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by

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Abstract

We examine the role that maximum demand charges (MDCs) can play in avoiding the death spiral that some utilities may otherwise face as the distributed generation (DG) of electricity proliferates. We find that MDCs generally secure gains for consumers that do not undertake DG, and often secure gains for consumers that undertake DG. However, the welfare gains tend to be modest in plausible settings. Furthermore, time-of-use pricing often secures larger welfare gains than do MDCs.

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1 Introduction

The distributed generation of electricity[1] is expanding rapidly throughout the world, often powered by solar panels installed on the rooftops of residential and commercial infrastructure.[2] Although solar distributed generation (DG) can provide many benefits, it can also introduce complications. In particular, when customers generate their own electricity instead of purchasing it from the local utility, utility revenue often declines by more than avoided cost declines, thereby potentially jeopardizing the utility's financial solvency. Higher prices for electricity can increase utility revenue. However, higher prices also can encourage expanded DG, thereby further reducing the demand for electricity supplied by the utility. The resulting "death spiral" and the associated increase in charges for electricity borne by consumers who do not undertake DG are presently of substantial concern to policymakers (Lively and Cifuentes, 2014).

The purpose of this research is to analyze the optimal design of utility rate structures in the presence of DG. We focus on the role that maximum demand charges can play as a complement to more common rate elements. A maximum demand charge (MDC) is a charge levied on a consumer that is proportional to the maximum amount of electricity he purchases from the local utility during a specified time period. Our focus on MDCs is motivated by the substantial interest they have garnered in recent policy discussions about the best means to avoid the death spiral in the presence of ever-increasing DG. Hledik (2014, p. 86), for example, reports the growing "interest among utilities in offering [maximum] demand charges to their residential customers."[3] Lively and Cifuentes (2014) and Faruqui and Hledik (2015) observe that the interest in MDCs may reflect in part their potential to better align charges for electricity with the costs that individual customers impose on the system and thereby

[1]The distributed generation of electricity entails 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" (American Council for an Energy-Efficient Economy, 2016).

[2]See, for example, DNV GL Energy (2014), the World Alliance for Decentralized Energy (2016), and Solar Energy Industries Association (2016).

[3]Also see Lively and Cifuentes (2014) and Faruqui and Hledik (2015), for example.

limit the extent to which the utility's costs are borne disproportionately by customers who do not undertake DG.[4]

Although the design and performance of MDCs have been analyzed in settings where DG is not present,[5] the corresponding analysis in the presence of DG has not been undertaken to our knowledge. The presence of DG is important because, although MDCs can reduce a customer's peak consumption of electricity and thereby reduce utility costs, they can also encourage expanded DG (to reduce the payments required by the MDCs) and thereby reduce utility revenue. We analyze the manner in which MDCs are optimally combined with the fixed charges and unit prices for electricity that regulators typically set.[6] We do so in the common setting where DG compensation takes the form of "net metering," under which the per-unit compensation for electricity produced via solar DG is precisely the prevailing unit price for electricity purchased from the utility.[7]

Our formal model considers a setting in which a utility serves both customers who can undertake DG and those who cannot. Each customer's demand for electricity varies over the course of a day. The electricity produced by solar panels also varies with the time of day and prevailing weather patterns. A regulator sets a fixed charge for electricity (R), a unit price of electricity (p), and a MDC (D) to maximize the expected welfare of consumers, while ensuring a normal expected profit for the utility. These instruments play several roles in our model, as they do in practice. The instruments affect electricity consumption, DG capacity investment, and utility revenue. The multiple roles complicate the specification of

[4]Specificially, Lively and Cifuentes (2014, p. 14) suggest that "Implementation of a [maximum] demand charge will reduce the subsidies that standard residential customers would otherwise pay to support the installation of rooftop solar." Faruqui and Hledik (2015, p. 4) state that "Since most capital grid investments are driven by demand, the idea is that [maximum] demand charges will better align the price that customers pay with the costs that they are imposing on the system."

[5]See, for example, Crew and Kleindorfer (1979), Berg and Savvides (1983), Veall (1983), Gallant and Koenker (1984), Taylor and Schwartz (1986, 1990), Neufeld (1987), Schwartz and Taylor (1987), Woo (1991), Lee (1993), Wilson (1993), Woo et al. (1995), Seeto et al. (1997), and Woo et al. (2002).

[6]Several studies (e.g., Borenstein and Holland, 2005; Borenstein, 2007, 2016; Brown and Faruqui, 2014) emphasize the potential merits of real-time prices. However, prices that adjust instantaneously to continually reflect the prevailing marginal cost of supplying electricity are not common in practice.

[7]Brown and Sappington (2016a) explore the potential merits of DG compensation policies other than net metering.

simple prescriptions that apply in all environments. Therefore, after providing some analytic characterization of the optimal regulatory policy in selected settings, we employ numerical solutions to provide a more complete characterization of the optimal policy in settings that are structured to reflect marketplace realities.

We show that although MDCs enhance aggregate expected welfare, they can either increase or decrease the welfare of distinct consumer groups. In particular, although MDCs can provide Pareto gains, they often reduce the welfare of customers who undertake DG while increasing the welfare of customers who do not undertake DG. This is the case because MDCs typically serve to increase the effective price of electricity during periods of peak demand. The increased price reduces the system-wide peak demand for electricity and thereby reduces the utility's operating costs. The reduced costs enable the regulator to reduce the price of electricity during off-peak periods of demand. Although these price reductions are of direct benefit to all customers, they can harm customers who undertake DG by reducing the compensation they receive for the electricity they produce.

These same considerations explain why MDCs can either increase or reduce DG capacity investment. Because MDCs increase the effective price of electricity during the period in which a customer's demand for electricity peaks, they increase DG compensation during this period. However, the accompanying price reductions in other periods reduce DG compensation under a net metering policy, and can thereby lead to reduced investment in DG capacity.

As other authors have suggested (e.g., Hausman and Neufeld, 1984; Neufeld, 1987; Borenstein, 2016), we demonstrate that MDCs tend to be most effective in settings where the demands of different customer groups all peak at the same time during the day. When customer demands for electricity peak at different times, MDCs are less effective at reducing the system-wide peak demand. Consequently, MDCs are optimally employed less extensively and secure less pronounced welfare gains.

Our analysis focuses on the common setting where the regulator sets a single unit price for electricity that persists throughout the day. However, we also consider the potential impacts of MDCs in settings where time-of-use pricing (TOU) is feasible. We show that MDCs can increase aggregate consumer welfare in this setting by effectively enabling the regulator to set customer-specific TOU prices when customer demands peak at different times during the day. However, the gains from MDCs are small in the settings we examine. Further, aggregate consumer welfare typically is higher under TOU pricing than under MDCs, even though certain consumer groups sometimes prefer MDCs to TOU pricing.

We develop and explain these findings as follows. Section 2 presents the key features of our formal model. Section 3 provides an analytic characterization of the optimal regulatory policy in selected settings. Section 4 employs numerical solutions to further characterize the optimal policy. Section 5 illustrates the potential impacts of MDCs when TOU pricing is feasible. Section 6 discusses the implications of our findings and suggests directions for further research.

2 Model Elements

For analytic ease, we consider a setting with two consumers, labeled G and N. Consumer G can undertake distributed generation (DG) of electricity, whereas consumer N cannot do so.[8] Both consumers can purchase electricity from the regulated supplier of electricity, called the utility.

There are three periods of demand for electricity: an off-peak period (period 0); a mid-peak period (period 1); and a peak period (period 2). Consumer $i \in \{G, N\}$ derives value $u_{it}(x, \theta_t)$ from x units of electricity in period $t \in \{0, 1, 2\}$ when state $\theta_t \in [\underline{\theta}_t, \overline{\theta}_t]$ is realized. This value is a strictly increasing, strictly concave function of x. As discussed further below, the state variable θ_t can be viewed as a measure of the intensity of the sunshine that prevails during period t. The distribution function for θ_t is $F_t(\theta_t)$.

[8] Our qualitative conclusions are unchanged if there are multiple G consumers and multiple N consumers. There are many reasons why some individuals are unable to undertake DG in practice. For instance, they may not own infrastructure on which solar panels can be installed or they may not possess the financial resources required to purchase solar panels.

The regulator sets both a fixed charge ($R \geq 0$) for the right to purchase electricity from the utility and a corresponding unit price of electricity (p). The regulator may also be able to set a MDC. When consumer $i \in \{G, N\}$ faces a MDC of magnitude D, he is required to pay the utility $D\,[\max_{t\,\in\,\{0,1,2\}} \{\, x_{it} \,\}\,]$, where x_{it} denotes the amount of electricity that consumer i purchases from the utility in period t. Thus, the total demand charge payment that a consumer makes to the utility is the product of D and the maximum amount of electricity the consumer purchases during the day.[9]

A consumer's demand for electricity from the utility in period t will depend upon the prevailing charges (p, R, D), the realized state (θ_t), and the amount of electricity the consumer produces via DG. Before the start of all three demand periods, consumer G can install k_G units of DG capacity at cost $K(k_G)$, where $K'(\cdot) > 0$ and $K''(\cdot) > 0$.[10] Each unit of DG capacity generates θ_t units of electricity in period t when state θ_t prevails. Thus, k_G can be viewed as the amount of solar generating capacity that consumer G installs, and θ_t is a measure of the average "solar intensity" that prevails in state θ_t in period t.

Consumer G's compensation for the electricity he supplies via DG is determined by what is commonly referred to as "net metering," so the unit compensation for DG in period t is the effective price of electricity the consumer faces in that period. This effective price is the sum of the unit price of electricity (p) and any relevant MDC. A MDC is relevant for consumer i in period t if the consumer's maximum purchase of electricity from the utility occurs in that period. We assume that once p, R, and D are specified, the consumer can determine the period in which his maximum demand will occur.[11] We also assume that this period of maximum demand for a consumer is the same for all realizations of the state variables.[12]

[9] In practice, the specified MDC often is applied to the customer's maximum hourly consumption of electricity in a given month. Our analysis captures the essence of such real-world demand charges while avoiding the complications associated with modeling instantaneous consumption choices throughout multiple extended time periods.

[10] Primes ($'$) denote derivatives here and throughout the ensuing analysis. To ensure that k_G is strictly positive and finite in equilibrium, we also assume that $\lim_{k_G \to 0} K'(k_G) = 0$ and $\lim_{k_G \to \infty} K'(k_G) = \infty$.

[11] This period can differ across consumers.

[12] This assumption allows us to abstract from the additional complications that arise when a consumer is not sure whether increased consumption of electricity in some period will trigger associated demand charges.

To specify the effective price of electricity formally, let the variable δ_{it} take on the value 1 if the amount of electricity that consumer i purchases from the utility in period t is no less than his corresponding purchase of electricity in any period other than t. Let $\delta_{it} = 0$ otherwise. Then the effective unit price that consumer i faces in period t (and hence the effective unit compensation that consumer i receives for the electricity he produces via DG) is $p + \delta_{it} D$.

Suppressing the dependence of demand on relevant prices and DG capacity for expositional ease, consumer i's electricity consumption in state θ_t in period t is:[13]

$$x_{it}(\theta_t) \;=\; \arg\max_x \; \{ \, u_{it}(x, \theta_t) - [\, p + \delta_{it} \, D \,] \, [\, x - \theta_t \, k_i \,] \, \} \, . \tag{1}$$

A consumer's welfare is the value he derives from electricity consumption, less the amount he pays for electricity, plus any profit he secures from his production of electricity. Formally, consumer i's expected welfare is:

$$E \{ \, U_i \, \} \;=\; \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \{ \, u_{it}(x_{it}(\theta_t), \theta_t) - [\, p + \delta_{it} \, D \,] \, [\, x_{it}(\theta_t) - \theta_t \, k_i \,] \, \} \, dF_t(\theta_t) - R - K_i(k_i) \, . \tag{2}$$

(2) implies that consumer G's choice of k_G is determined by:

$$\sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, p + \delta_{Gt} \, D \,] \, \theta_t \; dF_t(\theta_t) - K'_G(k_G) \;=\; 0$$

$$\Rightarrow \;\; \frac{\partial k_G}{\partial p} \;=\; \frac{\sum_{t=0}^{2} \theta_t^E}{K''_G(\cdot)} \;\; \text{and} \;\; \frac{\partial k_G}{\partial D} \;=\; \frac{\sum_{t=0}^{2} \delta_{Gt} \, \theta_t^E}{K''_G(\cdot)} \;\; \text{where} \;\; \theta_t^E \;\equiv\; \int_{\underline{\theta}_t}^{\overline{\theta}_t} \theta_t \; dF_t(\theta_t) \, . \tag{3}$$

The utility supplies all of the electricity that its customers wish to purchase in each demand period.[14] In doing so, the utility incurs both electricity procurement costs and transmission, distribution, and network management (TDM) costs. The utility's cost of

These complications render the analysis more cumbersome without admitting substantial additional insight.

[13] k_i is the DG capacity installed by consumer $i \in \{D, G\}$. Recall that k_N is assumed to be 0.

[14] For simplicity, we assume that the expected aggregate demand for electricity from the utility in the off-peak and mid-peak periods combined is strictly positive, i.e., $\sum_{i=G}^{N} \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, x_{it}(\theta_t) - \theta_t \, k_i \,] \, dF_t(\theta_t) > 0$.

procuring X_t units of electricity in period t is captured by the strictly increasing, weakly convex function $C_t(X_t)$. These costs can reflect either the expenses associated with purchasing electricity in a wholesale market or the costs that a vertically-integrated utility incurs when employing its own assets to generate electricity.

The utility's TDM costs, $T(m, k_G)$, include the expenses associated with installing, maintaining, and managing the infrastructure required to transmit electricity from generation sites to customer premises. The utility's TDM costs increase with $m \equiv \max_{t \in \{0,1,2\}} \{ \max_{\theta_t} \{ x_{Nt}(\theta_t) + x_{Gt}(\theta_t) \} \}$, which is a measure of the maximum potential demand for electricity supplied by the utility.[15] TDM costs can either increase or decrease as DG capacity (k_G) expands. Increased costs of accommodating the intermittent supply of electricity from solar DG might cause $T(\cdot)$ to increase with k_G. Alternatively, an increase in k_G might reduce the need to distribute electricity to remote regions, and thereby reduce $T(\cdot)$.[16]

The utility's profit is the revenue it receives from consumers less the sum of electricity procurement costs, TDM costs, and payments to consumer G for the electricity he produces. Formally, the utility's expected profit is:

$$E\{\Pi\} \equiv \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left\{ \sum_{i=G}^{N} [p + \delta_{it} D][x_{it}(\theta_t) - \theta_t k_i] - C_t\Big(\sum_{i=G}^{N} [x_{it}(\theta_t) - \theta_t k_i]\Big) \right\} dF_t(\theta_t) + 2R - T(m, k_G). \quad (4)$$

The regulator seeks to maximize a weighted average of the expected welfare of consumers G and N while ensuring nonnegative expected profit for the utility. Letting $w_i > 0$ denote the weight the regulator applies to the welfare of consumer $i \in \{G, N\}$, the regulator's problem, [RP], is:

[15] More generally, m might be defined as $\max_{t \in \{0,1,2\}} \{ \max_{\theta_t} \{ x_{Nt}(\theta_t) + x_{Gt}(\theta_t) - \eta \, \theta_t k_G \} \}$, where $\eta \in [0, 1]$ is a measure of the extent to which expected DG production reduces the need to expand the distribution infrastructure to meet consumer demand for electricity. For simplicity, we consider the setting where $\eta = 0$, so the utility must effectively stand prepared to serve all consumer demand regardless of how much DG output is produced. The analysis with $\eta > 0$ is more tedious and produces conclusions similar to those drawn below.

[16] See Cohen et al. (2015), for example, for a discussion of the varying impacts of DG on a utility's TDM costs.

$$\underset{p,\,R \geq 0,\,D \geq 0}{Maximize} \quad \sum_{i=G}^{N} w_i \; E\{U_i\} \quad \text{subject to} \quad E\{\Pi\} \;\geq\; 0\,. \tag{5}$$

3 Elements of the Optimal Regulatory Policy

The regulator employs her policy instruments (p, D, R) to influence electricity consumption, investment in DG capacity, and utility revenue. These varied roles for the policy instruments make it difficult to derive general prescriptions for their optimal use. However, some insight regarding the optimal structuring of these instruments can be gleaned by comparing the solution to [RP] with the solution to the regulator's corresponding problem (denoted [RP-n]) when MDCs are not feasible.[17] Proposition 1 characterizes the solution to [RP-n] in the setting where the utility's procurement costs increase linearly with output, i.e., where Assumption 1 holds.

Assumption 1. $C_t(X) = \underline{c} + c\,X$ for $t = 0, 1, 2$, where $\underline{c} \geq 0$ and $c > 0$ are constants.

Proposition 1. *Suppose Assumption 1 holds, $w_N = w_G$, and either $\frac{\partial T(\cdot)}{\partial k_G} \leq 0$ or $\frac{\partial T(\cdot)}{\partial k_G} > 0$ is sufficiently small. Then $p > c$ at the solution to [RP-n].*[18]

Proposition 1 reports that when the regulator must rely solely on the unit price of electricity (p) to control both electricity consumption and DG capacity investment, she increases p above the utility's marginal cost of procuring electricity (c). The resulting increase in DG compensation under net metering induces increased investment in DG capacity, which reduces the utility's TDM costs (when $\frac{\partial T(\cdot)}{\partial k_G} < 0$) or at least does not increase them substantially (when $\frac{\partial T(\cdot)}{\partial k_G} > 0$ is sufficiently small).[19] The increase in p above c also reduces the amount of electricity purchased from the utility during the period of peak demand (period

[17]Formally, problem [RP-n] is problem [RP] with the additional restriction that $D = 0$.

[18]The proof of Proposition 1 and the proofs of all other formal conclusions are presented in Appendix B.

[19]If $\frac{\partial T(\cdot)}{\partial k_G}$ is positive and sufficiently large, the regulator may optimally set p below c to discourage investment in DG capacity.

2) and thereby reduces the utility's capacity-related TDM costs (since $\frac{\partial T(\cdot)}{\partial m} > 0$).[20]

Proposition 2 illustrates the qualitative changes in the optimal regulatory policy that can arise when MDCs are feasible. The proposition considers the setting with *contemporaneous peak demands* where each consumer's maximum purchase of electricity from the utility always occurs in the peak period (period 2). Proposition 2 identifies conditions under which the regulator sets p below, not above, the utility's marginal cost of procuring electricity in this setting.

Proposition 2. *Suppose Assumption 1 holds, $w_N = w_G$, $\theta_0^E + \theta_1^E > 0$, and $\frac{\partial T(\cdot)}{\partial k_G} > 0$. Then $p < c$ at the solution to [RP] in the setting with contemporaneous peak demands.*

A reduction in p below c reduces expected DG compensation under net metering in periods 0 and 1,[21] and thereby reduces the utility's TDM costs (when $\frac{\partial T(\cdot)}{\partial k_G} > 0$).[22] The regulator employs the MDC to increase the effective price of electricity ($p + D$) in the peak period, and thereby reduce the utility's capacity-related TDM costs.

Propositions 1 and 2 illustrate the more general conclusion that the availability of MDCs can induce qualitative changes in the manner in which the regulator optimally employs her instruments to affect electricity consumption, DG capacity investment, and utility revenue.[23] Section 4 provides additional detail regarding the regulator's optimal use of her instruments.

4 Numerical Solutions

To further characterize the optimal regulatory policy and to determine how it varies as the prevailing environment changes, we characterize the solution to [RP] in selected settings using calibrated, tractable functional forms for key functions. Our calibrations rely primarily

[20] There is no first-order reduction in welfare in periods 0 and 1 as p is increased marginally above c.

[21] This is the case as long as expected DG production is strictly positive either in period 0 or in period 1 (i.e., if $\theta_0^E + \theta_1^E > 0$).

[22] There is no first-order reduction in welfare in periods 0 and 1 as p is reduced marginally below c.

[23] Propositions B1 and B2 in Appendix B identify more general conditions under which the regulator sets p below the utility's expected marginal cost of procuring electricity when she is able to implement MDCs.

upon data from California, in part because these data are readily accessible.[24]

To specify distribution functions for the state variables, we view these variables as measures of DG capacity utilization. Specifically, we define $\theta_t \in [0, 1]$ to be the ratio of DG output to the maximum feasible DG output in period t, given the installed DG capacity. Solar rooftop DG capacity in California was $2,792.58$ MWs in 2014 (EIA, 2014b). The California Independent System Operator (CAISO) supplies data on hourly solar electricity production in California in 2014 (CAISO, 2015). Using these data, we record the solar capacity utilization rate (output/capacity) for each of the $8,760$ hours in the year. We then employ maximum likelihood estimation to identify the distributions that best fit the observed strictly positive capacity utilization rates. We estimate one distribution for the presumed peak period (11 am – 7 pm) and another distribution for the presumed mid-peak period (7 am – 11 am and 7 pm – 11 pm). Standard tests reveal that the beta distribution fits the data well in both cases, with parameters (2.834641, 1.712483) in the peak period and with parameters (1.31113, 1.780069) in the mid-peak period. For simplicity, we take θ_t to be 0 throughout the presumed off-peak period (11 pm to 7 am).[25]

Consumer demand for electricity is assumed to be $x_{it}(\theta_t) = a_{it} [\, \underline{v} + \theta_t^{\epsilon_{it}} \,] - b_{it}\, p_t$, where a_{it}, b_{it}, $\underline{v}$, and ϵ_{it} are strictly positive parameters. To identify initial values for these parameters, we normalize $\underline{v}$ to 1, assume $b_{it} = b_i$ for $t = 0, 1, 2$, and choose a_{it} to ensure

$$a_{it} \left[\, \underline{v} + \left(\theta_t^E\right)^{\epsilon_{it}} \,\right] - b_i\, \overline{p} \;=\; \overline{x}_{it} \quad \text{for } i \in \{G, N\} \text{ and } t \in \{0, 1, 2\}, \tag{6}$$

where $\overline{p} = 151.5$ reflects the average retail price of electricity (in dollars per MWh) in California in 2014 (EIA, 2014b), and where $\overline{x}_{it}$ denotes the electricity consumption of consumer i in period t. To specify values for $\overline{x}_{it}$, note that the peak demand for electricity from California's largest utilities ranged from $2,848$ to $18,175$ MWs in 2014 (California Energy Almanac, 2016). To divide the midpoint of this range ($10,511.2$ MWs) between the two (types of)

[24] Although we employ data from California to calibrate our numerical solutions, our findings do not necessarily reflect outcomes that would likely arise in California in practice.

[25] The mean solar capacity utilization rate is 0.002 in the off-peak period in the sample, and 92.5% of the observations are zero. In the mid-peak (peak) period in the sample, the mean solar capacity utilization rate is 0.43 (0.64), and 58.9% (92.4%) of the observations are strictly positive.

consumers in our model, we take the ratio of consumption by consumer G to consumption by consumer N to be 0.176.[26] Therefore, the maximum consumption of consumers G and N are initially taken to be $1,573.1$ and $8,938.1$, respectively. We assume that each consumer's minimum consumption occurs in period 0. Furthermore, the ratio of a consumer's maximum consumption to his second-highest (lowest) consumption is taken to be 1.51 (1.867), reflecting the midpoint of the corresponding range of the ratio of system-wide peak to mid-peak (off-peak) electricity consumption in California in 2014 (CAISO, 2015).

We will consider two settings. In the *setting with contemporaneous peak demands*, each consumer's maximum consumption occurs in period 2. In the *setting with divergent peak demands*, consumer N's maximum consumption arises in period 2 whereas consumer G's maximum consumption occurs in period 1. Therefore, the initial values for $\overline{x}_{it}$ in these two settings are as follows:

	Contemporaneous Peak Demands				Divergent Peak Demands		
	$\overline{x}_{Gt}$	$\overline{x}_{Nt}$	$\overline{x}_{Gt} + \overline{x}_{Nt}$		$\overline{x}_{Gt}$	$\overline{x}_{Nt}$	$\overline{x}_{Gt} + \overline{x}_{Nt}$
$t = 0$	842.59	$4,787.42$	$5,630.01$		842.59	$4,787.42$	$5,630.01$
$t = 1$	$1,041.79$	$5,919.27$	$6,961.06$		$1,573.10$	$5,919.27$	$7,492.37$
$t = 2$	$1,573.10$	$8,938.10$	$10,511.20$		$1,041.79$	$8,938.10$	$9,979.89$

Given $\overline{p}$ and $\overline{x}_{it}$, initial values for b_i in (6) are set by taking the price elasticity of demand for both consumers in each period to be -0.25 (so we set $\frac{b_i \overline{p}}{\overline{x}_{it}} = 0.25$).[27] We also initially normalize the elasticity of demand for electricity with respect to solar intensity to be 0.25, reflecting a moderate increase in the demand for electricity as sunshine and ambient temperature increase. Formally, we set

[26] Thus, DG customers are assumed to account for 15% of total peak electricity consumption. This assumption reflects the facts that: (i) DG customers represent 10.6% of all customers in Hawaii, 2% in California, and 1.6% in Arizona (EIA, 2015b); (ii) there is rapid growth in solar penetration in these states (Schneider and Sargent, 2014); and (iii) on average, DG customers consume more electricity than non-DG customers (Borenstein, 2015).

[27] Typical estimates of the short-run price elasticity of demand for electricity for residential consumers are between -0.34 and -0.13. See, for instance, Bohi and Zimmerman (1984), King and Chatterjee (2003), Wade (2003), Espey and Espey (2004), Narayan and Smyth (2005), Bernstein and Griffen (2006), and Paul et al. (2009).

$$\frac{a_{it}\,\epsilon_{it}(\theta_t^E)^{\epsilon_{it}}}{\overline{x}_{it}} \;=\; 0.25 \;\text{ for } i \in \{G,N\} \text{ and } t \in \{0,1,2\}\,. \tag{7}$$

Given the estimated values for θ_t^E,[28] the identified values for $\overline{x}_{it}$, $\overline{p}$, and $\underline{v}$, and the resulting values for b_i, (6) and (7) provide a system of ten equations and ten unknowns, $(\epsilon_{i1}, \epsilon_{i1}, a_{i0}, a_{i1}, a_{i2})$ for $i \in \{G,N\}$.[29] Newton's method for solving a system of equations is employed to establish initial estimates for these parameters.

Consumer G's cost of installing k_G units of DG capacity is assumed to be $K_G(k_G) = \beta_1\, k_G + \beta_2\, (k_G)^2$. Estimates of the unsubsidized cost of residential solar capacity vary between \$100 and \$400/MWh (Branker et al., 2011; EIA, 2015a).[30] 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 \$31 and \$155/MWh (NCCETC, 2015a,b,c, 2016; Frankfurt School, 2016). Reflecting this lattermost range, we initially set $\beta_1 = 90$. To determine an initial value for β_2, we employ (3) to equate consumer G's expected marginal benefit of increased DG capacity ($\overline{p}\left[\,\theta_1^E + \theta_2^E\,\right]$) with the associated marginal cost $(90 + 2\,\beta_2\,\widehat{k}_G)$ at the observed level of DG capacity $\widehat{k}_G = 2,792.58$.[31]

TDM costs are assumed to be $T(m, k_G) = \gamma_m\, m + \gamma_G\, k_G$. We initially set $\gamma_G = 5.05$, reflecting the midpoint of estimates of the cost of transmission and distribution investment (per MWh) associated with solar generation of electricity (EIA, 2015a).[32] The initial value of γ_m that we adopt reflects estimates of the impact of a sustained reduction in the peak demand for electricity on (avoided) TDM costs. These estimates range from \$9,250 to \$101,360 per MW-year.[33] We take $\frac{1}{365}^{th}$ of the midpoint of this range ($\frac{55{,}305}{365} = 151.52$) as

[28] $\theta_0^E = 0$, $\theta_1^E = 0.43$, and $\theta_2^E = 0.64$.

[29] Values for ϵ_{G0} and ϵ_{N0} and not required because $\theta_0^E = 0$.

[30] The variation in these estimates reflects variation in such factors as the annual rate at which solar panels degrade, system installation costs, and the prevailing discount rate.

[31] Recall that $\overline{p} = 151.5$, $\theta_1^E = 0.43$, $\theta_2^E = 0.64$, and $\widehat{k}_G$ represents solar rooftop DG capacity in California in 2014.

[32] Estimates of TDM costs vary widely (Cohen et al., 2015) and $T(\cdot)$ in our model can incorporate a variety of network management costs associated with intermittent solar DG. Therefore, it will be particularly important to consider a range of values (including negative values) for γ_G.

[33] See Energy and Environmental Economics (2004, pp. 129-130), Beach and McGuire (2013, pp. 11-12), Exeter Associates (2014, p. 30), Los Angeles Department of Water and Power (2015, p. 29), and Navigant

our initial estimate of γ_m. This estimate converts the identified annual costs savings to the expected savings from reducing peak demand during the representative day in our model, assuming that system-wide peak demand for electricity is equally likely to arise during any such representative day.

The utility's cost of procuring electricity in period t is taken to be $C_t(X_t) = \underline{c}_t X_t + \frac{1}{2}\overline{c}_t (X_t)^2$. We assume $\underline{c}_t = 21.45$ for $t = 0, 1, 2$, which reflects the midpoint of the range of estimates of the cost per MWh of generating electricity using nuclear and baseload coal technologies (EIA, 2015a). The values of $\overline{c}_t$ are chosen to equate $\underline{c}_t + \overline{c}_t \overline{X}_t$ with the estimated marginal cost of generating electricity using: (i) a baseload technology (21.45) when $t = 0$; (ii) a mid-load conventional combined cycle natural gas unit (57.8) when $t = 1$; and (iii) a conventional combustion turbine natural gas unit (94.6) when $t = 2$ (EIA, 2015a).[34]

These functional forms and parameter values, along with identical welfare weights $w_G = w_N = 1$, constitute what we call *the baseline setting*. Tables 1 and 2 record the outcomes that arise under the optimal regulatory policy in this setting both when MDCs are feasible and when they are not feasible. The third column in the tables presents outcomes at the solution to problem [RP], where MDCs are feasible. The second column in the tables reports outcomes at the solution to problem [RP-n], where MDCs are effectively not feasible.[35] Table 1 (2) records outcomes in the setting with contemporaneous (divergent) peak demands.

In the setting with contemporaneous peak demands, the availability of MDCs leads the regulator to set a much lower price for electricity in periods 0 and 1 ($p = 36.12$) and to implement a sizable demand charge ($D = 184.74$) that increases the effective price of electricity ($p + D = 220.86$) in period 2. These price changes cause the demand for electricity from the utility to increase in periods 0 and 1 and to decline in period 2. As a result, the utility's expected marginal cost of supplying electricity in period 2 ($E\{C_2'(\cdot)\}$) declines, as

Consulting (2016, p. 26).

[34] $\overline{X}_t \equiv \overline{x}_{Gt} + \overline{x}_{Nt}$ for $t = 0, 1, 2$, where the values of $\overline{x}_{it}$ are the initial estimates of consumer demand described above.

[35] We represent the regulator's problem as a nonlinear mixed complementarity program and solve the program using the PATH algorithm in GAMS (Ferris and Munson, 2000).

do the utility's expected procurement costs ($\sum_{t=0}^{2} E\{C_t(\cdot)\}$) and TDM costs ($\gamma_m\, m + \gamma_G\, k_G$).

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	131.38	36.12	$-$ 95.26	$-$72.51
D	0.00	184.74	184.74	N/A[36]
R	716,554	784,741	68,187	9.52
k_G	346.53	628.03	281.50	81.23
Utility Demand				
$E\{x_{N0}(\cdot)\}$	4,946	5,699	753	15.21
$E\{x_{N1}(\cdot)\}$	6,106	7,036	930	15.24
$E\{x_{N2}(\cdot)\}$	10,439	9,120	$-$1,320	$-$12.64
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	871	1,003	132	15.21
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	988	1,082	94	9.46
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	1,638	1,243	$-$395	$-$24.08
m	23,145	21,593	$-$ 1,552	$-$ 6.71
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	58.49	63.84	5.35	9.15
$E\{C_2'(\cdot)\}$	105.50	93.57	$-$11.93	$-$11.31
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	1,207,325	1,118,479	$-$88,846	$-$7.36
$\gamma_m\, m + \gamma_G\, k_G$	3,508,672	3,274,942	$-$233,730	$-$6.66
Welfare				
$E\{U_N\}$	6,734,292	6,924,112	189,820	2.82
$E\{U_G\}$	600,717	591,464	$-$9,253	$-$1.54
$E\{U_N\} + E\{U_G\}$	7,335,009	7,515,576	180,567	2.46

Table 1. Outcomes in the Baseline Setting with Contemporaneous Peak Demands.

The decline in TDM costs reflects the decline in the utility's capacity costs due to the smaller maximum demand for electricity from the utility (m) in period 2. TDM costs associated with DG capacity (k_G) increase because k_G increases. Consumer G expands his investment in DG capacity because the effective unit compensation for DG output ($p + D$) increases in the period when DG capacity is most productive (period 2).

The introduction of an optimally-designed MDC produces a modest increase in aggregate welfare in the baseline setting. This increase reflects a gain for consumer N and a loss for consumer G. The welfare gain for consumer N arises in part from the reduced price of electricity in periods 0 and 1. The lower price in period 1 is less advantageous for consumer G because the reduction in p reduces the payment he receives for the electricity he produces.

The introduction of a MDC results in less pronounced variation in the effective price of electricity in the setting with divergent peak demands. (See Table 2.) In this setting, a MDC is less effective at reducing the peak demand for electricity from the utility because consumer G's peak demand occurs in period 1, not in period 2 when the system-wide peak demand arises. The reduced efficacy of a MDC leads the regulator to set a smaller value for D and a corresponding higher value for p.

Relative to the setting where MDCs are not feasible, each consumer reduces the amount of electricity he purchases from the utility in the period where the demand charge is in effect and increases his corresponding purchase in the periods where the charge is not in effect. The induced changes in demand reduce the utility's expected marginal cost of supplying electricity in period 2, its expected electricity procurement costs, and its TDM costs. The reduced TDM costs reflect in part the reduction in DG capacity investment. The reduced investment arises because the reduction in p reduces the effective unit compensation for DG output in the period when DG capacity generates the most electricity (period 2).

The reduced efficacy and impact of a MDC generates a more modest increase in aggregate welfare in the setting with divergent peak demands than in the setting with contemporaneous peak demands. The more modest increase in aggregate welfare arises despite an increase in the welfare of both consumers. The increase in consumer G's welfare arises in part because of the lower price for electricity that he faces in the peak period, which is when he values electricity consumption most highly.

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	128.17	54.05	-74.12	-57.83
D	0.00	164.66	164.66	N/A
R	$663,271$	$598,489$	$-64,782$	-9.77
k_G	303.49	110.05	-193.44	-63.74
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,972$	$5,557$	585	11.78
$E\{x_{N1}(\cdot)\}$	$6,137$	$6,861$	724	11.80
$E\{x_{N2}(\cdot)\}$	$10,487$	$9,151$	$-1,334$	-12.73
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	875	978	103	11.78
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	$1,555$	$1,369$	-186	-12.01
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	$1,047$	$1,286$	239	22.80
m	$22,028$	$20,820$	$-1,208$	-5.48
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	58.77	61.38	2.61	4.44
$E\{C_2'(\cdot)\}$	105.99	97.96	-8.03	-7.58
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,200,980$	$1,136,179$	$-64,801$	-5.40
$\gamma_m\, m + \gamma_G\, k_G$	$3,339,196$	$3,155,185$	$-184,011$	-5.51
Welfare				
$E\{U_N\}$	$6,856,722$	$6,904,413$	$47,691$	0.70
$E\{U_G\}$	$619,788$	$707,372$	$87,584$	14.13
$E\{U_N\} + E\{U_G\}$	$7,476,510$	$7,611,785$	$135,275$	1.81

Table 2. Outcomes in the Baseline Setting with Divergent Peak Demands.

More pronounced welfare gains can arise from the introduction of MDCs in other settings. To illustrate, suppose all parameters are as specified in the baseline setting except that the price elasticity of demand for electricity declines from -0.25 to -0.35. In the presence of increased price sensitivity, the regulator can secure desired changes in the amount of electricity purchased from the utility with less pronounced price variation. Consequently, the regulator implements a smaller MDC as price sensitivity increases. (See Tables A-1 and A-2 in Appendix A.) Despite the reduced variation in effective prices across periods, consumer demand for electricity from the utility in period 2 is reduced to a greater extent as price sensitivity increases. The resulting decline in the utility's electricity procurement costs and TDM costs generate relatively pronounced welfare gains for both consumers. For example, the welfare of consumer G increases by more than 18% in the setting with contemporaneous peak demands whereas consumer G's welfare declines when a MDC is introduced in the corresponding baseline setting.

Appendix A further illustrates how the optimal regulatory policy changes as other parameters in the baseline setting change. For instance, Tables A.3 and A.4 record the outcomes that arise when TDM costs decline, rather than increase, as DG investment increases. Additional DG investment is induced in this case, but the use of a MDC and its impact are similar to their counterparts in the baseline setting.

Tables A.5 and A.6 identify the outcomes that arise when TDM costs increase more rapidly as the utility's peak output (m) increases. Not surprisingly, the MDC is increased in this setting in order to reduce the peak demand for electricity. The welfare gains from MDCs increase as TDM costs rise more rapidly with m.

For expositional brevity, Appendix A does not document the effects of changes in other parameter values in the baseline setting. Outcomes similar to those identified in Tables 1 and 2 persist even as considerable variation in parameter values is introduced. The changes that arise generally are modest, and are largely predictable.[37] For instance, as the utility's marginal cost of production ($\bar{c}_1$ or $\bar{c}_2$) increases, the regulator increases p and D in order to further reduce electricity consumption and increase DG capacity investment.[38] Also, as w_N increases above w_G, the regulator reduces p and D because the associated reduction in DG compensation is less consequential from the regulator's perspective. The reductions in p and D increase the demand for electricity and raise the utility's electricity procurement costs and TDM costs. The increase in aggregate welfare secured from MDCs is little changed as w_N increases above w_G in the baseline setting.[39]

[37]See Brown and Sappington (2016b) for details.

[38]The welfare gains from MDCs are not very sensitive to changes in the utility's marginal cost of supplying electricity. For instance, when the utility's marginal cost is increased by 30% in both the mid-peak and peak periods, an MDC increases aggregate welfare by 3.01% in the setting with contemporaneous peak demands (rather than the 2.46% reported in Table 1). The corresponding increase in aggregate welfare is 2.21% in the setting with divergent peak demands (rather than the 1.81% reported in Table 2).

[39]As w_N increases from 1.0 to 1.1 in the baseline setting, the introduction of an MDC increases aggregate

5 Time-of-Use Pricing

The value of MDCs has been questioned in settings where time-of-use (TOU) pricing is feasible.[40] Before concluding, we briefly consider the potential use and impact of MDCs when TOU pricing is feasible. To do so, let [RPt] denote the counterpart to problem [RP] in the setting where the regulator can set distinct unit prices of electricity in each period.[41] In addition, let [RPt-n] denote problem [RPt] with the added restriction that $D = 0$, so MDCs are effectively not feasible.

Aggregate expected consumer welfare is always at least as high at the solution to [RPt-n] as at the solution to [RP] in the setting with contemporaneous peak demands.[42] This is the case because when MDCs are feasible but TOU pricing is not feasible (as in the solution to [RP]), the regulator can effectively set two distinct prices in this setting: p in periods 0 and 1, and $p + D$ in period 2. In contrast, the regulator can set three distinct prices (p_t for $t \in \{0, 1, 2\}$) when TOU pricing (only) is feasible (as in problem [RPt-n]). The expanded pricing flexibility afforded by TOU pricing in this setting ensures (weak) welfare gains.

Aggregate expected consumer welfare can be higher at the solution to [RP] than at the solution to [RPt-n] in the setting with divergent peak demands. This is the case because MDCs effectively allow the regulator to set consumer-specific TOU prices in periods 1 and 2 this setting. In period 1, consumer N faces price p whereas consumer G faces price $p + D$ at the solution to [RP]. In period 2, consumer N faces price $p + D$ while consumer G faces price p.[43] In contrast, the two consumers face the same price in each period (p_t in period

welfare by 2.45% in the setting with contemporaneous peak demands and by 1.81% in the setting with divergent peak demands. The corresponding increases in the baseline setting are 2.46% (Table 1) and 1.81% (Table 2), respectively.

[40]For instance, Borenstein (2016, p. 10) observes that "[s]mart meters permit time-varying price schedules that can easily be designed to more effectively capture the time-varying costs that a customer imposes on the system," and concludes that "[i]t is unclear why demand charges still exist."

[41]Formally, [RPt] is as stated in (5), using (1) – (4), where p is replaced by p_t in each expression (for $t \in \{0, 1, 2\}$) and where $\frac{\partial k_G}{\partial p_t} = \frac{\theta_t^E}{K_G''(\cdot)}$ in (3).

[42]Aggregate expected consumer welfare is $\sum_{i=G}^{N} w_i \, E\{U_i\}$, the regulator's objective function in (5).

[43]Both consumers face price p in period 0 at the solution to [RP].

$t \in \{0, 1, 2\}$) under TOU pricing.

The ability to set consumer-specific TOU prices can be of particular value to the regulator in the setting with divergent peak demands when the utility's TDM costs increase rapidly with DG capacity (so γ_G is relatively large) and when consumer G's cost of installing DG capacity is relatively low (so β_1 is relatively small). Under these conditions, the regulator would like to set a high price (p_2) in period 2 to reduce the system-wide peak demand for electricity without unduly expanding DG capacity investment. However, a high p_2 under TOU pricing will induce consumer G to install a considerable amount of DG capacity in part because each unit of capacity is expected to generate a relatively large amount of electricity in period 2. In light of this fundamental conflict between reducing system-wide peak demand for electricity and limiting DG capacity investment that arises under TOU pricing, the regulator can secure a higher level of aggregate consumer welfare through use of a MDC. The MDC enables the regulator to reduce system-wide peak demand by imposing a high effective price on consumer N in period 2 while limiting DG capacity investment by setting a relatively low effective price (and thus relatively limited DG compensation) for consumer G in this period.

These considerations are illustrated in Table 3, which compares selected outcomes at the solutions to [RP] and [RPt-n] when the model parameters are as specified in the baseline setting except that γ_G is increased to 45.05 and β_1 is reduced to 70. As Table 3 indicates, the regulator employs the MDC to induce less DG capacity investment (k_G declines from 963.11 to 312.47) by setting a relatively high effective price for electricity for consumer N in period 2 ($p + D = 209.72 > 192.64 = p_2$) and a much lower price ($p = 36.33$) for consumer G.[44] Doing so enables the regulator to secure a higher level of aggregate expected consumer welfare than she can secure with TOU pricing.[45]

[44] Brown and Sappington (2016b) provide additional characterization of the outcomes that arise in the setting of Table 3 (and in the settings of Tables 4 – 6 below).

[45] The substantial increase in γ_G (from 5.05 to 45.05) reflected in Table 3 suggests that although consumer welfare can, in principle, increase when an MDC replaces TOU pricing, this outcome may be unlikely in practice.

[RP]			[RPt-n]	
p	36.33		p_0	21.45
D	173.39		p_1	47.14
			p_2	192.64
R	$790,589$		R	$935,992$
k_G	312.47		k_G	963.11
$E\{U_N\}$	$7,018,027$		$E\{U_N\}$	$7,043,504$
$E\{U_G\}$	$572,748$		$E\{U_G\}$	$544,292$
$E\{U_N\} + E\{U_G\}$	$7,590,776$		$E\{U_N\} + E\{U_G\}$	$7,587,796$

Table 3. Outcomes in the Setting with Divergent Peak Demands when $\gamma_G = 45.05$ and $\beta_1 = 70$.

Because MDCs admit consumer-specific prices, they can generate strict Pareto gains in the presence of TOU pricing in the setting with divergent peak demands. Table 4 identifies the (small) gains that a MDC admits in the baseline setting when TOU pricing is also feasible. As in the setting of Table 3, the regulator employs her ability to set consumer-specific TOU prices to increase the effective price that consumer N faces in period 2 ($p_2 + D = 228.01 > 219.13$) while reducing the price that consumer G faces in this period ($191.60 < 219.13$). Because consumer N accounts for most of the demand for electricity from the utility, these price changes serve to reduce the system-wide peak demand (m). The diminished peak demand serves to reduce the utility's expected marginal cost of supplying electricity in period 2, its expected electricity procurement costs, and its TDM costs. These cost reductions support Pareto gains from coupling a MDC with TOU prices.

Outcomes	[RPt-n]	[RPt]	Change	% Change
p_0	21.45	21.45	0.00	0.00
p_1	61.29	52.50	-8.79	-14.34
p_2	219.13	191.60	-27.53	-12.56
D	0.00	36.41	36.41	N/A
R	$696,212$	$670,940$	$-25,272$	-3.63
k_G	647.30	560.93	-86.37	-13.34
m	$20,530$	$20,446$	-84	-0.41
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	62.37	62.54	0.17	0.27
$E\{C_2'(\cdot)\}$	93.56	93.31	-0.25	-0.27
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,097,948$	$1,096,991$	-957	-0.09
$\gamma_m\, m + \gamma_G\, k_G$	$3,113,944$	$3,100,853$	$-13,091$	-0.42
Welfare				
$E\{U_N\}$	$6,938,696$	$6,943,536$	$4,841$	0.07
$E\{U_G\}$	$715,925$	$716,942$	$1,017$	0.14
$E\{U_N\} + E\{U_G\}$	$7,654,621$	$7,660,479$	$5,858$	0.08

Table 4. Outcomes in the Baseline Setting with TOU Pricing and Divergent Peak Demands.

Even though aggregate expected consumer welfare is always at least as high at the solution to [RPt-n] (when only TOU pricing is feasible) as at the solution to [RP] (when only MDCs are feasible) in the setting with contemporaneous peak demands, the expected welfare of one of the consumers can be higher at the solution to [RP] than at the solution to [RPt-n] in this setting. Table 5 illustrates this more general conclusion by comparing selected outcomes at the solutions to these two problems when all parameters are as specified in the baseline setting except for γ_G, which is increased from 5.05 to 15.05. When the utility's TDM costs increase relatively rapidly as DG capacity increases, the regulator sets a relatively low price in periods 0 and 1 (to discourage investment in DG capacity) when the absence of TOU pricing forces her to set the same price in these two periods.[46] This low price is of substantial benefit to consumer N in period 1 (when his expected valuation of electricity is

[46]Observe that $35.16 < \frac{1}{2}\,[\,21.46 + 59.12\,]$. When TOU pricing enables the regulator to set distinct prices in periods 0 and 1, she reduces p_0 and increases p_1 toward expected marginal cost.

higher than in period 0), leading to a higher level of expected welfare.[47]

[RP]			[RPt-n]	
p	35.16		p_0	21.46
D	183.29		p_1	59.12
			p_2	216.19
$E\{U_N\}$	$6,935,520$		$E\{U_N\}$	$6,904,956$
$E\{U_G\}$	$573,847$		$E\{U_G\}$	$604,791$
$E\{U_N\} + E\{U_G\}$	$7,509,367$		$E\{U_N\} + E\{U_G\}$	$7,509,747$

Table 5. Outcomes when γ_G is Increased to 15.05 in the Baseline Setting with Contemporaneous Peak Demands.

Consumer G also can secure a higher level of expected welfare at the solution to [RP] than at the solution to [RPt-n]. To illustrate, Table 6 compares selected outcomes at the solutions to these two problems in the setting with divergent peak demands when all parameters are as specified in the baseline setting except that γ_m is reduced by 30% from 151.52 to 106.06. When he faces a MDC rather than TOU pricing in this setting, consumer G faces a relatively high effective price for electricity in period 1 ($p + D = 185.03 > 61.52 = p_1$) and a corresponding relatively low price in period 2 ($p = 53.77 < 185.83 = p_2$). A relatively high effective price harms consumer G by increasing the amount he must pay for electricity, but benefits him by increasing the amount he is paid for the electricity he produces. On balance, these countervailing effects serve to increase consumer G's expected welfare when γ_m is relatively small, so the regulator sets a relatively small MDC and a relatively small value for p_2 under TOU pricing.[48]

[47] A corresponding conclusion arises when γ_m is reduced by 30% from its value in the baseline setting (from 151.52 to 106.06). When the utility's capacity-related TDM costs increase less rapidly with consumer demand for electricity, the regulator sets a relatively low value of p at the solution to [RP]. This low price generates relatively large welfare gains for consumer N in period 1.

[48] Observe from Tables 2 and 4 that in the benchmark setting where γ_m is relatively large, the regulator sets a relatively high MDC ($D = 164.66$) when TOU pricing is not feasible and a relatively high peak-period price ($p_2 = 219.13$) when (only) TOU pricing is feasible. Consumer G prefers TOU pricing to MDCs in this setting. This preference reflects in part the relatively large unit payment that consumer G receives for the electricity he produces in the period when his electricity production is most pronounced (period 2).

[RP]			[RPt-n]	
p	53.77		p_0	21.45
D	131.26		p_1	61.52
			p_2	185.83
$E\{U_N\}$	$7,519,006$		$E\{U_N\}$	$7,544,428$
$E\{U_G\}$	$1,050,537$		$E\{U_G\}$	$1,045,893$
$E\{U_N\}+E\{U_G\}$	$8,569,543$		$E\{U_N\}+E\{U_G\}$	$8,600,320$

Table 6. Outcomes when γ_m is Reduced to 106.06 in the Baseline Setting with Divergent Peak Demands.

These observations illustrate some of the many subtleties that can arise when attempting to compare MDCs and TOU pricing or to assess the potential incremental contribution of each of these policies. Although TOU pricing ensures a higher level of aggregate expected consumer welfare than MDCs in the setting with contemporaneous peak demands, MDCs can secure a higher level of welfare than TOU pricing in the setting with divergent peak demands. In addition, even when TOU pricing secures a higher level of aggregate consumer welfare than MDCs, it can reduce the welfare of one of the two consumers in our model. This finding suggests that the pricing policy adopted in practice may depend upon the relative political strengths of consumers that undertake DG and those that do not.

6 Conclusions

We have analyzed a streamlined model of consumer behavior and optimal regulatory policy to help inform the ongoing policy debate about the role that maximum demand charges (MDCs) might play in avoiding a death spiral for utilities in the presence of ever-expanding distributed generation (DG) of electricity. We have shown that MDCs can secure Pareto gains relative to the standard policy instruments on which regulators often rely (i.e., a time-invariant unit price for electricity, p, and a fixed retail charge, R). However, MDCs that are structured to maximize aggregate consumer welfare often reduce the welfare of consumers that engage in the distributed generation of electricity.

The welfare gains secured by MDCs often were modest in the settings that we examined. Furthermore, time-of-use (TOU) pricing typically generated a higher level of welfare than did

MDCs. Therefore, although our analysis demonstrates that MDCs can enhance consumer welfare while avoiding a death spiral, the analysis does not indicate that MDCs should generally be preferred to other pricing policies, such as TOU pricing.

Extensions of our model merit consideration before drawing any final conclusions about the relative merits of MDCs and other pricing policies as distributed generation of electricity continues to proliferate. Future research should account explicitly for the nonlinear prices (e.g., increasing block tariffs) that many residential customers face in practice (e.g., Borenstein, 2015). The incremental value of policies like MDCs and TOU pricing may be less pronounced in the presence of nonlinear pricing of electricity.

Future research should also account for differences among consumers who undertake DG. In practice, different consumers often face different costs of generating electricity and may impose different TDM costs on the utility (or provide different reductions in the utility's TDM costs.) In the presence of such differences, MDCs may play an expanded role in reducing the system-wide peak demand for electricity and in better matching the charges imposed on individual consumers to the costs they impose on the utility.[49] MDCs (and TOU pricing) may also secure larger welfare gains in settings where consumers can shift their electricity consumption across time periods during the day and where MDCs can reflect consumption during relatively short periods of time (e.g., an hour, rather than an entire demand period). The optimal design of MDCs may also vary in the presence of dispatchable DG, rather than the non-dispatchable solar DG on which we have focused.[50]

[49] Systematic differences between DG consumers and non-DG consumers might also be considered. In practice, DG consumers tend to consume more electricity than non-DG consumers (Borenstein, 2015).

[50] A fully comprehensive analysis of MDCs would also account for the different levels of externalities (e.g., pollution) associated with electricity production by the utility, by dispatchable DG, and by non-dspatchable DG.

Appendix A. Variations in the Baseline Setting[51]

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	129.78	37.77	-92.01	-70.90
D	0.00	179.21	179.21	N/A
R	728,336	773,910	45,574	6.26
k_G	333.13	609.58	276.45	82.99
Utility Demand				
$E\{x_{N0}(\cdot)\}$	4,549	5,567	1,018	22.37
$E\{x_{N1}(\cdot)\}$	5,615	6,873	1,258	22.41
$E\{x_{N2}(\cdot)\}$	9,697	7,897	$-1,800$	-18.57
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	801	980	179	22.37
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	905	1,057	152	16.84
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	1,515	1,039	-476	-31.43
m	22,272	20,155	$-2,117$	-9.51
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	55.49	62.86	7.37	13.28
$E\{C_2'(\cdot)\}$	99.48	83.63	-15.85	-15.93
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	1,075,713	976,411	$-99,302$	-9.23
$\gamma_m\, m + \gamma_G\, k_G$	3,376,380	3,056,929	$-319,451$	-9.46
Welfare				
$E\{U_N\}$	3,850,664	4,077,826	227,162	5.90
$E\{U_G\}$	83,041	98,316	15,275	18.40
$E\{U_N\} + E\{U_G\}$	3,933,705	4,176,142	242,437	6.16

Table A1. Outcomes with Contemporaneous Peak Demands and Price Elasticity $= -0.35$.

[51] Any inconsistencies in the entries in the tables in this Appendix are due to rounding.

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	126.48	53.37	-73.11	-57.80
D	0.00	158.26	158.26	N/A
R	$677,273$	$635,487$	$-41,786$	-6.17
k_G	290.08	89.23	-200.85	-69.24
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,585$	$5,394$	809	17.64
$E\{x_{N1}(\cdot)\}$	$5,660$	$6,659$	999	17.67
$E\{x_{N2}(\cdot)\}$	$9,765$	$8,007$	$-1,758$	-18.00
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	807	949	142	17.64
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	$1,432$	$1,172$	-260	-18.11
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	971	$1,263$	292	30.03
m	$21,222$	$19,640$	$-1,582$	-7.46
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	55.85	59.45	3.60	6.45
$E\{C_2'(\cdot)\}$	100.15	89.40	-10.75	-10.73
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,074,389$	$998,589$	$-75,800$	-7.06
$\gamma_m\, m + \gamma_G\, k_G$	$3,217,090$	$2,976,343$	$-240,747$	-7.48
Welfare				
$E\{U_N\}$	$3,967,422$	$4,067,766$	$100,344$	2.53
$E\{U_G\}$	$114,779$	$191,579$	$76,800$	66.91
$E\{U_N\} + E\{U_G\}$	$4,082,201$	$4,259,345$	$177,144$	4.34

Table A2. Outcomes with Divergent Peak Demands and Price Elasticity $= -0.35$.

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	134.79	38.03	-96.76	-71.79
D	0.00	187.64	187.64	N/A
R	$670,466$	$739,285$	$68,819$	10.26
k_G	375.08	661.00	285.92	76.23
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,919$	$5,684$	765	15.54
$E\{x_{N1}(\cdot)\}$	$6,073$	$7,018$	945	15.56
$E\{x_{N2}(\cdot)\}$	$10,389$	$9,049$	$-1,340$	-12.90
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	866	$1,000$	134	15.54
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	975	$1,070$	95	9.74
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	$1,612$	$1,212$	-400	-24.85
m	$23,086$	$21,510$	$-1,576$	-6.83
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	58.25	63.68	5.43	9.32
$E\{C_2'(\cdot)\}$	104.97	92.86	-12.11	-11.54
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,195,982$	$1,106,612$	$-89,370$	-7.47
$\gamma_m\, m + \gamma_G\, k_G$	$3,492,320$	$3,249,172$	$-243,148$	-6.96
Welfare				
$E\{U_N\}$	$6,707,314$	$6,901,516$	$194,202$	2.90
$E\{U_G\}$	$634,961$	$627,039$	$-7,922$	-1.25
$E\{U_N\} + E\{U_G\}$	$7,342,275$	$7,528,555$	$186,280$	2.54

Table A3. Outcomes with Contemporaneous Peak Demands and $\gamma_G = -15.05$.

Outcomes	[RP-n]	[RP]	Change	% Change
p	131.44	58.39	-73.05	-55.58
D	0.00	162.29	162.29	N/A
R	$619,228$	$555,205$	$-64,022$	-10.34
k_G	329.48	138.83	-190.65	-57.86
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,946$	$5,523$	577	11.67
$E\{x_{N1}(\cdot)\}$	$6,105$	$6,819$	714	11.69
$E\{x_{N2}(\cdot)\}$	$10,439$	$9,122$	$-1,317$	-12.61
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	870	972	102	11.67
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	$1,540$	$1,356$	-184	-11.95
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	$1,027$	$1,262$	235	22.93
m	$21,974$	$20,783$	$-1,191$	-5.42
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	58.54	61.11	2.57	4.39
$E\{C_2'(\cdot)\}$	105.49	97.57	-7.92	-7.51
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,190,294$	$1,126,778$	$-63,516$	-5.34
$\gamma_m\, m + \gamma_G\, k_G$	$3,324,549$	$3,147,023$	$-177,526$	-5.34
Welfare				
$E\{U_N\}$	$6,830,354$	$6,876,065$	$45,711$	0.67
$E\{U_G\}$	$652,530$	$738,225$	$85,695$	13.13
$E\{U_N\} + E\{U_G\}$	$7,482,883$	$7,614,290$	$131,407$	1.76

Table A4. Outcomes with Divergent Peak Demands and $\gamma_G = -15.05$.

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	147.34	33.46	-113.88	-77.29
D	0.00	220.85	220.85	N/A
R	$1,042,842$	$1,120,990$	$78,148$	7.49
k_G	480.24	816.77	336.53	70.08
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,820$	$5,720$	900	18.66
$E\{x_{N1}(\cdot)\}$	$5,950$	$7,062$	$1,112$	18.70
$E\{x_{N2}(\cdot)\}$	$10,204$	$8,626$	$-1,578$	-15.46
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	848	$1,007$	159	18.67
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	927	$1,039$	112	12.05
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	$1,519$	$1,048$	-471	-31.04
m	$22,868$	$21,013$	$-1,855$	-8.11
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	57.36	63.75	6.39	11.14
$E\{C_2'(\cdot)\}$	103.03	88.77	-14.26	-13.84
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,154,618$	$1,055,107$	$-99,511$	-8.62
$\gamma_m\, m + \gamma_G\, k_G$	$3,506,966$	$4,143,202$	$-363,764$	-8.07
Welfare				
$E\{U_N\}$	$6,068,996$	$6,324,889$	$255,893$	4.22
$E\{U_G\}$	$220,214$	$222,377$	$2,163$	0.98
$E\{U_N\} + E\{U_G\}$	$6,289,210$	$6,289,210$	$258,055$	4.10

Table A5. Outcomes with Contemporaneous Peak Demands and $\gamma_m = 196.98$**.**[52]

[52] This value of γ_m represents a 30% increase above the corresponding value in the baseline setting.

Outcomes	**[RP-n]**	**[RP]**	**Change**	**% Change**
p	143.48	54.33	-89.15	-62.13
D	0.00	198.06	198.06	N/A
R	$971,744$	$891,996$	$-79,748$	-8.21
k_G	425.23	192.55	-232.68	-54.72
Utility Demand				
$E\{x_{N0}(\cdot)\}$	$4,851$	$5,555$	704	14.52
$E\{x_{N1}(\cdot)\}$	$5,988$	$6,859$	871	14.54
$E\{x_{N2}(\cdot)\}$	$10,261$	$8,655$	$-1,606$	-15.65
$E\{x_{G0}(\cdot)\} - \theta_0^E\, k_G$	854	978	124	14.52
$E\{x_{G1}(\cdot)\} - \theta_1^E\, k_G$	$1,485$	$1,261$	-224	-15.12
$E\{x_{G2}(\cdot)\} - \theta_2^E\, k_G$	951	$1,238$	287	30.21
m	$21,776$	$20,323$	$-1,453$	-6.67
Costs				
$E\{C_0'(\cdot)\}$	21.45	21.45	0.00	0.00
$E\{C_1'(\cdot)\}$	57.71	60.84	3.13	5.42
$E\{C_2'(\cdot)\}$	103.63	93.96	-9.67	-9.33
$\sum_{t=0}^{2} E\{C_t(\cdot)\}$	$1,151,307$	$1,077,041$	$-74,266$	-6.45
$\gamma_m\, m + \gamma_G\, k_G$	$4,291,532$	$4,004,145$	$-287,387$	-6.70
Welfare				
$E\{U_N\}$	$6,221,411$	$6,307,666$	$86,255$	1.39
$E\{U_G\}$	$259,507$	$368,978$	$109,471$	42.18
$E\{U_N\} + E\{U_G\}$	$6,480,918$	$6,676,644$	$195,726$	3.02

Table A6. Outcomes with Divergent Peak Demands and $\gamma_m = 196.98$.[53]

[53]This value of γ_m represents a 30% increase above the corresponding value in the baseline setting.

Appendix B. Additional Findings and Proofs of Formal Conclusions

This Appendix provides additional analytic characterizations of the regulator's optimal policy and presents the proofs of all formal conclusions.

B1. Additional Conclusions.

Propositions B1 and B2 supplement Proposition 2 by identifying alternative settings in which the regulator tends to set p below the utility's expected marginal cost of procuring electricity when MDCs are feasible. Proposition B1 considers the more general setting in which the utility experiences a strictly increasing marginal cost of procuring electricity.

Proposition B1. Suppose $w_N = w_G$ and $\frac{\partial T(\cdot)}{\partial k_G} \geq 0$. Then at the solution to [RP] in the setting with contemporaneous peak demands:

$$\sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, p - C_t'(\cdot) \,] \, \frac{\partial}{\partial p} \left(\sum_{i=G}^{N} \{ \, x_{it}(\theta_t) - \theta_t \, k_i \, \} \right) dF_t(\theta_t) \; \geq \; 0 \, , \tag{8}$$

with strict inequality if $\frac{\partial T(\cdot)}{\partial k_G} > 0$ and $\theta_0^E + \theta_1^E > 0$.

Because each consumer's purchase of electricity from the utility declines as p increases, the $\frac{\partial}{\partial p}(\cdot)$ term in (8) is strictly negative.[54] Therefore, (8) implies that p will tend to be set below the utility's expected marginal cost of production in periods 0 and 1 under the identified conditions. Proposition B1 reflects the fact that as p declines, consumer G anticipates reduced compensation for the electricity he generates in periods 0 and 1. Therefore, a reduction in p below the utility's marginal cost of supplying electricity reduces the utility's TDM costs by reducing DG investment when $\frac{\partial T(\cdot)}{\partial k_G} > 0$.

Proposition B2 reports that the regulator will continue to set the price of electricity below its marginal cost of supply when she values the welfare of consumer N relatively highly (so $w_N > w_G$), as long as consumer N is expected to purchase more electricity from the utility than is consumer G.

[54] Recall that $\frac{dk_G}{dp} > 0$ from (3).

Proposition B2. Suppose $w_N > w_G$, $\frac{\partial T(\cdot)}{\partial k_G} > 0$, and Assumption 1 holds. Then $p < c$ when $\sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} x_{Nt}(\theta_t)\, dF_t(\theta_t) \geq \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, x_{Gt}(\theta_t) - \theta_t\, k_G \,]\, dF_t(\theta_t)$ at the solution to [RP] in the setting with contemporaneous peak demands.

Proposition B2 reflects the fact that as she values consumer G's welfare less highly, the regulator becomes less averse to the reduction in DG payments that accrue to consumer G as p declines.

B2. Proofs of Formal Conclusions.

Proof of Proposition B1.

Let λ denote the Lagrange multiplier associated with the $E\{\,\Pi\,\} \geq 0$ constraint. Then (1) – (5) imply that the necessary conditions for a solution to [RP] include:

$$-\, w_G - w_N + 2\,\lambda \;\leq\; 0\,; \qquad R\,[\,-\, w_G - w_N + 2\,\lambda\,] \;=\; 0\,; \tag{9}$$

$$\begin{aligned}
&[\,\lambda - w_N\,] \int_{\underline{\theta}_2}^{\overline{\theta}_2} x_{N2}(\theta_2)\, dF_2(\theta_2) + [\,\lambda - w_G\,] \int_{\underline{\theta}_2}^{\overline{\theta}_2} [\, x_{G2}(\theta_2) - \theta_2\, k_G\,]\, dF_2(\theta_2) \\
&+\; \lambda \int_{\underline{\theta}_2}^{\overline{\theta}_2} [\, p + D - C_2'(\cdot)\,] \left[\, \sum_{i=G}^{N} \frac{1}{u_{i2}''(x_{i2}(\theta_2), \theta_2)} - \theta_2\, \frac{\theta_2^E}{K_G''(\cdot)} \,\right] dF_2(\theta_2) \\
&-\; \lambda \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, p - C_t'(\cdot)\,]\, \theta_t\, \frac{\theta_2^E}{K_G''(\cdot)}\; dF_t(\theta_t) \\
&-\; \lambda\, \frac{\partial T(\cdot)}{\partial k_G}\, \frac{\theta_2^E}{K_G''(\cdot)} - \lambda\, \frac{\partial T(\cdot)}{\partial m} \sum_{i=G}^{N} \frac{1}{u_{i2}''(x_{i2}(\overline{\theta}_2), \overline{\theta}_2)} \;\leq\; 0\,; \qquad D\,[\,\cdot\,] \;=\; 0\,.
\end{aligned} \tag{10}$$

$$[\,\lambda - w_N\,] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} x_{Nt}(\theta_t)\, dF_t(\theta_t) + [\,\lambda - w_G\,] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, x_{Gt}(\theta_t) - \theta_t\, k_G\,]\, dF_t(\theta_t)$$

$$+ \; \lambda \int_{\underline{\theta}_2}^{\overline{\theta}_2} [\, p + D - C_2'(\cdot)\,] \left[\frac{1}{u_{N2}''(\cdot)} + \frac{1}{u_{G2}''(\cdot)} - \theta_2 \, \frac{\sum_{t=0}^{2} \theta_t^E}{K_G''(\cdot)} \right] dF_2(\theta_2)$$

$$+ \; \lambda \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, p - C_t'(\cdot)\,] \left[\frac{1}{u_{Nt}''(\cdot)} + \frac{1}{u_{Gt}''(\cdot)} - \theta_t \, \frac{\sum_{t=0}^{2} \theta_t^E}{K_G''(\cdot)} \right] dF_t(\theta_t)$$

$$- \;\; \lambda \, \frac{\partial T(\cdot)}{\partial k_G} \, \frac{\sum_{t=0}^{2} \theta_t^E}{K_G''(\cdot)} - \;\; \lambda \frac{\partial T(\cdot)}{\partial m} \sum_{i=G}^{N} \frac{1}{u_{i2}''(x_{i2}(\overline{\theta}_2), \overline{\theta}_2)} \;\; = \; 0\,. \qquad (11)$$

Subtracting (10) from (11) provides:

$$[\, \lambda - w_N \,] \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} x_{Nt}(\theta_t) \, dF_t(\theta_t) \; + [\, \lambda - w_G \,] \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, x_{Gt}(\theta_t) - \theta_t \, k_G \,] \, dF_t(\theta_t)$$

$$+ \;\; \lambda \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, p - C_t'(\cdot)\,] \left[\frac{1}{u_{Nt}''(\cdot)} + \frac{1}{u_{Gt}''(\cdot)} - \theta_t \, \frac{\sum_{t=0}^{1} \theta_t^E}{K_G''(\cdot)} \right] dF_t(\theta_t)$$

$$- \;\; \lambda \, D \, \frac{\theta_2^E \, \sum_{t=0}^{1} \theta_t^E}{K_G''(\cdot)} \; - \; \lambda \, \frac{\partial T(\cdot)}{\partial k_G} \, \frac{\sum_{t=0}^{1} \theta_t^E}{K_G''(\cdot)} \;\; \geq \;\; 0\,. \qquad (12)$$

Suppose $\lambda = 0$. Then (12) implies that $\sum_{i=G}^{N} \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [\, x_{it}(\theta_t) - \theta_t \, k_i \,] \, dF_t(\theta_t) \leq 0$, contrary to the maintained assumption. Therefore, $\lambda > 0$. (9) implies that $\lambda \leq w_G = w_N$. Consequently, the conclusion in the proposition follows from (12). ■

Proof of Proposition B2.

(9) implies that $\lambda \leq w_N$ and/or $\lambda \leq w_G$. If both inequalities hold, then (12) implies that $p < c$. If $\lambda > w_G$, then (9) implies that $\lambda < w_N$ and $\lambda - w_G \;\leq\; |\, \lambda - w_N \,|$ because:

$$\lambda - w_G \;\; \leq \;\; |\, \lambda - w_N \,| \quad \Leftrightarrow \quad \lambda - w_G \;\; \leq \;\; w_N - \lambda \quad \Leftrightarrow \quad 2\,\lambda \;\; \leq \;\; w_G + w_N \, .$$

When $\lambda < w_N$, $\lambda - w_G \leq |\lambda - w_N|$, and the weak inequality in the statement of the proposition holds:

$$[\lambda - w_N] \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} x_{Nt}(\theta_t)\, dF_t(\theta_t) + [\lambda - w_G] \sum_{t=0}^{1} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [x_{Gt}(\theta_t) - \theta_t\, k_G]\, dF_t(\theta_t) \leq 0\,. \quad (13)$$

(12) and (13) imply that $p < c$ under the maintained conditions.

Proof of Proposition 1.

Let λ_n denote the Lagrange multiplier associated with the $E\{\Pi\} \geq 0$ constraint. Then (1) – (5) imply that the necessary conditions for a solution to [RP-n] include:

$$-w_G - w_N + 2\lambda_n \leq 0\,; \qquad R\,[-w_G - w_N + 2\lambda_n] = 0\,; \quad \text{and} \quad (14)$$

$$[\lambda_n - w_N] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} x_{Nt}(\theta_t)\, dF_t(\theta_t) + [\lambda_n - w_G] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} [x_{Gt}(\theta_t) - \theta_t\, k_G]\, dF_t(\theta_t)$$

$$+ \lambda_n [p - c] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{1}{u''_{Nt}(\cdot)} + \frac{1}{u''_{Gt}(\cdot)} - \theta_t \frac{\sum_{t=0}^{2} \theta_t^E}{K''_G(\cdot)} \right] dF_t(\theta_t)$$

$$- \lambda_n \frac{\partial T(\cdot)}{\partial k_G} \frac{\sum_{t=0}^{2} \theta_t^E}{K''_G(\cdot)} - \lambda_n \frac{\partial T(\cdot)}{\partial m} \sum_{i=G}^{N} \frac{1}{u''_{i2}(x_{i2}(\overline{\theta}_2), \overline{\theta}_2)} = 0\,. \quad (15)$$

If $R = 0$, then (4) implies that $p > 0$ to ensure $E\{\Pi\} \geq 0$. If $R > 0$, then (14) implies that $\lambda_n = w_G = w_N > 0$. Therefore, (15) implies:

$$[p - c] \sum_{t=0}^{2} \int_{\underline{\theta}_t}^{\overline{\theta}_t} \left[\frac{1}{u''_{Nt}(\cdot)} + \frac{1}{u''_{Gt}(\cdot)} - \theta_t \frac{\sum_{t=0}^{2} \theta_t^E}{K''_G(\cdot)} \right] dF_t(\theta_t)$$

$$= \frac{\partial T(\cdot)}{\partial k_G} \frac{\sum_{t=0}^{2} \theta_t^E}{K''_G(\cdot)} + \frac{\partial T(\cdot)}{\partial m} \sum_{i=G}^{N} \frac{1}{u''_{i2}(x_{i2}(\overline{\theta}_2), \overline{\theta}_2)}\,. \quad (16)$$

The conclusion in the proposition follows from (16). ■

Proof of Proposition 2.

Suppose $R = D = 0$. Then $p > c$ to ensure $E\{\Pi\} \geq 0$. Also, $\lambda \leq w_G = w_N$ from (9). But these conclusions imply that (12) is violated when Assumption 1 holds. Therefore, $R > 0$ or $D > 0$. If $R > 0$, then $\lambda = w_G = w_N > 0$ from (9). Consequently, (12) implies that $p < c$ under the maintained conditions. If $D > 0$, then because $\lambda \leq w_G = w_N$ from (9), (12) implies that $p < c$ under the maintained conditions. ■

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