in our model, more generally the optimal DG policy will vary with (and help to determine) the entire range of DG technologies that are employed.[52]

Second, alternative regulatory objectives merit consideration. In practice, political pressures can compel regulators to value differently the welfare of different constituents (e.g.,

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[52]A characterization of the optimal payments to a utility for the DG capacity it installs also merits investigation, as does competition in the electricity sector.

those who can readily install DG capacity and those who cannot).[53] Such differential welfare considerations can affect both the properties of the optimal DG policy and the effects of a net metering mandate.[54]

Third, additional policy instruments warrant consideration.[55] The regulator may be able to secure a higher level of welfare if, for example, she can compensate consumers directly for the DG capacity they install. Nonlinear and time-varying retail electricity prices also could enhance welfare, particularly in settings where consumers are readily able to substitute electricity consumption in one time period for electricity consumption in another time period. More generally, the optimal design of a DG policy is best viewed as an element of a broader exercise that includes, for example, the optimal design of demand-response, energy conservation, and renewable energy portfolio policies. The optimal coordination of these policies awaits formal investigation.[56]

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[53]See Cardwell (2012), for example.

[54]Regulators are often particularly concerned with the welfare of individuals who find it challenging to pay their utility bills. Future research might explicitly model both this concern and the role that high fixed charges for electricity (R) can play in compelling some customers to exit the distribution network.

[55]Alternative prevailing pricing structures also merit investigation. We have examined the impact of net metering mandates when retail electricity prices are set to maximize expected consumer welfare. Net metering mandates can have different effects if they are imposed in settings where prices are not set optimally.

[56]Richer temporal structures also merit formal study. The merits of making long-term commitments to DG compensation levels (as is common when feed-in tariffs are implemented) can be assessed in a model where (risk averse) consumers make long-lived investments in DG capacity.

Appendix A. Proofs of the Formal Conclusions

Proof of Proposition 1.

Let $\lambda_F \geq 0$ denote the Lagrange multiplier associated with constraint (6). Then at an interior solution to [RP-F]:

$$K_G: \quad \lambda_F \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(-\frac{\partial C^G(\cdot)}{\partial Q^v} \frac{dQ^v}{dK_G} - \frac{\partial C^G(\cdot)}{\partial K_G} \right) dF(\theta) - C^{K\prime}(K_G) - \frac{\partial T(\cdot)}{\partial K_G} \right] = 0; \quad (16)$$

$$w: \quad \int_{\underline{\theta}}^{\overline{\theta}} \theta\, K_D\, dF(\theta) - \lambda_F \left[\int_{\underline{\theta}}^{\overline{\theta}} \theta\, K_D\, dF(\theta) \right.$$

$$\left. + \int_{\underline{\theta}}^{\overline{\theta}} \left(w\,\theta + \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} \right) \frac{\partial K_D}{\partial w} dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \frac{\partial K_D}{\partial w} \right] = 0; \quad (17)$$

$$R: \quad -2 + 2\,\lambda_F = 0; \quad (18)$$

$$r: \quad \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\left[\frac{\partial V^j(X^j(\cdot))}{\partial X^j} - r \right] \frac{\partial X^j}{\partial r} - X^j(\cdot) \right) dF(\theta)$$

$$+ \lambda_F \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r \frac{\partial X^j}{\partial r} + X^j(\cdot) \right) dF(\theta) \right.$$

$$\left. - \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial X^j} \frac{\partial X^j}{\partial r} dF(\theta) \right] = 0. \quad (19)$$

$\frac{\partial V^j(X^j(r),\theta)}{\partial X^j} = r$ for $j \in \{D, N\}$ since $V^j(X,\theta)$ is the gross surplus consumer j derives from output X in state θ. Also, $\lambda_F = 1$ from (18) and $\frac{\partial Q^v}{\partial X^j} = 1$ because $Q^v(\cdot, \theta) = X(\cdot) - \theta\, K_D$. Therefore, (19) can be written as (9).

Since $\lambda_F = 1$ and $\frac{dQ^v}{\partial K_G} = 0$, (16) can be written as (7). Since $\lambda_F = 1$ and $\frac{\partial K_D}{\partial w}$ is not a function of θ, (17) can be written as:

$$\left[\int_{\underline{\theta}}^{\overline{\theta}} \left(w\,\theta + \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} \right) dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial w} = 0. \quad (20)$$

Because $\frac{\partial Q^v(\cdot, \theta)}{\partial K_D} = -\theta$, (20) can be written as (8).

Since $\lambda_F = 1$, (4) implies that (10) holds. ∎

Proof of Corollary 1

The proof follows immediately from (8) and (9). ∎

Proof of Corollary 2

(8) and (9) imply:

$$
r > w \iff \frac{\sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial X^j}{\partial r} \, dF(\theta)}{\sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial X^j}{\partial r} \, dF(\theta)} > \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \theta \, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D} \right]
$$

$$
\iff \frac{\partial T(\cdot)}{\partial K_D} > \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \theta \, dF(\theta) - \frac{\theta^E \sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial X^j}{\partial r} \, dF(\theta)}{\sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial X^j}{\partial r} \, dF(\theta)} . \quad \blacksquare
$$

Proof of Proposition 2

At an interior solution to [RP-r]:

$$
K_G: \quad \lambda_r \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(-\frac{\partial C^G(\cdot)}{\partial Q^v} \frac{dQ^v}{dK_G} - \frac{\partial C^G(\cdot)}{\partial K_G} \right) dF(\theta) - C^{K\prime}(K_G) - \frac{\partial T(\cdot)}{\partial K_G} \right] = 0; \quad (21)
$$

$$
w: \quad \int_{\underline{\theta}}^{\overline{\theta}} \theta \, K_D \, dF(\theta) - \lambda_r \left[\int_{\underline{\theta}}^{\overline{\theta}} \theta \, K_D \, dF(\theta) \right.
$$

$$
\left. + \int_{\underline{\theta}}^{\overline{\theta}} \left(w \, \theta + \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} \right) \frac{\partial K_D}{\partial w} \, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \frac{\partial K_D}{\partial w} \right] = 0; \quad (22)
$$

$$
r: \quad \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\left[\frac{\partial V^j(X^j(\cdot))}{\partial X^j} - r \right] \frac{\partial X^j}{\partial r} - X^j(\cdot) \right) dF(\theta)
$$

$$
+ \lambda_r \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r \frac{\partial X^j}{\partial r} + X^j(\cdot) \right) dF(\theta) \right.
$$

$$
\left. - \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial X^j} \frac{\partial X^j}{\partial r} \, dF(\theta) \right] = 0. \quad (23)
$$

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Because $\frac{\partial Q^v}{\partial X^j} = 1$, (23) can be written as:

$$\lambda_r \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r - \frac{\partial C^G(\cdot)}{\partial Q^v} \right) \frac{\partial X^j}{\partial r} \, dF(\theta) \right]$$

$$+ \left[\lambda_r - 1 \right] \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot) \, dF(\theta) \right] = 0. \tag{24}$$

If $\lambda_r = 0$, then $\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot) \, dF(\theta) = 0$, from (24). But this contradicts the maintained assumption that $X^j(\cdot) > 0$ for all $\theta \in [\underline{\theta}, \overline{\theta}]$. Therefore, $\lambda_r > 0$, and so (13) follows from (4).

Since $\lambda_r > 0$ and $\frac{dQ^v}{\partial K_G} = 0$, (21) can be written as (7). Since $\frac{\partial Q^v(\cdot)}{\partial K_D} = -\theta$ and $\frac{\partial K_D}{\partial w}$ is not a function of θ, (22) can be written as:

$$\left[1 - \lambda_r \right] \int_{\underline{\theta}}^{\overline{\theta}} \theta \, K_D \, dF(\theta) - \lambda_r \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(w - \frac{\partial C^G(\cdot)}{\partial Q^v} \right) \theta \, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial w} = 0,$$

which implies that (11) holds. $\blacksquare$

Proof of Proposition 3

From (24), when Assumption 2 holds:

$$\left[\lambda_r - 1 \right] \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(r, \theta) \, dF(\theta)$$

$$+ \lambda_r \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[r - c(K_G) - \sum_{i=2}^{n} i \, b_i \, (Q^v)^{i-1} \right] \frac{\partial X^j(\cdot)}{\partial r} \, dF(\theta) = 0$$

$$\Rightarrow \quad \lambda_r \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[\frac{r - c(K_G) - \sum_{i=2}^{n} i \, b_i \, (Q^v)^{i-1}}{r} \right] \frac{\partial X^j(\cdot)}{\partial r} \frac{r}{X^j(\cdot)} X^j(\cdot) \, dF(\theta)$$

$$= \left[1 - \lambda_r \right] \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(r, \theta) \, dF(\theta)$$

$$\Leftrightarrow \;\; \lambda_r \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[\frac{r - c(K_G) - \sum_{i=2}^{n} i\, b_i\, (Q^v)^{i-1}}{r} \right] \alpha_j\, X^j(\cdot)\, dF(\theta)$$

$$= \; [\,1 - \lambda_r\,] \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(r, \theta)\, dF(\theta)\,. \tag{25}$$

Assumption 1 implies $X^j(r, \theta) > 0$ for all r and θ. Therefore, (25) implies $\lambda_r \to 1$ as $\alpha_j \to 0$ for $j = D, N$.

When $\alpha_j = 0$ for $j = D, N$, (23) implies:

$$[\,\lambda_r - 1\,] \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot)\, dF(\theta) \right] = 0 \quad \Rightarrow \quad \lambda_r = 1\,.$$

Since $\lambda_r = 1$, (22) implies that w is as specified in (8). (8) and (13) imply:

$$r > w \quad \Leftrightarrow \quad \frac{\int_{\underline{\theta}}^{\overline{\theta}} C^G(Q^v(\cdot, \theta), K_G)\, dF(\theta) + C^K(K_G) + T(K_G, K_D)}{\int_{\underline{\theta}}^{\overline{\theta}} X(\cdot, \theta)\, dF(\theta)}$$

$$> w \left[1 - \frac{\theta^E\, K_D}{\int_{\underline{\theta}}^{\overline{\theta}} X(\cdot, \theta)\, dF(\theta)} \right]$$

$$\Leftrightarrow \;\; \int_{\underline{\theta}}^{\overline{\theta}} C^G(Q^v(\cdot, \theta), K_G)\, dF(\theta) + C^K(K_G) + T(K_G, K_D) \; > \; w\, E\{\,Q^v(\cdot)\,\}$$

$$\Leftrightarrow \;\; \int_{\underline{\theta}}^{\overline{\theta}} C^G(Q^v(\cdot, \theta), K_G)\, dF(\theta) + C^K(K_G) + T(K_G, K_D)$$

$$> \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v}\, \theta\, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D} \right] E\{\,Q^v(\cdot)\,\} \tag{26}$$

$$\Leftrightarrow \;\; \int_{\underline{\theta}}^{\overline{\theta}} \left(c(K_G)\, Q^v(\cdot) + \sum_{i=2}^{n} b_i [\, Q^v(\cdot)\,]^i \right) dF(\theta) + C^K(K_G) + T(K_G, K_D)$$

$$> \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(c(K_G) + \sum_{i=2}^{n} i\, b_i\, [\, Q^v(\cdot)\,]^{i-1} \right) \theta\, dF(\theta) \right] E\{\,Q^v(\cdot)\,\}$$

$$- \frac{1}{\theta^E} \left[\frac{\partial T(\cdot)}{\partial K_D} \right] E\{ Q^v(\cdot) \}$$

$$\Leftrightarrow \quad c(K_G) \int_{\underline{\theta}}^{\overline{\theta}} Q^v(\cdot)\, dF(\theta) + \int_{\underline{\theta}}^{\overline{\theta}} \sum_{i=2}^{n} b_i \left[Q^v(\cdot) \right]^i dF(\theta) + C^K(K_G) + T(K_G, K_D)$$

$$> \quad c(K_G)\, E\{ Q^v(\cdot) \} + \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \sum_{j=2}^{n} i\, b_i \left[Q^v(\cdot) \right]^{i-1} \theta\, dF(\theta) \right] E\{ Q^v(\cdot) \}$$

$$- \frac{1}{\theta^E} \left[\frac{\partial T(\cdot)}{\partial K_D} \right] E\{ Q^v(\cdot) \}$$

$$\Leftrightarrow \quad C^K(K_G) + T(K_G, K_D) + \frac{1}{\theta^E} \left[\frac{\partial T(\cdot)}{\partial K_D} \right] E\{ Q^v(\cdot) \}$$

$$> \quad \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \sum_{i=2}^{n} i\, b_i \left[Q^v(\cdot) \right]^{i-1} \theta\, dF(\theta) \right] E\{ Q^v(\cdot) \} - \int_{\underline{\theta}}^{\overline{\theta}} \sum_{i=2}^{n} b_i \left[Q^v(\cdot) \right]^i dF(\theta). \qquad (27)$$

As $b_i \to 0$ for all $i = 2, .., n$, inequality (27) holds if:

$$C^K(K_G) + T(K_G, K_D) + \frac{1}{\theta^E} \left[\frac{\partial T(\cdot)}{\partial K_D} \right] E\{ Q^v(\cdot) \} \; > \; 0. \qquad (28)$$

Each of the terms in (28) is positive, so the inequality holds.

It is apparent that the inequality in (27) also holds if $C^K(K_G) + T(K_G, K_D)$ is sufficiently large. ∎

Proof of Proposition 4

Let $\lambda \geq 0$ denote the Lagrange multiplier associated with constraint (6). Then at an interior solution to [RP]:

$$w: \quad \int_{\underline{\theta}}^{\overline{\theta}} \theta\, K_D\, dF(\theta) - \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial L(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} \frac{\partial K_D}{\partial w} + \frac{\partial L(\cdot)}{\partial Q^D} \frac{\partial Q^D}{\partial K_D} \frac{\partial K_D}{\partial w} \right) dF(\theta)$$

$$- \lambda \left[\int_{\underline{\theta}}^{\overline{\theta}} \theta\, K_D\, dF(\theta) \right.$$

$$\left. + \int_{\underline{\theta}}^{\overline{\theta}} \left(w\, \theta + \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} \right) \frac{\partial K_D}{\partial w}\, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \frac{\partial K_D}{\partial w} \right] \; = \; 0; \qquad (29)$$

$$r: \quad \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\left[\frac{\partial V^j(X^j(\cdot))}{\partial X^j} - r \right] \frac{\partial X^j}{\partial r} - X^j(\cdot) \right) dF(\theta)$$

$$- \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial L(\cdot)}{\partial Q^v} \sum_{j \in \{D,N\}} \frac{\partial Q^v}{\partial X^j} \frac{\partial X^j}{\partial r} \, dF(\theta)$$

$$+ \lambda \left[\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r \frac{\partial X^j}{\partial r} + X^j(\cdot) \right) dF(\theta) \right.$$

$$\left. - \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial X^j} \frac{\partial X^j}{\partial r} \, dF(\theta) \right] = 0. \qquad (30)$$

Conditions (16) and (18) also hold at the solution to [RP].

Because $\lambda = 1$ from (18) and $\frac{\partial Q^v}{\partial X^j} = 1$, (30) can be written as (15). Since $\lambda = 1$ and $\frac{dQ^v}{dK_G} = 0$, (10) holds and (16) can be written as (7). Because $\lambda = 1$ and $\frac{\partial K_D}{\partial w}$ is not a function of θ, (29) can be written as:

$$\left[\int_{\underline{\theta}}^{\overline{\theta}} \left(w \, \theta + \frac{\partial C^G(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} + \frac{\partial L(\cdot)}{\partial Q^v} \frac{\partial Q^v}{\partial K_D} + \frac{\partial L(\cdot)}{\partial Q^D} \frac{\partial Q^D}{\partial K_D} \right) dF(\theta) \right.$$

$$\left. + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial w} = 0. \qquad (31)$$

Because $\frac{\partial Q^v(\cdot, \theta)}{\partial K_D} = -\theta$ and $\frac{\partial Q^D(\cdot, \theta)}{\partial K_D} = \theta$, (31) can be written as (14). $\blacksquare$

Proof of Corollary 3

From (15):

$$r = \frac{\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} \right) \frac{\partial X^j}{\partial r} \, dF(\theta)}{\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial X^j}{\partial r} \, dF(\theta)}. \qquad (32)$$

(14) and (15) imply:

$$r > w \quad \Leftrightarrow \quad \frac{\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} \right) \frac{\partial X^j}{\partial r} \, dF(\theta)}{\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial X^j}{\partial r} \, dF(\theta)}$$

$$> \frac{1}{\theta^E} \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right) \theta \, dF(\theta) - \frac{\partial T(\cdot)}{\partial K_D} \right]$$

$$\Leftrightarrow \quad \frac{\partial T(\cdot)}{\partial K_D} \; > \; \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right) \theta \, dF(\theta)$$

$$- \; \frac{\theta^E \sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} \right) \frac{\partial X^j}{\partial r} \, dF(\theta)}{\sum\limits_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial X^j}{\partial r} \, dF(\theta)} \; . \quad \blacksquare$$

Proof of Corollary 4

The proof follows immediately from (14) and (15).   ∎ ■

Appendix B.   Elements of the Numerical Solutions

This Appendix further explains the methodology employed to derive the conclusions reported in section 5, illustrates how these conclusions change as parameter values change, and presents additional conclusions.

1.   Solution Methodology.

The key properties of the solutions to [RPE-r] and [RPE-rNM] are reported in Propositions B1 and B2, respectively.[57] The propositions refer to λ_1 and λ_2, which are the Lagrange multipliers associated with constraint (6) in [RPE-r] and [RPE-rNM], respectively.

Proposition B1. Equation (7) holds at the solution to [RPE-r]. Furthermore:

$$\lambda_1 \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r - \frac{\partial C^G(\cdot)}{\partial Q^v} \right) \frac{\partial X^j(\cdot)}{\partial r} \, dF(\theta) - \int_{\underline{\theta}}^{\overline{\theta}} \frac{\partial L(\cdot)}{\partial Q^v} \sum_{j \in \{D,N\}} \frac{\partial X^j(\cdot)}{\partial r} \, dF(\theta)$$

$$+ \, [\lambda_1 - 1] \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot) \, dF(\theta) \;=\; 0 \,, \;\; \text{and} \tag{33}$$

$$[1 - \lambda_1] \int_{\underline{\theta}}^{\overline{\theta}} \theta \, K_D \, dF(\theta) + \frac{\partial K_D}{\partial w} \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right) \theta \, dF(\theta)$$

$$- \, \lambda_1 \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(w - \frac{\partial C^G(\cdot)}{\partial Q^v} \right) \theta \, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial w} \;=\; 0 \,. \tag{34}$$

Proposition B2. Equation (7) holds at the solution to [RPE-rNM]. Furthermore:

$$\lambda_2 \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left(r - \frac{\partial C^G(\cdot)}{\partial Q^v} \right) \frac{\partial X^j(\cdot)}{\partial r} \, dF(\theta) + [\lambda_2 - 1] \sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} X^j(\cdot) \, dF(\theta)$$

$$- \int_{\underline{\theta}}^{\overline{\theta}} \left(\frac{\partial L(\cdot)}{\partial Q^v} \sum_{j \in \{D,N\}} \frac{\partial X^j(\cdot)}{\partial r} - \frac{\partial K_D}{\partial r} \left[\frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right] \theta \right) dF(\theta)$$

$$+ \, [1 - \lambda_2] \int_{\underline{\theta}}^{\overline{\theta}} \theta \, K_D \, dF(\theta) - \lambda_2 \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(r - \frac{\partial C^G(\cdot)}{\partial r} \right) \theta \, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial r} \;=\; 0 \,. \tag{35}$$

---

[57]The proofs of the propositions presented below parallel the proof of Proposition 2, and so are omitted.

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Propositions B1 and B2 identify the necessary conditions for solutions to the relevant problems. *Mathematica* and the Newton-Raphson Iteration Method are employed solve the conditions (and constraint (6)) for the optimal values of r, w, and K_D, given the specified functional forms and parameter values.

2. Sensitivity Analysis.

We now illustrate how the outcomes in the baseline setting analyzed in section 5 change as key parameter values change. Tables B1, B2, and B3 consider changes in the level of total demand for electricity $(\overline{X})$, the price elasticity of demand $(\alpha_D = \alpha_N)$, and the fraction of total demand accounted for by consumer D (η_D), respectively. Table B4 considers changes in the sensitivity of the demand for electricity to solar intensity $(\beta_D = \beta_N)$. Table B5 considers changes in the shape parameter (γ) for the beta distribution. Higher values of γ are associated with lower expected values of solar intensity (θ).

Tables B6, B7, and B8 consider changes in the VIP's generation (b_v), capacity (b_K), and transmission and distribution (a_T^D) costs, respectively. Table B9 considers changes in the cost of DG capacity (b_D). Table B10 considers changes in losses from environmental externalities (e_v) associated with centralized electricity production. In each case, parameters other than the one being varied are fixed at the levels identified in the baseline setting.

$\overline{X}$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
$23,000$	280.3	183.9	$66,323$	$4,454$	$8,033$	911	222	$8,722$
$25,391$	272.8	187.6	$68,231$	$4,953$	$8,789$	999	240	$9,549$
$27,000$	267.2	191.5	$69,844$	$5,465$	$9,463$	$1,079$	256	$10,286$

Table B1a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as $\overline{X}$ Changes.

$\overline{X}$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
$23,000$	370.9	370.9	$55,472$	$29,069$	$6,463$	$1,498$	136	$7,825$
$25,391$	313.7	313.7	$61,963$	$21,544$	$8,006$	$1,318$	184	$9,140$
$27,000$	294.4	294.4	$65,117$	$19,004$	$8,903$	$1,322$	211	$10,014$

Table B1b. Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as $\overline{X}$ Changes.

As industry demand for electricity increases, r can be reduced without reducing the VIP's expected profit below zero. K_G is increased to serve the increased demand for electricity. Furthermore, when net metering $(w = r)$ is not mandated, w is increased to induce increased DG capacity investment.

$\alpha_D = \alpha_N$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-0.10	269.9	190.1	$69,035$	$5,273$	$9,416$	$1,072$	248	$10,240$
-0.25	272.8	187.6	$68,231$	$4,953$	$8,789$	999	240	$9,549$
-0.40	275.7	185.2	$67,426$	$4,633$	$8,163$	927	232	$8,857$

Table B2a. **Outcomes at the Solution to** $[\text{RPE-}r]$ **in the Baseline Setting as** $\alpha_D = \alpha_N$ **Changes.**

$\alpha_D = \alpha_N$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-0.10	301.2	301.2	$63,935$	$19,888$	$8,793$	$1,342$	200	$9,934$
-0.25	313.7	313.7	$61,963$	$21,544$	$8,006$	$1,318$	184	$9,140$
-0.40	326.3	326.3	$59,990$	$23,199$	$7,220$	$1,294$	167	$8,346$

Table B2b. **Outcomes at the Solution to** $[\text{RPE-}r\text{NM}]$ **in the Baseline Setting as** $\alpha_D = \alpha_N$ **Changes.**

The constant elasticity demand function in the baseline setting implies that an increase in price sensitivity is associated with a reduced level of demand. Reduced equilibrium consumption of electricity requires an increase in r to ensure non-negative profit for the VIP. K_G is reduced in light of the reduced demand. In the absence of a net metering mandate, w is also reduced to induce a reduction in DG capacity investment.

η_D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.05	272.8	187.6	$68,231$	$4,953$	$9,278$	511	240	$9,549$
0.10	272.8	187.6	$68,231$	$4,953$	$8,789$	999	240	$9,549$
0.25	272.8	187.6	$68,231$	$4,953$	$7,324$	$2,464$	240	$9,549$

Table B3a. **Outcomes at the Solution to** $[\text{RPE-}r]$ **in the Baseline Setting as** η_D **Changes.**

η_D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.05	313.7	313.7	61,963	21,544	8,451	873	184	9,140
0.10	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
0.25	313.7	313.7	61,963	21,544	6,672	2,652	184	9,140

Table B3b. Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as η_D Changes.

Changes in the fraction of consumers that can undertake DG do not change the optimal DG compensation policy because consumers are otherwise identical and the regulator seeks to maximize aggregate consumer welfare.

$\beta_D = \beta_N$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-0.25	278.0	184.6	68,224	4,555	8,688	984	240	9,433
0.0	272.8	187.6	68,231	4,953	8,789	999	240	9,549
0.25	271.1	188.4	68,241	5,057	8,822	1,004	240	9,586

Table B4a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as $\beta_D = \beta_N$ Changes.

$\beta_D = \beta_N$	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-0.25	331.1	331.1	60,744	23,823	7,683	1,377	174	8,886
0.0	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
0.25	309.0	309.0	62,291	20,925	8,095	1,303	187	9,212

Table B4b. Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as $\beta_D = \beta_N$ Changes.

As $\beta_D = \beta_N$ increases, consumer demand for electricity increases. The resulting increased electricity consumption allows the regulator to reduce r without reducing the VIP's profit below zero. The increase in $\beta_D = \beta_N$ increases demand most when demand is high, thereby increasing the expected marginal cost of centralized electricity generation. High costs of centralized generation are avoided in part by increasing K_G. In the absence of a net metering mandate, more DG is also induced (by increasing w).

γ	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.90	272.8	188.7	67,968	5,096	8,790	1,004	237	9,557
1.205	272.8	187.6	68,231	4,953	8,789	999	240	9,549
1.50	272.8	186.5	68,430	4,798	8,789	995	242	9,542

Table B5a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as the shape parameter of the Beta distribution (γ) changes.

γ	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.90	337.3	337.3	58,940	24,641	7,568	1,484	160	8,891
1.205	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
1.50	304.7	304.7	63,354	20,360	8,176	1,249	195	9,229

Table B5b. Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as the shape parameter of the Beta distribution (γ) changes.

As γ increases (and so the expected value of θ declines), DG capacity produces less electricity. Consequently, w is reduced in order to induce less K_D. K_G is increased to support the increased centralized generation of electricity.

b_v	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.002	245.8	146.5	70,312	0	9,322	1,036	261	10,097
0.003	272.8	187.6	68,231	4,953	8,789	999	240	9,549
0.004	297.1	219.3	66,419	9,112	8,322	1,001	223	9,101

Table B6a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as b_v Changes.

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b_v	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.002	279.3	279.3	64,346	17,014	8,663	1,230	204	9,689
0.003	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
0.004	351.3	351.3	59,295	26,488	7,310	1,460	163	8,607

Table B6b. **Outcomes at the Solution to** [RPE-rNM] **in the Baseline Setting as** b_v **Changes**.

As the VIP's marginal cost of generating electricity rises more rapidly with output, r is increased to limit electricity consumption. In addition, w is increased to induce an increase in K_D, which helps to offset the reduced investment in K_G that is implemented in response to the increased cost of centralized electricity production.

b_K	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.00035	246.8	187.9	68,809	4,990	9,303	1,057	246	10,113
0.00045	272.8	187.6	68,231	4,953	8,789	999	240	9,549
0.00055	290.3	187.9	67,856	4,988	8,451	962	236	9,177

Table B7a. **Outcomes at the Solution to** [RPE-r] **in the Baseline Setting as** b_K **Changes**.

b_K	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.00035	262.9	262.9	65,348	14,857	8,983	1,202	214	9,970
0.00045	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
0.00055	388.0	388.0	56,708	31,313	6,648	1,643	143	8,148

Table B7b. **Outcomes at the Solution to** [RPE-rNM] **in the Baseline Setting as** b_K **Changes**.

Less centralized capacity is installed as its cost increases. r is also increased to reduce electricity consumption. Even though DG capacity becomes relatively less expensive as b_K increases, less DG capacity may be induced (via a reduction in w) due to the induced reduction in equilibrium electricity consumption.

a_T^D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-4.00	272.2	213.7	67,229	8,379	8,801	1,043	230	9,614
5.05	272.8	187.6	68,231	4,953	8,789	999	240	9,549
14.00	272.9	162.0	69,204	1,580	8,788	979	249	9,517

Table B8a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as a_T^D Changes.

a_T^D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
-4.00	293.8	293.8	63,346	18,924	8,384	1,262	195	9,450
5.05	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
14.00	358.7	358.7	58,763	27,453	7,176	1,493	159	8,510

Table B8b. Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as a_T^D Changes.

DG entails higher social costs as a_T^D increases, so w is reduced in order to induce less investment in DG capacity in the absence of a net metering mandate. In contrast, a requirement to increase w to the level of r results in increased DG payments that reduce the VIP's profit. r (and w) must be increased to ensure the VIP's financial solvency.

b_D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.003	272.8	186.2	68,069	5,507	8,790	1,001	238	9,552
0.0038	272.8	187.6	68,231	4,953	8,789	999	240	9,549
0.005	272.9	190.1	68,506	4,007	8,788	996	243	9,542

Table B9a. Outcomes at the Solution to [RPE-r] in the Baseline Setting as b_D Changes.

b_D	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
0.003	359.0	359.0	57,056	31,759	7,170	1,603	147	8,626
0.0038	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
0.005	294.7	294.7	64,786	14,473	8,366	1,184	208	9,343

Table B9b.   Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as b_D Changes.

As the marginal cost of DG capacity increases more rapidly, w is increased in the absence of a net metering mandate in order to avoid excessive under-investment in K_D. Equilibrium investment in K_D still declines, though, and is offset in part by an increase in K_G.

e_v	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
6.0	272.6	183.8	68,384	4,451	8,794	995	123	9,666
11.74	272.8	187.6	68,231	4,953	8,789	999	240	9,549
15.0	273.2	191.9	68,059	5,510	8,782	1,004	365	9,421

Table B10a.   Outcomes at the Solution to [RPE-r] in the Baseline Setting as e_v Changes.

e_v	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
9.0	313.7	313.7	61,963	21,544	8,006	1,318	94	9,230
11.74	313.7	313.7	61,963	21,544	8,006	1,318	184	9,140
15.0	313.7	313.7	61,963	21,544	8,006	1,318	282	9,042

Table B10b.   Outcomes at the Solution to [RPE-rNM] in the Baseline Setting as e_v Changes.

As the losses from environmental externalities due to centralized electricity production increase, r is increased in the absence of a net metering mandate in order to discourage electricity consumption. w is increased to encourage the production of "clean energy." K_G declines in light of the reduction in expected electricity consumption, and K_D increases in response to the increase in w.

3. The Baseline Setting with a Fixed Retail Charge.

The impact of a net metering mandate can be less pronounced when the regulator is able to set a fixed retail charge (R) that does not affect the demand for electricity.[58] The difference between the optimal values of w and r often is reduced when the regulator can employ a fixed retail charge to recover the VIP's fixed production costs (without inducing any customers to reduce their electricity consumption to zero). Consequently, a mandate to set identical values for w and r can be less constraining. To illustrate this point, consider the solutions to problems [RP] and [RP-NM] in the baseline setting. The latter problem is problem [RP] with the additional constraint that $w = r$.

Proposition B3. Equations (7) and (10) hold at the solution to [RP-NM]. Furthermore:

$$\sum_{j \in \{D,N\}} \int_{\underline{\theta}}^{\overline{\theta}} \left[r - \left(\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} \right) \right] \frac{\partial X^j}{\partial r} \, dF(\theta)$$

$$- \left[\int_{\underline{\theta}}^{\overline{\theta}} \left(r - \left[\frac{\partial C^G(\cdot)}{\partial Q^v} + \frac{\partial L(\cdot)}{\partial Q^v} - \frac{\partial L(\cdot)}{\partial Q^D} \right] \right) \theta \, dF(\theta) + \frac{\partial T(\cdot)}{\partial K_D} \right] \frac{\partial K_D}{\partial r} \; = \; 0 \,. \qquad (36)$$

Table B11 records the key outcomes at the solutions to problems [RP] and [RP-NM] in the baseline setting.

Problem	r	w	K_G	K_D	$E\{U^N\}$	$E\{U^D\}$	$E\{L\}$	$E\{W\}$
[RP]	195.4	195.3	70,156	5,956	8,861.7	1,017.4	259	9,620.0
[RP-NM]	195.3	195.3	61,963	5,964	8,861.6	1,017.5	259	9,620.0

Table B11. Outcomes in the Baseline Setting with a Fixed Retail Charge.

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[58]Faruqui and Hledik (2015), among others, stress the importance of implementing fixed retail charges that reflect the utility's fixed production costs.

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