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Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets

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Abstract
Diffusion of microgeneration technologies, particularly rooftop photovoltaic (PV), represents a key option in reducing emissions in the residential sector. We use a uniquely rich dataset from the burgeoning residential PV market in Texas to study the nature of the consumer's decision-making process in the adoption of these technologies. In particular, focusing on the financial metrics and the information decision-makers use to base their decisions upon, we study how the leasing and buying models affect individual choices and, thereby, the adoption of capital-intensive energy technologies. Overall, our findings suggest that the leasing model more effectively addresses consumers' informational requirements and that, contrary to some other studies, buyers and lessees of PV do not necessarily differ significantly along socio-demographic variables. Instead, we find that the leasing model has opened up the residential PV market to a new, and potentially very large, consumer segment—those with a tight cash-flow situation.

Keywords: residential solar PV, discount rates, solar business models, individual decision-making
S Online supplementary data available from stacks.iop.org/ERL/8/014022/mmedia

1. Introduction

Two questions prompted the work in this paper. First, what can be learned from the diffusion of solar photovoltaics (PV) for improving existing solar programs and the design of others in newer markets? As policy support for these technologies is waning, this increases the pressure for incentive programs to become more efficient (US DOE 2008, 2012). Second, what lessons can the residential PV market shed on the individual decision-making process? The scale of capital investment for solar PV is quite high relative to most other household investments. So, presumably, the choice to adopt PV forces individuals to consider the (alternative) options more carefully than most investment decisions (Jager 2006). Unpacking the decision to adopt PV, then, might provide insights into the nature of the individual decision-making process.

Understanding the nature of the decision-making process has important practical implications for the design of mechanisms that incentivize reduction of greenhouse gas (GHG) emissions from energy use. With 22.2% consumption of primary energy and 21.4% of the total GHG emissions (EIA 2010) the residential sector is a key target for reducing energy demand and GHG emissions. Diffusion of microgeneration technologies, particularly rooftop PV, represents a key option in meeting demand and emissions reductions in the residential sector (US DOE 2012). As different actors have tried to design programs and incentives to spread the adoption of more efficient and environmentally-friendly consumption and generation devices (Taylor 2008), the nature of the individual's decision-making process has come to sharper focus (Allcott and Mullainathan 2010, Dietz 2010, Drury *et al* 2011, Jager 2006, Keirstead 2007, Bollinger and Gillingham 2012). Therefore, the last few years of experience with

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residential PV provides an early and unique opportunity to refine our understanding of how individual decision-making impacts technology diffusion.

Three lines of theory are relevant to this work. First, decision-making at the individual level. While the neoclassical microeconomic theory presumes that individual decision-makers are rational and information-prescient, there is increasing evidence that individual decision-makers depart significantly from the neoclassical model (Camerer *et al* 2004, Frederick *et al* 2002, Gintis 2000, Todd and Gigerenzer 2003, Wilson and Dowlatabadi 2007).

Second, empirical evidence of the use of high discount rates for future returns from energy-saving technologies (Gately 1980, Hausman 1979, Meier and Whittier 1983, Ruderman *et al* 1987). Expectations of rapid technological change, information barriers, and other non-monetary costs are some of the factors that give rise to the use of high implicit discount rates (Hassett and Metcalft 1993, Howarth and Sanstad 1995). In general, this phenomenon discourages the adoption of technologies whose benefits are spread over a long time horizon. The use of upfront capital subsidies have been proposed as a way to overcome this adoption barrier (Guidolin and Mortarino 2009, Hart 2010, Jager 2006, Johnson *et al* 2012, Timilsina *et al* 2011).

Third, business models for accelerating the deployment of technologies by addressing market barriers (Gallagher and Muehlegger 2011, Margolis and Zuboy 2006, Sidiras and Koukios 2004) facing individual decision makers—in particular the leasing model. Several researchers suggest that the option to lease a technology effectively addresses the high discount rate problem (Coughlin and Cory 2009, Drury *et al* 2011)—as well as some of the information failures associated with new technologies (Faiers and Neame 2006, Shih and Chou 2011).

2. Data

Our analysis uses a new household-level dataset built through two complementary data streams: (i) a survey of residents who have adopted PV and (ii) program data for the *same* adopters obtained from utilities that administer PV rebate programs. The survey, among other factors, explores *why* PV adopters made the financial choices they did (say, buy versus lease), and their own assessment of the attractiveness of their investment (Rai and McAndrews 2012). The survey was administered electronically in Texas during August–November 2011 and received 365 responses from the 922 PV owners contacted.

All survey respondents reported residing in areas of retail electricity choice in Texas (see supplementary information for spatial distribution available at stacks.iop.org/ERL/8/014022/mmedia). The mean size of the PV system installed was 5.85 kW-DC and the average age of respondents was 52 yr old. The mean household income was between \$85 000 and \$149 999 and 84.9% reported that at least one member of the household had achieved a college degree or higher level of education. Each of the prior demographics is significantly different from state-wide averages. That is, the survey population was wealthier, older, and better-educated than the average Texas resident. No significant difference was found between lessees and buyers of PV on any demographic variable.

Of the 365 responses, we matched complementary program data for 210 respondents. The program data provides several data points, including (i) installed cost of the system, (ii) price and structure of lease payments if the system was leased, (iii) system capacity (kW, DC and AC), (iv) amount of rebates disbursed, (v) aggregate household electricity consumption from the prior year, (vi) retail electricity provider (REP), electric plan, and marginal cost of electricity consumption just prior to PV installation, and (vii) projected annual electricity generated by the system based on orientation, derating factor, and geography.

3. Methodology

Our strategy is to compare the financial metrics that PV adopters used to evaluate their investment decision (*reported metrics)* obtained through survey (above) with an 'objective' assessment of those same metrics (*modeled metrics*). To enable the comparison, we built a financial model that calculates the expected lifecycle costs and revenues of PV system ownership for the residential buying and leasing business models (NREL 2009, Kollins *et al* 2010). Our model is distinct in two ways. First, our uniquely comprehensive dataset allows detailed cost and revenue calculations for *each* respondent (decision maker). Second, it includes detailed features of *household-level* electricity consumption, electricity rates, and PV-based electricity generation, including time-of-day and monthly variations. Next, we provide an overview of our methodology; however a more thorough description is provided in the supplemental information.

3.1. Cash-flow model

For each PV adopter we calculate a series of monthly expected costs (C_k) and revenues (R_k) accrued over the lifetime of the PV system, where k is the number of months since the PV system was installed. Therefore, cash flows (CF_k) of the investment are:

$$\mathrm{CF}_k = R_k - C_k. \tag{1}$$

Using these cash flows we calculate the net present value (NPV) using a 10% annual discount rate, NPV per DC-kW, payback period for each household's investment, and estimate each individual's implicit discount rate.

3.2. System costs

Costs (C_k) have three monthly components: (a) system payments (C_{system_k})—either lease payments or loan payments when financed and a down payment as appropriate, (b) operations and maintenance costs ($C_{\mathrm{O\&M}k}$), and (c) cost of inverter replacement (C_{Inverter_k}) where:

$$C_k = C_{\mathrm{system}_k} + C_{\mathrm{O\&M}_k} + C_{\mathrm{Inverter}_k}. \tag{2}$$

System payments for *buyers* comprise a down payment in the first period and loan payments if the system was financed. The net system cost is the installed cost less the utility rebate reported in the program data less applicable federal tax credits. We assume that: (i) buyers will make periodic operation and maintenance-related (O & M) expenses equivalent to 0–0.75% yr^{-1} of the system's installed cost; these O&M costs are expensed equally each month, and (ii) inverters require replacement after 15 yr of use and cost \$0.7–0.95 per DC-Watt. In section 3.4 we present a set of scenarios that systematically vary these parameters.

Lessees are not obligated to pay O&M or inverter replacement costs as this is a value-adding service provided by the lessor (Mont 2004). Therefore, the only costs of ownership incurred are lease payments (upfront payment and monthly lease payments). Within the sample, 69% of lessees paid for their lease entirely through a 'prepaid' down payment, 26% through only monthly payments, and 4% through a combination of monthly payments and a down payment. For all leased systems analyzed, we use the actual lease payments being made by the lessees.

3.3. System revenue

PV systems generate value by reducing owners' electricity-bill expenses during the life of the system. Therefore, the difference between electric bills the owner would have incurred without the system (BAU bill) and those with the PV system (PV bill) is effectively a monthly stream of revenues (R_k). The value of these revenues depends on the structure and rates of both bills. Our model forecasts these revenues over the system's lifetime.

3.3.1. Electricity consumption and generation profiles. Two central factors in the PV value proposition are seasonal and hourly variations in the system's generation and the household's consumption of electricity. For both factors, we use each respondent's historic annual consumption and expected annual system production (kWh) as reported in the program data, but not individual consumption or generation patterns. To simulate these hourly and seasonal variations we used load profiles published by the Electricity Reliability Council of Texas (ERCOT) of average residential consumption patterns in north-central Texas in 2010 (ERCOT 2010) and a PV generation profile for the Dallas-Ft. Worth area taken from the PVWATTS model created by the US National Renewable Energy Laboratory (NREL 2011).

Furthermore, we assume that patterns and quantities of electricity consumption are invariant over the lifetime of the PV system. This is not a robust assumption per se, since we do not capture household-level patterns of consumption that differ from the ERCOT profile or that evolve over time. But, since the goal is to *compare* the objective and reported financial metrics, this assumption is robust enough for our analysis because any variations in consumption profiles will largely cancel out in the revenue calculations.

3.3.2. Electricity rates. Within the ERCOT deregulated electricity market customers freely choose retail electricity service among providers with varying rates and bill structures (TECEP 2012). An important factor is whether their Retail Electricity Provider (REP) offers a plan that credits any moment-to-moment excesses of PV generation over consumption outflowed to the grid (Darghouth *et al* 2011, Mills *et al* 2008). Unlike many retail choice states, the ERCOT market does not mandate that REPs provide credits for these 'outflows' (PUCT 2012). Current practice is for REPs to credit outflows at a rate below the marginal price of electricity.

While it is tempting to assume that consumers will select electricity plans which offer the highest value for their PV system, it is not obvious what depth of information finding and analysis decision-makers go through to determine which REP provides this greatest value (Conlisk 1996, Fuchs and Arentsen 2002, Gigerenzer and Todd 1999, Goett *et al* 2000, Roe *et al* 2001, Tversky and Kahneman 1974). We account for this dilemma through a set of scenarios, discussed next.

3.4. Scenarios

To account for uncertainty in the model's parameters (Bergmann *et al* 2006, Laitner *et al* 2003), calculations are structured as a series of five scenarios—*Very Conservative, Conservative, Baseline, Optimistic, and Very Optimistic* (table 1). Scenarios employ progressively more optimistic assumptions that increase the value of solar to the consumer. Parameters varied were: (i) the annual growth rate in nominal retail electricity price (0–5%) (ii) if bought, lifetime of the system (20 or 25 yr) (iii) system loss rate (0.75–0.25% yr^{-1}) (iii) O&M costs as a percentage of installed costs incurred per year (0.5–0% yr^{-1}), and (iv) inverter replacement cost (\$0.95 W^{-1}–\$0 W^{-1}). Note that these scenarios are not intended to represent likely or unlikely outcomes, but to explore how consumers' differing assumptions would affect their evaluation of PV's value.

Scenarios also vary the customer's retail electricity plan *post-installation*. The most conservative scenario (scenario 1) assumes that consumers remain on their pre-PV plan for the lifetime of the system, whereas the most optimistic scenario (scenarios 4 and 5) assumes that the consumer actively researches and selects plans that minimize their electricity bill. The baseline scenario (scenario 3) assumes that consumers will adopt a 'solar' plan if offered by their REP, but will not transfer REPs. In addition, the consumer is credited 7.5 ¢ kWh^{-1} for outflows if their current REP does not offer a solar plan—since we believe that nearly all REPs will offer an outflow credit in the future. Indeed, most major REPs do so already.

4. Results

We present here the results of our analysis. Framing this analysis are the differences between buying and leasing consumers. Contrary to Drury *et al* (2011), we found no statistically significant differences between the two groups on demographic factors including income, age, education, and race as well as contextual factors such as the size of their system, annual electricity consumed, or electricity rates. Based on these results and those that follow, our conclusion is that at this stage in the diffusion of residential PV buyers and leasers *do not* represent different demographic groups, but rather *different consumer segments* within the residential PV market.

Table 1. Description of the scenarios.

Scenario	(1) V. Conservative	(2) Conservative	(3) Baseline	(4) Optimistic	(5) V. Optimistic
Elec. cost growth	0.0% yr^{-1}	2.6% yr^{-1}	2.6% yr^{-1}	3.3% yr^{-1}	5.0% yr^{-1}
System life	20 yr	20 yr	25 yr	25 yr	25 yr
System loss rate	0.75% yr^{-1}	0.5% yr^{-1}	0.5% yr^{-1}	0.5% yr^{-1}	0.25% yr^{-1}
Maintenance costs	0.5% yr^{-1}	0.25%	0.25% yr^{-1}	0.15% yr^{-1}	0% yr^{-1}
Inv. replace. cost	\$0.95 W^{-1}	\$0.95 W^{-1}	\$0.7 W^{-1}	\$0.7 W^{-1}	None
Electricity plan after PV adoption	Keeps same REP and plan post-installation; no outflows	Adopts solar plan if offered by current REP	Adopts solar plan if offered by current REP; min. 7.5 ¢ kWh^{-1} outflow	Adopts plan with max. value among current market solar plans or BAU plan	Same as scenario 4

4.1. Installed cost and cost of ownership

Installed costs (\$$W^{-1}$) of leased systems (Mean = 8.3, Std. dev. = 0.53) were significantly more than those of bough systems (Mean = 6.2, Std. dev. = 1.4) and the mean differences were highly significant ($t(201) = 16.08$; $p < 0.001$). This corroborates similar installed cost differences for bought and leased systems nationally (Barbose *et al* 2012). As discussed in section 3.2, recall that while buyers' cost of ownership is the installed cost less applicable rebates, the installed cost is generally *not* reflective of the lessees' cost of ownership, which are only their lease payments. Surprisingly, the mean lessees' cost of ownership (\$0.70 W^{-1}) were substantially less than those of buyers (\$2.64 W^{-1})[4]. Accordingly, we found that lessees had a statistically significant greater NPV per capacity ratio (NPV/DC-kW) than buyers in all but scenario 5 (figure 1; only baseline scenario shown).

How is it possible that leased systems are installed at higher costs than bought systems, but that lessees face a lower cost of ownership than the equivalent bought system? As others have noted (for example see, Barbose *et al* 2012), the installed cost reported to state and utility PV incentive programs is often the 'fair market value', or the appraised value, reported when applying for the 1603 Treasury Cash Grant or Federal ITC. Since the benefits of both the 1603 Treasury Cash Grant and tax benefits from MACRS increase with the appraised value of the system, it is plausible that some leasing companies might be inflating the appraised value—at least the incentive to do so clearly exists. Indeed the SEC and IRS recently began an investigation of several leading leasing firms to determine if the true fair market value of installed PV systems were materially lower than what the firms had historically claimed (SEC 2012). If proven true, one implication of this financial strategy would be that since additional system costs and company profits are recouped through the tax structure, leasing companies adopting such strategies would be able to offer lower rates to their customers

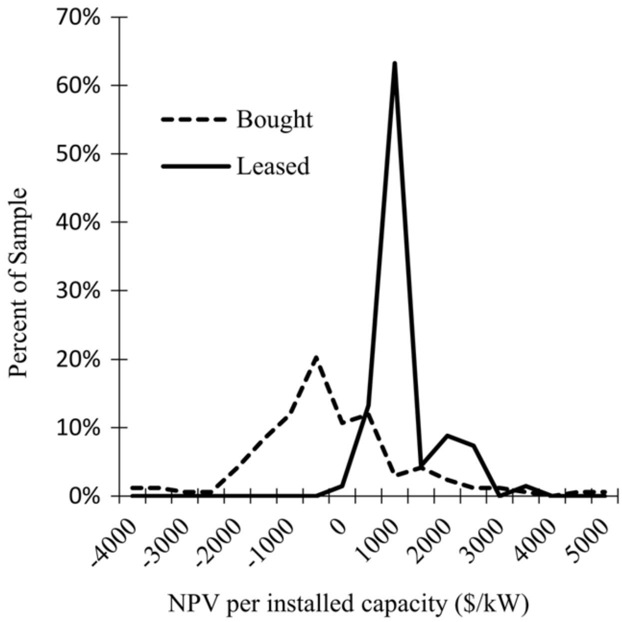

Figure 1. Distribution of modeled NPV kW^{-1} assuming *baseline* model parameters.

(the lessees). The fact that we indeed find the cost of leasing PV systems (by the lessees) to be much lower than the cost of buying PV systems lends some support to the hypothesis that some leasing companies might be employing such financial strategies.

Therefore, we tentatively explain lower lessees' costs of ownership through the following mechanisms: (i) maximization of federal tax benefits by leasing companies (lessors) through the financial strategy described above; (ii) in the current policy environment, lessors are able to access additional financial incentives that buyers cannot access, particularly, accelerated depreciation (Bolinger 2009, Coughlin and Cory 2009); (iii) economies of scale present in the operation of a larger fleet of leased systems; (iv) ability for lessors to raise capital at a lower cost, which would increase their leveraged return on capital; and (v) since the lease contracts are typically only 15–20 yr as compared to the generally reported lifetime of PV panels of 20–25 yr, leased systems will likely have some residual value; in theory, the lessors could recoup the residual value at a later date, which

[4] Note that the upfront cost of ownership does not reflect the operational life of PV systems or their performance over that lifetime. In general, most analyses assume an operational life for PV systems of 20–25 yr, which is applicable to buyers of PV systems. Lease contracts typically terminate after 15–20 yr. So the difference in the upfront cost of ownership of bought versus leased systems should be put in this context. However, as discussed below, NPV calculations incorporate this difference in the length of cash flows.

would allow them to offer the leased systems at lower rates today. All of these mechanism would lower costs faced by lessors, and therefore reduce the size of the lease payments required to achieve a given rate of return. In a competitive leasing market, then, these mechanisms would translate into lower costs faced by lessees—just as we find. A deeper explanation of these aspects would require financial analysis of the leasing companies' balance sheets, which is beyond the scope of this paper.

If leasing is financially more attractive, why don't more adopters choose to lease? For many the option did not exist—73% of buyers reported not having the option to lease when making their decision. There is also evidence in the literature of conspicuous consumption for novel 'green' technologies (Dastrop *et al* 2011, Sexton 2011); under this paradigm, consumers could derive additional utility from the status gained by owning, rather than leasing, their system. Residence uncertainty was not a factor, as each group reported a similar (10–15 yr) period that they expected to continue living in their homes. Finally, a majority of PV adopters who had the option to either buy or lease a PV system, but chose to buy report concerns about potential difficulties with the leasing contract as a factor in their decision to buy[5]. Considering all these factors, we conclude that buyers who did have the option to lease, but chose to buy, had adequate cash-flow such that they preferred the contractually simple buying option, even though the leasing option is nominally cheaper.

4.2. Payback period comparison

Consistent with previous research (Camerer *et al* 2004, Kempton and Montgomery 1982, Kirchler *et al* 2008), the majority of respondents (66%) reported using payback period to evaluate the financial attractiveness of their investment as opposed to NPV (7%), internal rate of return (27%), net monthly savings (25%), or other metrics (6%). 10% made no estimate of the financial attractiveness. Respondents also reported the values of the metrics they used. These responses allow us to compare reported metric values (*reported*) to the values individually generated from the financial model (*modeled*) (figure 2; only baseline scenario shown).

For buyers, scenario 4 minimized the average absolute difference between reported and modeled payback period ($M = 2.6$ yr, $SD = 2.4$), followed by scenario 5 ($M = 3.1, SD = 1.9$). For lessees, scenario 3 ($M = 1.1, SD = 0.7$) was the best fit, followed by scenario 2 ($M = 1.296, SD = 0.704$). Scenario 1 was a poor fit overall. This suggests that buyers assumed parameters similar to those of scenario 4 when evaluating their investment. That is, buyers were optimistic when assessing the likely revenues and costs associated with their investment decision. By the same argument, lessees were more realistic and precise when making their investment decision. This is consistent with the fact that lessees receive much of this financial information from leasing companies, who use very detailed and sophisticated financial models.

[5] There were 44 respondents in our sample who had the option to either lease or buy a PV system, but chose to buy. Of those 24 responded to a 5-point Likert-scale question on how strongly they agreed with the statement, 'I was concerned about potential difficulties related to the leasing contract'. 50% agreed or strongly agreed with the statement, while only 8.5% disagreed or strongly disagreed with the statement.

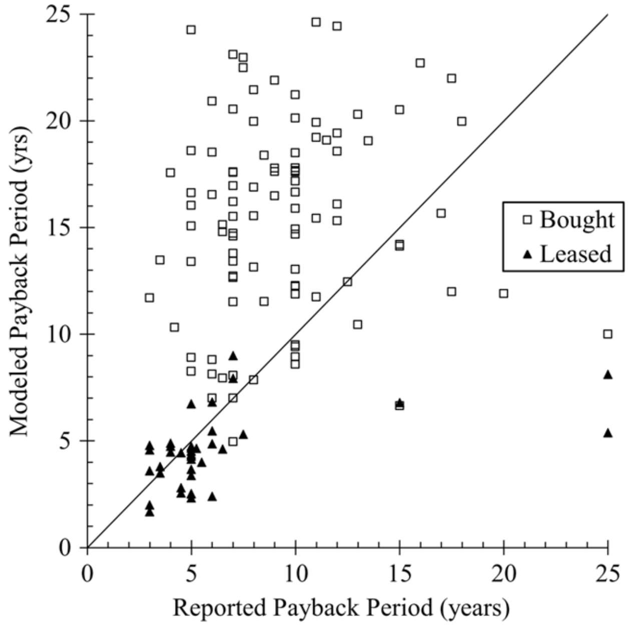

Figure 2. Comparison of reported and modeled payback period in scenario 3. Mean difference between modeled and consumer payback period: buyers = 7.1 yr^{-1}; leasers = 1.1 yr.

4.3. Implied discount rate

For all calculations of NPV reported above a 10% annual discount rate was assumed. In this section we present discount rates calculated separately for each individual respondent. Specifically, we first determine each respondent's *implied NPV* and then back-calculate their discount rate using the implied NPV and their modeled cash flows. To determine the implied NPV, respondents were asked on a 5-point Likert-scale how strongly they agreed with the following five statements: (i) 'I would not have installed the PV system if it had cost me $**1000** more'…(v) 'I would not have installed the PV system if it had cost me $**5000** more'. One expects respondents to increasingly *agree* that they would *not* have installed the PV system as the price increased. The above question estimates the respondent's implied NPV by extrapolating how much more the respondent would have paid before becoming indifferent to purchasing the system or forgoing the investment (figure 3).

Of the 210 respondents in our dataset, 92 responses were excluded from these calculations—69 whose implied NPV was outside the range tested ($0–$5000), 7 responses which implied an increasing willingness to pay, and 16 non-responses. Of the excluded respondents, 55 respondents indicated they would have been willing to pay at least $5000 more for their system—of which 76% were buyers and 24% leasers. That is, a significant per cent of the sample (26.2%) did assign a positive value to their investment, yet were not captured within this calculation because of insufficient data.

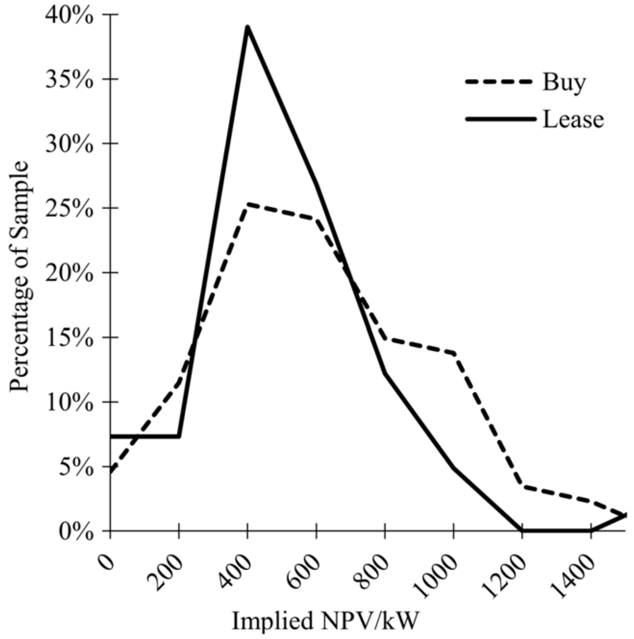

Figure 3. Distribution of implied NPV kW^{-1} for buyers and leasers; difference of mean is not significantly different than zero.

In the end, there are 81 buyers and 37 lessees remaining for the discount rate analysis reported in this section.

Using the implied NPV, we solve for the monthly discount rate (r_m), required to equate the respondent's implied NPV with the cash flows modeled earlier.:

$$\mathrm{NPV_{implied}} = \sum \mathrm{CF}_k = \sum \frac{[R_k - C_k]}{(1 + r_m)^k}. \tag{3}$$

The monthly discount rate is then annualized using (4):

$$r = (1 + r_m)^{12} - 1. \tag{4}$$

Thus, r represents each respondent's discount rate implied by their willingness to pay and their modeled cash flows. As the cash flows vary with each scenario, implied discount rates also vary with scenarios.

Using baseline (scenario 3) parameters, the mean discount rate for buyers was $7 \pm 5\%$ and for lessees was $21 \pm 14\%$ ($\pm 1\sigma$) (tables 2 and 3). The calculated implied discount rates are higher in the optimistic scenarios since cash flows increase as the scenarios become more optimistic. Across all scenarios and income levels lessees' implied discount rates are significantly higher than buyers by 8–21%.

It is important to note a similarity in the timing of leased and bought payments—the majority (69%) of lessee respondents chose to structure their leases as a single 'prepaid' down payment, which is similar to the financial structure of a bought system, but significantly smaller in the scale of investment. After taking all incentives into account, for lessees the upfront payment is on the order of \$4000 and for buyers it is \$15 000 for a 6 kW-DC system. Yet, each group expects to receive a similar (normalized) NPV for their investment. That is possible only when these groups have differing cash urgencies. Indeed, in open-ended survey questions, 66.2% of lessees agreed or strongly agreed that tight cash availability was one of the key factors in their decision to lease, whereas buyers generally did not have this problem. Given that there are little, if any, demographic differences between buyers and lessees, then, we infer that at this stage in the residential PV market buyers and lessees represent *different consumer segments* within a similar socio-demographic makeup. Put differently, compared to the average buyer the average lessee is not lower income *per se*—the majority of the lessees have some cash availability, just not enough to outright buy their PV system.

In general, our point is that within populations with similar demographics it is possible that there are variations in disposable income, and those variations are a key factor in ownership model choices[6]. Consistent with a large body of work in the diffusion of innovations tradition (Rogers 2003), our results suggest that there is a hierarchy within the population regarding the adoption of technologies. In early stages of technology diffusion, as is the case with PV now, information (awareness of products, interest in energy, etc) is the precursor, which is more likely to be found in higher income, more educated segments of the population. Within those segments, those with tighter cash flows opt for leasing, if that option is available. Thus, the leasing model appears to be especially effective in the early stages of a technology's diffusion, as it unlocks the cash-strapped but information-aware segments of the market. Put differently, the leasing model accelerates the early adoption stage of a technology's diffusion, thereby quickly establishing a wider base on which later adoption can build upon.

4.3.1. Discount rate and income. Previous literature starting with Hausman (1979) suggests that an inverse relationship exists between household income and consumer discount rate. That is, poorer consumers have more urgent needs for their cash than wealthy ones. At higher incomes, where one has a greater degree of spare income, the rate of return of investments (and hence, their discount rate) should converge to market returns. Our results are mixed in regard to these earlier findings.

A one-tailed t-test comparing the difference in mean discount rate among income groups for the baseline scenario was performed using the hypotheses H_o: $\mathrm{DR}_1 = \mathrm{DR}_2$, H_a: $\mathrm{DR}_1 \geq \mathrm{DR}_2$, and H_o: $\mathrm{DR}_2 = \mathrm{DR}_3$, H_a: $\mathrm{DR}_2 \geq \mathrm{DR}_3$, where DR_1 is the mean implied discount rate for income group 1 and so on[7]. This test was performed for both income pairs ($\mathrm{DR}_1 \geq \mathrm{DR}_2$, $\mathrm{DR}_2 \geq \mathrm{DR}_3$) since we expect the implied discount rate to monotonically decrease with income.

Even with a 90% confidence interval, we did not find a statistically significant relationship between income and discount rate for either buyers or lessees. We explain this discrepancy with two reasons. First, small sample size, particularly in the leasing sample, reduced our test's statistical

[6] We note, however, there are several factors besides cash availability that can guide ownership choices—priority of environmental value over financial concerns, intended length of residence, financial security, and so on.

[7] Income groups were: income 1: \$0–\$84 999 year^{-1}; income 2: \$85 000–\$149 999 year^{-1}; income 3:\$150 000 + year^{-1}.

Table 2. Mean implied discount rate for buyers along income and scenarios with $\pm 1\sigma$.

Buyers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
N	**81**	22	37	22
Scen 2: conservative	**6%** $\pm$ **6%**	6% $\pm$ 5%	6% $\pm$ 8%	7% $\pm$ 6%
Scen 3: baseline	**7%** $\pm$ **5%**	7% $\pm$ 4%	6% $\pm$ 6%	7% $\pm$ 6%
Scen 4: optimistic	**13%** $\pm$ **6%**	12% $\pm$ 5%	13% $\pm$ 6%	13% $\pm$ 7%
Scen 5: V. Optimistic	**18%** $\pm$ **7%**	17% $\pm$ 5%	18% $\pm$ 7%	17% $\pm$ 8%

Table 3. Mean implied discount rate for leasers along income and scenarios with $\pm 1\sigma$.

Leasers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
N	**37**	13	13	11
Scen 2: conservative	**20%** $\pm$ **15%**	22% $\pm$ 19%	20% $\pm$ 14%	18% $\pm$ 12%
Scen 3: baseline	**21%** $\pm$ **14%**	23% $\pm$ 18%	22% $\pm$ 13%	19% $\pm$ 12%
Scen 4: optimistic	**32%** $\pm$ **17%**	33% $\pm$ 22%	35% $\pm$ 15%	30% $\pm$ 14%
Scen 5: V. Optimistic	**35%** $\pm$ **13%**	29% $\pm$ 9%	38% $\pm$ 13%	36% $\pm$ 16%

power. Second, both groups exhibit characteristics typical of early adopters—wealthier, more educated, etc. These characteristics could negate the relationship between income and discount rate for products in settled markets as early adopters typically derive additional utility from adopting new technologies beyond financial benefits (Faiers *et al* 2007, Labay and Kinnear 1981, Rogers 2003). In agreement with previous literature, we do find that discount rates for buyers in the conservative, baseline, and optimistic scenarios (scenarios 2–4) ranges between 7 and 13%, which is close to market returns. This also supports our finding that buyers of PV systems are in a relatively comfortable cash-flow position.

5. Conclusion

We have studied the economics of the decision-process of individual consumers, particularly their decision to buy or lease a residential PV system. Consistent with several other studies, we find that a majority of PV adopters used payback period—not net present value (NPV)—as the decision-making criterion. We also find that owing to the peculiarities of financing and incentive mechanisms, the pre-rebate installed costs of leased PV systems are significantly higher than the bought systems, yet lessees end up paying nominally much lower amounts than buyers of PV. We calculate individual-level discount rates across a range of scenarios, finding that buyers employ discount rates 8–21% lower than lessees. Those who lease typically have a tighter cash-flow situation, which, in addition to less uncertainty about technological performance, are the main reasons for them to lease. As we do not find any significant variation between buyers and lessees on any socio-demographic dimension (income, age, etc) this suggests that the leasing model is making PV adoption possible for a new consumer segment—those with a tight cash-flow situation. As the diffusion of PV spreads to lower-income households, who generally experience tighter cash-flow than wealthier households, this implies that, *ceteris paribus,* moving forward the leasing model will likely be the predominant form of PV adoption. From this perspective, the leasing model has opened a new market segment at existing prices and supply chain conditions—and represents a business model innovation.

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VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013

IEE INNOVATION ELECTRICITY EFFICIENCY
An Institute of The Edison Foundation

Value of the Grid to DG Customers

IEE Issue Brief

September 2013
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VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.[1] While it is easy to say that a DG customer is "free from the grid," that is simply not true – even for a DG customer (or a micro-grid) that produces the exact amount of energy that it consumes in any given day or other time interval.[2]

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services. The utility's cost of providing grid services consists of at least four components – the typical fixed costs associated with: (i) transmission, (ii) distribution, (iii) generation capacity, and (iv) the costs of ancillary and balancing services that the grid provides throughout the day for the DG customer.

There is a related question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid. This paper does not explicitly address this "value of on-site energy" issue.

THE BENEFITS OF REMAINING CONNECTED TO THE DISTRIBUTION SYSTEM

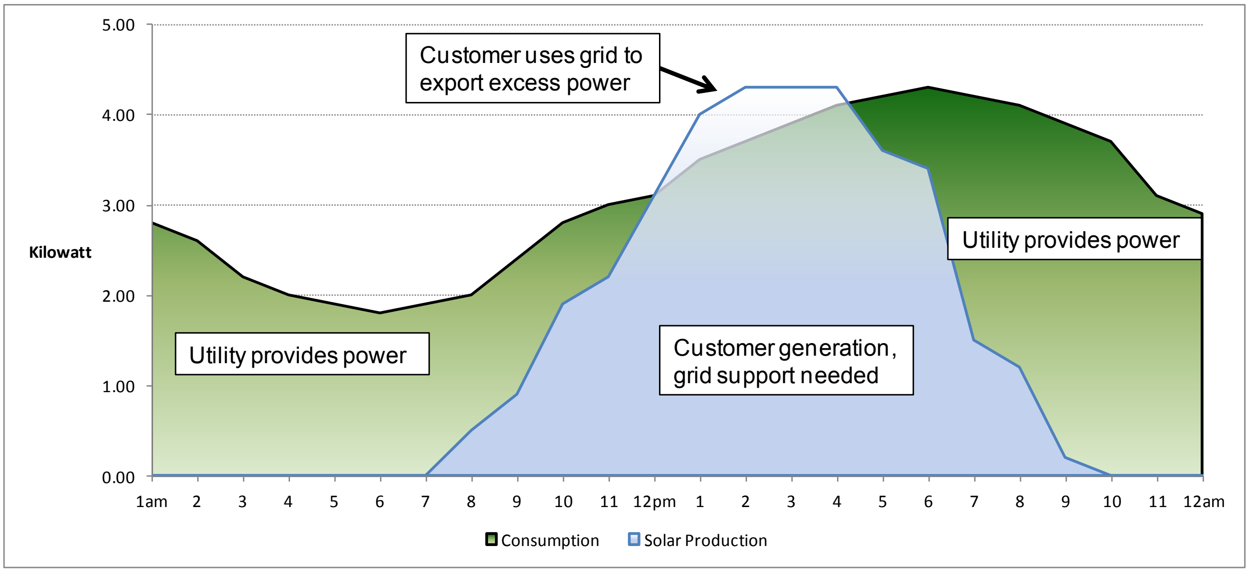
Consider a residential or small commercial customer with solar PV panels on its rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy delivered by the host utility and consumed by the customer. The area under the blue curve is the energy produced on-site by the solar panels. The area below the blue curve and above the green line is the excess energy injected into the utility's distribution system. The key take-away from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-

1 A recent Forbes article, "Distributed Generation Grabs Power from Centralized Utilities," August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to about 4:30 pm.

Figure 1: Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency *(i.e.*, regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (*i.e.*, backup service);
- provide voltage and frequency control services and maintain high AC waveform quality.

Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by examining the charges that a typical residential customer consuming an average of about 1000 kilowatt-hours (kWh) per month [average consumption based on Energy Information Administration (EIA) data and rounded] will pay for grid services, excluding the charges for the electric energy itself. These charges are designed to allocate to the customer its fair share of the fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity.[3] As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.[4]

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1000
Average Monthly Bill ($)*	$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**55%**

*Based on Energy Information Administration (EIA) data, 2011
^The charge for capacity varies depending upon location. This is just an estimate.

In this example, the typical residential customer consumes, on average, about 1000 kWh per month and pays an average monthly bill of about $110 (based on EIA data). About half of that bill (*i.e.,* $60 per month) covers charges related to the non-energy services provided by the grid,

3 In "retail choice" states the retail customer can choose its energy supplier, which may not be the utility. In all other states the utility will be the retail supplier.

4 Other charges, such as sales and franchise taxes and environmental charges could be added to the table; however, the focus of this paper is on the grid services that are provided by the host utility.

including a charge for generation capacity. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or all of its fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to $720 per year in costs (*i.e.,* $60 * 12 months) to other retail non-DG customers. To put this into context, if 50 percent of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increases of up to 55 percent – from $110 per month to $170 per month. Clearly this cost shift is substantial and simply not fair.

IEE submits that DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value provided by the grid for a solar PV customer, consider what it would cost that customer to self-provide the technical equivalent of these services through some combination of energy storage and/or thermal generation (*e.g.,* a Generac home generator).

Preliminary estimates of the monthly costs that a typical residential customer would have to incur to self-provide the balancing and backup services that the grid currently provides are substantially higher than the $60 charge shown in Table 1.[5] Furthermore, this cost estimate of self-provision excludes the additional cost of maintaining the level of voltage and frequency control and AC waveform quality currently provided by the grid. An off-the-grid DG customer (or micro-grid) simply cannot provide, at reasonable cost, the same quality of service that a large power system provides. So, in fact, most DG customers remain connected to the grid today and utilize grid services.

This straightforward cost comparison to "self providing" grid services reveals three things. First, the balancing and backup services that the grid provides to DG customers are needed and have substantial value. Second, it does not make economic sense for a DG customer to self-provide these services. Third, it is unfair for DG customers to avoid paying for these grid services,

5 The Electric Power Research Institute (EPRI) is developing estimates of the cost of self-providing grid services and expects to release its results in 2014.

thereby shifting the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

Economies of Scale Associated with Power Systems

In many ways, the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale that still exist today as ISO/RTO markets continue to grow and expand.[6]

These interconnection entities developed for good reasons. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. For example, the small system's operating reserve margin will decrease substantially. This phenomenon is even more pronounced when a micro-grid interconnects with a power system.

DG Market is Growing, Pricing it Right is Key

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policymakers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that net-metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these "grid" costs are quite significant – about 55 percent of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

6 Entergy's decision to join MISO is a recent example.

REVENUE DECOUPLING WILL NOT RESOLVE THE DG COST-SHIFTING ISSUE

Revenue decoupling is currently being used to promptly restore utility net revenues that would otherwise be lost due to declining electricity sales resulting from utility investments in energy efficiency (EE). Although revenue decoupling makes the utility whole, it does so by explicitly shifting costs from participating EE customers to nonparticipating EE customers using a public or system benefits charge (which is typically visible and transparent to all customers as a charge on their utility bills). Decoupling causes the same cost shifting problem that is created by DG with net metering. However, a fundamental difference is that the magnitude of the "cost shifting" to non DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are quite small – about 2 to 3 percent of the retail rate.[7] In contrast, as described earlier in this paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. This "diminishing return" aspect means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs – particularly for rooftop solar PV – are expected to decline over time. *Although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless some reforms to net metering are put into place.*[8]

ALTERNATIVE APPROACHES TO END COST SHIFTING DUE TO NET METERING

Three basic approaches to net metering are under examination across the nation, each of which seeks to ensure that a DG customer using grid services pays its fair share of the costs of those services while still receiving fair compensation for the excess energy that it produces:

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7 "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Pamela Morgan, Graceful Systems LLC. February 2013.

8 Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges);
- Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (*i.e.,* total on-site) generation; and
- Impose transmission and distribution (T&D) "standby" charges on DG customers.

These three approaches are illustrative and are further described below.

Redesign Retail Tariffs (APS Proposal). To address the fundamental issue that a residential customer with rooftop solar should be compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options.[9] The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services.

The second option allows the customer to choose an existing APS rate schedule for its total electric consumption and APS will purchase all of the customer's rooftop solar generation at market-based wholesale rates. This option ensures recovery of grid services and sends more accurate price signals to DG customers. It is also conceptually very close to what Austin Energy has already put in place.

Treat On-site Generation and Consumption Separately (Austin Energy Tariff). Austin Energy has implemented a solar tariff that fully compensates its DG customers for their gross on-site generation while separately charging them for their gross consumption under its existing retail tariff.[10] This approach effectively ensures that the cost of grid services are recovered from DG customers while also compensating DG customers for their generation at the utility's full avoided cost of procuring energy. The Public Utility Regulatory Policies Act (PURPA), under Title II, provides an established precedent for such compensation.[11] This approach requires a separate meter for on-site generation.

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9 APS conversation, July 2013.

10 Rabago, K.R., *The 'Value Of Solar' Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February, 2013. Available at www.solarindustrymag.com.

11 Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

Implement T&D Standby Charges for DG Customers (**Dominion Tariff).** Dominion requires a residential net-metered DG customer with a solar installation whose rated output is greater than 10kW and up to 20kW, to pay a monthly transmission standby charge of $1.40 per kW and a monthly distribution standby charge of $2.79 per kW. However, these standby charges are respectively reduced, dollar for dollar, by the customer's transmission and distribution charges that are recovered through kWh charges applied to the customer's monthly electricity consumption up to the point where each standby charge is fully phased out. This became effective on April 1, 2012. Dominion also proposed a placeholder for a future generation standby charge, but it was not approved. The Commission ruled that a generation standby charge should be studied and filed in a future proceeding.

A FINAL THOUGHT

In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now.

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A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

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Executive Summary

Net energy metering (NEM) is a state-level policy that permits a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. Forty-three states, the District of Columbia, and Puerto Rico have instituted NEM in some form to permit self-generation, typically at the urging of customers seeking to use solar, wind, and other renewable energy facilities. These NEM policies vary from state to state, particularly regarding how large an individual installation can be and how much NEM will be allowed in the aggregate. Restrictions on NEM are almost always driven by utility concerns that lower utility bills for NEM customers will lead to higher utility bills for customers who do not have NEM.

The intent of this report is to provide a consistent methodology to analyze the potential rate impacts of NEM. With reliable estimates of rate impacts, regulators can make informed decisions regarding modification of NEM rules, and our intent here is to provide a methodology for more reliable estimates. In this report, we review and synthesize three studies performed for major utilities in Arizona, California, and Texas during the past decade. All three were on a scale far beyond the scope of this report, but the broad categories of costs and benefits identified in the studies are not specific to a given utility.

Based on this review, we provide a generalized approach for any state or utility to analyze the potential rate impact of NEM in its area. The analysis and results of such studies are utility-specific, but the methodology should not be. If benefits exceed costs, then regulators may want to consider lifting restrictions on NEM and crediting NEM customers for the net benefits they provide. If costs exceed benefits, then other ratepayers are subsidizing NEM customers, and regulators must decide whether externalities such as reduced pollution, job creation, and resource diversity justify the subsidy.

Costs of NEM are often argued to be the utility's lost revenue and any associated administrative costs. Every kilowatt-hour (kWh) generated by an NEM customer means one less kWh sold by the utility at retail rates. The retail rate in question depends on the type of customer. Most residential and small commercial customers have a bundled rate that covers both their utility's fixed and variable costs, while large commercial customers typically have an "energy" charge based on kWh for variable costs and a "demand" charge based on the customer's peak usage, measured in kW, for fixed costs.

Typically, an NEM solar facility has minimal impact on the demand component of the demand-metered customer's bill. Even if the customer would have experienced peak demand coincident with sunshine without a solar array, and a solar array significantly lowered demand at that time, demand near that peak level after sunset or when the system is not operating will be unchanged. Thus, typically, demand-metered customers with an NEM solar facility primarily offset energy charges, which are much lower than the bundled rates for residential and small commercial customers. As the energy charge is based on variable costs that the utility no longer has to incur, the impact of NEM for these customers should be negligible. At present, roughly two-thirds of the installed capacity of all NEM solar facilities is located on commercial customer property, with much of that sized over 100 kW and likely to be offsetting the energy charges of demand-metered customers.

The other aspect of NEM costs is the utility's administrative expense. Most utilities use proprietary billing software that is costly to adapt for NEM. Therefore, in the short term many utilities use hand billing for NEM customers to avoid incurring a large cost for a relatively small group of customers. However, over the medium to long term, changes to a utility's billing software to support evolving energy use patterns—dynamic rates, advanced metering, plug-in electric vehicles, etc.—will occur in the ordinary course of business. Logically, updating billing software to handle NEM program participants can occur as part of this longer-term evolution. Accordingly, we believe that the anticipated long-term administrative costs of a NEM program should be used in any rate impact analysis, on the reasonable presumption that billing of NEM customers will be automated.

On the benefits side of the rate impact calculation, the three studies we reviewed indicate that NEM allows utilities to save fuel expenses, avoid line losses, and realize at least some capacity benefit, while also suggesting various secondary benefits. An important component to the benefit calculation is determining what generation will be offset. Utility variable rates are based on average operating costs, and more than two-thirds of utility generation is from high capital cost/low operating cost coal, nuclear, and hydropower facilities. NEM solar facilities generally do not offset these baseload generators. Rather, they offset the lower capital cost/higher operating cost natural gas-fired facilities that operate during business hours and other periods of above-average demand to supplement baseload generation.

No matter which type of generation is offset, line loss savings are an important benefit of NEM. For every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost on the way to customers in the form of transmission and distribution losses. In contrast, NEM generation occurs at the customer's site, with almost no line loss. Neighbors typically use excess generation from a NEM facility, with negligible line losses. The demand on the distribution circuit serving the NEM customer drops by the full amount of the facility's generation at any given moment. Any line losses are utility- and time-specific, but for many utilities, higher losses occur during hot, sunny conditions. To calculate line loss savings associated with NEM solar facilities requires a reasonable estimate of average daytime line losses for that utility.

The most contentious element of the benefits calculation relates to capacity benefits. To the extent that NEM facilities allow a utility to delay or avoid construction of the next generator, transmission line, substation, or distribution line, there are clearly associated savings enjoyed by the utility and its customers. The studies we reviewed differed in their treatment of capacity benefits. We conclude that capacity benefits are real and incremental, with aggregate distributed solar generation far more stable and predictable than the obviously intermittent nature of individual solar facilities. We also include information about the potential for combining solar energy with demand response or energy storage programs to assure capacity benefits. While solar energy facilities are typically available during high demand periods, utility planners are hesitant to attribute capacity values to them because of the perception that they are not as reliable as traditional resources. Firming the output of solar energy generation with demand response or energy storage will allow utility planners to confidently rely on solar energy, particularly as new smart grid capabilities come online that allow grid operators to balance supply and demand at local levels in real time.

Author Biographies

Jason B. Keyes focuses on regulatory matters related to interconnection of distributed generation to the U.S. electric grid. On behalf of the Interstate Renewable Energy Council, he has participated in interconnection and net metering rulemakings at the utility commissions of fifteen states. As a partner at Keyes & Fox, LLP, he also represents private clients with all regulatory aspects of renewable energy project development. Prior to his legal career, Mr. Keyes managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration solar energy systems. In the early 1990s, he helped develop the integrated resource plan and the demand forecast at Washington State's largest utility. Mr. Keyes received his juris doctor from the Seattle University School of Law, a master of arts in economics from the University of Washington, and a bachelor of arts from Dartmouth College. Mr. Keyes is a member of the Washington State Bar Association.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit Solar ABC's website:
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INTRODUCTION

Net energy metering (NEM) is critical to supporting customer investment in renewable distributed generation (DG). Although there are various policy options related to NEM, the basic structure allows a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. To facilitate the expansion of opportunities for customers to invest in DG, 43 states, the District of Columbia, and Puerto Rico have implemented NEM programs. Increasing interest in NEM programs has come at a particularly important juncture in the development of the solar industry as module prices declined markedly in 2009-2010. This decline in prices resulted in increased consumer interest in solar energy despite the economic climate. However, while many NEM programs in this two-year period broadened in scope, the quality of programs continued to vary widely between the states.

NEM programs have met with resistance, notably from utilities concerned that a robust NEM program in their service territory would result in significant rate impacts for nonparticipating customers and—in the case of an investor owned utility (IOU)—a loss of profit. Unfortunately, a detailed analysis of potential NEM rate impacts has only recently begun, so potential rate impacts are not well understood and there continues to be disagreement about the appropriate inputs for such analysis.

Despite this disagreement, efforts have moved forward, particularly in Arizona, California, and Texas, to more rigorously quantify the rate impacts of NEM programs. Together, these efforts facilitate the development of a consensus view of the most important considerations in the valuation of renewable energy resources, particularly distributed solar energy systems.

To assist state policy makers, utilities, utility regulators, renewables advocates, and other stakeholders in their efforts to evaluate the potential rate impacts of NEM in their states, we suggest a methodology based on standard NEM provisions in states with the highest levels of program participation. Because solar facilities make up the majority of net-metered facilities participating in state NEM programs, we focus on the impact of net-metered solar facilities. We analyze the methodology for determining rate impacts, and do not undertake a review of any particular state renewable energy program. In addition, we consider only the impact of net-metered solar facilities on non-participating customers' rates, not economic impacts, environmental impacts, or impacts on participating customers investing in DG resources.

The "Present Status of Net Energy Metering" section provides a background discussion focusing on the key NEM program variables that can impact rates. The "Relevant Studies for Evaluating Net Energy Metering Rate Impacts" section discusses the costs and benefits of NEM that should be considered in a rate impact analysis. The "Best Practices in Valuing Net Energy Metering" section reviews California's efforts to assess the rate impacts of NEM, which constitute the most thorough analysis to date. Finally, we present conclusions and recommendations. We cite references within the text by title or author, and include full citations in the "References" section at the end of the report.

PRESENT STATUS OF NET ENERGY METERING

NEM as a policy choice for supporting customer investment in renewable energy resources is thriving. According to the Database for State Incentives for Renewables & Efficiency *(http://www.dsireusa.org)*, 43 states, the District of Columbia, and Puerto Rico have adopted an NEM policy, as shown in Figure 1. Many states have adopted a policy that applies only to IOUs. However, some statewide policies also apply to municipal and cooperative utilities. Program rules vary widely among states on such crucial issues as overall NEM program size, facility size, allowance of third party ownership, and the ability to roll over excess generation from one month to the next.

Details on state NEM policies are thoroughly documented in an annual publication by the Network for New Energy Choices (NNEC) entitled Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures (Network for New Energy Choices, 2011). The document provides side-by-side comparison of state policies in 11 areas related to facility size, program size, eligibility, metering, treatment of excess generation, allowance of third party ownership, and protection from standby charges and other fees that nonparticipating customers do not face. Within those policy areas, NNEC awards a sliding scale of points based on the policy choices each state has made with the most points going to states with policies that accommodate more distributed generation.

For purposes of reviewing rate impacts of NEM programs, system size limitations, program size limitations, rollover of excess generation, and standby charges are discussed here. Policy choices in these areas directly affect rate impacts. These restrictions are often undertaken in an effort to address concerns about rate impacts on non-participating customers, with the intent of mitigating the perceived rate impacts of a NEM program. And yet, expansive NEM policies are an important element in state efforts to promote customer-sited renewable generation. (Itron, 2010; Doris, McLaren, Healey, & Hockett, 2009; Paidipati, Frantzis, Sawyer, & Kurrasch, 2008)

System Size Limitations

Figure 1 shows that eligible system size ranges from 20 kilowatts (kW) in Wisconsin—the size of a very large residential system—to two megawatts (MW) or more in 14 states.

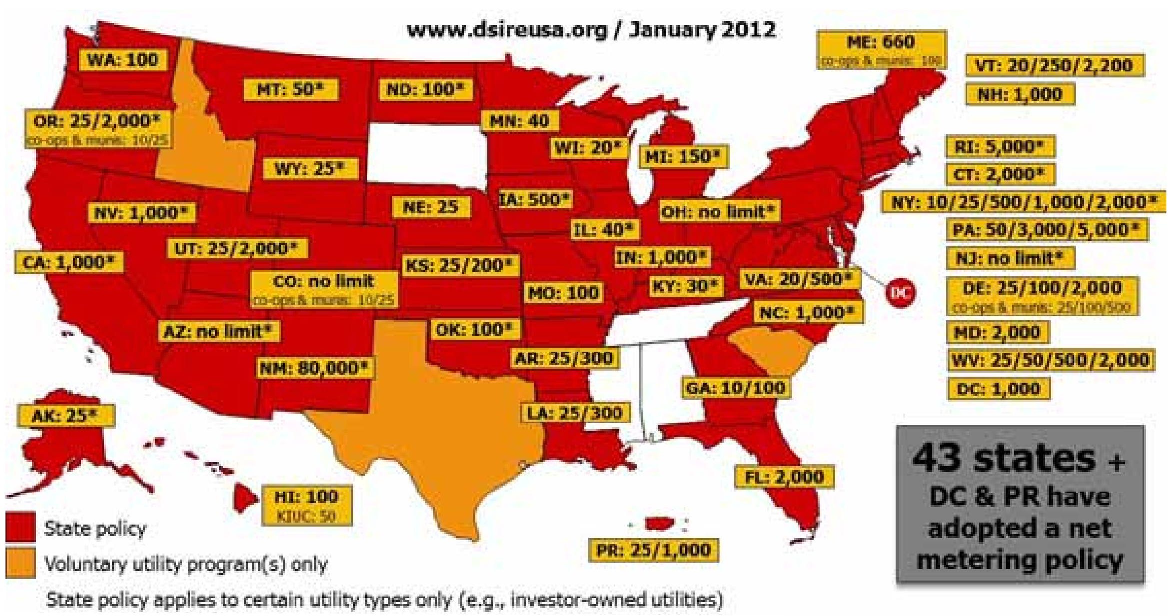

Figure 1. State net energy metering (January 2012, http://www.dsireusa.org). Numbers indicate residential/ commercial individual system capacity limits.

As Table 1 shows, the top ten states for customer-sited solar energy share the attribute of allowing NEM facilities of at least one MW, with the exception of Hawaii, which has unique characteristics.

TABLE 1
Top 10 States by Installed Capacity and Their NEM System Size Cap

2010 Rank by State	2010 Market Share	Cumulative MWDC	NEM System Size Cap
1. California	48%	1,022	1,000 kW
2. New Jersey	12%	260	no limit
3. Colorado	5%	117	no limit
4. Arizona	5%	105	no limit
5. Nevada	5%	102	1,000 kW
6. Florida	3%	73	2,000 kW
7. New York	3%	56	2,000 kW
8.Pennsylvania	3%	55	5,000 kW
9. Hawaii	2%	45	100 kW
10. New Mexico	2%	43	80,000 kW
All Other States	12%	261	

Source: Sherwood, L., ***U.S. Solar Market Trends 2010****, Interstate Renewable Energy Council, June 2011. (Total of 2,139* MW_{DC}*)*

Program Size Limitations

Limitations on program size and the size of eligible systems often go hand in hand. These policies appeal to those who believe that NEM programs are a subsidy, but this position is widely debated. A December 2009 report by the National Renewable Energy Laboratory reviewed how states have considered the rate impacts issue, with no example of a state finding that subsidization exists (Doris, Busche, & Hockett, p. 15). The report notes that North Carolina and Maryland looked into the issue and decided not to attempt studies because the experience in other states "had not shown a negative rate impact." The report notes that in New York, an attempt at quantification was underway, but "the impacts have not been large enough to measure under the current data collection scheme." Having surveyed states on the issue, the report concludes that "[t]he states that have increased the net metering system size cap generally cited the limited impacts of net metering on ratepayers in other states."

These policy choices also hinder the development of renewable energy markets in two ways. First, program capacity caps signal to potential new energy developers that their efforts will ultimately be thwarted, not by a lack of customer interest, but by regulatory restrictions. At the same time, a cap on DG system size to less than one MW precludes development of economical systems above the size cap, and those larger systems have been an important driving force in market growth during the past few years. In the end, both policy choices signal to developers that their investments in building solar businesses are best made elsewhere.

Rollover of Excess Generation

At the heart of any NEM program is the treatment of generation in excess of a customer's needs. When implemented properly, NEM has nearly the same impact on a participating customer's utility bill as would occur if the customer-generator used a bank of batteries to store energy until the customer's demand exceeded his or her generation (batteries have modest losses, so NEM has a slightly greater utility bill impact). At its most basic, NEM allows a customer's meter to run backwards when the customer produces more power than the customer can use. (Note that most mechanical meters can actually run backwards, but for newer digital meters, "running backwards" is figurative.) States that do not allow this basic aspect of NEM simply do not "net meter" in the widely accepted understanding of the concept.

Once treatment of instantaneous excess generation is addressed, policy makers must consider the treatment of generation at the end of a particular billing period as they develop program rules. The most expansive net metering policy is to allow for indefinite rollover of net excess generation from billing period to billing period until it is used by the customer-generator. This policy choice provides the greatest flexibility in allowing customers to design a renewable energy system to meet their individualized needs, given the variations in output from a system over the course of the year and a customer's yearly consumption pattern. For many homeowners seeking to meet their entire annual load, solar energy generation in the sunny summer months exceeds their summer loads, with the excess offsetting loads in the winter.

Perpetual rollover of excess generation also avoids possible federal regulatory issues related to wholesale sales and addresses concerns that NEM might produce incentives for customers to oversize their systems. As well, the Internal Revenue Service has indicated in at least one private letter ruling that payment for excess generation is taxable income.

Stakeholders with concerns over the rate impacts of NEM often attempt to limit possible rate impacts by requiring the customer-generator to donate net excess generation at the end of a calendar year or some other twelve month period to the utility or to accept payment for the net excess generation at the utility's average avoided cost. Both of these program choices undervalue the net excess generation a customer provides to a utility by providing no value or valuing the on-site, customer-owned renewable energy generation at the cost of fossil fuel generation. NEM programs almost always have a requirement that systems be sized to meet no more than the customer's expected consumption, so substantially oversized systems are not built. Treatment of annual excess generation is an issue for the odd year when generation was higher than expected or consumption was lower than expected. Perpetual rollover of excess generation avoids the administrative burden of an annual reconciliation and gives the customer an assurance of credit for all energy delivered to the utility.

Standby Charges

There have been many instances of utilities proposing special tariffs for customer-generators structured as standby charges or other fees to compensate the utility for possible services that the utility provides. A utility's regulator—the state public utilities commission for IOUs, the city council for many municipal utilities, and other boards for various co-ops and public utility commissions—must approve such tariffs. From another angle, some utilities have argued that any requirement that standby charges or fees may not be imposed is an unwarranted subsidy by nonparticipating ratepayers. Unfortunately, this argument does not account for the fact that standby charges were generally developed as a rate option for much larger cogeneration or combined heat and power facilities that supply energy on a steady 24/7 basis. These generators lower a customer's peak demand, and therefore the customer's demand charge, while their utility stands by to meet the customer's entire load if the generator fails. Solar energy generation ceases every night and dips during daytime due to cloud cover. For most commercial customers, this means that the utility will impose a demand charge based on peak demand that is nearly what the customer would pay without a solar generation facility. While residential customers typically do not have demand charges and can reduce their utility bills to nothing with NEM depending on facility size, the utility is still in the favorable position of receiving daytime energy that is more valuable than nighttime energy, and typically at least as valuable as early evening energy.

Because of these concerns, Freeing the Grid gives state programs that institute standby charges and other fees for net-metered systems fewer or even negative points. To the extent that proposed standby charges are based on actual rate impacts for a particular utility, institution of the charges is a policy choice available to regulators, but an NEM policy should be reviewed without standby charges to determine what rate impacts exist.

Relevant Studies For Evaluating Net Energy Metering Rate Impact

As solar has become a viable option for increasing numbers of consumers, considerable federal, state, and utility attention has begun to focus on valuation of solar energy from DG resources. The following three sections offer a review of recent solar valuation studies, recent efforts in California to develop a methodology for valuing demand-side resources including solar energy systems, and recent efforts to value the capacity benefits provided by solar energy systems. Synthesis of these efforts will provide insight into areas of consensus on the valuation of solar and, therefore, form the foundation of best practices for assessing the rate impacts of NEM.

Studies Valuing the Benefits of Solar Resources

There have been several efforts to value solar energy generation in specific locales, of which three stand out as particularly comprehensive. The first two are discussed in this section: The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Hoff et al., 2006, followed by a 2008 revision) (AE study) and Distributed Renewable Energy Operating Impacts and Valuation Study (R.W. Beck, Inc., 2009) (APS study). The third comprehensive study of solar energy valuation is incorporated within a broader review of the costs and benefits of net metering for California's largest IOUs. We review that study in the "California's Cost-Benefit Methodology for Distributed Energy Resources" section.

The Austin Energy (AE) and Arizona Public Service (APS) studies discussed below provide an in-depth look at the value solar photovoltaic (PV) generation can bring to the grid for a specific utility. Moreover, each study was subject to scrutiny from many perspectives and stakeholders, and, taken together, they represent a good starting point for identifying consensus elements of the value solar PV can bring to the grid.

Austin Energy Study

To support its determination to move forward with a goal of installing 100 MW of solar generation by 2020, Austin Energy commissioned Clean Power Research to quantify the benefits of solar generation to the utility. At the onset, the authors identified two perspectives as forming the core of the AE study—the "utility" perspective and the "all ratepayer" perspective—and the study's authors used these perspectives to inform the development of a methodology for valuing the benefits of distributed PV.

Based on the various perspectives, the AE study authors presented a comprehensive list of benefits stemming from distributed PV based on research performed by the National Renewable Energy Laboratory, and including the value of energy production, generation capacity value, transmission and distribution (T&D) deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control. Ultimately, the last four potential benefits listed here were not included in the AE study for various reasons, and the benefits associated with disaster recovery were studied, but not included in the primary analysis. (Hoff et al., 2006, p. 12).

The AE study found that PV offered a present value of $1,983 to $2,938/kW or on a levelized basis between 10.9¢ and 11.8¢ per kilowatt-hour (kWh) in 2006 dollars. In a 2008 recalculation, Austin Energy found substantially higher average values of $3,139/kW and 16.4¢/kWh in 2008 dollars.

From the standpoint of NEM, when a customer receives a credit for excess generation that can be used when consumption exceeds generation, Austin Energy's residential retail rate as of December 2010 on tariff E01 (the standard residential tariff), including a fuel adjustment of 3.65¢/kWh, is approximately 7.2¢/kWh for less than 500 kWh of consumption per month, 9.67¢/kWh for consumption of more than 500 kWh/month from November through April, and 11.47¢/kWh for consumption of more than 500 kWh/month from May through October. All of these rates are well below the 16.4¢/kWh unadjusted value of the benefits PV brings to Austin Energy.

Discussion of AE Study

In reaching these figures, it is important to note that ultimately, two important benefits were not included in the final valuation—disaster recovery and reactive power control.

Disaster recovery benefits were not included because the quantification of this benefit was the first known attempt to do so by the authors and, therefore, the results did not have the level of certainty desired. Ultimately, the authors of the study recommended further study of the issue by Austin Energy in combination with battery storage especially in the context of a hybrid electric vehicle program. Disaster recovery benefits were estimated to be $2,701/kW for capacity and for energy generation to range from $1,121 to $1,578/kW. These numbers would almost double the overall value of PV generation to Austin Energy.

Voltage support and reactive power control had a value of $0/kW in the final model because current technical standards do not allow for this benefit to be provided by inverters for the benefit of utility operators. The study estimated the value of this benefit at up to $20/kW, but the figure could be much higher, and the technology to provide this benefit is available. At present, the technology may not be incorporated into inverters pursuant to IEEE Standard 1547, the existing technical standard for interconnections. A working group of electrical engineers is developing a standard for interconnection of generation with inverters that provide reactive power and voltage support, which will become IEEE Standard 1547.8.

A recent study by the Electric Power Research Institute includes the graphic in Figure 2, displaying how voltage is less variable on a typical 12 kV circuit with solar energy and voltage control than it would be with no solar energy facilities at all. Already, New Jersey utility PSE&G (Public Service Electric & Gas Company) has mounted tens of thousands of individual solar modules on its power poles and is using the available voltage and reactive power support (as a utility, it does not need to wait for completion of IEEE 1547.8). Because of these developments, in any valuation of solar energy generation, it now seems reasonable to consider the value of voltage and reactive power support.

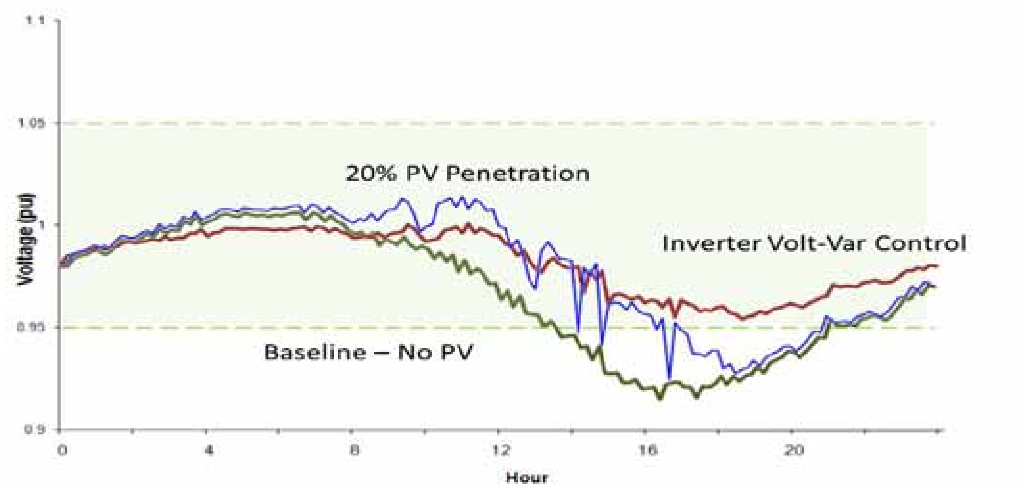

Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with "Inverter Volt-Var Control" (the brown line, with the least voltage variability). Source: Seal, B., Monitoring, Information, and Control: Management for Tomorrow's PV (PowerPoint), May 2010 (reprinted with permission).

Arizona Public Service Study

In early 2008, Arizona Public Service (APS) commissioned R.W. Beck, Inc., Energized Solutions, LLC, Phasor Energy Company, LLC, and Summit Blue Consulting, LLC to assess the impact of wide-scale deployment of distributed PV along with solar hot water systems and commercial daylighting systems on the APS system. Among the specific objectives of the study was an assessment of the benefits wide-scale deployment of these technologies could have for the APS system. In this sense, the APS study views the potential benefits of deployment of distributed solar from the utility perspective. The APS study was conducted in an open process with the participation of many stakeholders from within the solar industry, the business community, advocates, and the regulatory community.

In constructing the methodology for reviewing the benefits of the three distributed solar technologies discussed above, the study's authors focused on low, medium, and high penetration scenarios, with generating capacity as a percent of peak demand reaching 0.5%, 6.4%, and 14% respectively by 2025 (Arizona Public Service, 2010, Tables 5-3 and 5-4). Within these scenarios, the authors made a number of assumptions about PV capital cost reductions, the availability of federal tax credits, and the make-up of APS tariffs. The APS study also developed a target scenario that assumed APS would deploy solar technologies to achieve the greatest possible benefits. The target scenario included a general scenario and one in which all commercial PV used single-axis tracking.

The benefits identified in the APS study included reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in necessary equipment size within the distribution system, avoided electric generation capacity costs, avoided fixed operating costs, avoided energy purchases, and avoided fuel purchases. While labeled differently, this is a subset of the list used by the AE study, leaving off environmental benefits and the ability to provide a hedge on natural gas prices, as well as the four factors ultimately left out of the primary AE analysis (disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control).

After detailed modeling, the APS study found a range of benefits across the various penetration and target scenarios of approximately 7.9¢ to 14.1¢/kWh in 2008 dollars, without reference to a particular scenario (Arizona Public Service, 2010, p. xxii). Residential rates for APS customers as of December 2010 were just under 9.4¢/kWh, ramping up in stages during summer months to 17.4¢/kWh for higher energy usage. Assuming benefits have increased with inflation, the APS study appears to be inconclusive regarding whether there is a subsidy flowing from residential ratepayers to NEM participants (calculated benefits at the lower end of the reported range are less than costs). For demand-metered customers, it seems that benefits exceed costs substantially.

An APS review of this report stated that benefits identified in the APS study were based on locating facilities optimally and maintaining utility ownership and control of the installations, although the benefits of optimal siting are not broken out separately in the APS study. The most likely benefit of selective siting would be for individual distribution circuits. Most transmission and generation benefits would accrue regardless of the location of NEM systems. Reported distribution system benefits are only 0 to 0.31¢/kWh, implying that the impact of selective siting is relatively modest.

Discussion of APS Study

Two important aspects of the APS study directly affect the extent of the benefits it found, and explain the substantial difference from the AE study results.

First, virtually no capacity benefits were identified for the years prior to 2025 and even then, the capacity benefits were only significant in the high penetration case. The study notes that capacity pricing is rolled into energy prices used to calculate the energy benefit, and in that sense, there is a capacity value. However, by "capacity benefit" we are only referring to deferral or avoidance of new utility-built generation and T&D. The APS study's rationale for not attributing capacity benefits was that T&D and utility generation investments are "lumpy" so it would take a great deal of DG to have an impact on those investment decisions. (Arizona Public Service, 2010, p. 6-9). This view takes a primary advantage of PV—the ability to be installed incrementally—and gives it no value until output from the PV installation fully displaces a new utility generator. APS notes that its Integrated Resource Plan calls for no new construction for the next seven to eight years because it has sufficient capacity at present, but the PV installed over the next eight years could push the need for new construction out further and should be attributed some value. APS expects that peak demand will grow by 4,170 MW from 2010 to 2025. (Arizona Public Service, 2010, Table 5-6) and it is reasonable to assume that even a modest level of DG would defer some quantity of system level utility investments by a year or more, thereby saving ratepayers money by deferring investment in these lumpy assets. In conjunction with modest levels of demand response, as discussed later in this report, installed solar facilities could also provide APS with firm power, eliminating the need for at least some portion of its contemplated generation and T&D investments.

The APS study makes a jump from modest penetration levels in 2015 to high penetration in 2025 without analyzing impacts in between. Even the high scenario assumes only 63 MW of DG by 2015 (Arizona Public Service, 2010, Table 5-3), or roughly 0.7% of anticipated peak demand for APS in 2015 (Arizona Public Service, 2010, Table 5-4). By comparison, DG capacity in PG&E's service territory in California is more than 2% of PG&E's peak demand as of early 2011. While the APS study looks at 6.4% and 14% penetrations in 2025, it would have been interesting to present capacity benefits in the 2% to 5% range that are likely in earlier years.

The second significant deficiency in the APS study is that it does not consider the benefits at the optimal penetration level using the optimal orientation. Because the study is "forward looking" in so far as it is not assessing the impacts of a program as currently implemented, it would seem logical to have performed this analysis. Indeed, the study acknowledges that southwest facing modules or solar tracking will increase production per MW in the late afternoon, when APS experiences peak demand, and have a greater capacity benefit than a south facing array of the same size. However, the scenarios describing the benefits of DG under the low and medium penetrations do not appear to take the capacity benefits of deploying these optimally oriented arrays into consideration.

Interestingly, in the high penetration case, a solar tracking sensitivity analysis concludes that in 2025, tracking would shift the APS peak to a later hour, at which time the capacity benefit would be little more than it would be with a fixed array pointed south. However, this case envisions generating capacity of 1,677 MW (Arizona Public Service, 2010, Table 5-3), which would be 14.6% of peak demand. The analysis has thus skipped from a modest penetration of 0.7% (63 MW) in 2015 to a penetration of 14.6% in 2025 without looking at the optimal penetration that would occur in between. To its credit, the APS study does acknowledge that energy storage would increase the capacity value of solar energy systems, but it does not attempt to quantify the benefit.

Finally, the APS study did not attribute any environmental benefits to the utility or quantify natural gas hedging benefits as the AE study did. Inclusion of these benefits would have contributed to an overall valuation of the benefits to utility ratepayers from the solar resources modeled in the study. And like the AE study, the APS study did not attribute any value to the ability of solar generation to provide voltage and reactive power support or to provide disaster recovery benefits.

California's Cost-Benefit Methodology for Distributed Energy Resources

Starting in 2004 in Rulemaking (R.) 04-03-017, the California Public Utilities Commission (CPUC) embarked on an effort to develop a framework for valuing distributed energy resources. The overarching goal of the proceeding was to develop a methodology planners could use to compare demand-side resources in a consistent fashion across all resources—energy efficiency, renewable distributed generation, combined heat and power, etc. Efforts by numerous parties including renewable energy and combined heat and power advocates, CPUC staff, ratepayer advocates, and utilities to develop this methodology went on for a number of years and into successor distributed generation dockets R.06-03-008 and R.08-03-008. Stakeholders' efforts culminated in the issuance of Decision (D.) 09-08-026 on August 20, 2009.

In D.09-08-026, the CPUC established a methodology for valuing a wide range of distributed energy resources based on the approach used to value energy efficiency in California's Standard Practice Manual (SPM). In that vein, D.09-08-026 considers four tests described in the SPM for use in evaluating DG resources—the participant test, the rate payer impact (RIM) test, the program administrator (PA) test, and the total resource cost (TRC) test. Ultimately, the CPUC chose to use four tests—the participant test, the PA test, the TRC test, and the societal test—in evaluating DG resources. The societal test is very similar to the TRC test, but includes the impacts of externalities such as environmental costs/benefits, excludes tax benefits, and uses a different discount rate. Each of these tests views the costs and benefits of DG resources from different perspectives—the participating customer-generator (participant test), ratepayers generally (the RIM test), society (TRC and societal tests), and the program administrator, which in California is often the utility (the PA test).

Although D.09-08-026 does not require the use of the RIM test for a general evaluation of DG resources, the test is relevant to a discussion of the rate impacts of NEM because the RIM test attempts to compute bill and rate impacts due to changes in utility revenues and costs. D.09-08-026 identifies the following benefits within the RIM test—avoided T&D line losses, avoided energy and resource adequacy costs, T&D investment deferrals, environmental benefits, increased revenue from fuel transportation for natural gas-fired DG (not relevant for solar energy), and reliability benefits (ancillary benefits and volt-ampere reactive [var] support).

Unlike the AE and APS studies, the CPUC decision also identified costs, including net metering bill credits, program administration, reduced revenue from standby charge exemptions, lost revenue from non-bypassable charges, reduced T&D and non-fuel generation revenues, increased reliability costs for ancillary services and var support, cost of utility rebates or incentives, the cost of utility interconnection not charged to customer-generators, and increased utility fuel transportation costs for gas-fired DG (not relevant for solar energy).

Discussion of D.09-08-026

Inclusion of lost revenues must be handled very carefully in the context of NEM of intermittent resources such as solar and wind. In theory, the utility has a right to recover certain fixed costs under its standard tariffs, and NEM cuts into that expected recovery. However, great care must be taken to avoid double counting of costs. For instance, D.09-08-026 recognized that inclusion of lost standby charge revenue could result in double counting of lost T&D revenues, because standby charges developed in California were also designed to recover T&D expenses. Because both revenue streams would be recovering the same T&D expense, recovery of lost standby charge revenue along with recovery of lost T&D revenues could result in double counting of lost T&D revenues.

Additionally, practitioners must consider other factors when addressing lost revenue claims. First, utility standby charges are designed to recover the utility's cost of being constantly prepared to meet a customer's peak demand in the event that on-site generation is not functioning at the time of that peak demand. In the case of intermittent resources, it is a near certainty that generation will not be effective at some time during each billing cycle when the customer's demand nears the customer's peak demand. In other words, at those times, the customer's solar array is providing minimal generation to offset the customer's electricity consumption, and the customer will pay a demand charge based on almost all of the customer's peak consumption. For demand-metered customers in this situation, the demand charge resulting from their peak demand is already at or very close to their peak consumption, so the utility is not standing by, it is providing the necessary power and charging for it already. Claiming that preclusion from billing standby charges is a utility cost is effectively claiming that the utility can bill the customer twice for fixed costs, which obviously is not correct. Double counting would almost certainly occur if potential lost standby charge revenue is included as an additional cost of the NEM of intermittent resources.

Moreover, although residential and small commercial customers do not face demand charges, the variability in their relatively small loads due to renewable generation has not been shown to have any significant impacts on the grid or been shown to be potentially any different than customers without renewable generation who have significantly varying loads from one moment to the next. Accordingly, requiring that these customers pay standby charges would be discriminatory in the absence of a cost of service study showing a clear justification for such charges.

These are not abstract concerns. For example, when Southern California Edison (SCE) undertook a more detailed review of its standby charges in light of the diversity of standby customer load compared to regular retail load, SCE found that the diversity of standby customer load was imposing significantly less cost on the distribution system than its regular tariffed customers. Accordingly, SCE redesigned its standby charge rates by reducing demand charges when compared to regular tariff services. Looking at this change in reverse, prior to the change in demand charges, standby customers were significantly overcompensating SCE under its prior standby charges. It would be useful to see whether customer investment in renewable energy similarly results in a greater diversity in their load when compared to typical retail customers, and has a similarly less taxing impact on the grid.

In sum, inclusion of lost utility revenue related to standby charges has some logical appeal and merit, but care must be taken to avoid double counting. Moreover, standby charges and T&D charges designed to recover costs from ratepayers who have not invested in DG resources may overcompensate the utility in the absence of cost of service studies specific to DG customers, which would set these fees in that context. That is, calculating lost revenues based on these tariffs could overstate the amount of the utility's lost revenue.

California's Net Energy Metering Cost Effectiveness Evaluation

In late 2008, the CPUC commissioned Energy and Environmental Economics, Inc. to value the excess generation produced by net-metered systems for the state's three largest IOUs—Pacific Gas & Electric (PG&E), SCE, and San Diego Gas & Electric (SDG&E). The resulting study, Net Energy Metering (NEM) Cost Effectiveness Evaluation (Energy and Environmental Economics, Inc., 2010) (E3 study), was publicly issued in March 2010 (dated January 2010). The study delves into detail by utility, customer class, customer size, and location not seen in any other study.

E3 Study Overview

As part of its focus on the costs and benefits of net-metered solar generation from the utility perspective, the E3 study provides the country's first comprehensive look at the rate impacts of NEM, making it uniquely important in this report. Although it does not reference the RIM test discussed above, the E3 study relies heavily on the analysis performed in D.09-08-026. Because of that fact, despite the groundbreaking nature of the E3 study, many of the flaws and concerns discussed above are present in the E3 study.

The benefits of NEM provided in the E3 study are similar to those in the AE and APS studies. For the E3 study, they include avoided costs from avoided energy purchases, avoided generation capacity or resource adequacy, avoided line losses, avoided T&D capacity, avoided environmental compliance, avoided ancillary services, and avoided renewable energy purchases by the utilities under California's Renewable Portfolio Standard.

On the cost side of the equation, the study evaluated the cost of bill credits provided to NEM participants, administrative costs, and interconnection costs (under California law interconnection costs are not billed to NEM customers).

While the complexity of the analysis in the E3 study precludes a detailed discussion of the methodology here, one example highlights the comprehensive nature of the study. Recognizing that the impact of NEM will not be uniform for all customer-generators, the E3 study models the impacts in 1,253 distinct customer-groupings based on utility, customer type, facility sizing in relation to customer load, and location. (Energy and Environmental Economics, Inc., 2010, p. 29) The complexity of such an undertaking is daunting, but it is important to accurately reflect the timing, size, cost, and benefits of exported energy. Additionally, to further explore the impact of certain cost assumptions on the analysis, the E3 study includes a sensitivity analysis related to billing costs, T&D avoided costs, standby charges, and interconnection costs.

Overall, the E3 study finds that current rate impacts average just over a hundredth of a cent for every kWh purchased (0.011¢/kWh, Energy and Environmental Economics, Inc., 2010, Table 4). Delving more deeply into the average figure, the results for each utility were 0.018¢/kWh for PG&E, 0.0005¢/kWh for SCE, and 0.0009¢/kWh for SDG&E. These are truly small figures; utility rates often rise by a penny or more per kWh in a utility rate case, and the figures here are all less than a fiftieth of a cent.

Looking to the future, the E3 study finds that by 2020, 2,550 MW of net-metered solar generation will result in a 0.38% increase in utility rates or 0.064¢/kWh (Energy and Environmental Economics, Inc., 2010, Table 5). In 2020, 2,550 MW of generation would be 3.7% of forecast peak load of just over 60,898 MW for the three utilities. (California Energy Commission, December 2009, p. 51—adding coincident peak demands for PG&E, SCE, and SDG&E). Taking the facts provided here, for every 1% of solar generation, as a percentage of utility peak demand, the E3 study indicates a 0.1% impact on utility rates.

Discussion of the E3 Study

Although the E3 study concludes that NEM at the California IOUs entails a modest subsidy of customer-generators by other ratepayers, several assumptions drive that conclusion.

First, an important assumption made in the E3 study is that the rate impact of NEM is limited to the impact of exported energy. The study notes that customers can generate electricity without NEM, but would not be able to export. With this approach, rate impacts related to energy used on site at the time of generation are not impacts of NEM, they are impacts related to solar generation generally. The study notes that 243 customer-generators with a total of 43 MW of generating capacity do not export at all, and are excluded from the impact analysis entirely. (Energy and Environmental Economics, Inc., 2010, p. 14). While the E3 study does not say it, this approach implicitly assumes that without NEM in place to support customer-generators, customer-generators would have installed the same amount and type of generation, would not have changed their consumption patterns to make better use of their renewable energy investments, and, finally, that excess generation would be delivered to utilities for minimal compensation. This is not a likely outcome.

In the absence of NEM, there would still be federal and state incentives to install solar energy facilities along with the incentive of offsetting coincident customer load, but customer-generators would likely behave differently. On the one hand, some facilities might be sized smaller to reduce the amount of excess generation. Exported energy could still be sold at the utility's avoided cost in accordance with federal law, but that is less than retail rates, and customers could be expected to react to that lower payment. On the other hand, customers would be likely to try to better coordinate generation and consumption in the absence of NEM, to increase the percentage of generation used on site. For example, air conditioning equipment could be operated in conjunction with generation, cooling more at mid-day and less in the late afternoon. As well, customer-sited batteries could allow customers to synchronize inter-day generation and load for a modest additional investment.

It would be difficult to model generation and load in the absence of NEM, and it is understandable that the E3 study made the simplifying assumption that customers with solar energy facilities would not attempt to match generation and load in the absence of net metering. However, as a practical matter, the reported rate impact of NEM is probably overstated, because customer-generators would modify their behavior in the absence of an NEM program.

Second, it is important to recognize that the E3 study bases costs on the rates that utilities would have charged customer-generators, and California's IOUs have some of the highest residential rates in the country. For example, a residential customer exporting 1,000 kWh in a year will get a credit for 1,000 kWh from the customer's utility, which means the utility did not have the opportunity to sell that amount of energy to the customer for as much as 40¢/kWh. In many parts of the country, top residential rates are less than 10¢/kWh, and utilities' lost revenue from NEM is therefore much lower.

Additionally, the E3 study suffers from several deficiencies that, when looked at cumulatively, greatly decrease the value of the benefits from the energy provided by net-metered customers. Most importantly, the study finds that the utilities have limited need for additional capacity until 2015, so the study provides customer generation with limited credit for capacity value until after 2015. The E3 study values capacity starting at $28/kW/yr in 2008 and increases linearly to $141/kW/yr in 2015, then increases at a more modest pace to more than $200/kW/yr by 2036 (Energy and Environmental Economics, Inc., 2010, Appendix A, p. 15-16).

Broadly, this assumption implies that utility planning occurs without consideration of customer generation, and accordingly assigns a limited capacity value for customer-sited generation. This assumption simply does not square with current practice in California for a number of reasons. First, long-term resource planning in California does include customer-sited generation because the utilities' long-term resource acquisition plans rely on load forecasts based on historical loads that include customer-sited generation and anticipated future customer-sited generation. Second, the California Energy Commission recently denied an application to build the natural gas fired Chula Vista plant based partly on the fact that significant solar DG would be coming online. So both in theory and practice, customer-sited DG is being taken into account in long-term decision-making on the need for generating capacity.

Interestingly, the E3 study's valuation of the capacity benefit of NEM solar generation is considerably lower than the likely valuation of capacity for solar energy purchased by California utilities under long-term contracts. While still under consideration, it appears that the market price referent (MPR) will be used for these contracts (other than the contracts under the Renewable Auction Mechanism). The MPR is based on the total cost of generation for a natural gas combustion turbine, including capital costs, and thus incorporates capacity value. It has been argued that solar energy under contract has more value than NEM solar energy because there is no assurance that the latter will continue to operate. However, there is no reason to expect widespread decommissioning of NEM systems. Having paid to install their systems, NEM customers are unlikely to remove them and forgo utility bill savings, and there are very few instances of such actions to date. It seems reasonable to give NEM generation the same capacity credit accorded to solar energy purchased under long-term contracts.

To highlight the significance of this flaw in the study's methodology, an added capacity value of even a $20/kW/yr increase, applied to 2,550 MW of solar generation, is $51,000,000 per year—a significant added benefit that would negate much of the net cost per year of NEM in the E3 study. For other states and utilities attempting to value capacity, the lesson is that to properly determine capacity value, a base assumption should be that the generation was anticipated, or should have been anticipated, and its value should not be assessed after the utility has made its generation choices and has sufficient generation. At the margin, a prudent utility has sufficient capacity and there is limited value to adding more capacity.

The other important factor not considered in the E3 study is reactive power and voltage support, as discussed earlier in this report. D.09-08-026, identified var support as an NEM cost, presumably based on the assumption that fixed-voltage inverters on solar energy facilities might cause greater voltage fluctuations on the circuit. As discussed earlier, new technology and revised standards will allow inverters to provide adjustable voltage support and var control. While current utility infrastructure does not enable utilities' use of these functions, the implementation of smart grid with associated communications and controls enhancements offers the strong potential to turn this presently deemed cost into a future benefit.

Administrative costs are identified in the E3 study as well, based on reported utility costs. Monthly incremental administrative costs for residential net-metered customers are a reported $18.31 for PG&E, but only $3.02 for SCE and $5.96 for SDG&E. (Energy and Environmental Economics, Inc., 2010, p. 40) As noted above, to further explore the impact certain cost assumptions have on the results, the study performed sensitivity analysis. As part of that analysis, the study took a closer look at administrative costs, including a sensitivity analysis based on no administrative cost (the base case accepts the PG&E cost). This sensitivity analysis resulted in a 27% decrease from the base case. This sensitivity analysis is reasonable to consider because, while in practice there is some minor administrative cost per customer, that cost is likely to drop with automation and high volume. An overstatement of $12/mo for systems averaging 6 kW in PG&E's service territory is equivalent to roughly $24/kW/yr, implying an added cost of roughly $24,000,000 per year, which seems unreasonable.

Automation of billing to handle NEM over the long term is sensible as part of an overall update of utility billing software to support the move to a smart grid that supports distributed generation. A holistic view of the necessary changes to utility billing practices is also required to support investment in the smart grid. These changes include the need to accommodate NEM, demand response, advanced energy storage, vehicle electrification, and other necessary initiatives. All of these long-term policies have been identified as necessary to meet climate and environmental goals and therefore should not be viewed in isolation. In particular, smart metering has been justified based on traditional utility cost savings, and should allow administrative costs for NEM and other programs to drop to very low levels.

As noted earlier, it is critical to recognize that California IOUs have tiered rates as high as 40¢/kWh, so the lost-revenue cost to the California IOUs is two to five times higher than most utilities in the United States. In fact, the top rate at PG&E contemplated in the E3 study was 50¢/kWh, although that tier has since been eliminated.

Quantifying the Capacity Value of Solar

Because the capacity value for PV has been a particularly thorny issue in determining the value of solar resources for utilities, it is worthwhile to provide more discussion on this topic. For many utilities, peak demand typically occurs in the late afternoon. This fact is often cited as a key reason to dismiss the ability of solar to provide significant capacity benefits. However, depending on the actual hour of peak demand, modules can be oriented to the southwest to enable them to operate near their rated capacity in the late afternoon. Careful program design that encourages customers to orient their solar resources to meet a later system peak can address this concern. As discussed in the APS study, southwesterly oriented modules operate at more than two-thirds of rated capacity from 5:00 to 6:00 pm on a sunny summer day and at half of rated capacity from 6:00 to 7:00 pm. Moreover, modules pointed southwest are operating at only slightly less than their rated output between 3:00 and 4:00 pm, which was the peak load in California for 2008 (Self Generation Incentive Program Impact Report, 2008 revised).

The second challenge to solar energy's ability to provide capacity reliably is that cloud cover can dramatically impact an individual system's performance on short notice. In practice, the effect of cloud cover on a single solar energy system is not simultaneously felt across a whole region, and much of the variability is not even seen across a distribution circuit with multiple MW of interconnected generation. Perez et al. showed that just twenty systems over a limited service area will have a collective output with almost no variability on a partially cloudy day, despite the variability of each one of the systems individually (Perez et al., 2006). Likewise, researchers at Lawrence Berkeley National Laboratory recently calculated the smoothing effect of distributed solar power, finding that the relative aggregate variability of PV systems decreases with increased geographic diversity. That study showed aggregate variability over a 15-minute period is one-sixth of the variability of a single PV system, and over a one-hour period, it is one-third of the variability of a single PV system (Mills & Wiser, 2010).

Demand response or energy storage coupled with PV can play a role in meeting peak demand if peaking generation is not available at lesser cost. In a 2006 study, Perez et al. (Perez et al., 2006) analyzed the peak-month loads for three utilities and the coincidence of available solar generation. Stunningly, almost all of the loads above 90% of the utilities' peak load could be met with solar energy, with a minimal contribution provided by demand side management to fill in the gaps, as shown in Figure 3. In practical terms, these results show that solar energy is able to provide reliable energy peaking generation as needed with only a modest addition of demand side management.

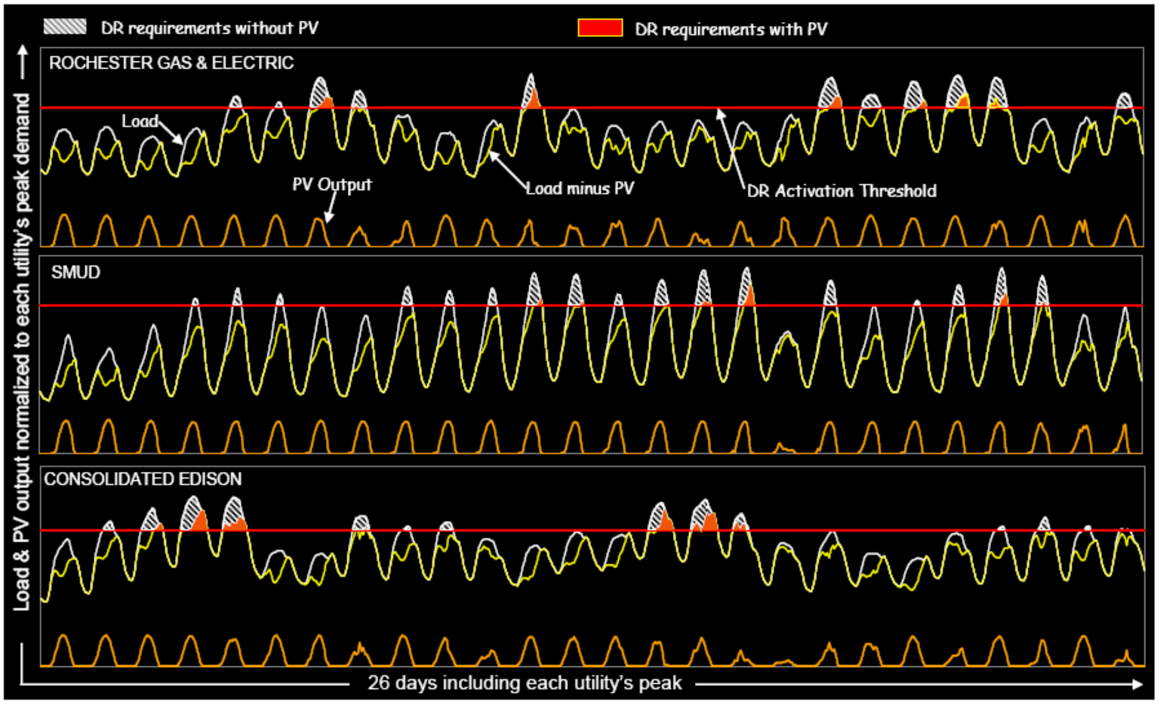

Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

In sum, research has demonstrated that many of the concerns that lead utility planners to discount the capacity value of PV can be addressed through program design, careful analysis of potential benefits from diffusion of solar resources, and coupling PV with demand response and energy storage. Based on these points, it is unreasonable to dismiss any capacity value to solar energy for a particular utility without considering these issues.

BEST PRACTICES IN VALUING NET ENERGY METERING

Given the recent efforts to value solar resources discussed in the "Relevant Studies" section, one can begin to see a relatively clear picture of the necessary inputs in a methodology to value solar resources.

Costs of Net Energy Metering from a Rate Impacts Perspective

On the cost side of the methodology, although the AE and APS studies did not attempt to develop a methodology for consideration of NEM costs, the two main inputs developed in D.09-08-026 for the RIM Test—NEM bill credits and program administration costs—are unsurprising and could be relatively noncontroversial if they are carefully developed.

As we have noted, careful calculation of NEM bill credits is important to avoid double counting of costs. CPUC D.09-08-026 suggests that costs should include reduced T&D and non-fuel generation revenues and lost potential revenues from a standby charge exemption. If NEM bill credits are determined by comparison of estimated bills before and after renewable resources are installed, "revenue losses" related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-fuel generation costs. For these reasons, inclusion of an additional input to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential "lost revenue."

Depending on how standby charge tariffs are actually implemented by a particular utility, calculating the potential lost revenues from a standby charge exemption would double count T&D charges again. Inclusion of lost standby charges is also troublesome because standby charges have usually not been developed for intermittent DG resources and, therefore, are not based on the cost of serving these particular customers. To its credit, the E3 study considered this "lost revenue" in a sensitivity analysis, but did not consider it in the base case.

Caution concerning program administration costs is also warranted. While it might be intuitive to include the actual costs the utility estimates it has incurred in administering its NEM program, it is clear from the E3 study that critical review is necessary. As discussed in the prior section, self-reported administrative costs at PG&E were nearly quintuple the costs reported by SCE and SDG&E with no explanation for this disparity. While some variation in costs is reasonable, a cost spread of this magnitude should raise concern and be justified before inclusion in any cost-benefit analysis. Moreover, as utilities begin to implement billing system updates to handle smart meters, demand response/control functions, and other emerging policies, those systems should be designed to handle NEM more efficiently, and the incremental costs of NEM should decline to slightly more than zero.

Benefits of Net Energy Metering from a Rate Impacts Perspective

On the benefits side of the equation, each study discussed in this report finds that avoided T&D line losses, avoided capacity and energy purchase costs, and avoided T&D investment deferrals should be included as benefits (though the studies did not agree on how to account for the benefits). Inclusion of these benefits in a methodology to assess the possible rate impacts of NEM should be relatively noncontroversial given their consistent identification as benefits of customer investment in renewable energy resources. Avoided line losses stem from locating the generation source on site, which allows line losses due to transmission from distant generation sources to load to be almost completely avoided (there are very modest losses associated with excess generation stepping up to utility line voltage then back down when used nearby on the same circuit). Avoided capacity and energy purchase costs stem from the reduction in on-site customer load and export of excess energy. T&D investment deferrals stem from decreased customer load at the feeder, substation, and transmission levels, and can include deferrals of investment and postponing of investment in T&D upgrades. Care should be taken to ensure evaluation of T&D investment deferrals includes not only the deferral of capacity investment but also equipment and operations and maintenance, as both the APS study and D.09-08-026 recognize these value streams.

Moreover, both the AE study and the E3 study recognize that renewable resources can provide environmental benefits due to avoided emissions from non-renewable energy sources. These benefits are a direct consequence of the investment by customers in generation sources that emit few or no pollutants during their production of energy. While the AE study and E3 study took different approaches to valuing this benefit, given regulatory frameworks in place for the measurement of NO_x, $SO_{x,}$ and particulate matter, and efforts to regulate CO_2, assessment of the environmental benefits of renewable resources should not be excluded as a benefit. The ability to mitigate carbon regulatory risk is particularly valuable. The CPUC Self Generation Incentive Program Eight-Year Impact Evaluation Revised Final Report (Itron, Inc., 2009) finds that PV was able to mitigate approximately 0.58 tons CO_2 per MWh. Given forecasts of future carbon prices in the range of $15 to $45 per ton on a levelized basis between 2013 and 2030, this would suggest a value of approximately $9 to 26/MWh in avoided carbon on a levelized basis. (Schlissel et al., 2008)

Additionally, consideration should be given to the possible benefits customer-sited renewable resources will have on a utility's obligations to purchase renewable energy to meet state mandates as discussed in D.09-08-026. For example, because the California Renewable Portfolio Standard bases each utility's compliance obligation on retail sales, utilities will be able to avoid purchases of renewable generation they might have otherwise been required to purchase because customer-sited generation lowers a utility's retail sales. For this reason, D.09-08-026 finds that a typical avoided cost methodology might not fully capture the benefits of customer-sited renewable resources in avoiding renewable generation additions by utilities to meet their RPS obligations. States like Arizona and Colorado with similar RPS obligations should take care to ensure this benefit is appropriately assessed in their cost benefit methodology.

The AE study and D.09-08-026 also recognized that customer investment in renewable energy resources could have significant impacts on the natural gas market. The AE study identified the ability of PV to act as a hedge on natural gas price increases, and D.09-08-026 recognized that customer investment in renewable energy could decrease the demand for natural gas and thereby lower the market price of natural gas for all participants. Unfortunately, it concluded that the impact is too small and too difficult to discern at current DG penetration levels.

The conclusion that renewable energy has no impact on natural gas prices is not supported by research. A Lawrence Berkeley National Laboratory study (Wiser, Bolinger, & St. Clair, 2005) provides a detailed review of studies assessing this benefit. These studies show that the price impacts in terms of $/MWh of renewable energy additions are significant, ranging from $10/MWh to $65/MWh nationally. Regional impacts were also evaluated. For example, the Lawrence Berkeley study found the impact of approximately $5/MWh within California. Similarly, the price hedge for natural gas was estimated in the California Energy Commission's 2007 Integrated Energy Policy Report at approximately $12/MWh. Given many utilities' substantial and increasing reliance on natural gas fired generation and consumer level consumption of natural gas, natural gas price impacts should not be ignored when estimating the rate impacts of NEM. Each of these benefits are significant and well documented and, therefore, worthy of inclusion as a benefit of customer-sited investment in renewable energy.

Regarding reliability, D.09-08-026 addressed only one part of the likely benefit of DG and arbitrarily set the value of other reliability benefits at zero. The decision concluded that demand reductions due to DG resources are likely to lead to the same reliability benefits that result from energy efficiency measures and the existing methodology to calculate that impact should be used for the present time. However, it only acknowledged that DG has the potential to provide ancillary services and var support. This ability has been widely acknowledged for inverter-based systems, although output voltage is typically preset rather than being reactive to utility grid voltage, so the ability to provide support is not used at present. However, this ability is very likely to be tapped, at least for larger solar facilities, and could add significant value. Even more importantly, the AE study properly noted that DG has the potential to provide backup power to both critical need customers and typical utility customers. The AE study placed a very high value on this functionality and it seems that some estimate should be made of this value. D.09-08-026 simply set var support and backup power values at zero, but properly directed that those values should be estimated.

Based on the three solar valuation studies reported here, best practices in developing a methodology for evaluating the rate impacts of net metering counsel for including the inputs noted in Table 2.

TABLE 2

Necessary Costs and Benefits Inputs in a Methodology for Evaluating the Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO_x, SO_x, PM, & CO_2	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

CONCLUSION

To date, views concerning the possible rate impacts of NEM programs have driven many of the policy deviations from best practices in NEM in many states. However, very little rigorous analysis of the relative costs and benefits of NEM has been done. In reviewing the major net metering and PV cost-benefit studies performed to date, we identified the benefits noted at the end of the previous section as essential for inclusion in any study of the possible NEM rate impacts.

On the cost side of the analysis, the three studies provide guidance as well. The primary cost of NEM is the utility's lost revenue from utility ratepayers, equal to what ratepayers would have paid had NEM not been available. As the E3 study did, we recommend that the lost ratepayer revenue only focus on the bill impacts directly attributable to NEM (i.e. directly attributable to providing value to excess generation). The lost revenue due to NEM should not be based on all production from customer-sited generation, because a customer can install a system to offset their energy needs without an NEM program in place. While simplifying assumptions—that the amount of generation installed would not change or other measures would not be taken to store excess energy for later consumption, for example—are necessary, given the relatively small percentage of generation that is actually net metered, such simplifications seem reasonable.

In addition, utility administrative costs should be included, as discussed in the E3 study. However, the variance in administrative costs among the three California utilities surveyed indicates a need to review cost claims carefully. An assumption regarding future administrative cost reductions per kWh should be included to account for automation of processes. Other costs can be considered based on any unique features of a state's net metering program, but they should be carefully considered to ensure they actually stem from a state's decision to allow net metering versus a decision to allow customer-sited generation as a general matter.

E3's pioneering work quantifying the benefits and costs of California's NEM program highlights the fact that further research is necessary to arrive at consensus on the appropriate methodology for quantifying these benefits and costs. However, the inclusion of the benefits listed at the end of the prior section should be relatively noncontroversial in most instances. As noted earlier, the cost-benefit analysis is utility-specific, and some utilities may realize little benefit from one or more of the items noted in Table 2. A utility in a state without an RPS will not have any savings associated with avoided RPS purchases. A winter-peaking utility will not have a substantial capacity benefit.

Based on the review undertaken in this report, it would be difficult to conclude that nonparticipating customers subsidize demand-metered customers with NEM facilities. The cost to the utility of demand-metered customers deploying NEM is the loss of energy charges, but those energy charges are based on the variable costs that the utility avoids by not having to provide the energy that is instead generated on site. The administrative cost in the long run should drop to almost nothing per kWh, and the non-energy benefits discussed here will still be provided. It appears that demand-metered customers with NEM facilities will typically provide a net benefit to nonparticipating customers.

For customers with bundled rates, such as residential customers, whether or not there is a net benefit will depend on utility-specific costs and benefits.

RECOMMENDATIONS

We recommend that utility regulators wishing to determine the NEM rate impact for specific utilities use the guidelines provided in this report. In particular, we recommend that:

- Studies comparing the costs and benefits of NEM include the costs and benefit inputs identified in Table 2 above.
- As part of this effort, none of the benefits identified in Table 2 should arbitrarily be set to zero based on unsupported assumptions.
- Capacity benefits associated with deferral of utility generation and T&D facilities should be modeled under a long-term framework to ensure that the value of PV to defer these resources under a long-term planning framework is properly captured.
- Assessment of the costs and benefits of net metering should be based only on exported energy, not the entire production of the facility.
- Program administrative costs should be based on a long-term assessment of costs based on the expectation that updating utility billing software to accommodate and support grid-modernization efforts, which include net metering, will be necessary.

At the earliest stages of a NEM program, the cost of such studies may be greater than any net costs or net benefits themselves, and regulators may understandably be hesitant to undertake studies prior to significant NEM deployment. The results discussed in this report should give regulators confidence that rate impacts at the earliest stages will be negligible and need not be a concern that leads to restrictive NEM policy.

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Appendix A

Summary of Costs and Benefits Inputs Used in Three Solar Valuation Studies

	Austin Energy Study	APS Study	CPUC E3 NEM Study
BENEFITS			
Energy production value	X	X	X
Generation capacity value	X	X	X
T&D deferrals	X	X	X
Reduced transformer losses	X	X	X
Reduced line losses	X	X	X
Environmental benefits	X		
Natural gas price hedge*	X	X	
Blackout prevention*	X		
Emergency utility dispatch*	X		
Managing load uncertainty*	X		
Retail price hedge*	X		
Reactive power control*	X		
Reduced distribution system size		X	
Avoided fixed operating costs		X	
Avoided environmental compliance			X
Avoided ancillary services			X
COSTS			
Net metering bill credits			X
Program administration**			X
Reduced standby charge revenue***			X
Costs of interconnection not charged***			X

* These benefits were not quantified in the Austin study. The study found that the benefits were real and quantifiable, but there was insufficient data to assign them a value for Austin Energy.

** Because of data problems with utility reported billing costs, these costs were also included in a sensitivity analysis.

*** These benefits were included as sensitivity analysis.

ACRONYMS

AE	Austin Energy
APS	Arizona Public Service
CPUC	California Public Utilities Commission
D.	decision
DG	distributed generation
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
MPR	market price referent
MW	megawatt
NEM	net energy metering
NNEC	Network for New Energy Choices
PG&E	Pacific Gas & Electric
PA	program administrator
PV	photovoltaic
R.	rulemaking
RIM	ratepayer impact
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPM	California's Standard Practice Manual
TRC	total resource cost
T&D	transmission and distribution
var	volt-ampere reactive

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LETTER

Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California

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Keywords: residential solar, third-party ownership, lease cost

Abstract

Over the past several years, third-party-ownership (TPO) structures for residential photovoltaic (PV) systems have become the predominant ownership model in the US residential market. Under a TPO contract, the PV system host typically makes payments to the third-party owner of the system. Anecdotal evidence suggests that the total TPO contract payments made by the customer can differ significantly from payments in which the system host directly purchases the system. Furthermore, payments can vary depending on TPO contract structure. To date, a paucity of data on TPO contracts has precluded studies evaluating trends in TPO contract cost. This study relies on a sample of 1113 contracts for residential PV systems installed in 2010–2012 under the California Solar Initiative to evaluate how the timing of payments under a TPO contract impacts the ultimate cost of the system to the customer. Furthermore, we evaluate how the total cost of TPO systems to customers has changed through time, and the degree to which contract costs have tracked trends in the installed costs of a PV system. We find that the structure of the contract and the timing of the payments have financial implications for the customer: (1) power-purchase contracts, on average, cost more than leases, (2) no-money-down contracts are more costly than prepaid contracts, assuming a customer's discount rate is lower than 17% and (3) contracts that include escalator clauses cost more, for both power-purchase agreements and leases, at most plausible discount rates. In addition, all contract costs exhibit a wide range, and do not parallel trends in installed costs over time.

Introduction

Residential solar photovoltaic (PV) systems constituted roughly one quarter of the PV capacity installed in the United States in 2013—an estimated 792 MW (GTM Research 2013). While the PV market has been growing rapidly, PV still makes up a very small portion of the total US energy mix. As costs continue to decline and the industry continues to grow, PV could begin to make a substantial contribution to the US energy mix over the next couple of decades (DOE 2012). PV costs have witnessed steady declines over the past several decades, and in the past four years, have nearly halved (Feldman and Friedman 2013). At the same time, PV incentives—including the federal investment tax credit (ITC) and various state, municipal, and utility rebates and tax credits—have substantially reduced the capital requirements to install solar. However, achieving grid parity (the ability to generate electricity at a cost that is less than or equal to the price of purchasing power from the electricity grid) will require additional cost reductions, and these cost reductions will need to be passed on to consumers.

The use of third-party-ownership (TPO) structures for PV has increased considerably over the past several years —from an estimated 10–20% in large US markets in 2009, to an estimated 65% of the US market in 2013 (GTM Research 2013, GTM Research 2014). TPO provides an attractive alternative for consumers who either do not want to assume risks associated with ownership or prefer a low money down payment option. Further, a TPO structure can make financial sense due to the challenges individual homeowners face in monetizing the ITC and modified accelerated cost recovery system (MACRs) depreciation[1]. Under a TPO contract, the contract type and payment structure between the solar customer (homeowner) and the system owner (solar integrator or third-party financer) can take the contractual form of a solar lease or a solar power-purchase agreement (PPA). In a solar lease, the customer pays a specified amount (agreed upon at the outset of the contract) every month, regardless of the system's energy production. In a solar PPA, the customer pays a specified amount per kilowatt-hour (kWh) of generation, so the amount paid varies monthly as a function of generation. Regardless of the type of contract (lease or PPA), customers typically pay a one-time, upfront down payment and monthly payments. The monthly payments can be flat, but in some cases, monthly payments may escalate at a flat rate through time. As a result, the timing of the payments by the homeowner varies by the magnitude of the down payment and monthly payments and the rate at which the payments escalate. Often the installer will provide the homeowner a menu of contract options by varying these parameters, with implied financial tradeoffs. Contract prices can be objectively compared and evaluated by aggregating the sum of down payments and the monthly payments over the duration of the contract and discounting. This total contract price—the real (i.e. 2012 dollars) out-of-pocket cost the customer is contractually obligated to pay—is the key economic measure for residential customers evaluating different TPO PV lease/PPA contracts.

While several current sources track installed PV prices via incentive program data and other market data sources (GTM Research 2013, Barbose *et al* 2014), there is little data on the out-of-pocket cost to the customer over the duration of the contract, which will be substantially reduced by available incentives. Further, while a few studies have evaluated the financial implications of buying versus leasing solar (Rai and Sigrin (2013), Navigant Consulting 2014), to date, no study has focused exclusively on comparing contract costs across the myriad TPO options offered to customers. In both of the above studies, results suggested that leasing provided a higher net present value than ownership—though the difference was more drastic in Rai and Sigrin (2013).

In this study, we use third-party contract data from the California Solar Initiative (CSI) to examine California's residential TPO market during 2010–2012[2]. We use a sample of 1113 contracts to evaluate how TPO contract structures vary and how this translates into a final TPO contract price. We use this data to evaluate the effect of contract structure, magnitude of down payment, and escalation clauses on the total contract price.

The remainder of this article is organized as follows. First, we discuss the study data, our sampling procedure and the method to convert contract terms into a total contract price (2012 dollars). Second, we evaluate contract characteristics: distribution of lease versus PPA and various payment structures (timing of payments and existence of escalation rates). Third, we evaluate TPO contract prices according to the structure and terms in the contract, as well as trends over time and by size. Finally, we assess whether customers appear to be selecting optimal contract structures.

Methodology

The California Public Utilities Commission (CPUC) oversees the CSI, a solar incentive program available to customers of the state's three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The CSI has a $2.4 billion budget to stimulate the deployment of approximately 1940 MW of new solar capacity between 2007 and 2016 via solar rebates for residential, commercial, and utility-scale systems, including systems for low-income residents and multifamily affordable housing. To drive continual PV price reductions, the CSI incentive amount declines incrementally as the program reaches specific levels of cumulative installed capacity (separately specified in each of the three utility areas).

In this analysis, we focus on the residential sector during 2010–2012. During this period, systems in the CSI database represented about 45% of the residential PV installed nationwide (GTM Research 2013, California Solar Statistics 2014). The initial residential customer rebate was $2.50/W in January 2007, and this declined to a final rebate of $0.10/W in 2013[3]. During 2010–2012, incentives for residential systems ranged from roughly $1.50/W–$0.20/W, depending on the utility.

The CPUC requires incentive applicants to submit the installed system cost and documentation supporting that cost. For TPO systems, the CPUC requires installers to submit signed system contracts, which in many cases include the terms of the lease arrangement between the solar customer and the system owner.

The CPUC provided NREL with access to more than 50 000 residential third-party contracts signed

[1] MACRS is the tax depreciation system that allows businesses to recover the cost basis of an asset via annual tax deductions for depreciation, for commercial entities. In contrast to straight-line depreciation, where an asset is depreciated in equal increments annual over the useful life of the asset, MACRS in the case of a solar asset specifies the following 5-year depreciation schedule (20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%).

[2] Over this period, residential third party ownership in California increased from 22% to 69% of new installations (CSI 2014).

[3] The CSI program pays an expected performance-based buydown (EPBB)—a capacity-based incentive that is adjusted based on expected system performance that considers major design characteristics of the system, such as panel type, installation tilt, shading, orientation, and solar insolation available by location. By the end of 2013, CSI rebates had been exhausted in PG&E territory.

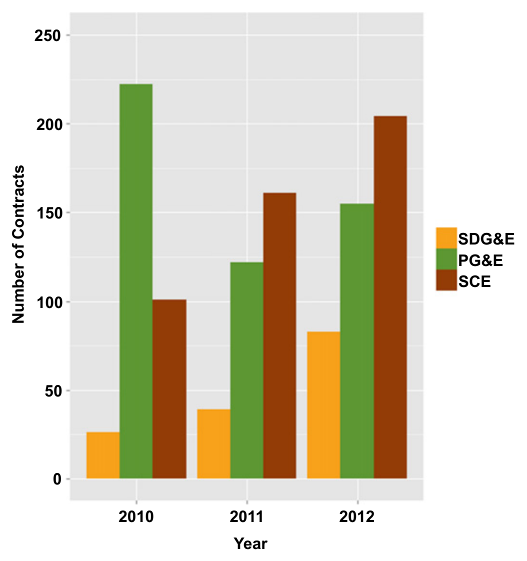


Figure 1. Number of TPO contracts in sample by year and utility.

during 2010–2012[4]. We sampled 2400 residential contracts, with a mean system size of 6.04 W_{DC}[5]. To maximize our ability to make inferences about changes over time, we stratified our sample by quarter, selecting 200 contracts for each quarter from the first quarter of 2010 to the last quarter of 2012, based on the 'completed date' as recorded in the CSI database[6]. This resulted in a sample of 1113 contracts with usable data (the remaining contracts simply provide the signed contract, without down payments or monthly payments), from 162 installers. The distribution of the contracts that did not include usable price terms closely matched the distribution of the contracts with usable price terms by utility and quarter, reducing concerns about selection bias. As a result, this sample can be considered representative of the geography and installation timeframe of the IOUs in California. The distribution of the final dataset by year and utility is displayed in figure 1.

To evaluate contract prices across leases and PPAs with varying payment horizons and escalators, we rely on a discounted cash flow (DCF) methodology. The DCF aggregates all payments, present and future, to assign a total present value to each contract in 2012 dollars, which enables us to compare contracts with different structures. For the rest of the article, we refer to this figure as the 'real contract price' or the 'TPO contract price'. This implies the real (2012 dollars) price of a lease or PPA contract to the homeowner. Future payments are discounted according to a selected discount rate intended to reflect the 'typical' consumer's tradeoff between present and future expenditures. In reality, each consumer will have a unique discount rate which will vary as a function of the opportunity cost of investing capital—i.e., what rate of return a consumer can expect from investing their money elsewhere. The cost of homeowner borrowing provides a reasonable proxy, which can range from low-rate home-equity lines of credit, to high-rate credit cards. However, additional factors present in a new market such as informational deficits, outsized perceptions of risk, aversion to sizable investments and other factors could increase a consumer's discount rate. Further, research has found that discount rates for energy conservation investments are higher than for other investment decisions (Meier and Whittier 1983, Train 1985), perhaps because of higher uncertainty over future conservation savings (Hassett and Metcalft 1993). Less research has evaluated the discount rate for green energy generation investments, but there may be a similar degree of uncertainty. Rai and Sigrin (2013) found implied discount rates as high as 60% for PV adopters in Texas.

Owing to the wide range of theoretically plausible discount rates, we evaluate contracts over a range of discount rates when possible. For figures or calculations relying on one discount rate, we use 7% as a default nominal discount rate. Equation (1) presents the formula used to calculate the price of each contract.

$$\begin{aligned}&\text{Real contract price}(\$2012)_i\\&\quad= \text{Upfront payment}\\&\qquad+\sum_{y=1}^{t}\Big(\Big[\text{monthly payment}^*(1+e)^{y}{}^*12\Big]/\\&\qquad\Big[(1+d)^{y-1}\Big]\Big),\end{aligned} \tag{1}$$

where i is the individual contract, t is the term length, y is the contract year, e is the escalation rate, d is the discount rate.

In the case of a PPA, the monthly payment is estimated based on assessed average monthly production stipulated in the contract[7]. We assume system production declines of 0.05% per year (Jordan and Kurtz 2011) and calculate the estimated monthly payment as follows:

$$\begin{aligned}&\text{Estimated monthly payment}\\&\quad= \text{estimated monthly production}\times(0.995)^{y-1}\\&\qquad\times\text{PPA rate}.\end{aligned} \tag{2}$$

Based on these calculations, we assign a real contract price to each contract.

[4] The CPUC only began storing digital versions of contracts beginning in 2010, so contract data were not readily available for previous years.

[5] All system sizes are reported in Watts-direct current.

[6] The 'completed date' is the date when the final incentive check was created and sent to the payee. This date may be several months after the contract terms were quoted to the customer.

[7] Companies likely rely on varying methods to estimate the average monthly production. We have no way to validate estimated monthly production or evaluate whether estimates are biased upwards or downwards as this depends on exact location, system design parameters, roof features and shading.

Table 1. Number of TPO contracts by year and type.

	2010	2011	2012
Lease	236	239	299
PPA	113	83	143

Results

Contract-type trends

Within our sample, nearly 69% of third-party contracts were structured as leases, with the remaining structured as PPAs (table 1). This proportion does not change substantially from 2010 to 2012. In our sample, most installers and integrators offered one structure exclusively (or nearly exclusively), although 10 of the 162 installers in our sample offered both leases and PPAs.

Whether a lease or a PPA, some contracts included an escalator clause, in which the base payment escalates at a given rate annually. Escalators are often included to allow revenue to keep pace with inflation[8]. In our sample, PPAs more consistently contained escalator clauses; 53% included an escalator of 3.0% (the most common level) or 3.9% per year. On the other hand, most leases in our sample data did not contain an escalator clause; among those that did, most had a relatively high escalator of 3.9% per year (figure 2). A smaller proportion of leases included escalators in 2012 than in 2010 or 2011, while the proportion of PPAs including escalators increased during our study period.

Contracts also varied in the timing of payments. The amount customers paid up front varied from zero (no-money-down) to the complete contract value (prepaid contract). Some contracts required partial payment up front, with the remaining contract price paid over time. With few exceptions, customers signed 20 year contracts.

Figure 2 shows the payment timing by contract type and year. The timing of PPA payments was weighted more toward the future compared with the timing of lease payments during each of the three years studied, with most PPAs structured as no-money-down contracts. However, the proportion of no-money-down leases increased substantially over the period. It is unclear whether this shift resulted from customer preferences or financer/integrator preferences.

Overall, the lease data suggests consolidation of preferences over time, with a trend towards an increasing percentage of no-money-down lease contracts. A recent trend towards securitization of solar leases and PPAs may play a role in this shift as a contract that is fully prepaid cannot be securitized. However, without additional data, it is not clear whether this shift is a result of customer preferences or financer/integrator preferences.

[8] Nationally, nominal residential electricity prices, on average, have increased by 2.01% annually in the last 20 years (U.S. Energy Information Administration 2011) and are forecasted to increase, on average, 2.20% annually from 2014–2040 (U.S. Energy Information Administration 2014).

Contract price analysis

In this section, we evaluate the full price of the TPO system to the end-consumer based on aggregating down payments and monthly payments from each contract to derive a real contract price. We provide an overview of the distribution of these prices, evaluating the value proposition provided by: (1) PPAs versus leases, (2) contracts with varying levels of upfront payments, and (3) contracts with and without escalators. Given that discount rates vary among consumers, we evaluate the contract price over discount rates of 0%–20%. Next, we evaluate effects of system installation year and system capacity on TPO contract price.

Impact of contract structure on contract price

Figure 4 shows the variation in contract price over the range of contracts sampled, assuming a 7% real discount rate. Both leases and PPAs exhibit a wide range. The mean contract price is \$3.04/W for leases and \$4.26/W for PPAs, with standard deviations of \$1.28 and \$1.08, respectively.

Figure 5 provides the distribution based on monthly lease payments per kilowatt and PPA rates per kilowatt-hour in order to provide a metric more comparable to terms found in TPO contracts. This is illustrated for no-money down contracts only. Monthly payments to lease a PV system range from \$12/kW to \$51/kW per month (sample mean \$24.30/kW per month), and PPA rates range from \$0.12/kWh to \$0.35/kWh (sample mean \$0.23/kWh).

PPA versus lease

Figure 6 illustrates the mean contract price, as well as the distribution of prices, for contracts with differing payment schedules. PPAs are consistently higher priced than leases, though much of this difference may be explained by the structure of the contracts; as a sample, leases are comprised of many more prepaid contracts. When comparing across similar payment structures, the difference between PPAs and leases declines as the amount of down payment declines. For the only category in which payment timing is exactly the same-0 down—the difference between PPAs and leases declines to \$0.52/W. Price differences between PPAs and leases, in all cases, are statistically significant. In the discussion section, we explore several hypotheses for this persistent pricing difference.

Contract payment timing: 'no-money-down' versus prepaid

Figure 7 illustrates the price differences in contract payment timing—focusing on leasing, which provides

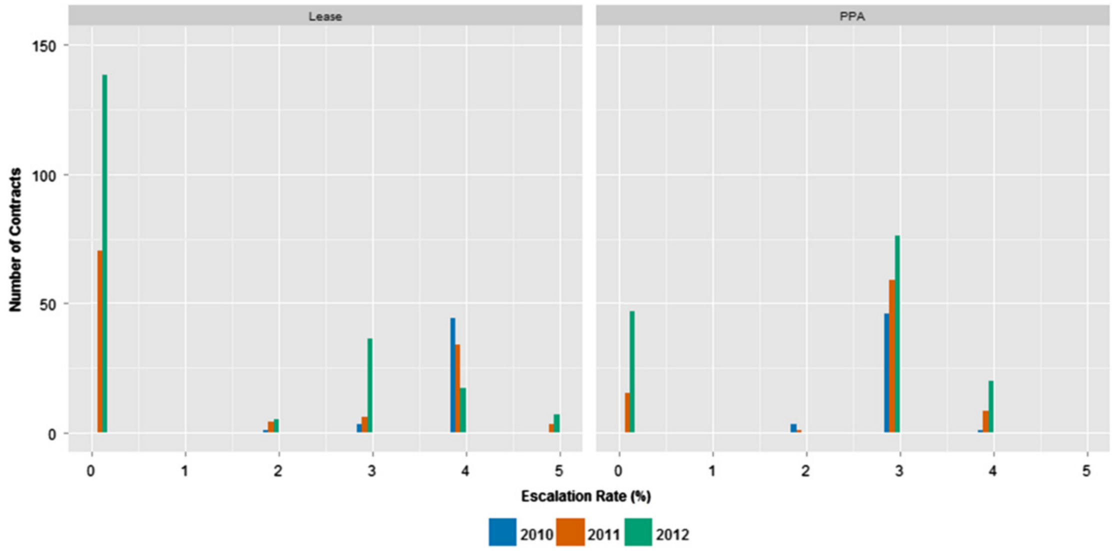


Figure 2. Escalation rate by contract type and year.

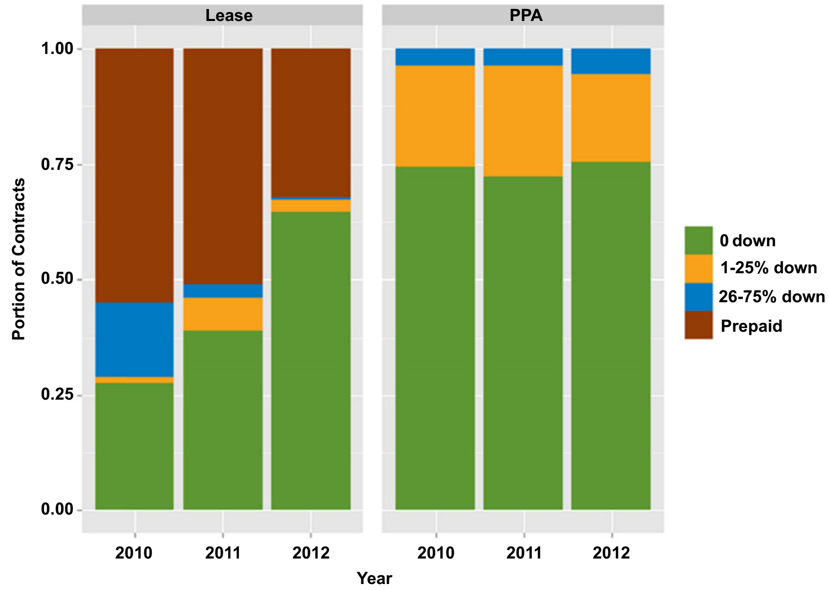


Figure 3. Contract payment schedule by contract type and year.

examples of both 'no money down' and fully prepaid contracts, at varying discount rates. As expected, no-money-down contracts cost more over the life of the contract in the lower range of discount rates. The two contract structures equate in price at a discount rate of approximately 17% as illustrated in figure 7.

These data suggest that, on average, a prepaid contract is financially preferable to a no-money-down contract if the consumer's expected rate of return on a competing investment is equal to or lower than 17%[9].

[9] This omits the additional option of paying a portion of the contract upfront and paying the remainder through monthly payments over a 20-year period. However, focusing on these two categories enables comparison across contracts that have identical payment timing within the two categories—payments are either fully paid upfront, or paid in equal increments over (typically) 20 years.

Escalators

As illustrated in figure 3, contracts commonly include payment escalators, although escalators are more common in PPAs than in leases. Figure 8 illustrates the real contract price of PPAs and leases with and without escalators[10]. It suggests that a contract with an escalator costs a consumer more than a contract without an escalator at nearly all plausible discount rates. At a discount rate just under 16%, leases with escalators approximately equate with leases without escalators. On average, PPAs with escalator clauses, at

[10] We combine all contracts with escalators over 2.9% and exclude seven contracts with 1.9% escalators. For both leases and PPAs, this results in a blending of escalation rates, although 94% of escalation rates are 3.9% and 2.9%.

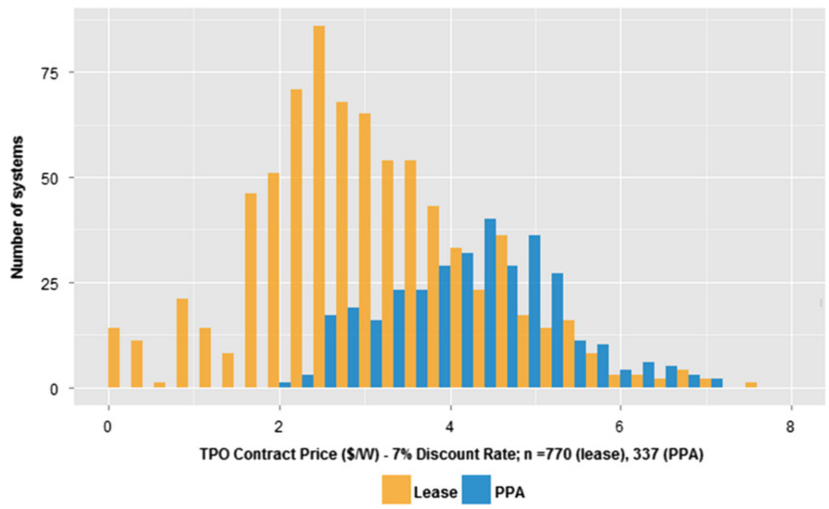


Figure 4. Distribution of contract prices for PPAs and leases (assuming a 7% discount rate).

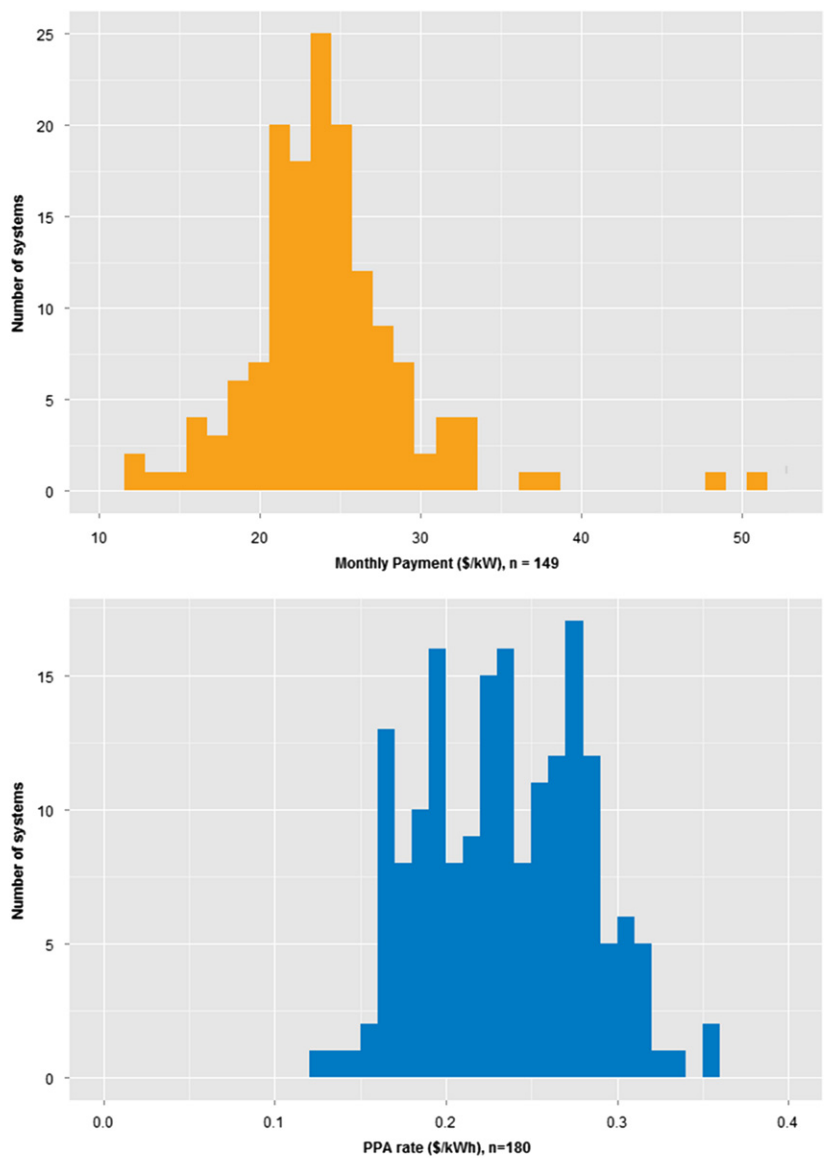
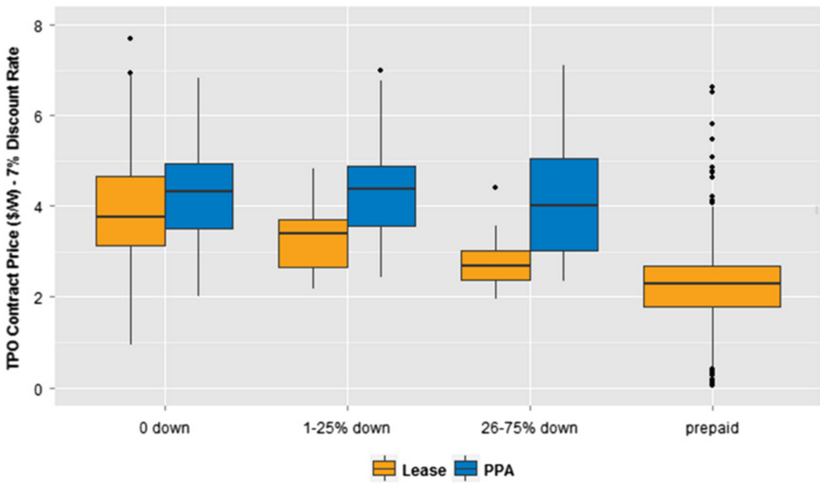


Figure 5. Distribution of monthly lease payments (top) and PPA rates (bottom); no-money down contracts.



	Lease	PPA
	Mean Contract Price ($/W) and observations	
0 down	$3.79 (n=351)	$4.31 (n=251)
1-25% down	$3.39 (n=27)	$4.38 (n=71)
26-75% down	$2.70 (n=46)	$4.01 (n=15)
prepaid	$2.30 (n=346)	NA (n=0)
All contracts	$3.04 (n=770)	$4.27 (n=337)

Figure 6. Real contract price by contract type, discount rate, and payment structure.

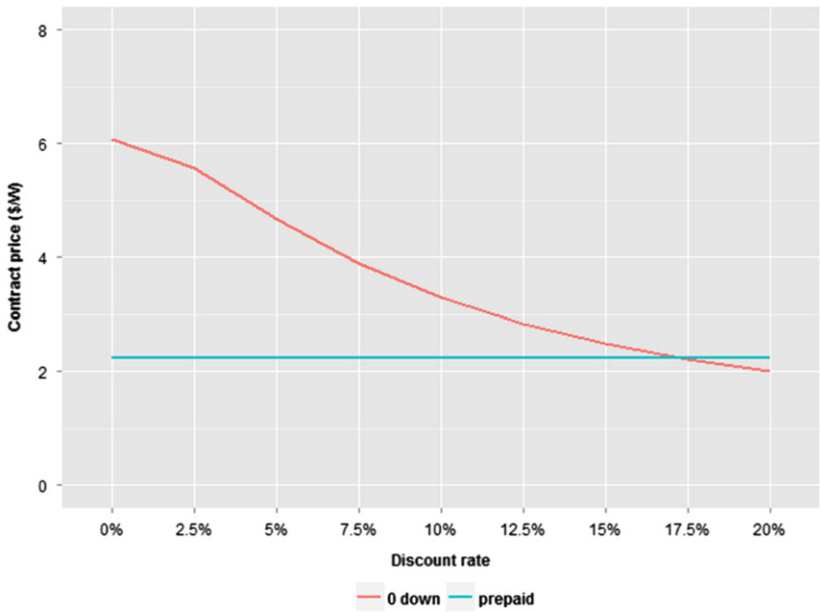


Figure 7. Present-value lease price by payment structure and discount rate.

every discount rate, cost more than PPAs without escalator clauses.

Contract price by reported price, installation year, and system capacity

In this section, we evaluate contract prices in relation to reported PV system prices, year of system installation, and system capacity.

As installed costs decline, we would expect installers to pass a portion of the cost declines along to TPO contracts and reduce prices. Installed prices reported to the CSI program declined by roughly $2.00/W during 2010–2012. Over this same period, the CSI incentive declined by $0.87/W, from a median of $2.40/W in the first quarter of 2010 to $1.53/W in the last quarter of 2012. That is, reported prices declined more rapidly than did incentives. However, the average price of contracts changed less over this period, with both lease and PPA prices *increasing* in 2010–2011, and then PPA prices decreasing in 2012,

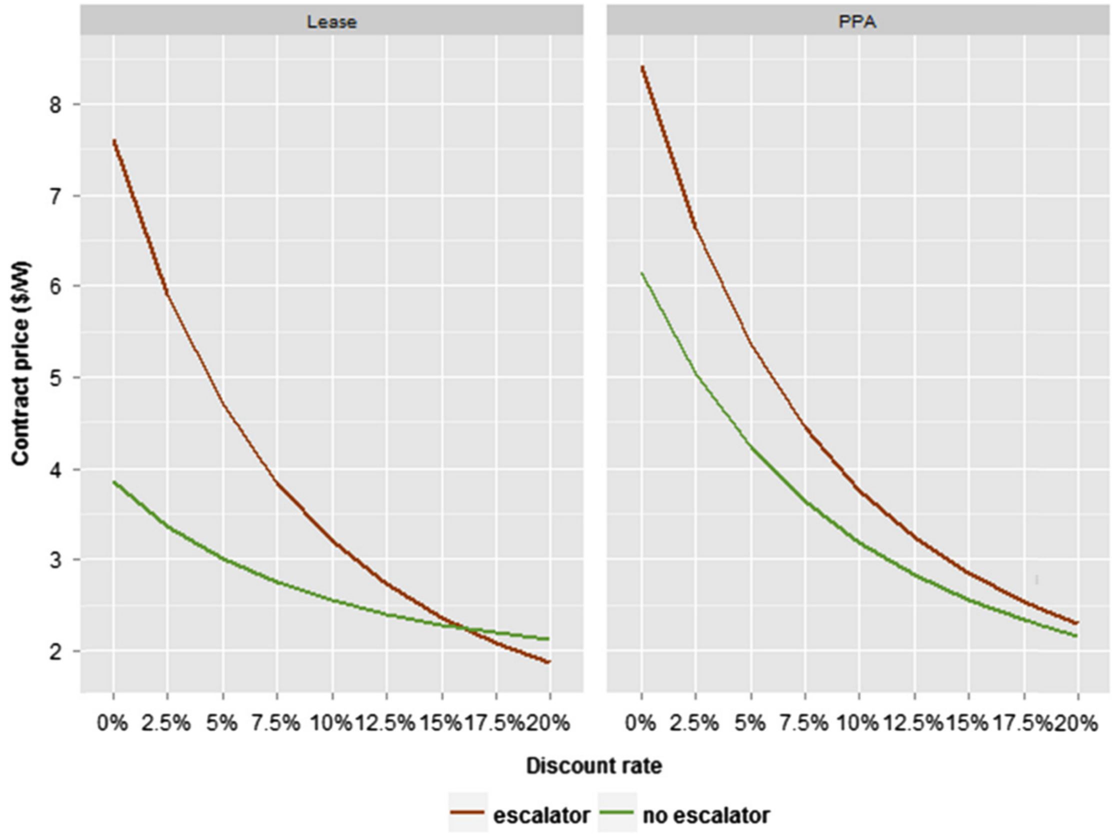


Figure 8. Real contract price by discount rate, contract type, and escalator.

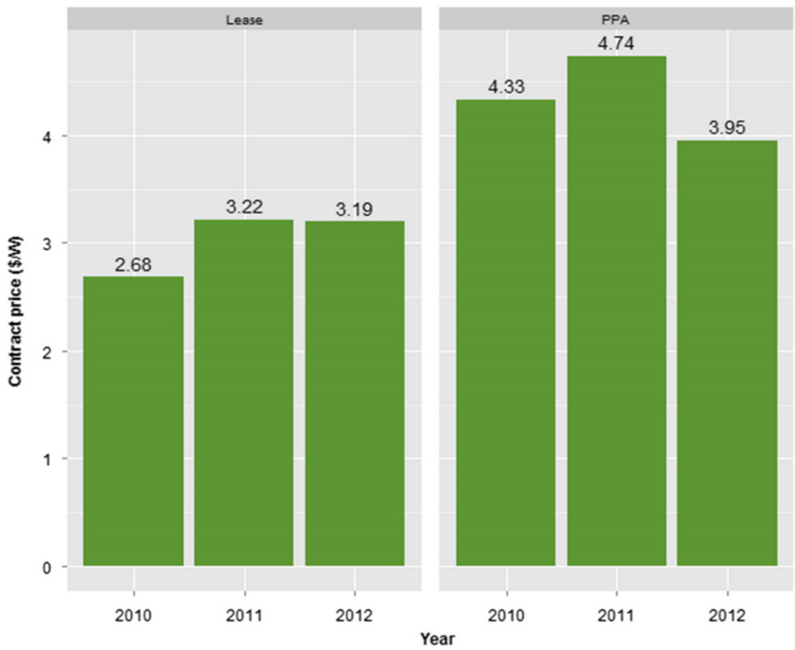


Figure 9. Real contract price (mean) by year for leases (left) and PPAs (right), 7% discount rate.

while lease prices remained flat (figure 9)[11]. While difficult to isolate the cause of these changes without further data, this suggests that factors beyond the installed cost of systems drive trends in contract prices. This may reflect costs associated with the TPO model (acquiring financing, operations and maintenance, system monitoring), outlined in Feldman

[11] The increase in lease prices between 2010 and 2011 was found to be statistically significant at <1%, however the difference between lease prices in 2011 and 2012 was statistically insignificant. The increase and subsequent decrease in PPA prices in 2010, 2011 and 2011, 2012, respectively, are both significant at <1%.

and Friedman (2013), but also likely reflects consumer demand dynamics.

We would also expect to observe economies of scale based on system size in contract prices, because larger systems enable the installer to spread certain fixed or lumpy costs (system permitting, business overhead) over a larger installed system. Barbose *et al* (2014) found that the mean installed reported price, nationwide, for systems of 5–10 kW was approximately \$0.50/W lower than for systems of 2–5 kW in 2012[12]. Similarly, Davidson and Steinberg (2013) found a difference of approximately \$0.70/W, focusing on host-owned systems in California. Our data suggests that contract prices (for leases and PPAs) are higher for small systems (2–5 kW)—statistically significant at <5%, but exhibit no statistically significant difference in price between 5 and 15 kW (figure 10)[13]. There is no notable difference in the distribution of leases and PPAs across the difference size categories—70–75% are between 2 and 7 kW, and ~25% are 7–10 kW for both contract types,

Each of these systems is associated with a corollary publically-reported price. While in the case of host-owned systems, this represents the transaction between the system owner (homeowner) and the installer, in the case of TPO systems, this can represent either the appraised value of the system (by an independent third-party), or the price of an intermediate transaction between the installer and the financer. We would expect reported prices to be higher than the end customers' price as lease/PPA prices net incentives (in this case, the CSI rebate, ITC and MACRS depreciation). The reported prices for the systems in our sample exhibit a wide range from \$5.10/W to \$7.98 \$/W (20th and 80th percentile), with a mean of \$6.38/W. Figure 11 illustrates the distribution of differences between prices reported to the CSI and the calculated contract price for each system in our sample. This illustrates a \$2.96/W difference, on average, though the distribution shows two peaks.While reported price and contract price are distinct metrics, they may be assumed to be strongly correlated given that they represent different transactions for the same system—but this is not the case in our sample. The Pearson correlation coefficient between the two metrics is 0.08.

Discussion and implications

The real contract price (discounted sum of all lease/PPA payments) of both leases and PPAs exhibit a rage of over \$7/W based on a 7% discount rate. Our findings suggest that differences in total contract price are partially driven by differences in contract structure and timing, although we note that a number of other factors may be contributing to these differences as well, not least of which is consumer willingness to pay, and price discrimination by installers.

First, we find that, on average, PPAs cost \$1.23/W more than leases assuming a 7% real discount rate—though this difference declines to \$0.52 when evaluating no-money-down contracts (the majority for the most recent year of data)[14]. Absent differences in payment timing, a number of potential reasons explain why a contract structured as a PPA costs the customer more than a lease, on average. The following are three potential factors:

(a) A PPA, relative to a lease implies two risks to the owner/financer: (1) seasonal revenue difference—lower revenue in winter months when systems are producing less; (2) ongoing production variance. The downside risk of system underproduction (due to cloud cover, low insolation, soiling, malfunction) is transferred from the host to the owner/financer since the host pays only for actual electricity generated. The owner/financer can be expected to be compensated for bearing this risk, and the host customer may be willing to pay a premium to reduce this risk. Further, PPAs typically stipulate a payment cap, regardless of production. The potential to receive 'free' energy if the system produces more than estimated in the contract may increase the host customer's perceived value.

(b) Due to this payment cap, system production may be overestimated (in the contracts) by the owner/financer in order to minimize the likelihood that 'free' energy is delivered to the customer above the cap. Estimates of monthly payments rely on production estimates, so if a system produces less than the amount estimated in the contract, the customer ultimately pays less than anticipated. Without system design parameters, there is no way to validate estimates of system production.

(c) Most companies that provided PPAs did not provide leases, so this could reflect installer-specific practices.

Second, we find that prepaid contracts, on average, cost less than no-money-down contracts at discount rates up to 17%—suggesting that consumers may have very high discount rates. This figure is consistent with the low end of implied discount rates for PV lessors in Rai and Sigrin (2013). Further, since a prepaid contract is analogous to purchasing a system in terms of payment timing, insights can be applied from research on the financial tradeoffs of buying versus leasing in other

[12] This excluded systems categorized as providing an appraised value, rather than a system cost.

[13] For this study, we did not have access to detailed system cost information that would fully characterize the costs of a given system. The cost—particularly the labor requirements—will vary by house based on factors such as system layout and roof structure/obstructions.

[14] This difference is found to be statistically significant at >0.1%.

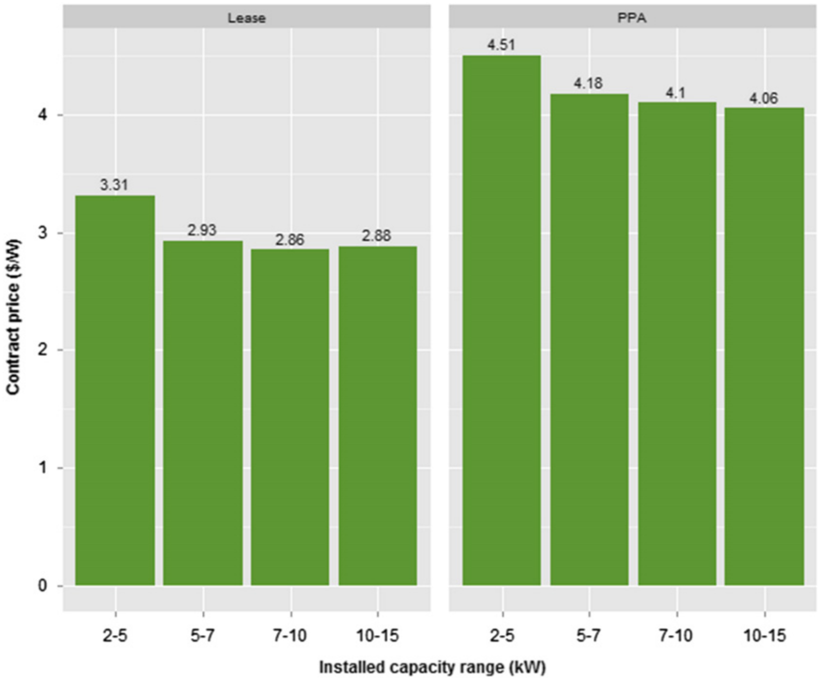


Figure 10. Real contract price (mean) by system capacity for leases (left) and PPAs (right), 7% discount rate.

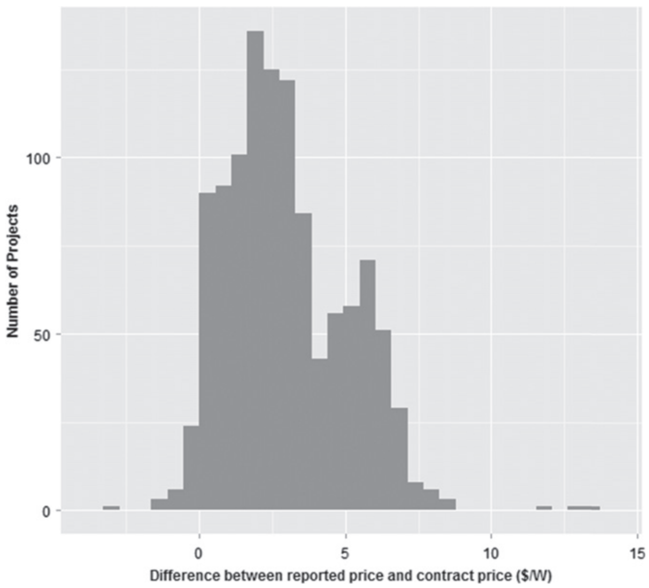


Figure 11. Difference between CSI-reported installed price and calculated contract price, 7% discount rate.

consumer durables. Typically, financial analysis suggests that monthly leasing provides a greater benefit than prepaying a lease (assuming this is analogous to a purchase) when the discount rate that equates the two cash flows is less than the after-tax rate of return that the lessee can obtain on invested capital. Although the implied discount rate in consumer durable markets sometimes appears high, this may be attributed to other consumer values. For example, Dasgupta *et al* (2007) and Nunnally and Plath (1989) found that the implied discount rate for automobile leases were higher than available returns on capital, but Mannering identified frequency of vehicle upgrades as a consumer value that could explain this consumer behavior[15].

However, analogies to other consumer durables are limited in that the adoption decision of a typical consumer durable does not directly offset another

[15] It is possible that some customers may not have the access to inexpensive capital to prepay a lease (savings, home equity lines of credit, etc)—but unlikely, as financers typically require a FICO score >700 to qualify for a lease or a PPA.

substantial household cost. Given a sufficiently high monthly savings on electricity costs, a homeowner may prefer to save their cash or divert it to other purposes, and opt for a monthly lease/PPA, foregoing the relatively higher return by not prepaying the lease[16].

Third, we find that changes in key drivers of installed costs do not necessarily impact the price of a TPO contract to the customer. This is reflected in the fact that TPO contract prices do not consistently decline over the period of analysis, though we do see modest evidence of economies of scale based on system size. In the absence of sufficiently informed customers, firms can price discriminate, selling systems above their marginal cost at prices influenced by consumers' willingness-to-pay. A consumer's willingness-to-pay for PV is, in part, a function of the savings produced by offsetting purchased electricity. However, without access to pre-solar electric bills, we cannot test whether this drives contract prices. As a relatively nascent market, several factors likely preclude competitive TPO pricing, including asymmetric information regarding attributes of PV systems and high search and cognitive costs to seek and compare quotes.

Conclusion

This analysis indicates that the choice of contract type and payment structure may have implications for the total cost to the customer over the lifetime of the contract. Our sample data suggest the following findings:

1. PPA contracts appear to cost more than leases, and this trend persists when contracts are categorized by the amount of upfront payment. This could be driven by several factors, including higher perceived value/lower risk of the PPA contract structure to the customer, company-specific pricing for companies that only offer PPAs, and/or overestimating system production resulting in higher *apparent* PPA payments per watt[17].
2. Delaying lease payment increases the total price to the customer at most plausible discount rates. Specifically, no-money-down contracts are more costly than pre-paid lease contracts assuming a customer's rate of return is lower than 17%.
3. Contracts that include escalator clauses cost more over the lifetime of the contract, for both PPAs and leases, at most plausible discount rates.

[16] However, in these cases, assuming a homeowner can access a sufficiently low interest rate home equity loan, it would be advantageous to prepay a system with a home equity loan.

[17] PPA contract costs are estimated based on assumed production —and may be ultimately be higher or lower depending on realized system production.

Variation in contract prices across different contract structures suggests insufficient customer information and/or very strong customer preferences for certain contract structures. There are likely high search costs and high cognitive costs involved in obtaining multiple bids and comparing bids that might vary by factors such as system size/configuration and perceived quality in addition to variations in contract structure. Future research could better evaluate the degree to which customers are electing the optimal choice by evaluating quotes to the same homeowner, and accounting for the full economic value of the system by understanding a homeowner's pre-solar electricity expenditure.

However, as the market continues to develop, increased competition, particularly in regions with an active solar market, will likely put downward pressure on TPO prices. Tools and resources that facilitate sharing contract bids and/ or comparing multiple bids can reduce information asymmetry by reducing the search cost for consumers and providing data on prices for similarly sized systems.

Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged. Appealing to a broader market, particularly homeowners with lower electricity expenditure and/or in areas with less abundant sunlight may require offering lower-cost contracts to homeowners.

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Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners

Technical Report
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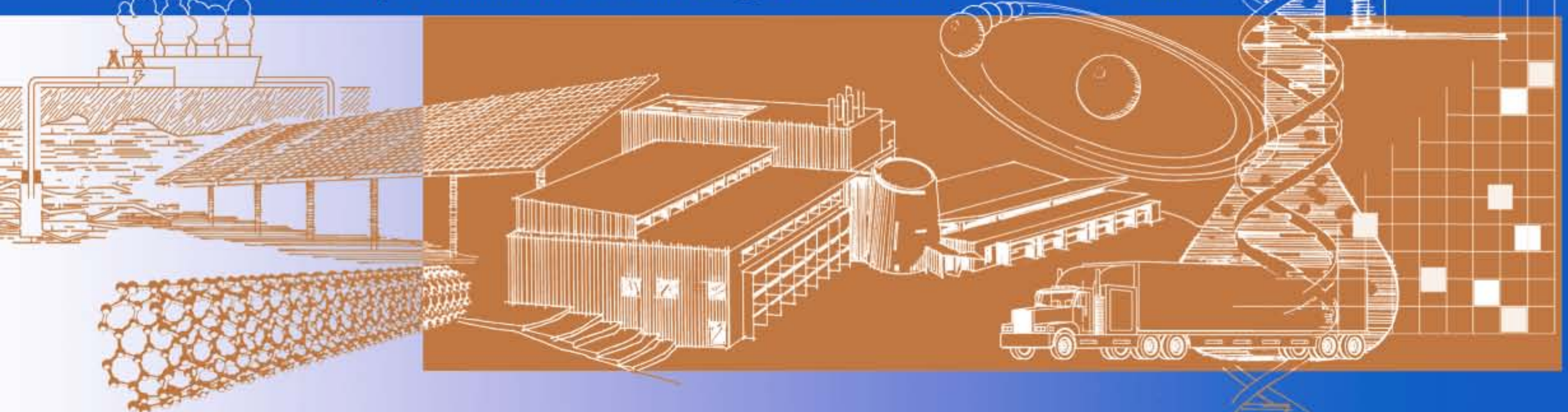

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A Note on the Revisions

This report, as originally published, contained editorial errors that have been corrected in this revision. No changes, except those noted here, changed the authors' intent.

- Page 8, last paragraph: Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are <u>not</u> subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption.
- Page 25, last paragraph: Under the most common of these, the solar lease, the customer does <u>not</u> pay for the equipment but receives the electricity generated from that equipment.
- Page 34, paragraph 5: However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to <u>the utility</u>.

List of Acronyms and Abbreviations

C&I	commercial and industrial
CPUC	Colorado Public Utilities Commission
CREB	clean renewable energy bond
CSI	California Solar Initiative
dba	doing business as
DG	distributed generation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
EIA	Energy Information Administration
ESS	electrical service supplier
FERC	Federal Energy Regulatory Commission
IOU	investor owned utility
IREC	Interstate Renewable Energy Council
IRS	Internal Revenue Service
ITC	investment tax credit
kWh	kilowatt-hour
LLC	limited liability company
LSE	load serving entity
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
OPUC	Oregon Public Utilities Commission
PPA	power purchase agreement
PUCN	Public Utilities Commission of Nevada
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy certificate
RES	renewable electricity standard
RPS	renewable portfolio standard
SREC	solar renewable energy certificate
SSA	solar services agreement
WAPA	Western Area Power Association

Executive Summary

Many end users of electricity would like to use on-site photovoltaic (PV) generation to hedge against volatile electric utility bills and reduce climate change impacts. However, PV systems have high initial costs, and they must be properly operated and maintained to deliver expected benefits.

Providing a potential solution to these cost challenges is a model in which a third-party owner uses a power purchase agreement (PPA) to finance an on-site PV system. This model—the third-party PPA model—allows a developer to build and own a PV system on the customer's property and sell the power back to the customer. In addition, the third-party PPA model enables the customer to support solar power while avoiding most or all initial costs as well as responsibilities for operations and maintenance, both of which typically transfer to the developer. These advantages appeal to owners of residential and commercial buildings who would like to obtain solar PV systems.

However, third-party electricity sales face regulatory and legislative challenges in some states and jurisdictions. Several of these challenges pertain to whether third-party owners are deemed to act as monopoly utilities, competitive service suppliers (competitive suppliers), or both depending on the degree of retail electricity market deregulation. If third-party owners are deemed to act similarly, according to state definitions or state public utility commission (PUC) definitions, the third-party owners may also need to be regulated by the state PUC. Third-party owners of solar PV systems face an additional challenge if they are not allowed to net meter,[1] as this is a significant financial incentive to owning these systems.

Legislative and Regulatory Challenges with Third-Party PPA Model

Five legislative and regulatory issues that challenge the third-party PPA model—and the solutions that several states have applied to them—are summarized below and in Table ES-1.

- **Challenge 1—Definition of Electric Utility as Seller of Electricity:** Because third-party owners sell electricity to site hosts or end users, their systems may require PUC regulation when the state defines a public electric utility (or electrical corporation in California) as a retail seller of electricity. Also, some municipal utilities prohibit others from selling power to their customers and require their customers to buy power exclusively from them.

  State Solutions: Colorado, New Mexico, and California determined that third-party owned systems are not utilities or electrical corporations and non-traditional power generators are not utilities, and are therefore exempt from PUC regulation.

[1] With net metering, an electric meter tracks net power usage—the difference in the amount of electricity provided by the utility and the amount generated by the PV system.

- **Challenge 2—Power Generation Equipment Included in Definition of Electric Utility:** When the definition of electric utilities includes power generation equipment (such as solar PV equipment), third-party owned systems may face regulatory challenges.

  State Solutions: Nevada and Oregon excluded third-party owned renewable energy systems (specifically solar and wind power in Oregon) from the definition of a public utility in PUC regulations.

- **Challenge 3—Definition of Provider of Electric Services:** Third-party owned systems in regulated or partially restructured ("hybrid") states may encounter challenges when legislation or regulation defines utilities or competitive suppliers in a way that includes those providing electric services. This is problematic for third-party owners who provide services to site hosts or end users.

  State Solutions: Oregon decided that third-party owned systems are not competitive suppliers (known as electricity service suppliers in Oregon) because they do not provide ancillary services.

- **Challenge 4—Muni and Co-op Concern over Opting into Deregulation of Electricity Generation:** Third-party ownership of systems is still an issue in Texas within municipal and co-op jurisdictions. Municipal utilities (munis) and rural cooperatives (co-ops) are concerned that by allowing a third party to sell power to customers within their service territory, the public utility commission would force them to allow customers to choose retail electricity service suppliers.

  State Solutions: Third-party ownership of systems remains an open issue in Texas within municipal and co-op jurisdictions.

- **Challenge 5—Determining Whether Third-Party Owned Systems May Net Meter:** Although net metering provides a significant financial incentive, it is not available in all states.

  State Solutions: According to legislation in New Jersey, qualifying facilities include customer-generators that use power from solar PV systems sited on their property (i.e., customer-generators do not have to own the solar PV system). However, this issue remains unresolved in Texas where there are no plans to address it via regulatory or legislative changes.

Alternatives to Third-Party PPA model

Although third-party owned systems have faced regulatory and legislative obstacles in several states, all states that have tried recently have overcome these challenges. Florida examined this situation in the late 1980s and did not develop a solution; but the issue has not been addressed recently. And, while the potential solutions described in this report are state-specific, they likely could be applied in other states that want to encourage solar PV deployment by allowing third-party owned systems. When legislative or regulatory solutions cannot be found, end-use electricity customers may pursue alternatives to the third-party PPA model, including:

- **Solar leases:** Under a solar lease, the customer does not purchase power from a third party but simply leases equipment and receives the power generated by that equipment. This solution has been used in Florida, which does not allow the third-party PPA model. Although it avoids the retail sale of electricity, the solar lease model creates challenges for the use of the federal tax credit and accelerated depreciation.
- **Utilities as Contractual Intermediaries:** A utility may act as a contractual intermediary. Under this arrangement, the third-party owner sells power from the solar PV system to the utility, which, in turn, sells the power back to the site host/end-user.
- **Standardized Contract Language:** Standardized third-party PPA contract language protects customers and reduces the likelihood the PUC will disallow the third-party PPA model or require future regulation.
- **Utility Ownership:** Utilities that own solar PV systems sited on customers' properties could take the federal investment tax credit (ITC) to reduce the capital costs of owning solar PV. However, this model is not as market oriented as others and could exclude third-party solar developers from the utility service territory.
- **CREBs:** For states and municipalities that want to install solar PV on government property, clean renewable energy bonds (CREBs)[2] offer an alternative financing mechanism to the third-party PPA model. However, some projects may be too large to qualify and project owners had to apply by August 2009 to secure a CREBs allocation.
- **Waived Monopoly Powers:** The state PUC and utility may work together to jointly waive the monopoly power rights of the incumbent utility. While this solution is not typical and less feasible than other alternatives, it was applied in Colorado until legislation was passed that replaced this arrangement. With consent from the PUC, the monopoly utility allowed projects financed under the third-party PPA model only when the projects provided renewable energy certificates (RECs) to the utility.

[2] The Internal Revenue Service (IRS) issues CREBs. They are an alternative to tax-exempt bonds that pay out as tax credits instead of interest payments. For more information, see Appendix D.

Table ES-1. Summary of Solutions to Third-Party PPA Model Regulatory Challenges

Solution / Challenge	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4.Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
PPA Solutions					
Clarify third-party owned systems are *not* utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems *used* by customer-generators					NJ
Alternative Solutions					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds [a]	*	*	*	*	
Utility and PUC Waive Monopoly Rights [b]	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.
* Indicates a probable solution with no barriers identified.
** Indicates a possible solution that requires further investigation
[a] This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.
[b] This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

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1 Introduction

The third-party PPA model is quickly becoming the financing method of choice across a wide range of PV generation market segments (Frantzis et al. 2008) and is even finding a niche in the residential and federal markets. However, use of this finance model may be inhibited if it conflicts with state legislation and regulation that was established before third-party ownership was used to finance renewable energy projects.

State regulations and legislation concerning the electric generation sector often define utilities and competitive service suppliers (competitive suppliers), and these definitions often become the starting points for determining which entities require regulation by the state PUC.[3] However, many of these regulations were written when monopoly utilities or competitive electricity suppliers were the main providers in electricity markets. Thus, the regulations do not account for a finance model in which a non-utility entity owns power generation equipment and sells the power generated by this system to a customer. Therefore, in states where utilities or competitive suppliers are defined (a) as sellers of electricity, (b) owners of power generation equipment, or (c) providers of electricity services, the third-party owners that meet the State or PUC definition of utilities or electricity service suppliers may be interpreted as such. If third-party owners are interpreted as meeting these definitions, they might face regulation as a utility. In deregulated retail electricity markets where only munis and co-ops maintain monopoly rights over their service territories, these entities may not allow third-party owned systems if regulation does not clarify whether they would be opening themselves up to customer choice.

In addition to facing regulatory uncertainty, developers using the third-party PPA model may be disincentivized to install solar PV in states where systems using this finance model are not allowed to net meter. Thus, the deployment of solar PV may be hindered in states where third-party owners are uncertain if they will be regulated or allowed to net meter. This paper explores these regulatory conflicts between third-party ownership, state laws, and PUC decisions. It also looks at how particular states have dealt with these challenging issues and explores existing and potential ways to address them.

Section 1 introduces the third-party PPA model, regulation of electric markets, and the related legislative and regulatory challenges. Section 2 describes the third-party PPA model for financing PV projects at customer sites. Section 3 summarizes electricity markets in the United States and explains why markets are regulated and related issues. Section 4 explores in depth several legislative and regulatory challenges to using the third-party PPA model, using California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas as examples. This section also details solutions or answers to these challenges, including legislative and regulatory solutions, and suggests other situations in which these solutions could be applied. Additional solutions, including variations of the third-party PPA model and alternatives to the third-party PPA model, are given in section 5.

[3] In addition to facing state regulation, the third party PPA model could be subject to regulation by the Federal Energy Regulatory Commission (FERC). However, in a recent declaratory order, FERC ruled that they do not have jurisdiction over behind-the-meter third-party PPA solar generating systems (FERC 2009a).

2 The Power Purchase Agreement (PPA)

Traditionally, the PPA was a vehicle for utilities to purchase energy from each other. With the dawn of the Public Utility Regulatory Policy Act (PURPA) in 1978, utilities were required to purchase all of the power from qualifying facilities (QFs) generating renewable assets under 80 MW (FERC 2009b). Utilities used the PPA to purchase from independent generators (the QFs) under long-term stable-priced contracts. PPAs involving QFs are not as common with recent Federal Energy Regulatory Commission (FERC) Orders weakening the utilities' mandate to buy power from QFs and promoting wholesale electricity competition through the opening of transmission access.[4] However, today utilities are signing PPAs with independent power producers for non-utility owned generating plants, for example to meet state renewable portfolio standards (RPS).

2.1 History and Explanation of the Third-Party PPA Model

While the traditional PPA is still the mechanism of choice for utility power purchases, in 2006 a new structure developed that uses a PPA to cater to the distributed generation (DG) markets.[5] SunEdison and Renewable Ventures (formerly MMA Renewable Ventures) pioneered this financing model (Johnson 2008; Renewable Ventures 2009), which was quickly employed by others developers. As Figure 1 indicates, the use of PPAs as a financing model for non-residential solar PV installations has grown rapidly since 2006, taking over other financing models in 2008; this trend is expected to continue through 2009 (Guice and King 2008).

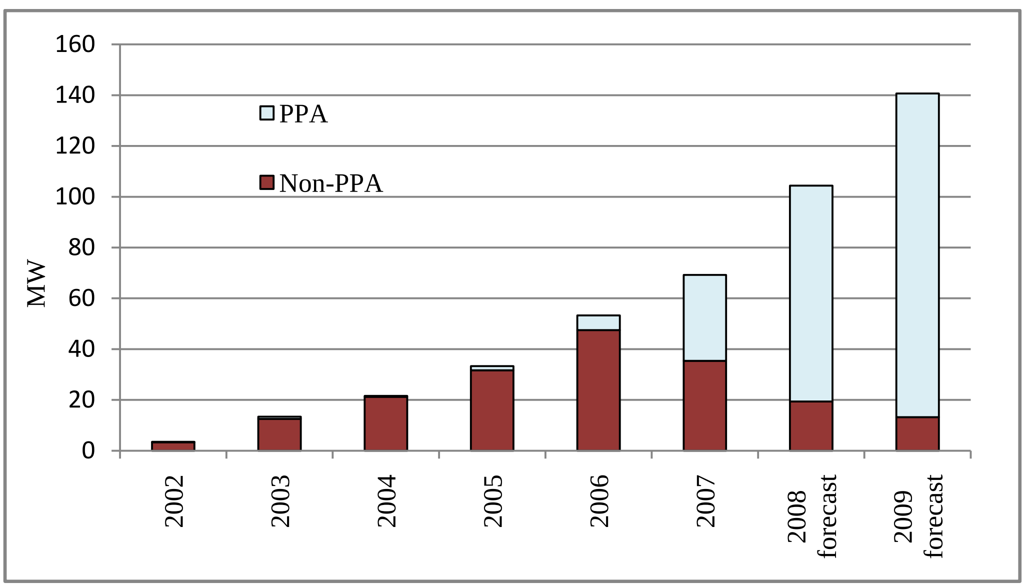

Figure 1. Use of PPAs for U.S. non-residential solar PV installations

[4] The goals of FERC Order 888, issued in 1996, were "promoting wholesale competition through open access non-discriminatory transmission services by public utilities" and the "recovery of stranded costs by public utilities and transmitting utilities" (FERC 2006). These changes led to fewer PPAs (Stoel Rives 2006). FERC Order 688 also removed the mandate that utilities "must buy" the power from QFs if they were greater than 20 MW and have access to one of three major wholesale markets (Stoel Rives 2006).

[5] DG is meant to encompass a variety of sizes of projects located behind customer meters. The larger the customer and the more electricity demanded, the larger the DG system can be. While this can be as small as 2 kW for residential systems, it can be up to 2 MW for large commercial and industrial customers.

Figure 2 details the third-party PPA model where a customer interested in hosting solar panels signs a PPA with a project developer who builds, owns, and operates a solar energy system on the customer's site, also known as the host site. The developer then sells the electricity back to the customer via the long-term PPA. In effect, this allows the customer to have the benefits of solar power while transferring the up-front capital costs to an entity designed to capture available tax benefits (with a potentially lower cost of capital) and foregoing the logistics of financing, building, and maintaining the system. The third-party PPA model is depicted in Figure 2 and is described in detail in Appendix A.

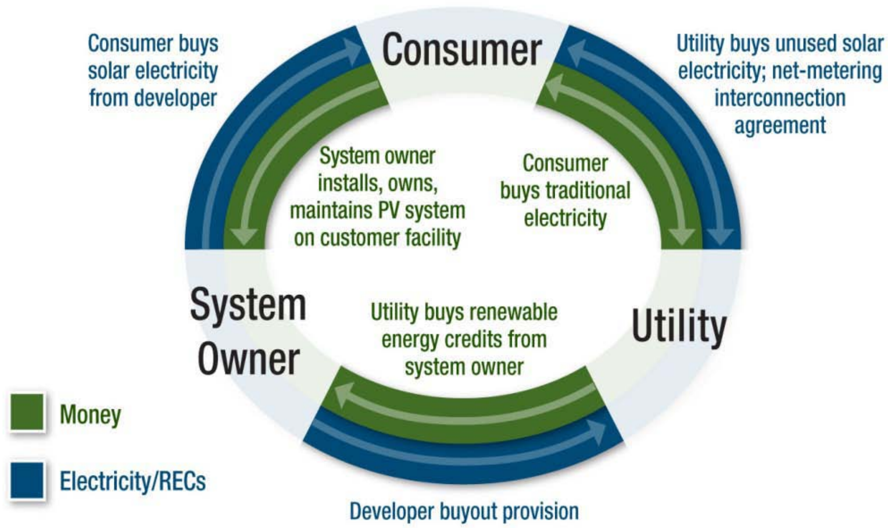

Figure 2. Third-party PPA model
(DOE Solar Energy Technologies Program)

In the PPA contract, a developer receives a combination of revenues and incentives that include electricity sales, sales of environmental attributes (RECs), cash incentives, and state and federal tax incentives in return for paying for the project up front. The customer and developer determine the right mix of up-front cost and payment for electricity sales to meet the developer's required rate of return. This means that customers who want to avoid paying any up-front costs will typically pay more for electricity.

2.2 The Benefits of the Third-Party PPA Model

One of the largest barriers to the deployment of solar energy systems is the high up-front cost. The recent emergences of financing structures that address this challenge have helped spur a significant increase in solar PV installations in the United States. In 2008, over 18,000 new PV systems were installed in the United States that generated 292 MW of the total 342 MW connected to the grid (SEIA 2009). The transfer of the up-front capital costs to an entity with greater access to capital, lower cost of capital, or greater ability to utilize tax specific incentives has been critical to commercial and industrial (C&I) customers adopting the technology. Although this financing model could be used for other installation types, it is primarily used for behind-the-meter installations (i.e., installations that affect only the use of the customer who hosts the installation) (Cory, Coughlin, and Coggeshall 2008).

3 U.S. Retail Electricity Markets and Third-Party PPA Model Interactions

Before examining the regulatory issues (Section 4), the context of state attempts to deregulate retail electricity generation markets must be understood. The level of restructuring in state retail electricity markets varies along a wide spectrum. While some states may be clearly defined as having traditionally regulated retail markets, other states may have "hybrid" markets that have characteristics of both regulated and deregulated electricity markets.[6] Examples of hybrid markets include California, New Jersey, and Oregon.

In states with regulated, vertically integrated utilities, third-party owners of PV must understand the regulatory framework within which they operate. First, the state's definition of a utility may be problematic. In some states, selling power to an end-use customer may mean that the third-party provider would be considered a utility and therefore need to be regulated by the utility regulators. In a few states with ample incentives or REC markets, the third-party owners have tried to get the regulations or laws changed (examples are discussed below).

In states with deregulated retail electricity markets, third-party owners must be aware of the regulations faced by competitive suppliers. And where hybrid markets exist, third-party owners need to be knowledgeable of how utilities and competitive suppliers are defined and where they are active. Developers using the third-party model in hybrid states should investigate whether munis and co-ops will allow these systems, especially in states like Texas where these utilities are concerned that this could open their territories to deregulation of the generation market. Lastly and in all types of markets, states must address whether third-party owned systems are allowed to net meter if they want to encourage the deployment of solar PV projects using the third-party PPA model.

When assessing the feasibility of third-party ownership, PUCs must consider consumer protection and grid safety. PUCs must also consider the degree to which third-party PPA models should be regulated, if at all. This section looks at the pros and cons of allowing third-party ownership in regulated and hybrid retail electricity markets, and it details some state positions on this issue.

3.1 Why Retail Electricity Markets are Regulated

Retail electricity markets in the United States remain regulated in most states in part to protect consumers (rates and reliability) and to ensure a highly functioning electric grid. If anyone could freely connect a generator to the existing grid, the electricity supply could become volatile and unsafe, which could cause congestion, blackouts, and maintenance concerns. Additionally, regulation of these markets prevents unnecessary duplication of assets such as transmission and distribution facilities. Regulated investor-owned utilities are given monopoly status in most service territories to prevent such problems. By having a single entity control the system, a utility can balance constantly changing supply and demand to ensure reliability and keep the electricity flow on the grid optimized and safe.

[6] This is a simplifying assumption—that no market has fully achieved competition in the retail electricity generation markets—that could be debated. However, in many states, the default utilities are still serving substantial portions of the load, so it is difficult to say that any retail electricity generation market is truly deregulated.

States dealing with high power prices in the 1990s began considering deregulating retail electricity markets to lower prices by creating competition among generators supplying electricity (Borenstein 2000). With the relative success of deregulation in the wholesale electricity market, several states began to deregulate retail sales and allow customers to choose where and how they purchased their power. Throughout this electric system restructuring process, most municipal utilities (munis) and rural cooperatives (co-ops) remained regulated by their cities (i.e., by city council members) rather than opening up their territory to competition. Therefore, in most states that restructured, munis and co-ops continue to operate under different rules and regulations than do investor owned utilities (IOUs). Although views on the effectiveness of restructuring vary—and some states are taking steps to re-regulate generation—there are a number of states where customers (sometimes just non-residential customers) continue to choose their power providers.

3.2 Legislative Issues and Challenges with Regulated Retail Electricity Generation Markets

Generation deregulation can affect whether third-party owners are regulated. In electricity markets where the retail customer has consumer choice of their power provider, the third-party PPA model may pose fewer legislative issues. If the utility does not have monopoly power over a given customer base, the customer can choose to purchase power from a company that has placed a solar PV system on its roof or from a competitive supplier, or from both. However, even in a deregulated market, customers may not be incentivized to use the third-party PPA.

Notably, not all states have clearly regulated or deregulated retail electricity generation markets. In fact, some could be said to have “hybrid” markets with characteristics similar to both regulated and deregulated markets. Oregon is an example of a hybrid electricity market where third-party ownership is allowed and where a combination of IOUs, munis, and co-ops provide electricity to customers (State of Oregon 2007); the case of Oregon is discussed in further detail later. However, since most electricity markets in the United States have not restructured to allow customer choice (Showalter 2008; EIA 2008), any model in which an entity other than the monopoly utility sells electricity directly to customers may be prohibited. This legislative issue could significantly challenge third-party owned models.

3.3 Consumer Protection

Some state PUCs are asking if a third party owns a system and sells the power to a retail customer in the service territory of a regulated utility, does the utility commission need to regulate that entity to protect customers from fraud and to protect the security of the electric system? The same question could be posed if the third party owns a system and sells the power to a retail customer where markets are deregulated. In that case, the third-party owner may be considered a competitive supplier.

The utility commissions serve to protect consumers' interests by regulating rates and service quality. Additionally, they serve as a clearinghouse for customer complaints and are charged with dealing effectively with these matters. However, in the case of third-party owners, the PUCs may have no oversight or control over these competitive suppliers. This lack of oversight may pose a challenge for customers. Developers maintain they must provide a quality product to retain customers and remain competitive, and that detailed contract language assures the customer of what can be expected from the system and its owner (Danielson 2008). Moreover, the third-party model aligns the interests of the customer and developer as the project is paid for performance and will not be successful if it underperforms. At a minimum, the customer is usually protected by state consumer protection laws.

3.4 Interconnection Standards

Utilities may use interconnection standards, which provide safety provisions to protect the grid and utility workers, to integrate non-utility owned DG systems. Best practice interconnection standards follow engineering standards and FERC technical screens that maintain the safety of the grid and give DG customers stable policies for interconnection (NNEC 2008).

Interconnection standards consider the effects of size and location of distributed resources on the electric grid. In addition, interconnection standards include provisions about maintenance and the utility's right to disconnect the system if it identifies a problem. Interconnection standards, net metering policies, and other incentives are discussed in detail in Appendix B.

4 Regulatory and Legislative Issues and Challenges to the Third-Party PPA Model

Most state laws and regulations that complicate third-party ownership in monopoly territories have been in place for decades and did not originate specifically to prevent the third-party PPA model. In general, the third-party PPA model is not specifically outlawed. Rather, any entity that sells power to retail customers has to be regulated by the utility commission. Because regulation adds substantial cost and delay, it effectively removes a developer's incentive to offer services in a state. The regulatory language, which is different in each state, gives an idea of the prohibitions on third-party ownership in these markets. This issue is not limited to regulated or hybrid states as some states that have deregulated with respect to customer choice still have sub-markets that remain monopoly utilities (such as the previously mentioned munis and co-ops). The challenge in this case is third-party owners who are allowed to sell retail power to customers might open municipal utilities and rural electric cooperatives up to competition, thereby subjecting them to regulation by the PUC, which these small utilities may not desire (Cory, Coggeshall, and Kollins 2008). Additionally, some munis and co-ops have ordinances that protect their monopoly and do not allow for third-party developers in their territory. Also, there may be regulatory issues for third-party owned systems within deregulated electricity markets where systems using this finance model must abide by the same legal and public utility commission regulation as competitive suppliers.

Interviews with PUC officials across the country were conducted to determine the third-party PPA legislative issues that challenge states, the arguments being presented, and the solutions that may exist. The following describes five legislative and regulatory issues that several states have recently addressed. A few of these challenges have subtleties that depend on state or PUC definitions of utilities or competitive suppliers. All regulatory challenges and their possible solutions, as well as alternative solutions, are summarized in Table 1. Appendix C summarizes the language surrounding third-party ownership, and the status of third-party PPA models, in California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas.

4.1 Challenge 1: Definition of Electric Utility as Seller of Electricity

In regulated markets where utilities are granted monopoly rights for selling electricity, definitions of utilities in PUC regulations or state legislation may prohibit third-party owned solar power generation systems. Because third-party owners of PV systems sell power to the hosts/end-users via the power purchase agreement, the owners could be considered sellers of electricity and thus utilities. Being considered a utility presents a challenge for developers wanting to use the third-party PPA model, as it would require that they be regulated by the state PUC. Regulation of third-party owned systems would add administrative costs and development time to projects, making this finance model less economically appealing.

In California, Colorado, Florida, and Arizona, utilities were defined as sellers of electricity, which created regulatory uncertainty for developers using the third-party PPA model. Colorado and California found legislative solutions for excluding third-party owned systems from being considered utilities; Colorado codified a previous regulatory solution and California addressed regulation of third-party owned systems several years ago.

4.1.1 California—Legislative Solution

California allowed the third-party PPA model for a number of years via a legislative decision. California Public Utilities Code 218 specifically allows certain ownership and technologies, and it promotes a clear path for long-term, customer-sited energy development. In fact, the code's definition specifically exempts an "Electrical Corporation" from regulation:

> …a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for… the use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

This language first establishes solar as an option by stating that non-conventional power sources are exempt. The key for the third-party ownership model is that a corporation can sell electricity if it is used solely on the property where it is generated. In fact, the electricity can even be sold to two other corporations or persons who are also on that property, according to the legislation.

California's language has several interesting implications. First, it allows third-party owners to sell to residential customers on an individual basis. Also, the exemption presents the possibility of selling power to multi-family housing units, as well as multi-tenant commercial and industrial buildings that are net-metered (with restrictions on the pricing of the power). However, the issue of selling power to tenants when the system is not net-metered remains unsettled. The state requires third-party owners to set up new independent business units (such as LLCs, or limited liability companies) for each commercial system they install in order to comply with the rules and use/employ the third-party PPA model.

When deciding whether a competitive supplier is subject to regulation as a public utility, California applies a standard of "dedication to public service." While states have interpreted differently what it means to offer service "to or for the public," California has interpreted their statutes in a way that provides an exception for the provision of power sales to a subset of customers such as tenants. Although California has consistently used this standard when interpreting the intention of power providers, the issue is still officially open.

4.1.2 Colorado—Legislative and Regulatory Solutions

Unlike California, Colorado did not allow third-party owned solar PV systems until very recently, at least not without the threat of PUC regulation. It was not clear if systems under 10 kW that were owned by third parties on a customer site would require regulation. In fact, the temporary response to this challenge was to allow Xcel Energy (Xcel), the state's largest utility, to waive monopoly rights for these smaller systems. That was until a challenge surrounding the regulatory uncertainty of third-owned systems was brought to the Colorado Public Utilities Commission (CPUC) at the request of SunRun, a residential solar developer that uses the third-party PPA finance model. SunRun wanted clarification on whether third-party owned systems smaller than 10 kW would be allowed. In February 2009, the PUC released a recommended decision (08-R-424E) in regard to changes to the renewable electricity standard (RES) confirming that systems less than 10kW are allowed, are not defined as utilities, and therefore, do not require CPUC regulation.

In addition, Colorado Senate Bill 51, which outlined the State's Renewable Electricity Standard, passed in April 2009, clarified whether third-party owned systems should be regulated (State of

Colorado 2009). Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are not subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption. The bill's specific language is:

> The supply of electricity or heat to a consumer of the electricity or heat from solar generating equipment located on the site of the consumer's property, which equipment is owned or operated by an entity other than the consumer, shall not subject the owner or operator of the on-site solar generating equipment to regulation as a public utility by the commissions if the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.

Prior to the recent legislative and regulatory solutions, Xcel and the CPUC agreed to waive Xcel's monopoly rights on specific projects that provided it with RECs, thereby allowing it to comply with Colorado's RPS requirements, including a 4% solar set-aside. For systems over 100 kW, Xcel held a competitive solicitation for RECs generated from third-party owned PPA projects as well as selected winning proposals in order to meet Colorado's RPS solar set-aside mandate. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel found the third-party ownership structure to provide an effective way of meeting that goal. However, Xcel provided this waiver only for those projects selected in its solicitation.[7] This allowed the utility to decide which providers were allowed to serve the market for commercial-scale systems using the third-party PPA model. The recent state legislation and CPUC ruling provides stronger regulatory clarification, which is needed for the long-term development of third-party owned systems.

4.1.3 Florida—No Solution

Unlike Colorado and California, the third-party PPA model has not recently been debated formally in Florida. However, in 1987, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project for which PW Ventures, Inc. (PW Ventures) would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide most of their power needs (*PW Ventures v. Nichols*, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, Florida Power & Light. The definition of a "Public utility" as defined by Florida Statute 366.02 is:

> Every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas…to or for the public within this state.

In their ruling on the issue, the FPSC focused on the definition of "to or for the public." PW Ventures argued that to be considered a utility they would have to sell their power to the general public to be considered a utility. However, the Commission determined that the definition of "to or for the public" could mean *one* customer, meaning that by selling only to Pratt and Whitney, PW Ventures was selling to the public and would be deemed a public utility. Without a change in

[7] Telephone conversation with Richard Mignogna, Professional Engineer, Colorado Public Utilities Commission, September 24, 2008.

statute, this ruling appears to eliminate the possibility of using the third-party PPA model in Florida without PUC regulation (FPSC 1987).

4.1.4 Arizona—No Solution

Arizona has not addressed the regulatory uncertainty about the third-party PPA model. As in Oregon, the retail electricity generation market in Arizona is a hybrid market where competitive suppliers are allowed to register and sell electricity within the utility's exclusive service territory, although no competitive suppliers are currently registered. However, according to the Arizona Corporation Commission, there are several solar PV projects that plan to use the third-party PPA model even though these project arrangements are not allowed.[8] Article 15 Section 2 of Arizona's Constitution defines a public utility as a corporation that "furnishes" electricity or power, requiring that any entity furnishing electricity be regulated in Arizona. Because the definition is part of the constitution, the issue would likely require a legislative solution rather than a regulatory one.

The Solar Alliance, a consortium of solar manufacturers, integrators, and financiers, in 2008 appealed to the Arizona Corporation Commission for a declaratory order in an attempt to resolve the third-party PPA model matter in the state. The Solar Alliance requested that providers of certain solar service agreements not be considered public service corporations (and therefore not be regulated by the Commission). The docket outlines the characteristics of these solar service agreements and argues they are not public service corporations because they are not "clothed with the public interest," which legal precedent has determined is a characteristic of an entity that requires regulation. The Solar Alliance argues that they therefore, do not require the Commission's economic regulation (Arizona Corporation Commission 2008).

Interestingly, in 2007 the Arizona legislature passed HB 2491 to make third-party financiers eligible for the Arizona corporate solar tax credits (State of Arizona 2007). It is to be determined whether the third-party owners will be able to take advantage of this legislation.

4.1.5 Applicability Elsewhere

California's legislative solution is applicable in fully regulated, hybrid, or deregulated power generation and supplier markets where third-party power suppliers are considered by definition to be electrical corporations. Of course, this type of legislative solution, in which renewable energy power suppliers are exempt from being regulated, requires the support of state lawmakers and their willingness to change state laws.

The recent solution applied in Colorado—clarifying in an RES bill that third-party owned systems are legal—could also be applied in other states with fully regulated electricity markets. This type of solution makes sense in states passing new RES legislation as both RESs and the allowance of third-party owned solar PV systems support renewable energy deployment.

The prior solution used in Colorado—allowing a utility to waive its monopoly rights—could be applied in other fully regulated or hybrid electricity markets. However, this solution is less feasible because a public utility commission may not always allow a utility simply to decide

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[8] Telephone conversation with Ray Williamson, utilities division, Arizona Corporation Commission, September 23, 2008.

whether third-party owned systems should be allowed, and the utility may not agree to this policy. Nonetheless, this might be a solution in a state where the public utility commission or legislature has not established rules that clearly allow for third-party owned systems, but the utility and its regulators desire this option to meet an RPS requirement.

4.2 Challenge 2: Power Generation Equipment Included in Definition of Electric Utility

Third-party owned systems may fit the definition of a utility in states where regulations or legislation defines electric utilities as those that use power generation equipment for purposes other than personal use. This is because third-party developers own solar PV equipment that generates power sold to the site host. Developers who worry that third-party owned systems could be interpreted as utilities may choose not to install projects in these states.

Both Nevada and Oregon have dealt with the issue of third-party owned systems meeting the definition of public electric utilities, which included power generation equipment.

4.2.1 Oregon—Regulatory Solution

In Oregon, whether third-party owned systems should be considered public utilities came into question when third-party PPA model developers approached the PUC about net metering. The issue was brought to the Oregon Public Utilities Commission (OPUC) via a Petition for Declaratory Ruling pursuant to ORS 756.450 by Honeywell and PacifiCorp seeking clarity on Honeywell's use of the third-party PPA model. To clarify whether third-party owned systems could net meter, the OPUC considered the definition of public utilities. According to Oregon's net metering law, ORS 757.00, public utilities are defined as:

> any corporation, company, individual, association of individuals, or its lessees, trustees or receivers, that owns, operates, manages or controls all or a part of any plant or equipment in this state for the production, transmission, delivery or furnishing of heat, light, water or power, directly or indirectly to or for the public, whether or not such plant or equipment or part thereof is wholly within any town or city.

Because third-party owned solar PV systems consist of equipment used within the state for the production of power, they may have to be considered as a utility in Oregon. However, whether third-party owned systems provide power "to or for the public" in Oregon is debatable because they would likely only provide power to one or two other users.

The Oregon legislature determined a solution prior to any PUC decision. PUC Order 08-388 found that according to ORS 757.005 a public utility does not include:

> …any corporation, company, individual or association of individuals providing heat, light or power…*from solar or wind resources* to any number of customers (Emphasis added).

Thus, a third-party owned solar PV systems may not be considered a public utility because solar and wind power generation systems are specifically exempt from the definition even though the definition of a utility includes generation equipment.

The OPUC also considered whether third-party owned systems may be considered competitive suppliers. This is discussed in section 4.3.

4.2.2 Nevada—Regulatory and Legislative Solutions

In Nevada, the question of whether third-party owned systems should be regulated came about because they fit the definition of an electric utility, according to Nevada Statute 704-020, which defined a utility as:

> any plant or equipment, or any part of a plant or equipment, within this State for the production, delivery or furnishing for or to other persons…. power in any form.

Thus, a third-party owned system could be deemed a utility because the equipment used to produce power is ultimately furnished "for or to other persons."

On November 20, 2008, the Public Utilities Commission of Nevada (PUCN) formally addressed the issue of third-party owned systems, ruling in favor of third-party ownership (IREC 2008a). According to the findings, which were a result of a PUCN vote to expand a net metering docket to include the issue of third-party ownership, third-party owned systems are not utilities even though they use power generation equipment. In addition, the PUCN found in their Report on Third Party Ownership of Net Metering Systems in Nevada, that third party owners of net-metered renewable energy systems are not public utilities and beyond the jurisdiction of the Commission. The PUCN noted in its comments that allowing third-party ownership of net-metered systems is consistent with state policy goals to encourage the development of, and private investment in, renewable energy resources, stimulate economic growth in Nevada, and enhance the diversification of energy resources (IREC 2008a).

Notably, Nellis Air Force Base in Nevada had the largest U.S. solar PV system to use a third-party PPA model even before third-party ownership was allowed without regulation in the state. Nellis contracted with MMA Renewable Ventures to provide a third-party PPA for a 14-MW solar PV array (WAPA 2008). According to conversations with the PUCN,[9] Nellis accomplished this because it is operated by a federal agency that has special exclusions in the state and as such can choose where to purchase electricity.

Finally, the 2009 Nevada legislature passed, and the Governor signed Assembly Bill 186, which, like Colorado's legislative regulatory solutions, codifies the exemption of third party developers from regulation. The pertinent language is as follows:

> Persons who for compensation own or operate individual systems which use renewable energy to generate electricity and sell the electricity generated from those systems to not more than one customer of a public utility per system if each individual system is:
>
> (a) Located on the premises of another person;

[9] Telephone conversation with Tammy Cordova, Assistant General Counsel, Public Utilities Commission of Nevada, September 23, 2008.

> (b) Used to produce not more than 150 percent of that other person's requirements for electricity on an annual basis for the premises on which the individual system is located; and
>
> (c) Not part of a larger system that aggregates electricity generated from renewable energy for resale or use on premises other than the premises on which the individual system is located As used in this subsection, "renewable energy" has the meaning ascribed to it in NRS 704.7811.

4.2.3 Applicability Elsewhere

Nevada's regulatory solution could be applied in states in which the definition of utility includes the use of power generation equipment to supply electricity to other persons or entities. Similar to Oregon's solution (discussed in section 4.4), Nevada also looked to state policy goals, which support renewable energy deployment, to guide their own regulatory decisions.

4.3 Challenge 3: Definitions and " Competitive Service Suppliers"

Regulatory uncertainty for third-party owned systems may arise when the definition of either "provider of electric services" or "public utility" does not explicitly exempt third-party owned PV systems. Competitive suppliers provide electricity to customers within deregulated or hybrid electricity markets, where customers can choose their electricity supplier. However, a vague definition of a competitive supplier may lead to confusion about whether third-party owned systems require regulation as they too provide some degree of service to the site host, usually in the form of operations and maintenance. Also, in regulated markets, the definition of public utility might not clearly exempt third-party owned systems. This is the case in New Mexico, which is examining the issue.

4.3.1 Oregon—Regulatory Solution

Oregon, which has a semi-regulated retail electricity market, addressed the issue of the regulatory uncertainty surrounding the use of third-party owned systems via a PUC decision. The question for Oregon was whether a third-party provider qualified as an electrical service supplier—Oregon's term for a competitive supplier. Oregon Legislative Statute 757.600 defines an "ESS" as:

> A person or entity that offers to sell electricity services available pursuant to direct access to more than one retail electricity consumer.

"Direct access" is defined as:

> The ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission . . . directly from an entity other than the distribution utility. (OPUC 2008)

Because third-party owners—who do sell electricity to hosts of solar PV systems and may sell to more than one retail electricity customer—would be considered electrical service suppliers under Oregon legislation and would need to be regulated by the state's public utilities commission. As discussed previously, the regulation as an ESS (or utility) is a disincentive to develop third-party owned systems.

In Order 08-338 entered on July 31, 2008, the OPUC interpreted the definitions and statutes in a manner they felt met the legislation's intent (OPUC 2008), especially because the legislation was designed to increase renewable energy generation. To be considered an ESS in Oregon, the entity must provide "direct access" and use the utilities' distribution system. Entities are considered to provide "direct access" if they provide both electricity *and* "ancillary services," which are defined as:

> Services necessary or incidental to the transmission and delivery of electricity from generating facilities to retail electricity consumers, including but not limited to scheduling, load shaping, reactive power, voltage control and energy balancing services. (OPUC 2008)

The OPUC recognized that ancillary services—which relate to the management of electric power delivered through the transmission and distribution grid—did not apply to the third-party owners who generated power on the customer's side of the meter and did not use the distribution system (OPUC 2008).

Even though most third-party owned PV systems participate in net metering in Oregon, DG systems there usually generate between 0.05% and 18% of the total electricity used in the state (OPUC 2008)."As such, the third-party owned PV systems are not intended to be annual net generators and are thus not considered energy wholesalers, which would require the ancillary services of the distribution system (OPUC 2008). Systems typically produce less than the customer's annual electricity use because any net excess generation will not be credited to the site host. Rather, it is credited to the utility's low-income assistance program. In addition, the net metering limit on a project is 25kW for residential systems and 2MW for commercial systems.

4.3.2 Applicability Elsewhere

Oregon's solution has the potential to be applied in other electricity generator and supplier markets in which third-party owned systems are in conflict with the definition of a competitive supplier or public utility. Clarification that third-party owned systems are not considered competitive suppliers or utilities is important as both are regulated by the state PUC making doing business too difficult for third-party providers. In Oregon, public utility officials were supported by legislation that guided state policy on renewable energy generation. Having state legislation that explicitly encourages the deployment of renewable energy could help steer regulatory decisions made by utility commissions.

4.4 Challenge 4: Munis and Co-ops Resisting Opting into Deregulation of Electricity Generation

As discussed earlier, many of the challenging issues surrounding the regulation of third-party owned systems arises in regulated retail electricity markets, where they could be viewed as being in competition with monopoly utilities. However, in some deregulated retail electricity markets, municipal utilities and cooperatives were not required to deregulate. Thus, within the service districts of those munis and co-ops, third-party owned systems could be seen as being in competition with these local, smaller utilities. This is the case in Texas, which has not attempted to address the issue.

4.4.1 Texas—No Solution

Texas presents an interesting case regarding the regulation of third-party owned systems within the jurisdiction of municipal utilities and co-ops that, per usual, were not required to deregulate. Thus, in most of Texas, the third-party PPA model can be used as a financing mechanism. However, this financing mechanism only makes sense when the third-party PPA owner is not producing more electricity than it consumes, as net metering is not allowed anywhere in the state. In addition, in jurisdictions such as Austin and San Antonio where municipal utilities supply the electricity, third-party PPAs may not be an option (Cory, Coggeshall, and Kollins 2008).

The Texas Utilities Code Section 40.053(a) says:

> If a municipally owned utility chooses to participate in consumer choice, after that choice all retail customers served by the municipally owned utility within the certificated retail service area of the municipally owned utility shall have the right of customer choice …, and the municipally owned utility shall provide open access for retail service.

Though the Texas PUC has made no formal statement on the matter, municipal utilities are concerned they might open themselves to competition if they allow generators to sell electricity to their customers. Even though these utilities may want to allow the third-party PPA model to facilitate the adoption of solar power, they will not risk inadvertently exposing themselves to deregulation and competition in their service territory.

However, the third-party PPA developer could create a contract with the utility that would effectively allow the utility to buy the electricity and resell it to the site host. This solution, which is described in detail in section 5.2.1, requires that utilities work with customers and developers on a project basis. It also requires that utilities act as silent intermediaries and do not create administrative or cost barriers that might reduce the appeal of using the third-party model.

4.4.2 Applicability Elsewhere

Although no solution has been found, this challenge could arise in other states that have fully or partially deregulated electricity markets and where munis and co-ops worry that by allowing for third-party owned systems, they will open themselves up to competitive suppliers. However, the municipal utility regulators (usually the city council, which is often also the utility's board of directors), state regulators, or state legislators could make a regulatory or legal exception for using the third-party PPA model. And as discussed previously, alternative solutions such as using the utility as a contractual intermediary might be an option for developers wanting to use the third-party PPA model in Texas or other states in similar situations.

4.5 Challenge 5: Net Metering

Allowing third-party owned systems to net meter could facilitate the deployment of solar PV systems because the on-site generation reduces electricity purchased from the utility and any excess is credited to the customer bill. However, in some states, third-party owned systems may not meet the definition of facilities or customers that are allowed to net meter. Net metering has been problematic for third-party owned systems in at least two states, New Jersey and Texas, and only New Jersey offers a (somewhat vague) solution.

Neither New Jersey nor Texas has explicitly addressed whether third-party owned systems are allowed to net meter; however, both states demonstrate how the interpretation of regulations or legislation can alter whether third-party owned systems are allowed to net meter.

4.5.1 New Jersey—Legislative Solution

New Jersey does not have legislative or regulatory language that determines whether third-party owned systems are allowed to net meter. However, New Jersey Administrative Code 14:8-4.2 and 4.3, which outline changes to net metering and interconnection rules, (Docket #: EX08070548) define a “customer-generator facility” as:

> …the equipment *used* [italics added] by a customer-generator to generate, manage, and/or monitor electricity. A customer-generator facility typically includes an electric generator and/or an equipment package.

New Jersey’s definition stipulates that the equipment need only be used by the customer; i.e., a customer-generator allowed to net meter is not required to own the generation equipment, and third-party owners are allowed to net meter (Keyes 2008).

4.5.2 Texas—No Solution

In Texas, where the retail electricity generation market is deregulated, the PUC claimed that *requiring* net metering is incompatible with deregulation, thus making the third-party PPA model financially less attractive as carrying excess generation forward would not be possible.

4.5.3 Applicability Elsewhere

New Jersey’s regulatory solution in which the PUC determined eligible customers only need to use the power generated by the facilities (regardless of ownership) could be applied in any state determining which kind of facilities are eligible to net meter. However, as noted previously, New Jersey was able to look to state legislation that clearly supports renewable energy deployment and make decisions in a consistent manner with the legislation. Thus, having state legislation that can serve as a guideline for PUC officials may help to create state regulations that support net metering for third-party owned/PPA financed systems.

Overall, implementing third-party PPA model financing is difficult in states where unclear legislation or regulations could result in the regulation of third-party PPA owners. Munis and co-ops might be concerned that allowing third-party owned systems to sell power to their customers will open their service territories to deregulation. The third-party PPA model is also problematic in states that do not explicitly allow net metering of third-party owned systems. Finding a one-size-fits-all policy solution is not possible when states not only define differently utilities and other competitive supplier, but also put in place different rules about what they can legally supply or how many customers they can serve. However, more parties are seeking resolution to these issues as evidenced by recent rulings in Colorado and Nevada, and a docket filing in Arizona.

See Appendix C for a summary of all the language variations explored in this section.

5 Alternatives to the Third-Party PPA Model

In cases where states have ruled against the third-party PPA model or where legislative change or PUC decisions are not feasible, the following alternative solutions may be applicable. Additionally, Clean Renewable Energy Bonds (CREBs) provide a potential alternative for munis and co-ops and are discussed in Appendix D.

5.1 Third-Party Ownership Solar Leases

The third-party solar lease model is sometimes called the solar services agreement (SSA) model. Like the third-party PPA model, it benefits from having a third party finance and own the solar energy system.

The solar lease is a relatively new way to provide customers access to on-site solar energy systems, however, the concept is the same as traditional equipment leases. Instead of purchasing a PV system, the customer enters into a service contract with a lessor (the owner) of a PV system and agrees to make fixed monthly lease payments (regardless of system generation) over time (Coughlin and Cory 2009). The customer consumes whatever electricity the leased system generates, net meters any excess or pays the utility rate for any additional electricity it requires.

5.1.1 Benefits of the Solar Lease

The benefits of the solar lease mirror most of those associated with the third-party PPA model, including transferring most or all of the up-front cost, using a developer who can partner with a tax equity investor to take advantage of federal tax incentives, and if indicated in the contract, transferring maintenance responsibilities to a qualified party. However, the price of electricity will differ somewhat because the customer effectively pays a set price for the equipment (and sometimes maintenance) and not the electricity itself. Ideally, monthly electric bill savings will equal, if not exceed the lease payments (which take into account available state and federal incentives) to create a cash neutral or cash positive transaction. Figure 3 presents the parties involved in the solar lease.

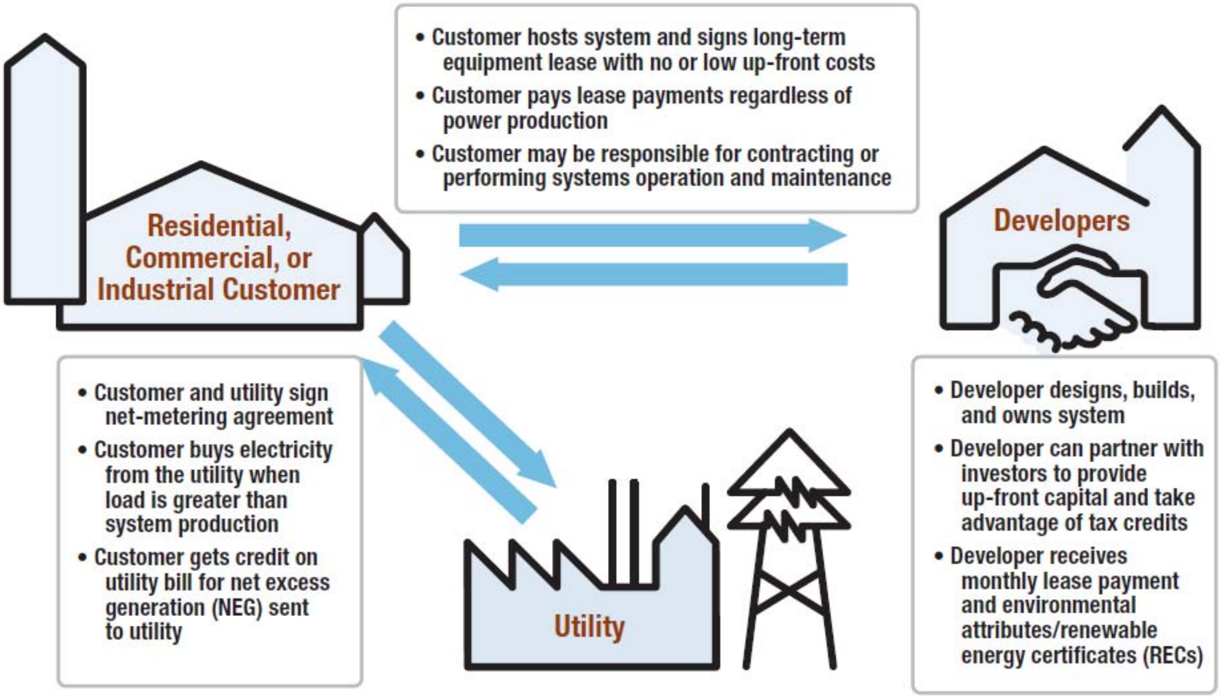

Figure 3. Solar lease structure (aka solar services agreement)

If the customer purchases a maintenance package, the solar leasing company may monitor the systems in real-time to detect issues and provide prompt resolution. Additionally, a solar lease may come with a performance guarantee to make the customer more comfortable with the arrangement (SolarCity 2008).

To make the projects economic (with lease payment levels close to the customer's retail utility rate), developers typically require that either they receive the RECs or that the RECs are sold to the utility (which may have an RPS requirement). As previously mentioned, many utilities mandate that they receive the RECs from those projects where they have contributed rebates and financial incentives (Holt et al. 2006). These up-front cash incentives exchanged for the environmental attributes generated by the PV system can be an important revenue stream to make the project economic. This is especially true with smaller residential projects.

5.1.2 Challenges with the Solar Lease

Under the solar lease model, more risk may be transferred to the customer and away from the developer compared to the third-party PPA model. The developer receives a fixed lease payment regardless of whether the system is operational and independent of the electricity produced. Operations and maintenance risks are therefore transferred to the customer unless maintenance services or operational guarantees can be procured from the developer or another provider. The customer may be responsible for property insurance for the system, which could be added to homeowner's insurance or an existing property policy. The developer, on the other hand, is responsible for insuring the construction and operation of the system; their policies may include workers' compensation and auto, business interruption, and liability insurance. Because large developers have established insurance relationships, they receive more favorable rates than do onetime residential or commercial customers looking for solar PV insurance.

In addition to taking on the previously mentioned risks, some types of customers also face more financial challenges with solar leases than they do with the third-party PPA model. Owners of systems sited on property owned by governmental entities or non-profits, including schools, are not eligible for the ITC (SEIA 2008). This removes a large incentive to the developer and in turn raises required lease payments for the customer. Another important financial challenge for the solar lease model regards the estimation of a system's electricity production. If estimates of solar PV system production are not accurate, the customer may pay more for the electricity on a levelized basis ($/kWh) than if had they entered into a PPA.

Notably, the solar lease (solar services agreement) model involves a traditional sale/leaseback arrangement between the developer/operator of the system and the tax equity partnership established to monetize the federal tax credits and use the accelerated depreciation. For the investor to receive the tax benefits, the agreement between its lessee and the host customer must be a *service* agreement (hence, the SSA), and the recipient of the service agreement cannot operate the system or stand to face significant financial loss or gain in case the system does not perform as predicted. Were the host customer to sublease the system, it would arguably be taking on the operation of the system (the definition of lease tends to include the lessee's "control" of the leased asset). Moreover, because lease payments are typically fixed, the host would either gain if the system overproduced or lose if the system under produced.

A direct lease—under which the solar developer owns the system and leases it to the host customer—is not feasible for most developers because neither the developer nor the host/lessee would be able to fully realize the benefits of the federal incentives. Solar developers, as system owners, typically do not have the tax appetite to realize the benefit of either the ITC or accelerated depreciation. The solar developer could pass the ITC (but not the accelerated depreciation) through to the host/lessee, but one-half of the ITC would be treated as taxable income to the host. Even in this pass-through scenario, the developer still holds the essentially worthless depreciation benefit. Thus, most of the benefit of the incentives would be lost making the project more costly or economically unreasonable.

It should be noted that, like the third-party ownership/PPA model, the solar lease could also face regulatory challenges. However, this appears not to be as common of a challenge as it is for the third-party PPA model. An example of the solar lease facing regulatory changes occurred in Nevada, where the Public Utility Commission of Nevada did not believe that the third-party PPA model or the solar lease structures are legal under Nevada law. The staff was also concerned with consumer protection if these third parties were not regulated. Further, they felt the Commission should implement rules that govern rates and fees as well as contractual obligations (PUCN 2008).

5.1.3 Applicability of the Solar Lease: Florida and Texas

The solar lease appears to be acceptable in those states that define a utility or load serving entity (LSE) as an entity that sells "electricity." With a solar lease, the owner leases the equipment and does not sell the electricity, which most states find to be an acceptable arrangement.

In Florida, the FPSC went so far as to rule in favor of a solar lease structure in the Monsanto case of 1987 (FPSC 1987). In that case, the Commission stated that there was no *sale of electricity* because Monsanto was leasing equipment that produced electricity rather than buying electricity that the equipment generated. The terms of the lease were the most important factor in this ruling:

> The lease payments would be fixed throughout the term of the lease. These payments, based on a negotiated rate of return on the lessor's investment, would be independent of electric generation, production rates, or any other operational variable of the facility. Thus, lease payments would continue to be due during either planned or unplanned outages of the facility.

This puts the operating risk on the customer instead of the third party, which the FPSC found to be a completely different transaction than the third-party PPA model where the risk was born by the third-party. Although this operational risk requirement is applicable in Florida, other states do not carry this stipulation, and O&M can be performed by the third-party owner, often with some sort of performance guarantee.

For the financial challenges with the federal tax credit and accelerated depreciation, the solar lease may be a good option in electricity markets where the legality of third-party owned systems is uncertain. However, it is not an option for projects on government or non-profit property (including schools) as the benefits of the ITC cannot be realized. In places such as Florida and possibly Texas where the third-party owned systems are not legal or cannot net meter, the solar lease may be a good financial alternative because the lease finance structure does not appear to face the same legislative barriers (specific situations should be checked with legal counsel). Because the solar lease is competitive cost-wise with the third-party model, it does not pose a real loss to those looking to install solar PV systems on property located in electricity markets where the third-party PPA model cannot be used.

Table 1. Incentives and Project Responsibilities for Solar Financing Mechanisms

Financing Mechanisms	**Self-Financing**	**Third-Party Ownership PPA**	**Solar Lease**
Incentives			
State Cash Incentive (production-based or upfront)	Yes	Yes	Yes
Use of Federal ITC	Requires large tax liability	Yes	Yes, except on government or non-profit property
Accelerated Depreciation	Yes	Yes	Yes, except on government or non-profit property
State Tax Credits	Yes**	Yes**	Yes**
Responsibilities			
Upfront Costs	Yes	No*	No
O&M	Yes	No	Yes, unless contracted to the developer

* The lower the up-front costs, the higher the price of electricity, therefore up-front costs depend on the contract arrangement between the third-party owner and the customer to meet the goals of both parties.
** Requires a larger tax liability within the state the system is located.

5.2 Other Alternative Solutions

When statutory interpretation is unclear with regard to third-party PPA models, it might make sense to consider variations of this model or alternative arrangements. Customers interested in solar PV systems and developers looking to enter new markets can explore the following alternatives to the standard third-party PPA model.[10]

5.2.1 Utilities as Silent Contractual Intermediaries:

If the utility is willing to work with customers and developers on a project-by-project basis, the project developer may sign a PPA with the customer's *utility* then have the utility sell the electricity back to the customer. With this potential solution, the utility is a silent intermediary in the third-party PPA model and only transfers the sales and purchases on paper, while the actual electricity is used directly by the customer. This process would likely require some standardization within the utility if it were to be deployed for more than a few projects. One potential concern with this model is that it turns the developer into the wholesaler of electricity, which could subject the developer to FERC regulation. While this regulation is workable and

[10] This does not constitute legal advice, and it should not be considered as such; a full legal opinion from your attorney, specific to your situation, should be obtained.

common in many states, it puts additional responsibility on the developer. Moreover, the retail transaction between the utility and the customer could be subject to regulation.

This solution, which clearly requires that the utility be interested in promoting solar resource development, is an important potential option for a regulated utility concerned about opening themselves to competition, as is the case for municipal utilities in Texas. Because of increased transaction costs, the structure may not come with pricing as favorable as the third party PPA model, but it could be an important solution when legal questions surround the third-party PPA model.

5.2.2 Standardized Third-Party PPA Contract Language

Many states noted that it would be in the customer's best interest to have standard rules and contract clauses in place that must be part of the third-party PPA. This would help ensure that customers receive a fair deal and are not paying hidden fees or signing up for services of which they are not aware. A standard contract approved by the PUC would leave less room for interpretation of legality down the road, but developers and their bankers might view it as a form of regulation.

5.2.3 Utility Owns Customer Sited Generation Assets

With the recent change to the federal ITC that allow utilities to take the 30% up-front PV tax credit (H.R. 2008), more tax-paying utilities may choose to own PV. Although these utilities may choose to build and own large-scale solar plants, they can also finance customer-sited DG and sell the power back to host customers. In this instance, the utility effectively takes the place of the third party in the third-party owned PPA model. If the model is properly structured, the customer can enjoy the same benefits of fixed-price power at or below utility retail rates, and the utility can take advantage of the tax credits. However, some argue that utility costs of developing customer-sited solar projects could be higher than costs available in the competitive marketplace. In addition, some suggest it is not fair or efficient to allow a utility to be the sole provider of a service that is a competitive offering in many states.

5.2.4 Utility- and PUC-Waived Monopoly Rights for Distributed Generation (DG)

Although not typical, monopoly utilities might be able to waive their monopoly rights and allow third-party owners to participate in their service territories if their regulators support this structure. Xcel Energy and their regulators in Colorado used this as an interim measure before the legislature passed a law allowing the third-party PPA ownership model.

To meet Colorado's RPS requirements, including the 4% solar set-aside, Xcel Energy (in agreement with their regulators) waived their monopoly rights on specific projects that provide it with RECs for compliance. For systems over 100 kW, Xcel holds a competitive solicitation and selects winning proposals in order to comply with the Colorado RPS solar set-aside. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel has found the third-party ownership structure to be an effective way of meeting that goal. However, Xcel provides this waiver for only those projects that are selected in its solicitation and that provide it with RECs for its compliance obligations (Mignogna 2008). This makes the utility the absolute power and "sole arbiter" of which providers are allowed to serve the market for commercial-scale systems using the third-party PPA model. For projects from 10kW to 100kW, Xcel has a standard rebate offer but only for projects that supply it with RECs. For the under 10-

kW “residential” segment, Xcel runs another standard rebate offer but requires that the customer own the system.

Table 2 illustrates the wide range of solutions previously discussed. Legislative or regulatory changes to allow the third-party PPA model might be out of the control of third-party developers or the customers who desire their services, but both variations to the traditional model or entirely different alternatives are possible. Some of the variations will require a ruling by a governing body (registration of DG service providers and standardized third-party PPA contracts), while others can be implemented in many jurisdictions without any legal issues.

Table 2. Summary of Attributes of Alternative Solutions to Third-Party PPAs

Attributes of Alternative Solutions	**PPA Parties**	**Low/No Up-front Costs**	**System Maintenance Responsibilities**	**Monthly Payments**
Solar Lease	No PPA, just flat lease fee	Yes	Customer, unless contracted to the developer	Fixed
Developer Sells Power to Utility	Third-party sells to the utility, which sells to the end-use customer	Yes	Third party	Based on electricity usage
Utility Owns Customer Sited Assets	Utility sells to end-use customer	Yes	Utility	Based on electricity usage
Standardized Third-Party PPA Contracts	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Clean Renewable Energy Bonds (Municipal utilities)	Customer (govt. entity) owns the system	Must pay issuing costs	Customer, unless contracted	None *

* Annual principal payments were required for CREBs before 2009.

Table 3 indicates in which states the five major regulatory challenges to the third-party ownership/PPA model have occurred, as discussed in Section 4, and the solutions that have been applied or are possible.

Table 3: Summary of Solutions to Third-Party Ownership Regulatory Challenges

Solutions \ Challenge	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4.Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
<u>PPA Solutions</u>					
Clarify third-party owned systems are *not* utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems *used* by customer-generators					NJ
<u>Alternative Solutions</u>					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds [a]	*	*	*	*	
Utility and PUC Waive Monopoly Rights [b]	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.
* Indicates a probable solution with no barriers identified.
** Indicates a possible solution that requires further investigation
[a] This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.
[b] This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

6 Summary

Of the states that have examined the legislative and regulatory issues with the third-party PPA model in recent years, most have accepted the structure as sound and clear of conflict with utility rights. This is true whether states deregulated their retail electric generation market or not. However, most states have not clarified the use of this model, and therefore it may not be clear whether this structure can be used. Of the cases investigated, no two states have had the same specific situation (language and regulating body, for example) regarding the regulation of third-party owners, which defies a single solution that will work everywhere. However, lessons from the examples in this report could be used in other states that wish to address the issue of regulation of the third-party PPA model.

Several regulatory challenges exist for the third-party PPA model. The first challenge occurred when state legislation or regulations defined electric utilities as sellers of electricity. Because the owners of third-party systems using a PPA sell their electricity to site hosts, these systems may be interpreted as being electric utilities and would therefore require PUC regulation. This issue has arisen in Colorado, Florida, and Arizona. However, Colorado and California determined that third-party owned systems using PPAs are not utilities or electrical corporations, and that non-traditional sources of power generation are exempt from being considered as utilities. Florida's ruling, which occurred in 1987, has not been revisited. The second challenge occurred when the definition of electric utilities included power generation equipment, such as solar PV, and thus required regulation. Solar developers in Nevada and Oregon who were using the third-party PPA model encountered this challenge, but PUC regulators in those states clarified that third-party owned renewable energy generation systems (solar and wind only, in the case of Oregon) using a PPA are not considered to be public utilities.

A third type of challenge occurred in Oregon, where the definition of competitive service suppliers (or ESS under Oregon's definition) and utilities came into conflict with third-party ownership. Oregon legislation defined an ESS as a seller of electricity that provides direct access and ancillary services. Nonetheless, the State of Oregon determined that third-party owned systems using a PPA are not electrical service suppliers because they do not provide ancillary services. The fourth challenge occurred when munis and co-ops were concerned they would open their service territories to deregulation of electricity markets if they allowed the third-party PPA model. This challenge has occurred only in Texas where the remainder of electricity markets is deregulated. Texas has not addressed this issue and has no plans to do so. The fifth and final challenge, which has been identified in New Jersey and Texas, occurred when third-party owned systems were not allowed to net meter. Texas has not resolved this issue, but New Jersey regulations allow net metering for all systems "used" by customer-generators, thus they do not have to be owned by the customers.

All of the solutions found here could be applied in regulated, hybrid, or deregulated markets. The solutions could be applied to a number of challenges. Lastly, in a few cases, PUC officials looked to their state's policies/goals for renewable energy deployment when making regulations favorable to third-party owned systems.

Other solutions include variations of the third-party PPA model, many of which also require legislative or regulatory approval. For example, states can allow a standardized third-party PPA contract. Other variations of the third-party PPA model do not require legislative approval but focus on the utility. For example, a developer may sell power to the end user via the utility as a contractual intermediary, allowing the utility to remain the only seller of electricity. In addition to these other regulatory solutions, effective financing mechanisms can be employed in jurisdictions where the third-party PPA model is unavailable. Under the most common of these, the solar lease, the customer does not pay for the equipment but receives the electricity generated from that equipment. However, this option is not available to government or non-profit entities. CREBs are available to state and local governments including co-ops and munis, that apply for and receive an allocation from the IRS, which allows them to finance and own solar PV without major up-front costs.

States that want to support renewable energy—and feel that adequate consumer protection provisions are in place—might want to consider explicitly allowing third-party owners using PPAs to be unregulated. The third-party PPA model provides benefits to customers who are interested in solar PV but do not want the up-front costs or maintenance responsibilities. The third-party PPA model can be an attractive financing option, and it has spurred solar PV growth in states where it is available. It also promotes market discipline and is instrumental in driving the cost of solar energy down. For these reasons, states may consider allowing third-party electricity sales as one way to meet their renewable energy, solar, and distributed generation mandates and goals.

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Appendix A: Overview of Third-Party PPA Model

Recently, attributes of the third-party PPA have popularized this model for financing new PV installations. The benefits (and challenges) of this model, which are outlined below, apply to both residential and commercial customers. Implications of using the model vary and depend on customer type.

Minimal Up-Front Costs

A primary benefit of the third-party PPA is that it dramatically reduces or eliminates up-front costs for commercial, industrial, and residential customers by transferring the up-front capital costs of the solar PV system to entities set up to use numerous revenue streams from the system; and, the third-party PPA potentially does this with lower costs of capital. Developers can eliminate the need for customers to provide up-front capital by finding capital to buy the systems, by either purchasing them outright or securing financing for most of their capital costs. The PPA contract payment level established by the customer and developer determines the amount of up-front cost, if any to the customer.

Project Financing Expertise

Solar energy developers participate in the niche tax equity financing market and form relationships with banks that have tax equity financing divisions. Because this is the developer's line of business, they are well equipped to manage the process and can usually find capital at lower costs than homeowners can or businesses can. However, the recent financial crisis in the United States has consolidated or eliminated many participants in the tax equity market, while others have scaled back as they have less taxable income to offset. Therefore, there are fewer tax equity investors in renewable project financing than before. The remaining players in the tax equity market are increasing their return on capital requirements and focusing on projects with low counterparty risk (Chadbourne & Parke 2009).

Efficient Use of Tax Credits

As mentioned earlier, a number of available tax credits encourage the installation of solar PV. However, only certain entities can take advantage of these financial incentives, and commercial businesses with taxable profits often have the most to gain. Third-party developers are set up to allow investors in their business to take advantage of incentives in the form of tax credits, thereby allowing them to use both more and higher-value incentives than traditional businesses or homeowners are able to use.

The most salient examples, the ITC and the residential tax credit, are only available to a homeowner or business with taxable income. A homeowner or commercial entity whose tax bill is not large enough to absorb the entire tax credit—even with the credit carried forward—cannot take advantage of an incentive that potentially offsets 30% of the up-front capital cost. The residential and non-tax paying customers are at a disadvantage because neither can use the Modified Accelerated Cost-Recovery System (MACRS) depreciation tax benefit. This means that the project owner must have predictable profits large enough to offset the depreciation benefits (MACRS) and tax credits they receive from the project.

By contracting with developers who can take advantage of these incentives and credits, certain customers can now realize cost savings that would have not been possible had they themselves purchased and owned the systems. The cost savings are subsequently passed from developers to customers in the form of lower electricity rates (equivalent to the system output).

Removal of Maintenance Responsibilities

For the most part, the businesses and residences that are installing PV do not have expertise in solar array maintenance and operations. With the third-party PPA model, the ownership and responsibility of the system is placed on the developer and not on the customer, who pays only for the electricity generated. If the system does not function properly, the customer does not pay for repairs or for the electricity. Ultimately, the customer just purchases more electricity from the utility. This arrangement provides a revenue incentive for developers to maintain their system because they are not paid unless the system produces power.

Predictable Costs in Volatile Electricity Markets

Both residential and business customers are looking at ways to reduce electricity costs and incorporate predictability in their future electricity expenditures. The third-party PPA model allows a customer to avoid some of the large rate increases seen across the nation in recent years (Smith 2008) by providing a contract with a pre-determined price for 20 to 25 years.

When businesses with large power needs are considering ways to reduce expenditure risk, locking in prices with suppliers via long-term contracts is an excellent way to manage this line item. Often these contracts start with electricity rates that are competitive with the utility retail rate for that customer and may remain constant or contain an annual escalation factor of 3 to 3.5% (Cory, Coughlin, and Coggeshall 2008). With this stability, businesses can plan a portion of their energy expenses with certainty, and project investors can count on a revenue stream as long as they maintain system performance.

The financial efficiency of the third-party model greatly increases opportunities for commercial, industrial, and government customers to use solar resources on-site. As a result of this expansive market, solar energy costs are driven down through volume purchases of equipment and efficient construction and installation methods.

Non-regulatory Challenges with the Third-Party PPA Model

Some challenges with the third-party PPA model are beyond the regulatory challenges examined in the body of this paper. One such challenge is determining whether the utility is entitled to the RECs. In net metering situations, some states have pre-determined whether the customer or the utility has rights to the RECs. The majority side in favor of the customer retaining the RECs, especially for generation associated with the customer’s load (vs. net excess generation). However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to the utility (Holt 2006). One exception is the California Solar Initiative (CSI), which does not require the surrendering of RECs as a condition for receiving financial incentives or rebates (California Public Utilities Commission 2009, DSIRE 2009).

In the case of the third-party PPA model, the developer typically sells the electricity to the customer and retains the RECs or more valuable solar RECs (SRECs) for sale into the REC market. The sale of SRECs helps the project make the necessary returns and allows the developer to offer the customer a price competitive with grid-supplied electricity. To claim they are “solar powered,” customers must purchase all or a portion of the SRECs from developers. In states with an RPS with a solar set-aside, which usually significantly increases the value of SRECs, the removal of SRECs from the deal can make the project uneconomic. However, customers do have other options in some cases. For example, federal agencies in regions with active REC markets often buy wind or landfill gas RECs for less on the open market, which allows them to retain the renewable energy claim (just not a “solar” energy claim) while taking advantage of high SREC prices (Cory, Coughlin, and Coggeshall 2008).

The contract states the customer’s options in the event they sell their property. Because the third party has taken on the credit risk of the initial customer, the new occupant is not automatically entitled to assume the terms of the contract; the new occupant often must meet a credit check and other requirements. In addition, some contracts have buy-out clauses that allow the customer to buy the system and sell it with the building. Some jurisdictions, such as Colorado, are beginning to address these issues in their rules governing customer-sited solar resources.

Appendix B: Solar Laws, Financial Incentives, and Policy Background

A successful solar installation involves logistical and economic prerequisites, including net metering laws, interconnection standards, financial incentives, and federal and state policies requiring incremental renewable generation.[11] All these must come together to ensure an economically viable project.

Connecting Solar Energy Systems to the Grid

The financial incentives discussed in the body of this paper help only when the state where the solar energy system is installed has the appropriate net metering and interconnection standards. Net metering and interconnection, which ensure that systems are adequately sized, safe, and affordable, are discussed below and in detail in the Interstate Renewable Energy Council's (IREC) 2008 annual report and in "Freeing the Grid" (NNEC 2008).[12]

Interconnection Standards

Interconnection standards govern the technical and procedural process by which an electric customer connects an electric-generating system to the grid. Generally, the distribution utility assesses and approves the customer-generator within the rules established by the public utilities commission based on input from utilities and other stakeholders.

IREC also recommends eliminating any requirement for external disconnect switches because all modern grid-connected systems automatically shut down in the event of a grid failure (NNEC 2008). Such improvements to interconnection standards will remove logistical barriers for small systems and make larger systems operate safely within the grid.

Net Metering

Net metering is the billing arrangement between customer-generators and utilities whereby the customer is credited by the utility for excess electricity that the customer generates. Typically, net metering allows a customer to earn a credit for net excess generation (NEG) produced by the customer's system over a billing period at the utility's wholesale rate, the utility's avoided cost, or the customer's retail rate. Essentially, the customer can use credit obtained through past NEG in one billing period toward electricity consumed in future billing periods.

IREC's best practices with respect to net metering include (1) removing size limits and customer classes from net metering, (2) allowing monthly carryover of NEG credited at the utility's full retail rate, and (3) standardizing net metering standards across the state without regard to the type of utility to make rules simpler and clear to all market participants (NNEC 2008). These

[11] The quality of the solar resource (i.e., location) is another critical element to PV projects. However, even in a location with excellent resource, incentives are needed for the project to be economic under current conditions. In fact, incentives can compensate for the differential between poor and great resources to help spur new development. Germany is a world leader in PV despite having a solar resource on par with Alaska's; government incentives make the difference.

[12] *Freeing the Grid* rates and reports the effectiveness of state interconnection standards and net metering standards with the goal of displaying best practices and helping states make incremental improvements and facilitating additional grid-tied solar development.

practices are important as net metering rules can determine a project's size and economic feasibility in many cases.

States' rules and requirements for net metering differ based on whether the customer is a commercial or industrial customer versus a residential customer. The primary element in net metering rules is the allowable size of the systems, which dictate whether customers can install systems large enough to (approximately) meet their load and realize economies of scale. Allowable size varies greatly from state to state—the range stretches from six states that have no net metering laws to New Mexico, which allows up to 80MW, and Ohio, which does not have a limit (DSIRE 2008b). Arizona now allows net-metered systems sized to 125% of the customer's "connected load."[13] The net metering limit in Colorado is 120% of consumption, for the first time breaking from a capacity-based limitation. Figure B_1 shows the states with net metering standards and the allowed system capacity in kilowatts.

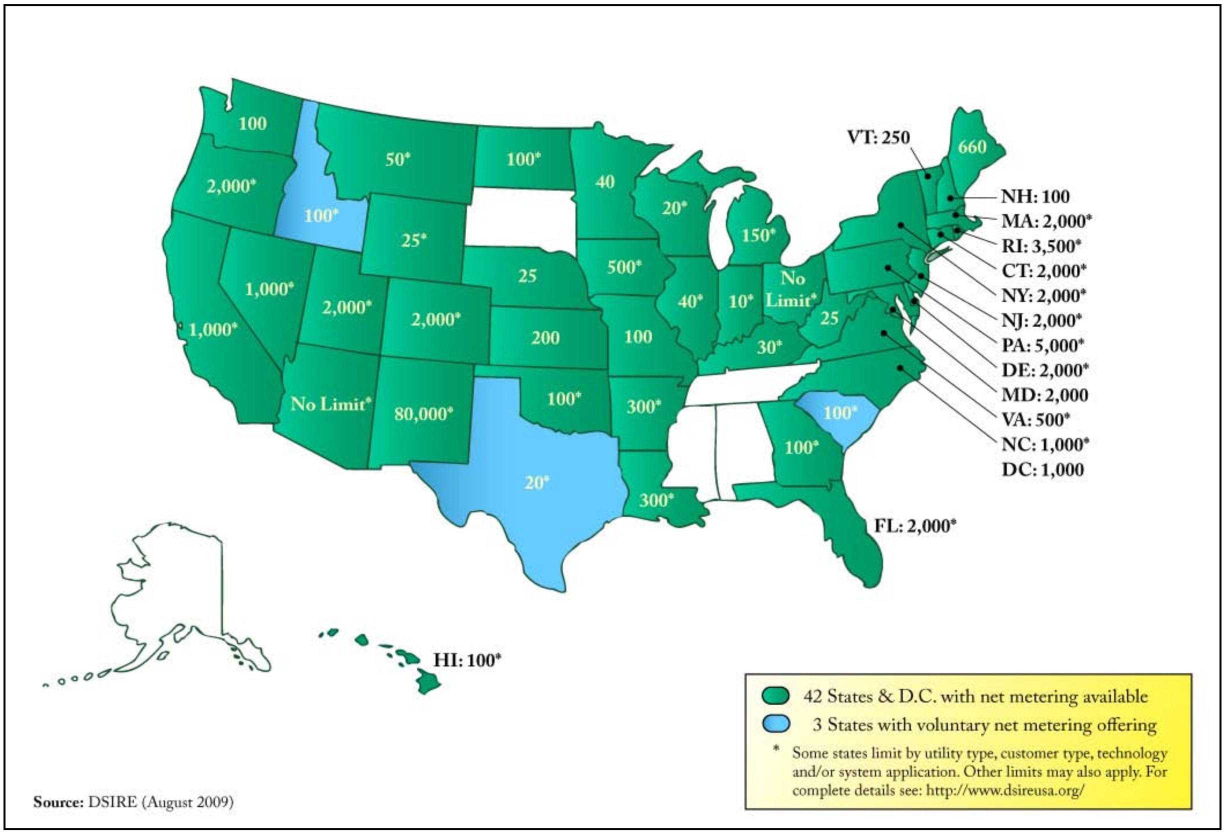

Figure B-1. Map of states with net metering standards (August 2009)

Although many states have net metering limits, they are generally unnecessary because financial mechanisms in most states discourage installation of systems larger than a customer's average load. For example, in many states, customer-generators are not paid for NEG held at the end of a 12-month period. This means that if a customer installs a system that produces more than their average load over the course of one year, they will not receive a financial benefit for overproduction (NNEC 2008).

[13] Connected load means the theoretical maximum a customer could load if all electrical devices were operating concurrently.

Other net metering provisions can discourage solar installations altogether. Because solar energy production varies significantly based on the time of day and the season, a system can produce more than the host site uses—particularly during the day and in sunny months—thereby creating a need for the NEG to rollover into the next month to average out over the course of a year. However, some state's net metering provisions do not allow rollover of NEG each month, thereby reducing the financial incentive to build a system sized to meet the customer's average load over the course of a year (rather than building a system to meet just peak demand). In some states, the customer is forced to pay an overlaying premium on a retail tariff for electricity purchased.[14] These charges can negate some or all of the financial benefit the customer would receive from the solar energy system even though the utility would benefit when the system's peak generation coincided with the utility's peak load.

Financial Incentives

With the proper net metering and interconnection standards in place, financial incentives from federal, state, and local governments, as well as utilities, can make solar power an economically attractive option.

Federal Investment Tax Credit

One of the most important incentives for solar PV is the federal investment tax credit (ITC). The ITC reduces federal income taxes for qualified tax-paying owners based on the capital investment of the solar project. The ITC is set at 30% of qualified expenses and was recently extended through December 31, 2016 (WRI 2008; H.R. 2008, Sec. 103). While the commercial ITC has never had a maximum amount, the 30% residential tax credit had a cap of $2,000 until October 2008 when Congress removed the cap as of January 2009. Additionally, a limited number of entities can take full advantage of the 30% credit. Because the entities must pay federal taxes, not-for-profit businesses, state and federal government agencies, and any other business that do not earn accounting profits are not eligible.[15] Finally, the October 2008 changes to the ITC now allow investor-owned utilities to use the tax credit starting in October 2008, which they were unable to do before.

Accelerated Depreciation

Another critical incentive for solar PV is the federal Modified Accelerated Cost-Recovery System (MACRS), which allows a business[16] to recover investments in property through accelerated asset depreciation, effectively reducing its tax liability. A business can depreciate solar equipment over a five-year period and thereby use this deduction over a time span that is less than the economic life of the equipment (20-30 years) (DSIRE 2008c).

Accelerated tax depreciation provides an incremental benefit equal to about 12% of system cost on a present value basis (assuming a 40% combined effective state and federal tax bracket and a

[14] This additional premium for net metering, which the state PUC must approve, goes to the utility because they must provide backup power when the customer generator's system does not perform.
[15] Accounting profits refer to the financial statements that companies submit to the IRS. These are different from the statements of cash transactions, which recognize revenue when the service is performed (not when the cash is obtained) and include non-cash expenses like depreciation. As a result, the business may earn a cash profit but have enough taxable expenses (such as depreciation) in a given year to offset taxable income, thereby eliminating profits on an accounting basis even though the business is cash positive.
[16] MACRS is only available to businesses, not residential customers.

10% nominal discount rate). Together then, the 30% ITC and accelerated depreciation provide a combined tax benefit equal to about 42% of the installed cost of a commercial PV system (Bolinger 2009).

Cash Incentives

In addition to federal incentives, a large number of cash incentives are available to solar projects through state, local, and utility-specific financing programs. These programs can be very creative with their incentives, which include grants, loans, income tax and property tax incentives, sales-tax exemptions, and more. The incentives are detailed in the Database of State Incentives for Renewables and Efficiency (DSIRE) maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC), which can be found at http:/www.dsireusa.org/. Some of these incentives are substantial enough to advance solar installations in their respective territories. Because state programs are the most widely available programs and tend to have the most funds available, a state-specific example is presented.

The California Solar Initiative (CSI) is a robust state incentive program. Adopted in January 2006 by the California Public Utilities Commission, the CSI is designed to provide more than $3 billion in incentives for solar energy projects with the objective of providing 3,000 megawatts (MW) of solar capacity by 2016. The program initially offers higher incentive levels, which are reduced over 10 years as utility-specific capacity targets are met.

Incentives are based on project size. When the program began in 2007, "buy downs" (rebates) for systems less than 50 kW were $2.50/W AC for residential and commercial systems, and $3.25/W AC for government entities and nonprofits. Incentives are adjusted based on expected performance of the specific PV system at a particular site. For a system greater than 50 kW, performance-based incentives are paid for the first five years starting at $0.39/kWh for taxable entities and $0.50/kWh for government entities and nonprofits. These incentives ramp down as state-level PV capacity is reached in each California utility's service territory.

On top of the generous state incentives, numerous utilities in the state offer grants, loans, and rebates to make solar PV even more financially attractive.

State Policies Encouraging Solar

State policies requiring renewable generation known as renewable portfolio standards (RPSs) play a major role in the development of new renewable energy generating assets. Most RPS policies mandate that utilities generate or purchase a certain percentage of electricity from new renewable energy sources on behalf of their customers. States looking specifically to encourage solar power can do so in a number of ways.

The most frequently implemented is a solar set-aside within the RPS (shown in Figure 3). The set-aside dictates the amount of power that must be generated from solar resources in particular. This solar-specific requirement fundamentally helps separate solar from less expensive forms of renewable generation, such as wind and landfill gas. Also, direct solar set-asides and set-asides for renewable DG are available and primarily fulfilled using customer-sited solar.

The "multiplier" is another mechanism to encourage specific types of generation. For each kWh of solar power generated, the utility gets bonus credit towards meeting the RPS requirement.

A number of states have tried multipliers, but they have not resulted in viable solar markets. In fact, many states that tried multipliers have switched to set-asides.

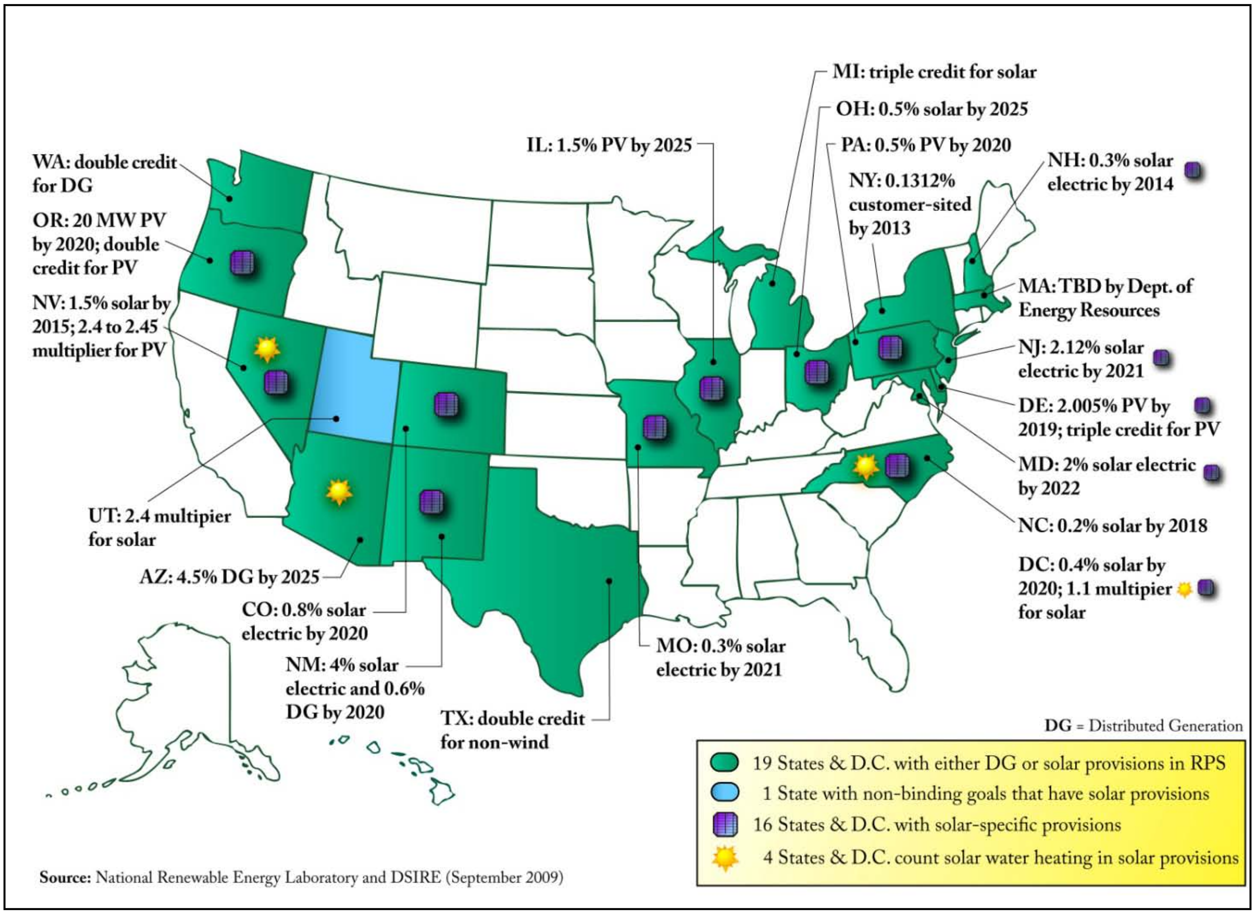

Figure C-1. Map of solar and DG provisions in RPS policies (August 2009)

Renewable energy certificates (RECs) have become the dominant mechanism for compliance with RPS policies.[17] RECs are tradable commodities separate from the electricity produced, meaning that the non-electricity "attributes" of renewable electricity generation are not bundled or sold with the electricity (although they can be if a contract provides for this). Definitions of "attributes" vary across contracts but typically include future carbon trading credits, emission reduction credits, and emission allowances (Cory, Coughlin, and Coggeshall 2008).

Solar RECs (SRECs) are generated exclusively by solar projects and have the potential to demand higher prices in markets with solar set-asides or tiers in their RPSs. Several states have instituted penalty prices on utilities or load serving entities (LSE) for not meeting their specified share of the RPS. The penalties are designed to be high enough to encourage utilities to obtain generation from renewable energy sources. The penalties come in the form of alternative compliance payments, explicit financial penalties (can be on a per MWh basis or fixed), and discretionary financial penalties (Wiser and Barbose 2008). The more concrete the penalty, the more it helps encourage utilities and developers to meet the RPS by letting them know what the

[17] RECs are not used for RPS compliance in Arizona, California, Hawaii, or Iowa (Wiser and Barbose 2008).

“alternative” payments will be if too few RECs or SRECs are generated or purchased. For example, New Jersey has a solar tier in its RPS and high penalties for non-compliance. Previously, New Jersey’s penalty price was set at $300/MWh (Corbin Solar 2007), and SRECs for compliance year 2008 (July 2007–August 2008) traded at a weighted average monthly price between $197 and $246/MWh (NJ Clean Energy 2009). When the RPS compliance year 2009 started in July 2008, the penalty price was set to $711/MWh (NJ Clean Energy 2007). As a result of the increase in penalty price, SREC prices traded at a weighted average monthly price between $308 and $513/MWh from July 2008 to June 2009 reaching a monthly high of $695/MWh (NJ Clean Energy 2009).

Best practice interconnection and net metering standards—which allow DG technologies to connect to the grid, bring about a fair price for generators, and reduce barriers to installation—can make solar PV expansion viable. Federal incentives have boosted solar energy systems in recent years, but state financial incentives and state policies encouraging solar truly drive the adoption of solar PV as indicated by significant penetration levels in California, Colorado, and New Jersey.

Appendix C: State Third-Party Language Summaries

Table C-1. Summary of State Third-Party Language

State	Are 3rd Party PPAs Allowed without Regulation?	Where is the Language?	What is the Language?	Status and Solutions
OR	Yes	PUC Decision: Order 08-388	Customer is not an Energy Services Supplier because they are not using the utility's distribution system (i.e., generation is less than load). Oregon Law exempts solar and wind from being "Public Utilities."	PUC made a Decision to allow the third-party PPA model.
NV	Yes	Legislation; Docket 07-06024	Third-party ownership of net-metered systems does not qualify as a utility, is legal, and is not under the jurisdiction of the Commission.	PUC found that the third-party PPA model should be allowed.
FL	No, except leases are okay	PUC Decision: Docket 860725-EU; Order 17009	Every legal entity supplying "electricity to or for the public" was determined by legal precedent that "to or for the public" could be just ONE customer	No current attempts to change
AZ	Yes, but must be regulated	State Constitution: Article 15 Section 2	Anyone who furnishes electricity shall be deemed a public service corporation.	Solar Alliance filed a Docket with the PUC to exempt third-party PPAs from regulation
CO	Yes	SB 51	Third-party owned systems are not subject to regulation so long as the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.	RES bill SB 51 passed with supporting PUC recommended decision 08-R-424E
TX – Munis	Unclear	Legislation: Texas Utilities Code Section 40.053	By allowing someone else to sell to muni customers, the muni could be opening themselves up to competition	Munis are exploring alternative solutions (e.g. solar leasing and utility as the intermediary)
CA	Yes	Legislation: California Public Utilities Code 218	Utility Code states that if the system generates non-conventional energy and if you serve two or fewer customers on that property, you are not considered an LSE or ESP	Legislation was used to make third-party PPAs allowable
NJ	Yes	BPU Docket EX08070548	Customer generators may “use” a “customer-generator facility” and are thus not required to own the facility.	No current attempts to change

Appendix D: Clean Renewable Energy Bonds

One major reason to consider the third-party PPA model is that it helps get projects financed economically without large up-front payments from the end-user. For munis and co-ops, customer-sited projects can be financed in another way as long as the projects are not too large to qualify.

Munis and co-ops may apply to the Internal Revenue Service (IRS) for clean renewable energy bonds (CREBs) to help finance renewable projects, which have traditionally been smaller projects. CREBs, an alternative to tax-exempt bonds, are a financing instrument with a structure similar to a tax-exempt bond except that the federal government provides the investor with a tax credit in lieu of an interest payment (Cory, Coughlin, and Coggeshall 2008). A recent allocation and authorization of $800 million in CREBs funding (H.R. 2008) makes this option again available to state and local governments, co-ops, and munis, each of which receives one third of the allocation.[18] While this structure has some challenges (Cory, Coughlin, and Coggeshall 2008), Congress updated the CREBs structure in October 2008 in an attempt to address a number of the drawbacks. More information about these updates is explained in the IRS guidance, which can be found at http://www.irs.gov/taxexemptbond/article/0,,id=206034,00.html.

[18] Munis and co-ops are eligible for CREBs, but approved systems are likely to be small based on how the IRS has traditionally allocated CREBs (from smallest to largest). New CREBs allow municipal utilities to get a pro rata share of $800M, which means that even large projects can take advantage of CREBs.

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14. ABSTRACT *(Maximum 200 Words)*
Residential and commercial end users of electricity who want to generate electricity using on-site solar photovoltaic (PV) systems face challenging initial and O&M costs. The third-party ownership power purchase agreement (PPA) finance model addresses these and other challenges. It allows developers to build and own PV systems on customers' properties and sell power back to customers. However, third-party electricity sales commonly face five regulatory challenges. The first three challenges involve legislative or regulatory definitions of electric utilities, power generation equipment, and providers of electric services. These definitions may compel third-party owners of solar PV systems to comply with regulations that may be cost prohibitive. Third-party owners face an additional challenge if they may not net meter, a practice that provides significant financial incentive to owning solar PV systems. Finally, municipalities and cooperatives worry about the regulatory implications of allowing an entity to sell electricity within their service territories. This paper summarizes these challenges, when they occur, and how they have been addressed in five states. This paper also presents alternative to the third-party ownership PPA finance model, including solar leases, contractual intermediaries, standardized contract language, federal investment tax credits, clean renewable energy bonds, and waived monopoly powers.

15. SUBJECT TERMS
solar PV systems; on-site; photovoltaic (PV); PV generation; PV-generating systems; site hosts; end users; solar developers; residential; commercial; electricity; electric utility; public utility; public utility commission; PUC definitions; PUC regulations; retail electricity markets; deregulation; power purchase agreements; PPA; third-party owners; third-party ownership; finance models; initial costs; O&M costs; legal definitions; regulatory definitions; legal problems;

regulatory problems; regulated electricity providers; electric services providers; competitive electricity suppliers; power generation equipment; sellers of electricity; Colorado; Florida; New Mexico; Nevada; New Jersey; Oregon; Texas; net meter; net metering; contracts, contract language; financial incentives

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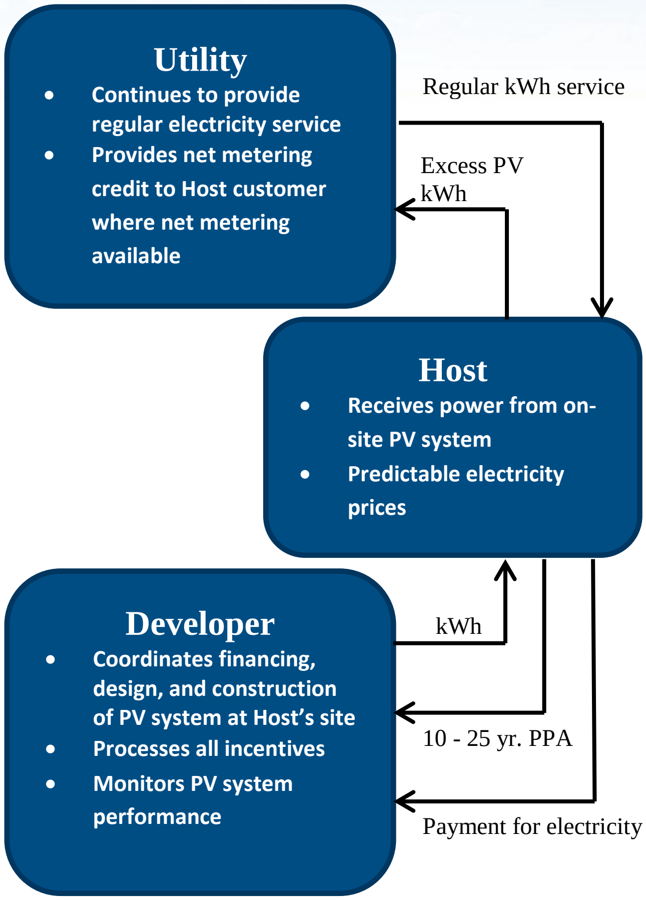
Solar Power Purchase Agreements (PPAs)

What is a solar power purchase agreement?

A solar power purchase agreement (PPA) is a financial agreement where a developer arranges for the design, permitting, financing and installation of a solar energy system on a customer's property at little to no cost. The developer sells the power generated to the host customer at a fixed rate that is typically lower than the local utility's retail rate. This lower electricity price serves to offset the customer's purchase of electricity from the grid while the developer receives the income from these sales of electricity as well as any tax credits and other incentives generated from the system. PPAs typically range from 10 to 25 years and the developer remains responsible for the operation and maintenance of the system for the duration of the agreement. At the end of the PPA contract term, a customer may be able to extend the PPA, have the developer remove the system or choose to buy the solar energy system from the developer.



Benefits of PPAs to Solar Customers

- No or low upfront capital costs: The developer handles the upfront costs of sizing, procuring and installing the solar PV system. Without any upfront investment, the host customer is able to adopt solar and begin saving money as soon as the system becomes operational.
- Reduced energy costs: Solar PPAs provide a fixed, predictable cost of electricity for the duration of the agreement and are structured in one of two ways. Under the fixed escalator plan, the price the customer pays rises at a predetermined rate, typically between 2% - 5%. This is often lower than projected utility price increases. The fixed price plan, on the other hand, maintains a constant price throughout the term of the PPA saving the customer more as utility prices rise over time.
- Limited risk: The developer is responsible for system performance and operating risk.
- Better leverage of available tax credits: Developers are typically better positioned to utilize available tax credits to reduce system costs. For example, municipal hosts and other public entities with no taxable income would not otherwise be able to take advantage of the Section 48 Investment Tax Credit.
- Potential increase in property value: A solar PV system has been shown to increase residential property values.[i] The long term nature of these agreements allows PPAs to be transferred with the property and thus provides customers a means to invest in their home at little or no cost.

Market Adoption and Policy

PPAs provide a means to avoid the upfront capital costs of installing a solar PV system as well as simplifying the process for the host customer. In some states, however, the PPA model faces regulatory and legislative challenges that would regulate developers as electric utilities. A solar lease is another form of third-party financing that is very similar to a PPA, but does not involve the sale of electric power. Instead, customers lease the system as they would an automobile. In both cases, the system is owned by a third party while the host customer receives the benefits of solar with little or no up-front costs. These third-party financing models have quickly become the most popular method for customers to realize the benefits of solar energy. Colorado, for example, first entered the market in 2010 and by mid-2011 third-party installations represented over 60% of all residential installations and continued to rise to 75% through the first half of 2012.[ii] This upward trend is evident throughout states that have introduced third-party financing models.

PPA Considerations

- SRECs: Solar renewable energy credits (SRECs) show that a certain amount of electricity was produced using solar energy. They are typically bought and sold by load serving entities (typically regulated utilities) to meet obligations associated with state-level renewable energy standards. SRECs are also used by consumers who voluntarily purchase them for marketing claims or other use. Most often in PPAs , SRECs are owned by the developer. When entering into a PPA, it will be important for a customer to clearly understand who owns and can sell the SRECs generated from the PV system, the risks attendant to SREC ownership, and the tradeoffs with respect to PPA price.

- How to finance: While both third-party financing models provide numerous benefits, purchasing a PV system outright has its own benefits. Anyone considering installing a solar PV system should consider each of the financing options available to find the best fit.

- Site upgrades: While the developer is responsible for installation, operation and maintenance of a solar PV system, the host customer may need to make investments in their property in order to support the installation of the system, lower the cost of installation or to comply with local ordinances. This might include, for example, rooftop repairs or trimming trees that shade the PV system.

- Possible higher property taxes: While a PV system may help to raise the site's property value, there is also a potential increase in property taxes when the property value is reassessed. Different states, however, have different policies in regards to these possible property tax increases.

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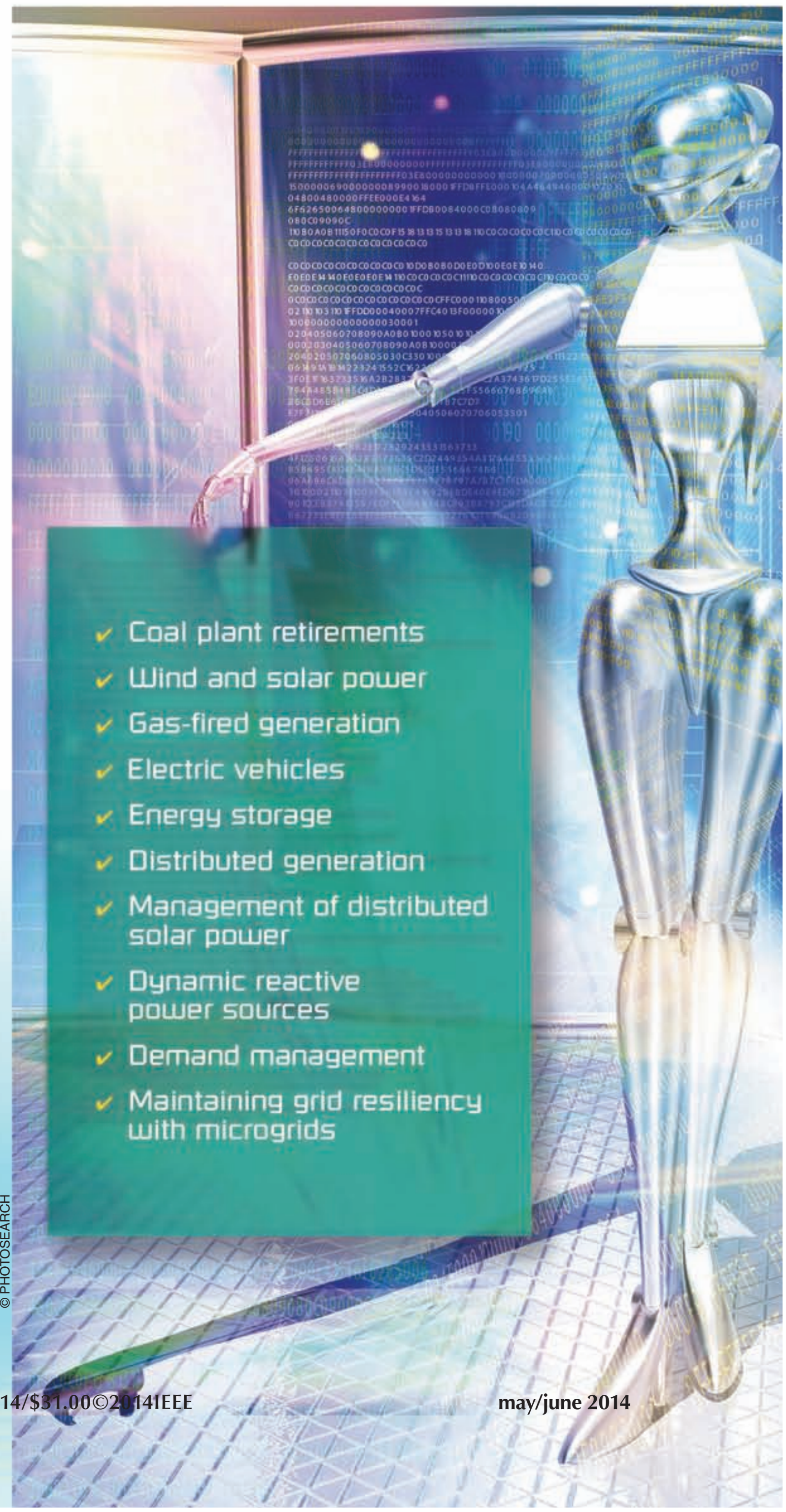
[i] Berkeley National Laboratory report (2011) - http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-4476e.pdf

[ii] Solar Market Insight Q2 2012 – Executive Summary. https://www.slideshare.net/SEIA/us-solar-market-insight-report-q2-2012

The Grid of the Future

By Devon Manz, Reigh Walling, Nick Miller, Beth LaRose, Rob D'Aquila, and Bahman Daryanian

FOR OVER A CENTURY, THE MISSION of the power industry has been to build and operate a reliable, affordable, and efficient grid. In the past few decades, developed regions have focused on increasing operational efficiency, while emerging economies have focused on attracting capital to grow their grids. Changing markets, new technologies, and an emerging societal focus on emissions have moved the industry in a new direction. The emergence of modern power electronics, widespread software development, and low-cost communications technologies creates opportunities. The cost-effective extraction of oil and gas in North America is expected to shift our generation mix away from coal and toward natural gas-fired generation. Wind and solar power have proliferated, creating new challenges and opportunities. Advancements in energy storage technologies have revolutionalized the consumer electronics industry and paved the way for hybrid and electric vehicles (EVs). In parallel, the resiliency of the aging electric power infrastructure has been questioned in light of the increased frequency and severity of natural disasters, making a



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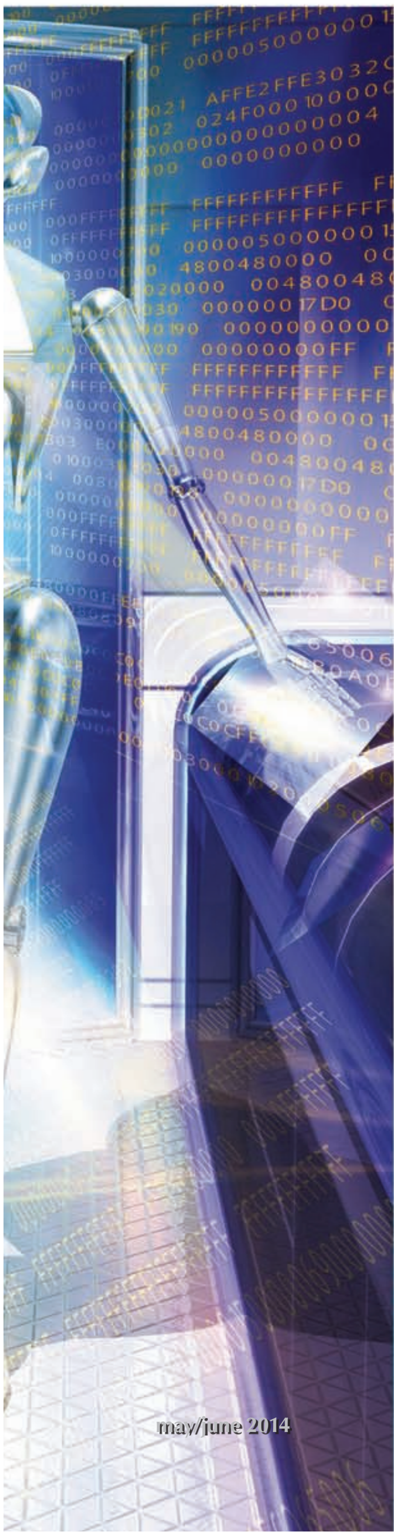
Ten Trends That Will Shape the Grid Over the Next Decade



stronger case for a major investment to build a stronger, more resilient, and sustainable U.S. grid.

Ten Key Trends

Today's electric power industry also manages the interplay of many moving parts and stakeholders. Local, state, and federal policies, the emergence of power marketplaces, and competition drive a fundamental shift away from traditional planning and design disciplines. New evaluation methodologies and analytical tools are being developed to address these emerging needs. This article focuses on presenting the authors' views on ten key trends and their potential impact on shaping the grid of the future.

- ✔ *Coal plant retirements:* Pending regulations and potential greenhouse gas (GHG) policies could lead to a significant retirement of coal-fired generation in the United States. How will the U.S. grid cope with a significant loss of base-load power generation?
- ✔ *Wind and solar power:* Industry's confidence in reliably accommodating nondispatchable resources is increasing while technical advances reduce the cost of wind and solar power. Will we continue to see growth in wind and solar resources?
- ✔ *Gas-fired generation:* Flexible gas-fired generation offers rapid ramping, turn down, and short start times, ideally suited to accommodate more wind and solar generation additions and cope with the retirement of less flexible, aging base-load generation. How will market forces reward the flexibility that will reduce system-wide costs and emissions?
- ✔ *Electric vehicles:* Electric vehicles are increasingly entering the transportation sector. Significant infrastructure investments and policy support will be needed in the near term to accelerate EV adoption. How important is "smart vehicle charging" and economic incentives in this transformation?
- ✔ *Energy storage:* Energy storage faces a cost challenge relative to alternate solutions to the challenges that face the grid. Storage can be an alternative for frequency regulation or short-term reserves. What hurdles must be overcome to see more widespread storage projects? Can storage technologies play a major role in a resilient grid?
- ✔ *Distributed generation:* Distributed generation (DG) growth is being driven by policy [e.g., subsidies and incentives for rooftop solar photovoltaics (PVs)], but DG can provide efficient energy when both electricity and heat are needed in combined heat and power (CHP) applications. Are we going to see DG and microgrids displacing the need for a conventional grid?
- ✔ *Management of distributed solar power:* Rapid growth in distributed solar PVs could challenge the ability of the grid to manage voltage and loading in the distribution system and will create opportunities for new distribution management and voltage control solutions. How will integration challenges impact growth in PVs, and what types of solutions will emerge?
- ✔ *Dynamic reactive power sources:* The retirement of power plants situated near loads, the growth of asynchronous wind and solar power generators, and changing loads on the grid will challenge the grid's reactive power reserves and ability

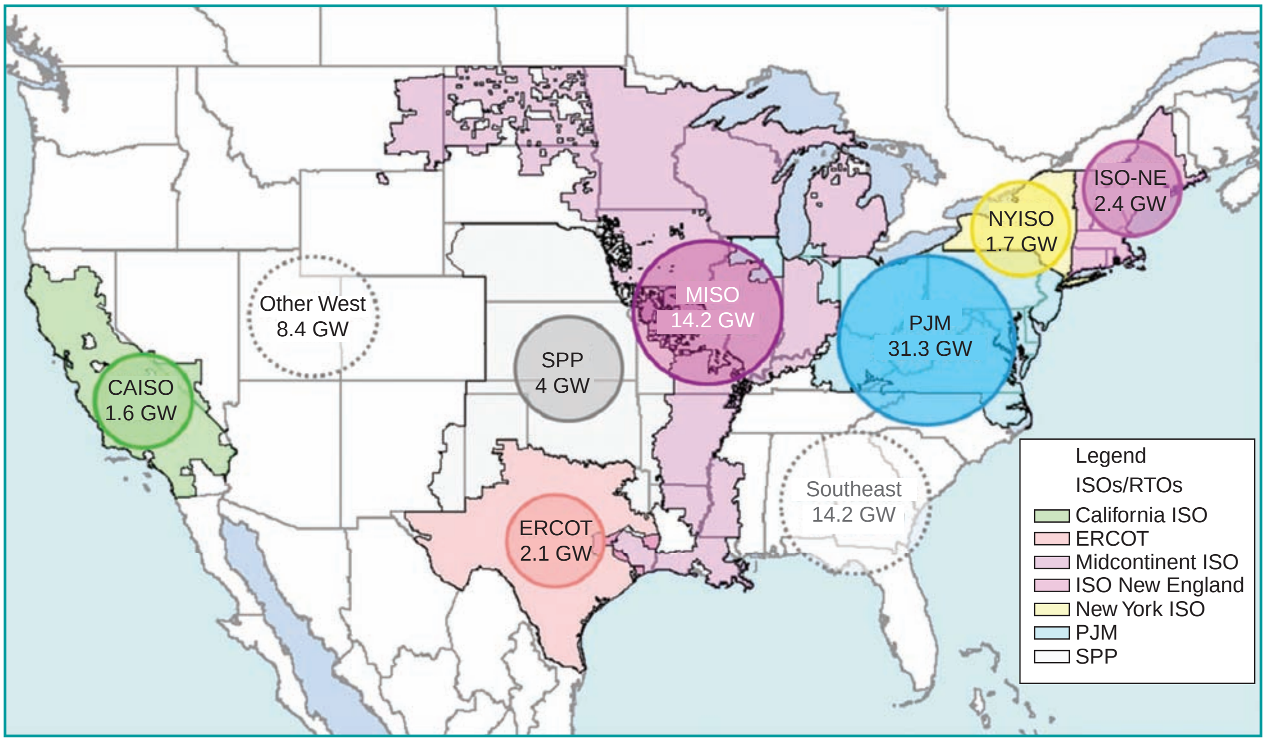


figure 1. Potential coal retirements (map created with Ventyx, an ABB Company, Energy Velocity Suite, Intelligent Map).

to maintain voltage stability. How will the grid maintain steady state and dynamic voltage support?

- ✔ *Demand management:* Generation resources were historically built to provide low-cost electricity and ancillary services and capacity to meet reliability at peak load. Today, demand management can provide these same services. What is the right mix and types of programs and incentives that can maximize the benefits of demand management?
- ✔ *Maintaining grid resiliency with microgrids:* Natural disasters, such as Hurricane Sandy, have registered strongly in the minds of policy makers and have motivated towns, cities, and electric utilities to provide greater operational resiliency for a wide range of critical infrastructure and services. What is the role of small microgrids in providing resiliency to the grid?

While there may be other trends driving the evolution of the grid, the authors expect these ten trends to be at the heart of the discussion in the coming years. The remainder of this article is devoted to more in-depth discussions of each trend.

Coal Plant Retirements

Coal plant owners face an important decision: Should they invest to comply with the proposed environmental regulations or retire their plants? The Environmental Protection Agency (EPA) has proposed a set of rules/standards to reduce air and water pollution: the Cross-State Air Pollution Rule (CSAPR), Clean Water Act Section 316(b), and regulations around hazardous air pollutants such as mercury and air toxics standards, GHGs, and coal combustion residual disposal. In August 2012, CSAPR was vacated by the U.S. Court of Appeals and has reverted back to previous requirements, the Clean Air Interstate Rule, until a valid version of CSAPR can be proposed and implemented. To continue operating, EPA regulations will require coal plant owners to retrofit their plants with environmental control technology or retire the affected coal units altogether.

Based on the authors' estimates, 17 GW of coal capacity was retired from 2010 through September 2013, and about 69 GW more is likely to retire or mothball through 2021 for a total of ~86 GW of coal retirements. The majority of the remaining coal capacity is likely to be retrofitted with technology, such as flue gas desulfurization and baghouses, for a projected cost of approximately US$90 billion expended in 2013 and beyond. Figure 1 shows the projected coal retirement capacity by NERC subregion.

To maintain reliability levels, it is estimated that about 40–50 GW of new capacity will be needed in the United States by 2020 to replace retirements, meet load growth, and maintain reliability. The price of natural gas, the cost of compliance, and the cost of gas-fired generation will affect the rate and amount of coal generation retired. With near-term gas prices around US$4/mmBtu, a high retirement scenario is being born out as reflected in the current estimates of 86-GW total retirements.

The evolution of future EPA regulations is not known, but as it stands, the power industry has opened the door for new generation capacity. Historically, drivers for new generation have hinged on economic growth and the associated load growth that follows. Today, the impact of policy and regulations for environmental sustainability and energy security are also drivers for growth. Historically low natural gas prices and the potential retirement of significant coal-fired generation suggest there could be a resurgence of development in new gas-fired generation over the coming decades.

Wind and Solar Generation

The United States has installed more than 50 GW of wind power, with the vast majority in under a decade. This growth, enabled by cost reductions, improvements in availability and reliability, and strong policy support, continues in the near term. Years in which the coveted wind energy production tax credit was available saw rapid growth in wind power, while years in which the tax credit did not exist saw a significant

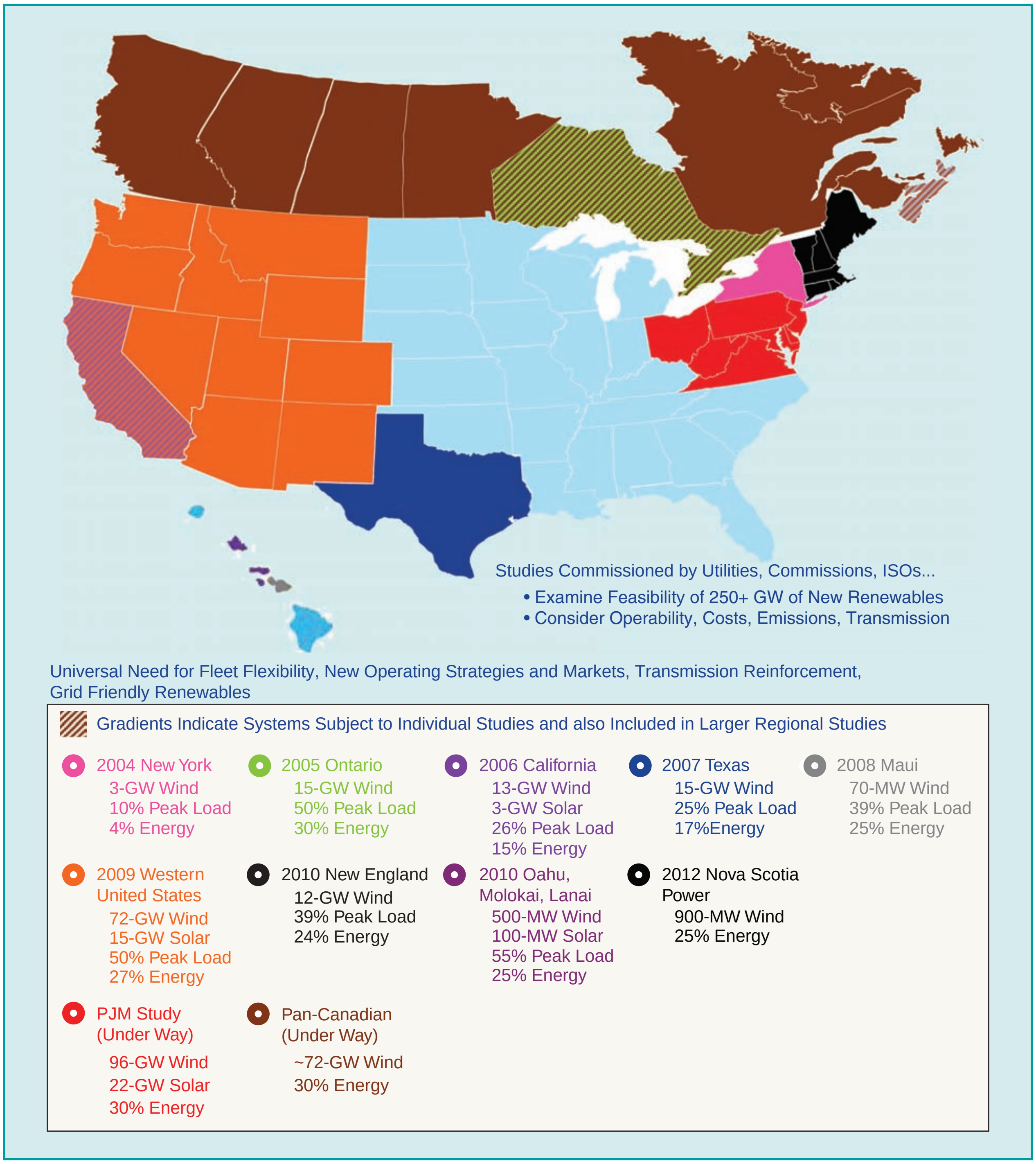
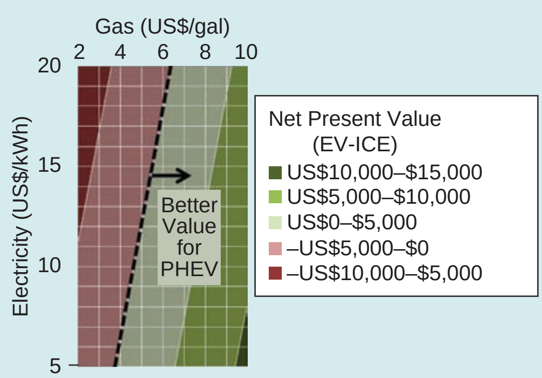


figure 2. Recent GE wind and solar integration studies.

Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

drop in new wind projects. While many states have renewable portfolio standards, it is not clear if the targets will suffice for continued wind power growth.

Like wind power, the value proposition for solar also relies on policy support in the form of feed-in tariffs in some European countries, an investment tax credit in the United States, and various state-by-state policies ranging from tax credits and renewable energy certificates to net metering policies to renewable portfolio standards. Each of these policies strengthens the value proposition for solar power. It is expected that strong policy support will continue to drive new wind and solar power in the United States. And as solar PV technology rapidly rides down the cost curve, solar power will continue to become more economical. Solar PVs have seen explosive growth in the United States over the past year or two, with PV capacity installations exceeding wind in 2012. In some parts of the United States, solar PVs are on a trajectory to become a significant resource in the generation mix. Wind and solar power continue to grow, even as load growth has slowed. Slow load growth in North America and Europe, and lower natural gas prices in North America, are challenging the economics of wind and solar power. Also, the subsidy to retail PVs provided by net metering policies is under increasing challenge as it inherently involves the transfer of costs to non-PV customers. In the near term, policy support is needed to maintain growth for both wind and solar power.



	PHEV	Hybrid ICE
Vehicle Cost	US$35,000	US$30,000
Fuel Economy	35 kWh/100 mi	51 mi/gal

10,000 mi/Year, 2% Interest Rate (Car Loan)

figure 3. Break-even economics for a hybrid ICE and a PHEV. The maintenance costs for each vehicle were assumed to be equal. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium).

Gas-Fired Generation

As both wind and solar resources increasingly constitute a significant portion of the generation mix, questions have been raised about the capabilities of the grid to manage the variability and uncertainty of wind and solar power. Numerous wind integration studies have been completed over the past decade, led by groups like the National Renewable Energy Laboratory, various utilities, state commissions, independent system operators, and regional transmission organizations, with each examining the performance and economic impact of integrating high levels of wind power in different regions of the world. A summary of the wind and solar integration studies that GE has led or contributed to is shown in Figure 2. These studies suggest that integrating enough wind power to generate more than 30% renewables by energy is possible, provided the system has adequate generation flexibility, transmission capacity, control area cooperation, and grid requirements for wind plants, to name a few. However, the capacity value of wind power remains relatively low, depending on the geographic diversity of the wind power plants, the size of the control area, and the strength and nature of the wind resources. The uncertainty and variability associated with wind and solar power demands flexibility from the rest of the generating fleet. Flexible generation will be needed as wind and solar plants are built out. Faster starting times, the capability to back plants down further, and higher unit ramping capabiliies are emerging as key needs to support the build out of significant levels of wind and solar power.

As the economics for recovering unconventional natural gas improve, North American natural gas prices are expected to remain relatively low. The relatively low gas prices and the potential retirement of significant levels of coal-fired generation over the next decade will further promote the build out of new natural gas-fired generation. Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

Electric Vehicles

EVs and plug-in hybrid EVs (PHEVs) are slowly emerging as alternatives to conventional gasoline-fueled vehicles but will

Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

continue to need strong incentives and a relatively high cost of gasoline to be viable. A key driver for these vehicles in the United States is the desire to reduce U.S. dependence on oil and reduce tailpipe emissions. Today there is strong policy support with a U.S. tax credit of up to US$7,500 for new EVs and PHEVs, which substantially covers the cost of the battery system, estimated today to cost as much as US$10,000 per vehicle, depending on the vehicles' range.

At today's gasoline and electricity prices, it will be some time before EVs are truly a cost-competitive alternative to conventional gas-fueled vehicles without policy support. If the cost of batteries is substantially reduced and a new car buyer, who drives 10,000 mi per year, is faced with a decision to buy a US$35,000 PHEV or a US$30,000 gas-fueled vehicle, the driver should still opt for a gas-fueled vehicle if economics are the determining criterion for the buyer. Today, a Toyota Prius achieves 51 mi/gal. A PHEV driving in all-electric mode is the favored alternative to a Prius only when gasoline prices exceed US$6/gal, assuming that the PHEV is charged with US$.18 per kWh electricity. Even if the price of electricity were US$.07 per kWh, the price of gasoline would still need to exceed US$4/gallon for the economic value of the PHEV to exceed that of the Prius. This is shown in Figure 3. At today's fuel prices, lower battery costs and stronger incentives are needed for these vehicles to make substantial inroads into the transportation sector. Even if the cost of the battery falls by 50%, incentives will still be needed to enable widespread growth of EVs and PHEVs. It took more than ten years for hybrid vehicles to constitute 2.5% of the U.S. vehicle market. It may take many years for EVs to reach a significant portion of the vehicle fleet.

If EVs are able to gain a substantial share of the automotive market, they will drive substantial load growth. A recent GE study showed that, for one region, transitioning 10% of the light-duty vehicle fleet to EVs would increase the load energy by ~5%. The implementation of a charging infrastructure for EVs and PHEVs offers a substantial new business opportunity. For the system studied, "smart" vehicle charging costs 19% less than serving uniform load growth, while completely uncontrolled charging costs 24% more (see Figure 4). These savings could be used to invest in the technologies needed to enable smart charging, provide customer incentives that promote controlled charging, and provide savings to customers. For the system examined, the difference in energy production cost between uncontrolled and smart charging equated to ~US$300/year per PHEV owner. In addition to the energy production cost savings, there are savings due to avoided power generation and delivery infrastructure otherwise needed to support increased peak demand driven by uncontrolled charging.

Uncontrolled EV charging can result in a substantial increase of peak load and a deterioration of system load factor. The peak-load increase could drive a substantial, and uneconomical, increase in generation, transmission, and distribution capacity to support this peak. Of these, the generation capacity costs to meet increased peak are typically dominant. If EV charging is appropriately controlled, the required energy can be supplied without an increase in peak system demand, and thus the high costs of incremental generation capacity to support EV charging can be avoided or deferred. Controlled EV charging could prove to be a significant beneficial asset for managing light load system operational challenges. However, even with the control of system peak demand, there may be the impact of EV charging on

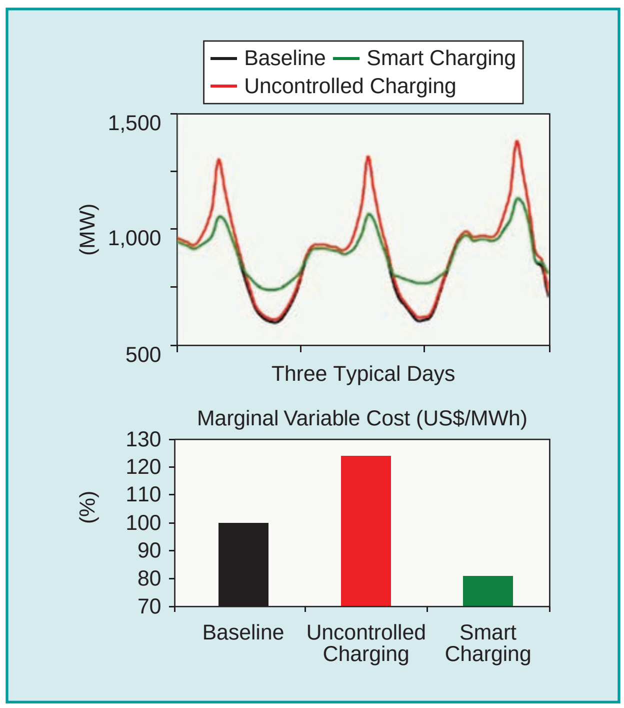


figure 4. Marginal variable cost of serving the EV load for two EV charging strategies, with respect to the marginal cost of serving uniform load growth. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium.)

figure 5. GE/GNB and Metlatkla Power and Light battery energy storage system in Alaska. (Reprinted with permission from George Hunt, GNB/Exide.)

transmission and distribution assets due to localized EV concentration or loading factors not directly related to just peak demand, such as limiting transformer cool-down during off-peak periods. Replacing overloaded transformers, reconfiguring heavily loaded distribution circuits, and building new substations may be needed in areas that experience sudden increases in EV charging loads. These system modifications and equipment additions/upgrades are expected to be manageable and reasonably small relative to the cost of the EVs and the charging infrastructure if charging patterns are managed. Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

Energy Storage

The grid is the ultimate "just-in-time" system, instantaneously serving customer load with generation that is precisely dispatched and controlled to match the load. Energy storage presents the capability to relax this constraint. Historically, the power system has been designed and controlled to manage variability in load by increasing or decreasing the output of generation. Wind and solar power exacerbate the variable power needed from the rest of the generation. However, sudies by the authors suggest that the variability of wind and solar power, when more than 30% of the annual energy is generated by these resources, can be managed by the grid. Generally, the significant wind and solar variability smoothing effect observed over large areas (similar to that of the load smoothing effect of a neighborhood relative to that of a single home) does not necessitate the *need* for energy storage. However, the grid is demanding more flexibility. This is manifesting in a greater need for frequency regulation and reserves. Wind turbine manufacturers have responded to this trend and advanced wind turbine technology to better manage variations in wind power output. For example, GE is currently offering a hybrid wind turbine with integrated battery energy storage that can competitively self-supply incremental ancillary services, given suitable power market structures.

While storage has not yet found widespread use in the grid, a long list of potential applications for storage has been cited. Applications that require substantial energy ratings range from capturing lower cost energy to displace higher cost energy at a later time, price arbitrage, or shifting energy from one time to another to avoid overloading equipment. In general, these applications do not currently offer strong value propositions as the cost of energy-storage technologies is high relative to energy prices and conventional approaches for managing overloaded equipment. It is the applications that demand the sudden injection or removal of energy of short durations that seem to offer the greatest value. Niche applications already exist, and more are emerging. Isolated systems with very high electricity costs also tend to have relatively high regulation and reserve requirements. Meeting some of these ancillary service requirements with energy storage rather than high-cost fossil fuel generation has the potential to be highly economical. For utilities operating in regions of the United States where there are no organized power markets, the evaluation of energy storage versus other sources of operational flexibility needs to be done on a cost-avoidance basis, rather than from ancillary service market revenues. For example, in the 1990s, GE worked with GNB/Exide Technologies to build a battery storage system in Metlakatla, Alaska, to reduce the use of expensive diesel-fired generation. The system is shown in Figure 5. The roughly US$2 million battery system reduced the diesel fuel bill by more than US$6 million over its 12 years of operation.

Even in large grids, storage can be an alternative provider of regulation. The application of storage in this case is not driven by necessity but must be economically competitive with generation flexibility. Power market prices for frequency regulation vary daily and seasonally. During periods of scarcity, prices can be high. The cost of storage for frequency regulation is approaching the average current prices for regulation in some energy markets. It remains to be seen if energy storage, without subsidies, can be truly competitive in the regulation application.

More applications are also being observed. Urban centers experiencing line or transformer overloads, with no room available for new equipment, may benefit from storage located closer to the loads to avoid expanding the substation or reconfiguring the lines. In September 2013, the California Public Utilities Commission issued a proposed Decision Adopting Energy Storage Procurement Framework and Design Program to address the policies and mechanisms for the procurement of electric energy storage pursuant to California Assembly Bill (AB) 2514. One of the objectives is to employ storage technology to help maximize existing generation and transmission investment and operation, integrate renewables, and minimize GHG emissions. The framework sets forth the storage targets for the investor-owned utilities and the procurement requirements for other load-serving entities in California, the procurement mechanisms, and the program evaluation criteria.

Ultimately, storage is another resource that can provide the grid with flexibility. As the grid evolves, flexibility requirements are likely to increase, and traditional sources of flexibility may be displaced. As the cost of storage decreases and more applications emerge, storage will contend with strong competitors in the form of demand response (DR), flexible fossil fuel-based generation, and other emerging technologies. While there are no challenges in the operation or performance of the grid for which storage is the only solution, applications where storage is the best technical and most cost-effective alternative do exist.

Distributed Generation

Electric power infrastructure originated over a century ago when isolated small generators supplied nearby loads. As the infrastructure rapidly evolved, the benefits of a system based on centralized generation emerged. Central generation within interconnected systems produced benefits of scale, diversification of loads, improved energy resource flexibility, and increased reliability. These outweighed the costs of the transmission and distribution infrastructure needed to connect the central generation with distributed loads and set a trend that evolved toward a large interconnected grid. More recently, regulatory changes, technical advancements, and environmental impacts have led to a significant increase in DG applications.

The definition of DG is somewhat ambiguous. There is presently no uniformly accepted industry definition, and definitions can vary from nondispatchable solar PVs located on the customer side of the meter to cogeneration facilities at large industrial sites with ratings of 100 MW or more. The drivers behind most customer-owned DG applications can be tied to one or more of the following:

- ✔ Utilize a locally available energy source that cannot be easily transported, such as biogas or sun.
- ✔ Increase efficiency by generating electricity and using exhaust for heating (CHP).
- ✔ Provide lower-cost electricity than that of the local utility. This may involve peak shaving for commercial facilities billed for demand charges.
- ✔ Take advantage of policy-driven economic incentives such as feed-in tariffs, net-metering rules, and rebates specific to DG.
- ✔ Increased reliability to a facility where the DG is located.
- ✔ Fulfill social and sustainability goals, including the desire to be independent from the utility, create microgrids for resiliency and security, and other similar values that cannot be measured purely in a pro-forma analysis.

Independent power producers and utilities may choose to connect at the distribution level when the scale of their development is small or when policy provides specific incentives for distribution interconnection. In general, generation built close to load, in locations that alleviate transmission congestion, will generate greater revenue in the wholesale market. Some utilities have also implemented strategies where DG is used to alleviate localized overloads of existing distribution substation capacity, where the cost of the next substation capacity step is excessive relative to the size of the overload.

The value of DG in offsetting transmission and distribution capacity requirements, however, is much less, and more indirect, than commonly perceived. To provide an effective substitute for transmission and distribution assets, DG output must be available at the time of system peak. This usually requires that the DG be dispatchable and contractually obligated to provide support when needed. Also, because individual generation equipment has a lower reliability and availability than the utility service we receive at our homes, DG redundancy needs to be considered. Where only a few DG units are involved, the costs to provide reliable capacity could be sizeable.

While wind generation and hydro power are presently the largest renewable energy sources in the grid, solar PVs represent the most rapidly growing DG segment. In general, the unsubsidized cost of PV is high relative to alternate forms of generation. When PVs are connected "behind the meter" on the roofs of customers, the electricity produced will displace the electricity typically provided by the utility. Where net metering tariffs are in place, the effective value to the owner of the generated energy is equal to the retail energy rate. Today, many utilities recover their fixed service costs through retail rates based entirely on the energy provided to the customer. Since the grid service will still be needed on the cloudy days when PVs are unable to entirely displace the utility electricity supply, much of the fixed service costs remain unchanged. Thus, utilities may need to consider alternative tariff structures to adequately recover these fixed costs without placing undue burden on the customers who are not self-generating. These alternatives could include demand charges, similar to those experienced by industrial customers, or larger fixed service charges. Either will tend to decrease the energy-based electricity rates. While PVs are approaching grid parity relative to conventional volumetric (kWh-based) retail electricity rates in some regions of the country, pricing mechanisms may change to ensure that the true cost of electric service is properly reflected in its price.

The aforementioned drivers for DG will continue to increase their presence in the grid of the future. The dominant driver for DG in North America will be policy, particularly those that promote renewable generation and grid resiliency. Distributed solar PVs and CHP will likely be the most pervasive form of DG. While growth in DG will continue, there is a long-term cost savings driver toward a grid comprised of centralized generation.

Managing Distributed Solar PV

Solar PVs have historically been applied as a small-scale distributed resource. However, in recent years, there has been explosive growth in large utility-scale PV power plants, with some facilities currently planned to exceed several hundred megawatts of capacity. Unlike wind, solar PVs do not suffer a large cost penalty when scaled to a small size. Thus, PV installations in the future are expected to be well divided

Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PV, are evolving.

between small distributed applications and large utility-scale plants.

The integration of large-scale PV plants in the transmission system can follow the successful model already established by wind integration, with the consequential impact of variability treated in the same manner. At the distribution level, locally high penetrations of connected PV capacity can be very disruptive to operations. Power variability due to intermittent cloud shading of PVs, in itself, is not of concern at the distribution level because energy balance is achieved on a much wider basis at the transmission level. However, the consequential impact of power variability is voltage variation that can cause premature failure of utility voltage-regulating equipment and power quality degradation for all customers served by the distribution system.

While energy storage is often discussed as a mitigating approach, voltage variations can, in most cases, be much more economically addressed using reactive power. Dynamic reactive devices, such as static synchronous compensators (STATCOM) and static var compensators (SVCs) can be applied to mitigate voltage variations at the feeder level and cover the temporal range of PV variability that cannot be mitigated by mechanically switched voltage regulators. IEEE Standard 1547 has until recently prevented PVs from participating in providing mitigation of these problems. Recent modifications to the standard have opened the door for advanced inverters to use their reactive power capability to help mitigate voltage variations caused by PVs. Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PVs, are evolving and are expected to help manage this emerging challenge that faces the grid.

Dynamic Reactive Power Sources

The growth in wind and solar power and DG and the retirement of coal plants and other large aging central-station generation plants will have an unintended consequence on the performance of the transmission system. Today, many of the oldest thermal units are located near large urban load centers. These units, which may be retired or displaced in the near future, often provide essential voltage support and needed short-circuit strength. This dynamic support is critical to maintain a strong and stiff voltage for the stability of the grid during and after disturbances such as the loss of a major transmission line. Unlike active power (watts), the need for and the provision of reactive power (vars) is highly locational. Since utility-scale wind and solar plants tend to be built far from load centers, the reactive power produced on a remote windy plain or out in the sunny desert is of little value to maintaining voltage in urban load centers.

Historically, nearly all electricity transmitted through the grid was delivered via synchronous generators equipped with excitation systems. In contrast, wind and solar use asynchronous generating technologies that contribute little to short-circuit strength. Wind and solar energy can provide the necessary dynamic reactive power to the grid to support voltage for normal operating conditions, but these asynchronous generators do not create the same level of voltage stiffness during deep grid disturbances as conventional synchronous generators. In addition to loss of dynamic reactive capability near load centers, there is growing evidence that the aggregate load on the grid is becoming less "grid friendly." Modern electronic loads, air conditioning, and computers can all increase the requirement for dynamic reactive support. The retirement of conventional generators and the displacement of remaining generators with wind and solar power could alter the present systems' capabilities to manage disturbances on the grid.

Generation retirements are typically announced fewer than two years before the planned retirement date, making the lead time for needed grid reinforcements short and transmission solutions impractical. For many voltage problems, shunt capacitors are a relatively inexpensive approach and can be installed quickly. However, shunt capacitors cannot regulate voltage dynamically due to the discrete switching necessary for operation. Power electronics, such as SVCs, have been used successfully for many years to meet dynamic voltage regulation requirements but require a stiff grid voltage that is created by nearby generation. More advanced power electronic devices such as STATCOM can provide improved performance in a weaker grid, but in a very weak grid they still have limited ability to stabilize voltage during a disturbance. The most robust and often the only viable option is synchronous condensers, which replicate the dynamic reactive power capability of a conventional power plant without the capability of generating power for the grid. An emerging trend in North America is the conversion of retired generation to synchronous condensers. This involves removing the turbine and operating the synchronous generator to produce only reactive power. This is often a very attractive approach from both a system performance and economic perspective.

Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

As loads become less grid friendly, as more wind, solar, and other asynchronous forms of power generation displace conventional power plants, and as older plants are retired, the grid will need both local dynamic reactive power sources and the means to maintain adequate short-circuit strength. Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

Demand Management

Demand management or DR covers the whole range of demand-side resources from direct load control (operators disconnect load on demand) to responsive demand based on dynamic pricing and other control signals (price schedules or signals are passed to customers to incent load reduction). The advent of new technology is enabling more sophisticated and engaging DR options that, coupled with dynamic pricing, are making possible more flexible and robust customer response behavior. Smart grid innovations in advanced metering infrastructures, communications, home emergency management systems, and smart appliances are making DR both technologically feasible and economically viable, enabling a wider deployment.

Despite the relatively slow economy, utility and retail DR programs are being driven by state regulatory commissions and by utilities in need of managing their peak demand and reducing long-term capacity costs. Furthermore, FERC orders #719 and #745 are opening up opportunities for the participation of DRs in wholesale markets, with DR to be paid ISO locational marginal prices and to be treated similarly to supply-side resources in energy, capacity, and ancillary services markets. DR benefits utilities, customers, and the power system in a number of ways, including deferring the need for new investment in generation and transmission, increased reliability, and increased economic efficiency by price responsive (and price-elastic) demand.

FERC estimates that, if the current level of DR is preserved through the next decade, DR would shave 38 GW off U.S. peak demand in the year 2019, and, with dynamic pricing, the total potential could range between 14 and 20% of peak demand or 138–188 GW depending on whether dynamic pricing is deployed on an opt-in or opt-out basis. The Brattle Group estimates US$65 billion in cost avoidance in the United States through 2030 from DR. With the proper alignment of technology, pricing, and incentives, DR is expected to play a key role in the value proposition for the grid of the future.

Grid Resiliency

Recent disasters in the United States, such as the 9/11 terrorist attack in 2001 and Hurricane Sandy in 2012, have highlighted a vital need for preventing power disruptions and blackouts that paralyze the operations of essential services and disrupt the provision of key necessities to the population at large. These include such services as those provided by the first responders, police departments, fire houses, hospitals, emergency shelters, elderly care facilities, water utilities, sewage treatment facilities, public transit systems, and other essential government and business operations.

According to the U.S. Department of Energy, outages caused by severe weather such as thunderstorms, hurricanes, and blizzards account for 58% of outages observed since 2002 and 87% of outages affecting 50,000 or more customers.

In June 2011, President Obama released "A Policy Framework for the 21st Century Grid," which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21st century smart grid technologies focused on increasing the grid's efficiency, reliability, and resilience, thereby making it less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage. Recently, in August 2013, the Executive Office of the President issued the report "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," which estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience.

One such strategy to make certain critical areas of the system more robust is by employing microgrids. Microgrids can be a useful means of providing electric service resiliency to certain areas by enabling sustainable operations and uninterrupted functioning of critical load in islanded mode in the event of widespread disruptions in electric utility services. The U.S. Department of Energy defines the term "microgrid" to mean "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode." Well-designed microgrid systems, which may include a combination of DG, energy storage, and DR, with an intelligent system platform that enables system integration, communication, monitoring, and smart control, would function seamlessly in a sustainable manner during contingency periods and judiciously utilize available resources on a selective manner to ensure continued operation of the critical loads.

Microgrids are particularly applicable when a facility or condensed load area has relatively secure intrafacility interconnections (e.g., underground distribution) but is supplied by relatively vulnerable connections to the grid. In the more general situation of entirely overhead supply and local distribution lines, the distribution secondaries and laterals tend to be more vulnerable to storm damage than the trunk feeders and subtransmission lines. With the likely unavailability of local interconnections following a storm or disaster, the microgrid model is less applicable in this more general situation.

Microgrids are just one potential approach to improving resiliency. A comprehensive strategy considers all the measures available, including intelligent approaches such as automated distribution reconfiguration, as well as lower-technology approaches such as moving distribution underground and increasing tree trimming.

Moving forward, a necessary step is the development of national and regional policies that place value on a resilient energy supply. These policies should focus on the definition and achievement of desired outcomes, such as the preservation of power supply to critical loads. Policies should be technology neutral, allowing existing and new strategies, including microgrids, to meet their objectives. In any event, all future systems designed for resiliency may have to be custom designed and implemented on a case-by-case basis to be suitable for their intended settings (e.g., urban, suburban, and rural) and appropriate for a different mix of government, civic, and business entities within each setting. The grid of the future will employ a spectrum of existing and new technologies to ensure grid resiliency during and following disasters.

Conclusions

New technologies, changing market conditions, more frequent extreme weather events, and new regulations and policies all shape the future of the grid. This is true for both the emerging and developed economies of the world. The many moving parts of policy, regulations, and market conditions and the cost and performance of new and existing technology makes it difficult to place bets as a product vendor, utility planner, or investor. While many factors will shape the future of the grid and many others can alter its course, the ten trends described in this article are some of the key drivers that will shape the grid over the next decade.

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Selling Into the Sun:

Price Premium Analysis of a Multi-State Dataset of Solar Homes

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Abstract

Capturing the value that solar photovoltaic (PV) systems may add to home sales transactions is increasingly important. Our study enhances the PV-home-valuation literature by more than doubling the number of PV home sales analyzed (22,822 homes in total, 3,951 of which are PV) and examining transactions in eight states that span the years 2002–2013. We find that home buyers are consistently willing to pay PV home premiums across various states, housing and PV markets, and home types; average premiums across the full sample equate to approximately $4/W or $15,000 for an average-sized 3.6-kW PV system. Only a small and non-statistically significant difference exists between PV premiums for new and existing homes, though some evidence exists of new home PV system discounting. A PV green cachet might exist, i.e., home buyers might pay a certain amount for any size of PV system and some increment more depending on system size. The market appears to depreciate the value of PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and the rate of straight-line depreciation over the asset's useful life. Net cost estimates—which account for government and utility PV incentives—may be the best proxy for market premiums, but income-based estimates may perform equally well if they accurately account for the complicated retail rate structures that exist in some states. Although this study focuses only on host-owned PV systems, future analysis should focus on homes with third-party-owned PV systems.

Key words: photovoltaic, PV, solar, homes, residential, property value, selling price, premium, hedonic, California, new homes, existing homes, host-owned

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1. Introduction

As of the second quarter (Q2) of 2014, solar photovoltaic (PV) energy systems have been installed on more than a half million homes in the United States; more than 42,000 systems were installed in Q2 alone, roughly four times the number installed in the same quarter in 2010 (SEIA & GTM, 2014). This growth is in part related to the dramatic decrease in installed PV costs over the last 10 years (Barbose et al., 2014) as well as the increase in financing options for property owners installing PV, such as leased PV systems and other zero-money-down purchase options (SEIA & GTM, 2014).

As PV installations have proliferated, so has the number of transactions involving homes with PV (Hoen et al., 2013b). Because of this, the real estate sales and valuation communities have been working to enable a better understanding of the valuation of PV systems and green features more generally (Adomatis, 2014). For example, courses on the marketing and valuation of green features are available through the Appraisal Institute and the NATIONAL ASSOCIATION OF REALTORS® (NAR)[1]; green attributes for a multiple listing services data dictionary have been recommended by a working group of the NAR (2014); the Appraisal Institute has developed a "Residential Green & Energy Efficient Addendum" to capture green attributes during an appraisal[2]; PV Value®, a web-based tool specifically designed for the valuation of PV systems, has been developed (Klise et al., 2013); the National Home Performance Council and CNT Energy developed a blueprint to make energy improvements more visible in the real estate market (CNT Energy & NHPC, 2014); Fannie Mae, in its updated standards for conforming loans it will repurchase, now mentions homes with solar panels and the need to "adjust" the appraised value of the home if the market warrants it (Fannie Mae, 2014); and, finally, the Federal Housing Administration has proposed requirements for valuing "Special Energy Related Building Components" in its *Draft Single Family Housing Handbook*, which governs conforming loans for homes with PV systems (FHA, 2014).

Despite the activity around valuing (and marketing) PV homes, little research documents the premiums for these homes. Farhar and Coburn (2008) first documented the apparent increase in values for 15 PV homes inside a San Diego subdivision. This was later corroborated by strong empirical evidence from greater San Diego and Sacramento (Dastrup et al., 2012) and from a relatively large dataset of approximately 1,900 California PV homes (Hoen et al., 2011; 2013a; 2013b); these studies employed hedonic pricing models to estimate premiums. Finally, a case study of 30 PV homes that sold in the Denver metro area found evidence of premiums (Desmarais, 2013). Because the evidence that PV homes garner a premium has focused on a relatively small number of California homes and a few in Colorado, there is need for further evidence of premiums outside of California and even inside California. There is also a need to analyze transactions that occurred after the recent housing bubble, the period from which most previous data had been collected and analyzed (Hoen et al., 2011; 2013a; 2013b).

In most local markets, few PV home sales occur, thus appraisers and other real estate professionals (real estate agents, lenders, underwriters, etc.) often cannot compare similar PV and non-PV home sales to derive a PV premium. Because of this, valuation professionals often use other methods to value PV systems, including the income and cost methods (Adomatis, 2014; FHA, 2014). Hoen et al. (2013b) used hedonic (regression) modeling, employing similar methods as the sales-comparison approach, and found premiums larger than the contributory values generated with the cost and income approaches—a counterintuitive result. Possible reasons for this result include issues with the underlying dataset, which

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[1] See, e.g., http://www.appraisalinstitute.org/education/education-resources/green-building-resources/ and http://www.greenresourcecouncil.org/.

[2] See http://www.appraisalinstitute.org/professional-practice/professional-practice-documents/new-residential-green-energy-efficient-addendum/.

included sales from homes with a very wide range of prices and sales that occurred largely during the housing boom. In addition to that California-based study, Desmarais (2013) compared the three methods in her analysis of 30 Colorado sales but did not use statistical tests. Therefore, additional comparison of the various methods—using a more recent dataset, statistical methods, and a broader group of transactions—would be a valuable contribution to the literature.

Other considerations are important as well. The gross installed costs (i.e., costs before state and federal incentives) of PV systems have declined steadily in recent years, while net costs (i.e., with incentives included) have remained fairly stable (Barbose et al., 2014). Examining premium changes over this period might indicate how the market responds to signals from gross and net costs. Moreover, over the same period, the housing market saw significant swings: the housing bubble, the subsequent crash, and then the recovery. Understanding whether observed PV premiums varied over this period would help illuminate how enduring these premiums might be. There also has been evidence that the new home market in California heavily discounted PV homes during the housing boom and bust (through 2009) in comparison to the premiums garnered by existing home sellers (Hoen et al., 2011; 2013a).[3] Therefore, examining how new home PV premiums fared in relation to existing home premiums within an expanded dataset would be of interest.

In addition, others have explored the existence of a green cachet, such as the “Prius effect” and other forms of “conspicuous (non)consumption,” where buyers appear to pay more for a “green” item than they will save over its life in decreased energy costs (White, 1978; Kahn, 2007; Sexton, 2011). Dastrup et al. (2012) find larger PV premiums where more Prius hybrid vehicles are registered, which they use as a proxy for environmental leanings. This analysis concentrated on only the San Diego and Sacramento areas, thus analysis of a broader dataset is warranted.

Finally, previous literature suggests the need for more research on the market’s depreciation of aging PV systems, especially for systems greater than 6 years old, which have not been well studied because of the immaturity of the PV market (Hoen et al., 2011; 2013a; 2013b). A clearer understanding of how the market depreciates PV systems would likely enhance appraisal techniques.

In summary, there are a number of gaps in the literature, each of which the present research seeks to address:

1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?
2. Are PV home premiums outside of California similar to those within California?
3. How do PV home premiums compare to contributory values estimated using cost and income methods?
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?
5. Are premiums for new PV homes similar to existing PV home premiums?
6. Is there evidence of a “green cachet” for PV homes above the amount paid for each additional watt added?
7. How does the age of the PV system influence the size of the PV premium?

[3] These discounts, it was assumed, were offset by decreased marketing times (i.e., “sales velocity”) for these homes, a priority for home builders as the market for new homes slowed and inventories increased (Dakin et al., 2008; Farhar and Coburn, 2008; SunPower, 2008).

It is important to clarify that this research focuses on only host-owned PV systems and therefore excludes third-party-owned systems, which, we recommend, should be the focus of future research.

The remainder of this report is organized as follows: Section 2 discusses our methodological approach; Section 3 details the data used for the analysis; and Section 4 presents the results, followed by a discussion of the results in Section 5 and conclusions in Section 6. An appendix detailing cost estimate preparation follows the references.

2. Methodological Approach

To examine the questions above, this research relies on a hedonic pricing model—the “Base Model”—against which a series of other models are compared. Those other models use a subset of the data (e.g., new or existing homes), an interaction term(s) (e.g., age of the PV system), or other variants to examine the various research questions and test the overall robustness of the results.

The basic theory behind the hedonic pricing model starts with the concept that a house can be thought of as a bundle of characteristics. When a price is agreed upon between a buyer and seller, there is an implicit understanding that those characteristics have value. When data from a number of sales are available, the average marginal contribution to the sales price of each characteristic can be estimated with a hedonic regression model (Rosen, 1974; Freeman, 1979; Sirmans et al., 2005). This relationship takes the basic form:

Sales price = f (home and site, neighborhood, and market characteristics)

“Home and site characteristics” might include, but are not limited to, the number of square feet of living area and the presence of a PV system. “Neighborhood” characteristics might include such variables as the crime rate and the distance to a central business district. Finally, “market characteristics” might include, but are not limited to, temporal effects such as housing market inflation/deflation.

2.1 Base Model

The “Base Model” to which other models are compared uses a relatively simple set of home and site characteristics: size of the home (i.e., square feet of living area); age of the home at the time of sale (in years); age of the home squared (in years); size of the parcel (in acres) up to 1 acre; and any additional acres more than 1 (in acres).[4] It also includes the presence and size of the PV systems. To control for neighborhood, we include a census block group fixed effect, which, in all cases, includes at least one PV home and one non-PV home.[5] Finally, market characteristics are accounted for by including a dummy variable for the quarter and year (e.g., 2013 Q2, 2009 Q1, etc.) in which the sale occurred. This model form was chosen for its relative parsimony, its high adjusted R^2, and its transparency.[6] It is estimated as follows:

$$\ln(\mathrm{P_{itk}}) = \alpha + \beta_1(\mathrm{T_i}) + \beta_2(\mathrm{K_i}) + \sum_{a} \beta_3(\mathrm{X_i}) + \beta_4(\mathrm{PV_i} \cdot \mathrm{SIZE_i}) + \varepsilon_{\mathrm{itk}} \quad (1)$$

[4] Acres is entered into the model as a spline function using two variables, up to 1 acre (*acreslt1*) and any additional acres above 1 (*acresgt1*), to capture the different values of up to the first and additional acres of parcels in the sample. Therefore *acreslt1 = acres* if *acres* ≤ 1 and 1 otherwise, while *acresgt1 = acres*-1 if *acres* > 1 and 0 otherwise. Additionally, square feet and age squared are entered into the model in 1,000s to allow for easier interpretation of the coefficients.

[5] A census block group contains approximately 600 to 3,000 people. By including this fixed effect, and requiring each to contain at least one PV and one non-PV home, the PV estimates are, therefore, essentially a comparison of those two home types within the block group, while controlling for temporal and characteristic differences between them.

[6] Model choice for this work was based on extensive robustness model exploration in previous analysis (Hoen et al., 2011; 2013a; 2013b). Other models were explored but are not presented here. They include adding other home and site parameters such as number of bathrooms, condition of the home, and if a pool is present, all of which further limited the dataset but did not substantively affect the results. Similarly, instead of using a fixed effect for sale year and quarter, interacting sale year and, separately, sale quarter, with a geographic variable, such as county, to control for geographic variation in market inflation/deflation was explored with no change to the results.

where

P_{itk} represents the sale price for transaction *i*, in quarter *t*, in block group *k*,

α is the constant or intercept across the full sample,

T_i is the quarter *t* in which transaction *i* occurred,

K_i is the census block group *k* in which transaction *i* occurred,

X_i is a vector of *a* home and site characteristics for transaction *i*,

PV_i is a fixed-effect variable indicating a PV system is installed on the home in transaction *i*,

$SIZE_i$ is a continuous variable for the size (in kW) of the PV system installed on the home prior to transaction *i*,[7]

β_1 is a parameter estimate for the quarter in which transaction *i* occurred,

β_2 is a parameter estimate for the census block group in which transaction *i* occurred,

β_3 is a vector of parameter estimates for home and site characteristics *a*,

β_4 is a parameter estimate for the change in sale price for each kilowatt added to a PV system, and

ε_{itk} is a random disturbance term for transaction *i*, in quarter *t*, in block group *k*.

The parameter estimate of primary interest in this model is β_4, which represents approximately the marginal percentage change in sale price over the average sale price of the comparable set of non-PV homes within the same census block group, with the addition of each kilowatt of PV.[8] If differences in selling prices exist between PV and non-PV homes, we would expect the coefficient to be positive and statistically significant.

This model allows an examination of many of the research questions depending on the dataset that is used. If the full dataset is used, the first question can be answered. If a subset of the dataset is used, many of the other questions can be answered. For example, if homes within and outside California are used, the second question can be explored. Similarly, if the data are restricted to particular subsets of the study period (e.g., 2002–2007, 2008–2009, 2010–2011, or 2012–2013), the fourth research question could be examined. To explore if new or existing homes had similar premiums (the fifth question), the data could be restricted to those subsets. Finally, if only PV systems of particular ages were used, the seventh question could be answered. Therefore, almost all of the research questions can be answered using subsets of the data, leaving only the sixth question regarding green cachet, which requires a slightly altered model and will be discussed next, and the third question, which can use either the full dataset or subsets of the data but also requires calculations of comparison valuation estimates using the cost or income method.[9]

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[7] All references to the size of PV systems in this paper, unless otherwise noted, are reported in terms of direct-current watts or kilowatts under standard test conditions. A discussion of this convention is offered in Appendix A of Barbose et al. (2014).

[8] To be exact, the conversion to percent is actually $EXP(\beta_4)$-1, but the differences are often *de minimis*.

[9] Although the preferred method is to estimate a separate model using a subset of the data, which allows all of the controlling parameters to take different values for each subset, we also explored estimating models with a categorical variable for each of the subsets interacted with either the variable of interest only or both the variable of interest and the other controlling parameters, with no substantive change in the results.

2.2 Base Model Variation: Size of PV System Model

Although the Base Model and variations to the subsets of data allow examination of almost all the research questions, the sixth question requires a slightly altered model: the Size of PV System Model. If the market exhibits a green cachet, theoretically a fixed amount might be added to the value of a home with PV regardless of the size of that PV system. Therefore, for smaller systems, a premium expressed in dollars per installed watt would be larger than it would be for larger systems, representing a decreasing marginal premium for each watt added to a PV system. To examine decreasing marginal returns, a second-order polynomial is added, and therefore we estimate the following model:

$$\ln(\mathrm{P}_{\mathrm{itk}}) = \alpha + \beta_1(\mathrm{T_i}) + \beta_2(\mathrm{K_i}) + \sum_{\mathrm{a}} \beta_3(\mathrm{X_i}) + \beta_4(\mathrm{PV_i} \cdot \mathrm{SIZE_i}) + \beta_5(\mathrm{PV_i} \cdot \mathrm{SIZE_i}^2) + \varepsilon_{\mathrm{itk}} \qquad (2)$$

where

$SIZE_i^2$ is a continuous variable for the squared size (in kilowatts) of the PV system installed on the home prior to transaction *i*, and

β_5 is a parameter estimate for the change in sale price for each additional squared kilowatt added to a PV system, and all other variables are as shown in Equation (1).

The parameter estimates of primary interest in this model are β_4 and β_5. If decreasing marginal returns exist for increasing sizes of PV systems, we would expect the β_4 coefficient to be positive and larger and the β_5 coefficient to be negative and smaller.

2.3 Model Summary

Combining the Base Model, the use of various subsets of data, and the Size of PV System Model allows examination of the seven research questions listed in Section 1. The full set of research questions, models, and sample sets are described in Table 1.

Table 1: Summary of Research Questions, Models, and Sample Sets

Research Question	Equation	Model Name	Sample Set(s)
1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?	Equation (1)	Base Model	All Data
2. Are PV home premiums outside of California similar to those within California?	Equation (1)	Location Models	CA vs. Non-CA Homes
3. How do PV home premiums compare to contributory values estimated using the cost and income methods?	Equation (1)	Various Models	All Data, or Subsets of Data, But Compare Results To Income and Cost Methods
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?	Equation (1)	Year of Sale Models	Subsets of Years in Sample Period (e.g., Pre-'08; 08-09, 10-11, Post 11)
5. Are premiums for new PV homes similar to existing PV home premiums?	Equation (1)	Home Type Models	New vs. Existing Homes
6. Is there evidence that there is a "green cachet" for PV homes over and above the amount paid for each additional watt added?	Equation (2)	Size of PV System Model	All Data
7. How does the age of the PV system influence the size of the PV premium?	Equation (1)	Age of PV System Models	Subsets of PV System Ages (e.g., < 2 years; 2-4; 5-6; 7-14 years)

2.4 Robustness Models

We also explore the robustness of our results with two alternative model specifications.

2.4.1 PV Only Model

It has been well documented that PV homes often have a suite of additional energy-efficiency (EE) features (CPUC, 2010; Hee et al., 2013; Langheim et al., 2014). Further, it has been theorized that PV home owners, who have the financial resources to install a PV system, might also make other (non-EE) upgrades, such as a new kitchen or bathroom, or may alternatively replace their roof contemporaneously with PV system installation. Therefore, the premium estimated from Equation (1) could also include effects of EE and other features and therefore overestimate the effect related to PV alone.

To test this, PV homes are compared to other PV homes based on system size. While the Base Model estimates a difference in sales prices between PV and non-PV homes, all else being equal, the PV Only Model compares the difference between PV homes and PV homes based on differences in their PV system size, all else being equal. Assuming all PV homes have the same frequency of EE and other features among them, an effect free of those influences can be estimated and then compared to the results in Equation (1).[10]

One complication of this model concerns possible collinearities of the block group fixed effects and PV when a single or small number of PV homes exist within a single block group. While in the Base Model the use of the block group fixed effect is appropriate, because each contains at least one PV and one non-PV home, in the PV Only Model collinearities might exist for block groups with only one or a few PV homes, or those that might have only similarly sized PV systems. In those block groups, the fixed effect might absorb the contributory effect of the PV variable. Therefore, this model uses the county as the fixed effect and is restricted to counties that have two or more PV homes, to allow more heterogeneity between the PV homes within the fixed effect delineation and therefore less collinearity between them and the PV variable; otherwise the model is identical to Equation (1).[11]

2.4.2 Repeat PV Home Model

A common concern with hedonic modeling, such as the Base Model, is that a suite of home and site characteristics are not controlled for, which could be driving the results. These omitted variables could include any manner of home features, such as granite countertops, a newly renovated basement, and Jacuzzi, as well as neighborhood features, such as location on a cul-de-sac, a scenic vista, or location next to a major road. These variables could be present for PV and non-PV homes. Although the assumption is that these unobserved features are randomly distributed among PV and non-PV homes, and therefore are not correlated with the presence of PV, this might not be the case. This can be tested using the Repeat PV Home Model.

The Base Model estimates a difference in sales prices between PV and non-PV homes all else being equal, but the Repeat PV Home Model compares sales prices of homes before they had PV installed to prices of the same homes after they had PV installed. Because many of the characteristics controlled for

[10] It is at least conceivable that EE and other features are correlated with PV system size, with a larger PV system correlated with more EE and other features. We expect, however, that this would likely be more correlated with the size of the home, which is controlled for in this and the Base Model.

[11] Although not shown here, using county fixed effects in the Base Model in place of block group fixed effects has no apparent effect on the premium estimate, and therefore this PV Only Model can be compared directly to the Base Model results. Also, this model assumes a tradeoff with being able to compare PV homes to PV homes, and therefore controlling for the unobservables associated with PV, versus controlling for the unobservables associated with the localized neighborhood effects that the block group fixed effect controls for.

in the Base Model are held constant in the Repeat PV Home Model, such as block group and size of the home and parcel, they do not need to be controlled for.[12] Therefore, the following greatly simplified model can be estimated:

$$\ln(\mathrm{P_{itk}}) = \alpha + \beta_1\left(\mathrm{T_i}\right) + \sum_{\mathrm{a}} \beta_2\left(\mathrm{X_i}\right) + \beta_3\left(\mathrm{PV_i} \cdot \mathrm{SIZE_i}\right) + \varepsilon_{\mathrm{itk}} \tag{3}$$

where

X_i is a vector of age of the home and age squared for transaction *i*,

β_2 is a vector of parameter estimates for age and age squared,

β_3 is a parameter estimate for the change in sale price for each additional kilowatt added to a PV system, and all other variables are as defined in Equation (1).

[12] Ideally we would have information on the size of the home as of the first sale and the second sale, but we only have information from the most recent assessment and therefore can only assume that it has not changed between sales. If it has changed, however, it would have likely increased the home's value, thus the second sale would include the increase in related value. If this were the case, the PV premium would capture this increase. Our results do not exhibit this increase, so it is assumed that the Repeat PV Home Model results are free of this influence.

3. Data Preparation and Summary

This section describes the underlying data used for this analysis—including PV home and non-PV home data, cost estimates, and income estimates—followed by a data summary.

3.1 PV and Non-PV Home Data

For the Tracking the Sun (TTS) report series (e.g., Barbose et al., 2013), Lawrence Berkeley National Laboratory was provided a set of approximately 150,000 host-owned (i.e., not third-party-owned) PV home addresses by various state and utility incentive providers, along with information on PV system size, date the incentive was applied for, date the system was put into service, and the average tilt and azimuth of the PV system, where available.[13] These data span the years 2002–2012 and stretch across eight states: California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania.[14]

These PV home addresses were matched to addresses maintained by CoreLogic,[15] which CoreLogic aggregates from county-level assessment and deed recorder offices. Once the addresses were matched, CoreLogic provided, when available, real estate information on each of the PV homes as well as similar information on approximately 200,000 non-PV homes located in the same (census) block group as the PV homes. The data for both of these sets of homes included, but were not limited to:

- address (e.g., street, street number, city, state and zip+4 code);
- most recent and previous (if applicable) sale date and amount;
- home characteristics (e.g., acres, square feet of living area, bathrooms, pool, and year built[16]);
- assessed value of land and improvements;
- parcel land use (e.g., commercial, residential);
- structure type (e.g., single-family residence, condominium, duplex); and,
- x/y coordinates.

These data were cleaned to ensure all data were populated and appropriately valued.[17] Using these data, along with the PV incentive provider data, we determined if a home sold after a PV system was installed, significantly reducing the usable sample because the majority of PV homes have not yet sold. We also culled a subset of these data for which previous sale information was available and for which a PV system

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[13] For a full discussion of how these data are obtained, cleaned, and prepared, see Barbose et al. (2013).

[14] The TTS dataset also included data on PV homes from other states, including Illinois, New Mexico, New Hampshire, Oregon, Texas, and Vermont. However, after matching to the CoreLogic sales transaction dataset and cleaning to ensure all the homes that did sell had data that were fully populated and appropriately signed, no PV home sales existed from these states.

[15] More information about this product can be obtained from http://www.corelogic.com/.

[16] Year built, along with previous sales information and a CoreLogic-provided flag on new homes, allowed for a determination of whether the home was newly built or existing at the time of sale.

[17] Because the CoreLogic data sometimes are missing or miscoded, the cleaning and preparation of these data were extensive and therefore not detailed here, but the process included the following screens: sale price greater than $165,000 and less than $900,000, size of the home between 1,000 and 5,000 square feet, sale price per square foot between $8 and $800, sale year after 2001, and size of the parcel between 0.05 and 10 acres.

had not yet been installed as of this previous sale. These “repeat sales” were used in the Repeat PV Home Model described in Section 2.4.2 .

Ideally, for each PV home transaction, we would have a set of identical (i.e., all else being equal) non-PV home transactions for comparison. This theory underlies the comparable-sales method used by appraisers and other valuation professionals (Adomatis, 2014), where comparable homes are chosen that are as similar as possible, and then adjustments are made to account for the observable differences.

To emulate the comparable-sales method, we employed the Coarsened Exact Matching (CEM) process (King et al., 2010), which finds a matched sample of PV and non-PV homes that are statistically equal on their covariates.[18] The covariates include being within the same block group, selling in the same year, and having similar values for size of the home, age of the home, size of the parcel, and ratio of assessed value of land to total assessed value.[19] This procedure results in a reduced sample of homes to analyze, but biases related to the selection of PV and non-PV homes are minimized.[20] The unmatched dataset has 173,982 non-PV homes and 5,373 PV homes, while the matched dataset—the one used for the analysis—has 18,871 non-PV homes and 3,951 PV homes. Various models, as described above, use subsets of the PV homes and therefore will need matching non-PV homes. For most of the subsets this is straightforward, because we divide the PV and non-PV homes along the same lines used for the CEM matching, such as whether the homes are located in California or the rest of the United States, or if they are newly built homes or existing. For the Age of PV Systems models, though, there is not an intuitive division for the non-PV homes, because age of the PV system was not used for matching. Therefore, for these models the CEM process was employed again for each set of PV homes. The resulting matched non-PV homes were not necessarily mutually exclusive between the sets of PV homes, but most importantly each block group contained at least one PV home and one non-PV home.

3.2 Cost Estimates

In this analysis, as in previous studies (Hoen et al., 2011; 2013a; 2013b), we compare the market premiums we find using our Base Model and alternative models to cost and income contributory-value estimates to illuminate how the market might be reacting to various signals. A cost estimate refers to the cost to replace an asset with a new equivalent. Appraisal theory posits that cost estimates are likely important price signals in the marketplace, and market values normally should not exceed the replacement cost of an asset. This might mean, for example, that a buyer of a PV system already installed on a home is not willing to pay more for it than the cost of a new system (i.e., its replacement cost).

For this analysis, we prepared two sets of cost estimates: gross costs and net costs, the detailed preparation of which is described in Appendix A. In this context “net” implies a cost after federal and state tax incentives and state rebates are factored in, while “gross” estimates do not factor these incentives

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[18] The procedure used, as described in the referenced paper, is CEM in Stata, available at: http://ideas.repec.org/c/boc/bocode/s457127.html. Because this matching process excludes non-PV homes that are without a statistically similar PV match (and vice versa), a large percentage of homes (approximately 90% of non-PV and 33% of PV) are *not* included in the resulting dataset. Pre-matching Multivariate Distance (0.95) compares favorably to post-matching Distance (0.82).

[19] The assessed value of land to total value ratio is expected to capture the unexplained within-block group locational variation that often is present, for example, due to being on a quiet road, abutting a park, or being on the waterfront. Assessed values, it is assumed, are consistently applied within the block group.

[20] Although the preferred model is one with a matched dataset, the Base Model was also estimated using the unmatched dataset, which results in a slightly higher estimated premium. We attribute this change to the heterogeneity of the unmatched PV and non-PV homes and the fact that the unmatched non-PV homes have lower-valued unobserved characteristics.

in.[21] We distinguish between the two because the ability of the homeowner to benefit from the incentives depends somewhat on their tax obligations. For example, the federal incentive for PV comes in the form of a reduced federal tax obligation (formally known as the Internal Revenue Code Section 25D: Residential Energy Efficient Property Credit). If a homeowner expects to pay very little in taxes (e.g., because they have a mortgage and very little taxable income), then the federal tax incentive might not be realized immediately (it can be carried over year to year). A similar scenario exists if state tax incentives are present. More generally, incentive availability changes with time, so home buyers may have some uncertainty about what incentives might be available, and their value. Because of these different scenarios, it is not immediately clear if the market would fully capitalize the incentives calculated as part of the net cost, thus net cost can serve as the low cost estimate for our purposes. Similarly, we expect that buyers would not be willing to pay more than the gross cost, which thereby serves as the high cost estimate.

Finally, in previous analyses, we prepared cost estimates depreciated using a straight-line 20-year depreciation schedule, assuming this would be roughly equivalent to the usable life of a PV system (Hoen et al., 2011; 2013a; 2013b). For the present analysis we use, instead, the un-depreciated amount. In doing so, we do not presuppose how the market depreciates PV systems and/or the replacement costs of those systems; rather, we allow the market to dictate how best to depreciate their values, if at all. This is the customary approach of appraisers (Adomatis, 2014).

3.3 Income Estimates Using the PV Value Algorithm

As with cost estimates, appraisal theory posits that income estimates—a discounted stream of income derived from an asset over time, such as rent—are likely important price signals in the marketplace. For example, an apartment seller might not be willing to sell a property for significantly less than the present value of rent (minus costs) it receives for that property. Similarly, the buyer and seller of a home with a PV system might use the discounted value of the system's energy cost savings as a key factor in determining any PV premium.

For each of the PV homes in our sample, we prepared data to estimate the present value of energy bill savings (income estimates) using the size and age of the system, the zip code of the home, and the estimated tilt and azimuth of the system.[22] These inputs were fed through the PV Value algorithm (Klise et al., 2013) to produce estimates for utility bill savings for a similarly sized system as of the time of sale.[23]

The algorithm is outlined by Klise and Johnson (2012), and the inputs for our current research effort are based on the following: the expected energy output of the PV system after the sale date and assuming a life span not greater than the warranty life of the panels (usually 25 years); an electricity retail rate at the time of sale and an escalation of the rate similar to the historical escalation over the previous years; discount rates as of the time of sale, which, for the purposes of this study, are equivalent to 100 basis points above the 30-year, fixed mortgage, 60-day Fannie Mae lock-in rate at the time of sale; a system

[21] Other incentives exist, such as state renewable energy credits, feed-in tariffs, and performance-based incentives, but these are rare throughout the analysis dataset and therefore are not considered. Understanding how to value them appropriately should be the subject of future research, however, because their value can be significant in certain circumstances.

[22] Because tilt and azimuth were not available for all PV systems (the data were not provided during the TTS data-collection effort), they were estimated via a cascading approach, based on systems with those data in the same census block group if available, then, if not available, census tract or, finally, county when needed.

[23] The estimation procedure produces a set of low, average, and high estimates of the present value of the expected energy output, based on a risk premium of 50, 100, and 200 basis points, respectively. Only the average value was used for this analysis.

direct current-to-alternating current derate factor of 0.77%; a module degradation factor of 0.5% per year; and an expected inverter replacement at 15 years. Tiered rates, which are prevalent in California, are not considered here, but instead an average zip-code level rate is used, as is the default for PV Value. We return to this issue in Section 5, where we discuss results from the model estimation in comparison to the income estimates.

The descriptions of the income estimation procedure are contained elsewhere (Klise and Johnson, 2012; Appendix A in Hoen et al., 2013b; Klise et al., 2013) and therefore are not detailed here.

3.4 Data Summary

The final dataset includes 22,822 transactions, consisting of matched PV (n = 3,951) and non-PV (n = 18,871) homes. This full matched dataset is composed of transactions occurring across eight states (Table 2) from 2002 to 2013 (Table 3), with the vast majority in California. All PV systems in this dataset are homeowner owned as opposed to third-party owned (leased or under a power-purchase agreement).

Table 2: Frequency Summary of PV and Non-PV Homes by State

State	Non-PV Homes	PV Homes	Total
CA	18,207	3,828	22,035
FL	317	25	342
Mid-Atlantic Region: MD, NC, PA	288	77	365
Northeast Region: CT, MA, NY	59	21	80
Total	18,871	3,951	22,822

Table 3: Frequency Summary of PV and Non-PV Homes by Sale Year

Sale Year	Non-PV Homes	PV Homes	Total
2002	107	18	125
2003	196	31	227
2004	238	53	291
2005	197	56	253
2006	348	64	412
2007	818	242	1,060
2008	1,251	453	1,704
2009	1,762	429	2,191
2010	2,751	504	3,255
2011	3,341	642	3,983
2012	3,928	694	4,622
2013	3,934	765	4,699
Total	18,871	3,951	22,822

Summary statistics for the PV and non-PV homes are shown, respectively, in Table 4 and Table 5. The mean sale price (*sp*) of the PV homes in the sample is \$473,373 and ranges from a minimum of \$165,500 to a maximum of \$899,500. The average PV home in the sample has 2,334 square feet of living area (*sfla*), is located on a parcel of 0.45 acres (*acres*), and was 17 years old (*age*) when it sold in 2010 (*sy*).[24] It has a 3.6-kW PV system (*size*), which was installed 2.7 years before the home was sold (*pvage*). The gross installed cost for a similarly sized PV system in the same county at the time of sale was $6.90/W (*grosscost*), while the net cost (after incentives) was $4.14/W (*netcost*). The present value of the stream of energy produced by the PV system, as calculated by the PV Value algorithm, is $2.93/W (*income*). PV systems in the sample range in size from 0.1 kW to 14.9 kW, with a median of 2.8 kW (*size*). The age of the PV systems at the time of sale ranges from new to more than 13 years, with a median of 2.2 years (*pvage*). For the 18,871 non-PV homes, we find a mean sale price of $456,378, which is $16,995 lower than that of the matching PV homes. The average non-PV home is slightly smaller than the average PV home (2,319 square feet), occupies a smaller parcel (0.41 acres), and is equivalent in age. The dataset contains 7,480 newly built homes and 15,342 existing homes, of which 1,444 and 2,507, respectively, are PV homes.

Table 4: Summary Statistics for All PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	3951	2010	2	2002	2011	2013
syq	year and quarter of sale (yyyyq)	3951	20103	23	20021	20111	20134
sp	price of sale (dollars)	3951	$ 473,373	$ 196,451	$ 165,500	$ 433,000	$ 899,500
lnsp	natural log of sale price	3951	12.98	0.43	12.02	12.98	13.71
sfla	living area (square feet)	3951	2,334	702	1,006	2,244	4,981
sfla1000	living area (in 1000s of square feet)	3951	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	3951	0.45	0.95	0.05	0.18	9.99
age	age of the home at time of sale (years)	3951	17	21	(2)	7	100
agesq1000	age of the home squared (in 1000s of years)	3951	0.7	1.3	0	0.0	10.0
pv	if the home has a PV system (1 if yes)	3951	1	-	1	1	1
size	size of the PV system (kilowatts)	3951	3.6	2.0	0.1	2.8	14.9
pvage	age of the PV system at time of sale (years)	3951	2.7	2.9	(0.5)	2.2	13.4
income	average PV Value estimate ($/watt)	3951	$ 2.93	$ 0.57	$ 1.18	$ 2.92	$ 4.98
netcost	net cost estimate ($/watt)	3951	$ 4.14	$ 0.93	$ 1.07	$ 4.04	$ 7.95
grosscost	gross cost estimate ($/watt)	3951	$ 6.90	$ 1.50	$ 3.15	$ 6.92	$ 11.83

Table 5: Summary Statistics for All Non-PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	18871	2010	2	2002	2011	2013
syq	year and quarter of sale	18871	20103	23	20021	20112	20134
sp	price of sale (dollars)	18871	$ 456,378	$ 197,004	$ 165,500	$ 413,000	$ 899,500
lnsp	natural log of sale price	18871	12.94	0.44	12.02	12.93	13.71
sfla	living area (square feet)	18871	2,319	714	1,001	2,200	4,990
sfla1000	living area (in 1000s of square feet)	18871	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	18871	0.41	0.86	0.05	0.18	9.8
age	age of the home at time of sale (years)	18871	17	21	(2)	8	100
agesq1000	age of the home squared (in 1000s of years)	18871	0.7	1.3	0	0.1	10.0
pv	if the home has a PV system (1 if yes)	18871	0	0	0	0	0

[24] Negative values for the minimum age of a home (e.g., -2) apply to newly built homes in the sample and occur when the sale date is prior to the date of home completion, as might occur when a home is purchased on spec. Similarly, for PV system age, a negative minimum value occurs when the completion date of the PV system occurred before the home sale date, which happens sometimes for new homes. Additionally, although acres is shown in the tables, it is entered in the model as a spline function of up to 1 acre and any additional acres above 1 (see Section 2.1). Finally, age of the home squared is not shown in the tables.

4. Results

This section presents results, starting with the Base Model, which addresses the first research question: Are PV home premiums evident for a broader group of PV homes than has been studied previously? This is followed by results for the various other models, which explore the remainder of the research questions (Table 1 shows the full set of questions), and the two robustness models.

4.1 Base Model Results

The Base Model estimates, over the entire dataset, the marginal return to each kilowatt of PV installed on a home as defined in Equation (1). The model is summarized in Table 6, with full results shown in Table 7.[25] Overall the model performs well, with an adjusted R^2 of 0.92, indicating that it captures approximately 92% of the price variation within the 22,822 home sales located in the 1,830 census block groups that make up the sample.

Table 6: Base Model Results Summary

Total *n*	22,822
PV *n*	3,951
Non-PV *n*	18,871
Adjusted R^2	0.92
Dependent Variable	lnsp
Block Group Fixed Effects	1,830

The full set of results is shown in Table 7. The controlling variables that account for size (*sfla1000*) and age of the home (*age, agesq1000*) and size of the parcel (*lt1acres*, for each acre up to 1, and *gt1acres*, for each acre over 1) are all highly statistically significant (i.e., *p*-value < 0.001). The model indicates that, in our sample, each additional 1,000 square feet adds approximately 21% to the selling price, while each acre up to 1 adds 39% and each additional acre beyond 1 adds 3%.[26] Each year a home ages initially takes approximately 0.7% off its value, but this annual value reduction declines with time, and homes over approximately 60 years in age appreciate in value as they age.[27] Using the fourth quarter of 2013 as the reference category, in our sample, prices start approximately 44% lower (Q1 2002) and then increase to approximately 20% higher (2005), before falling again to lows in early 2012 and then increasing to levels present in late 2013. This rise, fall, and eventual recovery are entirely consistent with the national trends in housing prices.[28] Combined, the various controlling characteristics are appropriately signed and leveled based on our expectations, giving us confidence that the model is acting appropriately and adequately capturing price differences across the sample.

Turning to the variable of interest, *pv*size*, the model estimates that, for each kilowatt of installed PV, sale prices increase by 0.91%, and this estimate is highly statistically significant (*p*-value < 0.001).

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[25] All models are estimated in Stata using *areg*, with block groups as the absorbed fixed effect and with robust standard errors.

[26] The exact percentage interpretation of coefficients in a semi-log model is as follows: exp(coefficient)-1, but the differences in this context are *de minimis*.

[27] Approximately 60 years is determined by dividing the age coefficient by the first derivative of the square term's (*agesq*) coefficient.

[28] As noted previously, we also explored interacting the year of sale with the county, to capture regional price trends, with no substantive change to the results.

Accordingly, at the 95% confidence interval, average price increases are estimated to vary between approximately 0.78% and 1.05% per kilowatt, a relatively precise estimate. This sample of approximately 4,000 PV homes shows a clear premium for each kilowatt of PV installed above the sale prices of comparable non-PV homes.

By using the mean sale price (in dollars) for non-PV homes, we can convert this percentage estimate into dollars per watt.[29] Doing so leads to an estimated premium of $4.18/W, with a 95% confidence interval of +/- $0.62/W, which corresponds to a premium of approximately $15,000 for an average-sized system of 3.6 kW. From Table 4, we see that, for these PV homes, the mean gross cost estimate is $6.90/W, while the net cost estimate is $4.14/W, and the average PV Value (income) estimate is $2.93/W. Therefore, the premium in our sample is almost identical to the average net cost for a similarly sized system as of the time of sale, is approximately $2.70/W less than the gross cost, and is $1.25/W higher than the PV Value income estimate.

4.2 Base Model Variations Using Subsamples

As shown in Table 1, many of the research questions can be investigated using variations of the Base Model that use subsamples of the data in place of the full sample. The following sections describe those model sets and include: Location Models, for California and the rest of the United States; Home Type Models, for newly built and existing homes; Age of PV System Models; and Year of Sale Models.

4.2.1 Location Model Results

Our Location Models estimate premiums for either the subset of homes located in California or those located in the rest of the United States; Table 8 shows the results, along with results for the Home Type Models (which are discussed in the next subsection).[30] Also shown in the table, for reference purposes, are the results for the Base Model using the full sample. Results shown for each model include the *pv*size* coefficient, standard error, and *p*-value; the mean non-PV home sale price; the $/W premium and its 95% confidence interval; and estimates for the net and gross costs and PV Value income. Finally, for each model, the table shows the total, PV, and non-PV sample sizes; the adjusted R^2; and the number of block groups represented by the sample.

The coefficient for the variable of interest for the California subsample is 0.0091, which is highly statistically significant and equates to a $4.21/W premium and a 95% confidence interval of +/- $0.64/W. Not surprisingly, the PV premium is very close to the premium estimated for the full sample, because California PV homes make up 97% of that sample. The PV premium can be compared to the net, gross, and PV Value estimates of $4.16/W, $6.94/W, and $2.95/W, respectively.

For homes outside of California where we have data (in Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania), the PV premium is estimated to be $3.11/W and highly statistically significant (*p*-value < 0.01), but with a 95% confidence interval of $2.33. This indicates that, in this broader sample of homes, a premium for PV homes is evident, but that the smaller sample of homes outside California does not allow for a very precise estimate of the effect size. The estimated premium is very similar to the net cost estimate for this subset of $3.09/W, and it is not statistically different from the premium estimated for California homes.

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[29] The formula for doing so is: $/W premium = ((exp (*pv*size* coefficient)-1)* *mean sale price in dollars for non-PV homes*)/1,000.

[30] For brevity, only the variable of interest is shown for the remainder of the report. Results for the controlling variables were similarly signed and leveled across the various models as they are in the Base Model. The full set of results is available upon request.

Table 7: Base Model Results

Variable	Coefficient	Standard Error	*t* Statistic	*p*-value	- 95% CI	+ 95% CI
intercept	12.498	0.016	758.00	0.000	12.465	12.530
pv*size	0.0091	0.0007	13.12	0.000	0.0078	0.0105
sfla1000	0.213	0.004	51.70	0.000	0.205	0.221
lt1acre	0.386	0.028	13.73	0.000	0.331	0.441
gt1acre	0.029	0.006	5.08	0.000	0.018	0.040
age	-0.007	0.001	-7.86	0.000	-0.008	-0.005
agesq1000	0.056	0.009	6.63	0.000	0.040	0.073
syq						
20021	-0.441	0.034	-13.100	0.000	-0.507	-0.375
20022	-0.379	0.038	-10.060	0.000	-0.453	-0.305
20023	-0.375	0.036	-10.480	0.000	-0.446	-0.305
20024	-0.306	0.073	-4.220	0.000	-0.448	-0.164
20031	-0.087	0.056	-1.560	0.118	-0.196	0.022
20032	-0.077	0.037	-2.050	0.040	-0.150	-0.004
20033	-0.025	0.038	-0.670	0.505	-0.100	0.049
20034	-0.035	0.037	-0.950	0.343	-0.108	0.037
20041	0.001	0.031	0.040	0.972	-0.060	0.062
20042	0.095	0.021	4.430	0.000	0.053	0.137
20043	0.121	0.024	5.120	0.000	0.075	0.168
20044	0.124	0.028	4.340	0.000	0.068	0.179
20051	0.137	0.047	2.910	0.004	0.045	0.230
20052	0.204	0.039	5.170	0.000	0.127	0.281
20053	0.164	0.062	2.640	0.008	0.042	0.285
20054	0.202	0.038	5.340	0.000	0.128	0.276
20061	0.159	0.021	7.710	0.000	0.119	0.200
20062	0.163	0.021	7.900	0.000	0.123	0.204
20063	0.160	0.022	7.300	0.000	0.117	0.203
20064	0.071	0.022	3.240	0.001	0.028	0.114
20071	0.162	0.017	9.700	0.000	0.129	0.195
20072	0.124	0.020	6.170	0.000	0.085	0.163
20073	0.074	0.016	4.580	0.000	0.042	0.106
20074	0.002	0.018	0.100	0.919	-0.034	0.038
20081	0.022	0.016	1.360	0.175	-0.010	0.054
20082	-0.005	0.013	-0.380	0.707	-0.031	0.021
20083	-0.050	0.014	-3.690	0.000	-0.077	-0.023
20084	-0.066	0.014	-4.630	0.000	-0.094	-0.038
20091	-0.113	0.014	-8.070	0.000	-0.141	-0.086
20092	-0.116	0.012	-9.800	0.000	-0.139	-0.092
20093	-0.124	0.012	-10.610	0.000	-0.147	-0.101
20094	-0.120	0.012	-9.700	0.000	-0.144	-0.096
20101	-0.121	0.013	-9.030	0.000	-0.147	-0.095
20102	-0.124	0.012	-10.750	0.000	-0.147	-0.102
20103	-0.144	0.012	-11.660	0.000	-0.168	-0.120
20104	-0.171	0.012	-14.070	0.000	-0.194	-0.147
20111	-0.173	0.011	-15.170	0.000	-0.196	-0.151
20112	-0.189	0.011	-17.360	0.000	-0.211	-0.168
20113	-0.190	0.011	-17.040	0.000	-0.212	-0.168
20114	-0.205	0.011	-18.360	0.000	-0.227	-0.183
20121	-0.212	0.011	-19.000	0.000	-0.234	-0.190
20122	-0.176	0.012	-15.180	0.000	-0.199	-0.153
20123	-0.154	0.011	-13.660	0.000	-0.176	-0.132
20124	-0.123	0.012	-10.220	0.000	-0.147	-0.099
20131	-0.090	0.010	-9.480	0.000	-0.109	-0.072
20132	-0.038	0.009	-4.150	0.000	-0.056	-0.020
20133	-0.009	0.009	-1.000	0.317	-0.027	0.009
20134			--- omitted ---			

Table 8: Location and Home Type Model Results[31]

	All Homes	Location: California	Location: Rest of US	Home Type: New Homes	Home Type: Existing Homes
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0091	0.0085	0.0084	0.0094
PV*Size Standard Error	0.0007	0.0007	0.0032	0.0012	0.0008
PV*Size *p*-value	*0.000*	*0.000*	*0.009*	*0.000*	*0.000*
Mean Sale Price Non-PV ($)	$ 456,378	$ 459,366	$ 364,854	$ 422,001	$ 476,124
PV Premium ($/watt)	$ 4.18	$ 4.21	$ 3.11	$ 3.58	$ 4.51
95% CI ($/watt)	$ 0.62	$ 0.64	$ 2.33	$ 1.00	$ 0.71
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.93	$ 2.95	$ 2.15	$ 3.04	$ 2.86
Net Cost ($/watt)	$ 4.14	$ 4.16	$ 3.09	$ 3.85	$ 4.29
Gross Cost ($/watt)	$ 6.90	$ 6.94	$ 5.64	$ 7.34	$ 6.65
Model Info					
Total *n*	22,822	22,035	787	7,480	15,342
PV *n*	3,951	3,828	123	1,444	2,507
Non-PV *n*	18,871	18,207	664	6,036	12,835
Adjusted R^2	0.92	0.93	0.88	0.97	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,830	1,721	109	155	1,766

4.2.2 Home Type Model Results

Dividing the data by the type of home, specifically whether the home was newly built or existing at the time of sale, allows examination of the differences between these subgroups. In previous analyses, premiums for existing homes were found to be significantly larger than those for newly built homes, but the sample used was smaller, only for homes in California, only extended through 2009, and included homes with sales prices up to almost $3 million (Hoen et al., 2011; 2013a). The present analysis enables a reexamination of this question by using a sample that is larger, more broadly distributed geographically, has more recent data, and uses homes no more expensive than $900,000.

The results from the Home Type Models that used the new and existing home subsamples are shown in Table 8. New homes have a premium of $3.58/W, while existing homes have a premium of $4.51/W, a difference of approximately $1/W. Both estimates are highly statistically significant (p-values < 0.001) by themselves, but they are not statistically different from each other (difference in coefficients = 0.001, p-value = 0.46; not shown in table). Therefore, we are unable to uncover a difference in premiums between those subgroups with the larger, more geographically diverse and recent dataset. Nonetheless, the differences between these two sets of estimates mimic the different net costs, which are higher for existing homes than for newly built homes.

4.2.3 Age of PV System Model Results

Dividing the full sample into subsamples consisting of four quartiles based on PV system age (0.5–2.4 years, 2.4–3.8 years, 3.8–5.9 years, and 5.9–14 years) allows us to explore if the market accounts for PV system age when valuing PV systems. For this set of quartiles, only existing homes are used, because all

[31] Here, as in other results tables, the numbers of block groups for subsets of data do not always sum to 1,830. This occurs when the block groups are not mutually exclusive between the subsets, e.g., with new or existing homes.

newly built homes have PV systems that are also new. Table 9 contains the results for the full set of existing homes and the four other quartile models. Each of the four quartile models uses a different set of PV homes and a set of non-mutually exclusive CEM matched non-PV homes, to which the PV homes are compared.[32]

The coefficients for each progressively older subset of PV systems are monotonically ordered, going from 0.0123 for the systems 0.5–2.4 years old to 0.0055 for systems 5.9–14 years old. These translate into premiums of $5.90/W for the newest systems and $2.60/W for the oldest systems, with relatively stable 95% confidence intervals of approximately $1.40/W and somewhat decreasing cost and income estimates. Clearly home buyers and sellers place greater value on newer systems than on older systems, all else being equal. Although not shown here, additional models were estimated with additional older age groups (e.g., 10–14 years), but the confidence intervals around those estimates increased such that the results were not any more revealing than what is presented here. In none of the models, however, did we find an estimate close to zero. This seems to indicate that, as systems age, their value flattens out, but additional analysis in future years is needed to understand this trend better.[33]

Finally, it appears that the premiums, as systems age, start well above what would be predicted by the net cost estimates for young systems and then fall well below what would be predicted by the net cost estimates for older systems. This is an artifact of how the net cost estimates are calculated. As discussed in Section 3.2 the cost estimates are prepared without any depreciation and therefore are estimates of a new system. Of course new systems likely would not have the same value as otherwise identical older systems, but knowing the correct amount of depreciation to apply to these estimates is beyond the scope of this work.

[32] As described above, because the characteristics on which the PV homes are matched to the non-PV homes are exclusive of PV system age, the set of non-PV homes (and the block groups in which they are located) are not mutually exclusive across the models, but the same rules apply to these subsets in that for each block group that contains a PV home at least one matched non-PV home is present.

[33] Additionally, we calculated a linear estimate of age of PV interacted with PV system size, which was, not surprisingly, negative and highly statistically significant. Although this reaffirms that increasing age of PV systems is highly correlated with lower premiums, by its very nature it implies that PV systems lose 100% of their value at some point in time. This was calculated to be about 13 years, but it is at the end of our dataset and is not borne out in other tests (e.g., bins shown above, polynomial interactions, and additional binning for older systems). Therefore, we conclude that older systems are of lower value, but not of no value, at least given the age distribution of 0 to 14 years contained in the sample.

Table 9: Age of PV System Model Results

	Existing Homes	Age of PV System Groups 0.5-2.4	2.4-3.8	3.8-5.9	5.9-14
PV Premium Estimates					
PV*Size Coefficient	0.0094	0.0123	0.0113	0.0076	0.0055
PV*Size Standard Error	0.0008	0.0014	0.0014	0.0015	0.0016
PV*Size *p* -value	*0.000*	*0.000*	*0.000*	*0.000*	*0.001*
Mean Sale Price Non-PV ($)	$ 476,124	$ 477,737	$ 474,560	$ 478,634	$ 474,476
PV Premium ($/watt)	$ 4.51	$ 5.90	$ 5.40	$ 3.67	$ 2.60
95% CI ($/watt)	$ 0.71	$ 1.30	$ 1.33	$ 1.37	$ 1.51
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.86	$ 3.06	$ 3.03	$ 2.83	$ 2.52
Net Cost ($/watt)	$ 4.29	$ 4.49	$ 4.27	$ 4.24	$ 4.16
Gross Cost ($/watt)	$ 6.65	$ 7.08	$ 6.65	$ 6.54	$ 6.34
Model Info					
Total *n*	15,342	4,398	3,865	4,100	3,607
PV *n*	2,507	633	613	635	626
Non-PV *n*	12,835	3,765	3,252	3,465	2,981
Adjusted R^2	0.91	0.93	0.93	0.92	0.90
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,766	574	504	509	540

4.2.4 Year of Sale Model Results

Because the dataset spans the period from 2002 through 2013, we can examine how premiums change over time. This is especially interesting given that, in the same period, the costs for PV modules dropped (Barbose et al., 2013) and housing market prices saw a rapid rise, fall, and recovery. We break the data into four subsamples roughly consistent with these broad changes (2002–2007, 2008–2009, 2010–2011, and 2012–2013) and estimate the Base Model specification for each subsample.

Results from these models are contained in Table 10. The model results for the full dataset are also contained in Table 10 for reference. In each model, the coefficient of the variable of interest, *pv*size*, is highly statistically significant (p-value ≤ 0.001), with relatively stable standard errors ranging from 0.002 to 0.001, or a tenth of a percent. Despite varying levels of non-PV homes prices, which range from $512,170 to $440,495, premiums are relatively stable, ranging from $3.41/W to $4.54/W, with none being statistically different from each other over the various periods.

During this period, we see mean gross costs descend from a high of $8.97/W in 2002–2007 to a low of $5.45/W in 2012–2013. Net costs fall much less between these two periods, from $5.39/W to $3.58/W, while PV Value income estimates remain near, or slightly below, $3/W. Despite falling gross costs, and shifts in the overall housing market, premiums remain fairly flat and not statistically different from the net costs in all periods and from the PV Value income estimates in two out of four periods.

Table 10: Year of Sale Model Results

	All Homes	2002-2007	2008-2009	2010-2011	2012-2013
		Year of Sale Groups			
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0066	0.0103	0.0083	0.0093
PV*Size Standard Error	0.0007	0.0020	0.0016	0.0011	0.0010
PV*Size *p*-value	*0.000*	*0.001*	*0.000*	*0.000*	*0.000*
Mean Sale Price Non-PV ($)	$ 456,378	$ 512,170	$ 440,495	$ 448,976	$ 453,988
PV Premium ($/watt)	$ 4.18	$ 3.41	$ 4.54	$ 3.73	$ 4.23
95% CI ($/watt)	$ 0.62	$ 2.03	$ 1.34	$ 0.97	$ 0.88
Contributory Value Estimates					
PV Value - Income ($/watt)	$ 2.93	$ 2.79	$ 2.73	$ 3.00	$ 3.02
Net Cost ($/watt)	$ 4.14	$ 5.39	$ 4.56	$ 4.00	$ 3.58
Gross Cost ($/watt)	$ 6.90	$ 8.97	$ 8.25	$ 6.88	$ 5.45
Model Info					
Total *n*	22,822	2,368	3,895	7,238	9,321
PV *n*	3,951	464	882	1,146	1,459
Non-PV *n*	18,871	1,904	3,013	6,092	7,862
Adjusted R^2	0.92	0.96	0.96	0.95	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects *n*	1,830	259	313	630	1,022

4.3 Size of PV System Model

To examine if larger PV systems garner an equal, lower, or higher marginal price premium than smaller systems, we estimate a polynomial model as described in Equation (2) with parameters for *pv*size* and *pv*size*^{2}. Abbreviated results from this model are shown in Table 11. Coefficients for the first- and second-order polynomials are highly statistically significant (p-value < 0.02) and indicate decreasing marginal returns to increasing PV system size. The *pv*size* coefficient equates to a premium of $5.86/W, while the *pv*size*^{2} coefficient corresponds to a decrease in value of $0.53/W. Therefore, the model estimates that, up to approximately 10 kW, each increase in PV system size adds value to a home, but progressively less value for each addition. Beyond 10 kW, premium increases with increasing system size seem to flatten out, but we are less confident of the results because of the relatively few observations in this size range.[34]

[34] We also estimated models using subsets of data, each containing progressively larger systems, and find a similar pattern, with decreasing $/W premiums for increasing sizes.

Table 11: Size of PV System Model Results

	PV*Size	PV*Size^2
Coefficient	0.0128	-0.0006
Standard Error	0.0015	0.0002
p -value	0.0000	0.0130
Mean Sale Price Non-PV ($)	$ 456,377	$ 456,377
PV Premium ($/watt)	$ 5.86	$ (0.53)
95% CI ($/watt)	$ 1.35	$ 0.42
Model Info		
Total *n*	22,822	
PV *n*	3,951	
Non-PV *n*	18,871	
Adjusted R^2	0.92	
Dependent Variable	lnsp	
Block Group Fixed Effects *n*	1,830	

4.4 Robustness Models

The various models estimated above, which mostly are based on the Base Model and subsets of the data, compare PV home prices to non-PV home prices. Here we estimate two Robustness Models, which allow us to examine the robustness of the results under alternative specifications: the PV Only Model and the Repeat Sales Model. The PV Only Model compares selling prices of only PV homes, while the Repeat Sales Model examines the selling prices of the same home for homes sold once before the PV system was installed and again after it was installed, as described by Equation (3). These models use both different sets or subsets of the data and different specifications of the model, which allows them to control for possible specification biases in the Base Model. They, therefore, serve as valuable comparisons to and, potentially, validations of the Base Model results.

4.4.1 PV Only Model

Results for the PV Only Model are shown in Table 12. The coefficient for *pv*size* is effectively identical to that estimated for the Base Model with the full dataset, and it is highly statistically significant (*p*-value ≤ 0.001). The fact that the coefficient is identical to the Base Model coefficient is remarkable given that it is derived from a model that uses county fixed effects, rather than the more geographically precise block group fixed effect used in the Base Model. The estimated premium is $4.37/W, although the 95% confidence interval is considerably larger at $2.62/W vs. the Base Model's $0.62/W, indicating considerably less precision in the PV Only Model estimate.

4.4.2 Repeat PV Home Model

Results from the Repeat PV Home Model are also shown in Table 12. The coefficient for *pv*size* is very similar to that estimated for the Base Model with the full dataset, but it is not statistically significant (*p*-value = 0.113). The estimated premium is $4.60/W, which is also very similar to that of the Base Model, although the 95% confidence interval, at $5.69/W, is considerably larger than those for the Base and PV Only Models.

4.4.3 Summary of Robustness Checks

Because of the large margins of error, we cannot say the three estimates are statistically different from each other. Despite this, none of the results appear markedly different from that estimated using the Base

Model where PV homes are compared to non-PV homes. When comparing PV homes to other PV homes, as in the PV Only Model, or the same PV home to itself over multiple transactions, as in the Repeat PV Home Model, we find little evidence to support the claim that the Base Model PV premium estimate is biased. Therefore, there appears to be no evidence that the PV estimate also contains the effects of other omitted features such as EE upgrades.

Table 12: Robustness Model Results

PV Premium Estimates	**All Homes**	**PV Only**	**Repeat**
PV*Size Coefficient	0.0091	0.0092	0.0087
PV*Size Standard Error	0.0007	0.0028	0.0055
PV*Size *p*-value	*0.000*	*0.001*	*0.113*
Mean Sale Price Non-PV ($)	$ 456,377	$ 474,529	$ 528,368
PV Premium ($/watt)	$ 4.18	$ 4.37	$ 4.60
95% CI ($/watt)	$ 0.62	$ 2.62	$ 5.69
Contributory Value Estimates			
PV Value - Income ($/watt)	$ 2.93	$ 2.93	$ 2.15
Net Cost ($/watt)	$ 4.14	$ 4.14	$ 3.09
Gross Cost ($/watt)	$ 6.90	$ 6.91	$ 5.64
Model Info			
Total *n*	22,822	3,915	1,698
PV *n*	3,951	3,915	849
Non-PV *n*	18,871	-	849
Adjusted R^2	0.92	0.68	0.23
Dependent Variable	lnsp	lnsp	lnsp
Fixed Effects *n*	1,830	65	n/a

5. Discussion of Research Questions

This section explores in more detail the seven research questions listed in Table 1, building on the full set of results described above.

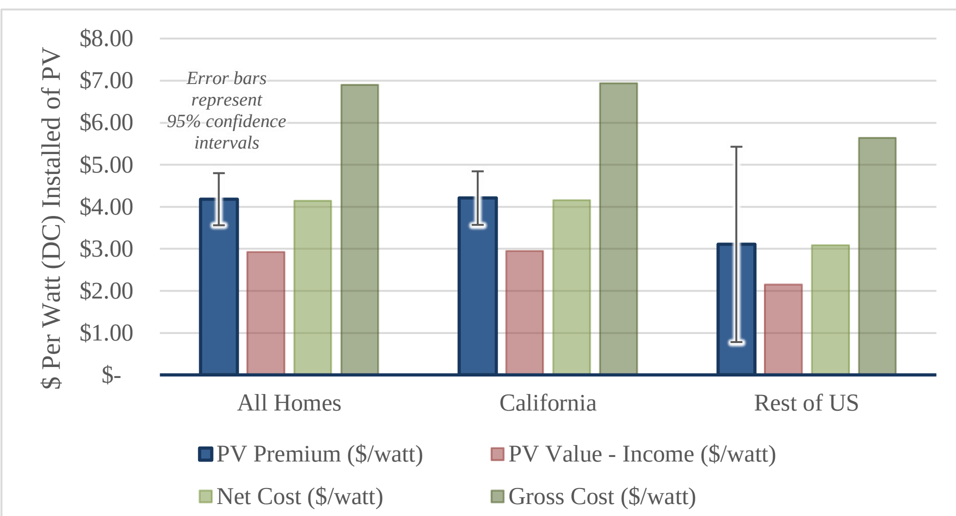
Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?

PV home premiums have been found by previous research of transactions of 15 PV homes in one California subdivision from 2001–2006 (Farhar and Coburn, 2008), of 594 PV homes in the San Diego and Sacramento metro areas between 1997–2010 (Dastrup et al., 2012), of approximately 1,900 PV homes in 31 California counties between 1999–2009 (Hoen et al., 2011; 2013a), and of 30 PV homes in the Denver metro area between 2011–2013 (Desmarais, 2013).

This analysis more than doubles the number of transactions analyzed, with data on almost 4,000 PV home transactions across 102 different counties in eight different states, including California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania. The data span the period from 2002 to 2013, with more than a third from 2012 and 2013 alone.

The Base Model and Location Models (Table 8 and Figure 1) show a consistent difference in PV home prices compared to matched non-PV homes across the dataset, with premiums ranging from a bit more than \$4/W in California to approximately \$3/W outside of California, both of which are highly statistically significant.[35] Moreover, this premium, as shown in the Year of Sale Models (Table 10 and Figure 2), survived both the dramatic decrease in installed costs over the study period as well as the market tumult which was the housing bubble, subsequent crash, and recovery. Clearly buyers of homes with PV are willing to pay a premium for PV, and this trend has continued despite dramatic changes in both the PV and housing markets. Finally, similarly sized premiums are found for the two robustness models—the PV Only Model and the Repeat PV Home Model—which further validates these results.

Figure 1: Base and Location Model Results



[35] The standard error for the Base Model of 0.0007 is 35% of the standard error found in the previous analysis of California PV homes of 0.0018 (Hoen et al. 2011; 2013a), indicating the increased precision of this estimate.

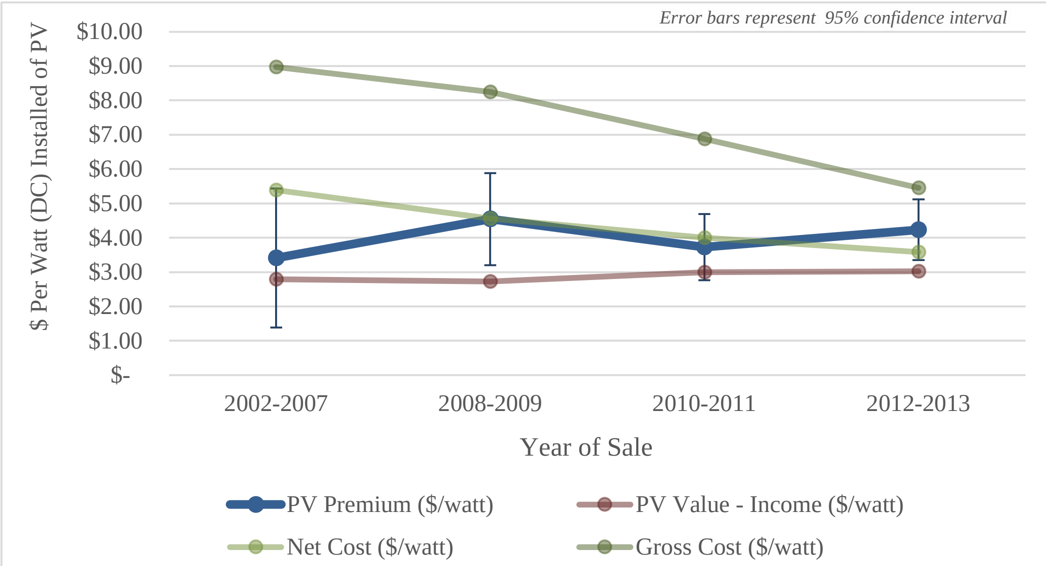
Are PV home premiums outside of California similar to those within California?

As shown in Table 8 and Figure 1, premiums for PV homes are estimated, on average, to be $1.10/W larger in California than outside of California. However, this difference, given the relatively large margin of error around the Rest of U.S. estimate, is not statistically significant. That notwithstanding, the apparent difference seems to echo decreases in each of the three other contributory value estimates we derived. For example, the gross and net costs in California are $1.30/W and $1.07/W higher than outside of California. Similarly, the PV Value income estimate is $0.80/W lower outside of California. In any case, these findings should give stakeholders outside of California greater confidence that PV adds value to homes in their markets.

How do PV home premiums compare to contributory values estimated using the cost and income methods?

The market premiums estimated from our suite of models seem to follow, at least to some degree, the contributory-value net cost estimates and, to a lesser degree, the PV Value estimates using the income approach, but not the gross cost estimates. For example, as shown in Figure 1, both the California and Rest of U.S. estimates are within a few pennies of the net cost estimates, but they are more than $2.50/W less than the gross cost estimates. Similarly, the Year of Sale Model results show PV premiums that are not statistically different in any period from the net cost estimates (Table 10 and Figure 2) despite widely changing gross cost estimates and underlying housing market tumult. Therefore, the net cost estimates—which account for the federal, state, and local incentives available at the time of sale—seem reasonably related to the value added (PV premiums) at least among average PV systems in our sample. Since the data indicate that, for the average systems in our sample, the PV premium is similar to the net cost estimate, it is reasonable to conclude the incentives are offsetting the influence of depreciation for those systems. At the same time and as discussed in further detail later, net cost estimates diverge from the calculated market premiums for those PV systems that are considerably newer or considerably older at the time of home sale. Depreciation in PV premiums is therefore apparent when other PV system ages are considered. As such, adjustments to net cost estimates may be required to account for market-derived depreciation. In this instance, it may be necessary for appraisers to estimate physical deterioration and functional obsolescence in situations where replacement costs exceed the contributory market value of older systems.

Figure 2: Year of Sale Model Results



Curiously, the PV Value income estimates are consistently lower than the premiums found in the market, while theory holds that cost savings should be a strong price signal. One reason for this disparity, which is especially evident in the California subset, might be related to the PV Value inputs that we used in this study, which were based on the average retail electricity rate. In California, tiered volumetric rates, which are based on the customer's consumption, are normal for most of the state's residential PV customers (CPUC, 2013). If customers consume more than the average retail customer, then they will be moved into higher-priced tiers. These tiers can be dramatic, with a doubling or even tripling of rates, depending on which tier the consumer falls into (CPUC, 2013). PV customers tend to be larger consumers of electricity than the average retail customer in California, thus they often pay more than the average (Darghouth et al., 2011; CPUC, 2013) and, with a PV system, may avoid higher-cost tiers altogether, increasing the value of the avoided costs. We cannot determine the exact level of this increase for the specific PV homes in our sample, but even a $0.05/kWh increase in the rate, which is well within the range proposed by others for PV customers (CPUC, 2013), would result in a substantial increase in the income estimate. The mean default electricity rate we entered into PV Value for the California portion of our sample is $0.1543/kWh. If that rate increased by $0.05/kWh, it would increase the PV Value estimate from $2.93/W to almost $4/W, within the margin of error of our premium estimate. Therefore, it seems possible that buyers and sellers might be using the cost savings as an important price signal, but they are estimating those savings at a slightly higher rate than the tool's default average retail rate. It is recommended that, when tiered rates are present that deviate substantially from the default average rate and normal consumption for a particular home would put the homeowner in higher tiers, users of the PV Value tool should input a custom rate that is more appropriate.[36]

How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?

While gross costs decreased dramatically over the study period, dropping 40% from $8.97/W in the 2002–2007 period to $5.45/W in the 2012–2013 period, PV premiums remained fairly consistent around

[36] For example, for California customers where tiered rates are common, weighting based on the tiers and the usage within each tier for particular PV homes might result in a more appropriate input rate.

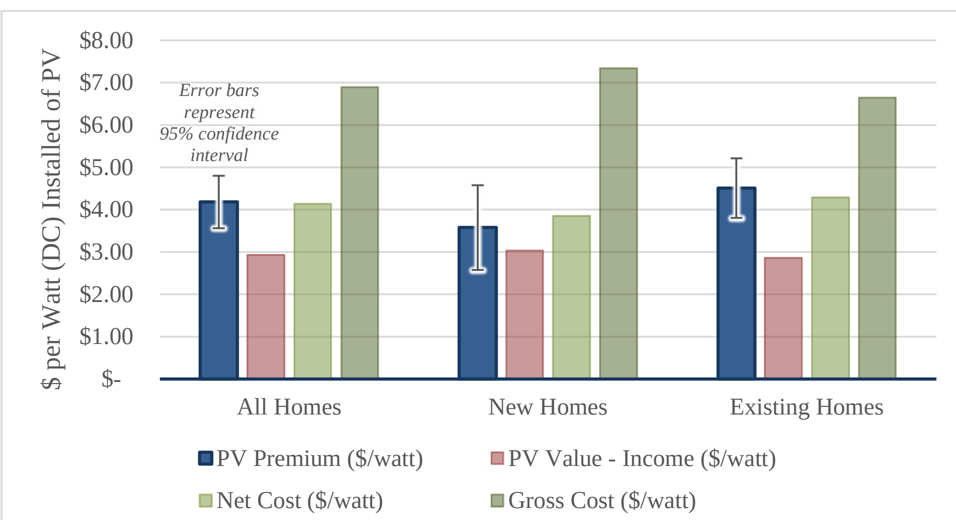
$4/W (see Figure 2). During this same period, the housing market was in upheaval, with a sizable rise, a subsequent crash, and then a recovery. This seems to show, first, that the gross cost is not a strong market signal. Rather, net cost, which over all periods was not statistically different from the premium, seems to be the more significant price signal. Moreover, it shows that the PV premium has been reasonably consistent during widely varying housing market conditions.

Are premiums for new PV homes similar to existing PV home premiums?

The results from the Home Type Model, which explores differences between new and existing home premiums, are shown in Table 8 and Figure 3. The average new home premiums of $3.58/W are lower than the existing home premiums of $4.51/W, a non-statistically significant difference of $0.93/W (*p*-value = 0.46). The net cost estimates for new homes are also lower (by $0.44/W) than those of existing homes, potentially explaining some of the difference.

Previous analyses found large, statistically significant differences between new and existing home premiums (Hoen et al., 2011; 2013a; 2013b). These differences occurred because existing home estimates were larger (near $6.50/W) and new home estimates were smaller (near $2.5/W) than found in the present analysis. It appears, based on analysis not shown here, that high-priced homes (e.g., over $1 million), which were included in the past analyses (up to $3.3 million) but excluded from this analysis, might explain a large portion of the differences. Including those homes in our analysis increased the existing home premiums and lowered the new home premiums, although not to the extent found previously. Including these homes also increased the margin of error around the estimates, however, implying that our models did a poorer job of explaining price differences and that many home and site characteristics for these homes likely are not included in the models. Further, the previous analyses included home transactions only through 2009, but this analysis included transactions through 2013, with two thirds occurring after 2009. In summation, this analysis is likely a better representation of the current market for most PV homes because it included many more recent sales, had more sales in total, and excluded high-priced homes (over $1 million) that were difficult to model, but it does not find a statistically significant difference between new and existing homes.

Figure 3: Home Type Model Results



One additional nuance to the present findings involves the new home premium and the net cost estimate. As discussed in Section 3.2, the net cost estimates (e.g., shown in Figure 3) represent the gross cost estimates less the appropriate federal and state incentives (and rebates where appropriate). The federal incentive, which normally comes in the form of an investment tax credit (ITC), is calculated as 30% of the gross cost of a PV system after state and utility incentives are applied. Interestingly, this incentive cannot be claimed by new home builders but instead only by the buyer of the home.[37] Therefore, the new home buyer not only receives the PV system on the home, but will also be able to receive a tax credit. Correspondingly, the net cost of the builder should not include this federal ITC reduction and, therefore, should be approximately $1.26/W higher and should affect the premium the buyer paid. This is interesting because we do not see a premium that reflects this incentive. If we did, the premium would be approximately $1.26/W higher or $4.84/W; instead we find a premium of $3.58/W.[38] Understanding the exact reasons for this discounting is beyond the scope of this work, but several plausible explanations exist: home builder discounting—the builder discounts the home for other reasons, for example to sell the home more rapidly (e.g., Dakin et al., 2008; SunPower, 2008), which has the effect of obscuring the premium related to the federal ITC; buyer discounting—the buyer is not willing to pay the full cost of the tax credit because it cannot be claimed until the following year when taxes are filed and might not be able to be claimed fully because of a lack of tax appetite by the homeowner; and lack of market clarity—because tax rules related to the federal ITC only recently were clarified (US IRS, 2013), both the home builder and buyer might not have consistently known if the ITC could be claimed.

Is there evidence of a "green cachet" for PV homes above the amount paid for each additional watt added?

Results from the Size of PV System Model suggest that the systems with the highest marginal premiums, in terms of dollars per watt, were the smallest systems, and as system size increased the dollar-per-watt premium decreased (Table 11). This decreasing slope is estimated in Figure 4 for PV systems from 1 to 10 kW, which shows both the decreasing dollar-per-watt value of each additional kilowatt added (left axis) and the total PV system premium (right axis). This indicates, potentially, that there is a fixed component of PV home premiums that occurs regardless of system size. This might indicate that a green cachet exists for PV homes in our sample. In other words, buyers might be willing to pay something for having any size of PV system on their homes and then some increment more depending on the size of the system. These findings echo those found previously (Dastrup et al., 2012).

How does the age of the PV system influence the size of the PV premium?

The results from the Age of PV System Models, which explore how premiums change as PV systems age, are shown in Table 9 and Figure 5. For systems installed on homes just before they were resold, larger premiums were garnered, with premiums falling by almost 60% in the oldest age group compared with the newest group.[39] This indicates that the market quickly depreciates PV systems in their first 10 years at a rate exceeding an average rate of PV efficiency losses, e.g., 0.5%/year (Dobos, 2014), and also exceeding the depreciation expected were straight-line depreciation applied over the asset's life; this might indicate functional obsolescence setting in. Because the mean age for the oldest quartile (5.9–14 years) is only 7.8 years (Figure 5), however, we cannot describe PV system values as they age into their second decade. Does their value level out and decrease at the rate of system degradation? Or do they lose 100% of their value before that? Those questions are recommended for future analyses.

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[37] In this instance we are referring to the federal ITC under Title 26 Section 25D of the Internal Revenue code (see: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F).

[38] The portion of the difference between net and gross cost attributable to the federal ITC ranges from approximately $0.80/W to as high as $1.84/W, with a mean of $1.26/W.

[39] Although not shown here, the average size of PV systems was very similar in all four age bins, at approximately 4.2 kW. We hypothesize that this larger premium for nearly new systems is related to additional nearly new features installed coincidently or the homeowner not fully taking advantage of tax incentives if they had planned on selling the home soon after the installation.

Figure 4: Estimated Dollar Per Watt Premium for Increasingly Larger PV Systems

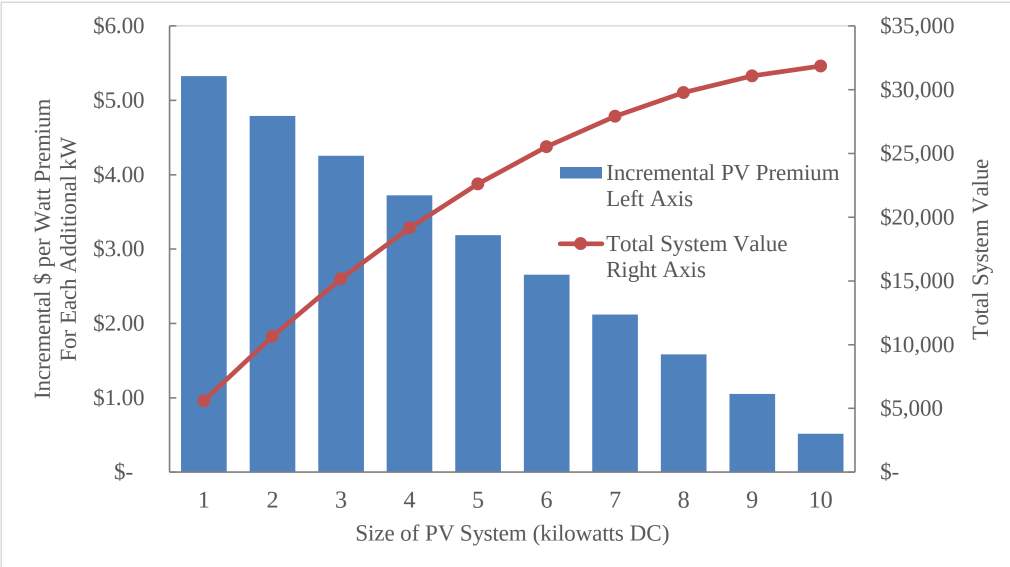
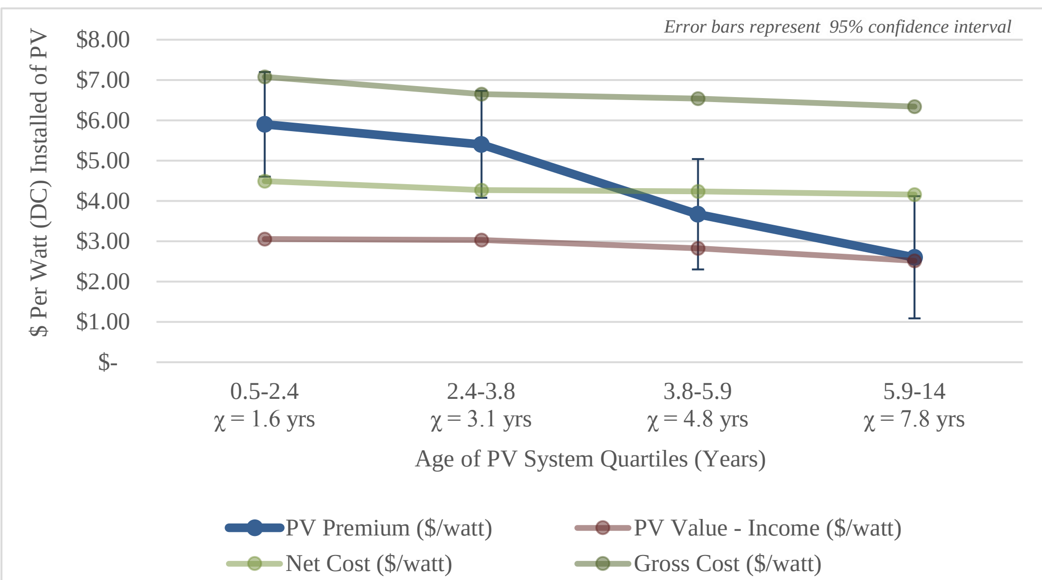


Figure 5: Age of PV System Model Results



6. Conclusion

As solar photovoltaic (PV) systems become an increasingly common feature of U.S. homes, the ability to value homes with these systems appropriately will become increasingly important. The U.S. Department of Energy estimates that achieving its SunShot PV system price-reduction targets could result in 108 GW of residential rooftop PV installed by 2050—equivalent to 30 million American homes with PV (US DOE, 2012).[40] Conversely, capturing the value of PV to residential properties is important for enabling a robust rooftop PV market.

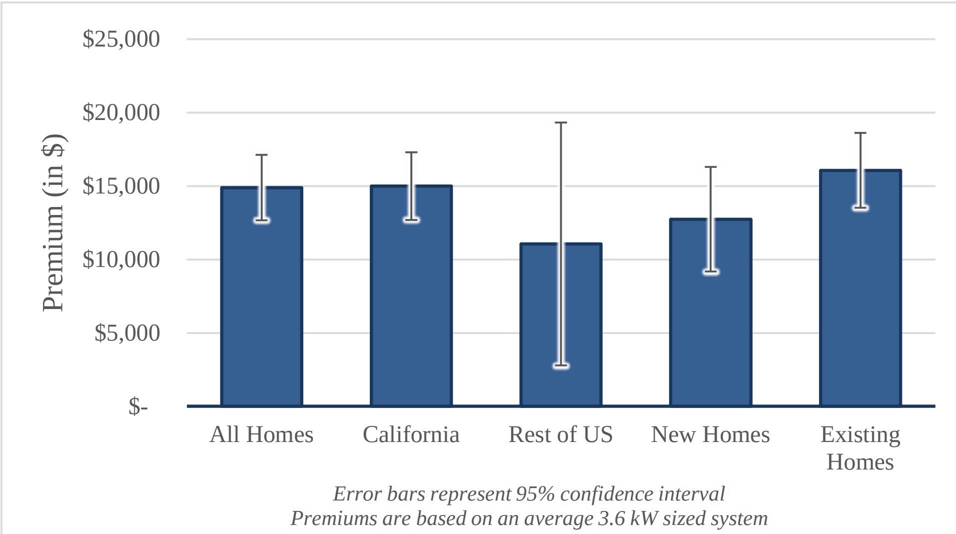
Appraisers, sales agents, and others tasked with property valuation have made strides toward valuing PV homes, and several limited studies suggest the presence of PV home premiums, particularly in California. Our study fills important gaps in this literature and illuminates various factors that might influence U.S. PV home premiums. The study more than doubles the number of PV home sales previously analyzed, examines transactions in eight different states, and spans the years 2002–2013, thus encompassing the recent housing boom, bust, and recovery. Based on our results, we draw the following major conclusions:

- Home buyers consistently have been willing to pay more for a property with PV across a variety of states, housing and PV markets, and home types. Average market premiums across the full sample of homes analyzed here are about $4/W or $15,000 for an average-sized 3.6-kW PV system (Figure 6).
- Our findings should provide greater confidence that PV adds value to non-California homes. Premiums for PV homes are $1.10/W larger in California than outside of California (respectively equating to $16,000 and $12,700 for an average-sized system – Figure 6), but this difference is not statistically significant: somewhat lower premiums outside of California are consistent with lower net cost and income estimates.
- Net cost estimates—which account for government and utility PV incentives—seem to be generally consistent with incremental market value premiums for the average PV home in our sample, but they do not appear to account accurately for market-based depreciation (the difference between value and cost). PV Value income estimates—which for this study used the default average retail rates—were consistently lower than the calculated market premiums, which seems to indicate that a higher retail rate would be more appropriate for that portion of the sample where tiered rates were present.
- PV premiums remained fairly consistent even as PV gross costs decreased dramatically over the study period and the housing market went through upheaval. This suggests that net cost, rather than gross cost, may be the more dominant market signal. It also suggests that PV premiums are robust to housing market conditions.
- In contrast to previous studies, our study found a relatively small and non-statistically significant difference between PV premiums for new and existing homes (respectively equating to $12,700 and $16,000 for an average-sized system – Figure 6), likely because our study includes many more sales and recent sales while excluding very-high-priced homes. That notwithstanding, there might be some evidence of either home builder or buyer discounting of new home PV systems.
- A green cachet might exist for PV homes; that is, buyers might be willing to pay a certain amount for having any size of PV system on their homes and then some increment more depending on the size of the system.
- The market appears to depreciate PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and of straight-line depreciation over the asset's life. Our data do not allow analysis

[40] Assuming the average PV system size of 3.6 kW found for all PV homes in this study.

of depreciation into the second decade of PV systems' operation—this is an area for future research.

Figure 6: Estimated Premiums Based on an Average-Sized 3.6 kW System



This study focuses only on homes with host-owned PV systems, as opposed to those with leased PV systems. Future analysis should focus on leased systems, because they are a growing portion of the PV home market and have not been studied. In addition, although our sample indicates that, as PV systems age, the size of the premium diminishes, our data are not robust to systems in their second decade; such older systems should be the focus of future study, as should the appropriate deprecation to place on PV systems throughout their lives.

Although this work allows for a robust analysis of average system premiums across the full dataset, and subsets of the data, the results are not necessarily applicable to individual markets and states that might have unique characteristics. Therefore, any market-specific ("small scale") analysis, especially one that employs appraisers and other valuers in those local markets, would be beneficial. Similarly, collecting and analyzing more data in a wide variety of states individually would be useful.

Because premium differences related to the availability of PV homes are unclear, investigating both buyer's markets (with many PV homes available) and seller's markets (with few PV homes available) would add clarity to PV home valuation. Finally, very large PV systems and systems on commercial properties were not represented in our data; both could have unique valuation characteristics and are thus areas for further study.

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8. Appendix A: Cost Estimate Preparation

To calculate both the net and gross cost estimates for each of the PV home transactions at the time of sale, we estimate a two-stage regression as used previously (Hoen et al., 2011; 2013a; 2013b). This procedure starts with the extensive dataset of more than 150,000 PV homes collected for TTS VI and their respective gross installed costs as reported (Barbose et al., 2013), for which the respective net installed costs (i.e., net of federal and state incentives) are calculated using the procedure outlined in Appendix C of Barbose et al. (2010). The first stage uses the net costs as the dependent variable and county, year, system size, and home type (new or existing) as the independent variables, in the following model:

$$C_{itsc} = \alpha + \beta_1(T_i) + \beta_2(S_i) + \beta_3(N_i) + \beta_4(C_i) + \varepsilon_{itsc} \qquad (4)$$

where

C_{itsc} is the "net installed cost" of PV system *i* after state and federal incentives from the full TTS dataset,

T_i is a vector of variables representing the year *t* in which the system was installed,

S_i is a vector of variables representing the size *s* of the system in rounded kilowatts (e.g., 1 kW, 2 kW, 3 kW…),

N_i is a fixed-effect variable indicating if the home was newly built when the system was installed,

C_i is a vector of variables representing the county *c* in which the system was installed,

α is the constant,

$\beta_{1\text{-}4}$ are coefficients for the parameters, and

ε_{itsc} is the error term.

The model accounts for the different state incentives and system component prices over the study period (via T_i), economies of scale (via S_i), different installed costs between new and existing homes (N_i), and the variety of rate structures, installer competitive prices, and market development (via C_i).

Using the predicted coefficients from this model, the data for the set of PV home transactions (county in which the home is located, PV system size, if the home is newly built, and substituting the sale year for the installation year *t*) are fed into the model to produce predicted net cost estimates. These represent, as of the time of sale, the approximate cost to replace a similarly sized system new on the same home.

An identical procedure is followed for gross cost estimates, except, for the first stage, C_{itsc} is the "gross installed cost" of PV system *i* <u>before</u> state and federal incentives from the full TTS VI dataset.

Tab 5

Presentations

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Floridians for Solar Choice, Inc.

SUBJECT: Financial Impact Statement for the Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 8, 2015

The Financial Impact Estimating Conference (FIEC) is statutorily charged with the responsibility of preparing a financial impact statement to the public regarding the probable financial impact of any amendment proposed by initiative. *See, § 5, Art. XI, Fla. Const. and § 100.371, Fla. Stat.* This memorandum is intended to provide information to the FIEC regarding the initiative entitled, "Limits or Prevents Barriers to Local Solar Electricity Supply" (Solar Amendment) from Floridians for Solar Choice, Inc., the Sponsors of the Solar Amendment. To put the Solar Amendment in context, this memorandum describes solar energy business models and explains the current Florida regulatory system of electric utilities and solar generated electricity, including the net metering requirements. Also included is a statement of the impact of the Solar Amendment on state and local revenues and costs.

The Solar Amendment

BALLOT TITLE: Limits or Prevents Barriers to Local Solar Electricity Supply

BALLOT SUMMARY: Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers.

ARTICLE AND SECTION BEING CREATED OR AMENDED: Add new Section 29 to Article X

FULL TEXT OF PROPOSED AMENDMENT:

Section 29. Purchase and sale of solar electricity. –

(a) PURPOSE AND INTENT. It shall be the policy of the state to encourage and promote local small-scale solar-generated electricity production and to enhance the availability of solar power to customers. This section is intended to accomplish this purpose by limiting and preventing regulatory and economic barriers that discourage the supply of electricity generated from solar energy sources to customers who consume the electricity at the same or a contiguous property as the site of the solar electricity production. Regulatory and economic barriers include rate, service and territory regulations imposed by state or local government on those supplying such local solar electricity, and imposition by electric utilities of special rates, fees, charges, tariffs, or terms and conditions of service on their customers consuming local solar electricity supplied by a third party that are not imposed on their other customers of the same type or class who do not consume local solar electricity.

(b) PURCHASE AND SALE OF LOCAL SMALL-SCALE SOLAR ELECTRICITY.

(1) A local solar electricity supplier, as defined in this section, shall not be subject to state or local government regulation with respect to rates, service, or territory, or be subject to any assignment, reservation, or division of service territory between or among electric utilities.

(2) No electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier.

(3) An electric utility shall not be relieved of its obligation under law to furnish service to any customer within its service territory on the basis that such customer also purchases electricity from a local solar electricity supplier.

(4) Notwithstanding paragraph (1), nothing in this section shall prohibit reasonable health, safety and welfare regulations, including, but not limited to, building codes, electrical codes, safety codes and pollution control regulations, which do not prohibit or have the effect of

prohibiting the supply of solar-generated electricity by a local solar electricity supplier as defined in this section.

(c) DEFINITIONS. For the purposes of this section:

(1) "local solar electricity supplier" means any person who supplies electricity generated from a solar electricity generating facility with a maximum rated capacity of no more than 2 megawatts, that converts energy from the sun into thermal or electrical energy, to any other person located on the same property, or on separately owned but contiguous property, where the solar energy generating facility is located.

(2) "person" means any individual, firm, association, joint venture, partnership, estate, trust, business trust, syndicate, fiduciary, corporation, government entity, and any other group or combination.

(3) "electric utility" means every person, corporation, partnership, association, governmental entity, and their lessees, trustees, or receivers, other than a local solar electricity supplier, supplying electricity to ultimate consumers of electricity within this state.

(4) "local government" means any county, municipality, special district, district, authority, or any other subdivision of the state.

(d) ENFORCEMENT AND EFFECTIVE DATE. This amendment shall be effective on January 3, 2017.

Purpose of the Constitutional Amendment

The Solar Amendment is intended to limit or prevent barriers to local solar electricity supply by accomplishing the following:

1. Prohibit the Public Service Commission (PSC) from regulating small scale solar energy providers as an electric utility. This means that small scale solar providers cannot be subject to PSC rate regulation, service regulation, or territorial regulation.

2. Preserve the electric utility's current obligation to serve customers who use local solar generated electricity.

3. Prohibit an electric utility's impairment of its customers' ability to purchase electricity from third party local solar energy providers by imposing unique rates, fees, charges, or terms or rules of service for customers making this choice.

In short, the Solar Amendment prohibits PSC-type regulation of local solar electricity suppliers.

What the Solar Amendment does not do:

1. Require or prohibit a change in the law regarding state or local taxation of solar energy.

2. Remove the authority of the State and local governments to regulate local solar energy suppliers regarding health, safety and welfare. For example, the amendment does not prohibit the applicability of electrical codes, building codes, or environmental protection regulations, and the like.

3. Eliminate the PSC's ability to regulate a local solar electricity supplier's interconnection of its generation facility via a customer's net metering arrangement with the electric utility, as long as the regulation does not allow the electric utility to discriminate against its customers choosing to purchase electricity from a local solar electricity supplier.

The Solar Amendment does not eliminate the PSC's ability to regulate interconnection and net metering for a local solar electricity supplier's customer who is connected to the electric grid. Such regulations are not regulations of the local solar electricity supplier's service, which are prohibited by the Solar Amendment. Rather, such regulations are regulations governing the relationship between the electric utility and its customer, and are authorized under the Solar Amendment as long as the regulations do not require the electric utility to discriminate against the customer because of its purchase of electricity from a local solar electricity supplier.

Solar Business Models

1. A property owner contracts for the purchase and installation of solar equipment that provides energy to the property. This model is currently authorized outside of PSC jurisdiction.

2. A property owner enters into a lease for the installation of solar equipment on the property with the solar energy being consumed on the property. The property owner pays the company for the use and maintenance of the solar equipment. This model is currently authorized outside of PSC jurisdiction.

3. A property owner allows a company to install equipment on the property and purchases some, but not necessarily all of the solar energy from the company. The purchase may be financed through a Power Purchase

Agreement which requires the purchaser to pay a monthly charge to the solar supplier based on the amount of solar electricity used at the property. This model is currently prohibited unless subjected to PSC jurisdiction.

4. A property owner provides solar generated electricity to itself and sells it to contiguous property owners. This model is currently prohibited unless subjected to PSC jurisdiction.

PSC Rate and Territorial Regulation of Electric Utilities

The Florida PSC has broad supervisory authority over "public" electric utilities, defined in the statutes to include Florida's five investor-owned electric utilities and any other type of electric utility that is not municipally owned or a rural electric cooperative. This broad supervisory power includes authority over the rates the public utilities charge, the service they provide and the means they use to finance their operations. In addition to the supervisory authority the PSC exercises over public utilities, the agency exercises authority over all electric utilities, including municipally owned electric utilities and rural electric cooperatives, for the following purposes:

- To prescribe uniform accounting systems and classifications;
- To prescribe a rate structure which establishes how rates are charged to allocate the utility's costs among different classes of customers;
- To require electric power conservation and reliability within a coordinated grid, for operational as well as emergency purposes;
- To approve territorial agreements among all types of electric utilities;
- To resolve territorial disputes;
- To require the filing of periodic reports and other data the PSC needs to carry out its regulatory jurisdiction;
- To supervise the planning, development and maintenance of a coordinated electric power grid throughout the state to assure an adequate and reliable source of energy for operational and emergency purposes and the avoidance of uneconomic duplication of facilities; and
- To prescribe and enforce safety standards for transmission and distribution facilities.

In addition to rates and territory, the PSC also regulates the service of public electric utilities. "Service" regulation includes those relating to the quality, reliability, safety and availability of service. Some of the PSC service regulations include the following:

- Prescribing the preferred location of distribution facilities (Rule 25-6.034, F.A.C);

- Prescribing standards for hardening against the impacts of hurricanes (Rule 25-6.0342, F.A.C.);
- Requiring the maintenance of a specified level of generating capacity above what is needed to meet reasonable load requirements (Rule 25-6.035, F.A.C.);
- Prescribing equipment standards (Rule 25-6.037, F.A.C);
- Requiring the collecting and tracking and reporting of reliability and continuity of service data (Rule 25-6.044, F.A.C.);
- Prescribing standards for variances between current supplied and service demand ratings (Rule 25-6047, F.A.C.);
- Rules governing the extension of service to new customers (Rule 25-6.064, F.A.C.); and
- Regulation of construction practices (Rule 25-6.081, F.A.C.), among others.

Barriers to Local Solar Electricity Supply

A "public" electric utility is defined as any person or legal entity "supplying electricity … to or for the public within this state . . . ." *See, § 366.02(1), Fla. Stat., attached as Appendix "A".* The Florida Supreme Court has determined that any single person or entity supplying electricity to a single different person or entity, even pursuant to a private contract between them with no offer to sell or supply electricity to the general public, is a "public utility" for the purposes of the statute, and is under the full regulatory jurisdiction of the PSC. *See, PW Ventures, Inc. v. Katie Nichols, 533 So.2d 281 (Fla. 1988), attached as Appendix "B".*

Therefore, under current law, any person or entity that owns a solar electric generating facility, such as an array of photo-voltaic solar panels, may not sell the electricity to another person, such as another homeowner, without coming under the full rate setting and service jurisdiction of the PSC and without being subject to existing PSC-enforced monopolies within established electric utility service territory. The exercise of rate, service, and territorial jurisdiction is intended to govern monopoly utilities with centralized power generation and sprawling networks of transmission and distribution power lines, and to prevent the uneconomic duplication of facilities. But the regulations also serve as a barrier in Florida to sales of locally generated solar electricity and to the use of Power Purchase Agreements, which are well-known small scale solar financing arrangements used in other states.

The Solar Amendment removes these regulatory barriers for the local sale of solar electricity generated on a limited scale. It prohibits rates, service and territorial regulation by the State and local governments except as otherwise provided in the Solar Amendment. The Solar Amendment's protection applies to local sales only: local sales include sales made to a customer on the same property as the facility generating the solar electricity, or sales made to a customer located on a property contiguous with the property where the facility generating the solar electricity is located. Further, it applies to sales of solar electricity generated only on a limited scale: up to two megawatts (2 MW) which has the potential to service an estimated 714 residential customers.[1] The Solar Amendment's 2 MW limitation coincides with the current PSC net metering rule.

PSC Regulation of Net Metering

Net metering is a system of metering electricity that allows a customer who connects an eligible renewable generation system, such as solar panels, to the electric grid to buy electricity from, and sell excess electricity back to, the electric utility. When a customer generates electricity from a solar array (for example) for his or her home or business, the amount of energy purchased from the electric utility is reduced, lowering the customer's monthly electric bills. If the solar array (used in this example) generates more electricity than can be used on the premises, the excess electricity flows through the two-way net meter onto the electric utility's distribution grid and is sold to the electric utility at a PSC-regulated price.

This activity is governed by the PSC's Interconnection and Net Metering of Customer-Owned Renewable Generation Rule. *See, Rule 25-6.065, F.A.C., attached as Appendix "C".* Under the Rule, the utility is authorized to charge the customer only for the amount of electricity used by the customer in excess of the amount of electricity the customer supplies to the grid. If at the end of the customer's billing cycle, he or she delivers more electricity to the grid than he or she consumes from it, the excess amount is credited to the customer's consumption for the next billing cycle. If consumption credits remain following a year of billing, the utility must pay the customer for the unused credits. The rate paid to the customer is the same rate paid to certain independent small power producers (also known as co-generators or Qualifying Facilities) which qualify under federal and state laws for a standardized wholesale payment rate.

In addition to authorizing the use of net metering and requiring payment of credits, the Rule establishes standards for the interconnection of the renewable generation facility to the grid, and prescribes what fees, if any, the electric utility can charge to the customer. The standards and fees may vary depending on the size of the facility; however, the Rule prohibits interconnection with the electric utility if the rated capacity of the renewable generation facility exceeds 90 percent of the customer's service rating established by the utility.

The Rule recognizes three Tiers. Tier 1 consists of facilities rated 10 kW or less. Tier 2 consists of facilities rated greater than 10 kW up to 100 kW. Tier 3 consists of facilities rated greater than 100 kW up to 2,000 kW (2 MW). A customer interconnecting a Tier 1 or 2 facility may do so without additional design or testing. Additional design

[1] 1 MW can serve the demand of 357 residential customers, based on an average demand of 2.8 kW, according to recent information provided by the PSC upon request of the Sponsor.

and testing standards to those included in the Rule may be imposed for a Tier 3 facility of sufficient size to require an interconnection study. The Rule also prohibits the utility from imposing any additional charge on a customer interconnecting a Tier 1 facility, but allows an application charge for Tiers 2 and 3 and an interconnection study charge for Tier 3.

Currently, a property owner who owns his own solar panels can net meter. A property owner who leases panels from a third party can net meter. These activities are permitted because the property owner is not purchasing solar electricity from a third party, but is instead purchasing or leasing the panels. A property owner who buys solar generated power from a company which has placed solar panels on his or her property cannot net meter.

Interconnection Regulation Under the Solar Amendment

Under the Solar Amendment, the PSC maintains the authority to regulate the interconnection between the customer who purchases electricity from a local solar electricity supplier and the customer's electric utility, as long as the regulations do not require the electric utility to impose any unique rules, rates, charges, or other conditions on the customer because of the customer's purchase of electricity from the local solar electricity supplier.

Effect on State and Local Revenues and Costs

The Solar Amendment's intent is to limit or prevent barriers to local solar electricity supply. It does not alter the current rates or the application of State and local government taxes and fees on solar generated energy. Thus, the Solar Amendment will have no direct impact on State and local government revenues.

It is currently unknown and speculative, how many, if any, businesses or households may avail themselves of any new solar business models that may enter the Florida market as a consequence of the Solar Amendment.

With regard to costs of the State and local government as a potential purchaser of solar generated electricity, it would be speculative to predict future policy and purchasing decisions of the State and local governments.

LIST OF APPENDICES

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Rule 25-5.065, F.A.C. C

.

APPENDIX A

The 2014 Florida Statutes

366.02 Definitions.—As used in this chapter:

(1) "Public utility" means every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state; but the term "public utility" does not include either a cooperative now or hereafter organized and existing under the Rural Electric Cooperative Law of the state; a municipality or any agency thereof; any dependent or independent special natural gas district; any natural gas transmission pipeline company making only sales or transportation delivery of natural gas at wholesale and to direct industrial consumers; any entity selling or arranging for sales of natural gas which neither owns nor operates natural gas transmission or distribution facilities within the state; or a person supplying liquefied petroleum gas, in either liquid or gaseous form, irrespective of the method of distribution or delivery, or owning or operating facilities beyond the outlet of a meter through which natural gas is supplied for compression and delivery into motor vehicle fuel tanks or other transportation containers, unless such person also supplies electricity or manufactured or natural gas.

(2) "Electric utility" means any municipal electric utility, investor-owned electric utility, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state.

(3) "Commission" means the Florida Public Service Commission.

History.—s. 2, ch. 26545, 1951; s. 3, ch. 76-168; s. 1, ch. 77-457; ss. 2, 16, ch. 80-35; s. 2, ch. 81-318; ss. 1, 20, 22, ch. 89-292; s. 4, ch. 91-429; s. 14, ch. 92-284.

APPENDIX B

PW VENTURES, INC., Appellant, v. KATIE NICHOLS, Chairman of Florida Public Service Commission, and FLORIDA PUBLIC SERVICE COMMISSION, Appellees

No. 71,462

Supreme Court of Florida

533 So. 2d 281*; *1988 Fla. LEXIS 1161*; *13 Fla. L. Weekly 635

October 27, 1988

PRIOR HISTORY: [**1] An Appeal from the Public Service Commission.

COUNSEL: Richard D. Melson of Hopping, Boyd, Green & Sams, Tallahassee, Florida, for Appellant.

Susan F. Clark, General Counsel, Florida Public Service Commission, Tallahassee, Florida, for Appellees.

Richard A. Zambo and Paul Sexton of Richard A. Zambo, P.A., Brandon, Florida, for Amici Curiae: C.F. Industries, Inc., IMC Fertilizer, Inc., The Monsanto Company and W. R. Grace & Co.

JUDGES: Grimes, J. Ehrlich, C.J., and Overton, Shaw, Barkett and Kogan, JJ., concur. McDonald, J., dissents with an opinion.

OPINION BY: GRIMES

OPINION

[*282] PW Ventures, Inc. (PW Ventures) appeals from an adverse ruling of the Florida Public Service Commission (PSC). We have jurisdiction. *Art. V, § 3(b)(2), Fla. Const.*

PW Ventures [1] signed a letter of intent with Pratt and Whitney (Pratt) to provide electric and thermal power at Pratt's industrial complex in Palm Beach County. PW Ventures proposes to construct, own, and operate a cogeneration [2] project on land leased from Pratt and to sell its output to Pratt under a long-term take or pay contract. [3] Before proceeding with construction of the facility that would provide the power, PW Ventures sought a declaratory statement from the PSC that it would [**2] not be a public utility subject to PSC regulation. After a hearing, the PSC ruled that PW Ventures proposed transaction with Pratt fell within its regulatory jurisdiction.

1 PW Ventures is a Florida corporation which was originally owned by FPL Energy Services, Inc. (a wholly owned subsidiary of FPL Group, Inc.) and Impell Corporation (a wholly owned subsidiary of Combustion Engineering, Inc.). After the entry of the PSC order, FPL Energy Services, Inc. transferred its 50% interest to Combustion Engineering, Inc.

2 Cogeneration involves the use of steam power to produce electricity, with some of the energy from the steam being recaptured for further use. The PSC seeks only to regulate the sale of electrical power.

3 The power would be used by Pratt and several affiliated corporate entities and by the Federal Aircraft Credit Union which is also located on the property.

At issue here is whether the sale of electricity to a single customer [4] makes the provider a public utility. The decision hinges on the phrase "to the public," as it is used in *section 366.02(1), Florida Statutes* (1985). In pertinent part that subsection provides:

> "Public utility" means every person, [**3] corporation, partnership, association, or other [*283] legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state . . . .

4 While the PSC reminds us that the power generated by the project will actually be passed on to several entities, we prefer to address the issue in the context argued by PW Ventures.

Distilled to their essence, the parties' views are as follows: PW Ventures says the phrase "to the public" means to the general public and was not meant to apply to a bargained-for transaction between two businesses. The PSC says the phrase means "to any member of the public." While the issue is not without doubt, we are inclined to the position of the PSC.

At the outset, we note the well established principle that the contemporaneous construction of a statute by the agency charged with its enforcement and interpretation is entitled to great weight. *Warnock v. Florida Hotel & Restaurant Comm'n, 178 So.2d 917 (Fla. 3d DCA 1965), appeal dismissed, 188 So.2d 811 (Fla. 1966)*. The courts will not depart from such a construction unless it is clearly unauthorized or erroneous. [**4] *Gay v. Canada Dry Bottling Co., 59 So.2d 788 (Fla. 1952).*

Also, it is significant that the statute itself would permit the type of transaction proposed by PW Ventures and Pratt to be unregulated if it were for natural gas services. *Section 366.02(1)* provides the following exemption: "The term 'public utility' as used herein does not include . . . any natural gas pipeline transmission company making only sales of natural gas at wholesale and to direct industrial consumers. . . ." The legislature did not provide a similar exemption for electricity. The express mention of one thing implies the exclusion of another. *Thayer v. State, 335 So.2d 815 (Fla. 1976).*

This rationale is further illustrated in the statutory regulation of water and sewer utilities. As explained in the PSC order:

> In parallel with *Section 366.02(1), Section 367.021, Florida Statutes* (1985), defines a water or sewer utility as every person "providing, or who proposes to provide, water or sewer service to the public for compensation." *Section 367.022(6), Florida Statutes*, expressly exempts from this definition "systems with the capacity or proposed capacity to serve 100 or fewer persons". There is not a parallel [**5] numerical exemption to the statutory definition of a public utility supplying electricity. Yet the statutory interpretation advocated by PW Ventures would require a line to be drawn somewhere between sales to some members of the public, as a presumably nonjurisdictional activity, and sales to the public generally and indiscriminately, an admittedly jurisdictional activity.

Moreover, the PSC's interpretation is consistent with the legislative scheme of chapter 366. The regulation of the production and sale of electricity necessarily contemplates the granting of monopolies in the public interest. *Storey v. Mayo, 217 So.2d 304 (Fla 1968), cert. denied, 395 U.S. 909, 89 S. Ct. 1751, 23 L. Ed. 2d 222 (1969). Section 366.04(3), Florida Statutes* (1985), directs the PSC to exercise its powers to avoid "uneconomic duplication of generation, transmission, and distribution facilities." If the proposed sale of electricity by PW Ventures is outside of PSC jurisdiction, the duplication of facilities could occur. What PW Ventures proposes is to go into an area served by a utility and take one of its major customers. [5] Under PW Ventures' interpretation, other ventures could enter into similar contracts with other high use [**6] industrial complexes on a one-to-one basis and drastically change the regulatory scheme in this state. The effect of this practice would be that revenue that otherwise would have gone to the regulated utilities which serve the affected areas would be diverted to unregulated producers. This revenue would have to be made up by the remaining customers of the regulated utilities since the fixed costs of the regulated systems would not have been reduced.

5 Initially, Florida Power and Light had an interest in PW Ventures and would, in effect, transfer its own client to a subsidiary. FP & L is not now involved. Yet, if the argument of PW Ventures is accepted, there might be nothing to prevent one utility company from forming a subsidiary and raiding large industrial clients within areas served by another utility.

[*284] We do not believe that *Fletcher Properties v. Florida Public Service Commission, 356 So.2d 289 (Fla. 1978)*, mandates a different result. In that case, we did approve a PSC order which included reasoning to the effect that service to the public meant service to the indefinite public or to all individuals within a given area. However, the case did not arise in the context [**7] of a sale to a single customer. We simply affirmed the PSC's determination that the developer and owner of lines and lift stations who proposed to furnish water and sewer service to single family homes at the same rate as it was charged by the area water and sewer utility occupied the status of a public utility. [6]

> 6 The holding of that case actually supports the PSC's alternative position that PW Ventures will actually serve several customers at the Pratt facility.

The fact that the PSC would have no jurisdiction over the proposed generating facility if Pratt exercised its option under the letter of intent to buy the facility and elected to furnish its own power is irrelevant. The expertise and investment needed to build a power plant, coupled with economies of scale, would deter many individuals from producing power for themselves rather than simply purchasing it. The legislature determined that the protection of the public interest required only limiting competition in the sale of electric service, not a prohibition against self-generation.

We approve the decision of the Public Service Commission.

It is so ordered.

Ehrlich, C.J., and Overton, Shaw, Barkett and Kogan, JJ., concur. McDonald, J., dissents with an opinion.

DISSENT BY: McDONALD

DISSENT

McDONALD, J., dissenting.

I dissent. In doing so, [**8] I accept the argument of PW Ventures, Inc. as set forth in its brief where it urges:

> The cornerstone of "public utility" status and Commission jurisdiction under Chapter 366 is the provision of electric service "to the public". This phrase is not defined in Chapter 366, nor in any of the Commission's other jurisdictional statutes. Under Florida's rules of statutory construction, the phrase "to the public" must therefore be given either its plain and ordinary meaning or, if it is a legal term of art, its legal meaning. *City of Tampa v. Thatcher Glass Corporation, 445 So.2d 578 (Fla. 1984)*; *Citizens v. Florida Public Service Commission, 425 So.2d 534 (Fla. 1982)*; *Tatzel v. State, 356 So.2d 787 (Fla. 1978)*; *Ocasio v. Bureau of Crimes Compensation, 408 So.2d 751 (Fla. 3d DCA 1982)*. Under either test, a sale to a single industrial host in the circumstances of this case is not a sale "to the public."
>
> * * *
>
> The phrase "to the public" commonly connotes the people as a whole, or at least a group of people. Webster's Ninth New Collegiate Dictionary (1983) gives two relevant definitions for "public":
>
>> 2: the people as a whole: POPULACE
>>
>> 3: a group of people having common interests or characteristics: [**9] *specif*: the group at which a particular activity or enterprise aims
>
> Black's Law Dictionary (Revised 4th ed.) similarly defines "public" to mean:
>
>> The whole body politic, or the aggregate of the citizens of a state, district, or municipality. . . . In one sense, everybody; and accordingly the body of the people at large; the community at large, without reference to the geographical limits of any corporation like a city, town, or county; the people. In another sense the word does not mean all the people, nor most of the people, nor very many of the people of a place, but so many as contradistinguishes them from a few.
>
> Thus if *Section 366.02(1)* is given its plain and ordinary meaning, a person is not supplying electricity "to the public, " if it supplies electricity only to a single [*285] industrial customer on whose property the electric generating facility is located.

APPENDIX C

25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.

(1) Application and Scope. The purpose of this rule is to promote the development of small customer-owned renewable generation, particularly solar and wind energy systems; diversify the types of fuel used to generate electricity in Florida; lessen Florida's dependence on fossil fuels for the production of electricity; minimize the volatility of fuel costs; encourage investment in the state; improve environmental conditions; and, at the same time, minimize costs of power supply to investor-owned utilities and their customers. This rule applies to all investor-owned utilities, except as otherwise stated in subsection (10).

(2) Definitions. As used in this rule, the term.

(a) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy. The term "customer-owned renewable generation" does not preclude the customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions that do not include the retail purchase of electricity from the third party.

(b) "Gross power rating" means the total manufacturer's AC nameplate generating capacity of an on-site customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility's distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site.

(d) "Renewable energy," as defined in Section 377.803, F.S., means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, solar energy, geothermal energy, wind energy, ocean energy, waste heat, or hydroelectric power.

(3) Standard Interconnection Agreements. Each investor-owned utility shall, within 30 days of the effective date of this rule, file for Commission approval a Standard Interconnection Agreement for expedited interconnection of customer-owned renewable generation, up to 2 MW, that complies with the following standards:

(a) IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems;

(b) IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

(c) UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

(d) A copy of IEEE 1547 (2003), ISBN number 0-7381-3720-0, and IEEE 1547.1 (2005), ISBN number 0-7381-4737-0, may be obtained from the Institute of Electric and Electronic Engineers, Inc. (IEEE), 3 Park Avenue, New York, NY, 10016-5997. A copy of UL 1741 (2005) may be obtained from COMM 2000, 1414 Brook Drive, Downers Grove, IL 60515.

(4) Customer Qualifications and Fees.

(a) To qualify for expedited interconnection under this rule, customer-owned renewable generation must have a gross power rating that:

1. Does not exceed 90% of the customer's utility distribution service rating; and

2. Falls within one of the following ranges:

Tier 1 – 10 kW or less;

Tier 2 – greater than 10 kW and less than or equal to 100 kW; or

Tier 3 – greater than 100 kW and less than or equal to 2 MW.

(b) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in subsection (3).

(c) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to paragraph (4)(b) that performs the function of automatically isolating the customer-owned generation equipment from the electric grid in the event the electric grid loses power.

(d) For Tiers 1 and 2, provided the customer-owned renewable generation equipment complies with paragraphs (4)(a) and (b), the investor-owned utility shall not require further design review, testing, or additional equipment other than that provided for in subsection (6). For Tier 3, if an interconnection study is necessary, further design review, testing and additional equipment as identified in the study may be required.

(e) Tier 1 customers who request interconnection of customer-owned renewable generation shall not be charged fees in addition to those charged to other retail customers without self-generation, including application fees.

(f) Along with the Standard Interconnection Agreement filed pursuant to subsection (3), each investor-owned utility may propose for Commission approval a standard application fee for Tiers 2 and 3, including itemized cost support for each cost contained within the fee.

(g) Each investor-owned utility may also propose for Commission approval an Interconnection Study Charge for Tier 3.

(h) Each investor-owned utility shall show that their fees and charges are cost-based and reasonable. No fees or charges shall be assessed for interconnecting customer-owned renewable generation without prior Commission approval.

(5) Contents of Standard Interconnection Agreement. Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement shall, at a minimum, contain the following:

(a) A requirement that customer-owned renewable generation must be inspected and approved by local code officials prior to its operation in parallel with the investor-owned utility to ensure compliance with applicable local codes.

(b) Provisions that permit the investor-owned utility to inspect customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with subsections (2) through (4). The customer shall notify the investor-owned utility at least 10 days prior to initially placing customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on the in-service date. If the customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the customer must notify the investor-owned utility by submitting a new application specifying the modifications at least 30 days prior to making the modifications.

(c) A provision that the customer is responsible for protecting the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the investor-owned utility system in delivering and restoring power; and is responsible for ensuring that customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer's instructions to ensure that it is operating correctly and safely.

(d) A provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation of the customer-owned renewable generation, except when the loss occurs due to the negligent actions of the investor-owned utility. A provision that the investor-owned utility shall hold harmless and indemnify the customer for all loss to third parties resulting from the operation of the investor-owned utility's system, except when the loss occurs due to the negligent actions of the customer.

(e) A requirement for general liability insurance for personal and property damage, or sufficient guarantee and proof of self-insurance, in the amount of no more than $1 million for Tier 2, and no more than $2 million for Tier 3. The investor-owned utility shall not require liability insurance for Tier 1. The investor-owned utility may include in the Interconnection Agreement a recommendation that Tier 1 customers carry an appropriate level of liability insurance.

(f) Identification of any fees or charges approved pursuant to subsection (4).

(6) Manual Disconnect Switch.

(a) Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement may require customers to install, at the customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the customer-owned renewable generation and any customer wiring connected to the investor-owned utility's system. Inverter-based Tier 1 customer-owned renewable generation systems shall be exempt from this requirement, unless the manual disconnect switch is installed at the investor-owned utility's expense. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the investor-owned utility and capable of being locked in the open position with a single investor-owned utility padlock.

(b) The investor-owned utility may open the switch pursuant to the conditions set forth in paragraph (6)(c), isolating the customer-owned renewable generation, without prior notice to the customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the utility shall at the time of disconnection leave a door hanger notifying the customer that their customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The investor-owned utility shall reconnect the customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.

(c) Any of the following conditions shall be cause for the investor-owned utility to disconnect customer-owned renewable generation from its system:

1. Emergencies or maintenance requirements on the investor-owned utility's electric system;

2. Hazardous conditions existing on the investor-owned utility system due to the operation of the customer's generating or protective equipment as determined by the investor-owned utility;

3. Adverse electrical effects, such as power quality problems, on the electrical equipment of the investor-owned utility's other electric consumers caused by the customer-owned renewable generation as determined by the investor-owned utility;

4. Failure of the customer to maintain the required insurance coverage.

(7) Administrative Requirements.

(a) Each investor-owned utility shall maintain on its website a downloadable application for interconnection of customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the investor-owned utility shall provide a hard copy of the application within 5 business days.

(b) Within 10 business days of receipt of the customer's application, the investor-owned utility shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the utility shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the customer-owned renewable generation necessary for the investor-owned utility to confirm compliance with subsections (2) through (6), and confirmation of whether a Tier 3 interconnection study will be necessary.

(c) The Standard Interconnection Agreement shall be executed by the investor-owned utility within 30 calendar days of receipt of a completed application. If the investor-owned utility determines that an interconnection study is necessary for a Tier 3 customer, the investor-owned utility shall execute the Standard Interconnection Agreement within 90 days of a completed application.

(d) The customer must execute the Standard Interconnection Agreement and return it to the investor-owned utility at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the utility within 30 calendar days of receipt of the customer's executed Standard Interconnection Agreement. If the inspection is delayed at the customer's request, the customer shall contact the utility to reschedule an inspection. The investor-owned utility shall reschedule the inspection within 10 business days of the customer's request.

(8) Net Metering.

(a) Each investor-owned utility shall enable each customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.

(b) Each investor-owned utility shall install, at no additional cost to the customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the customer from the investor-owned utility and the electricity generated by the customer and delivered to the investor-owned utility's electric grid.

(c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.

(d) The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation in accordance with normal billing practices.

(e) During any billing cycle, excess customer-owned renewable generation delivered to the investor-owned utility's electric grid shall be credited to the customer's energy consumption for the next month's billing cycle.

(f) Energy credits produced pursuant to paragraph (8)(e) shall accumulate and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the investor-owned utility shall pay the customer for any unused energy credits at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(g) When a customer leaves the system, that customer's unused credits for excess kWh generated shall be paid to the customer at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(h) Regardless of whether excess energy is delivered to the investor-owned utility's electric grid, the customer shall continue to pay the applicable customer charge and applicable demand charge for the maximum measured demand during the billing period. The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation at the investor-owned utility's otherwise applicable rate schedule. The customer may at their sole discretion choose to take service under the investor-owned utility's standby or supplemental service rate, if available.

(9) Renewable Energy Certificates. Customers shall retain any Renewable Energy Certificates associated with the electricity

produced by their customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the customer's expense, unless otherwise determined during negotiations for the sale of the customer's Renewable Energy Certificates to the investor-owned utility.

(10) Reporting Requirements. Each electric utility, as defined in Section 366.02(2), F.S., shall file with the Commission as part of its tariff a copy of its Standard Interconnection Agreement form for customer-owned renewable generation. In addition, each electric utility shall report the following, by April 1 of each year.

(a) Total number of customer-owned renewable generation interconnections as of the end of the previous calendar year;

(b) Total kW capacity of customer-owned renewable generation interconnected as of the end of the previous calendar year;

(c) Total kWh received by interconnected customers from the electric utility, by month and by year for the previous calendar year;

(d) Total kWh of customer-owned renewable generation delivered to the electric utility, by month and by year for the previous calendar year; and

(e) Total energy payments made to interconnected customers for customer-owned renewable generation delivered to the electric utility for the previous calendar year, along with the total payments made since the implementation of this rule.

(f) For each individual customer-owned renewable generation interconnection:

1. Renewable technology utilized;

2. Gross power rating;

3. Geographic location by county; and

4. Date interconnected.

(11) Dispute Resolution. Parties may seek resolution of disputes arising out of the interpretation of this rule pursuant to Rule 25-22.032, F.A.C, Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

Rulemaking Authority 350.127(2), 366.05(1), 366.92 FS. Law Implemented 366.02(2), 366.04(2)(c), (5), (6), 366.041, 366.05(1), 366.81, 366.82(1), (2), 366.91(1), (2), 366.92 FS. History–New 2-11-02, Amended 4-7-08.

Floridians for Solar Choice

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Floridians for Solar Choice, Inc.

SUBJECT: Financial Impact Statement for the Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 22, 2015

This second memorandum from the sponsors of the Solar Amendment to the FIEC is intended to provide additional information on issues raised at the FIEC public hearing on April 10, 2015. This memorandum discusses the Solar Amendment's implications for the wheeling of local solar energy on the electric grid, the electric utilities' recovery of sunk costs, and local government franchise agreements. The memorandum considers these issues within the context of the FIEC's duty to issue a statement on the Solar Amendment's probable financial impact on the revenues and costs to the state and local governments.

Wheeling

The Solar Amendment envisions a local solar electricity supplier directly providing electricity to its customer instead of using the electric utility's grid to transmit and distribute or "wheel" the electricity to its customer. The Solar Amendment neither prohibits nor requires wheeling through the electric grid to a customer the electricity generated by a local solar electricity supplier. In the event wheeling occurs, the Solar Amendment does not prohibit an electric utility from charging rates for such a service provided to a local solar electricity supplier or its customer when such rates are also charged for wheeling electricity generated by a source other than a local solar electricity supplier.

Restriction on Regulating Local Solar Electricity Suppliers

Paragraph (b)(1) of the Solar Amendment prohibits state or local government from regulating a local solar electricity supplier "with respect to its rates, service, or territory," and further provides that such a local solar electricity supplier may not be "subject to any assignment, reservation, or division of service territory between or among electric utilities." In a scenario where a local solar electricity supplier desires to use the electric grid owned by an electric utility, nothing in paragraph (b)(1) prevents the electric utility from charging the local solar electricity supplier for the service of transporting the electricity on behalf of the local solar electricity supplier, and nothing prevents the entity regulating rates from approving any such rate or charge.

By its plain language, paragraph (b)(1) restricts government authority over rates and service of a local solar electricity supplier, but imposes no such restriction on regulation of rates and service of electric utilities. A state agency's or local government's requirement that the electric utility charge a particular rate or fee for "wheeling" services, and that such a rate or fee be established following prescribed procedures, is not a regulation of the local solar electricity supplier's rates, service or territory, because such requirements do not regulate the rates the solar electricity supplier charges to its customer, do not regulate the service that it provides to its customer, and do not enforce territorial boundaries in a way that restricts the local solar electricity supplier from providing service to its customer.

Impairment of Solar Electricity from a Local Solar Electricity Supplier

Paragraph (b)(2) of the Solar Amendment provides that "[n]o electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier." The Merriam-Webster Online dictionary defines the term "impair" to mean: "to damage or make worse by or as if by diminishing in some material respect." Additionally, Black's Law Dictionary, 6th Edition, defines the term "impair" to mean: "[t]o weaken, to make worse, to lessen in power, diminish, or relax, or otherwise affect in an injurious manner." Applying either definition, it is clear that an electric utility's term of service or rule requiring either the local solar electricity supplier or the ultimate customer to pay for wheeling services will diminish in some material respect or lessen in some way the customer's purchase or consumption of the electricity produced by the local solar electricity supplier by imposing additional costs on the customer, either through higher rates for the solar electricity or through utility charges, depending on how the wheeling charges are collected by the electric utility. However, such a wheeling charge is one that would be charged under current law to any producer of electricity seeking to wheel power over the electric utility's distribution or transmission system whether it would be to a separate customer or to itself at a facility remote from the self-generating facility. Thus, every customer who receives electricity wheeled over the grid is subject to such "impairment." As such, the rate or charge that creates the impairment is one that is "also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier."

An example in current law where wheeling is authorized can be found in Section 366.051, Fla. Stat. That statute provides in part:

> Public utilities shall provide transmission or distribution service to enable a retail customer to transmit electrical power generated by the customer at one location to the customer's facilities at another location, if the commission finds that the provision of this service, and the charges, terms, and other conditions associated with the provision of this service, are not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers . . . .

This statute authorizes a utility customer to use the utility's distribution or transmission system to transport self-generated electricity to its facilities at a different location, and authorizes the electric utility providing the transportation to charge for the service. Because those generating the electricity are charged by the utility for wheeling the power to their remote facilities, they are in the same position as a customer of the same utility who receives electricity wheeled from a local solar electricity supplier's facility. The charge would not constitute an unauthorized impairment in violation of the Solar Amendment because other customers of the same type (customer's receiving electricity "wheeled" to them by the electric utility) are similarly impaired by the same kind of rate or charge for the same kind of service.

Authority to Recover Fixed or "Sunk" Costs by Dedicated Fee or Charge, or Through Base Rates

What an electric utility charges its customer is set forth in a group of rate schedules, which each apply to a particular class of customer and set forth the charges that can appear on the customer's bill. For public utilities, these schedules are established by the utility, subject to review and approval by the Public Service Commission. For municipal electric utilities, these schedules are established by the utility, subject to review and approval by the authority with oversight responsibilities for the utility, usually the city governing body, but sometimes a separate board or authority answerable to the city governing body or residents. For rural electric cooperatives, these schedules are established by the utility and are subject to review and approval by a board of directors elected by the customer members of the cooperative.

The components of a customer's bill typically consist of several types of charges varying in amount depending on the class of customer. The first type of charge is called a customer charge. It is the minimum amount a customer is required to pay, regardless of the amount of electricity consumed. This charge is supposed to allow the utility to collect its fixed costs to serve a particular customer regardless of the amount of electricity consumed. These "fixed costs" typically include the costs to the utility of maintaining and keeping the customer's account records active, such as data processing, meter reading, billing, and other administrative-type costs.

The second type of charge is a consumption (or energy) charge, which is a per kilowatt-hour rate that is charged to a customer depending on the amount of electricity consumed. This charge is designed to cover the customer's share of the utility's investment in the physical plant, the cost of maintenance and operations, and for an investor-owned public utility, the authorized shareholder return on investment (for a municipal utility some amount above actual utility costs may be charged to support general governmental operations).

These first two types of charges combine to make up what is referred to as the utility's "base rate." However, most utilities also charge one or more "additional charges" to cover either recurring operating costs that are outside of the utility's control, such as the cost of fuel to run generating plants, or temporary costs to the utility, such as the cost to pay for hurricane damages. Additional charges have historically been imposed for such things as fuel cost recovery, recovery of costs related to hurricane damage, and pass-through of franchise fees and taxes.

Assuming the Solar Amendment becomes law, and assuming for the sake of argument that electric utilities and their rate regulators determine that activities authorized by the Solar Amendment either inhibit cost recovery by utilities or shift too much of the cost burden to customers who do not consume electricity produced by a local solar electricity supplier, the Solar Amendment preserves sufficient flexibility for utilities and their rate regulators to address the matter.

The Solar Amendment does not prohibit imposition of utility rates, fees or charges that impair a customer's purchase or consumption of *solar electricity*. Rather, the amendment has a far narrower effect. It prohibits a utility from imposing a rate, fee or charge that impairs a customer's purchase or consumption of solar electricity *from a local solar electricity supplier*, and then, only if the rate, fee or charge is one that is not also imposed on other customers of the same type or class. The focus of the Amendment is to remove regulatory barriers inhibiting the third-party local solar supplier business model specifically, not to protect the use of distributed solar electricity generally.

To the extent that current law authorizes the imposition of a rate, fee or charge on a customer who uses solar electricity because such use reduces the revenue the electric utility anticipated collecting from that customer when it made its system investments, the Solar Amendment would allow the same rate, fee or charge to a customer purchasing or consuming electricity from a local solar electricity supplier. Such a rate, fee or charge imposed by the electric utility would not violate the Solar Amendment's "impairment" provision because it is likewise charged to customers of the same type (customers who consume solar electricity from a source other than the regulated electric utility) who do not consume electricity from a local solar electricity supplier.

A utility may, for example, include a rider in its tariff (subject to approval of its rate regulator) allowing a surcharge or a rate adjustment for all customers of a certain class (such as residential, or commercial) who reduce their demand by using electricity produced from renewable generating equipment not owned by the utility. Such a rider does not violate the Solar Amendment because the rider does not impair the consumption or purchase of electricity solely for customers of a local solar supplier, but applies to others as well. If, however, the same utility attempts to impose a rider that applies the same surcharge or rate adjustment to customers of local solar electricity suppliers ONLY, such a rider would violate the impairment provisions of the Solar Amendment.

Revenue Requirement and Rates

Every electric utility has what is known as a "revenue requirement." The revenue requirement is the amount of revenue that the utility must collect through its rates, fees and charges to recover all of its reasonable costs and meet all of its legitimate and reasonable obligations. For an investor-owned public utility, the revenue requirement includes the amount of revenue the utility must collect from its established rates, fees and charges to meet all of its operating and maintenance expenses, recover the amount of capital invested in the physical plant, service its debt, and pay to shareholders a return on investment that has been approved by the Public Service Commission and determined to be adequate to fairly compensate the shareholders for their investment. The Florida Supreme Court has determined that a utility's return on its shareholder's equity may vary within a range above or below the percentage established by the PSC and remain fair to shareholders and reasonable to customers. Court opinions have established that a realized rate of return on equity that falls within one percentage point of the percentage established by the PSC is presumptively reasonable. Therefore, a utility will typically not seek a change in its rates unless the return on equity is anticipated to fall below or rise above the ends of this established range.

Similarly, a municipal utility establishes rates to cover its revenue requirement. While no municipal utility pays shareholders a fair return on investment, some use utility revenues to fund non-utility operations, and therefore have a revenue requirement in excess of the actual costs of financing, constructing, operating and maintaining the utility system.

Whether a policy change such as that proposed in the Solar Amendment alters an investor-owned public utility's revenues enough so that it would be compelled to amend its rates or to impose an additional charge in order to meet its revenue requirement would likely depend on whether revenues declined to a degree that the utility no longer earned a return on its investment falling within the range established by the PSC. Whether passage and application of the Solar Amendment increases distributed solar generation enough to decrease revenues and trigger the need to raise rates so that the utility may continue to earn a rate of return within the authorized range is speculative and uncertain. Whether any potential decrease in revenue caused by activities authorized by the Solar Amendment may be offset by separate increases in revenues brought about by increased operating efficiencies, management cost cutting, and customer growth is also unknown.

Likewise, whether increases in distributed solar prompted by the Solar Amendment would decrease municipal utility revenues to a level that jeopardizes non-utility governmental funding is uncertain, and whether any revenue decreases, should they materialize, will be offset by separate increases in revenues from increased operating efficiencies, management cost cutting, and customer growth, is also uncertain.

The FIEC notebook distributed after the public hearing includes papers on a variety of solar topics, including reports on electric utility rate implications of local solar, particularly whether non-solar customers cross-subsidize the rates of local solar customers. Appendix "A" includes a concise yet scholarly analysis of the debate by immediate past Chair of the Federal Energy Regulatory Commission Jon Wellinghoff and James Tong: "A Common Confusion Over Net Metering is Undermining Utilities and the Grid" at:http://www.utilitydive.com/news/wellinghoff-and-tong-a-common-confusion-over-net-metering-is-undermining-u/355388/ The article suggests cross-subsidization of rates regularly occurs in other contexts, such as the snowbird discount mentioned at the FIEC public hearing, and points to studies demonstrating that local solar customers contribute more than their fair share.

Will the Solar Amendment Cause Cancellation of Franchise Agreements?

Passage of the Solar Amendment will not result in the widespread cancellation of franchise agreements between cities and counties and the franchisee public electric utilities. Beginning in 1996, electric utilities began including within franchise agreements offered to local government provisions that could be exercised to cancel the agreement in the event that changes in state or federal law result in retail competition. These provisions typically state the following, or something substantially similar:

> If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being

> served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

This example is excerpted from the initial form agreement offered by FPL to the City of South Miami during its recent negotiation for a franchise agreement renewal and is identical to language found in numerous FPL franchise agreements entered after 1996.

First, under these provisions, termination of the agreement is not automatic. The right of the utility to terminate is not triggered by a change in the law, rather it is triggered when the utility determines that the existence of the franchise agreement has placed it at a competitive disadvantage with respect to the new service provider, and the local government has failed to provide a remedy acceptable to the utility. The language in these agreements is usually silent as to the nature of the remedy required to avoid termination. It is uncertain and speculative that any utility will be placed at a competitive disadvantage with respect to a local solar electricity supplier who operates as authorized under the Solar Amendment. It is also uncertain and speculative that any franchise agreement will be terminated if a utility actually determines that it is at a competitive disadvantage, because the local government has the opportunity to propose a remedy or negotiate revised terms, which may or may not involve the amount of revenue paid to the local government. In a review of nearly 190 such agreements only one turned up which contained this kind of termination provision did not also provide an express opportunity to remedy prior to termination.

Second, franchise agreements are not uniform throughout the state and across utilities. Each utility offers its own form agreement, and every local government to varying degrees, negotiates its own terms which deviate from the form agreement. Several current agreements are attached as Appendix "B" for comparison purposes. Consider that agreements entered between 1985 and1996 (all of which remain in effect – the term is almost uniformly 30 years) contain no right of termination due to competitive disadvantage.

Third, a franchise agreement is more than just an agreement as to the electric utility's payment of a fee to the local government. Such agreements grant significant benefits to the utility franchisee, including the city or county's agreement, for a 30-year term, not to take over and operate the portions of the utility system located within the local government's jurisdictional boundaries. Additionally, such agreements provide a means for addressing the utilities' uses of the public rights of way and public easements within the jurisdiction, which may be more advantageous to the utility than terms provided in statutes. In short, there are compelling reasons for a utility to continue operating under a franchise agreement notwithstanding changes in the law that allow third parties to provide electric service in the jurisdiction without being subject to the same franchise terms.

Finally, it is unclear whether provisions like those excerpted above, which are intended to apply in the event of a restructured retail electricity market, would even apply in the event that the Solar Amendment is approved and becomes law. The Solar Amendment will not be likely to cause any electric utility to lose its customer because of retail competition. Indeed, the express language contained in paragraph (b)(3) of the Solar Amendment provides that the electric utility may not be relieved of its obligation under law to provide electric service to any customer in its service territory on the basis that the customer also purchases electricity from a local solar electricity supplier. A customer of a local solar electricity supplier, therefore, remains a customer of the electric utility. If the utility does not lose its customer, is it at a competitive disadvantage with respect to a local solar electricity supplier? To the extent that ambiguity exists in any such termination provision within a franchise agreement, the Florida Supreme Court requires that the ambiguity be resolved in favor of the government and against the franchisee. See, Tampa-Hillsborough County Expressway Authority v. K.E. Morris Alignment Service, Inc., 444 So.2d 926, 928 (Fla. 1983) (attached as Appendix "C").

Revenues and Costs to the State and Local Government

The foregoing discussion about the Solar Amendment's electric utility rate implications and the franchise agreement consequences inform the FIEC's consideration of the revenue and cost consequences of the Solar Amendment. Section 100.371(5)(a), Florida Statutes, requires the FIEC to "complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative." With regard to revenues, the state and local governments impose a variety of taxes and fees on electric utilities and can generate tax and fee revenues from local solar electricity suppliers and their customers. How much and whether the revenue amounts will vary from those received today depends on a variety of factors, including among others the extent to which customers choose to utilize local solar electricity suppliers and the state and local regulatory reaction to rate change requests, if any, from the electric utilities. Because the degree to which customers take advantage of new local solar authorized by the Amendment and the regulatory reactions are unknown, the state and local revenue effects are unknown. Likewise, those factors affect the analysis of the costs to state and local government as customers of electric utilities. There is no way to know whether the Solar Amendment will result in the state and local government becoming customers of local suppliers or will result in higher or lower costs for the purchase of electric utility power from rates adjusted upwards or downwards by state or local regulatory changes. Consequently, neither the revenue nor the cost impacts can be known with the degree of certainty constitutionally required for the FIEC to determine the "probable financial impact" of the Solar Amendment.

LIST OF APPENDICES

"A Common Confusion Over Net Metering is Undermining Utilities and the Grid"
by Jon Wellinghoff and James Tong .... A

Sample Franchise Agreements .... B

Tampa-Hillsborough County Expressway Authority v.
K.E. Morris Alignment Service, Inc.,
444 So.2d 926, 928 (Fla. 1983).. C

.

APPENDIX A

Utility Dive

OPINION

Wellinghoff and Tong: A common confusion over net metering is undermining utilities and the grid

'Cost-shifting' and 'not paying your fair share' are not the same thing.

By Jon Wellinghoff and James Tong | January 22, 2015

Editor's Note: The following is a guest post written by Jon Wellinghoff and James Tong. Wellinghoff is the former chairman of the Federal Energy Regulatory Commission and is currently a partner at law firm Stoel Rives LLP. Tong is the vice president of strategy and government affairs for Clean Power Finance, a financial services and software firm in the residential solar market. This article is the first in a series from Tong and Wellinghoff looking at issues surrounding utilities, distributed energy resources, and the grid. Tong and Wellinghoff's joint proposal to create an independent distribution system operator was covered in Utility Dive here (http://www.utilitydive.com/news/jon-wellinghoff-utilities-should-not-operate-the-distribution-grid/298286/) .

Correction: A previous version of this post said a report by the California Public Utilities Commission (CPUC) found that net energy metering (NEM) customers in the state were paying 106% of the full cost of service. The report was, in fact, a draft. The final report found California NEM customers were paying 103% of the full cost of service.

Public discussion on net energy metering (NEM) has gone from heated to downright nasty. It started as an arcane and seemingly innocuous policy: solar customers get a one-for-one bill credit from their utility for each kWh they produce and send to the grid. NEM has become a full-blown wedge issue.

Critics assert NEM customers use the grid but do not pay their fair share of the costs. They say that NEM shifts grid costs to non-solar ratepayers, especially lower-income households and minorities. They invoke phrases such as "regressive tax", "reverse Robin Hood," or even "robbin' (http://www.fortnightly.com/fortnightly/2013/07/reverse-robin-hood) the hood (http://www.fortnightly.com/fortnightly/2013/07/reverse-robin-hood) ," to suggest that solar customers – purportedly far wealthier and whiter – are getting a free ride at everyone else's expense.

"Nonsense," reply NEM advocates. "NEM critics don't care about ratepayer fairness – they care about protecting profits and monopolies for utilities that have never faced competition." They contend that, far from shifting costs, NEM customers create net value to the grid and all grid users. One only need look to a study commissioned by the neutral Nevada Public Utility Commission (http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study) that shows NEM customers provide a net present value benefit of $36M to non-NEM customers in Nevada.

However, both arguments miss the point. That is because both use "cost-shifting" and "not paying the fair share" interchangeably. This understanding is wrong – critically wrong. And it is resulting in needlessly fractious debates and bad policies, including arbitrary fixed fees on solar customers.

A telling example: In 2013, the California Public Utilities Commission (CPUC) published a study (http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf) that projected a cost shift of $1.1 billion per year by 2020 due to NEM policy. NEM critics, including the American Legislative Council (http://alec.org/docs/Net-Metering-reform-web.pdf) (ALEC), Americans for Prosperity (http://americansforprosperity.org/georgia/article/why-the-sun-isnt-free-by-joel-aaron-foster/) , and even some academics cited the study as proof that NEM customers were not paying their fair share. So they pushed harder for fixed fees for NEM customers, a policy that various states, including Wisconsin, Arizona, Kansas, and Oklahoma, have since either explored or enacted.

But critics (as well as NEM advocates) overlooked that the same CPUC report also found that NEM customers as a whole "appear to be paying slightly more than their full cost of service" – 103% of their costs, to be precise. In other words, NEM customers were not zeroing out their bills and "free-riding:" on average, they were paying more to utilities in fixed-cost recovery than non-NEM customers.

Why do so many policy wonks on both sides consistently conflate cost-shifting with not paying one's fair share? It could be that explaining these concepts is difficult and doesn't make for good sound bites. Or it could be that few people understand the arcane subject of utility rate design or are willing to admit that the prevailing utility regulatory model is highly redistributive to begin with (http://www.utilitydive.com/news/why-the-net-metering-fight-is-a-red-herring-for-utilities/307061/) .

According to the CPUC study, before going solar, all NEM customers (commercial and residential) had paid 133% of their full cost of service. The residential segment alone paid 154% of its cost. By going solar, NEM customers were mitigating or reversing the subsidies they had traditionally been paying to support the grid. This is the crux of what is called cost-shifting.

Cost-shifting should not be ignored. But the focus on NEM customers dangerously obscures more critical problems with the utility model (http://www2.deloitte.com/us/en/pages/energy-and-resources/articles/the-math-series-solving-for-disruption-in-US-electric-power-industry.html) , namely slowing demand, escalating costs, and disruptive innovations. In such an environment, any technology that reduces sales of electrons will challenge traditional practices of cross-subsidization.

For example, the energy economist Catherine Wolfram estimates that adoption of LED lighting may shift costs as much as the adoption of distributed solar. (https://energyathaas.wordpress.com/2014/03/17/why-arent-we-talking-about-net-energy-metering-for-leds/) Does this mean we should condemn LED users for cheating the system, or charge them fixed fees? Or should we fix the system in which the mere adoption of LED lighting can hurt the poor?

Vulnerable customer segments should not bear more cost when others adopt distributed energy resources (DERs) (http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx) , such as rooftop solar or efficiency technologies. But all customers – not just solar or DER customers – need to address the potential equity issues that new technologies, however promising, may raise. The Regulatory Assistance Project's concept of a minimum bill (http://www.raponline.org/featured-work/the-minimum-bill-an-effective-alternative-to-high-customer) – which utilities and solar advocates in Massachusetts had agreed to (http://www.greentechmedia.com/articles/read/why-the-massachusetts-net-metering-compromise-could-be-a-model-for-other-st) before getting stuck in the legislature – can ensure that all grid users pay their fair share. While imperfect (we advocate for more comprehensive reforms (http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity?authkey=694f9b6d88b73bb34af7a1dfe32592897cf7300b810bfb7d7d2030eab37ffed0)), the concept is more efficient and fairer than a sweeping fixed fee that singles out one technology with almost no regards of its benefits and costs to the grid.

The recent push for fixed fees is problematic for many reasons; for one, it does not rely on actual data or results (http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/) , but rather on the faulty assumption that users of technologies that shift costs are necessarily not paying their fair share. This fallacy will handicap the deployment of all promising DERs, which, by virtue of being distributed, will necessarily create uneven benefits and costs. Even worse, it may ultimately harm those ratepayers that NEM critics are trying to protect.

Separate analyses from the Rocky Mountain Institute (http://www.rmi.org/electricity_grid_defection) and Morgan Stanley (http://www.greentechmedia.com/articles/read/Solar-Fixed-Charges-May-Cause-Grid-Defection) show that grid defection will soon be economically viable, and that levying more fixed fees would accelerate defection. Even if "mass defection" is unlikely, defection by a small group will probably have an outsized impact. Utilities rely disproportionately on heavy users, who tend to be more affluent and thus more economically capable of going off-grid. If these users do start defecting en masse, then we really will have an unprecedented problem of cost-shifting from the "haves" to the "have-nots" – but we can't blame the "haves" for not paying their fair share for a grid they aren't using.

Let us hope that we never have to face this calamity to finally understand the distinction between cost-shifting and not paying one's fair share.

Top Image Credit: San Jose Inside (http://www.sanjoseinside.com/news/entries/4_19_13_sustainable_energy_solar_utilities/)

Filed Under:

APPENDIX B

ORDINANCE NO. 19-14-2197

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of South Miami, Florida recognizes that the City of South Miami (the "City") and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company ("FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City and FPL, the terms of which are set forth in City Ordinance No. 7-84-1202, passed and adopted May 15, 1984, and FPL's written acceptance thereof dated May 18, 1984 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"). As a result of short extensions passed and adopted by the City on May 14, 2014 and on August 19, 2014, respectively, and accepted by FPL, the Current Franchise Agreement expires on September 18, 2014; and

WHEREAS, FPL and the City (collectively, the "Parties") desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity within the City free of competition from the City, pursuant to certain terms and conditions; and

WHEREAS, the City Commission deems it to be in the public interest to enter into this agreement addressing certain rights and responsibilities of the Parties as they relate to the use of the public rights-of-way within the City's jurisdiction.

NOW, THEREFORE, BE IT ORDAINED BY THE MAYOR AND CITY COMMISSION OF THE CITY OF SOUTH MIAMI, FLORIDA:

Section 1. The foregoing recitals are hereby found to be true and correct, and are incorporated herein and adopted and approved as if set out at length.

Section 2. There is hereby granted to FPL, its successors and assigns, for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City and its successors, in accordance with FPL's customary practices, and practices prescribed herein, with respect to construction and maintenance of the electrical light, power and related facilities, including, without limitation, conduits, underground conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to FPL's provision of electricity and other services (hereinafter called "facilities") to the City and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 3. (a) FPL's facilities shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transporation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the City may prescribe in accordance with all applicable federal and state laws, and pursuant to the City's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining in, under, upon, along, over and across said public rights-of-way, provided such rules and regulations:

(i) shall be for a valid municipal purpose;

(ii) shall not prohibit the exercise of FPL's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above;

(iii) shall not unreasonably interfere with FPL's ability to furnish reasonably sufficient, adequate and efficient electric service to all its customers while not conflicting with the standards set forth above; or

(iv) shall not require relocation of any of FPL's facilities installed, before or after the effective date hereof, in any public right-of-way, unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way causes the facilities to unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road," or unless such relocation is required by state or federal law.

(c) Such rules and regulations shall recognize that FPL's above-grade facilities installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by FPL or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by FPL at its expense.

(e) The City shall not be liable to FPL for any cost or expense incurred in connection with the relocation of any of FPL's facilities required under this Section, except, however, that FPL may be entitled to reimbursement of its costs and expenses from others and as provided by law.

Except as expressly provided, nothing herein shall limit or alter the City's existing rights with respect to the use or management of its rights-of-way that are not otherwise preempted by the state or federal government.

Section 4. The acceptance of this New Franchise Agreement shall be deemed an agreement on the part of FPL to the following: (a) to indemnify and save the City harmless from any and all damages, claims, liability, losses and causes of action of any kind or nature arising out of a negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder; (b) to pay all damages, claims, liabilities and losses of any kind or nature whatsoever, in connection therewith, including the City's attorney's fees and expenses in the defense of any action in law or equity brought against the City, including appellate fees and costs and fees and expenses incurred to recover attorney's fees and expenses from FPL, arising from the negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by FPL from time to time shall be subject to such regulation as may be provided by law.

Section 6(a). As a consideration for this franchise, FPL shall pay to the City, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the City against FPL's property, business or operations and those of its subsidiaries during FPL's monthly billing period ending 60 days prior to each such payment will equal six percent of FPL's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the City for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6 percent of such revenues for any monthly billing period of FPL. For clarity, actual write-offs will be subtracted from FPL's billed revenues. In the event FPL subsequently collects previously written-off billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, FPL shall pay to the City a franchise payment on such revenues in accordance with the formula set forth above in this Section 6(a). FPL shall continue to remit payment in a manner consistent with the Current Franchise Agreement until the first payment is due under this New Franchise Agreement.

The City understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 7-84-1202, to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

(b) If during the term of this franchise FPL enters into a franchise agreement with any other municipality located in Miami-Dade County or Broward County, Florida, where the number of FPL's meters for active electrical customers does not exceed the number of meters for FPL's active electrical customers within the incorporated area of the City by more than one hundred and fifty (150) percent, the terms of which provide for the payment of franchise fees by FPL at a rate greater than 6 percent of FPL's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under substantially similar terms and conditions as specified in Section 6(a) hereof, FPL, upon written request of the City, shall negotiate and enter into a new franchise agreement with the City in which the percentage to be used in calculating monthly payments under Section 6(a) hereof shall be no greater than that percentage which FPL has agreed to use as a basis for the calculation of payments to the other municipality, provided however, that such new franchise agreement shall include additional benefits to FPL, in addition to all benefits provided herein, at least equal to those, if any, provided by its franchise agreement with the other municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the City shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and FPL shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

(c) The City reserves the unilateral right at its sole discretion and at any time during the term of this franchise, but only once per calendar year, to reduce or increase the franchise fee percentage rate upon 120 days written notice to FPL, provided that the franchise fee percentage rate shall in no event exceed 6 percent or be reduced to zero percent.

(d) The City's options hereunder shall be limited solely to the percentages or calculations of the amount of the franchise fee to be paid by FPL as consideration for this franchise as specifically set forth in this Section 6. Except as provided in this Section 6, no other Section of this New Franchise Agreement may be altered, amended or affected by the City without the written concurrence of FPL, and nothing herein shall require the City to exercise any of its options hereunder.

Section 7. (a) As a further consideration, during the term of this franchise or any extension thereof, the City agrees: (a) not to engage in the distribution and/or sale, in competition with FPL, of electric capacity and/or electric energy to any other ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by FPL other than the City, and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate FPL to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies). Nothing specified herein shall prohibit the City from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

(b) Nothing herein shall prohibit or limit a customer of FPL, including the City, if permitted by law, from installing an approved renewable generation system to generate electric energy for use at the customer's or the City's premises respectively. Furthermore, nothing herein shall prohibit or limit a person, including the City, if permitted by law, from selling renewable energy or capacity to FPL.

Section 8. If the City grants a right, privilege or franchise to any other person to provide retail electric service within any part of the incorporated areas of the City in which FPL may lawfully serve or compete on terms and conditions which FPL reasonably determines are more favorable than the terms and conditions contained herein, FPL may at any time thereafter terminate this franchise if such terms and conditions are not revised within the time period provided hereafter. FPL shall give the City at least one hundered eighty (180) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The City shall then have ninety (90) days in which to correct or otherwise remedy the terms and conditions complained of by FPL. If FPL determines that such terms or conditions are not remedied by the City within said time period, FPL may terminate this franchise agreement by delivering written notice by Certified United States Mail to the City's Clerk with copies to the Mayor, the City Manager and the City Attorney and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 9. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person who offers retail electric service to the public is permitted to provide electric service within the incorporated areas of the City to any applicant for electric service within any part of the incorporated areas of the City in which FPL may lawfully serve, and FPL reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, FPL may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage resulting from this fanchise is not remedied within the time period provided hereafter. FPL shall give the City at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of the consequences of such action which resulted in the competitive disadvantage. The City shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the City within said time period, either by a franchise agreement with such other person or otherwise, FPL may terminate this franchise agreement by delivering written notice to the City's Clerk and termination shall take effect on the date of delivery of such notice. Agreement by the City with such other person to enter into a franchise containing substantially the same terms as those provided herein shall be a sufficient, but not exclusive, remedy precluding FPL's termination of this franchise. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 10. Failure on the part of FPL to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by FPL until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that FPL has failed to comply in a substantial respect with any of the provisions of this franchise, and FPL shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the City at its discretion to grant such additional time to FPL for compliance as necessities in the case may warrant.

Section 11. Failure on the part of the City to comply in substantial respect with any of the provisions of this New Franchise Agreement, including but not limited to: (a) denying FPL use of public rights-of-way for reasons other than as set forth in Section 3 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Federal or Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing FPL a use permit to construct its facilities in public rights-of-way, shall constitute breach of this franchise. FPL shall notify the City of any such breach in writing sent by Certified United States Mail or via nationally recognized overnight courier and the City shall then remedy such breach as soon as practicable. Should the breach not be timely remedied, FPL shall be entitled to seek a remedy available under law or equity from a court of competent jurisdiction, including the withholding of the payments provided for in Section 8 as a court of competent jurisdiction determines to be just and reasonable under all the circumstances hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination dispositive of the matter.

Section 12. The Parties to this franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes. If such informal efforts are unsuccessful after a reasonable period of time, or when an impasse is declared by the Parties, then the Parties may exercise any of their available legal remedies.

Section 13. The City may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the City's expense, examine the records of FPL relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at FPL's office where such records are maintained. Records not prepared by FPL in the ordinary course of business or as required herein may be provided at the City's expense and as the City and FPL may agree in writing. Information identifying FPL's customers by name or their electric consumption shall not be taken from FPL's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the City, shall be reported to FPL. The City's right to examine

FPL's records in accordance with this Section shall not be conducted by any third party employed by the City whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

The City waives, settles and bars all claims relating in any way to the amounts paid by FPL under the Current Franchise Agreement embodied in Ordinance No. 7-84-1202, however, this provision shall not be construed to waive, settle or bar claims relating to any amounts due after the effective date of this New Franchise Agreement, including those amounts to be paid in a manner consistent with the terms of the Current Franchise Agreement until the first payment is made under this New Franchise Agreement.

Section 14. The provisions of this ordinance are interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of ninety (90) days, during which, this agreement may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of such ninety (90) day period, this entire ordinance shall then become null and void, and of no further force or effect.

Section 15. The City acknowledges it is fully informed concerning the existing franchise granted by Miami-Dade County, Florida, to FPL, and accepted by FPL as set out in Ordinance No. 60-16 adopted on May 3, 1960, and subsequently renewed and accepted by FPL as set out in Ordinance No. 89-81 adopted on September 5, 1989 by the Board of County Commissioners of Miami-Dade County, Florida. The City agrees to indemnify and hold FPL harmless against any and all liability, loss, cost, damage and expense incurred by FPL in respect to any claim asserted by Miami-Dade County against FPL arising out of the franchise set out in the above referenced ordinances for the recovery of any sums of money paid by FPL to the City under the terms of this New Franchise Agreement. FPL acknowledges and the City hereby relies, in part, on then Dade County Resolution No. R-709-78 adopted on June 20, 1978 in the granting of this franchise.

Section 16. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 17. Ordinance No. 7-84-1202, passed and adopted May 15, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 18. This New Franchise Agreement shall be governed and construed by the laws and administrative rules of the State of Florida and the United States. In the event that any legal proceeding is brought to enforce the terms of this franchise, it shall be brought by either party hereto in Miami-Dade County, Florida, or, if a federal claim, in the U.S. District Court in and for the Southern District of Florida, Miami Division.

Section 19. This New Franchise Agreement is intended to constitute the entire agreement between the City and FPL with respect to the subject matters hereof, and it supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

Section 20. Except in exigent circumstances, and except as otherwise may be specifically provided for in this franchise, all notices by either party shall be made by Certified United States Mail or via nationally recognized overnight courier service. Any notice given by facsimile or email is deemed to be supplementary, and does not alone constitute notice hereunder. All notices shall be addressed as follows:

To the City:

City Manager
City Hall, 1st Floor
6130 Sunset Drive
South Miami, FL 33143

Copy to:

City Attorney
1450 Madruga Avenue
Suite 202
Coral Gables, FL 33146

To FPL:

Vice President, External Affairs
700 Universe Boulevard
Juno Beach, FL 33408

Copy to:

General Counsel
700 Universe Boulevard
Juno Beach, FL 33408

Any changes to the above shall be in writing and provided to the other party as soon as practicable.

Section 21. As a condition precedent to the taking effect of the New Franchise Agreement, FPL shall file its acceptance hereof with the City's Clerk within 30 days of adoption of this ordinance. The effective date of the New Franchise Agreement shall be the date upon which FPL files such acceptance.

Ord. No. 19-14-2197

PASSED AND ENACTED this 16th day of September, 2014.

ATTEST:

CITY CLERK
1st Reading - 9/2/14
2nd Reading - 9/16/14

APPROVED:

MAYOR

READ AND APPROVED AS TO FORM, LANGUAGE, LEGALITY AND EXECUTION THEREOF

CITY ATTORNEY

COMMISSION VOTE:	4-1
Mayor Stoddard:	Yea
Vice Mayor Harris:	Yea
Commissioner Edmond:	Nay
Commissioner Liebman:	Yea
Commissioner Welsh:	Yea

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 19-14-2197
BY FLORIDA POWER & LIGHT COMPANY

City of South Miami, Florida　　　　　　　　　　October 1, 2014

Florida Power & Light Company does hereby accept the electric franchise in the City of South Miami, Florida, granted by Ordinance No. 19-14-2197, being:

> AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on September 16, 2014.

This instrument is filed with the City Clerk of the City of South Miami, Florida, in accordance with the provisions of Section 21 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela M. Rauch
Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 30 day of September, 2014 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Beverly A Calderon
My Commission EE017269
Expires 10/18/2014

Beverly A. Calderon
NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 19-14-2197 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of South Miami, Florida on this 1st day of October, 2014.

(SEAL)

Maria M. Menendez
City Clerk, City of South Miami, Florida

MIAMI DAILY BUSINESS REVIEW

Published Daily except Saturday, Sunday and
Legal Holidays
Miami, Miami-Dade County, Florida

STATE OF FLORIDA
COUNTY OF MIAMI-DADE:

Before the undersigned authority personally appeared MARIA MESA, who on oath says that he or she is the LEGAL CLERK, Legal Notices of the Miami Daily Business Review f/k/a Miami Review, a daily (except Saturday, Sunday and Legal Holidays) newspaper, published at Miami in Miami-Dade County, Florida; that the attached copy of advertisement, being a Legal Advertisement of Notice in the matter of

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING FOR 9/16/2014

in the XXXX Court,
was published in said newspaper in the issues of

09/05/2014

Affiant further says that the said Miami Daily Business Review is a newspaper published at Miami in said Miami-Dade County, Florida and that the said newspaper has heretofore been continuously published in said Miami-Dade County, Florida, each day (except Saturday, Sunday and Legal Holidays) and has been entered as second class mail matter at the post office in Miami in said Miami-Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this

05 day of SEPTEMBER , A.D. 2014

B Thomas

(SEAL)

MARIA MESA personally known to me

B. THOMAS
Notary Public - State of Florida
My Comm. Expires Nov 2. 2017
Commission # FF 034747
Bonded Through National Notary Assn.

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami, and providing for an effective date.

An Ordinance amending Section 20-7.12 of the City of South Miami Land Development Code concerning parking requirements for restaurants within the Hometown District Overlay (HD-OV) Zone.

An Ordinance of the City of South Miami, Florida, amending Section 2-7, Administrative department; functions and duties; creating a cost recovery administrative program; providing for repeal of ordinances in conflict; and providing an effective date.

An Ordinance relating to the fee schedule; amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

ALL interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at: 305-663-6340.

Maria M. Menendez, CMC
City Clerk

Pursuant to Florida Statutes 286.0105, the City hereby advises the public that if a person decides to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeal is to be based.

9/5 14-3-345/2341375M

POLICE REPORT

• SOUTH MIAMI

A vandal painted red graffiti on the sign at the Rosie Lee Wesley Health Center at **6601 SW 62nd Ave.** between 7 p.m. July 18 and 7:45 a.m. July 21. Damage was estimated at $220.

A thief shattered the front passenger window of a black 2010 Audi TT and stole a backpack, an Apple MacBook Pro, and a Duofold pen, all valued at $2,365, in a parking lot in the **6200 block of South Dixie Highway** between 5:15 and 6:30 p.m. July 22.

• PINECREST

A woman reported damage to her 2012 Hyundai when she arrived at the police department at 2:15 p.m. July 28. The woman, who lives in the **11800 block of Southwest 69th Avenue,** said the vehicle had been parked in an unfenced driveway since July 26 and had not been moved again until she discovered the damage, which is valued at $2,300.

Police were called to the Bank of America at **9101 S. Dixie Hwy.** about 4:15 p.m. July 28 in reference to verbal threats. The victim reported that a customer had verbally threatened her. The victim told police that when the offender arrived at the bank and inquired why his accounts had been closed, he became loud and offensive. When the offender was asked to leave, he was reported to have said, "Don't worry, I will take care of you." The offender was not on the scene when police arrived and contact was not made with him.

A mail carrier called police about 12:30 p.m. Aug. 14 after he noticed a broken window at a residence in the **8200 block of Southwest 133rd Street.** Police determined that a thief broke into the house and took an unknown number of items.

• KENDALL

A thief smashed the left rear window of a white 2012 Cadillac Escalade EXT and stole all four rims and tires while the vehicle was in the driveway of a residence in the **12000 block of Southwest 100th Avenue** between 9 p.m. Aug. 4 and 8:45 a.m. Aug. 5. Damage and loss were estimated at $3,000.

• PALMETTO BAY

A woman called police in reference to a personal identification fraud. The woman, who lives in the **8900 block of Southwest 150th Street,** said that someone used her personal identification information to try to change her home and email addresses on record at her bank on Aug. 18.

Police were called in reference to a bank fraud after a man, who lives in the **7200 block of Southwest 174th Street,** fraudulently cashed a forged check to his bank account on Aug. 11.

• CORAL GABLES

One or more thieves broke into and ransacked a residence in the **2000 block of Red Road** between noon and 6:45 p.m. Aug. 7.

A thief broke into and ransacked a residence in the **100 block of Oak Avenue** between noon Aug. 7 and 9:30 a.m. Aug. 9.

A 20-year-old woman was arrested and charged with grand theft after she tried to steal $3,088 worth of merchandise from the Nordstrom Department store at **4310 Ponce de Leon Blvd.** between 2:30 and 3 p.m. Aug. 6.

A 51-year-old woman became a victim of a strong arm robbery in the **500 block of Biltmore Way** between 3 and 3:15 p.m. Aug. 6.

• CUTLER BAY

A thief broke into a gray 2013 Toyota Tundra and stole tools valued at $2,000 from the driveway of a residence in the **10500 block of Southwest 200th Terrace** between 6 p.m. July 30 and 10 a.m. July 31.

A thief broke into a silver 2007 Toyota RAV4 and stole $5 in change while the vehicle was parked in the driveway of a residence in the **18500 block of Southwest 87th Court** between 4 p.m. July 24 and 9:30 a.m. July 25.

A thief broke into a black 2007 Dodge Ram 3500 parked along the roadside near **Southwest 103rd Avenue and Caribbean Boulevard,** and stole several tools and a wallet, all valued at $9,100, between 12:45 and 1 a.m. July 19.

This list is a sampling of crimes reported in Miami-Dade County cities. The information is taken from official police reports, which may not contain statements from all parties involved.

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LEE COUNTY ORDINANCE NO. 14-06

AN ORDINANCE OF LEE COUNTY GRANTING TO THE LEE COUNTY ELECTRIC COOPERATIVE, INC. ("LCEC"), ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC UTILITY FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR FRANCHISE FEE PAYMENTS TO LEE COUNTY; PROVIDING FOR SEVERANCE, CONFLICTS, SEVERABILITY, AND AN EFFECTIVE DATE.

WHEREAS, the Lee County Board of County Commissioners is the governing body in and for Lee County, Florida ("County"), a political subdivision and Charter County of the State of Florida; and

WHEREAS, the Board of County Commissioners is lawfully authorized to enter into non-exclusive franchise agreements with electric utilities defining terms and conditions for the use of County Public Rights-of-Way and other County property for the purpose of supplying electricity and electric utility services (hereafter, "Grantor," "County," or Board"); and

WHEREAS, the Lee County Electric Cooperative, Inc. ("LCEC"), a not-for-profit electric cooperative organized under Chapter 425, F.S., is authorized to conduct business in the State of Florida and Lee County, and as such, is an electric utility desiring to enter into a non-exclusive franchise agreement with the County for such purpose (hereafter, "Grantee" or "LCEC"); and

WHEREAS, the County desires to grant a non-exclusive franchise to LCEC relating to LCEC's use of the County's Public Rights-of-Way and other County property for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County free of competition from Lee County.

NOW THEREFORE, BE IT ORDAINED BY THE LEE COUNTY BOARD OF COUNTY COMMISSIONERS that:

SECTION 1. The above recitations are hereby found to be true and accurate and are adopted and approved as if set out herein at length.

SECTION 2.

Lee County hereby grants to LCEC its successors and assigns, for the period of thirty (30) years from the Effective Date hereof, the nonexclusive right, privilege and franchise (hereafter, "Franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future County owned or held roads, streets, alleys, bridges, easements, and other County property (hereinafter, "Public Rights-of-Way") throughout the unincorporated area of Lee County. LCEC shall exercise its Franchise granted herein in accordance with its customary practices with respect to the construction and maintenance of the electric light and power related facilities, including, without limitation, conduits, underground conduits, poles, wires, communications facilities, transmission and distribution lines, fiber optic, and any other facilities installed in conjunction with or ancillary to all of LCEC's electric power operations (hereafter, "facilities"), for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County and persons beyond the limits thereof as may be authorized by law or agreement. The County recognizes that LCEC must construct, maintain and own or have the lawful use of sites and facilities for the transmission and distribution of electric power in order to adequately serve its customers in unincorporated Lee County, and that the County will not unreasonably withhold from LCEC, permits to construct such facilities within the County's Public Rights-of-Way or authorized County-held easements for such placement, unless the operation, construction and maintenance of such facilities would unreasonably interfere with the traveling public's safety and welfare. The County also recognizes and agrees that nothing in this Franchise constitutes or shall be deemed to constitute a waiver of LCEC's delegated and independent right of Eminent Domain.

SECTION 3.

(i) LCEC Facilities shall be installed, located or relocated, so as not to unreasonably interfere with the Public's travel over the Public Rights-of-Way or the reasonable egress from and ingress to abutting properties. To avoid conflicts with the Public's travel, the location or relocation of all LCEC Facilities shall be made in accordance with the County's adopted reasonable rules and regulations as they may be revised, amended, or re-numbered from time to time, for the placement and maintaining of electric utility infrastructure in, under, upon, along, over and across the County's Public Rights-of-Way.

(ii) The County's adopted rules and regulations for the placement of electric utilities in its Rights-of-Way (a) shall not unreasonably prohibit the exercise of LCEC's right to use said Public Rights-of-Way for reasons other than when such use creates an unreasonable interference with the safety of the Public's travel thereon, (b) shall not unreasonably interfere with LCEC's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of LCEC's Facilities installed before or after the Effective Date hereof in any County Public Rights-of-Way unless or until: (1) the County's widening or reconfiguring of the paved portion of any Public Rights-of-Way used by motor vehicles causes such installed LCEC Facilities to unreasonably interfere with motor vehicular traffic, or (2) the location of the LCEC Facilities constitutes an unavoidable hazard to non-motor vehicular traffic exercising reasonable care, taking into account established customs and practices with respect to the placement of utility facilities, and other structures or obstructions commonly installed or located in and around sidewalks and other non-motor vehicular travel ways.

(iii) The County's adopted rules and regulations for the County's electric utility construction permits will recognize and take into consideration that the installation of the above grade (surficial) LCEC Facilities that are installed or relocated in the County's Rights-of-Way after the Effective Date hereof will be installed or relocated at, or as close to the outermost boundaries of the Rights-of-Way to the extent most reasonably possible, unless otherwise permitted by the County in a writing.

(iv) The County will not be liable to LCEC for any costs or expenses relating to any installations or relocations of LCEC's Facilities made pursuant to subparagraphs (i) and (ii), above. However, if the County directs LCEC in a writing signed by the County Manager, to locate or relocate its Facilities in a manner that is not consistent with LCEC's then-existing standard construction methods for such installations or relocations, the County will then be liable to LCEC for those costs under LCEC's then-existing contribution-in-aid of construction policies, unless during the term of this Franchise Ordinance, there are changes in law or rules, or judicial determination(s) that dictate otherwise.

(v) If any construction work is performed in a portion of a County Public Right-of-Way by LCEC in the course of the location or relocation of any of its Facilities, the portion of the Public Right-of-Way where such construction work is performed shall be restored by LCEC at its sole cost and expense to as good a condition as it existed at the time immediately prior to the commencement of such construction work within thirty (30) days after its completion.

(vi) For so long as LCEC remains in substantial compliance with the provisions of this Section, the County will not unreasonably deny LCEC the use of the County's Public Rights-of-Way as defined herein, and will not deny LCEC the necessary County permits to construct, maintain and operate its Facilities within such Public Rights-of-Way, other than what will be reasonable and necessary for the County to preserve the traveling public's safety and welfare from time to time.

SECTION 4. The County by the grant of this Franchise to LCEC, shall in no way be liable to or responsible for in any manner whatsoever for, any accident, personal injury, property damage, or any claim or damage that may occur in the construction, installation, operation or maintenance by LCEC, its employees, agents, contractors, sublicenses or licensees for any of its facilities hereunder, except for any damage specifically caused by or arising solely out the negligence, strict liability, intentional torts or criminal acts of the County. For and in consideration of the sum of One-Hundred and 00/100 Dollars ($100.00) in hand paid, and other good and valuable consideration accepted by the County, LCEC agrees to indemnify and hold the County harmless from and against any and all liability, loss costs, damages or expenses, to include any reasonable attorney fees of the County which may accrue to the County as the result of or by reason of any negligence, default or misconduct by LCEC in the construction, operation and maintenance of its facilities hereunder in or on the County's Public Rights-of-Way or any other County granted properties. For the term of this Franchise, LCEC shall maintain general liability insurance in such amounts as are ordinary in the course of LCEC's electric utility business to further support this indemnification. Copies of LCEC's general liability insurance policies shall be provided to the County upon its written request.

SECTION 5.

(i) As a consideration for this Franchise and as reasonable rent for LCEC's use of the County's Public Rights-of-Way granted herein, LCEC shall pay to the County, beginning on the first day of the month immediately following the month in which the Ordinance becomes effective, and then thereafter at the end of each calendar quarter for the remainder of the term of this Franchise; an amount which when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the County against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than four and one-half percent (4.5%) of LCEC's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers located within the unincorporated areas of the County within LCEC's service territory for the quarterly billing period ending thirty (30) days prior to each such payment (hereinafter, "Franchise Fee").

(ii) It is hereby provided and agreed to by LCEC, that the County shall have the unilateral option after the fifth (5^{th}) anniversary date from the implementation of the Franchise Fee, or at any time thereafter, to increase the franchise percentage rate herein to no more than six percent (6.0%). Such increase will not be exercised more than twice by the County (if an initial increase is less than 6.0%) in years to be reasonably selected by the Board. The increase option(s) will be exercised through a County Ordinance, adopted by the Board at a duly advertised Public Hearing. A certified copy of which will be delivered to LCEC no later than ninety (90) days before the fifth (5^{th}) anniversary date hereof on which such increase is to become effective following the Board's adoption of the Ordinance. Any such ordinance shall provide that LCEC shall pay to the County, no later than thirty (30) days after the end of LCEC's first quarterly billing period occurring after the fifth (5^{th}) anniversary date as stated above, or after any subsequent year as the County may elect to exercise this option and the effective date of the County Ordinance establishing the new franchise rate percentage; and no later than thirty (30) days after the end of each succeeding quarterly billing of LCEC, an amount which, when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the county against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than six percent (6.0%) of the billed revenues from the LCEC's sale of electricity, less actual write-offs, to residential, commercial and industrial customers located in the unincorporated area of the County within LCEC's service territory.

(iii) It is hereby further provided and agreed to by LCEC, that if during the term of this Franchise Agreement LCEC enters into a franchise agreement with any other municipality or county government, the terms of which provide for the payment of a Franchise Fee by LCEC at a rate greater than 6.0 percent of billed revenues from LCEC's residential, commercial and industrial customers under the same terms and conditions as specified in Section 5 (i) and (ii) hereof, then LCEC, upon written request of the County, shall negotiate and enter into a new franchise agreement with the County in which the percentage to be used in calculating the monthly payments under Section 5 (i) and (ii), using the same terms and conditions as specified in said Section, shall be at the greater rate being paid to the other municipality or county, provided however, that if the franchise with such other municipality or county contains additional benefits given to LCEC in exchange for the increased Franchise Rate, and such additional benefits are not contained within this Franchise Agreement, then LCEC shall have the option to include within such new franchise agreement with the County, the additional benefits included in the initiating franchise (i.e., the new municipality or county franchise that initiated the negotiation of the new franchise as contemplated above).

(iv) In the event during the term of this Franchise that LCEC recovers and collects previously written-off and uncollected billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, LCEC shall pay to the County in accordance with this Section and other relevant terms of this Ordinance, the then applicable Franchise Fee payment on such revenues so collected and received, such payment to be made in the next quarterly Franchise Fee payment to the County pursuant to the terms herein following the recovery of the funds.

(v) The County reserves the unilateral right, at its sole discretion and at any time during the term of this Franchise to reduce the Franchise Fee, by providing to LCEC a certified copy of an Ordinance adopted by the County Commission at a duly advertised Public Hearing, amending the Franchise Ordinance to reduce the Franchise Fee. The certified copy of the Amended Ordinance shall be provided to LCEC no later than thirty (30) days following the Board's adoption of the Ordinance. The reduced Franchise Fee will be applied by LCEC to its customers as of the date of the adoption of the Franchise Fee Reduction Ordinance unless otherwise provided for in the terms of the Ordinance.

(vi) The County's options hereunder shall be limited solely to the percentages or calculations of the amount of the Franchise Fee to be paid by LCEC as consideration for this Franchise as specifically set forth in this Section. No other Sections or provisions of this Franchise ordinance may be altered, amended or affected by the County without the written concurrence of LCEC. Nothing herein shall require the County to exercise any of its options as outlined under this Section.

SECTION 6.

(i) As consideration during the term of this Franchise, the County agrees not to: (a) engage in the distribution and/or sale, in competition with LCEC, of electric capacity and/or electric energy as set out above to any ultimate consumer of electric utility service ("retail customer") or to any electrical distribution system established solely to serve any customer formerly served by LCEC, (b) participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate LCEC to transmit and/or distribute, electric capacity and/or electric energy from any third party to any other LCEC customer's facility, or (c) seek to have LCEC transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the County at one location to the County's facility at any other location(s).

(ii) However, nothing herein shall prohibit the County, if permitted by law, or judicial determination, from: purchasing electric capacity and/or electric energy from any third party, or (ii) seeking to have LCEC transmit and/or distribute to any facility of the County, electric capacity and/or electric energy purchased by the County from any third party; provided, however, that before the County elects to purchase electric capacity and/or electric energy from any third party, the County shall notify the LCEC in writing. Such written notice shall include a summary of the specific rates, terms and conditions of the proposed purchase which have been offered by the third party and identify the County's facilities to be served under the offer. LCEC shall thereafter have ninety (90) days to evaluate the offer and, if LCEC offers rates, terms and conditions to the County which are equal to or better than those offered by the third party, the County shall be obligated to continue to purchase electric power capacity from LCEC and/or electric energy to serve the identified facilities of the County at the revised rates, terms and conditions for a term no longer than the remainder term of this franchise. If LCEC does not agree to provide rates, terms and conditions which are equal to or better than the third party's offer, then the terms and conditions of this franchise shall continue to remain in full force and effect for its term, and the County shall have the right to proceed with the purchase of either electric capacity or electric energy from the third party; or prohibit the County from engaging with other utilities in wholesale transactions for the sale of any amount of the electric power generated by its Waste-to-Energy Facility.

SECTION 7. If the County grants a right, privilege or franchise to any other party or otherwise enables any other such party to construct, operate or maintain electric light and power facilities within any part of the service territory of LCEC within the unincorporated area of the County on terms and conditions which LCEC determines are more favorable than the terms and conditions contained herein, LCEC may at any time thereafter terminate this Franchise if such terms and conditions are not revised by the County within the time period provided for herein. LCEC shall give the County at least sixty (60) Business Days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of such terms and conditions offered to the other party that it considers more favorable. The County shall then have sixty (60) Business Days in which to correct or otherwise remedy the terms and conditions complained of by LCEC. If LCEC determines that such terms and conditions are not remedied by the County within said time period, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and the Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 8. If as a direct or indirect consequence of any legislative, judicial, regulatory or other action by the United States or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) enacted after the Effective Date of this Ordinance, any person is permitted to provide electric service within LCEC service territory in the unincorporated area of the County to a customer then being served by LCEC, or to any new applicant for electric service within any part of the unincorporated area of the County in which LCEC may lawfully provide service, and LCEC determines that its obligations hereunder or otherwise resulting from this Franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person providing the electric service, LCEC may, at any time after the taking of such action, terminate this Franchise if such competitive disadvantage, and which is within the jurisdiction and authority of the County to remedy, is not remedied within the time period provided for in this Section 9. LCEC shall give the County at least sixty (60) Business Days advance written notice sent by United States Mail of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of the consequences of such action which resulted in the competitive disadvantage. The County shall then have sixty (60) Business Days or such other time as may be agreed to by LCEC in consultation with the County, for the County to correct or otherwise remedy the competitive disadvantage, if it is within the County's jurisdiction and authority to do so. If such competitive disadvantage is not remedied by the County within the determined time period and such remedy is within the County's jurisdiction and authority to do so, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 9. Failure on the part of LCEC to comply in any substantial respect with any of the provisions of this Franchise shall be grounds for a forfeiture of this Franchise by the County, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by LCEC through either administrative or judicial proceedings until there is final determination by a court of competent jurisdiction (after the expiration or exhaustion of all rights of appeal) that LCEC has failed to comply in a substantial manner with any of the provisions of this Franchise. Thereafter, LCEC shall have six (6) months after such final determination to remedy the default before a forfeiture shall result, with a right of the County at its sole discretion to grant such additional time to LCEC for its compliance, if found to be warranted. If the default is not cured within the prescribed time, LCEC shall then immediately forfeit this Franchise.

SECTION 10. Failure on the part of the County to substantially comply with any of the provisions of this Ordinance, including: (a) denying LCEC the use of County Public Rights-of-Way in the LCEC service territory for reasons other than the unreasonable interference with public travel; (b) imposing conditions for the use of Public Rights-of-Way contrary to Florida law or the terms and conditions of this Franchise; or (c) an unreasonable delay in issuing LCEC a use permit, if any such permit is required, to construct facilities in County Public Rights-of-Way pursuant to this Franchise, shall constitute a County breach of this Franchise. LCEC shall notify the County of any such breach in writing sent by United States Mail and the County shall then remedy such breach as soon as practicable, taking into account LCEC's obligation(s) to provide reasonably sufficient, adequate and efficient electric service to its customers; otherwise, within no later than thirty (30) Business Days. Should the breach not be remedied within the specified thirty (30) Business Days, LCEC shall be entitled to withhold up to the maximum of thirty percent (30%) of the payments to the County as provided for in Section 5 herein until such time as the use permit is issued, or a court of competent jurisdiction has reached a final determination with respect to the issue(s) in dispute. In the event that such final determination by the court is in favor of the County as to such issue(s) in dispute, LCEC shall promptly remit to the County all payments withheld hereunder together with simple interest, for the period withheld at the then established rate for judgments pursuant to Florida law.

SECTION 11. The Parties to this Franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree to notify one another in writing sent by United States Mail and any other available electronic means commonly used in the ordinary course of business when such dispute arises, and agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes within no later than thirty (30) Business Days from such notice. If such efforts are unsuccessful, and after an impasse is declared by either of the Parties, then the Parties may exercise any of their other available legal remedies.

SECTION 12. The County may, upon reasonable notice and within ninety (90) days after each annual anniversary date from the Effective Date of this Franchise, at the County's sole expense, examine the records of LCEC relating to the calculation of the franchise payments for the year preceding such anniversary date. Such examination shall be made during normal business hours at the LCEC office where such records are generally maintained. Records not prepared by LCEC in the ordinary course of its business may be provided to the County at the County's expense, and as the Parties may agree in writing. Any information identifying individual LCEC customers by name, address or individual electric consumptions shall not be recorded in any manner, or taken from LCEC's premises by County auditors. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the County, shall be reported to LCEC. The County's right to examine the records of LCEC in accordance with this section shall not be conducted by any third party employed by the County whose fee, in whole or in part, for conducting such audit is contingent upon the third party's findings of the audit.

SECTION 13. The provisions of this ordinance are hereby deemed by the Parties to be interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of sixty (60) days, during which, this Ordinance may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of the such sixty (60) day period, this entire ordinance shall then become null and void, and of no further force or effect.

SECTION 14. Any County ordinances and/or parts of County ordinances in conflict herewith are hereby repealed to the extent that they may be in conflict with the terms and provisions as set out herein.

SECTION 15. This Ordinance shall be governed and construed by the Laws, Administrative Rules and judicial determinations of the United States and the State of Florida. Nothing in this Franchise shall be either construed or considered as an abrogation, surrender or mitigation by the County of any of its rights and authority to use and to require the relocation of any uses within its Public Rights-of-Way as provided in Section 3. In the event that any legal proceeding is brought to enforce the terms of this Franchise, it shall be brought by either Party hereto in state court in Lee County, Florida, or, if a federal claim, in the U.S. District Court in and for the Middle District of Florida, Fort Myers Division. In any legal action between the Parties arising out of this Franchise, any attempts to enforce this Franchise, or any breach of this Franchise, the prevailing Party may recover its expenses from such legal action including, but not limited to, costs of litigation and reasonable attorneys' fees from the other party together with reasonable fees and costs on appeal.

SECTION 16. Except in exigent circumstances, and except as otherwise may be specifically provided for in this Franchise, all notices by either Party shall be made by either depositing such notice into the United States Mail or by facsimile or other electronic transmission. Certified Mail shall be deemed delivered five (5) days following the date of such deposit into the United States Mail unless otherwise provided. Any notice given by facsimile or email is deemed to be received on the same Business Day. "Business Day" for purposes of this Ordinance shall mean Monday through Friday, with Saturday, Sunday and observed holidays excepted. All notices shall be addressed as follows:

To the County:
Chairman, Board of County Commissioners
2120 Main Street
Fort Myers, Florida 33901
Telephone: (239) 533-2227
Facsimile: (239) 485-2021
Email: dist3@leegov.com

Copy to:
Lee County Attorney
P.O. Box 398
Fort Myers, Florida 33902
Telephone: (239) 533-2236
Facsimile: (239) 485-2106
Email: rwesch@leegov.com

To LCEC:
Lee County Electric Cooperative, Inc.
Chief Executive Officer
4980 Bayline Drive
North Fort Myers, Florida 33917-3910
Telephone: (239) 995-2121
Facsimile: (239) 995-7904
Email: ceooffice@lcec.net

Copy to:
LCEC General Counsel
John Noland, Esq.
Henderson Franklin Starnes & Holt, P.A.
1715 Monroe Street
Fort Myers, Florida 33907
Telephone: (239) 344-1140
Facsimile: (239) 344-1515
Email: John.Noland@henlaw.com

Any changes to the Parties' representatives above shall be made in writing and provided to the other Party as soon as practicable by U.S. Mail or other electronic conveyance.

SECTION 17. This Ordinance is intended to constitute the entire agreement between the County and LCEC with respect to the subject matters herein, and supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

SECTION 18. As used herein for the purposes of this Franchise Ordinance, the term "person" means an individual, or, a partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture, governmental authority or any other entity authorized to conduct business in Florida.

SECTION 19. The Board of County Commissioners intends that this Ordinance will be made part of the Lee County Code. Sections of this Ordinance can be renumbered or relettered and the word "ordinance" can be changed to "section," "article," or other appropriate word or phrase to accomplish such codification. Regardless of whether this Ordinance is ever codified, this Ordinance can be renumbered or relettered and typographical errors that do not affect the intent or substantive provisions herein may be administratively corrected upon the authorization of the County Manager and County Attorney, without the need for a further public hearing. Any such administrative revisions made hereto will be provided to LCEC within five (5) Business Days of their being made and incorporated into this Ordinance.

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SECTION 20.

(i) A certified copy of this Ordinance shall be filed by the County with the Florida Department of State within ten (10) days following its adoption.

(ii) As a condition precedent to the taking effect of this Ordinance, LCEC shall file a written acceptance hereof on its official letterhead stationery and executed by the Chief Executive Officer of LCEC, within thirty (30) days after the adoption of this Ordinance. The effective date ("Effective Date") of this Ordinance shall then be the date upon which LCEC files such written acceptance with the Clerk to the Lee County Board of County Commissioners, with copies to the Chairman of the Board of County Commissioners, the County Manager and the County Attorney.

The foregoing Ordinance was offered by Commissioner Manning who moved its adoption. The motion was seconded by Commissioner Mann and being put to a vote, the vote was as follows:

JOHN MANNING	Aye
CECIL PENDERGRASS	Nay
LARRY KIKER	Aye
BRIAN HAMMAN	Nay
FRANK MANN	Aye

DULY PASSED AND ADOPTED this 18th day of March, 2014.

ATTEST: LINDA DOGGETT
CLERK OF THE COURT

By: Marcia Wilson
Deputy Clerk

BOARD OF COUNTY COMMISSIONERS
SEAL
LEE COUNTY, FLORIDA

BOARD OF COUNTY COMMISSIONERS
OF LEE COUNTY, FLORIDA

By: Larry Kiker
Larry Kiker, Chairman

APPROVED AS TO FORM:

By: Andrea R. Fraser
Office of the County Attorney

FLORIDA DEPARTMENT *of* STATE

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

March 20, 2014

Honorable Linda Doggett
Clerk of the Circuit Courts
Lee County
Post Office Box 2469
Fort Myers, Florida 33902-2469

Attention: Lisa Pierce, Deputy Clerk

Dear Ms. Doggett:

Pursuant to the provisions of Section 125.66, Florida Statutes, this will acknowledge receipt of your electronic copy of Lee County Ordinance No. 14-06, which was filed in this office on March 20, 2014.

Sincerely,

Liz Cloud
Program Administrator

LC/elr

RECEIVED
MAR 20-14
MINUTES OFFICE

R. A. Gray Building • 500 South Bronough Street • Tallahassee, Florida 32399-0250
Telephone: (850) 245-6270 • Facsimile: (850) 488-9879
www.dos.state.fl.us

Lee County Electric Cooperative, Inc.
Post Office Box 3455
North Fort Myers, FL 33918-3455
(239) 995-2121 • FAX (239) 995-7904
www.lcec.net

PEOPLE. POWER. POSSIBILITIES.

March 20, 2014

Ms. Linda Doggett
Clerk of the Circuit Court & Comptroller
Lee County Justice Center
1700 Monroe Street
Fort Myers, FL 33901

Dear Ms. Doggett:

Re: Lee County Ordinance No. 14-06

The Board of Trustees of Lee County Electric Cooperative, Inc. accepted Lee County Ordinance No. 14-06 at its meeting held on March 20, 2014. This letter serves as the written acceptance as required by paragraph 20 (ii) of the Ordinance.

Respectfully,

William D. Hamilton

William D. Hamilton
Executive Vice President
and Chief Executive Officer

cc: Larry Kiker, Chairman, Board of County Commissioners
Roger Desjarlais, County Manager
Richard Wesch, County Attorney
David M. Owen, Esq.
John A. Noland, Esq.

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City of Boca Raton

Incorporated 1925

expired 6-1-2036

This is a true copy. No. of Pages 10
IN WITNESS WHEREOF, I hereunto set my hand and affix the Seal of the City of Boca Raton, Florida, this 26th day of April A.D., 20 06.
City Clerk

ORDINANCE

4937

AN ORDINANCE OF THE CITY OF BOCA RATON GRANTING TO FLORIDA POWER AND LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING MONTHLY PAYMENTS TO THE CITY OF BOCA RATON; PROVIDING FOR REPEALER; PROVIDING AN EFFECTIVE DATE

WHEREAS, the City Council of the City of Boca Raton recognizes that the City of Boca Raton and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Boca Raton does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, FPL and the City of Boca Raton desire to enter into a franchise agreement providing for the payment of fees to the City of Boca Raton in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City of Boca Raton free of competition from the City of Boca Raton, pursuant to certain terms and conditions; and

WHEREAS, the City Council of the City of Boca Raton deems it to be in the best interest of the City of Boca Raton and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement; now therefore

THE CITY OF BOCA RATON HEREBY ORDAINS:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Boca Raton, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee, installed after the effective date hereof, should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation within the time provided in any permit for excavation issued by the Grantor or extension thereof or if no permit is issued within a reasonable time. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law.

Section 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 4. All rates, rules, and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5. As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal 5.9 percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 5.9 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 2310, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; and (h) other service charges.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, all of the terms and conditions of this franchise shall remain in effect.

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have 120 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Palm Beach County, Florida, the population of which is equal to or less than that of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5 hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5 hereof shall be no greater than that percentage which the Grantee has agreed to use as a basis for the calculation of payments to the other County municipality, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, at least equal to those provided by its franchise agreement with the other Palm Beach County municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the Grantor shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and the Grantee shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

Section 9. If, as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them), any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

Section 10. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 11. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 12. The Grantor may, upon reasonable notice and within 120 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee.

<u>Section 13</u>. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

<u>Section 14</u>. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

<u>Section 15</u>. Ordinance No. 2310, passed and adopted October 12, 1976, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

<u>Section 16</u>. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance, but not sooner than 10 days after the date of adoption of this ordinance.

PASSED AND ADOPTED by the City Council of the City of Boca Raton this 25th day of April, 2006.

CITY OF BOCA RATON, FLORIDA

ATTEST:

Steven L. Abrams, Mayor

Sharma Carannante, City Clerk

Approved as to form:

Diana Grub Frieser
City Attorney

COUNCIL VOTE	YES	NO	ABSTAINED
MAYOR STEVEN L. ABRAMS	✓		
DEPUTY MAYOR SUSAN WHELCHEL	✓		
COUNCIL MEMBER M. J. MIKE ARTS	✓		
COUNCIL MEMBER PETER BARONOFF	✓		
COUNCIL MEMBER BILL HAGER	✓		

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101 Legal Notices

CITY OF BOCA RATON
NOTICE OF
REGULAR PUBLIC HEARINGS

NOTICE IS HEREBY GIVEN that the City Council of the City of Boca Raton. Florida will hold public hearings on the following proposed ordinances at the Regular Meeting on Tuesday. April 25. 2006 at 6:00 p.m.. or as soon thereafter as possible. at which time they will consider their adoption. Presentations may be made by staff at the City Council Workshop Meeting on Monday. April 24. 2006 at 1:30 p.m.. or as soon thereafter as possible.

Both meetings will be held in the Council Chamber at Boca Raton City Hall. 201 West Palmetto Park Road. Boca Raton. Florida. The ordinances in their entirety may be inspected at the Office of the City Clerk during regular business hours. All interested parties are invited to attend either or both meetings and be heard with respect to the proposed ordinances.

Ordinance No. 4936

An ordinance of the City of Boca Raton providing for the vacation and abandonment of the unimproved portion of Banyan Trail located south of N.W. Spanish River Boulevard and east of North Military Trail. as more specifically described herein: providing conditions for vacation and abandonment: providing for severability: providing for repealer: providing an effective date (AB-05-03)

Ordinance No. 4937

An ordinance of the City of Boca Raton granting to Florida Power and Light Company. its successors and assigns. an electric franchise: imposing provisions and conditions relating thereto: providing monthly payments to the City of Boca Raton: providing for repealer: providing an effective date

NOTICE: If any decision of City Council affects you. and you decide to appeal any decision made at this meeting with respect to any matter considered. you may need to ensure that a verbatim record of the proceedings is made. which record includes the testimony and evidence upon which the appeal is to be based. (The above NOTICE is required by State Law. If you desire a verbatim transcript. you shall have the responsibility. at your own cost. to arrange for the transcript.)

In accordance with the Americans with Disabilities Act and Florida Statutes 286.26. persons with disabilities

101 Legal Notices

needing special accommodation to participate in this proceeding should contact the Office of the City Clerk at 393-7741 at least three business days prior to the proceeding (whenever possible) to request such accommodation

Sharma Carannante CMC
City Clerk
City of Boca Raton Florida

PUBLISH: April 13. 2006
ACCOUNT NO. 98842
FURNISH PROOF OF PUBLICATION
PO30429 (49-A)

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 4937
BY FLORIDA POWER & LIGHT COMPANY

Boca Raton, Florida June 1, 2006

Florida Power & Light Company does hereby accept the electric franchise in the City of Boca Raton, Florida, granted by Ordinance No. 4937, being:

AN ORDINANCE OF THE CITY OF BOCA RATON GRANTING TO FLORIDA POWER AND LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING MONTHLY PAYMENTS TO THE CITY OF BOCA RATON; PROVIDING FOR REPEALER; PROVIDING AN EFFECTIVE DATE.

which was passed and adopted on April 25, 2006.

This instrument is filed with the City Clerk of the City of Boca Raton, Florida, in accordance with the provisions of Section 16 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By____________________
Jeffrey S. Bartel
Vice President

ATTEST:

____
Jay W. Molyneaux, Assistant Secretary

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 4937 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of Boca Raton, Florida, on this 1st day of June, 2006.

Shauna Cavarante
____
City Clerk, City of Boca Raton, Florida

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ORDINANCE NO. 00-08

AN ORDINANCE OF THE CITY OF BONITA SPRINGS GRANTING FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, A NON-EXCLUSIVE ELECTRIC UTILITY FRANCHISE, IMPOSING CITY-WIDE PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF BONITA SPRINGS, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Council of the City of Bonita Springs ("City" or "Grantor") recognizes that the citizens of the City need and desire the benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company ("FPL" or "Grantee") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, FPL and the City desire to enter into a franchise agreement providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City free of competition from the City, pursuant to certain terms and conditions.

NOW, THEREFORE, THE CITY COUNCIL OF BONITA SPRINGS

HEREBY ORDAINS:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (herein called the "Grantee"), for the period of 25 years from the effective date hereof, with one additional five (5) year extension at FPL's sole option the non-exclusive right, privilege and franchise, (herein called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (herein called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Bonita Springs, Florida, and its successors (herein called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (herein called "facilities"), for the purpose of supplying electricity and other services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law.

<u>Section 3</u>. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance

by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 4. All rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5(a). As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing sixty (60) days after the effective date of this Ordinance and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending sixty (60) days prior to each such payment will equal three (3%) percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending sixty (60) days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed three (3%) percent of such revenues for any monthly billing period of the Grantee.

Section 5(b): Notwithstanding the above, for the first eighteen months of this franchise, the Grantee shall pay to the Grantor an amount equal to four (4%) percent of the Grantee's billed revenues, as specified in Section 5(a).

Section 5(c). It is further provided that the Grantor shall have the option, subject to the limitations specified below, once each calendar year to increase or reduce the amount to be paid by the Grantee as consideration for this franchise, such option to be exercised by the adoption of an ordinance, a certified copy of which must be delivered to the Grantee no later than 90 days before any such increase or reduction is to become effective. Such ordinance shall provide that the Grantee shall pay to the Grantor, no later than thirty (30) days after the end of the Grantee's first billing period and no later than 30 days after the end of each succeeding monthly billing of the Grantee during the term of this franchise, an amount which when added to the amount of all City licenses, excise fees or charges (except ad valorem property taxes and non-ad valorem special assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending thirty (30) days prior to each such payment will equal five (5%) percent (or such lesser percentage as the Grantor may elect) of the Grantee's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending thirty (30) days prior to each such payment, and in no event shall the Grantee's payment for the rights and privileges granted herein exceed five (5%) percent, or such percent of such revenues as specified by the Grantor in the exercise of its option, for any monthly billing period of the Grantee. In no event may the Grantor increase the amount by more than one (1%) percent from the percentage then being collected in any given year. The Grantor shall have the option to reduce the amount to be paid by the Grantee to zero, but in no event shall the Grantor have the option to increase the percentage used to calculate the amount to be paid by the Grantee as consideration for this franchise to any percentage which is greater than five (5%) percent. The Grantor's option hereunder shall be limited solely to the percentage to be used in the calculation of the amount to be paid by the Grantee as consideration for this franchise and as specifically set forth in this subsection, and no other section or provision of this franchise ordinance may be altered, amended or affected by the Grantor without the concurrence of the Grantee. Nothing herein shall require the Grantor to exercise its option hereunder.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have sixty (60) days to evaluate the offer and, if the Grantee agrees to meet or beat the other person's offer, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to meet or beat the other person's offer, all of the terms and conditions of this franchise shall remain in effect.

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least sixty (60) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have sixty (60) days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least ninety

(90) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have ninety (90) days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this franchise;

(c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this franchise constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. The Grantor may, upon reasonable notice and within ninety (90) days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this section shall not be conducted by any third party employed by the Grantor whose fee for conducting such audit is contingent on findings of the audit.

Section 12. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

Section 13. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 14. All ordinances and parts of ordinances in conflict herewith are hereby repealed.

Section 15. As a condition precedent to the taking effect of this ordinance the Grantee shall file its acceptance hereof with the Grantor's Clerk within forty (40) days of adoption of this ordinance. The effective date of this ordinance shall be the date on which Grantee files its acceptance.

DULY PASSED AND ENACTED by the City Council of the City of Bonita Springs, Florida this 19th day of July, 2000.

AUTHENTICATION:

MAYOR

CITY CLERK

APPROVED AS TO FORM: City Attorney

7/20/00
Date

Vote:	Arend	Aye	Piper	Aye
	Edsall	Aye	Wagner	Aye
	Nelson	Aye	Warfield	Aye
	Pass	Aye		

I CERTIFY THAT THIS IS A CORRECT COPY OF AN OFFICIAL PUBLIC RECORD ON FILE WITH THE CITY OF BONITA SPRINGS, FLORIDA.

Dianne J. Lynn, City Clerk
Date: 7/20/00

Date Filed with City Clerk: 7/20/00

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ORDINANCE NO. 91-1

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF GLEN RIDGE, AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE TOWN OF GLEN RIDGE, FLORIDA:

Section 1. There is hereby granted to Florida Power & Light Company (herein called the "Grantee"), its successors and assigns, the non-exclusive right, privilege or franchise to construct, maintain and operate in, under, upon, over and across the present and future streets, alleys, bridges, easements and other public places of the Town of Glen Ridge, Florida (herein called the "Grantor") and its successors, in accordance with established practice with respect to electrical construction and maintenance, for the period of 30 years from the date of acceptance hereof, electric light and power facilities (including conduits, poles, wires and transmission lines, and, for its own use, telephone and telegraph lines) for the purpose of supplying electricity to the Grantor and its successors, and inhabitants thereof, and persons and corporations beyond the limits thereof.

Section 2. As a condition precedent to the taking effect of this grant, the Grantee shall have filed its acceptance hereof with the Grantor's Clerk within 30 days hereof.

Section 3. The facilities of the Grantee shall be so located or relocated and so erected as to interfere as little as possible with traffic over said streets, alleys, bridges and public places, and with reasonable egress from and ingress to abutting property. The location or relocation of all facilities shall be made under the supervision and with the approval of such representatives as the governing body of the Grantor may designate for the purpose, but not so as to unreasonably interfere with the proper operation of the Grantee's facilities and service. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall, within a reasonable time and as early as practicable after such excavation, be replaced by the Grantee at its expense and in a condition as good as it was at the time of such excavation..

Section 4. Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 6. No later than 60 days after the first anniversary date of this grant, and no later than 60 days after each succeeding anniversary date of this grant, the Grantee, its successors and assigns, shall have paid to the Grantor and its successors an amount which added to the amount of all taxes as assessed, levied, or imposed (without regard to any discount for early payment or any interest or penalty for late payment), licenses, and other impositions levied or imposed by the Grantor upon the Grantee's electric property, business, or operations, and those of the Grantee's electric subsidiaries for the preceding tax year, will equal six percent of the Grantee's revenues from the sale of electrical energy to residential, commercial and industrial customers within the corporate limits of the Grantor for the 12 fiscal months preceding the applicable anniversary date.

Section 7. Payment of the amount to be paid to the Grantor by the Grantee under the terms of Section 6 hereof shall be made in advance by estimated monthly installments commencing 90 days after the effective date of this grant. Each estimated monthly installment shall be calculated on the basis of 90% of the

Grantee's revenues (as defined in Section 6) for the monthly billing period ending 60 days prior to each scheduled monthly payment. It is also understood that for purposes of calculating each monthly installment, all taxes, licenses, and other impositions shall be estimated on the basis of the latest data available for all such amounts imposed on the Grantee, before being prorated monthly. The final installment for each fiscal year of this grant shall be adjusted to reflect any underpayment or overpayment resulting from estimated monthly installments made for said fiscal year.

Section 8. As a further consideration of this franchise, the Grantor agrees not to engage in the business of distributing and selling electricity during the life of this franchise or any extension thereof in competition with the Grantee, its successors and assigns.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after the final determination of the question to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, such decision shall not affect the validity of the remainder as a whole or as to any part, other than the part declared to be invalid.

Section 11. That all ordinances and parts of ordinances in conflict herewith be and the same are hereby repealed.

Section 12. This ordinance shall take effect on the date upon which the Grantee files its acceptance.

PASSED First Reading this 12th day of Sept 1991.

PASSED Second and Final Reading this 2nd day of Oct, 1991.

President of Council

ATTEST:

Town Clerk

APPENDIX C

TAMPA-HILLSBOROUGH COUNTY EXPRESSWAY AUTHORITY, Petitioner, v. K.E. MORRIS ALIGNMENT SERVICE, Inc., Respondent

No. 62,281

Supreme Court of Florida

444 So. 2d 926*; *1983 Fla. LEXIS 2899

November 10, 1983

SUBSEQUENT HISTORY: [**1] Rehearing Denied February 22, 1984.

PRIOR HISTORY: Application for Review of the Decision of the District Court of Appeal - Direct Conflict of Decisions Second District - Case No. 81-1714.

COUNSEL: William C. McLean, Jr., Tampa, Florida, for Petitioner.

Paul B. Johnson of Johnson, Paniello and Hayes, Tampa, Florida, for Respondent.

JUDGES: Boyd, J. Alderman, C.J., Overton, McDonald, Ehrlich and Shaw, JJ., concur. Adkins, J., dissents.

OPINION BY: BOYD

OPINION

[*927] This case is before us on the petition of the Tampa-Hillsborough County Expressway Authority for review of a decision of the District Court of Appeal for the Second Appellate District of Florida. The decision of which review is sought is reported as *K.E. Morris Alignment Service, Inc. v. Tampa-Hillsborough County Expressway Authority, 414 So.2d 299 (Fla. 2d DCA 1982)*. The decision is in conflict with *Division of Administration, Department of Transportation v. Ely, 351 So.2d 66 (Fla. 3d DCA 1977)*. We therefore have jurisdiction to provide the requested review. *Art. V, § 3(b)(3), Fla. Const.*

The Tampa-Hillsborough County Expressway Authority instituted eminent domain proceedings against numerous parcels of land in Hillsborough [**2] County, including a small tract owned by K.E. Morris Alignment Service, Inc. The Authority sought to take only a part of respondent's land, however, and respondent operated a business on remaining land adjoining the property taken.

In the course of the proceedings for determination of compensation, respondent made a claim for business damages under *section 73.071(3)(b), Florida Statutes* (1979). Although respondent had been in business at the location adjacent to the land being taken for only three years and two months, * its business had been in continuous operation for more than thirty years. The trial court held that since the business had been in operation at the location for which business damages were claimed for [*928] less than five years, no business damages were recoverable under *section 73.071(3)(b)*. The landowner appealed.

> * Pursuant to chapter 74, Florida Statutes (1979), the court entered an order of taking on September 7, 1979, prior to the proceedings for determination of just compensation.

[**3] The district court reversed and held that *section 73.071(3)(b)* does not require, as a prerequisite to an award of business damages, that the business have been in operation at the location for which business damages are claimed for more than five years.

Section 73.071(3)(b) provides in pertinent part as follows:

> (3) The jury shall determine solely the amount of compensation to be paid, which compensation shall include:
>
> . . . .

> (b) Where less than the entire property is sought to be appropriated, any damages to the remainder caused by the taking, including, when the action is by the Division of Road Operations of the Department of Transportation, county, municipality, board, district or other public body for the condemnation of a right-of-way, and the effect of the taking of the property involved may damage or destroy an established business of more than 5 years' standing, owned by the party whose lands are being so taken, located upon adjoining lands owned or held by such party, the probable damages to such business which the denial of the use of the property so taken may reasonably cause.

The district court looked at the three criteria for business damages [**4] and found that they were independent requirements: the business must be established for more than five years, the business must be owned by the party whose lands are being taken, and the business must be located upon adjoining land owned or held by such party. Thus the district court found that there was no requirement in the statute that the business for which damages are sought have been operated for more than five years at the location adjoining the land being taken. We believe contrarily that the words "located upon adjoining lands" and the words "established business of more than 5 years' standing" are intended to be read together and to qualify each other. We therefore hold that the district court erred in its construction of the statute. The statute indicates that the legislative intent is to allow business damages only to concerns having a physical existence for more than five years at the location where the partial taking is alleged to have caused business damages. Examined in the light of sound principles of statutory construction, the statute sustains the ruling of the circuit judge and demonstrates the error of the district court's holding.

The power of eminent domain [**5] is an inherent feature of the sovereign authority of the state. *Daniels v. State Road Department, 170 So.2d 846 (Fla. 1964)*. The constitution limits this power by requiring that full compensation be paid to the owner for the property taken. *Art. X, § 6(a), Fla. Const.* The payment of compensation for intangible losses and incidental or consequential damages, however, is not required by the constitution, but is granted or withheld simply as a matter of legislative grace. *Jamesson v. Downtown Development Authority, 322 So.2d 510 (Fla. 1975)*. Business damages such as those sustained in the instant case fall in the category where compensation is not constitutionally required but depends on legislative authorization. *City of Tampa v. Texas Co., 107 So.2d 216 (Fla. 2d DCA 1958), cert. dismissed, 109 So.2d 169 (Fla. 1959)*.

The allowance of business damages in eminent domain proceedings, being a matter of legislative grace, is analogous to other forms of legislative largess, such as grants of franchise rights. The allowance of business damages can also be compared to a waiver of sovereign immunity. Legislative grants of property or franchise rights must, when construction [**6] is necessary, be strictly construed in favor of the state and against the grantee. *Tampa & Jacksonville Railway v. Catts, 79 Fla. 235, 85 So. 364 (1920)*. A waiver of sovereign immunity, similarly, should be strictly construed in favor of the state and against the claimant. *Arnold v. Shumpert, 217 So.2d 116 (Fla. 1968)*; *Spangler v. Florida State* [*929] *Turnpike Authority, 106 So.2d 421 (Fla. 1958)*. So, any ambiguity in *section 73.071(3)(b)* should be construed against the claim of business damages, and such damages should be awarded only when such an award appears clearly consistent with legislative intent.

Of course, the district court took the view that the plain language of the statute seemed to authorize an award, so that no resolution of ambiguity was necessary. But the district court gave the statute an interpretation it had never before received, and one that is at odds with the traditional understanding of the purpose and effect of the statutory business damages criteria. *See, e.g., State Road Department v. Bramlett, 189 So.2d 481 (Fla. 1966)*; *State Road Department v. Lewis, 170 So.2d 817 (Fla. 1964)*; *Glessner v. Duval County, 203 So.2d 330 (Fla.* [**7] *1st DCA 1967)*; *Intercoastal Drydock, Inc. v. State Road Department, 203 So.2d 19 (Fla. 3d DCA 1967), cert. denied, 210 So.2d 223 (Fla. 1968)*; *State Road Department v. Abel Investment Co., 165 So.2d 832* (Fla. 2d DCA), *cert. denied, 169 So.2d 485 (Fla. 1964)*; *State Road Department v. Peter, 165 So.2d 771 (Fla. 2d DCA 1964)*. It is true that none of the above-cited cases dealt with the precise issue that has arisen now. But in reasoning that "if the legislature had intended the requirement that the business be located on the adjacent land for five years, it could have used plain language to so provide," *414 So.2d at 300*, the district court construed the statute as though there existed a presumption in favor of the claimant.

Statutes should be construed in light of the manifest purpose to be achieved by the legislation. *Van Pelt v. Hilliard, 75 Fla. 792, 78 So. 693 (1918)*; *Curry v. Lehman, 55 Fla. 847, 47 So. 18 (1908)*. The purpose of *section 73.071(3)(b)* is to mitigate the hardship that may result when the state exercises the power of eminent domain paying only the constitutionally required full compensation for the property actually taken. The legislature [**8] in doing so has recognized that a business location may be an asset of considerable value and susceptible of being substantially damaged by a partial taking. To assure the existence of a substantial business interest in the location as a prerequisite to an award of business damages, the legislature included the requirement of five years of operation at the location. The requirement of "more than 5 years' standing," seen in the light of the legislative purpose, obviously refers to the length of time the business has operated *at the location* where business damages are claimed to have been incurred due to condemnation of adjoining land. The length of time that the operator of the business has been in business at previous or other locations and the duration of its existence as a business entity are obviously irrelevant to the inquiry mandated by the statute.

When a statute is susceptible of and in need of interpretation or construction, it is axiomatic that courts should endeavor to avoid giving it an interpretation that will lead to an absurd result. *State ex rel. Florida Industrial Commission v. Willis, 124 So.2d 48 (Fla. 1st DCA 1960), cert. denied, 133 So.2d 323 (Fla.* [**9] *1961)*. If we were to adopt the district court's view of *section 73.071(3)(b)*, there could be absurd and unfair results in hypothetical situations that readily come to mind. Under the district court's approach, two property owners operating businesses, both equally damaged by a partial taking of their respective properties, and both having been in operation at the affected location for less than five years, would be treated differently insofar as their eligibility to claim business damages is concerned if one of them had been in existence as a business entity for more than five years and the other had not. Thus the different treatment of the two landowners on the question of eligibility to claim business damages would be based on a factor having nothing whatsoever to do with the duration of their operations at the respective locations and therefore the degree of hardship imposed upon them by the partial taking of their respective premises. This would be an irrational [*930] distinction upon which to justify such differential treatment. "An interpretation of the language of a statute that leads to absurd consequences should not be adopted when, considered as a whole, the statute [**10] is fairly subject to another construction that will aid in accomplishing the manifest intent and the purposes designed." *City of Miami v. Romfh, 66 Fla. 280, 285, 63 So. 440, 442 (1913)*. Since the construction given the statute by the circuit judge comports with the obvious purpose of the statute, it should have been sustained by the appellate court.

Decisions of the appellate courts of Florida clearly indicate that the essential inquiry under the business damages statute is that of continuous operation of the business at the location where business damages are alleged to have been suffered. In *Hooper v. State Road Department, 105 So.2d 515 (Fla. 2d DCA 1958)*, the trial court refused to allow a claim for business damages because the landowners had been operating the business for only about one year. The district court of appeal reversed because the owners had acquired the business as a going concern and it had been in continuous operation at the location for more than five years. Conversely, in *Hodges v. Division of Administration, Department of Transportation, 323 So.2d 275 (Fla. 2d DCA 1975)*, the district court affirmed the trial court's refusal of a business damages [**11] claim because, although a business similar to the landowner's had some time previously been operated on the premises, the landowner had not acquired a business there but only a "business place" in which he opened a new business. *323 So.2d at 277*. There was no continuous operation and the landowner's business had been in existence for less than five years. The same kind of situation produced a consistent holding in *Division of Administration, Department of Transportation v. Lake of the Woods, Inc., 404 So.2d 186 (Fla. 4th DCA 1981)*.

The district court of appeal in the instant case acknowledged that its decision was in conflict with *Division of Administration, Department of Transportation v. Ely, 351 So.2d 66 (Fla. 3d DCA 1977)*. There a propane gas dealer claimed that the partial taking of a mobile home park with which it had a service agreement and where it had access easements for its facilities had taken its property and caused it business damages. The district court held that the service easement was not a kind of property the loss of which had to be compensated and rejected the claim of business damages for two reasons:

> Business damages under *Section 73.071(3)(b),* [**12] *Florida Statutes* (1975) are equally inapplicable in the instant case. Southeastern Propane Gas Co. did not own or have any property interest in the condemned land as required by the statute in order to qualify for business damages. Moreover, its business had not been operating on the adjoining land for more than five years as further required by the statute. The fact that Southeastern Propane Gas Co. as a company has been incorporated and doing business elsewhere throughout the state since the early 1950's does not satisfy this five year requirement under the statute.

351 So.2d at 69. The second reason given, of course, pertains to the issue in the instant case upon which our conflict jurisdiction is predicated. Under our holding today, the *Ely* decision was correct.

The decision of the district court of appeal is quashed and the case is remanded with instructions that the ruling of the trial court be affirmed.

It is so ordered.

ALDERMAN, C.J., OVERTON, McDONALD, EHRLICH and SHAW, JJ., Concur.

ADKINS, J., Dissents.

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Floridians for Solar Choice, Inc.

SUBJECT: Financial Impact Statement for the Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: May 6, 2015

This third memorandum from the sponsors of the Solar Amendment to the FIEC is intended to provide additional information on issues raised at the FIEC public hearing on April 24, 2015. Included are comments on the speculation that municipal officials will increase Public Service taxes (PST) or franchise fees to make up for any perceived reduction in those revenues as a consequence of the Solar Amendment. Also addressed is the issue of termination clauses in franchise agreements. This memorandum begins with a proposed financial impact statement from the Solar Amendment sponsors for the FIEC's consideration.

Proposed Financial Impact Statement

The amendment's financial impact, if any, on state and local government revenues cannot be reasonably determined at this time. The most likely financial impact is on local franchise revenues which are likely negative, but minimal, in the short term. Revising laws to comply with the amendment will cost the state and local governments minimally. Purchases, if any, by state and local governments of lower priced electricity from local solar electricity suppliers will reduce governments' costs.

Rate Adjustments

Public Service Tax

FIEC's duty is to analyze and address the probable financial impact of an amendment. That mandate does not include the power to speculate that a local government will increase the PST rates if the Solar Amendment passes. The PST issue may arise under a theory that the Solar Amendment acts to incentivize a person to buy their own solar panels, use the solar electricity (which use is not subject to PST) and sell electricity to a neighbor (which is subject to the PST). Under those facts, a conclusion that a local government will raise the PST to offset any revenue lost on the use of solar energy is attenuated at best and is not within the realm of a probable financial impact. A decision to raise a tax rate assumes that a local government has the capacity to raise the rate, which is not the situation for all cities that currently levy the PST. Further, the decision to raise a tax rate is a tough political decision by a locally elected official. It is certainly not a probable conclusion that a local government will increase rates.

Moreover, a conclusion by the FIEC that a PST rate increase is a probable outcome is outside the REC's typical convention and it charts new territory. For example, consider HB 173 from the 2015 Regular Session which provided for the increase of the ad valorem exemption for widows, the blind and the disabled. The Revenue Estimating Conference analyzed this legislation and determined that it reduced local government revenues. See, REC Impact Conference Results (Apr. 27, 2015). The REC did not conclude that the local governments will increase taxes to make up the revenue lost by the exemption. See, REC Estimate of HB 173 included in Appendix A. Another example is the commercial rental tax rate reduction bill considered this past Session. The REC did not conclude in its analysis that the legislature would make up for the lost revenue through a tax increase. See, REC Analysis of SB 140, a copy of which is attached as Appendix A.

A decision whether and how to offset a tax or revenue reduction, whether by a budget reduction or a rate adjustment, is wholly within the discretion of the legislative body. It is not within the purview of the REC to speculate whether and how the legislature or a local government will respond. In fact, the REC has never speculated on tax increases in its official estimates of tax law changes. And the FIEC should not start now when there is a constitutional standard for the statements and that standard is established as "probable." Statements that speculate on government actions and predict reactions go way beyond "probable."

Franchise Fees

Statements that the local governments will increase the franchise fee rates as a consequence of the Solar Amendment should not appear in the FIEC's statements. Franchise agreements are binding contracts between the electric utilities and local government, typically for a long period of time--20 or 30 years. The provisions of an agreement, including the franchise fee rates, cannot in all instances be unilaterally altered or increased by the local government. It is evident that an electric utility would not agree to increase the rates it pays when it has a long term agreement that is binding on the local government. A statement that states that franchise fees will increase belies the nature of a franchise agreement and enters the realm of constitutionally forbidden speculation.

Franchise Terminations

The FIEC should not speculate that a local government's franchise agreement with an electric utility will be terminated because of the Solar Amendment. Not all franchise agreements allow for termination based on competition. See, e.g., the franchise agreement between the Town of Glen Ridge and Florida Power & Light Company (Ordinance No. 91-1), a copy of which is included at page 509 of the Revised Notebook and is also included here in Appendix B. Some franchise agreements do contain a termination provision. The recent Florida Power & Light Company (FPL) franchise agreement with the City of South Miami provides an example of one that is included in the FIEC revised notebook beginning on page 450. Another copy of that Agreement is attached in Appendix B. Section 9 provides as follows:

> Section 9. If as a direct or indirect consequence of any legislation, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) an person who offers retail electric service to the public is permitted to provide electric service within the incorporated areas of the City to any applicant for electric service within any part of the incorporated areas of the City in which FPL may lawfully serve, and FPL reasonably determines the its obligations hereunder, or otherwise resulting from this franchise in respect to rates and services, place it at a competitive disadvantage with respect to such other person, FPL may, at any time after the taking of such action terminate this franchise if such competitive disadvantage resulting from this franchise is not remedied within the time period provided hereafter. FPL shall give the city at least 180 days advanced written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of the consequences of such action which resulted in the competitive disadvantage. The City shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. Is such competitive disadvantage is not remedied by the City within said time period, either by a franchise agreement with such other person or otherwise, FPL may terminate this franchise agreement by delivering written notice to the City's Clerk and termination shall take effect on the date of delivery of such notice. Agreement by the City with such other person to enter into a franchise containing substantially the same terms as provided herein shall be a sufficient, but not exclusive, remedy precluding FPL's termination of this franchise. Nothing contained herein

> shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

There are several reasons this paragraph and similar ones in other franchises do not give the electric utility the unilateral right to terminate the franchise agreement if the Solar Amendment becomes law. The termination section is inapplicable to constitutional amendments. By its language, the section allows termination only upon actions of the State of Florida, and a constitutional amendment is not an action of the State, it is an action of the people, the voters and not of the government. Further, in support of that point, the section itself assumes that the remedy for the competitive disadvantage is an action within the City's power to take. See sentences 3 and 4 of section 9. And see the penultimate sentence which provides that entering into a franchise agreement with the competitor is one type of remedy available to the City, but not the City's exclusive remedy precluding FPL's termination. Construing section 9 as providing a right to terminate if the Solar Amendment passes is contrary to the language in section 9, when in fact and law, the City cannot "remedy" a constitutional amendment, it can only remedy something within its control, such as a requiring a competitor to enter into a franchise agreement.

Moreover, the agreement contains a bargain consisting of several benefits to the electric utility. Those include the right to use the City's the rights-of-way through-out the incorporated area, even where the City adds geographic area and additional rights-of-way, for conducting its private business in a manner prescribed in the Agreement. See sections 2 and 3. This right to use the rights of way is not available otherwise.

Additionally, the Agreement provides that as a further consideration, during the term of the franchise the City agrees not to distribute or sell electricity in competition with FPL. See section 7. Without such a provision, such as if the Agreement is terminated, the City has the home rule power to generate electricity. Further, in the Agreement, the City promises not to participate in any PSC or other regulatory or legal proceeding or contractual arrangement which would obligate FPL to transmit or distribute electricity from a third party to any other retail customer's facility. Id. This limitation is one of the rights FPL bargained for and would have to give up if it terminated the Agreement.

Finally, the Agreement expressly allows an FPL customer within the City to generate its own electricity from an approved renewable generation system, showing that both the City and FPL recognize and agree that franchise fee revenues may be affected by self-generation of renewable energy such as solar and that such generation does not create a competitive disadvantage.

The exercise of the termination clause is not automatic when FPL gives notice to the City. Section 9's last sentence provides that the City can challenge FPL's termination in Court. Additionally, Section 12 provides that prior to filing suit, the parties shall participate in discussions in an attempt to avoid litigation. The City may contest the action in several ways, including by claiming that the facts do not support a conclusion that the utility is at a competitive disadvantage under the Solar Amendment's local solar energy supplier model because the local solar energy supplier does not need the rights of way to conduct its business, and that the payment for the franchise to use the rights of way and for the City not to compete is a consequence of the utilities' business model and not from any actions of the City.

Therefore, as detailed above, it is not probable that an electric utility would terminate an existing franchise agreement. Even if it does, as detailed below, the city and county have the home rule authority to unilaterally impose a franchise fee or right-of-way fee for the use of the local government's property.

Right-of-Way Fees

A franchise fee is a charge imposed upon a utility for the grant of a franchise and for the privilege of using the local government's rights-of-way to conduct the utility business. A franchise fee is fair rent for the use of such rights-of-way and consideration for the local government agreeing not to provide competing utility services during the franchise term. See City of Plant City v. Mayo, 337 So. 2d 966 (Fla. 1976); Santa Rosa County v. Gulf Power Co., 635 So. 2d 96 (Fla. 1st DCA 1994), rev. denied, 645 So. 2d 452 (Fla. 1994); and City of Hialeah Gardens v. Dade County, 348 So. 2d 1174 (Fla. 3d DCA 1977).

By definition, a franchise ordinance grants a special privilege that is not available to the general public. The Florida Supreme Court explained in Leonard v. Baylen Street Wharf Co., 52 So. 718 (Fla. 1910), that "[a] franchise is a special privilege conferred upon individuals or corporations by governmental authority to do something that cannot be done of common right." Id. at 718. However, "[f]ranchises [are] not . . . the absolute property of any one, but their use may be granted or permitted by proper governmental authority, subject to supervision and regulation, and upon such terms as may be lawfully imposed." Id. Franchises are used for "the good of the public, usually for the purpose of rendering an adequate service without unjust discrimination, and for a reasonable compensation." Id. Finally, "[p]rivate rights in franchises are confined to a proper use of them for the general welfare, subject to lawful governmental regulation." Id.

In addition to compensation for the relinquishment of property rights, when counties and municipalities have the authority to own, operate, and maintain utilities themselves any permission granted to another entity to perform those services is additional justification for the fee. See Alpert v. Boise Water Corp., 795 P. 2d 298 (Idaho 1990). In Alpert, each franchise provided that the utility would pay to the cities a three percent (3%) franchise fee from all sales within the corporate limits as "consideration for the franchise contract." Id. at 300. The Idaho Supreme Court stated, "[C]ities have the right to own and operate utilities and provide those services to their residents[.] [T]he surrender of this right is valid consideration for the franchise fee charged to the utilities." Id. at 306.

The home rule authority of a county or municipality to enter into a franchise agreement with a utility and to impose a fee that is bargained for in exchange for the government property rights relinquished is settled. An evolving issue is the extent of the power of a county or municipality to unilaterally impose a fee for a privileged use of its right-of-way whether such charge is characterized as a rental fee, a regulatory fee or both.

Customarily, a franchise fee is calculated as a percentage of the gross revenues received by a utility from a defined geographic area. A franchise fee imposed by a municipality is based upon the gross revenues received by the utility from the municipal areas and a franchise fee imposed by a county is generally based upon the gross revenues received by the utility from the unincorporated areas (whether a franchise fee imposed by a county could be based on gross receipts received by the utility countywide has not been addressed.)

In Alachua County v. State, 737 So. 2d 1065 (Fla. 1999), because the electric utilities would not consent to a franchise agreement, Alachua County unilaterally imposed a fee for the privileged use of its rights-of-way. The fee imposed was three percent (3%) of the gross revenues generated by the electric utilities and the utilities were allowed to separately state the fee on the electric bill. The record in the validation proceedings did not, in the words of the Court, establish any "nexus between its alleged 'reasonable rental charge' . . . and the rental value of the rights-of-way." Id. at 1067-68. As a consequence, the Court held that the unilaterally imposed privilege fee was a tax not authorized by general law.

The Alachua County case was distinguished by the Court in Florida Power Corp. v. City of Winter Park, 887 So. 2d 1237 (Fla. 2004). There, the electric utility refused to renegotiate a franchise agreement which had previously provided for the payment of a franchise fee of six percent (6%) of the gross revenues received from the sale of electricity within the City of Winter Park. The Court likened the electric utility to a holdover tenant in the public rights-of-way and held that the electric utility would be subject to the six percent fee until the parties reached a new agreement or the City exercised its rights to acquire granted under the franchise agreement. The Court distinguished its prior holding in Alachua County as follows:

> Moreover, we reiterate that Alachua validates fees that are reasonably related to the government's cost of regulation or the rental value of the occupied land, as well as those that are the result of a bargained-for exchange. [cit. omitted] In the instant case, the trial court specifically found that the City had "offer[ed] sufficient evidence that the six percent fee was reasonably related" to the costs of regulation, and had "also

> presented strong evidence that the six percent fee is a fair 'market rate' for such use, occupation, or rental."

887 So. 2d at 1241.

In summary, a bargained for reasonable fee in a franchise agreement is not a tax. The fact that the franchise agreement has expired does not render the charge a tax and it remains a valid fee until a new agreement is reached or any contractually granted acquisition rights are exercised. Additionally, a unilaterally imposed fee reasonably related to the cost of regulation and constituting a reasonable rental charge for the use of public property is a valid fee.

A city and a county have the home rule power to impose such a fee on electric utilities for the use of the rights-of-way.

Conclusion

The FIEC's constitutional and statutory duty is to determine the probable financial impact on state and local government revenues and costs. The Solar Amendment authorizes a local solar electricity supplier to sell the electricity to a person on the same property and also sell it to a person on contiguous property. The Solar Amendment does not directly reduce or increase taxes. It contains no language relating to taxes at all. Thus, the Solar Amendment has no direct impact on revenues.

As to indirect impacts, the extent to which the Solar Amendment will be successful in luring local solar energy suppliers to Florida is indeterminate because such decisions consists of many economic factors and government policies absent in Florida, but present to varying degrees in other States that have adopted policies supporting the use of third party solar. Those policies include the State adoption of a mandatory renewable energy requirement, which Florida does not have. Also negatively impacting a decision to use third party solar in Florida beginning in 2017 is the sunsetting of Federal tax credits for residential solar and the reduction to 10 percent for commercial solar. Unlike other States, Florida has no more solar rebates, as they were recently repealed by the PSC. Ad valorem taxes in Florida also constrain the local solar electricity supplier in Florida, as evidenced in SJR 400 filed in the 2015 Session proposing a constitutional amendment to provide an ad valorem tax exemption for certain renewable energy devices.

Consequently, the probable financial impact cannot be reasonably determined at this time.

LIST OF APPENDICES

Revenue Estimating Conference Impact Analyses .... A
Franchise Agreements .... B

.

APPENDIX A

REVENUE ESTIMATING CONFERENCE

Tax: Ad Valorem
Issue: Widows, Widowers, Blind and Totally Disabled Exemption Increase
Bill Number(s): HB 173

☒ **Entire Bill**
☐ **Partial Bill**:
Sponsor(s): Rep. Goodson
Month/Year Impact Begins: Tax Years beginning January 1, 2016
Date of Analysis: 1/23/2016

Section 1: Narrative

a. Current Law: Article VII, Section 3(b) of the Florida Constitution provides: There shall be exempt from taxation, cumulatively, to the head of a family residing in this state, household goods and personal effects to the value fixed by general law, not less than one thousand dollars, and to every widow or widower or person who is blind or totally and permanently disabled, property to the value fixed by general law not less than $500.

Section 196.202, Florida Statutes, Provides: Property of widows, widowers, blind persons, and persons totally and permanently disabled.—
(1) Property to the value of $500 of every widow, widower, blind person, or totally and permanently disabled person who is a bona fide resident of this state is exempt from taxation. As used in this section, the term "totally and permanently disabled person" means a person who is currently certified by a physician licensed in this state, by the United States Department of Veterans Affairs or its predecessor, or by the Social Security Administration to be totally and permanently disabled.
(2) An applicant for the exemption under this section may apply for the exemption before receiving the necessary documentation from the United States Department of Veterans Affairs or its predecessor, or the Social Security Administration. Upon receipt of the documentation, the exemption shall be granted as of the date of the original application, and the excess taxes paid shall be refunded. Any refund of excess taxes paid shall be limited to those paid during the 4-year period of limitation set forth in s. 197.182(1)(e).

b. Proposed Change: Increases the exemption amount for widows, widowers, blind persons, and persons totally and permanently disabled persons from $500 to $5000.

Section 2: Description of Data and Sources

2014 Tax Roll
Exemptions Fields 08- Totally and Permanently Disabled with income limitation (Total Exemption)
31 Blind
32 Widowers
33 Widows
34 Totally and Permanently Disabled $500
05 Certain Permanently Disabled Veterans (Total Exemption)
06 Disabled Veterans confined to a wheel chair (Total Exemption)
2013 American Community Survey
Annual Statistical Report on the Social Security Disability Insurance Program, 2013
November 2014 Demographic Estimating Conference

Section 3: Methodology (Include Assumptions and Attach Details)

The 2014 Ad Valorem tax rolls were used to identify those parcels for which an exemption under 196.202 was granted ($500 for Blind [31], Widower [32], Widow [33], and Totally and Permanently Disabled [34]). Those parcels that had multiple exemptions were identified. A Code was created to indicate the total number of exemptions. The total maximum potential exemption increase was calculated by multiplying the number of exemptions by the amount of increase ($4500). The impact was determined by then comparing the maximum potential increase to the total taxable value at the parcel level for school and non-school taxable values. If the maximum potential exemption increase was less than the respective taxable value, the impact was the maximum potential exemption increase. If the maximum potential exemption increase was greater than the respective taxable value, the impact would be equal to the respective school or non-school taxable value. This amount was used for the low impact. 2014 average school and non-school millage rates were applied to determine tax impact.

In order to develop the impact, exemption fields 08 and 34 had to be scrutinized. There appeared to be certain instances where the section 196.202 exemption of $500 was reported in the exemption 08 field and where the total exemption authorized by section

REVENUE ESTIMATING CONFERENCE

Tax: Ad Valorem
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196.101 was reported in the exemption 34 field. Both fields were examined and those exemptions that appeared to be mischaracterized were either included or excluded from the analysis. If the exemption was greater than a certain dollar amount ($2000) and resulted in zero taxable value, it was excluded from exemption 34. If the exemption was in exemption 08 and was $2000 or less, it was included in the analysis. 95.3% of those included from exemption 08 were exactly $500 and 4.6% were exactly $1000.

In order to develop the middle and high estimate, certain data was obtained regarding the number of disabled persons in Florida. From the 2013 American Community Survey (ACS) from the Bureau of the Census was obtained data on the percent and therefore implied number of disabled individuals in Florida between the age of 18 -64 and those over the age of 65. Data on the number of individuals that received Social security Disability Benefits in Florida in 2013 was obtained from the Annual Statistical Report on the Social Security Disability Insurance Program, 2013 for those individuals 18 to full retirement age. The number of those 18-64 indicated as disabled in the 2013 ACS was compared to the number received Social Security Disability benefits. The resulting ratio was then applied to the implied number disabled over age 65 to approximate the number over 65 that would meet the Social Security Administration definition of totally and permanently disabled. The rate of homeownership from the 2013 ACS was used to approximate the high estimate of total individuals that might be eligible to receive the exemption. For the middle, the assumed home ownership rate for disabled was 50% of the ACS homeownership rate in order to determine potential total eligible individuals.

The assumption for the middle and high is that there are individuals that are eligible for the exemption but that have not bothered to apply for it given that the exemption is worth around $10 and that those individuals would apply for it if the exemption were increased. The number currently receiving an exemption based on disability or blindness were subtracted from the counts derived as described above. The result was then multiplied by $4900 average exemption amount to get taxable value impact in addition to those already receiving the exemption. 2014 average school and non-school millage rates were applied to determine tax impact.

Population growth rates from the November 2014 Demographic conference were used to estimate future year impacts.

Section 4: Proposed Fiscal Impact

School

	High		Middle		Low	
	Cash	Recurring	Cash	Recurring	Cash	Recurring
2015-16	($ 0)	($26.0 M)	($0)	($19.3 M)	($ 0)	($16.4 M)
2016-17	($26.4 M)	($26.4 M)	($19.6 M)	($19.6 M)	($16.7 M)	($16.7 M)
2017-18	($26.8 M)	($26.8 M)	($19.9 M)	($19.9 M)	($16.9 M)	($16.9 M)
2018-19	($27.2 M)	($27.2 M)	($20.2 M)	($20.2 M)	($17.1 M)	($17.1 M)
2019-20	($27.5 M)	($27.5 M)	($20.4 M)	($20.4 M)	($17.4 M)	($17.4 M)

NonSchool

	High		Middle		Low	
	Cash	Recurring	Cash	Recurring	Cash	Recurring
2015-16	($ 0)	($38.3 M)	($28.8 M)	($28.4 M)	($0)	($24.1M)
2016-17	($38.8 M)	($38.8 M)	($29.2 M)	($28.8 M)	($24.1M)	($24.5 M)
2017-18	($39.4 M)	($39.4 M)	($29.6 M)	($29.2 M)	($24.5 M)	($24.8 M)
2018-19	($39.9 M)	($39.9 M)	($30.0 M)	($29.6 M)	($24.8 M)	($25.2 M)
2019-20	($40.5 M)	($40.5 M)	($28.8 M)	($30.0 M)	($25.2 M)	($25.5 M)

List of affected Trust Funds:

Ad Valorem group

REVENUE ESTIMATING CONFERENCE

Tax: Ad Valorem
Issue: Widows, Widowers, Blind and Totally Disabled Exemption Increase
Bill Number(s): HB 173

Section 5: Consensus Estimate (Adopted: 01/30/2015) The Conference adopted the low estimate but with a 2% increase in the starting point for the estimate.

	GR		Trust		Local/Other		Total	
	Cash	Recurring	Cash	Recurring	Cash	Recurring	Cash	Recurring
2015-16	0.0	0.0	0.0	0.0	0.0	(41.3)	0.0	(41.3)
2016-17	0.0	0.0	0.0	0.0	(41.9)	(41.9)	(41.9)	(41.9)
2017-18	0.0	0.0	0.0	0.0	(42.5)	(42.5)	(42.5)	(42.5)
2018-19	0.0	0.0	0.0	0.0	(43.1)	(43.1)	(43.1)	(43.1)
2019-20	0.0	0.0	0.0	0.0	(43.7)	(43.7)	(43.7)	(43.7)

	A	B	C	D	E	F	G	H	I	J	K	L
1			Exemption 31 -Blind		Exemption 32 - Widowers		Exemption 33 - Widows		Exemption 34 - Disabled		Disabled with Income Limit - Exemption_08	
2	County #	County	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value
3	11	Alachua	68	$34,500	363	$180,530	2848	$1,423,670	554	$290,030		
4	12	Baker	3	$1,500	66	$33,000	406	$203,000	236	$125,500		
5	13	Bay	33	$16,500	526	$263,000	3057	$1,527,366	694	$358,042	3	$4,418
6	14	Bradford	1	$500	88	$43,759	586	$292,324	254	$130,569	1	$1,129
7	15	Brevard	221	$111,000	2753	$1,376,500	14296	$7,148,000	3681	$1,841,000		
8	16	Broward	222	$112,500	7726	$3,885,990	29627	$14,786,850	4240	$2,167,420		
9	17	Calhoun	2	$1,000	26	$12,814	198	$98,513	27	$13,500		
10	18	Charlotte	95	$48,000	1457	$726,997	5288	$2,634,335	2378	$1,246,050		
11	19	Citrus	88	$44,925	1208	$603,058	5030	$2,515,552	2196	$1,152,469		
12	20	Clay	53	$26,500	596	$298,000	2926	$1,465,538	1267	$669,814		
13	21	Collier	84	$42,000	1772	$887,500	6864	$3,435,091	377	$193,500		
14	22	Columbia	25	$12,500	194	$96,432	1111	$554,964	372	$192,000		
15	23	Dade	157	$78,500	3729	$1,864,500	26838	$13,425,500	5498	$2,781,000	2	$2,397
16	24	Desoto	11	$5,500	152	$76,000	550	$275,694	299	$157,500		
17	25	Dixie			82	$41,202	304	$150,915	192	$100,017		
18	26	Duval	109	$54,500	1847	$923,760	12284	$6,140,282	3493	$1,798,705	1	$639
19	27	Escambia			1287	$643,500	6288	$3,144,957	2262	$1,176,931		
20	28	Flagler	59	$30,000	574	$287,000	2525	$1,265,804	951	$502,500		
21	29	Franklin	1	$500	42	$21,000	260	$129,767	147	$72,793		
22	30	Gadsden	5	$2,500	99	$48,600	753	$376,851	112	$58,000		
23	31	Gilchrist	3	$1,500	85	$42,500	333	$167,000	129	$68,500		
24	32	Glades	2	$1,000	62	$30,743	219	$108,996	118	$63,000		
25	33	Gulf	1	$500	45	$22,500	302	$150,437	105	$53,000		
26	34	Hamilton	2	$1,000	22	$11,000	264	$131,596	117	$61,673	1	$1,982
27	35	Hardee	6	$3,000	85	$42,381	423	$212,500	178	$92,562	1	$883
28	36	Hendry	1	$500	94	$46,780	440	$217,640	213	$109,040		
29	37	Hernando	47	$24,000	1445	$720,899	5543	$2,770,522	1646	$873,426		
30	38	Highlands	41	$20,500	834	$417,000	3161	$1,582,500	1260	$663,500		
31	39	Hillsborough	224	$112,500	2208	$1,103,500	14152	$7,081,491			3879	$2,015,000
32	40	Holmes	3	$1,500	42	$21,000	380	$189,357	64	$32,617		
33	41	Indian River	1350	$702,794	619	$309,500	3357	$1,680,097				
34	42	Jackson	21	$10,500	163	$81,332	1011	$503,914	397	$208,132		
35	43	Jefferson	8	$4,500	85	$42,500	367	$182,538	269	$135,500		
36	44	Lafayette	1	$500	30	$14,593	137	$67,873	22	$11,000		
37	45	Lake	179	$88,572	1255	$627,500	6124	$3,062,268	2104	$1,105,502		
38	46	Lee	119	$61,079	2164	$1,081,110	10178	$5,083,306	1725	$890,059		
39	47	Leon	71	$35,427	701	$350,076	3405	$1,701,830	314	$157,000		
40	48	Levy	22	$11,000	220	$110,000	1050	$527,000	573	$299,000	6	$6,000
41	49	Liberty	2	$1,000	20	$10,000	86	$43,000	19	$9,500		
42	50	Madison	10	$5,000	69	$34,500	425	$212,409	236	$121,231		
43	51	Manatee	102	$52,500	2010	$1,003,742	7644	$3,810,691	1015	$523,762		
44	52	Marion	41	$20,500	1820	$906,905	8569	$4,278,552	2282	$1,188,196		
45	53	Martin	60	$31,000	683	$341,500	3646	$1,821,469	445	$229,920		
46	54	Monroe	11	$5,500	319	$159,500	1192	$596,500	250	$129,000		
47	55	Nassau	30	$15,000	376	$187,626	1456	$727,539	411	$215,000		
48	56	Okaloosa	16	$8,000	715	$357,331	3208	$1,605,500	406	$209,000		
49	57	Okeechobee	3	$1,500	166	$83,000	667	$333,841	323	$173,368		
50	58	Orange	4	$2,000	1882	$940,670	10017	$5,006,330	2582	$1,355,153		
51	59	Osceola	36	$18,000	525	$262,091	2692	$1,347,244	1833	$962,958	1	$133
52	60	Palm Beach	255	$127,389	4618	$2,306,042	27068	$13,526,196	3025	$1,582,928		
53	61	Pasco	113	$56,500	2695	$1,347,500	11255	$5,627,500	2576	$1,288,000		
54	62	Pinellas	460	$233,500	5187	$2,589,675	23574	$11,783,247	4502	$2,352,956		
55	63	Polk	179	$90,000	2313	$1,156,500	11057	$5,531,500	3836	$2,033,500		
56	64	Putnam	26	$13,500	371	$185,055	1710	$851,743	572	$305,329		
57	65	Saint Johns	49	$25,000	788	$393,722	3546	$1,774,326	676	$360,646		
58	66	Saint Lucie	115	$57,500	1314	$656,777	6003	$3,006,643			3376	$1,779,900
59	67	Santa Rosa	25	$12,500	552	$275,980	2488	$1,243,005	985	$508,625		
60	68	Sarasota	161	$80,500	3124	$1,561,565	12538	$6,274,000			826	$429,500
61	69	Seminole	141	$70,500	1251	$625,433	5998	$3,003,247	1632	$843,500		
62	70	Sumter	85	$42,010	1215	$607,500	4217	$2,107,748	1195	$630,335		
63	71	Suwannee	16	$8,000	158	$79,000	927	$461,772	471	$235,398		
64	72	Taylor	6	$3,000	51	$25,500	376	$188,274	139	$70,500		
65	73	Union	5	$2,500	20	$10,000	163	$81,278	139	$71,037		
66	74	Volusia	254	$130,000	2195	$1,098,000	11631	$5,824,000	5264	$2,789,500		
67	75	Wakulla	10	$5,000	65	$32,500	421	$209,931	132	$66,500		
68	76	Walton	9	$4,500	180	$90,000	1126	$563,288	559	$287,041		
69	77	Washington	4	$2,000	92	$46,000	589	$293,190	260	$138,122		
70		Statewide	5,566	$2,827,196	69,520	$34,761,670	337,174	$168,549,801	74,229	$38,531,856	8,097	$4,241,981
71												
72		Impact - Current	Total School Impact	Total NonSchool Impact								
73		Taxable Value	$248,912,504	$248,912,504								
74		Millage Rate	7.4334	10.9369								
75		Tax Impact	$1,850,263	$2,722,336								
76												

	A	B	C	D	E	F
1						
2			2014 Simulated Impact			
3			Exemptions 31-34		Certain Exemption _08	
4	County #	County	Taxable Value Impact School	Taxable Value Impact NonSchool	Taxable Value Impact School	Taxable Value Impact NonSchool
5	11	Alachua	$16,789,380	$14,791,250		
6	12	Baker	$3,183,610	$2,378,390		
7	13	Bay	$19,279,392	$15,358,518	0	0
8	14	Bradford	$4,039,354	$3,410,982	0	0
9	15	Brevard	$90,274,688	$90,274,290		
10	16	Broward	$185,011,120	$158,641,670		
11	17	Calhoun	$1,059,636	$605,050		
12	18	Charlotte	$41,242,712	$41,241,359		
13	19	Citrus	$36,844,451	$36,835,278		
14	20	Clay	$21,915,561	$19,038,197		
15	21	Collier	$40,799,776	$38,875,368		
16	22	Columbia	$7,447,383	$6,024,251		
17	23	Dade	$160,374,764	$112,124,631	0	0
18	24	Desoto	$4,492,407	$3,259,279		
19	25	Dixie	$2,252,984	$2,252,984		
20	26	Duval	$76,974,888	$65,274,400	0	0
21	27	Escambia	$44,059,928	$34,807,531		
22	28	Flagler	$18,697,852	$15,542,614		
23	29	Franklin	$1,903,080	$1,548,667		
24	30	Gadsden	$4,234,620	$4,084,648		
25	31	Gilchrist	$2,434,050	$2,223,129		
26	32	Glades	$1,779,343	$1,699,782		
27	33	Gulf	$1,971,842	$1,647,940		
28	34	Hamilton	$1,737,667	$1,183,964	0	0
29	35	Hardee	$3,022,807	$2,189,850	0	0
30	36	Hendry	$3,215,800	$2,276,870		
31	37	Hernando	$38,885,788	$29,489,113		
32	38	Highlands	$22,123,696	$21,221,538		
33	39	Hillsborough	$70,837,365	$59,844,065	$17,034,745	$15,136,588
34	40	Holmes	$2,117,939	$1,213,158		
35	41	Indian River	$23,708,055	$21,288,425		
36	42	Jackson	$6,897,148	$6,149,706		
37	43	Jefferson	$3,158,985	$3,023,585		
38	44	Lafayette	$806,791	$798,000		
39	45	Lake	$43,304,662	$35,607,982		
40	46	Lee	$63,183,968	$52,208,112		
41	47	Leon	$20,031,736	$18,061,547		
42	48	Levy	$6,923,292	$5,130,065	$45,645	$18,645
43	49	Liberty	$543,231	$354,958		
44	50	Madison	$3,173,223	$2,710,600		
45	51	Manatee	$47,775,626	$44,099,451		
46	52	Marion	$56,254,671	$56,254,072		
47	53	Martin	$21,227,243	$18,695,223		
48	54	Monroe	$8,008,918	$7,727,118		
49	55	Nassau	$10,198,491	$9,264,137		
50	56	Okaloosa	$19,524,751	$17,259,140		
51	57	Okeechobee	$5,088,273	$3,919,025		
52	58	Orange	$64,666,492	$57,579,070		
53	59	Osceola	$22,470,757	$18,830,876	$4,500	$4,500
54	60	Palm Beach	$155,525,565	$141,847,967		
55	61	Pasco	$69,804,663	$69,804,663		
56	62	Pinellas	$149,975,086	$149,950,719		
57	63	Polk	$71,121,123	$56,980,566		
58	64	Putnam	$11,596,466	$8,181,316		
59	65	Saint Johns	$22,830,772	$19,636,582		
60	66	Saint Lucie	$32,421,098	$25,185,725	$15,736,506	$13,962,322
61	67	Santa Rosa	$18,084,494	$14,192,686		
62	68	Sarasota	$70,901,187	$70,837,713	$3,829,169	$3,819,901
63	69	Seminole	$40,555,239	$32,465,273		
64	70	Sumter	$30,027,400	$29,699,270		
65	71	Suwannee	$6,821,680	$6,183,074		
66	72	Taylor	$2,509,664	$2,509,664		
67	73	Union	$1,425,920	$1,291,772		
68	74	Volusia	$85,913,815	$85,822,765		
69	75	Wakulla	$2,723,919	$2,049,188		
70	76	Walton	$8,243,654	$6,518,447		
71	77	Washington	$4,121,905	$2,856,855		
72		Statewide	$2,140,553,846	$1,894,334,103	$36,650,565	$32,941,956

	H	I	J
73	Low Impact	Total School Impact	Total NonSchool Impact
74	Taxable Value	$2,177,204,411	$2,173,495,802
75	Millage Rate	7.4334	10.9369
76	Tax Impact	$16,184,000	$23,771,344

	B	C	D
1			
2	2013 American Community Survey		
3	http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_13_1YR_S0201&prodType=table		
4	Florida Population	19,552,860	
5	Civilian NonIncarcerated Population 18-64	11,646,895	
6	% with Disability	10.30%	
7	Implied # with Disability 18-64	1,199,630	
8	Civilian NonIncarcerated Population over 65	3,578,397	
9	% with Disability	34.10%	
10	Implied # With Disability	1,220,233	
11			
12	Total with Disability	2,419,864	
13			
14			
15	Annual Statistical Report on the Social security Disability Insurance Program, 2013		
16	http://www.ssa.gov/policy/docs/statcomps/di_asr/2013/sect01c.html		
17			
18	Total Disabled Workers (Receiving SSI benefits)	2013	
19	Florida Ages 18 - Full Retirement Age	551,858	
20			
21			
22	2013 American Community Survey		
23	Home Ownership Rate - Florida	64.80%	
24	Average Household size - owner occupied	2.64	
25			
26			
27			
28	Implied potential additional Exemptions		
29		At ACS Home Ownership Rate (64.8%	Assuming Home Ownership rate 50% of total population
30	18 to Full Retirement age	357,604	178,802
31	Over 65	363,746	181,873
32			
33	Less - Current Exemptions		
34	Blind	5,566	5,566
35	Disabled (34)	74,229	74,229
36	Disabled(08)	14,748	14,748
37	Other Veteran totally Disabled Exemptions	8,449	8,449
38	Total	102,992	102,992
39			
40	Implied Additional Exemptions	260,754	78,881
41			
42	Additional Impact - Taxable Value (Assuming $4,900 average additional		
43	School	$1,277,693,112	$386,516,156
44	NonSchool	$1,277,693,112	$386,516,156
45			
46	School Impact - Tax	$ 9,497,586	$ 2,873,124
47	NonSchool Impact - Tax	$ 13,974,024	$ 4,227,295
48			
49		Added to Low for High Impact	Added to Low for Middle Impact

	G	H
45	Population	Nov 5 Demographic Estimating Conference
46	Growth Rate	
47	2015	1.39%
48	2016	1.45%
49	2017	1.44%
50	2018	1.41%
51	2019	1.38%

	School	High	Middle	Low
54	2014	($25,681,586)	($19,057,124)	($16,507,680)
55	2015	($26,038,560)	($19,322,018)	($16,737,137)
56	2016	($26,416,119)	($19,602,187)	($16,979,825)
57	2017	($26,796,511)	($19,884,459)	($17,224,335)
58	2018	($27,174,342)	($20,164,829)	($17,467,198)
59	2019	($27,549,348)	($20,443,104)	($17,708,245)

	NonSchool	High	Middle	Low
54	2014	($37,745,368)	($27,998,640)	($24,246,771)
55	2015	($38,270,029)	($28,387,821)	($24,583,801)
56	2016	($38,824,944)	($28,799,444)	($24,940,266)
57	2017	($39,384,024)	($29,214,156)	($25,299,406)
58	2018	($39,939,338)	($29,626,076)	($25,656,128)
59	2019	($40,490,501)	($30,034,915)	($26,010,182)

	A	B	C	D	E	F	G	H	I	J	K	L
1			2013 Exemption Data For Blind, Widowers, Widows, and Totally and Permanently Disabled									
2			Exemption 31 -Blind		Exemption 32 -		Exemption 33 - Widows		Exemption 34 - Disabled		Disabled with Income Limit	
3	County #	County	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value	Count	Taxable Value
4	11	Alachua	76	$38,500	362	$180,510	2,922	$1,461,210	564	$297,520		
5	12	Baker	3	$1,500	68	$34,000	405	$202,500	232	$123,265		
6	13	Bay	33	$16,500	525	$262,500	3,128	$1,564,375	694	$358,563		
7	14	Bradford	1	$500	78	$39,000	578	$287,566	244	$126,054		
8	15	Brevard	221	$111,000	2,735	$1,367,500	14,224	$7,112,000	3,527	$1,764,000		
9	16	Broward	271	$136,930	7,942	$3,996,470	30,299	$15,104,490	4,353	$2,219,610		
10	17	Calhoun	2	$1,000	24	$12,000	191	$95,278	26	$13,000		
11	18	Charlotte	98	$49,500	1,428	$712,624	5,300	$2,647,520	2,288	$1,195,469		
12	19	Citrus	86	$43,550	1,247	$622,217	5,162	$2,580,155	1,999	$1,049,456		
13	20	Clay	58	$29,000	558	$279,000	2,818	$1,412,301	1,220	$648,190		
14	21	Collier	82	$41,000	1,700	$850,500	6,794	$3,397,591	378	$194,000		
15	22	Columbia	30	$15,000	189	$94,390	1,115	$557,080	354	$182,979		
16	23	Dade	144	$72,000	3,817	$1,908,500	27,314	$13,663,500	5,581	$2,822,750		
17	24	Desoto	12	$6,000	156	$77,568	559	$279,644	287	$151,000		
18	25	Dixie			70	$35,100	297	$146,256	186	$96,155		
19	26	Duval	118	$59,000	1,848	$923,835	12,419	$6,203,469	3,453	$1,774,764		
20	27	Escambia			1,318	$658,250	6,375	$3,190,413	2,246	$1,169,494		
21	28	Flagler	56	$28,500	581	$290,500	2,487	$1,246,512	906	$478,000		
22	29	Franklin	1	$500	41	$20,500	250	$124,940	145	$71,392		
23	30	Gadsden	5	$2,500	97	$48,100	761	$380,140	108	$55,000		
24	31	Gilchrist	3	$1,500	92	$46,000	374	$187,215	132	$69,500		
25	32	Glades	2	$1,000	64	$31,633	238	$119,000	117	$62,500		
26	33	Gulf	1	$500	45	$22,500	309	$154,135	100	$50,500		
27	34	Hamilton	1	$500	23	$11,500	259	$129,053	114	$59,854		
28	35	Hardee	5	$2,500	89	$44,006	423	$212,058	174	$90,536		
29	36	Hendry	2	$1,000	104	$51,930	442	$220,550	210	$108,730		
30	37	Hernando	50	$25,500	1,493	$746,300	5,722	$2,858,354	1,589	$840,571		
31	38	Highlands	45	$22,500	839	$419,500	3,189	$1,596,500	1,220	$643,500		
32	39	Hillsborough	232	$117,000	2,262	$1,130,500	14,489	$7,251,250			3,796	$1,972,000
33	40	Holmes	3	$1,500	44	$22,000	380	$188,881	68	$34,500		
34	41	Indian River	1,247	$649,157	630	$314,118	3,393	$1,697,498				
35	42	Jackson	21	$10,500	162	$81,000	1,046	$521,065	379	$199,647		
36	43	Jefferson	8	$4,500	85	$42,500	383	$190,299	278	$139,958		
37	44	Lafayette	1	$500	29	$14,500	142	$71,000	22	$11,000		
38	45	Lake	183	$91,012	1,278	$638,801	6,150	$3,074,116	2,066	$1,084,073		
39	46	Lee	131	$67,500	2,144	$1,070,961	10,165	$5,078,692	1,540	$790,161		
40	47	Leon	74	$37,000	667	$333,600	3,451	$1,725,092	293	$147,452		
41	48	Levy	24	$12,000	238	$119,000	1,070	$537,500	585	$307,000	6	$6,000
42	49	Liberty	2	$1,000	17	$8,500	92	$46,000	19	$9,500		
43	50	Madison	11	$5,500	67	$33,500	428	$213,076	242	$125,000		
44	51	Manatee	112	$57,500	2,024	$1,010,944	7,657	$3,823,398	927	$478,428		
45	52	Marion	44	$22,000	1,828	$912,496	8,603	$4,295,258	2,300	$1,205,185		
46	53	Martin	63	$32,500	709	$354,212	3,643	$1,820,842	419	$214,500		
47	54	Monroe	13	$6,500	312	$156,000	1,182	$591,448	232	$118,500		
48	55	Nassau	29	$14,500	351	$175,500	1,439	$719,583	393	$206,500		
49	56	Okaloosa	18	$9,000	708	$354,000	3,256	$1,628,567	399	$205,000		
50	57	Okeechobee	3	$1,500	157	$78,200	670	$333,077	311	$166,066		
51	58	Orange	5	$2,500	1,863	$930,654	10,117	$5,054,535	2,567	$1,342,144		
52	59	Osceola	40	$20,000	519	$259,200	2,651	$1,326,045	1,781	$931,544		
53	60	Palm Beach	255	$127,430	4,706	$2,350,659	27,640	$13,812,361	3,030	$1,582,718		
54	61	Pasco	120	$60,000	2,680	$1,340,000	11,533	$5,766,500	2,611	$1,305,500		
55	62	Pinellas	493	$249,978	5,224	$2,609,060	24,287	$12,138,975	4,596	$2,395,511		
56	63	Polk	176	$88,500	2,239	$1,119,500	11,181	$5,593,500	3,859	$2,038,000	9	$2,388
57	64	Putnam	27	$14,000	352	$175,525	1,730	$863,241	569	$304,348		
58	65	Saint Johns	49	$25,000	772	$386,000	3,543	$1,773,413	645	$333,707		
59	66	Saint Lucie	113	$56,500	1,340	$669,600	6,082	$3,045,700	1	$2,256	3,304	$1,737,900
60	67	Santa Rosa	30	$15,000	534	$266,603	2,487	$1,243,376	989	$513,000		
61	68	Sarasota	170	$85,000	3,064	$1,531,018	12,596	$6,302,221			813	$423,443
62	69	Seminole	130	$65,000	1,235	$616,595	6,030	$3,018,334	1,675	$865,977		
63	70	Sumter	85	$42,500	1,138	$568,680	4,006	$2,002,518	1,127	$593,980		
64	71	Suwannee	16	$7,846	156	$78,000	938	$467,213	458	$228,587		
65	72	Taylor	8	$4,000	49	$24,500	386	$192,937	136	$69,000		
66	73	Union	5	$2,500	19	$9,500	168	$83,586	134	$68,808		
67	74	Volusia	265	$135,000	2,198	$1,099,500	11,793	$5,905,000	5,277	$2,799,500		
68	75	Wakulla	9	$4,500	77	$38,500	411	$205,244	137	$69,000		
69	76	Walton	9	$4,500	181	$90,500	1,097	$549,392	516	$262,827		
70	77	Washington	4	$2,000	98	$49,000	592	$294,111	249	$132,500		
71	2013	Statewide	5,634	$2,859,903	69,689	$34,849,359	341,261	$170,578,649	73,277	$37,997,729	7,928	$4,141,731
72												
73	2014	Statewide	5,566	$2,827,196	69,520	$34,761,670	337,174	$168,549,801	74,229	$38,531,856	8,097	$4,241,981
74												
75		Change	-1.21%	-1.14%	-0.24%	-0.25%	-1.20%	-1.19%	1.30%	1.41%	2.13%	2.42%
76												

REVENUE ESTIMATING CONFERENCE

Tax: Sales and Use Tax
Issue: Reduce state tax rate from 6% to 5% for commercial rentals
Bill Number(s): SB 140

- [x] **Entire Bill**
- [ ] **Partial Bill**:

Sponsor(s): Senator Hukill
Month/Year Impact Begins: February 2016
Date of Analysis: Updated 3/11/205

Section 1: Narrative

a. Current Law: Section 212.031 Provides for a tax levied in an amount equal to 6% of and on the total rent or license fee charged for the exercise of the taxable privilege of engaging in the business of renting, leasing, letting, or granting a license for the use of any real property unless the property is one of 13 specifically identified types of property.

b. Proposed Change: Reduces the tax levied on the taxable privilege of engaging in the business of renting, leasing, letting, or granting a license for the use of any real property from 6% to 5%.

Section 2: Description of Data and Sources

DOR Sales Tape for 2011, 2012, and 2013 Calendar Years
DR-15 Line 3.C. (Taxable Commercial Rent) or 4.C. (Tax on Commercial Rent).
DR-15EZ line 3 (Total Taxable Sales) and line 4 (Total Tax Collected)

Instructions for DR-15EZ read in part: "If you only report tax collected for the lease or rental of commercial property, you may file a DR-15EZ return."

Section 3: Methodology (Include Assumptions and Attach Details)

For 2013, those dealers who either were identified as Kind Code 82 – Lease or Rental of Real Property or as having positive amounts inform DR15 line 3.C. (Taxable Commercial Rent) or 4.C. (Tax on Commercial Rent). Those dealers that indicated Kind Code 82 were further broken into 5 groups:
KindCode 82 - Form DR15 With line 4C > 0
KindCode 82 - Form DR15 with line 4C = 0
Kindcode 82 - Form DR15EZ
Kind Code 82 - No form ID with line 4C > 0
Kind Code 82 - No form ID with line 4C = 0

For those dealers that were Kind Code 82 and filed using form DR-15, taxable sales amounts for commercial rent were used to calculate the state 6% sales tax on commercial rent where the dealer had reported some amount on line 3.C. For those dealers in Kindcode 82 that either filed form DR-15EZ or filed DR-15 but did not report any tax on line 4.C., line 3 (Taxable Sales/Purchases) or line 3.A. (Taxable Sales) multiplied by the state 6% rate to calculate the state 6% sales tax collected on commercial rent.
For those dealers that were not in Kindcode 82 the amount reported on line 3.C. was multiplied by the state 6% rate to calculate the sales tax on commercial rent.

For 2012 and 2011, the dataset used for analysis did not provide data on type of form used by the dealer. Those dealers that either were identified as Kind Code 82 – Lease or Rental of Real Property or as having positive amounts inform DR15 line 3.C. were identified. This se was broken into three groups:
KindCode 82 - Amount on Commercial rental line
Kindcode 82 - No amount on Commercial rental line
Dealers with Commercial rental tax not in Kindcode 82

For those identified as "KindCode 82 - Amount on Commercial rental line" or "Dealers with Commercial rental tax not in Kindcode 82", the reported taxable sales of Commercial Rent was multiplied by 6% to get state sales tax on commercial rent. For those identified as "Kindcode 82 - No amount on Commercial rental line", the amount in the Taxable Sales Line was multiplied by 6% to calculate the state sales tax on commercial rent.

For the low estimate, Nonresidential Real Property Growth rates from the March 4, 2015 Ad Valorem Assessments Estimating Conference were used to estimate 6% sales tax for future years. For the Middle estimate, the growth rates for Sales Tax on Business

REVENUE ESTIMATING CONFERENCE

Tax: Sales and Use Tax
Issue: Reduce state tax rate from 6% to 5% for commercial rentals
Bill Number(s): SB 140

Investments from the March 10, 2015 General Revenue Estimating Conference were used. The High estimate is 10% higher than the middle, upon the assumption that there is some commercial rental activity outside kind code 82 that is due to commercial rental activity that is either by entities filing the dR-15EZ or that are not appropriately filling out line 3.C. or 4.C. on DR-15EZ.

The calendar year values are converted to state fiscal year. The tax that would be collected at 5% is calculated and compared to the estimate for the tax at 6% to determine recurring impact. The first year cash is 5/12th of the recurring impact due to the January 1, 2016 effective date.

Section 4: Proposed Fiscal Impact

	High		Middle		Low	
	Cash	Recurring	Cash	Recurring	Cash	Recurring
2015-16	($127.6 M)	($306.2 M)	($116.0 M)	($278.4 M)	($110.8 M)	($265.9 M)
2016-17	($323.0 M)	($323.0 M)	($293.7 M)	($293.7 M)	($277.9 M)	($277.9 M)
2017-18	($344.3 M)	($344.3 M)	($313.0 M)	($313.0 M)	($289.3 M)	($289.3 M)
2018-19	($364.9 M)	($364.9 M)	($331.8 M)	($331.8 M)	($300.6 M)	($300.6 M)
2019-20	($381.5 M)	($381.5 M)	($346.8 M)	($346.8 M)	($312.3 M)	($312.3 M)

List of affected Trust Funds:

Section 5: Consensus Estimate (Adopted: 03/13/2015): The Conference adopted the growth rate for commercial properties and reduced by half the impact from filers who were under kind code 82 but did not indicate commercial rental collections on their tax return.

	GR		Trust		Revenue Sharing		Local Half Cent	
	Cash	Recurring	Cash	Recurring	Cash	Recurring	Cash	Recurring
2015-16	(97.8)	(234.9)	(Insignificant)	(Insignificant)	(3.3)	(7.8)	(9.4)	(22.5)
2016-17	(246.4)	(246.4)	(Insignificant)	(Insignificant)	(8.2)	(8.2)	(23.6)	(23.6)
2017-18	(256.9)	(256.9)	(Insignificant)	(Insignificant)	(8.5)	(8.5)	(24.7)	(24.7)
2018-19	(267.2)	(267.2)	(Insignificant)	(Insignificant)	(8.9)	(8.9)	(25.6)	(25.6)
2019-20	(277.6)	(277.6)	(Insignificant)	(Insignificant)	(9.2)	(9.2)	(26.6)	(26.6)

	Local Option		Total Local		Total	
	Cash	Recurring	Cash	Recurring	Cash	Recurring
2014-15	0.0	0.0	(12.7)	(30.3)	(110.5)	(265.2)
2015-16	0.0	0.0	(31.8)	(31.8)	(278.2)	(278.2)
2016-17	0.0	0.0	(33.2)	(33.2)	(290.1)	(290.1)
2017-18	0.0	0.0	(34.5)	(34.5)	(301.7)	(301.7)
2018-19	0.0	0.0	(35.8)	(35.8)	(313.4)	(313.4)

	A	B	C	D	E	F
3						
4	Calendar Year 2013	Total Sales Tax - Line 5 DR-15 or Line 4 DR-15EZ	Tax Reported on line 4C-Commercial Rentals	Number of Accounts		
5	KindCode 82 - Form DR15 With line 4C > 0	$657,646,338	$605,604,349	31,313		
6	KindCode 82 - Form DR15 with line 4C = 0	$33,919,942	$0	2,954		
7	Kindcode 82 - Form DR15EZ	$673,207,983	0	88,350		
8	Kind Code 82 - No form ID with line 4C > 0	$181,523,526	$173,774,754	10,001		
9	Kind Code 82 - No form ID with line 4C = 0	$5,484,683	$0	2,435		
10	Dealers with Commercial rental tax not in kindcode 82	$1,427,896,233	$77,888,864	7,699		
11						
12	Statewide 2013			142,752		
13						
14						
15	Calendar Year 2012	Total Sales Tax - Line 5 DR-15 or Line 4 DR-15EZ	Tax Reported on line 4C-Commercial Rentals	Number of Accounts		
16	KindCode 82 - Amount on Commercial rental line	$750,687,770	$707,300,371	33,311		
17	Kindcode 82 - No amount on Commercial rental line	$716,786,311		100,168		
18	Dealers with Commercial rental tax not in kindcode 82	$1,427,896,233	$57,215,368	6,274		
19						
20	Statewide 2012			139,753		
21						
22	Calendar Year 2011	Total Sales Tax - Line 5 DR-15 or Line 4 DR-15EZ	Tax Reported on line 4C-Commercial Rentals	Number of Accounts		
23	KindCode 82 - Amount on Commercial rental line	$753,766,839	$701,063,519	34,036		
24	Kindcode 82 - No amount on Commercial rental line	$702,409,728		97,876		
25	Dealers with Commercial rental tax not in kindcode 82	$1,438,655,438	$66,678,201	6,612		
26						
27	Statewide 2011			138,524		
28						
29	Note - for Calendar year 2013 data file had variable denoting form used by dealer. This data was not a part of the 2012 or 2011 data sets.					
30						

	A	B	C	D	E	F
31						
32	Calendar Year 2013	Sales/Services Taxable Sales (Line 3A DR-15 or Line 3 DR-15EZ)	Taxable Sales Reported on line 3C- Commercial Rentals	Sales Tax at 6% rate applied to Taxable Sales (Line 3A DR-15 or Line 3 DR-15EZ)	Sales Tax at 6% rate applied to line 3C- Commercial Rentals	Number of Accounts
33	KindCode 82 - Form DR15 With line 4C > 0	$668,576,684	$9,187,064,349		$551,223,861	31,248
34	KindCode 82 - Form DR15 with line 4C = 0	$411,980,060		$24,718,804		2,954
35	Kindcode 82 - Form DR15EZ	$10,219,270,436		$613,156,226		90,719
36	Kind Code 82 - No form ID with line 4C > 0	$120,898,245	$2,626,883,968		$157,613,038	10,001
37	Kind Code 82 - No form ID with line 4C = 0	$84,173,669		$5,050,420		2,435
38	Dealers with Commercial rental tax not in kindcode 82	$20,940,595,250	$1,166,438,863		$69,986,332	7,699
39						
40	Statewide 2013			$642,925,450	$778,823,231	145,056
41						
42						
43	Calendar Year 2012	Sales/Services Taxable Sales (Line 3A)	Taxable Sales Reported on line 3C- Commercial Rentals	Sales Tax at 6% rate applied to Taxable Sales (Line 3A DR-15 or Line 3 DR-15EZ)	Sales Tax at 6% rate applied to line 3C- Commercial Rentals	Number of Accounts
44	KindCode 82 - Amount on Commercial rental line	$43,504,345	$10,721,712,227		$643,302,734	33,311
45	Kindcode 82 - No amount on Commercial rental line	$10,844,225,989		$650,653,559		100,168
46	Dealers with Commercial rental tax not in kindcode 82	$18,828,894,116	$856,395,403		$51,383,724	6,274
47						
48	Statewide 2012			$650,653,559	$694,686,458	139,753
49						
50	Calendar Year 2011	Sales/Services Taxable Sales (Line 3A)	Taxable Sales Reported on line 3C- Commercial Rentals	Sales Tax at 6% rate applied to Taxable Sales (Line 3A DR-15 or Line 3 DR-15EZ)	Sales Tax at 6% rate applied to line 3C- Commercial Rentals	Number of Accounts
51	KindCode 82 - Amount on Commercial rental line	$78,813,932	$10,578,070,012	$634,684,201		34,036
52	Kindcode 82 - No amount on Commercial rental line	$10,569,099,439			$634,145,966	97,876
53	Dealers with Commercial rental tax not in kindcode 82	$18,867,994,443	$997,194,450	$59,831,667		6,612
54						
55	Statewide 2011			$694,515,868	$634,145,966	138,524
56						
57			Sales Tax @ Business Investment Growth Rate	Sales Tax @ Commercial Property Growth Rate	Business Investment Growth Rate (GR-REC 3/15)	Commercial Property Growth Rate
58	Total Estimated State Sales Tax - Commercial Rent	2011	$1,328,661,834	$1,328,661,834		
59		2012	$1,345,340,017	$1,345,340,017		
60		2013	$1,421,748,681	$1,421,748,681		
61		2014	$1,519,849,340	$1,479,756,027	6.90	4.08
62		2015	$1,636,877,739	$1,563,510,218	7.70	5.66
63		2016	$1,721,995,381	$1,647,158,015	5.20	5.35
64		2017	$1,811,539,141	$1,720,291,830	5.20	4.44
65		2018	$1,947,404,577	$1,790,995,825	7.50	4.11
66		2019	$2,038,932,592	$1,860,844,662	4.70	3.90
67		2020	$2,128,645,626	$1,933,417,604	4.40	3.90
68						

	A	B	C	D	E	F
69			Sales Tax @ Business Investment Growth Rate	Sales Tax @ Commercial Property Growth Rate		
70	Estimated Sales tax at 5% rate	2015	$1,364,064,782	$1,302,925,182		
71		2016	$1,434,996,151	$1,372,631,679		
72		2017	$1,509,615,951	$1,433,576,525		
73		2018	$1,622,837,147	$1,492,496,521		
74		2019	$1,699,110,493	$1,550,703,885		
75		2020	$1,773,871,355	$1,611,181,336		
76						
77	Calendar Year to Fiscal Year conversion					
78		Sales Tax @ 6%	Sales Tax @ Business Investment Growth Rate	Sales Tax @ Commercial Property Growth Rate		
79		2015-16	$1,679,436,560	$1,605,334,116		
80		2016-17	$1,766,767,261	$1,683,724,923		
81		2017-18	$1,879,471,859	$1,755,643,828		
82		2018-19	$1,993,168,584	$1,825,920,243		
83		2019-20	$2,083,789,109	$1,897,131,133		
84						
85		Sales Tax @ 5% for recurring Impact	Sales Tax @ Business Investment Growth Rate	Sales Tax @ Commercial Property Growth Rate		
86		2015-16	$1,399,530,467	$1,337,778,430		
87		2016-17	$1,472,306,051	$1,403,104,102		
88		2017-18	$1,566,226,549	$1,463,036,523		
89		2018-19	$1,660,973,820	$1,521,600,203		
90		2019-20	$1,736,490,924	$1,580,942,611		
91						
92			Middle	Low		
93			Sales Tax @ Business Investment Growth Rate	Sales Tax @ Commercial Property Growth Rate		
94	Recurring Impact	2015-16	$279,906,093	$267,555,686		
95		2016-17	$294,461,210	$280,620,820		
96		2017-18	$313,245,310	$292,607,305		
97		2018-19	$332,194,764	$304,320,041		
98		2019-20	$347,298,185	$316,188,522		
99						
100	2015-16 Cash @ 5/12	2015-16	$116,627,539	$111,481,536		
101						
102						
103	High Impact -110% of Impact at Business Investment growth	2015-16	$307,896,703			
104		2016-17	$323,907,331			
105		2017-18	$344,569,841			
106		2018-19	$365,414,240			
107		2019-20	$382,028,003			
108						
109		2015-16 cash	$128,290,293			

NAICS code for those dealers within Kind Code 82

North American Industrial Classification Code	Description	Frequency	Percent
531120	Lessors of Nonresidential Buildings (except Miniwarehouses)	129,346	97.9
531190	Lessors of Other Real Estate Property	1,232	.9
531210	Offices of Real estate Agents and Brokers	327	.2
531312	Nonresidential Property Managers	533	.4
531320	Offices of Real Estate Appraisers	1	.0
531390	Other Activities Related to Real Estate	405	.3
561431	Private Mail Centers	97	.1
561920	Convention and Trade Show Organizers	54	.0
711310	Promoters of Performing arts, Sports, and Similar Events with Facilities	66	.0
812220	Cemeteries and Crematoriums	3	.0
813990	Other Similar Organizations (except Business, Professional, Labor, and Political Organizations)	35	.0
Total		132,099	100.0

APPENDIX B

ORDINANCE NO. 91-1

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF GLEN RIDGE, AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE TOWN OF GLEN RIDGE, FLORIDA:

Section 1. There is hereby granted to Florida Power & Light Company (herein called the "Grantee"), its successors and assigns, the non-exclusive right, privilege or franchise to construct, maintain and operate in, under, upon, over and across the present and future streets, alleys, bridges, easements and other public places of the Town of Glen Ridge, Florida (herein called the "Grantor") and its successors, in accordance with established practice with respect to electrical construction and maintenance, for the period of 30 years from the date of acceptance hereof, electric light and power facilities (including conduits, poles, wires and transmission lines, and, for its own use, telephone and telegraph lines) for the purpose of supplying electricity to the Grantor and its successors, and inhabitants thereof, and persons and corporations beyond the limits thereof.

Section 2. As a condition precedent to the taking effect of this grant, the Grantee shall have filed its acceptance hereof with the Grantor's Clerk within 30 days hereof.

Section 3. The facilities of the Grantee shall be so located or relocated and so erected as to interfere as little as possible with traffic over said streets, alleys, bridges and public places, and with reasonable egress from and ingress to abutting property. The location or relocation of all facilities shall be made under the supervision and with the approval of such representatives as the governing body of the Grantor may designate for the purpose, but not so as to unreasonably interfere with the proper operation of the Grantee's facilities and service. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall, within a reasonable time and as early as practicable after such excavation, be replaced by the Grantee at its expense and in a condition as good as it was at the time of such excavation..

Section 4. Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 6. No later than 60 days after the first anniversary date of this grant, and no later than 60 days after each succeeding anniversary date of this grant, the Grantee, its successors and assigns, shall have paid to the Grantor and its successors an amount which added to the amount of all taxes as assessed, levied, or imposed (without regard to any discount for early payment or any interest or penalty for late payment), licenses, and other impositions levied or imposed by the Grantor upon the Grantee's electric property, business, or operations, and those of the Grantee's electric subsidiaries for the preceding tax year, will equal six percent of the Grantee's revenues from the sale of electrical energy to residential, commercial and industrial customers within the corporate limits of the Grantor for the 12 fiscal months preceding the applicable anniversary date.

Section 7. Payment of the amount to be paid to the Grantor by the Grantee under the terms of Section 6 hereof shall be made in advance by estimated monthly installments commencing 90 days after the effective date of this grant. Each estimated monthly installment shall be calculated on the basis of 90% of the

Grantee's revenues (as defined in Section 6) for the monthly billing period ending 60 days prior to each scheduled monthly payment. It is also understood that for purposes of calculating each monthly installment, all taxes, licenses, and other impositions shall be estimated on the basis of the latest data available for all such amounts imposed on the Grantee, before being prorated monthly. The final installment for each fiscal year of this grant shall be adjusted to reflect any underpayment or overpayment resulting from estimated monthly installments made for said fiscal year.

Section 8. As a further consideration of this franchise, the Grantor agrees not to engage in the business of distributing and selling electricity during the life of this franchise or any extension thereof in competition with the Grantee, its successors and assigns.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after the final determination of the question to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, such decision shall not affect the validity of the remainder as a whole or as to any part, other than the part declared to be invalid.

Section 11. That all ordinances and parts of ordinances in conflict herewith be and the same are hereby repealed.

Section 12. This ordinance shall take effect on the date upon which the Grantee files its acceptance.

PASSED First Reading this 12th day of Sept 1991.

PASSED Second and Final Reading this 2nd day of Oct, 1991.

President of Council

ATTEST:

Town Clerk

ORDINANCE NO. 19-14-2197

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of South Miami, Florida recognizes that the City of South Miami (the "City") and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company ("FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City and FPL, the terms of which are set forth in City Ordinance No. 7-84-1202, passed and adopted May 15, 1984, and FPL's written acceptance thereof dated May 18, 1984 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"). As a result of short extensions passed and adopted by the City on May 14, 2014 and on August 19, 2014, respectively, and accepted by FPL, the Current Franchise Agreement expires on September 18, 2014; and

WHEREAS, FPL and the City (collectively, the "Parties") desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity within the City free of competition from the City, pursuant to certain terms and conditions; and

WHEREAS, the City Commission deems it to be in the public interest to enter into this agreement addressing certain rights and responsibilities of the Parties as they relate to the use of the public rights-of-way within the City's jurisdiction.

NOW, THEREFORE, BE IT ORDAINED BY THE MAYOR AND CITY COMMISSION OF THE CITY OF SOUTH MIAMI, FLORIDA:

Section 1. The foregoing recitals are hereby found to be true and correct, and are incorporated herein and adopted and approved as if set out at length.

Section 2. There is hereby granted to FPL, its successors and assigns, for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City and its successors, in accordance with FPL's customary practices, and practices prescribed herein, with respect to construction and maintenance of the electrical light, power and related facilities, including, without limitation, conduits, underground conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to FPL's provision of electricity and other services (hereinafter called "facilities") to the City and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 3. (a) FPL's facilities shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transporation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the City may prescribe in accordance with all applicable federal and state laws, and pursuant to the City's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining in, under, upon, along, over and across said public rights-of-way, provided such rules and regulations:

(i) shall be for a valid municipal purpose;

(ii) shall not prohibit the exercise of FPL's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above;

(iii) shall not unreasonably interfere with FPL's ability to furnish reasonably sufficient, adequate and efficient electric service to all its customers while not conflicting with the standards set forth above; or

(iv) shall not require relocation of any of FPL's facilities installed, before or after the effective date hereof, in any public right-of-way, unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way causes the facilities to unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road," or unless such relocation is required by state or federal law.

(c) Such rules and regulations shall recognize that FPL's above-grade facilities installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by FPL or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by FPL at its expense.

(e) The City shall not be liable to FPL for any cost or expense incurred in connection with the relocation of any of FPL's facilities required under this Section, except, however, that FPL may be entitled to reimbursement of its costs and expenses from others and as provided by law.

Except as expressly provided, nothing herein shall limit or alter the City's existing rights with respect to the use or management of its rights-of-way that are not otherwise preempted by the state or federal government.

Section 4. The acceptance of this New Franchise Agreement shall be deemed an agreement on the part of FPL to the following: (a) to indemnify and save the City harmless from any and all damages, claims, liability, losses and causes of action of any kind or nature arising out of a negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder; (b) to pay all damages, claims, liabilities and losses of any kind or nature whatsoever, in connection therewith, including the City's attorney's fees and expenses in the defense of any action in law or equity brought against the City, including appellate fees and costs and fees and expenses incurred to recover attorney's fees and expenses from FPL, arising from the negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by FPL from time to time shall be subject to such regulation as may be provided by law.

Section 6(a). As a consideration for this franchise, FPL shall pay to the City, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the City against FPL's property, business or operations and those of its subsidiaries during FPL's monthly billing period ending 60 days prior to each such payment will equal six percent of FPL's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the City for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6 percent of such revenues for any monthly billing period of FPL. For clarity, actual write-offs will be subtracted from FPL's billed revenues. In the event FPL subsequently collects previously written-off billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, FPL shall pay to the City a franchise payment on such revenues in accordance with the formula set forth above in this Section 6(a). FPL shall continue to remit payment in a manner consistent with the Current Franchise Agreement until the first payment is due under this New Franchise Agreement.

The City understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 7-84-1202, to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

(b) If during the term of this franchise FPL enters into a franchise agreement with any other municipality located in Miami-Dade County or Broward County, Florida, where the number of FPL's meters for active electrical customers does not exceed the number of meters for FPL's active electrical customers within the incorporated area of the City by more than one hundred and fifty (150) percent, the terms of which provide for the payment of franchise fees by FPL at a rate greater than 6 percent of FPL's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under substantially similar terms and conditions as specified in Section 6(a) hereof, FPL, upon written request of the City, shall negotiate and enter into a new franchise agreement with the City in which the percentage to be used in calculating monthly payments under Section 6(a) hereof shall be no greater than that percentage which FPL has agreed to use as a basis for the calculation of payments to the other municipality, provided however, that such new franchise agreement shall include additional benefits to FPL, in addition to all benefits provided herein, at least equal to those, if any, provided by its franchise agreement with the other municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the City shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and FPL shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

(c) The City reserves the unilateral right at its sole discretion and at any time during the term of this franchise, but only once per calendar year, to reduce or increase the franchise fee percentage rate upon 120 days written notice to FPL, provided that the franchise fee percentage rate shall in no event exceed 6 percent or be reduced to zero percent.

(d) The City's options hereunder shall be limited solely to the percentages or calculations of the amount of the franchise fee to be paid by FPL as consideration for this franchise as specifically set forth in this Section 6. Except as provided in this Section 6, no other Section of this New Franchise Agreement may be altered, amended or affected by the City without the written concurrence of FPL, and nothing herein shall require the City to exercise any of its options hereunder.

Section 7. (a) As a further consideration, during the term of this franchise or any extension thereof, the City agrees: (a) not to engage in the distribution and/or sale, in competition with FPL, of electric capacity and/or electric energy to any other ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by FPL other than the City, and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate FPL to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies). Nothing specified herein shall prohibit the City from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

(b) Nothing herein shall prohibit or limit a customer of FPL, including the City, if permitted by law, from installing an approved renewable generation system to generate electric energy for use at the customer's or the City's premises respectively. Furthermore, nothing herein shall prohibit or limit a person, including the City, if permitted by law, from selling renewable energy or capacity to FPL.

Section 8. If the City grants a right, privilege or franchise to any other person to provide retail electric service within any part of the incorporated areas of the City in which FPL may lawfully serve or compete on terms and conditions which FPL reasonably determines are more favorable than the terms and conditions contained herein, FPL may at any time thereafter terminate this franchise if such terms and conditions are not revised within the time period provided hereafter. FPL shall give the City at least one hundred eighty (180) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The City shall then have ninety (90) days in which to correct or otherwise remedy the terms and conditions complained of by FPL. If FPL determines that such terms or conditions are not remedied by the City within said time period, FPL may terminate this franchise agreement by delivering written notice by Certified United States Mail to the City's Clerk with copies to the Mayor, the City Manager and the City Attorney and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 9. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person who offers retail electric service to the public is permitted to provide electric service within the incorporated areas of the City to any applicant for electric service within any part of the incorporated areas of the City in which FPL may lawfully serve, and FPL reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, FPL may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage resulting from this fanchise is not remedied within the time period provided hereafter. FPL shall give the City at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of the consequences of such action which resulted in the competitive disadvantage. The City shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the City within said time period, either by a franchise agreement with such other person or otherwise, FPL may terminate this franchise agreement by delivering written notice to the City's Clerk and termination shall take effect on the date of delivery of such notice. Agreement by the City with such other person to enter into a franchise containing substantially the same terms as those provided herein shall be a sufficient, but not exclusive, remedy precluding FPL's termination of this franchise. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 10. Failure on the part of FPL to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by FPL until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that FPL has failed to comply in a substantial respect with any of the provisions of this franchise, and FPL shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the City at its discretion to grant such additional time to FPL for compliance as necessities in the case may warrant.

Section 11. Failure on the part of the City to comply in substantial respect with any of the provisions of this New Franchise Agreement, including but not limited to: (a) denying FPL use of public rights-of-way for reasons other than as set forth in Section 3 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Federal or Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing FPL a use permit to construct its facilities in public rights-of-way, shall constitute breach of this franchise. FPL shall notify the City of any such breach in writing sent by Certified United States Mail or via nationally recognized overnight courier and the City shall then remedy such breach as soon as practicable. Should the breach not be timely remedied, FPL shall be entitled to seek a remedy available under law or equity from a court of competent jurisdiction, including the withholding of the payments provided for in Section 8 as a court of competent jurisdiction determines to be just and reasonable under all the circumstances hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination dispositive of the matter.

Section 12. The Parties to this franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes. If such informal efforts are unsuccessful after a reasonable period of time, or when an impasse is declared by the Parties, then the Parties may exercise any of their available legal remedies.

Section 13. The City may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the City's expense, examine the records of FPL relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at FPL's office where such records are maintained. Records not prepared by FPL in the ordinary course of business or as required herein may be provided at the City's expense and as the City and FPL may agree in writing. Information identifying FPL's customers by name or their electric consumption shall not be taken from FPL's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the City, shall be reported to FPL. The City's right to examine

FPL's records in accordance with this Section shall not be conducted by any third party employed by the City whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

The City waives, settles and bars all claims relating in any way to the amounts paid by FPL under the Current Franchise Agreement embodied in Ordinance No. 7-84-1202, however, this provision shall not be construed to waive, settle or bar claims relating to any amounts due after the effective date of this New Franchise Agreement, including those amounts to be paid in a manner consistent with the terms of the Current Franchise Agreement until the first payment is made under this New Franchise Agreement.

Section 14. The provisions of this ordinance are interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of ninety (90) days, during which, this agreement may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of such ninety (90) day period, this entire ordinance shall then become null and void, and of no further force or effect.

Section 15. The City acknowledges it is fully informed concerning the existing franchise granted by Miami-Dade County, Florida, to FPL, and accepted by FPL as set out in Ordinance No. 60-16 adopted on May 3, 1960, and subsequently renewed and accepted by FPL as set out in Ordinance No. 89-81 adopted on September 5, 1989 by the Board of County Commissioners of Miami-Dade County, Florida. The City agrees to indemnify and hold FPL harmless against any and all liability, loss, cost, damage and expense incurred by FPL in respect to any claim asserted by Miami-Dade County against FPL arising out of the franchise set out in the above referenced ordinances for the recovery of any sums of money paid by FPL to the City under the terms of this New Franchise Agreement. FPL acknowledges and the City hereby relies, in part, on then Dade County Resolution No. R-709-78 adopted on June 20, 1978 in the granting of this franchise.

Section 16. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 17. Ordinance No. 7-84-1202, passed and adopted May 15, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 18. This New Franchise Agreement shall be governed and construed by the laws and administrative rules of the State of Florida and the United States. In the event that any legal proceeding is brought to enforce the terms of this franchise, it shall be brought by either party hereto in Miami-Dade County, Florida, or, if a federal claim, in the U.S. District Court in and for the Southern District of Florida, Miami Division.

Section 19. This New Franchise Agreement is intended to constitute the entire agreement between the City and FPL with respect to the subject matters hereof, and it supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

Section 20. Except in exigent circumstances, and except as otherwise may be specifically provided for in this franchise, all notices by either party shall be made by Certified United States Mail or via nationally recognized overnight courier service. Any notice given by facsimile or email is deemed to be supplementary, and does not alone constitute notice hereunder. All notices shall be addressed as follows:

To the City:

City Manager
City Hall, 1st Floor
6130 Sunset Drive
South Miami, FL 33143

Copy to:

City Attorney
1450 Madruga Avenue
Suite 202
Coral Gables, FL 33146

To FPL:

Vice President, External Affairs
700 Universe Boulevard
Juno Beach, FL 33408

Copy to:

General Counsel
700 Universe Boulevard
Juno Beach, FL 33408

Any changes to the above shall be in writing and provided to the other party as soon as practicable.

Section 21. As a condition precedent to the taking effect of the New Franchise Agreement, FPL shall file its acceptance hereof with the City's Clerk within 30 days of adoption of this ordinance. The effective date of the New Franchise Agreement shall be the date upon which FPL files such acceptance.

Ord. No. 19-14-2197

PASSED AND ENACTED this 16th day of September, 2014.

ATTEST:

CITY CLERK
1st Reading – 9/2/14
2nd Reading – 9/16/14

APPROVED:

MAYOR

READ AND APPROVED AS TO FORM, LANGUAGE, LEGALITY AND EXECUTION THEREOF

CITY ATTORNEY

COMMISSION VOTE:	4-1
Mayor Stoddard:	Yea
Vice Mayor Harris:	Yea
Commissioner Edmond:	Nay
Commissioner Liebman:	Yea
Commissioner Welsh:	Yea

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 19-14-2197
BY FLORIDA POWER & LIGHT COMPANY

City of South Miami, Florida   October 1, 2014

Florida Power & Light Company does hereby accept the electric franchise in the City of South Miami, Florida, granted by Ordinance No. 19-14-2197, being:

> AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on September 16, 2014.

This instrument is filed with the City Clerk of the City of South Miami, Florida, in accordance with the provisions of Section 21 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela M. Rauch

Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 30 day of September, 2014 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Beverly A Calderon
My Commission EE017269
Expires 10/18/2014

Beverly A. Calderon

NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 19-14-2197 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of South Miami, Florida on this 1st day of October, 2014.

(SEAL)

Maria M. Menendez

City Clerk, City of South Miami, Florida

MIAMI DAILY BUSINESS REVIEW

Published Daily except Saturday, Sunday and
Legal Holidays
Miami, Miami-Dade County, Florida

STATE OF FLORIDA
COUNTY OF MIAMI-DADE:

Before the undersigned authority personally appeared MARIA MESA, who on oath says that he or she is the LEGAL CLERK, Legal Notices of the Miami Daily Business Review f/k/a Miami Review, a daily (except Saturday, Sunday and Legal Holidays) newspaper, published at Miami in Miami-Dade County, Florida; that the attached copy of advertisement, being a Legal Advertisement of Notice in the matter of

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING FOR 9/16/2014

in the XXXX Court,
was published in said newspaper in the issues of

09/05/2014

Affiant further says that the said Miami Daily Business Review is a newspaper published at Miami in said Miami-Dade County, Florida and that the said newspaper has heretofore been continuously published in said Miami-Dade County, Florida, each day (except Saturday, Sunday and Legal Holidays) and has been entered as second class mail matter at the post office in Miami in said Miami-Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this

05 day of SEPTEMBER , A.D. 2014

B. Thomas

(SEAL)

MARIA MESA personally known to me

B. THOMAS
Notary Public - State of Florida
My Comm. Expires Nov 2. 2017
Commission # FF 034747
Bonded Through National Notary Assn.

CITY OF SOUTH MIAMI
INCORPORATED 1927
FLORIDA

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami, and providing for an effective date.

An Ordinance amending Section 20-7.12 of the City of South Miami Land Development Code concerning parking requirements for restaurants within the Hometown District Overlay (HD-OV) Zone.

An Ordinance of the City of South Miami, Florida, amending Section 2-7, Administrative department; functions and duties; creating a cost recovery administrative program; providing for repeal of ordinances in conflict; and providing an effective date.

An Ordinance relating to the fee schedule; amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

ALL interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at: 305-663-6340.

Maria M. Menendez, CMC
City Clerk

Pursuant to Florida Statutes 286.0105, the City hereby advises the public that if a person decides to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeal is to be based.

9/5 14-3-345/2341375M

POLICE REPORT

• SOUTH MIAMI

A vandal painted red graffiti on the sign at the Rosie Lee Wesley Health Center at **6601 SW 62nd Ave.** between 7 p.m. July 18 and 7:45 a.m. July 21. Damage was estimated at $220.

A thief shattered the front passenger window of a black 2010 Audi TT and stole a backpack, an Apple MacBook Pro, and a Duofold pen, all valued at $2,365, in a parking lot in the **6200 block of South Dixie Highway** between 5:15 and 6:30 p.m. July 22.

• PINECREST

A woman reported damage to her 2012 Hyundai when she arrived at the police department at 2:15 p.m. July 28. The woman, who lives in the **11800 block of Southwest 69th Avenue,** said the vehicle had been parked in an unfenced driveway since July 26 and had not been moved again until she discovered the damage, which is valued at $2,300.

Police were called to the Bank of America at **9101 S. Dixie Hwy.** about 4:15 p.m. July 28 in reference to verbal threats. The victim reported that a customer had verbally threatened her. The victim told police that when the offender arrived at the bank and inquired why his accounts had been closed, he became loud and offensive. When the offender was asked to leave, he was reported to have said, "Don't worry, I will take care of you." The offender was not on the scene when police arrived and contact was not made with him.

A mail carrier called police about 12:30 p.m. Aug. 14 after he noticed a broken window at a residence in the **8200 block of Southwest 133rd Street.** Police determined that a thief broke into the house and took an unknown number of items.

• KENDALL

A thief smashed the left rear window of a white 2012 Cadillac Escalade EXT and stole all four rims and tires while the vehicle was in the driveway of a residence in the **12000 block of Southwest 100th Avenue** between 9 p.m. Aug. 4 and 8:45 a.m. Aug. 5. Damage and loss were estimated at $3,000.

• PALMETTO BAY

A woman called police in reference to a personal identification fraud. The woman, who lives in the **8900 block of Southwest 150th Street,** said that someone used her personal identification information to try to change her home and email addresses on record at her bank on Aug. 18.

Police were called in reference to a bank fraud after a man, who lives in the **7200 block of Southwest 174th Street,** fraudulently cashed a forged check to his bank account on Aug. 11.

• CORAL GABLES

One or more thieves broke into and ransacked a residence in the **2000 block of Red Road** between noon and 6:45 p.m. Aug. 7.

A thief broke into and ransacked a residence in the **100 block of Oak Avenue** between noon Aug. 7 and 9:30 a.m. Aug. 9.

A 20-year-old woman was arrested and charged with grand theft after she tried to steal $3,088 worth of merchandise from the Nordstrom Department store at **4310 Ponce de Leon Blvd.** between 2:30 and 3 p.m. Aug. 6.

A 51-year-old woman became a victim of a strong arm robbery in the **500 block of Biltmore Way** between 3 and 3:15 p.m. Aug. 6.

• CUTLER BAY

A thief broke into a gray 2013 Toyota Tundra and stole tools valued at $2,000 from the driveway of a residence in the **10500 block of Southwest 200th Terrace** between 6 p.m. July 30 and 10 a.m. July 31.

A thief broke into a silver 2007 Toyota RAV4 and stole $5 in change while the vehicle was parked in the driveway of a residence in the **18500 block of Southwest 87th Court** between 4 p.m. July 24 and 9:30 a.m. July 25.

A thief broke into a black 2007 Dodge Ram 3500 parked along the roadside near **Southwest 103rd Avenue and Caribbean Boulevard,** and stole several tools and a wallet, all valued at $9,100, between 12:45 and 1 a.m. July 19.

This list is a sampling of crimes reported in Miami-Dade County cities. The information is taken from official police reports, which may not contain statements from all parties involved.

Data and Information Prepared for the Financial Impact Estimating Conference

Proposed Initiative: *"Limits or Prevents Barriers to Local Solar Electricity Supply"*

Presented by Jerry McDaniel, on behalf of
Florida's Four Major Investor-Owned Electric Utilities

April 10, 2015

Introduction

- This presentation has been prepared on behalf of Florida's four major investor-owned electric utilities for the Financial Impact Estimating Conference's analysis of the proposed constitutional amendment, *"Limits or Prevents Barriers to Local Solar Electricity Supply"*
- This presentation is not intended to advocate for or against the proposed constitutional amendment

Overview

- Floridians are served by 55 electric utilities
- The four major investor-owned electric utilities (FPL, Duke Energy, Tampa Electric and Gulf Power) serve and pay taxes/fees to a combined total of 345 Florida municipalities and counties
- Together, these four utilities supply about 76 percent of Florida's electricity needs while municipally owned and cooperative utilities serve about 24 percent

State/Local Government Taxes & Fees

- State laws and local governmental ordinances and agreements require all of Florida's electric utilities to pay a range of taxes and fees
- These taxes and fees are generally based on percentages of a utility's electricity sales

State/Local Government Taxes & Fees

- **Sales Tax (state)** – 4.35 percent, applicable to utilities' sales to commercial customers
- **Gross Receipts Tax (state)** – 2.5 percent on utilities' residential sales, 2.6 percent on' commercial sales
- **Municipal Public Service Tax (local)** – Rate varies by municipality from 0 percent to 10 percent
- **Municipal Franchise Fees (local)** – Rates vary by municipality up to a maximum of 6 percent
- **Regulatory Assessment Fees (state)** – Current rate is 0.00072 percent (cannot exceed 0.125 percent)

State/Local Government Taxes & Fees

In 2014, four major utilities paid state/local taxes & fees totaling $2,229,228,642 ($2.9 billion for state as a whole)

Utility	Total Taxes/Fees	Sales Tax	Gross Receipts Tax	Municipal Public Service Tax	Franchise Fees	Regulatory Assessment Fees
FPL	$1,444,249,701	$192,208,859	$265,389,503	$524,126,515	$454,890,566	$7,634,259
DUKE	$477,695,719	$79,526,314	$103,713,790	$187,960,611	$103,299,937	$3,195,067
TECO	$187,878,745	$38,243,579	$46,263,324	$52,314,525	$44,896,719	$1,428,233
GULF	$119,404,477	$22,398,470	$32,118,573	$23,115,210	$40,813,388	$958,837
Utility Total	$2,229,228,642	$332,377,222	$447,485,190	$787,516,861	$643,900,610	$13,216,996
State Total *	$2.9 Billion	$439 Million	$591 Million	$1.04 Billion	$850 Million	$17 Million

* **Approximate Totals based on Utility total representing 76% of the State of Florida**

State/Local Government Taxes & Fees

Effect on State-Wide Tax Revenues with Solar Penetration at Various Levels

	Total Taxes/Fees	Sales [1]	GRT [2]	MPST [3]	Franchise [4]	RAF [5]
1%	$29,000,000	$4,390,000	$5,910,000	$10,400,000	$8,500,000	$170,000
3%	$87,000,000	$13,170,000	$17,730,000	$31,200,000	$25,500,000	$510,000
5%	$145,000,000	$21,950,000	$29,550,000	$52,000,000	$42,500,000	$850,000
10%	$290,000,000	$43,900,000	$59,100,000	$104,000,000	$85,000,000	$1,700,000

1) **Sales = Sales Tax;**
2) **GRT = Gross Receipts Tax;**
3) **MPST = Municipal Public Service Tax;**
4) **Franchise = Franchise Fees;**
5) **RAF = Regulatory Assessment Fee**

State/Local Government Taxes & Fees

- While local taxes and fees vary from municipality to municipality, a broad analysis can be accomplished based on actual taxes paid by utilities
- Extrapolating from the investor-owned utility data ($2.2 billion in state/local taxes and fees), we estimate that the combined state/local taxes and fees paid by all 55 electric utilities in 2014 totaled approximately $2.9 billion

Proposed Constitutional Amendment

- If the proposed amendment results in increased electricity production and sales by non-utility entities that are not taxed, those non-utility sales will displace taxable sales of electricity by Florida's 55 electric utilities
- Displacement of taxable utility sales by untaxable non-utility entities will reduce revenues for state and local government

Proposed Constitutional Amendment

- The actual impact of the amendment on taxable utility electricity sales depends on a variety of factors
- Using the 2014 statewide utility tax/fee estimate of $2.9 billion, we can project that each 1 percent displacement of taxable utility sales by untaxable non-utility entities would equate to a reduction in state/local revenue of approximately $29 million
- This estimate can be scaled down or up based on a projected displacement of taxable electricity sales

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company

RE: Additional Information Concerning Financial Impact Statement for the Proposed Initiative Entitled Re: "Limits or Prevents Barriers to Local Solar Electricity Supplier"

DATE: April 22, 2015

At the Financial Impact Estimating Conference ("FIEC") public meeting held on April 10, 2015, proponents of the proposed Initiative asserted that it would have no financial impact on the revenues of state and local government. At this time, Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company (the "Utilities") are not taking a position on the proposed Initiative. However, the proponents' assertion of no financial impact is demonstrably incorrect, and the Utilities are submitting this additional information in support of that conclusion.

As summarized in the materials that the Utilities submitted at the April 10 public meeting, there is a range of taxes and fees that the Utilities, as well as municipal utilities and electric cooperatives, pay to state and local government based on their sales of electricity. Those taxes and fees include sales tax, gross receipts tax, municipal public service tax, the regulatory assessment fee and municipal franchise fees. Approximately $2.9 billion of such fees and taxes were paid to state and local government in Florida during 2014.

The express purpose of the proposed Initiative is to "encourage and promote local small-scale solar-generated electricity" (Section (a) of the proposed Initiative) and to facilitate its sale to electric consumers in Florida. Those sales will necessarily displace sales of electricity currently made by the Utilities, as well as by municipal utilities and electric cooperatives. For some of the taxes and fees that are currently paid by utilities on electric sales, it is unclear whether or not sales by local solar electricity suppliers ("LSES") would also be subject to those same taxes and fees. The FIEC has asked the Department of Revenue to advise it as to the applicability of certain taxes to LSES sales. However, one of the largest sources of revenues to *local* government from electric sales by utilities is franchise fees. The Utilities paid $643,900,610 in franchise fees in 2014 and estimate that a total of about $850 million was paid that year on sales by all utilities. There is no question that those franchise fees would *not* be paid on LSES sales. This is because the agreements pursuant to which utilities pay franchise fees are bilateral contracts between the specific utilities and the counties and municipalities that the utilities serve. There is no counterpart to those franchise agreements for LSES sales. Thus, for every kilowatt-hour of electricity sold by an LSES rather than a utility, it is absolutely certain that there will be a county or municipality somewhere in Florida that loses revenue in the form of foregone franchise fees. This is not speculation; it is a fact.

Attachment 1 to these comments is a series of tables that show the counties and municipalities that have franchise agreements with each of the four Utilities. These are the local governments that will lose franchise-fee revenues on each LSES sale that displaces a Utility sale within their boundaries. There is insufficient information to predict the extent to which LSES sales will displace utility sales, but even displacement of 1% of the Utility sales would result in a loss of about $8.5 million annually to the affected counties and municipalities. Higher levels of displaced sales would lead inexorably and proportionately to larger losses of local government franchise-fee revenues. And, of course, the displacement of Utility sales may reduce revenues from other taxes and fees as well, depending upon whether the applicability provisions for each tax and fees is ultimately construed to apply to LSES sales.

The Utilities are aware of no meaningful reductions in the costs of providing government services that would result from the proposed Initiative. Indeed, the displacement of their electric sales described above is likely to result in increased electric rates for all electric customers, including state and local governments.

ATTACHMENT I

Florida Power & Light Company Franchises

Florida Power & Light Company ("FPL" or "the company") is an investor-owned electric public utility company serving more than 4.7 million customers throughout much of eastern and southwestern Florida. The company pays franchise fees to the following 177 counties and municipalities pursuant to franchise agreement ordinances:

Anna Maria	Davie	Hillsboro Beach	Malabar
Arcadia	Daytona Beach	Holly Hill	Manalapan
Atlantis	Daytona Beach Shores	Hollywood	Mangonia Park
Baker - Uninc.	DeBary	Holmes Beach	Margate
Bal Harbour	Deerfield Beach	Hypoluxo	Marineland
Bay Harbor Islands	Delray Beach	Indialantic	Medley
Belle Glade	Deltona	Indian Creek	Melbourne
Beverly Beach	DeSoto - Uninc.	Indian Harbour Beach	Melbourne Beach
Biscayne Park	Edgewater	Indian River - Uninc.	Melbourne Village
Boca Raton	El Portal	Interlachen	Miami
Bonita Springs	Fellsmere	Jupiter	Miami Beach
Boynton Beach	Flagler Beach	Jupiter Inlet Colony	Miami Shores Village
Bradenton	Florida City	LaBelle	Miami Springs
Bradenton Beach	Fort Lauderdale	Lake Butler	Miami-Dade - Uninc.[17]*
Bradford - Uninc.	Fort Myers	Lake City	Miramar
Brevard - Uninc.	Glen Ridge	Lake Clarke Shores	Naples
Broward - Uninc.	Glen Saint Mary	Lake Mary	North Bay Village
Bunnell	Golden Beach	Lake Park	North Lauderdale
Callahan	Golf	Lantana	North Miami Beach
Cape Canaveral	Grant-Valkaria	Lauderdale Lakes	North Miami[2]*
Charlotte - Uninc.	Greenacres	Lauderdale-by-the-Sea	North Palm Beach
Cloud Lake	Gulf Stream	Lauderhill	North Port
Cocoa	Hallandale Beach	Lawtey	Oak Hill
Cocoa Beach	Hampton	Lazy Lake	Oakland Park
Coconut Creek	Hastings	Lee - Uninc.	Ocean Ridge
Cooper City	Haverhill	Lighthouse Point	Okeechobee
Coral Gables	Hialeah	Live Oak	Opa-locka
Coral Springs	Hialeah Gardens	Longboat Key/Parent	Ormond Beach
Crescent City	Highland Beach	Loxahatchee Groves	Oviedo
Dania Beach	Hilliard	Macclenny	Pahokee

Palatka	South Bay	*Miami-Dade Cnty Cities listed below:
Palm Bay	South Daytona	Aventura
Palm Beach	South Miami/#1 Parent[2]*	Cutler Bay
Palm Beach - Uninc.	South Palm Beach	Doral
Palm Beach Gardens	Southwest Ranches	Key Biscayne
Palm Beach Shores	St. Augustine	Homestead
Palm Shores	St. Augustine Beach	Miami Gardens
Palm Springs	St. Lucie - Uninc.	Miami Lakes
Palmetto	Starke	Palmetto Bay
Pembroke Park	Stuart	Pinecrest
Pembroke Pines	Sunrise	Sunny Isles Beach
Penney Farms	Surfside	
Plantation	Sweetwater	
Pomona Park	Tamarac	
Pompano Beach	Tequesta	
Ponce Inlet	Titusville	
Port Orange	Venice	
Port St. Lucie	Virginia Gardens	
Punta Gorda	Waldo	
Raiford	Welaka	
Riviera Beach	Wellington	
Rockledge	West Melbourne	
Royal Palm Beach	West Miami	
Sanford	West Palm Beach	
Sarasota	West Park	
Sarasota - Uninc.	Weston	
Satellite Beach	Wilton Manors	
Sea Ranch Lakes		
Sebastian		
Sewall's Point		

Duke Energy Florida Franchises

Duke Energy Florida ("DEF") is an investor-owned electric public utility company serving more than 1.7 million customers throughout much of western, central and northern Florida. DEF pays franchise fees to the following 123 counties and municipalities pursuant to franchise agreement ordinances:

Alachua	Fort White	Oakland
Altamonte Springs	Frostproof	Ocala
Apalachicola	Gilchrist County	Ocoee
Apopka	Groveland	Orange City
Archer	Gulfport	Orlando
Avon Park	Haines City	Oviedo
Bartow	High Springs	Perry
Belle Isle	Highland Park	Pierson
Belleair	Hillcrest Heights	Pinellas Park
Belleair Beach	Howey-In-The-Hills	Port Richey
Belleair Bluffs	Indian Rocks Beach	Port St Joe
Belleair Shore	Indian Shores	Reddick
Belleview	Inglis	Redington Beach
Bowling Green	Inverness	Redington Shores
Branford	Jasper	Safety Harbor
Bronson	Jennings	Sanford
Brooksville	Kenneth City	Sebring-SUC
Carrabelle	Lacrosse	Sebring
Casselberry	Lady Lake	Seminole
Center Hill	Lake Hamilton	So Pasadena
Chiefland	Lake Helen	Sopchoppy
Clearwater	Lake Mary	St. Marks
Clermont	Lake Placid	St. Pete Beach
Coleman	Lake Wales	St. Petersburg
Cross City	Largo	Tarpon Springs
Crystal River	Lee	Tavares
Davenport	Longwood	Treasure Island
Deland	Madeira Beach	Trenton
Deltona	Madison	Umatilla
Debary	Maitland	Wakulla County
Devlmpt Dist - Celebration	Mascotte	Webster
Devlmpt Dist - Enterprise	Mayo	White Springs

Dundee	Mcintosh	Wildwood
Dunedin	Mexico Beach	Windermere
Dunnellon	Micanopy	Winter Garden
Eatonville	Minneola	Winter Haven
Edgewood	Monticello	Winter Park
Eustis	Montverde	Winter Park Annexed
Eustis Manufacturing	Mt Dora	Winter Springs
Fanning Springs - Gilchrist	New Port Richey	Zephyrhills
Fanning Springs – Levy	No. Redington Beach	Zolfo Springs

Gulf Power Company Franchises

Gulf Power Company ("Gulf") is an investor-owned electric public utility company serving more than 440,000 thousand customers throughout much of Northwest Florida. Gulf pays franchise fees to the following 32 counties and municipalities pursuant to franchise agreement ordinances:

Chipley	Milton
Vernon	Defuniak Springs
Graceville	Paxton
Campbellton	Ponce de Leon
Bonifay	Crestview
Caryville	Laurel Hill
Panama City	Niceville
Springfield	Valparaiso
Cedar Grove	Shalimar
Lynn Haven	Fort Walton Beach
Panama City Beach	Cinco Bayou
Parker	Mary Esther
Callaway	Destin
Pensacola	Escambia County
Century	Jackson County
Gulf Breeze	Santa Rosa County

Tampa Electric Company Franchises

Tampa Electric Company ("Tampa Electric" or "the company") is an investor-owned electric public utility company serving more than 706,000 customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The company pays franchise fees to the following 13 municipalities pursuant to franchise agreement ordinances:

Auburndale	Lake Alfred	Plant City	St. Leo
Dade City	Mulberry	Polk City	Tampa
Eagle Lake	Oldsmar	San Antonio	Temple Terrace
Winter Haven			

Exhibit D

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company (the "Utilities")

RE: Financial Impact Statement for the Proposed Initiative Entitled Re: "Limits or Prevents Barriers to Local Solar Electricity Supplier"

DATE: May 4, 2015

Based on the presentations to, and deliberations by, the Financial Impact Estimating Conference ("FIEC" or "Conference"), there is no reasonable doubt that the proposed solar amendment will reduce state and local government revenues, although the extent of the reduction may not be quantifiable at this time. In support of this conclusion, the Utilities note the following for consideration by the Conference:

1. As summarized by the memorandum that the Utilities submitted on April 24, 2015 to the Conference, one of the largest sources of revenues to local government from electric sales by utilities is franchise fees.[1] The Utilities paid $643,900,610 in franchise fees in 2014 and estimate that a total of about $850 million was paid that year on sales by all utilities.
2. Franchise fees are paid pursuant to franchise agreements, which exist between utilities and a multiplicity of municipalities and counties. Nothing presented to the Conference suggests that Local Solar Electricity Suppliers would enter into franchise agreements or otherwise obligate themselves to pay franchise fees or their equivalent.

---

[1] See attached McDaniel FIEC Memo 4-24-15

3. The amount of franchise fees paid is a direct function of utility electric sales. Sales of electricity by Local Solar Electricity Suppliers that are facilitated by the proposed amendment will displace sales by utilities. As a result, utility sales will be lower and franchise revenues will be correspondingly reduced.

4. The displacement of utility sales by Local Solar Electricity Suppliers is likely to reduce tax revenues for state and local government as well. Public service tax revenues are likely to decline. Absent a change in the approach to administering the Gross Receipts Tax generally, and its use tax component specifically, the state can also expect a reduction in revenues caused by the proposed amendment.

5. Adoption of the proposed amendment is likely to increase costs to state and loeal government as well. Statutes and rules likely will need to be enacted and amended in order to administer, implement and accommodate the amendment.

Accordingly, the Utilities recommend that the Conference adopt the following Financial Impact Statement:

> The overall financial impact of this amendment on state and local government revenues and costs cannot be precisely determined. There will be a direct reduction in franchise fee and tax revenues to government, the extent of which is dependent upon the adoption rate of local solar electricity under the amendment and the resulting displacement of electric sales by electric utilities. State and local governments will incur additional costs due to the amendment. (72 words)

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company

RE: Additional Information Concerning Financial Impact Statement for the Proposed Initiative Entitled Re: "Limits or Prevents Barriers to Local Solar Electricity Supplier"

DATE: April 22, 2015

At the Financial Impact Estimating Conference ("FIEC") public meeting held on April 10, 2015, proponents of the proposed Initiative asserted that it would have no financial impact on the revenues of state and local government. At this time, Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company (the "Utilities") are not taking a position on the proposed Initiative. However, the proponents' assertion of no financial impact is demonstrably incorrect, and the Utilities are submitting this additional information in support of that conclusion.

As summarized in the materials that the Utilities submitted at the April 10 public meeting, there is a range of taxes and fees that the Utilities, as well as municipal utilities and electric cooperatives, pay to state and local government based on their sales of electricity. Those taxes and fees include sales tax, gross receipts tax, municipal public service tax, the regulatory assessment fee and municipal franchise fees. Approximately $2.9 billion of such fees and taxes were paid to state and local government in Florida during 2014.

The express purpose of the proposed Initiative is to "encourage and promote local small-scale solar-generated electricity" (Section (a) of the proposed Initiative) and to facilitate its sale to electric consumers in Florida. Those sales will necessarily displace sales of electricity currently made by the Utilities, as well as by municipal utilities and electric cooperatives. For some of the taxes and fees that are currently paid by utilities on electric sales, it is unclear whether or not sales by local solar electricity suppliers ("LSES") would also be subject to those same taxes and fees. The FIEC has asked the Department of Revenue to advise it as to the applicability of certain taxes to LSES sales. However, one of the largest sources of revenues to *local* government from electric sales by utilities is franchise fees. The Utilities paid $643,900,610 in franchise fees in 2014 and estimate that a total of about $850 million was paid that year on sales by all utilities. There is no question that those franchise fees would *not* be paid on LSES sales. This is because the agreements pursuant to which utilities pay franchise fees are bilateral contracts between the specific utilities and the counties and municipalities that the utilities serve. There is no counterpart to those franchise agreements for LSES sales. Thus, for every kilowatt-hour of electricity sold by an LSES rather than a utility, it is absolutely certain that there will be a county or municipality somewhere in Florida that loses revenue in the form of foregone franchise fees. This is not speculation; it is a fact.

Attachment 1 to these comments is a series of tables that show the counties and municipalities that have franchise agreements with each of the four Utilities. These are the local governments that will lose franchise-fee revenues on each LSES sale that displaces a Utility sale within their boundaries. There is insufficient information to predict the extent to which LSES sales will displace utility sales, but even displacement of 1% of the Utility sales would result in a loss of about $8.5 million annually to the affected counties and municipalities. Higher levels of displaced sales would lead inexorably and proportionately to larger losses of local government franchise-fee revenues. And, of course, the displacement of Utility sales may reduce revenues from other taxes and fees as well, depending upon whether the applicability provisions for each tax and fees is ultimately construed to apply to LSES sales.

The Utilities are aware of no meaningful reductions in the costs of providing government services that would result from the proposed Initiative. Indeed, the displacement of their electric sales described above is likely to result in increased electric rates for all electric customers, including state and local governments.

ATTACHMENT I

Florida Power & Light Company Franchises

Florida Power & Light Company ("FPL" or "the company") is an investor-owned electric public utility company serving more than 4.7 million customers throughout much of eastern and southwestern Florida. The company pays franchise fees to the following 177 counties and municipalities pursuant to franchise agreement ordinances:

Anna Maria	Davie	Hillsboro Beach	Malabar
Arcadia	Daytona Beach	Holly Hill	Manalapan
Atlantis	Daytona Beach Shores	Hollywood	Mangonia Park
Baker - Uninc.	DeBary	Holmes Beach	Margate
Bal Harbour	Deerfield Beach	Hypoluxo	Marineland
Bay Harbor Islands	Delray Beach	Indialantic	Medley
Belle Glade	Deltona	Indian Creek	Melbourne
Beverly Beach	DeSoto - Uninc.	Indian Harbour Beach	Melbourne Beach
Biscayne Park	Edgewater	Indian River - Uninc.	Melbourne Village
Boca Raton	El Portal	Interlachen	Miami
Bonita Springs	Fellsmere	Jupiter	Miami Beach
Boynton Beach	Flagler Beach	Jupiter Inlet Colony	Miami Shores Village
Bradenton	Florida City	LaBelle	Miami Springs
Bradenton Beach	Fort Lauderdale	Lake Butler	Miami-Dade - Uninc.[17]*
Bradford - Uninc.	Fort Myers	Lake City	Miramar
Brevard - Uninc.	Glen Ridge	Lake Clarke Shores	Naples
Broward - Uninc.	Glen Saint Mary	Lake Mary	North Bay Village
Bunnell	Golden Beach	Lake Park	North Lauderdale
Callahan	Golf	Lantana	North Miami Beach
Cape Canaveral	Grant-Valkaria	Lauderdale Lakes	North Miami[2]*
Charlotte - Uninc.	Greenacres	Lauderdale-by-the-Sea	North Palm Beach
Cloud Lake	Gulf Stream	Lauderhill	North Port
Cocoa	Hallandale Beach	Lawtey	Oak Hill
Cocoa Beach	Hampton	Lazy Lake	Oakland Park
Coconut Creek	Hastings	Lee - Uninc.	Ocean Ridge
Cooper City	Haverhill	Lighthouse Point	Okeechobee
Coral Gables	Hialeah	Live Oak	Opa-locka
Coral Springs	Hialeah Gardens	Longboat Key/Parent	Ormond Beach
Crescent City	Highland Beach	Loxahatchee Groves	Oviedo
Dania Beach	Hilliard	Macclenny	Pahokee

Palatka	South Bay	*Miami-Dade Cnty Cities listed below:
Palm Bay	South Daytona	Aventura
Palm Beach	South Miami/#1 Parent[2]*	Cutler Bay
Palm Beach - Uninc.	South Palm Beach	Doral
Palm Beach Gardens	Southwest Ranches	Key Biscayne
Palm Beach Shores	St. Augustine	Homestead
Palm Shores	St. Augustine Beach	Miami Gardens
Palm Springs	St. Lucie - Uninc.	Miami Lakes
Palmetto	Starke	Palmetto Bay
Pembroke Park	Stuart	Pinecrest
Pembroke Pines	Sunrise	Sunny Isles Beach
Penney Farms	Surfside	
Plantation	Sweetwater	
Pomona Park	Tamarac	
Pompano Beach	Tequesta	
Ponce Inlet	Titusville	
Port Orange	Venice	
Port St. Lucie	Virginia Gardens	
Punta Gorda	Waldo	
Raiford	Welaka	
Riviera Beach	Wellington	
Rockledge	West Melbourne	
Royal Palm Beach	West Miami	
Sanford	West Palm Beach	
Sarasota	West Park	
Sarasota - Uninc.	Weston	
Satellite Beach	Wilton Manors	
Sea Ranch Lakes		
Sebastian		
Sewall's Point		

Exhibit A

Duke Energy Florida Franchises

Duke Energy Florida ("DEF") is an investor-owned electric public utility company serving more than 1.7 million customers throughout much of western, central and northern Florida. DEF pays franchise fees to the following 123 counties and municipalities pursuant to franchise agreement ordinances:

Alachua	Fort White	Oakland
Altamonte Springs	Frostproof	Ocala
Apalachicola	Gilchrist County	Ocoee
Apopka	Groveland	Orange City
Archer	Gulfport	Orlando
Avon Park	Haines City	Oviedo
Bartow	High Springs	Perry
Belle Isle	Highland Park	Pierson
Belleair	Hillcrest Heights	Pinellas Park
Belleair Beach	Howey-In-The-Hills	Port Richey
Belleair Bluffs	Indian Rocks Beach	Port St Joe
Belleair Shore	Indian Shores	Reddick
Belleview	Inglis	Redington Beach
Bowling Green	Inverness	Redington Shores
Branford	Jasper	Safety Harbor
Bronson	Jennings	Sanford
Brooksville	Kenneth City	Sebring-SUC
Carrabelle	Lacrosse	Sebring
Casselberry	Lady Lake	Seminole
Center Hill	Lake Hamilton	So Pasadena
Chiefland	Lake Helen	Sopchoppy
Clearwater	Lake Mary	St. Marks
Clermont	Lake Placid	St. Pete Beach
Coleman	Lake Wales	St. Petersburg
Cross City	Largo	Tarpon Springs
Crystal River	Lee	Tavares
Davenport	Longwood	Treasure Island
Deland	Madeira Beach	Trenton
Deltona	Madison	Umatilla
Debary	Maitland	Wakulla County
Devlmpt Dist - Celebration	Mascotte	Webster
Devlmpt Dist - Enterprise	Mayo	White Springs

Dundee	Mcintosh	Wildwood
Dunedin	Mexico Beach	Windermere
Dunnellon	Micanopy	Winter Garden
Eatonville	Minneola	Winter Haven
Edgewood	Monticello	Winter Park
Eustis	Montverde	Winter Park Annexed
Eustis Manufacturing	Mt Dora	Winter Springs
Fanning Springs - Gilchrist	New Port Richey	Zephyrhills
Fanning Springs – Levy	No. Redington Beach	Zolfo Springs

Gulf Power Company Franchises

Gulf Power Company ("Gulf") is an investor-owned electric public utility company serving more than 440,000 thousand customers throughout much of Northwest Florida. Gulf pays franchise fees to the following 32 counties and municipalities pursuant to franchise agreement ordinances:

Chipley	Milton
Vernon	Defuniak Springs
Graceville	Paxton
Campbellton	Ponce de Leon
Bonifay	Crestview
Caryville	Laurel Hill
Panama City	Niceville
Springfield	Valparaiso
Cedar Grove	Shalimar
Lynn Haven	Fort Walton Beach
Panama City Beach	Cinco Bayou
Parker	Mary Esther
Callaway	Destin
Pensacola	Escambia County
Century	Jackson County
Gulf Breeze	Santa Rosa County

Exhibit C

Tampa Electric Company Franchises

Tampa Electric Company ("Tampa Electric" or "the company") is an investor-owned electric public utility company serving more than 706,000 customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The company pays franchise fees to the following 13 municipalities pursuant to franchise agreement ordinances:

Auburndale	Lake Alfred	Plant City	St. Leo
Dade City	Mulberry	Polk City	Tampa
Eagle Lake	Oldsmar	San Antonio	Temple Terrace
Winter Haven			

MEMORANDUM

TO: Financial Impact Estimating Conference

SUBJECT: Financial Impact Statement for the Proposed Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 24, 2015

Summary

The proposed solar energy amendment to Florida's constitution generally permits a "local solar electricity supplier" to use solar energy to generate up to two megawatts of electricity and to either consume it on the supplier's property or to sell it to the owners of "contiguous" property. The amendment prohibits electric utilities, including municipal electric utilities, from charging any fee or placing any service condition on the supplier's customers that are not imposed on the utility's other customers. The proposed amendment permits laws designed to protect the public's health, safety and welfare so long as the laws do not prohibit "the supply of solar generated electricity by a local solar electricity supplier."

Initial indications are the proposal will have a material financial impact on the membership of the Florida League of Cities largely because the amendment will affect the franchise fees and public service tax (PST) revenues received by Florida's municipalities. The magnitude and timing OF the financial impact that will occur will be primarily determined by the saturation level of generation of local small-scale solar-generated electricity into the traditional electric market.

Franchise Fees

Local governments may exercise their home rule authority to impose a franchise fee upon a utility for the grant of a franchise and the privilege of using local government's rights-of-way to conduct the utility business. The fee is considered fair rent for the use of such rights-of-way[1] and consideration for the local government's agreement not to provide competing utility services during the term of the franchise agreement. The franchise fee consists of three main components: it is fair rent for the use of the municipality's rights-of-way to make a profit; it is consideration for the municipality to agree not to compete with the electric utility and to prohibit others from competing with the electric utility during the term of the franchise agreement; and it is a fee paid the municipality to offset the costs incurred by the municipality as a result of the electric utilities' disparate and exclusive use of public property.[2]

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[1] Leonard v Baylen Street Wharf Co., 52 So 718 (Fla 1910), City of Plant City v. Mayo, 337 So. 2d 966 (Fla. 1976)

[2] Florida Power Corp v. City of Winter Park, 887 So 2d 1237 (Fla. 2004), City of Hialeah Gardens v Dade Co., 348 So. 2d 1174 (Fla 3d DCA 1977), Santa Rosa Co. v. Gulf Power Co, 635 So 2d 96 (Fla 1st DCA 1994) rev denied, 645 So 2d 452 (Fla. 1994), Flores v. City of Miami, 681 So. 2d 803 (Fla. 3d DCA 1996).

The imposition of the fee requires the adoption of a franchise agreement Typically, the franchise fee is calculated as a percentage of the utility's gross revenues within a defined geographic area A fee imposed by a municipality is based upon the gross revenues received from the incorporated areas while a fee imposed by a county is generally based upon the gross revenues received from the unincorporated areas

Reported municipal franchise fee collections from electric utilities were $ $563,206,940 for fiscal year 2011-12[3]. Franchise fees from electric constitutes approximately 1.8 percent of total municipal revenues[4]. Below is a sample selection of franchise fee rates throughout the state

Municipality	County	Electricity	Electric Utility	Franchise Fee Rate
Ponce de Leon	Holmes	$ -	Gulf Power Company	4 00%
Apopka	Orange	$ 2,978,723	Duke Energy	6 00%
Cape Canaveral	Brevard	$ 600,068	Florida Power & Light Company	6 00%
Clermont	Lake	$ 1,995,234	Duke Energy	6 00%
Fernandina Beach	Nassau	$ 1,252,097	Florida Public Utilities Company	6 00%
Fort Lauderdale	Broward	$ 15,561,277	Florida Power & Light Company	6 00%
Lee	Madison	$ 16,942	Duke Energy	6 00%
Longboat Key	Manatee/Sarasota	$ 843,299	Florida Power & Light Company	6 00%
Miami	Miami-Dade	$ 26,257,819	Florida Power & Light Company	6 00%
Ocoee	Orange	$ 2,155,543	Duke Energy	6 00%
Panama City	Bay	$ 3,798,295	Gulf Power Company	6 00%
Polk City	Polk	$ 57,332	Tampa Electric Company	6 00%
Windermere	Orange	$ 235,501	Florida Power & Light Company	6 00%
St Augustine	St Johns	$ 1,125,547	Florida Power & Light Company	5 90%
Temple Terrace	Hillsborough	$ 1,764,912	Tampa Electric Company	5 40%
Tampa	Hillsborough	$ 31,646,686	Tampa Electric Company	4 60%

There are two scenarios in which the franchise fee revenues could be impacted. The first would be the reduction of the gross revenues of an electric utility due to the increased generation of local small-scale solar-generated electricity and a corresponding reduction of the franchise fees. Based on the purpose and intent statement of the petition form, it can be assumed that the purpose of the amendment is to encourage and promote such generation but the extent that this would occur has yet to be determined.

The second potential impact on franchise fees would come from the termination or renegotiation of the franchise fee agreement. Should the proposed amendment be approved by the voters, it will impair the electric utilities' exclusive rights to provide electric service within the geographical boundaries of the municipalities. It is not unreasonable to assume electric utilities will take the position there is now insufficient consideration to support the franchise agreement because the fee no longer bears a discernable relationship to the cost to municipalities for the use of the public rights-of-ways.[5]

Below is a segment of language that is found in the Town of Longboat Key Franchise Agreement with Florida Power and Light Company.[6]

> *SECTION 8: If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of*

[3] Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments
[4] Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments
[5] Alachua County v. State, 737 So. 2d 1065 (Fla 1999); See also, Gulf Power Co., supra.
[6] Town of Longboat Key Ordinance 2014-13

either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determined that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it as a competitive disadvantage with respect to such other person, the Grantee may, at any time after taking of such action, terminate this franchise if such competitive disadvantage is not remedied as provided hereafter The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the claimed competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall have 90 days in which to correct or otherwise remedy the competitive disadvantage, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of the Grantee's claimed disadvantage during this 90-day period. If such competitive disadvantage is, in a reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of completive disadvantage leading to termination under this Section.

The League recognizes that the termination of franchise agreements will undoubtedly present significant problems for the utilities, the fact remains the proposed amendment will disrupt the current contractual relationship between Florida's municipalities and the electric utilities currently serving or servicing those jurisdictions. As a result, it places municipal franchise fees on electric utilities at risk.

Public Service Tax

Municipalities and charter counties may levy by ordinance a PST on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service.[7] The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed ten percent of the payments received by the seller of the taxable item. The tax proceeds are considered general revenue for the municipality or charter county. Municipal collections of the public service tax on the purchase of electricity were $666,317,873 for fiscal year 2011-2012.[8] Based on initial surveys, two municipalities and two counties have explicitly pledged the public utility tax as primary repayment for bonds. This does not include local governments that have utilized covenant to budget and appropriate, which is a security for debt to a covenant to budget and appropriate legally available non ad valorem revenues, and securities where the public service tax is a secondary pledged revenue source

[7] Section 166.231(1), Florida Statutes

[8] Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments

Potential impacts on the public services are expected to result from a reduction in the base of the public service tax base which could occur in two ways The first would be an overall reduction in purchase of electricity due to the increase generation of local small-scale solar-generated electricity and onsite consumption. This would appear to be energy efficiently as it will not be accounted for in the traditional methods. Once again, the extent that this would occur has yet to be determined. The secondary impact will come from an anticipated increase in the utilization of net metering, a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site[9] or a similar relationship to buy excess local small-scale solar-generated electricity. While both of these reductions have the same impact or reducing the energy purchased from a utility, both incidences occur on the same property.

Based on initial research, the most common method of net metering allows for the utility to credit the customer for the amount of kilowatts that are produced by solar devices that can be used at a later date against kilowatts that are purchased from the electric utility. This will cause a reduction in the amount of the customer's bill that it owed to the electric utility and corresponding reduction in the PST owed on that taxable transaction.

One unique program is that of the Gainesville Regional Utilities (GRU) Solar Feed-in-Tariff (FIT) Program. Customers selected for the FIT Program invest in their own solar photovoltaic systems to generate electricity and sell that energy directly to GRU under a 20-year fixed-price contract The 20-year fixed rate is based on the year the project was approved and the type of installation. The responsibility of collecting and remitting applicable taxes falls to the customer in the program. It is important to note that the Solar FIT program has been suspended and is no longer accepting applications or adding capacity.

Municipal and Utility Administration

The process for the installation of a solar energy system on a residential dwelling or commercial building generally follows the same process one would currently use to secure a building or electrical permit The solar energy device owner, lessee or contractor (owner) makes application to the municipality's building department, submits a set of plans for the solar energy system, and pays the normal permit fee associated with the work. The municipality reviews and approves the plans, issues the permit, and inspects the work over the course of installation.

Specific to the installation of solar devices, there are two additional steps. The first is the requirement for the owner to enter a "net metering agreement" with the utility or municipality. The net metering agreement outlines the duties and responsibilities of the owner and the utility or municipality, provides or specifies the process by which the utility or municipality will compensate the owner for electricity generated by the system, and often requires the owner to carry insurance and indemnify the utility or municipality for any damages the system causes the utility or municipalities electrical system.[10] Under the proposed amendment, a utility may not place any condition of service on a solar energy generator that is not placed on a customer who does not generate solar energy; therefore, it is questionable whether the utility or municipality will be able to require a net metering agreement should the amendment pass. Additionally, the municipality requires an electrical engineer to inspect the plans and assess the impact the system will have on the electric system's infrastructure, including electrical lines and

[9] Section 366.91 (2)(a), Florida Statutes
[10] 25-6.065, Florida Administrative Code.
Gainesville Regional utilities Agreement for Interconnection and Parallel Operation of Distributed Generation Resources.
Electric Rate Tariffs Volume 1 Lakeland Electric.

transformers, to ensure the solar generated energy will not unduly disrupt the flow of the utility's electricity.

In the case of the City of Tallahassee, they do not currently charge the owner for the cost incurred with the additional steps. However, the city currently gets only one or two applications a year to install solar energy systems and would undoubtedly consider charging for the latter two steps should the applications increase significantly. Again, it is questionable whether the proposed amendment will permit the city to charge solar energy generators this fee if it does not charge the fee to customers who do not generate solar energy Additionally, many municipalities and utilities charge an application for the net metering program.

Renewable generator systems connected to the grid without batteries are not a standby power source during an outage The system must shut down when utility's grid shuts down in order to prevent dangerous back feed on the grid. This is required to protect utility employees who may be working on the grid. Most municipal electrics require the disconnect switch at the meter. Investor-owned electric utilities may only require the external disconnect for Tier 2 and Tier 3 systems OR systems greater than 10 kW.[11]

When power outages occur during emergencies, the electric utility must be able to turn the solar energy system off to assure the unit doesn't sporadically send electricity through the electric lines. This minimizes the chance electrical workers work on "hot" lines while trying to restore power. With a disconnect switch, the utility worker can simply throw the switch to turn off the solar energy system. Then, the owner can simply throw the switch back on when overall power is restored. On the other hand, the electric utilities must physically remove the meter to assure the solar energy system is turned off and the electric lines aren't "hot." Then, when overall power is restored, the electric utility must return and reinstall the meter. Obviously, the latter process takes longer and, as a result, power remains off longer

Generally speaking, municipal electric utilities must continue to maintain the infrastructure to provide utility service to solar energy customers because solar electricity generating facilities do not generate electricity all the time. So, regardless of whether a customer can generate solar electricity, the utility must remain capable of providing electricity to the customer when, for example, the customer's solar energy facility is not generating electricity for any number of reasons. Moreover, customers generating solar energy have a disparate cost impact on a utility's infrastructure that is not shared by the customers who do not generate or consume solar electricity. The transmission of solar generated electricity through transmission lines and transmission facilities, as well as the accounting of solar generated electricity, are but a few of the places where the customers of solar generated electricity will have a disparate cost impact on the utility that is different in kind and degree than the costs of customers who do not generate local solar electricity. But, a fair reading of the proposed amendment will not permit the utility to charge the solar electricity customer for disparate impact on the system. Therefore, it stands to reason the proposed amendment will have a financial impact on municipal electric utilities and it stands to reason the amendment will require the utilities will spread the disparate cost throughout its other customers.

[11] 25-6.065, Florida Administrative Code

Appendix

Security Description	Maturity Date	Dated Date	Principal Amount At Issuance
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2017	11/3/2010	$ 155,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2018	11/3/2010	$ 160,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2019	11/3/2010	$ 165,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2020	11/3/2010	$ 165,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2025	11/3/2010	$ 900,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2030	11/3/2010	$ 1,055,000
CITY OF PALM BAY, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2010 (FEDERALLY TAXABLE- BABS-RZEDB- DIRECT SUBSIDY)	10/1/2040	11/3/2010	$ 2,730,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2019	9/30/2014	$ 445,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2020	9/30/2014	$ 465,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2021	9/30/2014	$ 485,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2022	9/30/2014	$ 505,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2023	9/30/2014	$ 535,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2024	9/30/2014	$ 560,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2025	9/30/2014	$ 590,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2026	9/30/2014	$ 615,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2027	9/30/2014	$ 650,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2028	9/30/2014	$ 680,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2029	9/30/2014	$ 715,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2030	9/30/2014	$ 740,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2031	9/30/2014	$ 775,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2032	9/30/2014	$ 800,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2033	9/30/2014	$ 830,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2034	9/30/2014	$ 860,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2039	9/30/2014	$ 4,840,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, SERIES 2014B (RECOVERY ZONE FACILITY BONDS)	9/1/2043	9/30/2014	$ 4,685,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2019	9/30/2014	$ 315,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2020	9/30/2014	$ 325,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2021	9/30/2014	$ 335,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2022	9/30/2014	$ 345,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2023	9/30/2014	$ 355,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2024	9/30/2014	$ 370,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2025	9/30/2014	$ 385,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2026	9/30/2014	$ 400,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2027	9/30/2014	$ 420,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2028	9/30/2014	$ 435,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2029	9/30/2014	$ 455,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2034	9/30/2014	$ 2,635,000
CITY OF PORT ST LUCIE, FLORIDA / PUBLIC SERVICE TAX REVENUE BONDS, TAXABLE SERIES 2014A	9/1/2043	9/30/2014	$ 6,750,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2015	9/28/2011	$ 3,390,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2016	9/28/2011	$ 2,255,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2016	9/28/2011	$ 3,515,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2017	9/28/2011	$ 2,340,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2017	9/28/2011	$ 3,645,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2018	9/28/2011	$ 2,425,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2018	9/28/2011	$ 3,785,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2019	9/28/2011	$ 2,520,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2019	9/28/2011	$ 3,940,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2020	9/28/2011	$ 2,610,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2020	9/28/2011	$ 4,100,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2021	9/28/2011	$ 2,710,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2021	9/28/2011	$ 4,270,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2022	9/28/2011	$ 2,825,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2022	9/28/2011	$ 4,440,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2023	9/28/2011	$ 2,945,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	10/1/2023	9/28/2011	$ 4,625,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2024	9/28/2011	$ 3,065,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2025	9/28/2011	$ 3,230,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2026	9/28/2011	$ 3,400,000
MIAMI-DADE COUNTY, FLORIDA / PUBLIC SERVICE TAX REVENUE REFUNDING BONDS (UMSA PUBLIC IMPROVEMENTS), SERIES 2011	4/1/2027	9/28/2011	$ 3,575,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2015	7/9/2013	$ 4,910,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2016	7/9/2013	$ 4,610,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2017	7/9/2013	$ 3,375,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2018	7/9/2013	$ 3,545,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2019	7/9/2013	$ 3,615,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2020	7/9/2013	$ 2,220,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2021	7/9/2013	$ 2,070,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2022	7/9/2013	$ 2,075,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2023	7/9/2013	$ 2,190,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2024	7/9/2013	$ 2,295,000
ORANGE COUNTY, FLORIDA / PUBLIC SERVICE TAX REFUNDING REVENUE BONDS, SERIES 2013	10/1/2025	7/9/2013	$ 1,450,000

Data from the Electronic Municipal Market Access

ORDINANCE NO. 2014-13

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF LONGBOAT KEY, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the Town Commission of the Town of Longboat Key, Florida recognizes that the Town of Longboat Key and its citizens need and desire the continued benefits of electric service; and

WHEREAS, there is currently in effect a franchise agreement between the Town of Longboat Key and Florida Power and Light Company (FPL), the terms of which are set forth in Town of Longboat Key Ordinance No. 84-8, passed and adopted May 7, 1984, and FPL's written acceptance thereof dated May 29, 1984, granting to FPL, its successors, and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the Town of Longboat Key desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the Town of Longboat Key in exchange for the nonexclusive right and privilege of supplying retail electricity service within the Town of Longboat Key free of competition from the Town of Longboat Key, pursuant to certain terms and conditions, and

WHEREAS, the Town Commission of the Town of Longboat Key deems it to be in the best interests of the Town of Longboat Key and its citizens to enter into the New Franchise Agreement;

NOW, THEREFORE, BE IT ORDAINED BY THE TOWN COMMISSION OF THE TOWN OF LONGBOAT KEY, FLORIDA:

SECTION 1. There is hereby granted to Florida Power & Light Company (FPL), its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, and rights-of-way (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the Town of Longboat Key, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying retail electricity service and other electricity-related services incidental thereto (which other electricity-related services are defined as FPL's facility to facility data capabilities over the lines to identify faults, load information, and other data necessary or helpful to the provision of electric service, and which do not include any services that are sold to others) to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof

SECTION 2. (a) The facilities of the Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction, or erection of all facilities shall be made as representatives of the Grantor may prescribe in accordance with all applicable federal, state, and local statutes, laws, ordinances, rules, and regulations and pursuant to Grantor's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining, in, under, upon, along, over, and across said public rights-of-way, provided such rules and regulations:

(i) shall be for a valid municipal purpose,
(ii) shall not prohibit the exercise of Grantee's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above,
(iii) shall not unreasonably interfere with Grantee's ability to furnish reasonably sufficient, adequate, and efficient electric service to all its customers while not conflicting with the standards set forth above, or
(iv) shall not require relocation of any of the Grantee's facilities installed before or after the effective date hereof in any public right-of-way unless or until the facilities unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road".

(c) Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible, and such installation shall be consistent with the Florida Department of Transportation's Manual of Uniform Minimum Standards for Design, Construction, and Maintenance for Streets and Highways.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by Grantee or any of its agents, contractors, or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged, or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by the Grantee at its expense.

(e) The Grantor shall not be liable to the Grantee for any cost or expense incurred in connection with the relocation of any of the Grantee's facilities required under this Section, except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

SECTION 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation, or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage, or expense, including Grantor's reasonable attorneys fees and costs incurred in defending itself against any claims for such liabilities, losses, costs, damages, or expenses asserted against Grantor by others, which may accrue to the Grantor by reason of the negligence, default, or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

SECTION 4. All rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

SECTION 5. (a) As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal 6.0 percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6.0 percent of such revenues for any monthly billing period of the Grantee, provided, however, that this limitation shall not apply if the Grantor and Grantee have, pursuant to Section 5(b) below, entered into a new franchise agreement providing for a rate greater than 6.0 percent.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 84-8, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; and (h) other service charges.

With each monthly payment remitted to Grantor, Grantee shall include a detailed calculation showing how the amount remitted was determined. Each such detailed calculation shall show. (i) the amount of Grantee's revenues subject to the franchise fee, (ii) the actual calculation of 6.0 percent of that amount, (iii) the resulting franchise fee amount before offsets and write-offs, (iv) the amount of actual write-offs deducted by Grantee, and (v) the resulting amount of the franchise fee payment being remitted to Grantor. Itemized information regarding any write-offs or deductions from the franchise fee shall be made available to the Grantor upon request to the Grantee.

(b) If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Sarasota County, Manatee County, Charlotte County, Collier County, or Lee County, Florida, where the number of Grantee's active electrical customers is equal to or less than the number of Grantee's active electrical customers within the incorporated areas of Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5(a) hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5(a) hereof shall be equal to that percentage which the Grantee has agreed to use as a basis for the calculation of payments to the other municipality, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, at least equal to those provided by its franchise agreement with such other municipality.

SECTION 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee; and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), provided that the Grantor shall not be considered a "third party" or an "other retail customer" for purposes of this provision. Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions, which are subject to the provisions of the Federal Power Act, or from utilizing generators and/or other electricity or energy-generating equipment during emergency situations. Nothing herein is intended to restrict the Grantor from providing services other than retail electricity service, which is the subject of the Grantor's agreement not to compete set forth in this paragraph.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may purchase such electric capacity and/or electric energy from such other person and all of the remaining terms and conditions of this franchise shall remain in effect.

SECTION 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied, or if the dispute between Grantee and Grantor is not resolved, as provided hereafter. The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of Grantee's claims during this 90-day period. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, and if no mutually acceptable resolution is reached by Grantee and Grantor through negotiation, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk, and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination leading to termination under this Section.

SECTION 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and such person is authorized, whether by federal or state law or regulations, or by the Grantor, to provide electric service without paying a franchise fee equal to that paid by the Grantee hereunder (such unequal application of franchise fees being hereafter referred to as the "competitive disadvantage" resulting from the legislative, regulatory, or other governmental action), the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage created by the unequal application of franchise fees on the Grantee and other persons supplying retail electricity is not remedied as provided hereafter. Such competitive disadvantage can be remedied by either of the following methods: (i) If the Grantor either cannot legally, or does not, charge a franchise fee to other electricity supplier(s), then the Grantor can remedy the disadvantage by reducing the Grantee's franchise fee rate to zero; or (ii) if the Grantor is able to charge, and does charge, such other electricity supplier(s) a franchise fee at a rate less than the 6.0% rate calculated as provided in Section 5 of this franchise, then the Grantor can remedy the disadvantage by reducing the Grantee's franchise fee rate to the same rate, with the same applicability and calculation methodology, as applies to such other electricity suppliers. If the Grantor does not implement either of the foregoing solutions, the Grantee may terminate the franchise, in accordance with the following process. The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the claimed competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in

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which to correct or otherwise remedy the competitive disadvantage, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of Grantee's claimed disadvantage during this 90-day period. If such competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section.

SECTION 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

SECTION 10. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than as set forth in Section 2 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this New Franchise Agreement; or (c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold such portion of the payments provided for in Section 5 hereof as a court of competent jurisdiction has, upon action instituted by Grantee, determined to be equitable, just, and reasonable, considering the totality of the circumstances, until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination (after the expiration or exhaustion of all rights of appeal) in the matter. The Grantor recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right as provided by law. The Grantee recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantor's delegated sovereign right of condemnation and that the Grantor, in its sole discretion, may exercise such right as provided by law, provided that the Grantor shall not exercise such right so as to violate the Grantor's covenant, set forth in Section 6 hereof, not to compete against the Grantee in the distribution and/or sale of electricity to ultimate consumers.

SECTION 11. The Grantor may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not otherwise created, prepared, maintained, or kept by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Consistent with the foregoing, Grantor shall have 90 days following acceptance by the Grantee of the franchise granted by this New Franchise Agreement to initiate a final audit of Grantee's franchise fee payments pursuant to Ordinance No. 84-8. Upon the conclusion of any such audit, or upon the expiration of 90 days following Grantee's acceptance of the franchise granted by this New Franchise Agreement, whichever is later, any and all of Grantor's claims, other than such claims as may have been raised pursuant to the final audit contemplated by this section, relating in any way to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 84-8 shall be deemed waived, settled, and barred.

<u>SECTION 12</u> Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, or otherwise rendered invalid or unenforceable as a direct or indirect consequence of any legislative, regulatory, or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them), such decision or action shall not affect the validity of the remainder hereof as a whole or any part hereof, other than the part declared to be invalid. Grantor and Grantee further agree that, in the event that any material provision of this ordinance is thus declared to be invalid or rendered invalid or unenforceable, the Grantor and Grantee will negotiate in good faith to amend this Agreement so as to restore, to the maximum extent legally permissible, the original economic bargain embodied in this ordinance. The parties recognize that Sections 1, 2, 3, 5, and 6 are critical to the fundamental economic bargain of this Franchise Agreement, and accordingly, if any of the provisions of these sections are found or adjudged to be invalid, or rendered invalid or unenforceable, and the Grantor and Grantee are unable to agree on replacement language that restores the original economic bargain embodied in the ordinance to their mutual satisfaction, then either party may, in its sole discretion, terminate the franchise by giving 60 days written notice to the other party.

<u>SECTION 13.</u> As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

<u>SECTION 14.</u> Subject to the Grantor's right to conduct a final audit expressly reserved by Section 11 of this New Franchise Agreement, Ordinance No. 84-8, passed and adopted May 7, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

<u>SECTION 15</u> Notwithstanding any provision of this Ordinance, nothing herein shall prevent, prohibit or in any way restrict the Grantor's ability to take advantage of all applicable services set forth in Grantee's tariffs as those tariffs are approved from time to time by Grantee's regulators, and nothing herein shall prevent, prohibit or in any way restrict the

Grantor's ability to avail itself of all rights accruing to Grantor as a retail customer of Grantee under Florida law and the rules and regulations of the Florida Public Service Commission.

SECTION 16. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.

PASSED on first reading the 21st day of April, 2014.

PASSED AND ADOPTED on second reading and public hearing the ________ day of

__________________, 2014.

TOWN OF LONGBOAT KEY, FLORIDA

By: ______________________________
Jack G. Duncan, Vice Mayor

ATTEST:

By: ______________________________
Trish Granger, Town Clerk
Town of Longboat Key, Florida

(SEAL)

APPROVED AS TO FORM AND LEGALITY

____
Maggie Mooney-Portale, Town Attorney
Town of Longboat Key, Florida

Florida Power & Light - 1177 N. Lime Avenue, Sarasota, Fl 34237

FPL

May 5, 2014

The Honorable Jim Brown
Mayor
Town of Longboat Key
501 Bay Isles Road
Longboat Key, FL 34228

Re: Florida Power & Light Company

Dear Mayor Brown.

Please accept this letter as acknowledgment and agreement by FPL to the following:

(1) FPL will provide reasonable and sufficient advance notice to the Town of any planned relocation or replacement of three or more consecutive FPL poles within the incorporated areas of the Town so that the Town may: (i) evaluate underground conversions of such poles and associated facilities pursuant to FPL's applicable tariffs and Florida Public Service Commission rules; or (ii) request different locations for the poles and associated facilities as desired by the Town pursuant to FPL's applicable tariffs and Florida Public Service Commission rules. Additionally, FPL agrees that it will provide sufficient notice of any relocations or replacements of overhead distribution facilities that cross Gulf of Mexico Drive within the Town so that the Town can avail itself of such opportunities to have such facilities converted to underground service, pursuant to FPL's applicable tariffs and Florida PSC rules. Conversely, we would ask that the Town notify FPL within a reasonable period if it becomes aware of a construction project or other circumstance that may include or require the relocation or replacement of overhead distribution facilities that cross Gulf of Mexico Drive. The foregoing notice provisions shall not apply in emergencies, *e.g.*, installing facilities to restore service following damage to FPL's system due to a hurricane, tropical storm, tornado, or other weather event or other event necessitating the emergency restoration of service by FPL.

(2) FPL acknowledges and agrees that the Town may apply to FPL for approval to attach telecommunications and cable devices to FPL's poles. All FPL authorized pole attachments will be made on a non-discriminatory basis and in compliance with all applicable federal, state, and local laws, rules, codes, and regulations. FPL's commitment in this paragraph (2) shall apply and continue throughout the term of the Franchise without regard to whether there is any legal mandate that FPL do so. Any pole attachments, if authorized, will be made by a separate agreement between FPL and the Town.

These commitments represent FPL's binding commitments with respect to the subjects of the foregoing paragraphs.

FPL sincerely appreciates the opportunity to serve the Town of Longboat Key and has enjoyed the ongoing cooperative relationship with the Town. We look forward to a continuing cooperative effort in the future.

Sincerely,

Rae Dowling
External Affairs Manager

ORDINANCE NO. 05-2011

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CAPE CANAVERAL, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY; PROVIDING FOR THE REPEAL OF PRIOR INCONSISTENT ORDINANCES AND RESOLUTIONS, PROVIDING FOR QUALIFIED SEVERABILITY, PROVIDING FOR INCORPORATION INTO APPENDIX "A" OF THE CITY CODE, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Council is granted the authority, under Section 2(b), Article VIII, of the State Constitution, to exercise power for municipal purposes, except when expressly prohibited by law; and

WHEREAS, Section 166.021(1) provides that municipalities shall have the governmental, corporate, and proprietary powers to enable them to conduct municipal government, perform municipal functions, and render municipal services, and may exercise any power for municipal purposes except when expressly prohibited by law; and

WHEREAS, the City Council of the City of Cape Canaveral, Florida recognizes that the City of Cape Canaveral and its citizens need and desire the continued benefits of electric service; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, on December 15, 1981, the City Council granted a 30 year franchise to Florida Power & Light Company (FPL) for the purpose of supplying electricity to the City and for the other purposes stated therein; and nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain, in accordance with the National Electrical Safety Code to the extent applicable, in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, publicly dedicated rights-of-way, applicable publicly dedicated utility easements and other public places (hereinafter called "public rights-of-way") in the City of Cape Canaveral, Florida, and its successors (hereinafter called the "Grantor") throughout all of Grantor's incorporated areas, as such incorporated areas may be constituted from time to time, in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other directly electric-related services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof. This grant is intended to provide a franchise to Grantee for the provision of electric and directly electric-related services, and is not intended to be a grant or franchise for the placement or construction of gas lines or appurtenances thereto, or for fiber optics or appurtenances thereto.

Section 2. Facilities Requirements.

(a) The facilities of Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by Grantee or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to its original condition before such damage by the Grantee at Grantee's expense.

(e) If Grantor requires the removal or relocation of Grantee's facilities because the facilities interfere with the standards set forth in subsection (a) above, and Grantee fails to remove or relocate such facilities at Grantee's expense within thirty (30) days after written notice from Grantor, then Grantor may proceed to cause the facilities to be removed or relocated and the expense therefore shall be charged against the Grantee.

(f) The Grantor shall not be liable to the Grantee for any cost or expense incurred in connection with the relocation of any of the Grantee's facilities required under this Section, except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

Section 3. Indemnification. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee, to indemnify Grantor, its officers, agents, attorneys, servants, employees, or contractors and hold it harmless against any and all liability, loss, costs, injuries (including death), damages, attorneys' fees, or expense, which may accrue to, or be incurred by or charged against Grantor or any of its officers, agents, attorneys, servants, employees, or contractors by reason of commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 6.0 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 25-81, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

Section 6. Most Favored Nations. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Brevard County, Florida, or within any contiguous county of Brevard County where the number of Grantee's active electrical customers is equal to or less than the number of Grantee's active electrical customers within the incorporated area of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5 hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may proceed with the other person's offered sale and purchase arrangement and all of the terms and conditions of this franchise shall remain in effect except as provided herein.

Section 8. Competitive Disadvantage; Termination by Grantee. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Notwithstanding the foregoing, upon written request of the Grantor within the 150 day notice period for a face to face meeting between representatives of the Grantor and Grantee, Grantee agrees that it shall meet in good faith with Grantor prior to terminating the franchise. Nothing contained herein shall be construed as constraining Grantor's right to legally challenge Grantee's reasonable determination of competitive disadvantage leading to termination pursuant to Section 8 and/or 9 herein.

Section 10. Default by Grantee. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a material respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Grantor may, upon reasonable notice given within one (1) year following the Grantee's acceptance of the New Franchise Agreement, conduct a final audit of the Grantee's records relating to the calculation of the franchise payments that have been made to Grantor pursuant to the Current Franchise Agreement embodied in Ordinance No. 25-81. Other than any claims arising from alleged fraud, deceit, misrepresentation, intentional withholding of information, or other similar intentional misconduct by Grantee in relation to the calculation or remittance of the franchise payments under the Current Franchise Agreement, Grantor waives, settles, and bars all claims relating to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 25-81.

Section 13. Renewable Energy.

(a) Grantor and Grantee recognize that it is in the best interests of the City, its residents, businesses and inhabitants thereof to reduce and control the growth rates of electric consumption; to reduce the growth rates of weather-sensitive peak demand; to increase the overall efficiency and cost-effectiveness of electricity production and use and to encourage further development of demand-side renewable energy systems. To that end Grantor and Grantee agree to use their best efforts to cooperatively work each with the other to promote incentives for customer-owned and utility owned- energy efficiency and demand-side renewable energy intended to offset all or part of a customer's electricity requirements. Nothing contained in this franchise shall be construed as prohibiting or impeding the residents, businesses, and inhabitants within the incorporated area of the City from installing and using renewable energy systems provided the renewable energy systems referred to are otherwise permitted by Florida law.

FPSC or regulatory approval, Grantee shall implement its infrastructure hardening plan within the Grantor's boundaries.

Section 17. Preferential or Discriminatory Practices Prohibited. All services rendered and all rules and regulations adopted by the Grantee shall have general application to all persons and shall not subject any person to prejudice or disadvantage on account of race, gender, religion, origin, physical condition or ethnicity. No otherwise qualified person shall, solely by reason of his or her race, gender, religion, origin, physical condition or ethnicity, be excluded from participation in, be denied services, or be subject to discrimination under any provision of this franchise.

Section 18. No Joint Venture. Nothing herein shall be deemed to create a joint venture or principal-agent relationship between the parties, and neither party is authorized to, nor shall either party act toward third persons or the public in any manner which would indicate any such relationship with the other.

Section 19. Notices. All notices from the Grantee to the Grantor pursuant to this ordinance shall be sent to: City Manager, City of Cape Canaveral, 105 Polk Avenue, or such other address where City Hall may be located in the City of Cape Canaveral, Florida, 32920. All notices from the Grantor to the Grantee pursuant to this ordinance shall be sent to: Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, or such other address where Grantee's corporate office may be located, marked: Attention: External Affairs.

Section 20. Captions. Captions to sections throughout this ordinance are solely to facilitate the reading and reference to the sections and provisions of the ordinance. Such captions shall not affect the meaning or interpretation of the ordinance.

Section 24. Qualified Severability. If any clause, section, provision or other part of this ordinance or any portion thereof shall be held invalid or unconstitutional by a court of competent jurisdiction, then said holding in no way affects the validity of the remaining portions of this ordinance. Notwithstanding the foregoing, it is expressly provided that if any of the provisions or Sections of this ordinance are held invalid or unconstitutional, the parties shall attempt in good faith to negotiate a new lawful agreement that restores the fundamental terms of the original agreement. In the event the parties are unable to reach a new lawful agreement, the ordinance shall be null and void and of no force and effect.

Section 25. Definition of "Person". As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 26. Repeal of Prior Inconsistent Ordinance, Resolutions and Agreements. Ordinance No. 25-81, passed and adopted December 15, 1981, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 27. Incorporation Into Code. This Ordinance shall be incorporated into "Appendix A" of the Cape Canaveral City Code and any section or paragraph, number or letter, and any heading may be changed or modified as necessary to effectuate the foregoing. Grammatical, typographical, and like errors may be corrected and additions, alterations, and omissions, not affecting the construction or meaning of this ordinance and the City Code may be freely made.

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 05-2011
BY FLORIDA POWER & LIGHT COMPANY

City of Cape Canaveral, Florida — September 1, 2011

Florida Power & Light Company does hereby accept the electric franchise in the City of Cape Canaveral, Florida, granted by Ordinance No. 05-2011, being:

> AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CAPE CANAVERAL, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY; PROVIDING FOR THE REPEAL OF PRIOR INCONSISTENT ORDINANCES AND RESOLUTIONS, PROVIDING FOR QUALIFIED SEVERABILITY, PROVIDING FOR INCORPORATION INTO APPENDIX "A" OF THE CITY CODE, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on August 16, 2011.

This instrument is filed with the City Clerk of the City of Cape Canaveral Florida, in accordance with the provisions of Section 28 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela Rauch
Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 24th day of August, 2011 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.

HEATHER P. MELIGONIS
MY COMMISSION # DD 937635
EXPIRES. December 6, 2013
Bonded Thru Notary Public Underwriters

Heather P. Meligonis
NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 05-2011by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of Cape Canaveral, Florida on this 1 day of September, 2011.

Angela M. Apperson
City Clerk, City of Cape Canaveral, Florida

(SEAL)

projects premised upon the use of green energy, conservation, sustainability and the use of renewable energy.

(6) FPL agrees to use reasonable efforts to coordinate FPL activities with any City sidewalk projects and in accordance with applicable laws and regulations. FPL will use reasonable efforts to avoid constructing new poles within sidewalk areas, bicycle paths, or in any other place where such poles might interfere with pedestrian or bicycle traffic.

(7) FPL will use reasonable efforts to avoid the placement of electric facilities in public places other than public rights-of-way where practical and feasible alternatives exist. FPL recognizes the sensitivity of the City of Cape Canaveral to electric facilities being installed in public places other than public rights-of-way. Additionally, FPL will use reasonable efforts to accommodate the City of Cape Canaveral's concerns related to electric facility installation, operation and maintenance in public places other than public rights-of-way. Upon request by the City of Cape Canaveral, FPL will meet with the City to address specific concerns of the City. FPL agrees that it will not install electric facilities over or under any community center, police station, fire station, any existing or future city hall complex, or structures located within any city park. Additionally, FPL will use reasonable efforts to avoid installing electric facilities upon city-owned waterfront property and city-owned cemeteries (if any).

(8) FPL will not assert in any dispute with the City of Cape Canaveral, or in any legal or regulatory proceeding to which the City of Cape Canaveral and FPL are parties, that the terms of the franchise, with respect to substation siting and construction, prevail over state statutes or state regulations pertaining to substation siting and construction, including specifically Florida Statute Section 163.3208.

FPL has enjoyed an ongoing cooperative relationship with the City of Cape Canaveral and we look forward to a continuing cooperative effort in the future.

Sincerely,

Leonard G. Sanderson, Jr.

Accepted by:

Angela M. Apperson
City Clerk

cc: Anthony A. Garganese, Esq.
Kenneth M. Rubin, Esq.

CERTIFICATION

I certify this to be a true and correct copy of the record of the City of Fort Lauderdale, Florida.

WITNESSETH my hand and official seal of the City of Fort Lauderdale, Florida, this the 23 day of October 20 09

City Clerk

Sp. Asst

ORDINANCE NO. C-09-26

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, A NONEXCLUSIVE ELECTRIC FRANCHISE, PROVIDING FOR MONTHLY FRANCHISE FEE PAYMENTS TO THE CITY; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, INCLUDING PROVISIONS FOR INDEMNIFICATION; MAINTENANCE OF BOOKS AND RECORDS AND THE RIGHT TO AUDIT SAME; MOST FAVORED NATIONS CLAUSE PROTECTING THE CITY; IMPOSITION OF RESTRICTIONS ON CITY COMPETING BY SELLING ELECTRICITY; AUTHORITY OF CITY TO GENERATE ELECTRICITY TO TRANSMIT BETWEEN CITY FACILITIES; PROVISIONS RESPECTING FORFEITURE OF THE FRANCHISE; GRANTING TO CITY THE OPTION TO PURCHASE FACILITIES AT THE END OF THE TERM; AND PROVIDING AN EFFECTIVE DATE.

Be it Ordained by the City Commission of the City of Fort Lauderdale, Florida:

WHEREAS, the City Commission of the City of Fort Lauderdale, Florida recognizes that the City of Fort Lauderdale and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Fort Lauderdale does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, the City of Fort Lauderdale is vested with jurisdiction, authority and control of certain public rights-of-way within its corporate boundaries based upon functional classifications under the Florida Transportation Code and is responsible for management of such public rights-of-way and balancing the competing needs for use of its public rights-of-way with regard to, among other matters, installing, constructing, placing, maintaining, operating and relocating, from time to time, over, across, under, above and within any public right-of-way any aerial or underground electric generating and transmission facilities, telephone transmission facilities, telegraph transmission facilities, electronic date transmission facilities, communication

SECTION 1. Grant of Electric Utility Franchise; Term of Franchise. That there is hereby granted to Florida Power & Light Company, its successors and assigns, (herein called the "Grantee") for a period of thirty (30) years from the date of acceptance hereof by Grantee, the nonexclusive right, privilege, or franchise to construct, install, locate, relocate, maintain, and operate in accordance with the National Electrical Safety Code to the extent applicable, in, under, upon, over, and across the present and future streets, alleys, bridges, publicly dedicated rights-of-way that have been classified as "city streets" under the Florida Transportation Code and publicly dedicated utility easements, but not including easements granted to Grantee (hereinafter called "public rights-of-way") in the City of Fort Lauderdale, Florida, (herein called the "Grantor") and its successors and assigns, throughout all of Grantor's incorporated areas, as such incorporated areas may be constituted from time to time~~,~~ and subject to any applicable federal, state and local laws, statutes, ordinances, rules and regulations, including Grantor's valid regulation of public rights of way with respect to electrical construction, installation, location, relocation and maintenance, of electric light and power facilities (including conduits, poles, wires, transmission and distribution lines, and appurtenances incidental thereto) installed in conjunction with and ancillary to Grantee's electrical generating, transmission and distribution operations and, for Grantee's own facility-to-facility use, telephone, telegraph and telecommunication lines and facilities) (hereinafter called. "facilities") for the purpose of supplying electricity to Grantor, and its successors, and inhabitants thereof, and persons beyond the limits thereof ("2009 Electric Utility Franchise").

SECTION 2. Condition Precedent; Acceptance by Grantee. As a condition precedent to the taking effect of this Grant, Grantee shall have filed its acceptance hereof with the Grantor's clerk within thirty (30) days of the date this ordinance is adopted on second reading.

SECTION 3. Facilities Requirements.

(a) That the facilities of Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the Grantor may prescribe in accordance with all applicable federal, state and local statutes, laws, ordinances, rules and regulations and pursuant to Grantor's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

SECTION 4. Indemnification of Grantor. Acceptance of this ordinance by Grantee shall be deemed an agreement on the part of Grantee to indemnify Grantor, its officers, agents, servants, employees, or contractors and hold it harmless against any and all liability, loss, costs, damages, attorneys' fees, or expense which may accrue to or be incurred by or charged or sought against Grantor or any of its officers, agents, servants, employees or contractors by reason of installation, location, relocation, construction, reconstruction, operating, maintenance or repair of Grantee's facilities or acts or omissions of negligence, gross negligence or intentional torts, default or misconduct of the Grantee, its officers, directors, agents, servants, employees, contractors or subcontractors. The indemnity hereunder includes not only the reasonable costs, expenses and attorneys' fees incurred by the Grantor in defense of any third party's claim (prior to and during all phases of litigation, including trial and post trial and appellate proceedings) and also includes the reasonable costs, expenses and attorneys' fees incurred by the Grantor in the event it must enforce the terms of this indemnity prior to and during all litigation including trial, post trial and appellate proceedings. This indemnity shall survive termination of this franchise.

SECTION 5. Rates, Rules and Regulations of Grantee. That all rates and rules and regulations established by Grantee from time to time shall at all times be reasonable, subject to and not in conflict with such rules and regulations as may be provided by law.

SECTION 6. Franchise Fee; Calculation; Payment.

(a) As a consideration for the nonexclusive right to use the Grantor's public rights-of-way under this 2009 Electric Utility Franchise, the Grantor's agreement to not compete with the Grantee as set forth in Section 9 hereof, and other valuable consideration all as set forth herein, the Grantee shall pay to the Grantor a franchise fee, commencing ninety (90) days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem tax and non-ad valorem assessments on property) levied or imposed by the Grantor against Grantee's property, business or operations during the Grantee's monthly billing period ending sixty (60) days prior to each such payment will equal 6.0 percent of the Grantee's billed revenues including fuel charges, less actual write-offs from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff within the incorporated areas of the Grantor ("Retail Customers") for the monthly billing period ending sixty (60) days prior to each such payment, and in no event shall payment for the rights and privileges granted herein calculating the franchise fee. Such examination of books and records of Grantee by Grantor shall be made during the regular business hours of the Grantee at the general office of the Grantee. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit. Records shall be retained by Grantee for a period of five (5) years. The provisions of this Section 7 shall survive termination of this franchise.

__SECTION 8__. __Most Favored Nations__. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Broward or Miami-Dade County, Florida, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's revenues for all Retail Customers, under the same terms and conditions as specified in Section 6 hereof, then the Grantee, upon written request of the Grantor, shall enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 6, utilizing the same terms and conditions as set forth in Section 6 hereof shall be that greater rate provided for such other municipality within Broward or Miami-Dade County; provided, however, that if the franchise with such other municipality within Broward or Miami-Dade County contains additional benefits given to Grantee in exchange for the increased franchise rate, which such additional benefits are not contained in this 2009 Electric Utility Franchise, such new franchise agreement shall include those additional benefits to the Grantee.

__SECTION 9__. __Non-Competition by Grantor__.

(a) As a further consideration during the term of this franchise, Grantor agrees not to engage in the business of distributing and/or sale, in competition with Grantee, of electric capacity and/or electric energy to any Retail Customer of electric utility service or to any electrical distribution system established solely to serve any Retail Customer formerly served by the Grantee. Grantor further agrees not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) other than governmental bodies, to any other Retail Customer's facility(ies). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to the franchise fee, place it at a material competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such material competitive disadvantage is, in the reasonable determination of Grantee, not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the material competitive disadvantage and the objective basis or bases of the material competitive disadvantage. The Grantor shall then have 120 days in which to correct or otherwise remedy the material competitive disadvantage. If such material competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time FPL's determination of material competitive disadvantage leading to termination under this Section 11 and/or 14.

SECTION 12. **Default by Grantee; Forfeiture.** That failure on the part of the Grantee to comply in any material respect with any of the provisions of this ordinance, shall be grounds for a forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that Grantee has failed to comply in a material respect with any of the provisions of this franchise, and the Grantee shall have six (6) months after the final determination of the question, to make good the default before a forfeiture shall result with the right in Grantor at its discretion to grant such additional time to Grantee for compliance as necessitates in the case require.

SECTION 13. **Default by Grantor.** Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to:

(i) denying the Grantee use of public rights-of-way for reasons other than as set forth in Section 3;

Recovery of Undergrounding Fees (MGRUF), along with other undergrounding tariffs. Requests made by Grantor for undergrounding shall be implemented by Grantee with the applicable tariffs in effect on the date of Grantor's request.

SECTION 17. Renewable Energy.

(a) The parties recognize that it is in the best interests of the City of Fort Lauderdale, its residents, businesses and inhabitants thereof to reduce and control the growth rates of electric consumption; to reduce the growth rates of weather-sensitive peak demand; to increase the overall efficiency and cost-effectiveness of electricity production and use and to encourage further development of demand-side renewable energy systems. To that end Grantor and Grantee agree to use their best efforts to cooperatively work each with the other to promote incentives for customer-owned and utility-owned energy efficiency and demand-side renewable energy intended to offset all or part of a customer's electricity requirements.

(b) Grantor may, if permitted by law, (i) generate electric capacity and/or energy at any facility owned by the Grantor for storage or utilization at that facility or other Grantor facilities, operations or equipment; (ii) use renewable energy sources to generate electric capacity and/or energy for use in demonstration projects or at Grantor's facilities, operations or its equipment; and (iii) sell electric capacity and/or energy to Grantee or other wholesale purchaser in compliance with applicable rules and regulations controlling such transactions.

SECTION 18. Smart Grid Technology. Grantee acknowledges that Grantor's policies strongly favor the widespread dissemination of meters featuring "smart grid technology" which utilize an interactive monitoring network capable of providing real time electrical energy usage information to both Grantee and Grantee's Retail Customers via an advanced, two-way communication device. If this technology is implemented by Grantee, Grantee shall utilize its best practicable efforts to provide Retail Customers located in the incorporated area of Grantor receipt of such technology.

SECTION 19. Infrastructure Hardening. Grantee understands and acknowledges that Grantor's policies strongly favor strengthening electric utility infrastructure. Grantee has filed and received Florida Public Service Commission (FPSC) approval for a plan which includes strengthening feeders delivering power to critical infrastructure facilities, including feeders located within the Grantor's boundaries. Subject to continued FPSC or regulatory approval, Grantee will implement its infrastructure hardening plan within the Grantor's boundaries.

ORDINANCE NO. 2008-15

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF ST. AUGUSTINE, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of St. Augustine, Florida recognizes that the City of St. Augustine and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of St Augustine does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City of St. Augustine and FPL, the terms of which are set forth in City of St. Augustine Ordinance No. 79-21, passed and adopted June 25, 1979, and FPL's written acceptance thereof dated June 27, 1979 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the City of St. Augustine desire to enter into a new agreement (New Franchise Agreement) providing for the payment of fees to the City of St. Augustine in exchange for the nonexclusive right and privilege of supplying electricity and

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of shall payment for the rights and privileges granted herein exceed 5.9 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 79-21, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 60 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have 60 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. The Grantor may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Grantor waives, settles and bars all claims relating in any way to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 79-21.

Section 12. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

RECEIVED

JUL 2 3 2008

CITY CLERK

The St. Augustine Record

~~COPY OF AD~~VERTISEMENT

PUBLISHED EVERY MORNING SUNDAY THROUGH SATURDAY
ST AUGUSTINE AND ST JOHNS COUNTY, FLORIDA

STATE OF FLORIDA,
COUNTY OF ST. JOHNS

Before the undersigned authority personally appeared **KAREN J BRANNON**

who on oath says that she is an Employee of the St. Augustine Record,

a daily newspaper published at St. Augustine in St. Johns County, Florida:

that the attached copy of advertisement, being a **NOTICE OF HEARING**

In/ the matter of **ORDINANCE #2008-15**

was published in said newspaper **JULY 17, 2008.**

Affiant further says that the St. Augustine Record is a newspaper published at St. Augustine, in said St. Johns County, Florida, and that the said newspaper heretofore been continuously published in said St. Johns County, Florida, each day and has been entered as second class mail matter at the post office in the City of St. Augustine, in said St. Johns County, for a period of one year preceding the first publication of the copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing the advertisement for publication in the said newspaper.

Sworn to and subscribed before me this **17th day of JULY 2008.**

by Karen J Brannon who is personally known to me
or who has produced **PERSONALLY KNOWN** as identification.

Patricia A Bergquist

(Signature of Notary Public)
PATRICIA A BERGQUIST

Notary Public State of Florida
Patricia A Bergquist
My Commission DD732015
Expires 12/18/2011

(Seal)

**NOTICE OF PROPOSED ENACTME
OF ORDINANCE 2008-15 BY THE
CITY OF ST. AUGUSTINE, FLORID**

NOTICE IS HEREBY GIVEN O
PUBLIC HEARING TO BE HELD
THE CITY COMMISSION OF THE C
OF ST. AUGUSTINE CONCERNING
SECOND READING OF ORDINA
2008-15 THE PUBLIC HEARING WILL BE HE
ON JULY 28, 2008, BEGINNING AT 5:00 P.M.,
THE ALCAZAR ROOM, 1ST FLOOR, WEST WI
CITY HALL, 75 KING STREET, ST. AUGUSTI
PUBLIC COMMENTS ARE INVITED ON T
FOLLOWING MATTER.

ORDINANCE NO. 2008-15

AN ORDINANCE GRANTING TO FLORIDA POV
& LIGHT COMPANY, ITS SUCCESSORS A
ASSIGNS, AN ELECTRIC FRANCHISE, IMP
ING PROVISIONS AND CONDITIONS RELAT
THERETO, PROVIDING FOR MONTHLY P
MENTS TO THE CITY OF ST. AUGUSTINE, A
PROVIDING FOR AN EFFECTIVE DATE.

Related documents may be inspected by the publ
the office of the City Clerk, City Hall, Lobby B,
ond floor, 75 King Street, St. Augustine, FL 32
during the hours of 8:00 A.M. and 5:00 P.M. ex
weekends and holidays.

All interested parties may appear at the meeting
be heard with respect to the proposed ordinance

In accordance with Florida Statute 286.0105; "If
person decides to appeal any decision made by
City Commission with respect to any matter co
ered at this scheduled meeting or hearing, the
son will need a record of the proceedings, and
such purpose the person may need to ensure th
verbatim record of the proceedings is made, w
record includes the testimony and evidence u
which the appeal is to be based."

In accordance with the Americans with Disabil
Act, persons needing a special accommodatio
participate in this proceeding should contac
individual or agency sending notice not later
seven days prior to the proceeding at the add
given on notice. Telephone: Karen Rogers, C
City Clerk (904)825-1007; or 1-800 955-8771 (TDD
1-800-955-8770 (V), via Florida Relay Service.

Karen Rogers,
City C
L2012-8 July 17,

00097
0001149

CITY OF ST. AUGUSTINE
COUNTY OF ST. JOHNS
STATE OF FLORIDA

I, Karen Rogers, City Clerk, City of St. Augustine, Florida, do hereby certify that the attached copy of the proof of publishing from the St. Augustine Record for Ordinance 2008-15, granting Florida Power and Light Company, its successors and assigns, an electric franchise imposing provision and conditions relating to provisions for monthly payments to the City of St. Augustine, contains a full, true and correct copy as the same appears of Record and on file in my office, City of St. Augustine, 2nd Floor, S.E., Elevator B, City Hall, 75 King Street.

CORPORATION OF THE CITY OF ST. AUGUSTINE

IN WITNESS WHEREOF, I have hereto set my hand and affixed the corporate seal of the City of St. Augustine, Florida, this 19th day of February, 2009.

Karen Rogers, CMC, City Clerk

FPL FRANCHISE AGREEMENT ORDINANCE 13169
ADOPTED 5/13/10

..Title
AN ORDINANCE OF THE MIAMI CITY COMMISSION GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF MIAMI DURING A TERM OF 30 YEARS; CONTAINING A SEVERABILITY CLAUSE, AND PROVIDING FOR AN EFFECTIVE DATE.

..Body

WHEREAS, the City Commission of the City of Miami Florida, a Florida municipal corporation (hereunder "Grantor" or "City"), recognizes that the City of Miami and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Miami does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company (hereinafter "Grantee" or "FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City of Miami and FPL, the terms of which are set forth in City of Miami Ordinance No. 9472, passed and adopted September 9, 1982, and FPL's written acceptance thereof dated October 7, 1982 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the City of Miami desire to enter into a new agreement (New Franchise Agreement) providing for the payment of fees to the City of Miami in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City of Miami free of competition from the City of Miami, pursuant to certain terms and conditions; and

WHEREAS, the City Commission of the City of Miami deems it to be in the best interest of the City of Miami and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement;

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COMMISSION OF THE CITY OF MIAMI, FLORIDA:

Each "WHEREAS" clause set forth above is true and correct and herein incorporated in this Ordinance by this reference.

DEFINITIONS

As used in this New Franchise Agreement, the following words and terms shall have the following meanings:

City shall mean the City of Miami, Florida, a municipal corporation organized and existing under the laws of the State of Florida and also the Grantor for purposes of this Franchise.

City Commission shall mean the local legislative body of the City of Miami. The City Commission is the body that approves City Franchises.

File # 10-00179

customers, (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with Traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible and practicable. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others, excluding the City of Miami, and as is provided by law.

Section 3. Indemnification of Grantor. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, regardless of other easement agreements that may be or have been executed by the parties to this Franchise without hold harmless and indemnification provisions, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify and defend the Grantor and hold the Grantor, its officials, employees and assigns, harmless against any and all liability, loss, cost, damage, judgment, decree, action, cause of action, claim, or expense which may accrue to the Grantor by reason of the negligence, default, omission, or misconduct of the Grantee in the installation, removal, relocation, sub-lease, construction, operation or maintenance of its Facilities.

Section 4. Rates, Rules and Regulations of Grantee. All rates and rules and regulations established by the Grantee from time to time shall be subject to regulation as may be provided by law.

Section 5(a). Franchise Fee; Calculation; Payment. As a consideration for this Franchise, the Grantee shall pay to the Grantor the following amounts: (a) commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this Franchise, the Grantee shall pay an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever, except ad valorem property taxes and non-ad valorem tax assessments on property, levied or imposed by the Grantor against the Grantee's property, business, facilities, or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal six (6%) percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment and in no event shall payments for the rights and privileges granted herein exceed six (6%) percent of such revenues for any monthly billing period of Grantee. For purposes of this section, the term "write-offs" refers to uncollectable billed revenues from the sale of electrical energy to residential, commercial, and industrial customers within the incorporated areas of Grantor. For the term of this franchise, Grantor waives construction permit fees for facilities which otherwise would be imposed on Grantee by the Grantor.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment

Section 7. Competitive Disadvantage; Grantee's Rights. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee reasonably determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section 7.

Section 8. Legislative or Regulatory Action. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section 8.

Section 9. Grantee's Failure to Comply. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee, until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction within Miami-Dade County, Florida that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require. Venue in any proceedings involving a civil action or actions between the parties under the terms of this Franchise shall be with courts of competent jurisdiction located within Miami-Dade County, Florida.

Section 10. Grantor's Failure to Comply. Failure on the part of the Grantor to comply in substantial

Section 14. Previous Franchise. Ordinance No. 9472 passed and adopted September 9, 1982 is hereby repealed, and all ordinances and parts of ordinances in conflict herewith are hereby superseded to the extent of any such conflict.

Section 15. Effective Date. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.{1}

Section 16. Notice. For the present, the parties designate the following as the respective places for giving of notice, to-wit:

CITY OF MIAMI GRANTOR
c/o City Manager
3500 Pan American Drive
Miami, Florida, 33133

FPL GRANTEE
c/o Vice-President
External Affairs
700 Universe Blvd.
Juno Beach, FL 33408

Section 17. Compliance with Federal, State and Local Laws. FPL understands that agreements between private entities and local governments are subject to certain laws and regulations, including laws pertaining to public records, conflict of interest, and recordkeeping. City and FPL agrees to comply with and observe all applicable Federal, State and local laws, rules, regulations, Codes and Ordinances, as they may be amended from time to time.

Section 18. Nondiscrimination. FPL represents and warrants to the City that FPL does not and will not engage in discriminatory practices and that there shall be no discrimination in connection with FPL's performance under this Franchise on account of race, color, sex, religion, age, handicap, marital status or national origin. FPL further covenants that no otherwise qualified individual shall, solely by reason of his/her race, color, sex, religion, age, handicap, marital status or national origin, be excluded from participation in, be denied services, or be subject to discrimination under any provision of this Franchise.

Section 19. Governing laws. This Agreement shall be governed by applicable laws of the Federal Government, State of Florida, Miami-Dade County and the Codes and Ordinances of the City of Miami.
Section 20. No Rights to City's Employment Benefits. Grantee shall not attain, nor be entitled to, any rights or benefits under the Civil Service or Pension Ordinances of the Grantor, nor any rights generally afforded classified or unclassified employees. Grantee further understands that Florida Workers' Compensation benefits available to employees of the Grantor are not available to Grantee's employees or agents.

Section 21. Entire Agreement. This Franchise Agreement and its attachments constitute the sole and only AGREEMENT of the parties relating to the subject matter hereof and correctly sets forth the rights, duties, and obligations of each of the other as of its date. Any prior Agreements, promises, negotiations, or representations not expressly set forth in this Agreement are of no force or effect. Both parties were represented by counsel with regard to this Agreement.

Section 22. Modification. It is further understood that no modification, amendment or alteration in the

FEED IN TARIFF SOLAR ENERGY PURCHASE AGREEMENT

Seller Name: ______________________________________

Seller Address. ______________________________________

____

____

Facility Location ______________________________________

____

____

____

This Solar Energy Purchase Agreement ("SEPA" or "Agreement") is made by and between ______________________________ ("**Seller**") and the City of Gainesville, Florida, a municipal corporation d/b/a Gainesville Regional Utilities ("**Buyer**") with its principal place of business at 301 SE 4th Ave, Gainesville, FL Seller and Buyer may hereinafter be referred to individually as "Party" and collectively as "Parties"

WHEREAS, Buyer seeks to purchase solar electric energy together with the "Environmental Attributes" (which term is defined herein below in Paragraph 2 1) associated with it, and

WHEREAS, Seller seeks to develop, design, construct, own and operate a solar electric *generating facility with an expected combined nameplate capacity of approximately*

_______ **Kilowatts (direct current rating –DC)**

which is further described hereinafter below as "Facility" or "Facilities", and

WHEREAS, the scale and design of the Facility or Facilities is accommodated by the Buyer's current criteria and policies for interconnection and purchase of solar power by means of a "Feed In Tariff" as defined and legislated by City of Gainesville in Appendix A of Section 27, City of Gainesville's Code of Ordinances, and

WHEREAS, Seller seeks to sell 100% of the net output of the Facilities as alternating current (AC) electricity at standard voltage and frequency, further defined below as Solar Energy, to Buyer, and Buyer has accepted Seller's offer in accordance with the terms and conditions set forth in this SEPA, and

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following

ARTICLE 1 – DEFINITION OF MILESTONES

1.1 "Completion Date" is October 31, 2013 for roof mounted and December 31, 2013 for ground mounted

1.2 "Termination Date" is December 31, 2033

ARTICLE 2 – DEFINITIONS

2.1 **"Environmental Attributes"** means any and all regulatory credit or market value accrued as the result of generating solar energy, including but not limited to renewable energy credits (RECs), carbon offsets, SO2 and NOx emission offsets, and any other environmental benefits, reductions, offsets, allowances, certificates, or green tags resulting from the generation of Solar Energy or the avoidance of the emissions of any gas, chemical or other substance to the air attributable to the electricity generated by the Facility (defined below). For the avoidance of doubt, "Environmental Attributes" exclude (i) any local, state or federal production or investment tax credit, depreciation deductions or other tax consideration providing a tax benefit based on ownership or a security interest in the Facility, or energy production from any portion of the Facility, including any investment tax credit expected to be available to Seller with respect to the Facility, including but not limited to any tax credit available under United States Code Title 26, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart E, Section 48 (*Energy Credits*), as amended; and (ii) depreciation deductions and benefits, and other tax benefits arising from ownership or operation of the Facility unrelated to its status as a generator of renewable or environmentally clean energy.

2.2 **"Facility" or "Facilities"** means Seller's solar electric generating equipment which produces solar energy subject to this SEPA, each of which delivers such electricity to the Buyer at a single Point of Interconnection (defined below) Each Facility will include equipment or other tangible assets necessary for the operation and maintenance of the Facility, including but not limited to solar modules, mounting systems, wiring harnesses, conduits, inverters, transformers, breakers, lightning protection, and grounding apparatus, together with any easements or leases Seller needs for the construction operation and maintenance of the Facility and the delivery of Solar Energy to the Point of Interconnection Any Facility covered by this SEPA will be owned by Seller and will be operated and maintained by Seller at Seller's sole cost and expense, for Seller's benefit as legal and beneficial owner of the Facility.

2.3 **"Interconnection Agreement"** is defined as the agreements between the Buyer and Seller setting forth the terms and conditions under which Seller's Facilities are Interconnected with the Buyer's, as attached here as Attachment A to the SEPA, which by this reference is incorporated herein

2.4 **"Point of Interconnection"** is defined as the point at which the ownership of electric facilities and/or equipment transitions from Buyer to Seller.

2.5 **"Solar Energy"** means the energy produced by the Facility from the conversion of sunlight to electricity The devices that perform this conversion produce direct current (DC) voltage which then must be transformed to alternating current (AC) synchronized to the Buyer's frequency and voltage at the Point of Interconnection Revenue metering and payment is based on AC kilowatt-hours System capacity is measured in DC watts.

ARTICLE 3 – GENERAL PROVISIONS

3.1 **Disclaimer.** Should any section in this SEPA be in conflict with The City of Gainesville's Code of Ordinances, the Code of Ordinances shall prevail

3.2 **Applicability.** This SEPA shall only apply to Facilities approved pursuant to Attachment A that are to be installed by Seller at the aforementioned "Facilities Address" for the express purpose of selling 100% of the net Solar Energy output of the Facility to the Buyer. Attachment A describes the approved Facilities covered under this SEPA

3.3 **Interconnection Requirements.** Notwithstanding any other provision of this SEPA, Buyer shall have no obligation to purchase Solar Energy from any Facility until and unless Seller is in compliance with the approved interconnection requirements for the Facility If any conflict arises between any portion of this SEPA and the requirements of Attachment A, Attachment A shall take precedence Disconnection of any Facility from the Buyer's electric system for any contractual, operational or safety reason, shall not obligate the Buyer to replace any revenues thus lost by the Seller

3.4 **Metering.** Seller shall, at Seller's sole cost and expense, provide and install the meter socket approved by the Buyer. Except as provided under Section 4 2 of Attachment A, the Buyer shall provide a revenue meter to be read by the Buyer at approximately monthly intervals for determination of payment due to Seller Seller will incur a monthly service administrative charge as imposed by the City of Gainesville in Appendix A of Section 27, City of Gainesville Code of Ordinances, and the charge will be deducted from Seller's monthly payment received from Buyer for kilowatt-hours ("kWh") of solar energy that are produced and delivered to the revenue meter at point of interconnection Any request by Seller to test the metering accuracy shall be conducted at Seller's cost pursuant to Buyer's prevailing rates, practices and policies for testing retail revenue meters

3.5 **No Electric Supply to the Facility.** The Parties recognize that this SEPA does not provide for the supply of any electric service by Buyer to Seller or to Seller's Facility, and Seller must enter into separate arrangements for the supply of electric services to the Facility Should the Facility need any electric service, Buyer will identify a connection point and Seller shall make the appropriate connection arrangements and shall pay Buyer for power consumed and customer service charges in accordance with the prevailing applicable retail electric rates in Appendix A, City of Gainesville Code of Ordinances

3.6 **Facility Operation.** Seller shall provide staff to control and operate each Facility in a manner consistent at all times with Attachment A Personnel employed by Seller capable of starting, operating and stopping the Facilities shall be reachable by telephone, cell phone, or pager at all times

3.7 **Information Requirement.** Seller shall provide documentation signed by system provider of final total installed cost and installed capacity of the Facility covered by this agreement before any payments for energy are made by the Buyer

3.8 **Conflict with Business Partners Rate Discount Agreement.** Buyer waives the prohibition contained in any Business Partners Rate Discount Agreement between Seller and Buyer that prohibits Seller from utilizing self-generated electricity This waiver shall survive the termination of this Agreement

3 9 **Adherence to FIT Program Rules.** Buyer agrees to abide by all applicable Feed In

Tariff Program rules and guidelines promulgated by the General Manager of Utilities which are in effect on the Effective Date of this Agreement.

ARTICLE 4 – TERM OF AGREEMENT

The Term hereof shall begin on the Effective Date, when SEPA is executed by Buyer and shall, unless sooner terminated or amended as provided herein, end on the Termination date as designated in Article 1 Seller may terminate this agreement at any time and is under no obligation to produce Solar Energy In the event that this SEPA is terminated, Seller may continue to self-generate electricity but may not interconnect with the Buyer's distribution system until a replacement interconnection agreement is executed Upon execution of the replacement interconnection agreement, Seller shall be allowed to deliver energy to the Buyer in accord with the prevailing policies of the Buyer at that time

ARTICLE 5 – SALE AND PURCHASE OF SOLAR ENERGY

5.1 **Sale and Purchase Obligation.** During the Term and subject to the provisions of this SEPA, Seller shall sell and deliver or cause to be delivered, and Buyer shall purchase and receive or cause to be received, one hundred percent (100%) of the net Solar Energy and Environmental Attributes generated by the Facility.

5.2 **Solar Fuel Exclusivity** No energy from a fuel source other than solar shall be generated, distributed or transmitted from this Facility

5.3 **Solar Energy Price.** Buyer shall pay Seller for each kilowatt hour ("kWh") of solar energy that is actually produced and delivered by Seller to the Point of Interconnection, inclusive of the associated Renewable Energy Credits, at the following rates

- ☐ Tier one $0 21/kWh 10 kW or less rooftop
- ☐ Tier one $0 21/kWh 10 kW or less ground mount
- ☐ Tier two $0 18/kWh greater than 10 kW up to 300 kW rooftop
- ☐ Tier two $0 18/kWh greater than 10 kW up to 25 kW ground mount
- ☐ Tier three $0 15/kWh greater than 25 kW ground mount

as required by the City of Gainesville Should the rate in this section be in conflict with the rate in Appendix A of Section 27, City of Gainesville's Code of Ordinances, the Code of Ordinances shall prevail Further, should any term in this SEPA conflict with the City of Gainesville Code of Ordinances, the Code of Ordinances shall prevail

5.4 **Taxes and Fees.** Seller shall have sole responsibility for paying any taxes or fees applicable to the Facility or from the sale of Solar Energy to the Buyer Seller is subject to all applicable fees and charges set forth in Appendix A of Section 27, City of Gainesville Code of Ordinances These fees include a monthly service administrative charge deducted from Seller's monthly payment received from Buyer for solar energy; a one-time capacity reservation deposit as applicable based on system size which is refundable if the facility is completed in accordance with the terms of this Agreement and if not otherwise used to pay for GRU system upgrades, and a one-time non-refundable application processing fee as applicable based on system size

ARTICLE 6 – BILLING AND PAYMENT

6.1 **Records, Invoices, and Payments.** Each Facility shall be treated as a unique account in the Buyer's accounting system which shall record the amount of Solar Energy delivered by Seller and which will produce the invoice of payment due from the Buyer The meter at the Point of Interconnection of each Facility shall be read as part of the Buyer's normal meter reading procedures, which is approximately once a month The kilowatt-hours delivered to the Buyer shall then be recompensed to Seller on a monthly basis All documents received or created by the Buyer shall be subject to disclosure under the

Public Records Law of Florida as may be amended from time to time

6.2 **Billing Disputes.** Either Party may dispute invoiced amounts, but shall pay to the other Party the undisputed portion of invoiced amounts on or before the invoice due date. To resolve any billing dispute, the Parties shall use the procedures set forth in Section 9 2 When a billing dispute is resolved, the Party owing shall pay within thirty (30) Business Days of the date of such resolution, with late payment interest charges calculated at 0 016% compounded daily

ARTICLE 7 – SUCCESSORS AND ASSIGNS

7.1 **Assignment by Seller** This Agreement shall be freely assignable by Seller to any third party upon written notice of such assignment to Buyer within 10 days of the assignment, which notice contains complete contact information regarding the assignee and is accompanied by Buyer's Assignment Form(s); and, provided said third party qualifies by owning and operating a Solar Electric Generating Facility which qualifies under Buyer's criteria and policies for interconnection and purchase of solar power by means of a "Feed In Tariff" as provided under applicable ordinances of the City of Gainesville at the time of said Assignment; the assignee executes a written undertaking acceptable in form to Buyer by which assignee is bound to all the terms and conditions of this Agreement; and further provided, that Seller may collaterally assign its interest in this Agreement to any lender or any financial institution or institutions participating in the financing of the Facility, provided, however, Seller shall remain fully responsible according to this Agreement for all of its obligations and liabilities hereunder No such assignment shall alter or impair the rights of any surety.

7.2 **Assignment by Buyer.** This Agreement shall not be assigned by Buyer without the prior written consent of Seller, which shall not be unreasonably withheld or delayed

7.3 **Successors and Assigns** This Agreement shall bind and inure to the benefit of the parties to this Agreement and any successor or assignee acquiring an interest hereunder consistent with Sections 7.1 and 7.2 hereof

ARTICLE 8 – EVENTS OF DEFAULT

Failure of Seller to satisfy and comply with all of the terms, provisions and conditions set forth in this Agreement, which failure continues beyond 30 days after receiving written notice of the failure, shall be an event of default. Failure of this Facility to stay in compliance with the requirements of Attachment A shall be an event of default and may result in the Buyer disconnecting this Facility from the electric system. Should Seller participate in any form of current diversion or theft of electricity from the Buyer, such act will be considered an event of default Upon an event of default by Seller and upon the expiration of any cure or notice period required by this Agreement, Buyer may.

(1) Terminate this Agreement, and
(2) Recover from Seller the damages Buyer incurred as a direct result of the event of default; and
(3) Except as may be limited under the terms of this SEPA, exercise any other remedy Buyer may have at law or equity.

ARTICLE 9 – CONTRACT ADMINISTRATION AND NOTICES

9.1 **Notices in Writing.** Except as provided below, notices required by this SEPA shall be addressed to the other Party at the addresses noted below.

Seller. ______________________________

____

____

Buyer. Assistant General Manager/Customer Support Services
P.O Box 147117 Station A118
Gainesville, Florida 32614-7117
Phone 352-393-1035
Fax 352-334-3498

For the purpose of making emergency or other communications relating to the operation of the Facility under the provisions of this Agreement, the Parties designate the following for said notification.

Emergency Contact ______________________

Phone Numbers Office/Home ______________

Cell ______________________

Address: ______________________________

____

Buyer Assistant General Manager/Energy Delivery
P O Box 147117 Station A126
Gainesville, Florida 32614-7117
Phone: 352-393-1513
Fax. 352-334-2784

9.2 **Dispute Resolution.** In the event of any dispute arising under this SEPA (a "Dispute"), within ten (10) business days following the delivered date of a written request by either Party (a "Dispute Notice"), the Parties' authorized representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively In the event the authorized representatives cannot resolve the Dispute within thirty (30) business days after commencement of negotiations, within ten (10) business days following any request by either Party at any time thereafter, each authorized representative (i) shall independently prepare a written summary of the Dispute describing the issues and claims, (ii) shall exchange its summary with the summary of the Dispute prepared by the other authorized representative, and (iii) shall submit a copy of both summaries to a senior officer of the respective Parties with authority to irrevocably bind the Party to a resolution of the Dispute. Promptly upon receipt of the Dispute summaries, the senior officers for both Parties shall negotiate in good faith to resolve the Dispute If the Parties are unable to resolve the Dispute within fourteen (14) business days following receipt of the Dispute summaries by the senior officers, either Party may seek available legal remedies Notwithstanding any provision in this SEPA to the contrary, if no Dispute Notice has been issued within four (4) months following the occurrence of all events and the existence of all circumstances giving rise to the Dispute (regardless of the knowledge or potential knowledge of either Party of such events and circumstances), the Dispute and all claims related thereto shall be deemed waived and the aggrieved Party shall thereafter be barred from proceeding thereon.

ARTICLE 10 -SELLER INSURANCE REQUIREMENTS

10.1 Coverage. Seller and/or property owner shall maintain in full force and effect, general liability insurance for personal injury and property damage of at least $200,000 per occurrence per Facility identified on page one of this agreement. A home owner, system owner or business owner's policy that provides at least this level of coverage is acceptable for meeting the insurance requirement of this Agreement Buyer shall be named as an "additional interest" or an interested party on the insurance policy, since Buyer has an interest in being notified whenever a policy cancels or has a major change made to it.

10.2 Certificate of Insurance. Seller shall provide a Certificate of Insurance documenting the required coverage as set forth above in Article 10.1 to Buyer and the Certificate of Insurance, including all updated or modified Certificates of Insurance shall become a part of this Agreement Automatic notification to Buyer must be established for both annual renewals and, if appropriate, any termination of such insurance In the event that Seller fails to maintain the insurance coverage required in accordance with this Agreement, Buyer has the right to immediately terminate this Agreement, immediately terminate the Facility interconnection and require Seller to permanently disconnect the Facility from the distribution system

ARTICLE 11 - INDEMNIFICATION

Seller shall indemnify, hold harmless and defend the City of Gainesville, Buyer, its officers and employees from and against any and all liability, proceedings, suits, cost or expense for loss, damage or injury to persons or property, including the Facility, in any manner directly or indirectly connected with, or growing out of the installation, operation or maintenance of Seller's Facility, except in those cases where loss occurs due solely to the negligent actions of Buyer.

ARTICLE 12 - TERMINATION OF AGREEMENT

12.1 Completion. This SEPA will terminate automatically if Seller's Facility as described in Exhibit I is not fully completed and operational by the Completion Date defined above in Article 1, unless an extension has been granted in writing by the Buyer A single extension may be granted by Buyer if the Facility is substantially, but not fully, completed by the Completion Date. The Facility will be deemed substantially completed if sixty-five *percent (65%) or more, by cost, of total budgeted equipment for this Facility has been* installed on site by the Completion Date and a current year's SEPA has already been executed by both Parties

12.2 Failure to Insure. In the event that Seller fails to maintain the insurance coverage required by this Agreement, Buyer shall have the right to immediately terminate this Agreement

12.3 Audit/Disconnection. Buyer may perform periodic audits and testing of the Facility at such intervals as it may deem proper. In the event that Buyer has, pursuant to the provisions of this Agreement (including but not limited to 6.1 of Attachment A hereto) disconnected the Facility, Buyer shall provide written notice thereof as soon as practicable to Seller of the issue or deficiency causing Buyer to disconnect the Facility If after thirty (30) calendar days from the receipt of the aforementioned notice, the issue which caused the disconnection is not remedied to Buyer's satisfaction, Buyer may terminate this Agreement and provide written notification to Seller to that effect Once this Agreement has been terminated, Seller may be required to submit a new Application and adhere to the then current process for Facility interconnection

12.4 **Right to Lock Out.** Upon termination of this SEPA for any reason, Buyer may padlock the manual disconnect switch in the open (disconnected) position and may modify or remove any Buyer installed equipment.

12.5 **Supplementary Rights.** The rights described in this section are supplementary to any rights Buyer may have in law or equity arising out of any violation of the terms of this Agreement.

12.6 Engineering design changes are permitted as long as the installed capacity is not materially increased more than 5%. A material change in the design or capacity exceeding 5% will result in the SEPA being voided and forfeiture of the capacity allocation and capacity reservation charge.

ARTICLE 13 – NO THIRD PARTY BENEFICIARIES

Nothing in this SEPA confers, is intended to confer, or shall be deemed to confer upon any party other than the Parties hereto and their permitted successors and assigns any rights, remedies, obligations, or liabilities under or by reason of this SEPA except as expressly provided in this SEPA

ARTICLE 14 - COMPLETE AGREEMENT; AMENDMENTS

The terms and provisions contained in this SEPA constitute the entire agreement between Buyer and Seller and supersedes any prior agreement between the Parties regarding the subject matter hereof No amendment to this SEPA shall be effective unless in writing and signed by both Parties hereto.

ARTICLE 15 – CONTROLLING LAW; VENUE

The validity, performance, and all matters relating to the interpretation and effect of this SEPA shall be governed by the laws of the State of Florida and the venue for any dispute shall be Alachua County, Florida.

IN WITNESS WHEREOF, the Parties have executed this SEPA

Seller:

____
Name of Company (if applicable)

____
Signature of Authorized Representative

____
Print Name

____
Title

____
Date

Buyer.

The City of Gainesville, Florida
d/b/a Gainesville Regional Utilities

____
Signature of Authorized Representative

____
Print Name

____
Title

____
Date

Approved as to form and legal sufficiency:

____
Shayla L McNeill, Utilities Attorney

ATTACHMENT A

APPROVAL OF FACILITIES FOR INTERCONNECTION AND CONDITIONS FOR OPERATION
This Attachment A constitutes the approval of Seller's facilities for interconnection with Buyer's electric distribution system and conditions required for parallel operation of Seller's distributed generation resource under this SEPA This approval is required in order to provide interconnection of Seller's facilities under conditions which will insure the safety of Buyer's customers and employees, as well as the reliability and integrity of its distribution system For the purposes of this Attachment A, the term Distributed Generation Resource ("DGR") shall be interchangeable with the term Facility as used in the SEPA and is defined as any source of *electrical energy that is not connected directly to the high voltage electrical transmission system*, but typically connected to the medium voltage electrical distribution system For the purpose of this SEPA the DGR is defined as a solar photovoltaic generation system and any reference to the "distribution system" will mean Buyer's electrical distribution system which the Buyer operates pursuant to authority of its Charter, Ch. 90-394, Laws of Florida, as amended, serving the City of Gainesville and certain unincorporated areas of Alachua County, Florida

1. SCOPE

This Attachment defines the terms and conditions under which Seller and Buyer agree to interconnect a specific DGR at a specific location on the electric distribution system (both as described in Exhibit I of this Attachment).

2. ESTABLISHMENT OF POINT OF INTERCONNECTION

2.1 Buyer will evaluate the capability of the existing distribution system and make an initial determination of the feasibility of interconnecting the DGR If the initial evaluation is inconclusive a system study may be required to determine the adequacy of the distribution system to interconnect a DGR Seller is responsible for all costs for the system impact study and Buyer will not approve interconnecting any DGR until the system impact study is completed Buyer reserves the right to disallow the interconnection of the DGR if in its sole discretion the DGR will adversely impact the Buyer's distribution system.

2.2 Determination of the Point of Interconnection is at Buyer's sole discretion. Buyer and Seller agree to interconnect the DGR at the Point of Interconnection in accordance with Buyer's rules, regulations, rates, and tariffs (the "Rules") which are incorporated herein by reference The interconnection equipment installed by Seller ("Interconnection Facilities") shall be in accordance with the Rules as well

3. EQUIPMENT AND INSTALLATION STANDARDS

3.1. Seller must provide written documentation satisfactory to Buyer that the design specifications of the DGR, including but not limited to, the associated inverter, all connecting wiring and disconnect means, control and protective circuits, meters and any other related equipment adhere to the prevailing versions of the following applicable standards in effect at the time of this Agreement:

3.1.1. IEEE Standard 1547, entitled "Interconnecting Distributed Resources with Electric Power Systems"

3.1.2. UL Standard 1741, entitled "Standard for Safety for Static Inverters and Charge Controllers for use in Distributed Resources

3.1.3. UL Standard 1703 entitled "Standard for Safety Flat Plate Photovoltaic Modules and Panels

3.1.4. IEEE Standard 1262-1995, entitled "Recommended Practice for Qualification of Photovoltaic Modules" or IEC Standard 61646

3.1.5. The National Electrical Code.

3.2. Seller agrees that the requirements of this Attachment shall be in effect prior to interconnection of any DGR equipment with the distribution system. It is the responsibility of Seller to ensure that this condition is satisfied If a DGR system (or elements thereof) is found to be interconnected to the distribution system without a fully executed SEPA, Buyer reserves the right to isolate, secure, and lock out of service the DGR system. If such efforts are not practical or effective, Buyer may operate or configure its equipment as necessary to isolate the DGR system from the distribution system

3.3. Seller agrees that the installer of the DGR will be a licensed Florida Solar Contractor or Florida Electrical Contractor and will meet at least one of the following conditions to the satisfaction of Buyer.

3.3.1. Possess a solar PV installer certification issued by the North American Board of Certified Energy Practitioners (NABCEP), or

3.3.2. Have completed the course "Installing Photovoltaic Systems" offered by the Florida Solar Energy Center.

3.4. Seller shall provide written certification that the installation of the DGR was permitted and inspected by all local building code officials having jurisdiction over the DGR installation Seller shall also provide written certification that the equipment and installation have met all applicable mechanical and electrical code requirements and has been approved by local code officials for operation Seller may meet this requirement by attaching a letter from the installation contractor certifying compliance with all equipment and installation standards. A copy of the construction permit shall be forwarded to the Buyer representative identified in Article 9.1 so that it can be attached to this document.

3.5. Seller shall provide all materials, labor and equipment necessary to deliver the output of the DGR to the Point of Interconnection In accordance with Buyer's Energy Delivery Service Guide, Seller shall install, at Seller expense, and within ten (10) feet of the Buyer meter, a dedicated DGR disconnect switch This device shall be manually operated, lockable, and of the visible load break type to isolate the output of the DGR and any Seller wiring connected to Buyer's distribution system. Seller shall also be responsible for any and all costs to be incurred by Buyer to establish the Point of Interconnection as set forth in Section Two of Exhibit I of this Attachment. Payment is required by Seller prior to execution of such work by Buyer Upon Completion of the DGR project Seller shall be responsible for any additional distribution system modification cost, if required, to deliver the output of the DGR to the Point of Interconnection not accounted for initially An additional invoice will be generated and must be paid prior to final interconnection of the DGR No Facility shall be allowed to deliver energy to Buyer until the cost of interconnection is fully resolved Any deviation from Buyer's interconnection requirements shall be reviewed and approved in writing by Buyer prior to construction

3.5.1. The manual disconnect means shall be mounted on the same wall, if practical, but shall be separate from the meter socket, readily accessible to Buyer personnel, and capable of being locked in the open position with a standard Buyer padlock

3.5.2. The disconnect means must be clearly labeled "Auxiliary Generation Disconnect" and be readily visible to GRU personnel The label shall be permanently riveted to the disconnect device, and shall be made of red, weatherproof, hard plastic, with engraved white block lettering (see Exhibit II)

3.6. Buyer shall have the right to open the disconnect means isolating the DGR without prior notice to Seller To the extent practicable, Buyer will make reasonable attempts to provide prior notice to Seller but assumes no liability if such notice is not given Buyer shall make reasonable efforts to reconnect the DGR to the distribution system as soon as practical following resolution of the issue that required the disconnection Seller should take an active interest in ensuring that the DGR is reconnected within a reasonable period of time

3.7. In the event that the DGR manual disconnect switch is opened or the DGR is otherwise isolated from the distribution system for any reason and for any expanse of time, Seller shall not be due any compensation associated with the inability to deliver energy to the distribution system

4. METERING REQUIREMENTS

4.1. Buyer shall solely determine the equipment required to properly and accurately meter the DGR Installation

4.2. Should the nameplate rating of the DGR be 250 kilowatts DC or greater, telemetry and metering equipment shall be installed to provide the Buyer with DGR monitoring and performance data. The required telemetry and metering equipment shall be installed by the Buyer at Seller's expense Seller shall also be responsible for the recurring communication costs and maintenance costs of the telemetry equipment Buyer shall be solely responsible for supplying the communications link between the telemetry equipment and the Buyer's systems for monitoring the operation and performance of the DGR Should the nameplate rating of the DGR be less than 250 kilowatts DC, the installation of telemetry by Seller is optional.

4.3. The meter socket and all other required metering equipment (if any) shall be provided by Seller and shall be approved by Buyer in advance of installation

4.4. For self-contained metering applications, the meter socket shall have a clearly legible label reading "Warning electric shock hazard Do not touch terminals Terminals on both the line and load sides may be energized in the open position " The labels shall be made of hard plastic, permanent, weatherproof, colored red with engraved white block lettering (see Exhibit III) and readily visible to Buyer personnel

4.5. An appropriate electric meter shall be provided by Buyer at no cost to Seller, except as provided in Section 4 2 above

5. INITIAL TESTING, STARTUP AND OPERATION

5.1. Initial testing, startup, and operation shall not commence until all construction required by Buyer to establish the point of interconnection is completed and final payments are made, pursuant to Section 3 5 of this Attachment

5.2. Upon execution of this SEPA, receipt of all required DGR documentation, including the final building and electrical inspection by the local codes enforcement personnel and upon request by Seller, an authorized representative of Buyer shall audit the DGR installation to ensure operational and interconnection requirement compliance within five (5) business days. A successful audit and test may result in an immediate interconnection of the DGR if so requested followed by written confirmation of the action taken

5.3. In the event that Buyer determines, in the exercise of its sole discretion as a result of the above mentioned audit, that the DGR is unacceptable for interconnection, Buyer shall provide Seller written notice of the DGR deficiencies including but not limited to safety and/or reliability risks. Such notice shall include a list of all noted DGR equipment or documentation issues that must be remedied. Seller shall be solely responsible for correcting all deficiencies and notifying Buyer of readiness for re-audit and possible interconnection A failed DGR audit will prevent interconnection until all deficiencies have been remedied.

6. BUYER'S RIGHT TO DISCONNECT THE DGR FOR CAUSE

6.1. Buyer shall have the right to disconnect Seller's DGR without notice if Buyer, in the exercise of its sole discretion determines any of the following conditions have occurred, or are occurring:

6.1.1. Adverse electrical effects (such as power quality problems) imposed upon the distribution system and/or the electrical equipment of Buyer's electrical customers attributed to the DGR as determined by Buyer.

6.1.2. Utility system emergencies or maintenance requirements

6.1.3. Hazardous conditions existing on the utility system due to the operation of Seller's DGR generating or protective equipment.

6.1.4. Failure of Seller to comply with applicable federal, state or local law, regulation or rules relating to the operation of the DGR

6.1.5. Buyer's identification of un-inspected or unapproved equipment, or modifications to the DGR after initial approval.

6.1.6. Recurring abnormal operation, substandard operation or inadequate maintenance of DGR

6.2. In the event that Buyer opens the manual disconnect means for routine meter maintenance, system emergencies, or any other operating consideration, other than events or conditions arising out of Seller's operation of the DGR, Buyer shall make reasonable efforts to reconnect Seller generation equipment. This Agreement shall not entitle Seller to any restoration priority over any other of Buyer's customer.

7. DGR OPERATION AND MAINTENANCE REQUIREMENTS

7.1. Seller shall operate and maintain the DGR and all associated equipment in accordance with the manufacturer's requirements and all applicable state or local building codes

7 2. Seller shall be solely responsible for protecting its generating equipment, inverters, protection devices, and other system components from damage from the normal and abnormal conditions and operations that may occur on the distribution system in delivering or restoring power including temporarily grounding of said system as required for safe work practices.

7.3. Seller shall promptly notify Buyer if any modifications, repairs, or component replacements result in a change to the initial configuration, rating, and/or operation of the DGR Buyer shall have right to audit the DGR prior to its reconnection to the distribution system

7.4. Buyer shall have the right to periodically audit the DGR installation to ensure compliance with operational and interconnection requirements

7.5. If during the Term of the Agreement the operation of the DGR adversely impacts the distribution system, Seller shall be responsible for any and all costs for Buyer to remedy these impacts if possible including disconnection, as stated in Section 6

EXHIBIT I

LIST OF FACILITIES SCHEDULES AND POINTS OF INTERCONNECTION

DGR Seller will, at its own cost and expense, operate, maintain, repair, and inspect, and shall be fully responsible for its facilities, unless otherwise specified on Exhibit I. The following information is to be specified for each Point of Interconnection, if applicable.

SECTION ONE - Owner Information *(to be supplied by applicant)*

1. System Owner

Name ____________________

Address ____________________

City, State, ZIP ____________________

Phone ____________________

Email ____________________

2. System Installer/Contractor

Name ____________________

Address ____________________

City, State, ZIP ____________________

Phone ____________________

Email ____________________

<u>Location of system</u>

Storefront name (if applicable) ____________________

Address ____________________

City, State, ZIP ____________________

Phone ____________________

3. PV System Specifications

DC Power Rating (Watts) __________ No Phases. ______

AC Power Rating (Watts) __________

4. Three-Line Diagram/System Sketch

Attach diagram for proposed system with all major components, both DC and AC

Diagram must be dated and initialed.

SECTION TWO - Interconnection Requirements *(to be completed by Buyer)*

1. **Engineering Review of PV System Information Provided By Seller**
   A) Elevation/Riser Diagram with Site Plan & Metering Location _____
   B) 1-line Diagram with Point of Interconnection & Metering Description_____
   C) Panel schedule (on 3-phase installations) ______
   D) Verify Installation does not exceed PV Allocation Size _______
   Determination of Point of Interconnection
   A) Summary of required distribution system additions or modifications

   B) Cost of additions/modifications above

   C) GIS graphic depicting Point of Interconnection (attach)

   D) Point of Interconnection detail
   Padmount transformer no (if known) ____________________

   Overhead transformer at pole no. (if known) ____________________

   Approved by ______________________________

   Date Approval Completed ______________________________

2. **Metering Requirements**
   A) Voltage ____________

   B) Meter installation description

   C) Communication protocol (including Seller's access to data)

   D) Summary of required metering Cost and infrastructure

   Approved by ______________________________

   Date Approval Completed. ______________________________

3. ***Summary of Required Upgrades and Estimated Costs to Seller***

ESTIMATED TOTAL COST $____________________

4. **Supplemental terms and conditions attached (check one): /_______Yes /_______ No**

SIGNATURES INDICATING ENGINEERING APPROVAL ON THE NEXT PAGE REQUIRED BEFORE SEPA CAN BE EXECUTED

Acknowledged By DGR Seller

Signature. ____________________ Print Name ____________________ Date __________

Buyer Authorized Representative for Engineering

Signature ____________________ Print Name. ____________________ Date __________

Buyer Authorized Representative for Measurement and Energy Regulation

Signature· ____________________ Print Name· ____________________ Date· __________

Buyer Authorized Representative – Final Approval
Based on the information contained herein, Seller's DGR system will meet the interconnection requirements of the Buyer

Signature· ____________________ Print Name ____________________ Date: __________

EXHIBIT II

MANUAL DISCONNECT LABEL

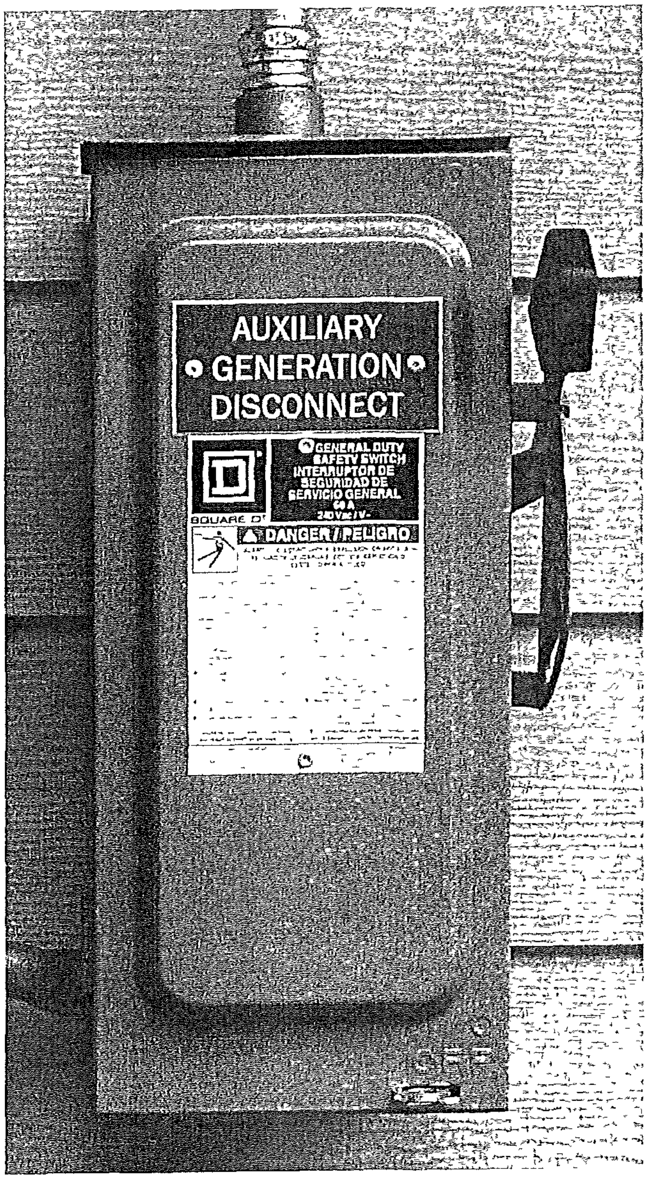

EXHIBIT III

METER LABEL

EXHIBIT IV

SOLAR PHOTOVOLTAIC INSTALLER'S INFORMATION

Please provide names and contact information for all installation contractors and subcontractors. If any of the parties are to be determined at a later date, signify this with "TBD" in the appropriate line.

System designer:

Name· ______________________________

Address. ______________________________

Telephone: ______________________________

Email. ______________________________

Electrical contractor

Name: ______________________________

Address: ______________________________

Telephone· ______________________________

Email· ______________________________

Roofing contractor (if applicable)

Name: ______________________________

Address· ______________________________

Telephone. ______________________________

Email. ______________________________

GAINESVILLE REGIONAL UTILITIES (GRU)

AGREEMENT FOR INTERCONNECTION AND PARALLEL OPERATION OF DISTRIBUTED GENERATION RESOURCES (DGR)

This **Interconnection Agreement** ("**Agreement**") is made and entered into this ___ day of __________, 20_____, by and between ____ (hereinafter called the Owner/Operator) located at ____ in Gainesville, Florida and the City of Gainesville, a Florida municipal corporation doing business as Gainesville Regional Utilities ("GRU"). Owner/Operator's Account pursuant to this Agreement is GRU Account Number ____________________

This Agreement constitutes the approval of Owner/Operator's facilities for interconnection with GRU's electric distribution system and sets forth the conditions required for parallel operation of Owner/Operator's distributed generation resource This approval is required in order to provide interconnection of Owner/Operator's facilities under conditions which will insure the safety of GRU's customers and employees, as well as the reliability and integrity of its distribution system For purposes of this Agreement, the term Distributed Generation Resource ("DGR") shall be interchangeable with the term "Facility" For purposes of this Agreement DGR is defined as a solar photovoltaic generation system and any reference to the "distribution system". For purposes of this Agreement, any reference to the "distribution system" will mean GRU's electrical distribution system which GRU operates pursuant to its Charter, as authorized by Chapter 90-394, Laws of Florida, as amended

1. SCOPE OF AGREEMENT

This Agreement defines the terms and conditions under which GRU and Owner/Operator agree to interconnect a specific DGR of ______ kW DC or less as more particularly described in Attachment A, attached hereto and made a part hereof by reference as if fully set forth herein, at the specific location as stated above and at a standard GRU primary or secondary voltage to the distribution system.

2. ESTABLISHMENT OF POINT OF INTERCONNECTION

2 1. The "Point of Interconnection" is defined as the point at which ownership of electric facilities and/or equipment transitions from GRU to Owner/Operator. GRU will evaluate the capability of the existing distribution system and make an initial determination of the feasibility of interconnecting the DGR If the initial evaluation is inconclusive a system study may be required to determine the adequacy of the distribution system to interconnect a DGR Owner/Operator is responsible for all costs for the system impact study and GRU will not approve interconnecting any DGR until the system impact study is completed GRU reserves the right to disallow the interconnection of the DGR if in its sole discretion the DGR will adversely impact GRU's distribution system

2 2. Determination of the Point of Interconnection is at GRU's sole discretion GRU and Owner/Operator agree to interconnect the DGR at the Point of Interconnection in accordance with GRU's rules, regulations, rates, and tariffs (the "Rules") incorporated herein by reference The interconnection equipment installed by Owner/Operator ("Interconnection Facilities") shall be consistent with and pursuant to the Rules.

3. EQUIPMENT AND INSTALLATION STANDARDS

3 1 Owner/Operator must provide written documentation satisfactory to GRU that the design specifications of the DGR, associated inverter, all connecting wiring and disconnect means, control and protective circuits, meters and any other related equipment adhere to the prevailing versions of the following applicable standards in effect at the time of this Agreement.

3 1 1 IEEE Standard 1547, entitled "Interconnecting Distributed Resources with Electric Power Systems"

3 1 2 UL Standard 1741, entitled "Standard for Safety for Static Inverters and Charge Controllers for use in Distributed Resources

3 1 3 UL Standard 1703 entitled "Standard for Safety Flat Plate Photovoltaic Modules and Panels

3 1.4. IEEE Standard 1262-1995, entitled "Recommended Practice for Qualification of Photovoltaic Modules" or IEC Standard 61646

3 1 5 IEEE Standard 929 "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

3 1 6 and the National Electrical Code

3 2 Owner/Operator agrees that the requirements of this Agreement shall be in effect prior to interconnection of any DGR equipment with the distribution system It is the responsibility of Owner/Operator to ensure that this condition is satisfied If a DGR system (or elements thereof) is found to be interconnected to the distribution system without a fully executed Agreement, GRU reserves the right to isolate, secure, and lock out of service the DGR system If such efforts are not practical or effective, GRU may operate or configure its equipment as necessary to isolate the DGR system from the distribution system

3 3 Owner/Operator agrees that the installer of the DGR will be a licensed Florida Solar Contractor or Florida Electrical Contractor

3 4 Owner/Operator shall provide written certification that the installation of the DGR was permitted and inspected by all local building code officials having jurisdiction over the DGR installation. Owner/Operator shall also provide written certification that the equipment and installation have met all applicable mechanical and electrical code requirements and has been approved by local code officials for operation Owner/Operator may meet this requirement by attaching a copy of the final electrical permit and a copy of any necessary construction permit(s) shall be forwarded to the GRU representative identified in Section 13 so that it can be attached to this Agreement.

3 5 Review of Owner/Operator specifications by GRU shall not be construed as confirming or endorsing the design or any warranty of safety or durability of the DGR

3 6 Owner/Operator shall provide all materials, labor and equipment necessary to deliver the output of the DGR to the Point of Interconnection Pursuant to GRU's Energy Delivery Service Guide, Owner/Operator shall install, at Owner/Operator's sole expense, within ten (10) feet and within site of the GRU revenue meter, a dedicated DGR disconnect switch. This device shall be manually operated, lockable, and of the visible load break type to isolate the output of the DGR and any Owner/Operator wiring connected to GRU's distribution system Owner/Operator shall also be responsible for any and all costs to be incurred by GRU to establish the Point of Interconnection as set forth in Section Two of Attachment A. Payment is required by Owner/Operator prior to execution of such work by GRU Upon Completion of the DGR project Owner/Operator shall be responsible for any additional distribution system modification cost, if required, to deliver the output of the DGR to the Point of Interconnection not accounted for initially An additional invoice will be generated and must be paid prior to final interconnection of the DGR No Facility shall be allowed to deliver energy to GRU until the cost of interconnection is fully resolved Any deviation from Owner/Operator interconnection requirements must be reviewed and approved in writing by GRU prior to construction

3.6 1. The manual disconnect means shall be mounted on the same wall as the revenue meter, but shall be separate from the revenue meter socket, readily accessible to GRU personnel, and capable of being locked in the open position with a GRU padlock

3.6 2 The disconnect means must be clearly labeled "**Auxiliary Generation Disconnect**" and be readily visible to GRU personnel The label shall be permanently riveted to the disconnect device, and shall be red, weatherproof, hard plastic with engraved white block lettering. (see Exhibit 1)[1]

3 7 The disconnect means shall have an interrupting rating sufficient for the nominal circuit voltage and the current that is available at the line terminals of this equipment

3.8 GRU shall have the right to open the disconnect means isolating the DGR without prior notice to Owner/Operator. To the extent practicable, GRU will make reasonable attempts to provide prior notice to Owner/Operator but assumes no liability if such notice is not given. GRU shall make reasonable efforts to reconnect the DGR to the distribution system as soon as practical following resolution of the issue that required the disconnection. Owner/Operator should take an active interest in ensuring that the DGR is reconnected within a reasonable period of time.

3.9. In the event the DGR manual disconnect switch is opened or the DGR is otherwise isolated from the distribution system for any reason and for any expanse of time, Owner/Operator shall not be due any compensation associated with the inability to deliver energy to his/her load or to the distribution system.

3 10 When the size of the DGR system precludes the use of Owner/Operator's service entrance equipment as the connection point, an alternate disconnect means must be designed and provided by Owner/Operator and approved by GRU before installation.

3.11. On both the REC and GRU revenue meter socket covers the labeling shall state "**Warning: Electric Shock Hazard. The terminals on both line and load side may be energized in the open position**" and be readily visible to GRU personnel. The labels shall be permanently riveted to the covers, and shall be made of red, weatherproof, hard plastic with engraved white block lettering (see Exhibit 2)[2]

4. OWNER/OPERATOR INSURANCE REQUIREMENTS

4.1 Owner/Operator shall maintain in full force and effect, general liability insurance for personal injury and property damage of at least $100,000 per occurrence. Owner/Operator's policy that provides at least this level of coverage is acceptable for meeting the insurance requirements of this Agreement.

4.2. Owner/Operator shall provide a Certificate of Insurance to GRU and the certificate shall become a part of the Application If applicable, automatic notification to GRU must be established for both annual renewals and any termination of such insurance. In the event that Owner/Operator fails to maintain the insurance coverage required by this Agreement, GRU has the right to immediately terminate this Agreement, immediately terminate the DGR interconnection and require Owner/Operator to permanently disconnect the DGR from the distribution system.

5. , METERING REQUIREMENTS

5.1. GRU shall solely determine the equipment required to properly and accurately meter the DGR Installation.

5.2. Should the nameplate rating of the DGR be 250 kilowatts DC or greater, telemetry and metering equipment shall be installed to provide GRU with DGR monitoring and performance data The required telemetry and metering equipment shall be installed by GRU at Owner/Operator's expense Owner/Operator shall also be responsible for the recurring communication costs and maintenance costs of the telemetry equipment If Owner/Operator so chooses, he shall be solely responsible for

[1] GRU Energy Delivery Service Guide
[2] GRU Energy Delivery Service Guide

supplying the communications link between the telemetry equipment and Owner/Operator's systems for monitoring the operation and performance of the DGR. Should the nameplate rating of the DGR be less than 250 kilowatts DC, the installation of telemetry by Owner/Operator is optional.

5.3. The meter socket and all other required metering equipment, if any, shall be provided by Owner/Operator and shall be approved by GRU in advance of installation

5.4. For self-contained revenue metering applications, the meter socket shall have a clearly legible label reading "**Warning: electric shock hazard. Do not touch terminals. Terminals on both the line and load sides may be energized in the open position.**" The labels shall be made of hard plastic, permanent, weatherproof, colored red with engraved white block lettering and readily visible to GRU personnel (see Exhibit 2)[3]

5 5. An appropriate electric meter(s) shall be provided by GRU at no cost to Owner/Operator, except as provided in Section 5.2 above

6. INITIAL TESTING, STARTUP AND OPERATION

6 1 Initial testing, startup, and operation shall not commence until all construction required by GRU to establish the point of interconnection is completed and final payments are made, pursuant to Section 3 6 of this Agreement.

6.2. Upon execution of this Agreement, receipt of all required DGR documentation and fees, including the final building and electrical inspection by the local codes enforcement personnel and upon request by Owner/Operator, an authorized representative of GRU shall audit the DGR installation to ensure operational and interconnection requirement compliance. A successful audit and test may result in an immediate interconnection of the DGR

6 3 In the event that GRU determines, in the exercise of its sole discretion as a result of the above mentioned audit, that the DGR is unacceptable for interconnection, GRU shall provide Owner/Operator written notice of the DGR deficiencies including but not limited to safety and/or reliability risks. Such notice shall include a list of all noted DGR equipment or documentation issues that must be remedied Owner/Operator shall be solely responsible for correcting all deficiencies and notifying GRU of readiness for re-audit and possible interconnection. A failed DGR audit will prevent interconnection until all deficiencies have been remedied

7. METERING AND COMPENSATION FOR EXCESS ELECTRIC ENERGY SUPPLIED TO THE GRU ELECTRICAL DISTRIBUTION SYSTEM BY OWNER/OPERATOR DGR

7.1. GRU shall solely determine the metering equipment required at Owner/Operator location to measure any excess generation produced by the DGR that is delivered into the distribution system if Owner/Operator desires For the purposes of this Agreement, excess generation is defined as any kWh of electrical energy produced by the DGR which is not consumed by Owner/Operator's electrical requirements and is delivered to the distribution system. The cost of metering equipment, installation, maintenance, and any recurring or non-recurring costs for reading and billing shall be borne by GRU.

7 2 Owner/Operator shall receive a monthly energy credit for all excess kilowatt-hours delivered into the distribution system. If the energy credit exceeds the total electric energy billed amount in any corresponding month, the excess energy credit shall be applied to the subsequent month's billing An annual true up with conversion to money will be applied at the end of each calendar year using an avoided cost price GRU reserves the right to develop the annual avoided cost pricing and/or modify its tariff at any time without prior notice to Owner/Operator

[3] GRU Energy Delivery Service Guide

7.4. In the event that GRU opens the DGR manual disconnect means for any reason for any time period, Owner/Operator agrees that GRU shall have no liability for and shall not pay Owner/Operator for any actual or potential generation that may or could have occurred while the DGR was disconnected from the distribution system.

8. GRU'S RIGHTS TO DISCONNECT THE DGR FOR CAUSE

8.1. GRU shall have the right to disconnect Owner/Operator's DGR without notice if GRU, determines any of the following conditions have occurred, or are occurring.

8.1 1 Adverse electrical effects (such as power quality problems) imposed upon the distribution system and/or the electrical equipment of GRU's electrical customers attributed to the DGR as determined by GRU.

8 1 2 Utility system emergencies or maintenance requirements.

8.1.3. Hazardous conditions existing on the utility system due to the operation of Owner/Operator's DGR generating or protective equipment.

8.1.4 Failure of Owner/Operator to comply with applicable federal, state or local law, regulation or rules relating to the operation of the DGR.

8.1 5. GRU's identification of un-inspected or unapproved equipment, or modifications to the DGR after initial approval

8.1.6 Recurring abnormal operation, substandard operation or inadequate maintenance of DGR.

8 2. In the event that GRU opens the manual disconnect means for routine meter maintenance, system emergencies, or any other operating consideration, other than events or conditions arising out of Owner/Operator's operation of the DGR, GRU shall make reasonable efforts to reconnect Owner/Operator's generation equipment. This Agreement shall not entitle Owner/Operator to any restoration priority over any other of GRU's customers.

9. DGR OPERATION AND MAINTENANCE REQUIREMENTS

9.1. Owner/Operator shall operate and maintain the DGR and all associated equipment in accordance with the manufacturer's requirements and all applicable state or local building codes.

9.2. Owner/Operator shall be solely responsible for protecting its generating equipment, inverters, protection devices, and other system components from damage from the normal and abnormal conditions and operations that may occur on the distribution system in delivering or restoring power including temporarily grounding of said system as required for safe work practices

9 3. Owner/Operator shall promptly notify GRU if any modifications, repairs, or component replacements result in a change to the initial configuration, rating, and/or operation of the DGR. GRU shall have the right to audit the DGR prior to its reconnection to the distribution system

9 4. GRU shall have the right to periodically audit the DGR installation to ensure compliance with operational and interconnection requirements

9 5 If during this Agreement, the operation of the DGR adversely impacts the distribution system, Owner/Operator shall be responsible for any and all costs for GRU to remedy these impacts if possible including disconnection.

10. RENEWABLE ENERGY CREDITS

10 1. A Renewable Energy Credit (REC) represents the environmental attributes of one thousand kWh (1 MWh) of electricity produced by a renewable resource (i e., solar) A REC is the commodity used by electric providers to account for their participation in renewal energy programs.

10 2 Owner/Operator retains all REC's generated by this DGR facility The REC meter shall be owned and maintained by GRU for the purpose of providing operational data as needed by GRU.

11. OWNER/OPERATOR INDEMNIFICATION OF GRU FOR OPERATION OF DGR

Any fines or other penalties incurred by Owner/Operator for noncompliance with any Laws shall not be reimbursed by GRU but shall be the sole responsibility of Owner/Operator Owner/Operator shall indemnify, hold harmless and defend the City of Gainesville, GRU, its elected officials and employees from and against any and all liability, proceedings, suits, cost or expense for loss, damage or injury to persons or property, including the Facility, in any manner directly or indirectly connected with, or growing out of the installation, operation or maintenance of Owner/Operator's Facility, except in those cases where loss occurs due solely to the negligent actions of GRU. If Owner/Operator is not a single legal entity, then all such entities comprising Owner/Operator shall be jointly and severally liable to for all representations, warranties, obligations, covenants, and liabilities under this Agreement and all other agreements

12. TERMINATION OF AGREEMENT

12 1 In the event that Owner/Operator fails to maintain the insurance coverage required by this Agreement, GRU shall have the right to immediately terminate this Agreement.

12.2. GRU may perform periodic inspections and testing of the DGR at such intervals as it may deem proper. In the event that GRU, in the exercise of its sole discretion, determines that the DGR is performing in an abnormal or unsafe manner on a recurring basis, GRU shall have the right to immediately disconnect the DGR and shall provide written notice to Owner/Operator of the issue or deficiency If after a reasonable time as determined by GRU the issue which caused the disconnection is not remedied to GRU's satisfaction, GRU will terminate this Agreement and provide written notification to Owner/Operator to that effect. Once this Agreement has been terminated, Owner/Operator will be required to submit a new Application and adhere to the then current process for DGR interconnection.

12.3. This Agreement is not transferable or assignable. In the event that the DGR located at the above location is sold, leased, or if ownership is transferred to another person or entity without GRU's prior written consent, this Agreement may be terminated.

12.4 Upon termination of this Agreement for any reason, GRU may padlock the manual disconnect means in the open position and may modify or remove any GRU installed metering equipment.

12 5 The rights described in this section are supplementary to any rights GRU may have in law or equity arising out of any violation of the terms of this Agreement

13. POWER SALES THROUGH GRU

Interconnection of DGR facilities with GRU's distribution system does not grant Owner/Operator any right to export power to others nor does it constitute an agreement by GRU to wheel excess power.

14. OFFICIAL NOTIFICATION

For the purpose of making emergency or other communication relating to the operation of the DGR under the provisions of this Agreement, the parties designate the following for said notification·

For Owner/Operator: Name: ______________________________

Address. ______________________________

Phone: ______________________________

Email. ______________________________

For Gainesville Regional Utilities:
Rachel D Meek or her successor
Business Efficiency Program Coordinator
Gainesville Regional Utilities
(352) 393-1484
(352) 334-2731 (Fax)
meekrd@gru com

IN WITNESS WHEREOF, and intending to be legally bound hereby, Owner/Operator and GRU have caused this Agreement to be executed this __________ day of ____________________ , 20______.

______________________________ Owner/Operator· Individual's Name or Organization's Title	**GAINESVILLE REGIONAL UTILITIES**
By: ______________________________	By: ______________________________ David Beaulieu or designee
Title. ______________________________	Title·Assistant General Manager Energy Delivery
Date ______________________________	Date ______________________________

Approved as to Form and Legality:
Shayla L McNeill, on November 30, 2014
City Attorney, Utilities

Attachment A – Section 1

LIST OF FACILITIES SCHEDULES AND POINTS OF INTERCONNECTION

Facility Customer will, at its own cost and expense, operate, maintain, repair, and inspect, and shall be fully responsible for its facilities, unless otherwise specified on this Attachment A. The following information is to be specified for each Point of Interconnection, if applicable.

SECTION ONE - Owner Information *(to be supplied by applicant)*

1. **System Owner**

Name. ______________________________
Address· ______________________________
City, State, ZIP ______________________________
Phone· ______________________________
Email ______________________________

2. **System Installer/Contractor**

Name· ______________________________
Address· ______________________________
City, State, ZIP ______________________________
Phone· ______________________________
Email: ______________________________

3. **Location of system**

Storefront name (if applicable): ______________________________
Address· ______________________________
City, State, ZIP ______________________________
Phone ______________________________
Email ______________________________

4. **PV System Specifications**

DC Power Rating (Watts) ________
Number of Phases. ________

Contractor must submit an Electrical One Line Diagram, Mounting Elevation drawing, a Location site plan and a solar panel layout that will be included with this document.

Customer must submit a copy of their Declaration page for their home owner's insurance that will be included with this document.

Attachment A – Section 2

SECTION TWO – Interconnection Requirements ***(to be completed by GRU)***

1. **Engineering Review of PV System Information Provided By Owner/Operator**
   a. Elevation Drawing with Metering Location ____________________
   b. One-line Diagram with Point of Interconnection & Metering Description ________
   c. Electric Panel schedule (on all installations) ____________________
   d. Verify Installation does not exceed PV Allocation Size ____________________
   e. Verify voltage rise concerns do not exist. If it does, take needed action
   f. Verify project does not exceed the PV Saturation Threshold for Circuit
   g. Developer confirmed by email that they reviewed Section 8 of the ED Service Guide and have abided by its contents in their design & drawings
   h. Solar Panel Layout
   i. Location Site Plan

2. **Determination of Point of Interconnection**
   a. Summary of required distribution system additions or modifications:
   b. Cost estimate of additions/modifications above: $ ____________
   c. GIS graphic depicting Point of Interconnection (see attached map)
   d. Point of Interconnection detail: (Indicate where on GRU system)
      i (Circle One) Underground or Overhead transformer no. NNNNN, NN kVA, VVV Voltage
      ii. Approved by ______ *GRU Engineer* ______
      iii. Date Approval Completed: ____________________

3. **Metering Requirements**
   a Voltage ____________
   b. Meter installation description
   c. Communication protocol
   d. Summary of required metering infrastructure and costs:
      i. Approved by. ______ *GRU METERING Engineer* ______
      ii. Date Approval Completed: ____________

4. **Summary of Required Upgrades and Estimated Costs to Owner/Operator**

5. **ESTIMATED TOTAL COST** $ ____________

6. **Supplemental terms and conditions attached** (check one): ______ Yes / ______ No

SIGNATURES INDICATING ENGINEERING/METERING APPROVAL ON THIS PAGE REQUIRED BEFORE INTERCONNECTION AGREEMENT CAN BE EXECUTED.

The City of Fort Myers, Florida
Community Development Department
Building Division
1825 Hendry Street, Suite 101
Fort Myers, FL 33901
(239) 321-7925

City of Palms

Solar Permit Application

☐ **Residential** ☐ **Commercial**

NOTE: A COPY OF THE INSPECTION RECORDS & APPROVED DRAWINGS MUST BE ON JOB SITE FOR INSPECTORS TO USE

Application Date: ______________________

Job Name ______________________

Job Address ______________________

STRAP (tax folio) number: ______________________

Valuation $ ____________ **dollars** (all work including fair market value of design fees, site prep, labor, materials, sub-trades and mechanical trades, roofing, fire alarm systems, elevators, overhead and profit)

Permit Application and Supporting Documents

1. ____ Permit Application completed in its entirety including original, notarized signatures. If the owner is acting as his or her own contractor, Florida Statute 489.103(7) requires the owner to **personally appear** to sign the application.
2. ____ Proof of ownership in the public records of Lee County or A recorded deed is acceptable proof of ownership.
3. ____ Recorded "Notice of Commencement" for all jobs in excess of $2,500 as required per Florida Statute 713.135(d).
4. ____ Current Contractor registration with the City of Fort Myers

All Forms are available in our lobby or on our website:
www.cityftmyers.com/Departments/CommunityDevelopment/Divisions/BuildingPermitsInspections/Documents/OnlineForms

Contractor (license holder's real name): ______________________

Doing Business As (Name of Company) ______________________

Mailing address: ______________________

City ______________ State ________ Zip________

Telephone (____) ____________ fax (____) ____________

E-mail ______________________

Contractor's State Certification or Registration No. ______________ or,

Contractor's Lee County Certificate of Competency # ______________

Owner's Name ______________________

Owner's Address ______________________

City ______________ State ________ Zip________

Telephone (____) ____________ fax (____) ____________

E-mail ______________________

Person to whom Plan Review comments should be delivered:

Name: ______________________

Address: ______________________ Suite: ________

City: ______________ State: ________ Zip: ________

Telephone: (____) ____________ Fax: (____) ____________

E-mail: ______________________

Permit Type	Inspections Required
☐ **Solar for Heating Pool** - Installer must be a CV & CW Certified Solar Contractor, CF/RF Certified Plumbing Contractor, CP & RP Commercial Pool Contractor, CP & RP Residential Pool Contractor No Plan Review Required – Residential Only	• 207 - Solar
A roof attachment detail by an engineer is required for the solar panels. Contractor can do electric work associated with this installation.	

☐ **Solar Water Heating System** - Installer must be CV/CF/RF Contractor; CW Contractor for Residential Only No Plan Review Required – Residential Only	• 207 – Solar
Installer may install new or replace existing control attached to a cord-and-plug connected solar controller. For a photovoltaic pump controller, the CV-CW Contractor may install new or replace existing direct current power wiring between the photovoltaic panel and pump motor.	

☐ **Residential PV System** - DC circuit wiring from the collector to the inverter may be installed by a CV or EC contractor - AC circuit wiring can only be installed by a licensed Electrical Contractor (EC) *Drawings Required*	• 207 – Solar – Roof Attachment • 305 – Electric Final
☐ **Commercial PV System** - Can only be contracted and installed by a licensed Electrical Contractor *Drawings Required*	• 207 – Solar – Roof Attachment • 305 – Electric Final
Note: Roof attachments are considered to be components of a PV system and are within the scope of the EC, CV, CF, RF or CW Contractor. *** An Engineered Design is Required for All Solar & P.V. Panel Installations**	

☐ **Other:** ____________________ ____________________ ____________________	• Inspections as required

Description of Work: (be specific to determine the type of contractor):

____

____

____

____

Two, (2), copies of plans are required to be submitted

FINALS MUST BE CALLED IN PRIOR TO EXPIRATION DATE ON PERMIT. IF FAILURE TO DO SO, YOU WILL BE SUBJECT TO $100 FINE + BPI PERMIT FEE AND WILL BE REQUIRED TO FILL OUT A NEW PERMIT APPLICATION

Application is hereby made to obtain a permit to do the work and installations as indicated. **I certify that no work has commenced prior to the issuance of a permit** and that all work will be performed to meet the standards of all construction laws in this jurisdiction. I understand that a **separate permit must be secured for** ELECTRICAL WORK, PLUMBING, SIGNS, WELLS, POOLS, FURNACES, BOILERS, HEATERS, TANKS, and AIR CONDITIONERS, **etc**.

OWNER'S AFFIDAVIT: I certify that all the foregoing information is accurate and that all work will be done in compliance with all applicable laws regulating construction and zoning. **WARNING TO OWNER: YOUR FAILURE TO RECORD A NOTICE OF COMMENCEMENT MAY RESULT IN YOUR PAYING TWICE FOR IMPROVEMENTS TO YOUR PROPERTY.** IF YOU INTEND TO OBTAIN FINANCING, CONSULT WITH YOUR LENDER OR AN ATTORNEY BEFORE RECORDING YOUR NOTICE OF COMMENCEMENT.

If the owner is acting as his or her own contractor, Florida Statute 489.103(7) requires the owner to **personally appear** to sign the application.

Owner's signature____Date__________________
STATE OF FLORIDA, COUNTY OF _______ Sworn to (or affirmed) and subscribed before me this _____ day of _______, ________, by ______________________________ (name of person making statement),
Personally known ___ OR Produced identification ___ Type of Identification ______________________
____(Signature of Notary Public-State of Florida)
(Print, Type, or Stamp Commissioned Name of Notary Public)

OR

***Sign only in the presence of a Notary Public ***

Contractor's signature ____ Date ________________,
STATE OF FLORIDA, COUNTY OF _______ Sworn to (or affirmed) and subscribed before me this _____ day of _______, ________, by ______________________________ (name of person making statement),
Personally known ___OR Produced identification ___, type of identification ________________________
____(Signature of Notary Public-State of Florida)
(Print, Type or Stamp Commissioned Name of Notary Public)

Applicable codes:
2010 Edition Florida Building Code, *Building, Plumbing, Mechanical, Fuel Gas or Residential or Existing*
2010 Edition Florida Fire Prevention Code if applicable
2008 Edition National Electric Code as published by NFPA or NFPA 70A
The City of Fort Myers, Code of Ordinances
Florida Department of State, Administrative Code
The 2011 Florida Statutes

Application received by: **Office Use Only**
Permit Representative____ Date Received_________________
☐ Application scanned into system

PERMIT #		
DATE		CLERK
Payment method:		

Miscellaneous Application

Drop-down boxes are in yellow

CONTRACTOR INFORMATION	
Contractor Business Name:	License Holder's Name:
Mailing Address:	City License #:
City: State: Zip:	State License #:
Phone #: Fax #:	Contact Person:
To Construct:	Email:

PROPERTY INFORMATION	
Property Owner:	
Site Address:	Strap #:
City: State: Zip:	Block/Lot:
Phone #: Fax:	Unit:
Existing use:	
Proposed Use:	
Setback Distances: North South	East West
Zoned Foundation:	Corner Lot Waterfront Property
(Commercial Only) Construction Type: Lawn Irrigation System:	Water Usage:
Heads in right of way: Clean-up Contractor Name:	
If "YES" Check One: PIPING TO RUN PARALLEL TO ROAD ☐ PIPING TO RUN PERPENDICULAR TO ROAD ☐	
Valuation $	

Application is hereby made to obtain a permit to do the work and installation as indicated. I certify that no work or installation has commenced prior to the issuance of a permit and that all work will be performed to meet the standards of all laws regulating construction in this jurisdiction. I further certify that I have entered into a contract with the owner/agent of the subject property to make the specified improvements to, or perform the contracting at, the real property specified in this application. I have also made the owner/agent aware of the provisions of the Homebuyers Protection Act. I certify that all the foregoing information is accurate, the city has been advised of all easements on the property and all work will be done in compliance with all applicable laws regulating construction and zoning. I acknowledge and accept responsibility for compliance with the current Florida Building Code, regulations, and ordinances, as well as the payment of all legally constituted fees regarding this development application, including but not limited to ALL REVIEW FEES, PERMIT FEES, AND IMPACT FEES. I understand that a separate permit must be secured for ELECTRICAL WORK, PLUMBING, SIGNS, WELLS, POOLS, FURNACES, BOILERS, HEATERS, TANKS AND AIR CONDITIONERS, etc. **NOTICE**: In addition to the requirements of this

____________ INITIALS

permit, there may be additional restrictions to this property that may be found in the public records of this county or that may be required from other governmental entities such as water management district, state agencies or federal agencies.

OWNER'S AFFIDAVIT: I certify that all the foregoing information is accurate and that all work will be done in compliance with all applicable laws regulating construction and zoning.

OWNER'S ELECTRONIC SUBMISSION STATEMENT: Under penalty of perjury, I declare that all the information contained in this building permit application is true and correct.

WARNING TO OWNER: YOUR FAILURE TO RECORD A NOTICE OF COMMENCEMENT MAY RESULT IN YOUR PAYING TWICE FOR IMPROVEMENTS TO YOUR PROPERTY. A NOTICE OF COMENCEMENT MUST BE RECORDED AND POSTED ON THE JOB SITE BEFORE THE FIRST INSPECTION.

IF YOU INTEND TO OBTAIN FINANCING, CONSULT WITH YOUR LENDER OR AN ATTORNEY BEFORE COMMENCING WORK OR RECORDING YOUR NOTICE OF COMMENCEMENT.

I hereby acknowledge that I have read and understand the above affidavit on the __________ day of ______________, 20____.

NAME (PLEASE TYPE OR PRINT) SIGNATURE OF OWNER/AGENT/CONTRACTOR

(SIGNATURE MUST BE NOTARIZED)

STATE ______, COUNTY OF __________________

Sworn to (or affirmed) and subscribed before me this _____ day of _____, 20__, by ________________________ who is personally known or produced ____________________________ as identification.

Exp. Date: ___________ Commission Number: _______________

Signature of Notary Public: ____________________

Printed name of Notary Public: ____________________

FOR OFFICE USE ONLY					
Zoning Verification Verified by:	Date:	Approved Use: ☐ Yes ☐ No	Zoning District:		Flood Zone:
Classification:	Land Use:	On Site:	Used:	Parking Standard:	Total:

FEES:	APPROVALS:	
Building Permit $:	Building Approval by:	Date:
Surcharge$:	Zoning Approval by:	Date:
Notary $:	Species Approved by:	Date:
Surface Water $:	Fire Approved by:	Date:
Fire Permit $:	Surface Water Approved by:	Date:
Total $:	Released by (Permit Tracker):	Date:
Issued by (Building Clerk):	Permit # / Issue Date:	Expiration Date:

Broward encourages solar energy with easier permits

January 25, 2013 | By Doreen Hemlock, SunSentinel

Making energy from the sun seems a no-brainer for the Sunshine State, but cost has proven to be a hurdle.

Broward County has taken a big step to cut costs for solar-panel systems on rooftops and homeowners, businesses and other counties are taking notice, a Go Solar conference showed Friday.

With help from a $673,000 federal grant, Broward has simplified the process to apply for permits for roof-top solar-panel systems, saving time and money — perhaps thousands of dollars per system.

Click on a website, choose one of several pre-approved solar-panel system designs, and you can get the go-ahead online for that installation in select areas in the county, officials said.

"It can all be done electronically in a few minutes — instead of a few weeks — in some cases," said Armando Linares, deputy director of Broward's Environmental Protection & Growth Management Department.

The change is key because the U.S. Department of Energy estimates up to 40 percent of the cost of solar systems often involves expenses other than equipment, such as permits and design.

Fourteen cities in Broward are signed up for the one-stop permit program, which recently went live. Another nine Broward cities want to join. Plus, five counties in Florida are looking to use Broward's program as a model, including Miami-Dade and Orange, county officials said.

"And we're still waiting to hear from other cities and counties," added Linares.

More than 300 people turned out Friday at the Broward County Convention Center to learn more about the county's Go Solar program and opportunities for sun energy. Many were pleased to find out that costs are plunging as technology improves. Panels now run less than half the price from two years ago.

David Tringo, building department director for Weston, knows the challenges of solar first-hand. He shelled out $56,000 last year to install 48 solar panels in the backyard of his sprawling Sunrise home. He figures his 10-kilowatt system produces enough energy to save him about $250 a month on his electric bill. And it would probably cost him $10,000 less for a similar system now, as costs drop.

Still, Tringo recognizes that many people can't afford to pay out tens of thousands of dollars for solar — even if they get hefty tax credits from Florida Power & Light and the U.S. government after their outlay.

What would really boost solar locally is upfront financing, from loans to leases, participants agreed.

TD Bank, which operates a solar-powered bank in Fort Lauderdale, now lends for commercial solar systems, with loans generally from $500,000 to $5 million. But the bank doesn't offer loans for solar systems for homes, said Greg Kealey, regional manager for Florida for TD Equipment Finance.

Florida lags other states in installing and financing solar energy, partly because the state lacks a renewable energy standard or goal to spur companies and residents to act, analysts say.

California, Arizona and New Jersey led growth in solar installations through the first three quarters of 2012, according to the Solar Energy Industries Association, a Washington D.C.-based trade group.

Installations of solar panels nationwide more than doubled in 2010 and in 2011, and they were on pace to

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rise about 70 percent last year to a new high, the trade group said. Renewable energy accounted for more than half all new electricity generation added in the country last year, studies show.

Even so, solar accounts for less than 1 percent of energy produced nationwide, the group said, leaving ample room for growth, especially in the Sunbelt states.

The Go Solar Fest continues today from 9 a.m. to noon at the Broward County Convention Center, featuring exhibits from companies such as FP&L, The Energy Store of Hollywood and solar-powered vehicles, including a solar race car made by students at South Plantation High School.

dhemlock@sunsentinel.com, 305-810-5009

Go Solar Rooftop Challenge

What: A U.S. Department of Energy program to encourage solar panels on roofs of homes and businesses. Broward County received a grant to help with such key issues as simplified permits.

Broward cities participating: Coconut Creek, Dania Beach, Davie, Deerfield Beach, Fort Lauderdale, Hallandale, Hillsboro Beach, Lauderdale-by-the-Sea, Miramar, North Lauderdale, Oakland Park, Pompano Beach, Sunrise, Tamarac and unincorporated Broward County.

Broward cities seeking to join: Cooper City, Coral Springs, Hollywood, Lauderdale Lakes, Lighthouse Point, Parkland, Pembroke Pines, Southwest Ranches and Wilton Manors.

Counties looking to use Broward as a model: Miami-Dade, Monroe, Orange, Sarasota and Alachua.

More information: 954-519-1260 or broward.org/gogreen.

Source: Broward County Environmental Protection & Growth Management Department

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Regulatory Assessment Fees

Presentation to the

Financial Impact Estimating Conference

Mark Futrell
Florida Public Service Commission Staff
April 24, 2015

Regulatory Assessment Fees
Statutory Authority

Florida Public Service Regulatory Trust Fund

- Section 350.113, F.S.
- Fees collected and credited to the trust fund are used in the operation of the Commission as authorized by the Legislature
- Each regulated company under the jurisdiction of the commission, shall pay a fee based upon gross operating revenues

Chapters 364, 366 and 367, F.S., establish maximum regulatory assessment fees to be paid by electric, natural gas, and water and wastewater utilities, and telecommunications companies.

Regulatory Assessment Fees – Electric Utilities Implementation

Maximum Fees Established by Section 366.14, F.S.

- Investor-owned electric utilities: 0.125%
- Municipal and rural electric cooperative utilities: 0.015625%

Commission Rule 25-6.0131, F.A.C., establishes the fee

- Investor-owned electric utilities: 0.072%
  - Reduced from 0.0833% in 1999
- Municipal and rural electric cooperative utilities: 0.015625%

Regulatory Assessment Fees – Electric Utilities
($ millions)

	Investor-Owned Utilities			Municipal and Rural Cooperative Utilities		
Fiscal Year	Percentage Rate	RAF Collected	Operating Revenues	Percentage Rate	RAF Collected	Operating Revenues
13/14	0.072%	$12.4	$17,267.3	0.015625%	$0.945	$6,302.8
12/13	0.072%	$12.5	$17,384.0	0.015625%	$0.962	$7,769.1
11/12	0.072%	$12.9	$17,969.2	0.015625%	$0.993	$6,791.7

Regulatory Assessment Fees – Electric Utilities

Regulated Company Under Commission Jurisdiction → Public Utility; Municipal Utility; Rural Electric Cooperative → Electricity Sales to Customers

→ Operating Revenues → RAF Assessment → RAFs Remitted to the Commission

Public Utility: Entity supplying electricity to or for the public, and subject to the full regulatory authority of the Commission (s. 366.02, F.S.)

Tab 6

Impact

INITIATIVE FINANCIAL INFORMATION STATEMENT
LIMITS OR PREVENTS BARRIERS TO LOCAL SOLAR ELECTRICITY SUPPLY

SUMMARY OF INITIATIVE FINANCIAL INFORMATION STATEMENT

The amendment prohibits state and local government regulation of local solar electricity suppliers with respect to rates, service, or territory, and prohibits electric utilities from discriminating against customers of local solar electricity suppliers with respect to rates, charges, and terms of service. The amendment limits or prevents barriers to the sale of electricity by local solar electricity suppliers directly to customers. The Financial Impact Estimating Conference believes that the amendment will induce more solar electricity generation than would have occurred in its absence.

Based on information provided at public workshops and information collected through staff research, the conference expects the amendment will have several financial effects.

- Revenues from the following sources will be lower than they otherwise would have been as sales by local solar electricity suppliers displace sales by traditional utilities:
    - State regulatory assessment fees;
    - Local government franchise fees;
    - Local Public Service Tax;
    - State Gross Receipts Tax;
    - State and local Sales and Use Tax; and
    - Municipal utility electricity sales.
- At current millage rates, Ad Valorem Tax revenues will increase as a result of the installation of more solar energy systems than would have occurred in the amendment's absence. The increase in Ad Valorem Tax revenues is not expected to offset the reductions in other revenue sources. Over time, the Ad Valorem Taxes paid by electric utilities may be lower than otherwise as their need for additional generating capacity is reduced by expanded solar electricity production.
- Implementation and compliance costs will likely be minimal and include the following:
    - The Public Service Commission will incur one-time administrative costs related to the implementation of the amendment, particularly in regard to rule-making activities.
    - The Department of Revenue will incur administrative costs related to the implementation of the amendment, particularly in regard to rule-making, enforcement and compliance activities.
    - To the extent that current administrative practices are changed, local governments will incur costs related to the implementation of and compliance with the amendment. Some of these costs will likely be offset by fees.

There are numerous favorable and unfavorable factors affecting the adoption of solar technology to produce electricity in Florida. The magnitude of the revenue reductions cannot be determined because the following factors are uncertain: the extent and timing of the shift in electricity production from electric utilities to solar producers; continuation of federal solar investment tax credits; the methodology for determining the basis for the use tax on solar electricity; the pace of decline in solar energy production costs; the removal of technological barriers to greater deployment; and future legislative or administrative actions by state and local governments to mitigate the revenue reduction.

FINANCIAL IMPACT STATEMENT

Based on current laws and administration, the amendment will result in decreased state and local government revenues overall. The timing and magnitude of these decreases cannot be determined because they are dependent on various technological and economic factors that cannot be predicted with certainty. State and local governments will incur additional costs, which will likely be minimal and partially offset by fees.

I. SUBSTANTIVE ANALYSIS

A. Proposed Amendment

Ballot Title:

Limits or Prevents Barriers to Local Solar Electricity Supply

Ballot Summary:

Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers.

Text of Proposed Amendment:

The amendment proposes to add Section 29 to Article X as follows:

Purchase and sale of solar electricity. –

(a) PURPOSE AND INTENT. It shall be the policy of the state to encourage and promote local small-scale solar-generated electricity production and to enhance the availability of solar power to customers. This section is intended to accomplish this purpose by limiting and preventing regulatory and economic barriers that discourage the supply of electricity generated from solar energy sources to customers who consume the electricity at the same or a contiguous property as the site of the solar electricity production. Regulatory and economic barriers include rate, service and territory regulations imposed by state or local government on those supplying such local solar electricity, and imposition by electric utilities of special rates, fees, charges, tariffs, or terms and conditions of service on their customers consuming local solar electricity supplied by a third party that are not imposed on their other customers of the same type or class who do not consume local solar electricity.

(b) PURCHASE AND SALE OF LOCAL SMALL-SCALE SOLAR ELECTRICITY.

(1) A local solar electricity supplier, as defined in this section, shall not be subject to state or local government regulation with respect to rates, service, or territory, or be subject to any assignment, reservation, or division of service territory between or among electric utilities.

(2) No electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier.

(3) An electric utility shall not be relieved of its obligation under law to furnish service to any customer within its service territory on the basis that such customer also purchases electricity from a local solar electricity supplier.

(4) Notwithstanding paragraph (1), nothing in this section shall prohibit reasonable health, safety and welfare regulations, including, but not limited to, building codes, electrical codes, safety codes and pollution control regulations, which do not prohibit or have the effect of prohibiting the supply of solar-generated electricity by a local solar electricity supplier as defined in this section.

(c) DEFINITIONS. For the purposes of this section:

(1) “local solar electricity supplier” means any person who supplies electricity generated from a solar electricity generating facility with a maximum rated capacity of no more than 2 megawatts, that converts energy from the sun into thermal or electrical energy, to any other person located on the same property, or on separately owned but contiguous property, where the solar energy generating facility is located.

(2) “person” means any individual, firm, association, joint venture, partnership, estate, trust, business trust, syndicate, fiduciary, corporation, government entity, and any other group or combination.

(3) "electric utility" means every person, corporation, partnership, association, governmental entity, and their lessees, trustees, or receivers, other than a local solar electricity supplier, supplying electricity to ultimate consumers of electricity within this state.

(4) “local government” means any county, municipality, special district, district, authority, or any other subdivision of the state.

(d) ENFORCEMENT AND EFFECTIVE DATE. This amendment shall be effective on January 3, 2017.

Effective Date:

January 3, 2017

B. Effect of Proposed Amendment

The amendment prohibits state and local government regulation of local solar electricity suppliers with respect to rates, service, or territory, and prohibits electric utilities from discriminating against customers of local solar electricity suppliers with respect to rates, charges, and terms of service. The amendment limits or prevents barriers to the sale of electricity by local solar electricity suppliers directly to customers.

C. Background

Sponsor of the Proposed Amendment

Floridians for Solar Choice, Inc. is the official sponsor of the proposed amendment. The sponsor's website describes the organization as a "grassroots citizens' effort to allow more homes and businesses to generate electricity by harnessing the power of the sun."[1]

Public Service Commission (PSC)

The Florida Public Service Commission (PSC) is an arm of the legislative branch that regulates the electric, natural gas, water and wastewater, and telecommunications industries in the state. The PSC consists of five commissioners who are appointed by the Governor to four-year terms.[2]

For electric utilities, the commission has regulatory authority over each public utility. "Public utility" is defined to mean every person or legal entity supplying electricity to or for the public within this state, but to expressly exclude both a rural electric cooperative and a municipality or any agency thereof.[3]

With respect to electric utilities, the PSC regulates investor-owned electric companies' rates and charges, meter and billing accuracy, electric lines up to the meter, reliability of the electric service, new construction safety code compliance for transmission and distribution, territorial agreements and disputes, and the need for additional power plants and transmission lines. The PSC does not regulate rates and adequacy of services provided by municipally owned and rural cooperative electric utilities, except for safety oversight; electrical wiring inside the customer's building; taxes on the electric bill; physical placement of transmission and distribution lines; damage claims; right of way; and the physical placement or relocation of utility poles.[4]

Electric Utilities

Pursuant to Chapter 366, F.S., the PSC has regulatory authority over 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives.[5] According to the PSC's 2012 publication entitled "Statistics of the Florida Electric Utility Industry," for each year between 1998 and 2012, of total net capacity statewide, investor-owned utilities had approximately 75 percent of total megawatts, and municipal and rural electric cooperatives combined made up the other 25 percent.

[1] Floridians for Solar Choice website: http://www.flsolarchoice.org/
[2] Chapter 350, Florida Statutes.
[3] Section 366.02(1), F.S.
[4] Florida Public Service Commission, "When to Call the Florida Public Service Commission" available at http://www.psc.state.fl.us/publications/consumer/brochure/When_to_Call_the_PSC.pdf
[5] Florida Public Service Commission, "Facts and Figures of the Florida Utility Industry" March 2015 available at http://www.psc.state.fl.us/publications/pdf/general/factsandfigures2015.pdf

Investor-Owned Electric Utilities

Currently, five investor-owned utilities (Florida Power and Light Company, Duke Energy Florida, Inc., Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Corporation) operate in Florida. The PSC has regulatory authority over all aspects of operations, including rates and safety.[6]

Municipal Electric Utilities

There are 35 generating and non-generating municipal electric utilities in Florida.[7] According to the Florida Municipal Electric Association, municipal utilities are not-for-profit and are governed by an elected city commission or an appointed or elected utility board. Capital is raised through operating revenues or the sale of tax-exempt bonds.[8] Together, these utilities serve 15 percent of the state's population.[9] Payments from their customers are considered to be local government revenues.

Rural Electric Cooperatives

Rural electric cooperatives were created as the result of the Rural Electrification Act of 1936. At the time, electric utilities did not provide service in large portions of Florida since the cost of providing such service in the non-urban areas was prohibitive. The cooperatives were formed to make electricity available in rural areas. Today these electric cooperatives are still not-for-profit electric utilities that are owned by the members they serve and provide at-cost electric service to their members. Each cooperative is governed by a board of cooperative members that is elected by the membership. Today Florida has 16 distribution cooperatives and 2 generation and transmission cooperatives that serve 10 percent of the state's population.[10]

Solar Energy in Florida

According to the PSC, as of 2013, there were 6,678 customer-owned solar systems in Florida.[11] This number dramatically increased over the previous six years, as can be seen in the following table prepared by the PSC. The increase was primarily due to the rapidly decreasing price of solar energy systems and the availability of state and federal incentives which alleviate substantial up-front costs to customers.

---

[6] Ibid, p.10.
[7] Ibid, p.11.
[8] Florida Municipal Electric Association, "Florida Public Power" webpage, available at http://publicpower.com/floridas-electric-utilities-2/
[9] Florida Municipal Electric Association, "Who is FMEA?" webpage, available at http://publicpower.com/who-is-fmea/
[10] Florida Electric Cooperatives Association, "About Us" webpage, available at http://www.feca.com/about.html
[11] PSC Memorandum provided for presentation at April 10, 2015 FIEC Public Workshop

Customer-Owned Solar Generation												
	# of Customer-Owned Solar Systems						kW Gross Power Rating					
	2008	2009	2010	2011	2012	2013	2008	2009	2010	2011	2012	2013
IOU	383	1,045	1,855	2,803	3,799	4,818	1,696	7,653	12,442	19,441	30,401	43,876
Municipal	137	313	493	614	791	1,007	797	3,378	4,099	5,002	7,021	11,787
Rural Electric Cooperative	57	267	461	549	684	853	272	1,955	2,667	3,262	4,099	4,865
TOTAL	577	1,625	2,809	3,966	5,274	6,678	2,765	12,986	19,208	27,705	41,521	60,528

Net Metering

Net metering allows utility customers with renewable energy systems to pay their utility for only the net energy used. Depending on its supply of or demand for electricity at various times, a home or business with a solar energy system may export excess power to the electric grid or import power from the grid. If a customer produces more electricity than consumed, the utility bill will be credited for the excess production. Net metering is currently allowed and commonly used in Florida.

Third-Party Financing Models

Third-party financing models alleviate the large upfront costs of purchasing and installing solar energy systems, making it more affordable for customers to adopt the use of solar power without the initial capital investment requirements.

Solar Leases

A solar lease is a financial agreement in which a property owner enters into a lease for the installation of a solar energy system. The property owner pays the company for the use and maintenance of the solar equipment. Typically, the electricity produced by the solar energy system is consumed on the property with any excess being transferred to the electric utility serving the property. Solar leases are permitted under current law in Florida.

Solar Power Purchase Agreements (PPAs)

A solar power purchase agreement (PPA) is a financial agreement in which a developer installs and finances a solar energy system on a customer's property. The customer then purchases the power generated from the system from the developer at a fixed rate, which is typically lower than the local utility's retail rate. The developer maintains responsibility for the operation and maintenance of the system for the duration of the PPA, which typically ranges from 10 to 25 years.

In the U.S. Department of Energy's 2010 report entitled "Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners", refers to the following court case and ruling related to PPAs in Florida:

> "In 1987, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project for which PW Ventures, Inc. (PW Ventures) would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide most of their power needs (PW Ventures v. Nichols, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, Florida Power & Light. The definition of a "Public utility" as defined by Florida Statute 366.02 is:
>
> > Every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas…to or for the public within this state.
>
> In their ruling on the issue, the FPSC focused on the definition of "to or for the public." PW Ventures argued that to be considered a utility they would have to sell their power to the general public to be considered a utility. However, the Commission determined that the definition of "to or for the public" could mean one customer, meaning that by selling only to Pratt and Whitney, PW Ventures was selling to the public and would be deemed a public utility. Without a change in statute, this ruling appears to eliminate the possibility of using the third-party PPA model in Florida without PSC regulation (FPSC 1987)."

Further, in regards to net metering and PPAs, Floridians for Solar Choice, the proponents of the ballot amendment, provided the following:

> "Currently, a property owner who owns his own solar panels can net meter. A property owner who leases panels from a third party can net meter. These activities are permitted because the property owner is not purchasing solar electricity from a third party, but is instead purchasing or leasing the panels. A property owner who buys solar generated power from a company which has placed solar panels on his or her property cannot net meter."

Current law in Florida makes PPAs infeasible because the purchase of solar-generated electricity in these types of financial agreements would subject the provider of electricity to PSC regulation as an "electric utility."

<u>State and Local Revenues</u>

Sales Tax

Section 212.08(7)(hh), F.S., provides a sales tax exemption for solar energy systems and any component thereof. Section 212.02(26), F.S., defines "solar energy system" as "the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity." The Florida Solar Energy Center publishes a comprehensive list of solar energy system components.

Section 212.08(7)(j), F.S., provides an exemption for household fuels including sales of utilities to residential households by utility companies that pay gross receipts tax. The sale of electricity produced from solar energy is included in this exemption.

Section 212.05, F.S., levies a 4.35 percent tax on the sale of electricity to nonresidential consumers. Section 212.06(1)(b), F.S., provides the corresponding use tax. Section 212.07(1)(b), F.S., provides an exemption for sales for resale.

Gross Receipts Tax

Pursuant to ch. 203, F.S., Gross Receipts Taxes are imposed on sellers of electricity and natural or manufactured gas at a rate of 2.5 percent and on the sale of communications services at a rate of 2.52 percent. In addition, a rate of 2.6 percent is levied on sales to non-residential customers not otherwise exempt.

The gross receipts "use tax" in ss. 203.01(1)(h)&(i), F.S., provides that any electricity produced and used by a person, cogenerator, or small power producer, is subject to the Gross Receipts Tax.

All Gross Receipts Tax revenues are deposited in the Public Education Capital Outlay (PECO) Trust Fund, which is administered by the Department of Education (DOE). These revenues are primarily used to pay debt service on outstanding PECO bonds, but may be used for additional education-related purposes if any revenues are available after debt service is paid.

Ad Valorem Tax

The ad valorem tax is an annual tax levied by local governments based on the value of real and tangible personal property as of January 1 of each year. Florida's constitution prohibits the state government from levying an ad valorem tax except on intangible personal property. The taxable value of real and tangible personal property is the just value (i.e., the fair market value) of the property adjusted for any exclusion, differential, or exemption allowed by the Florida Constitution or the statutes. The Florida Constitution strictly limits the Legislature's authority to provide exemptions or adjustments to fair market value. Also, with certain exceptions for millage levies approved by the voters, the Florida Constitution limits county, municipal and school district levies to ten mills each.

Section 193.624 (2), F.S., provides that when determining the assessed value of real property used for residential purposes, an increase in the just value of the property attributable to the installation of a renewable energy source device may not be considered.

Franchise Fees[12]

Article VIII, Section 2(b), Florida Constitution, provides:

> (b) POWERS. Municipalities shall have governmental, corporate and proprietary powers to enable them to conduct municipal government, perform municipal functions and render municipal services, and may exercise any power for municipal purposes except as otherwise provided by law. Each municipal legislative body shall be elective.

Section 166.021, F.S., grants extensive home rule power to municipalities. A municipality has the complete power to legislate by ordinance for any municipal purpose, except in those situations that a general or special law is inconsistent with the subject matter of the proposed ordinance.

Not all local government revenue sources are taxes requiring general law authorization under Article VII, Section 1(a), Florida Constitution. When a county or municipal revenue source is imposed by ordinance, the judicial test is whether the charge meets the legal sufficiency test, pursuant to Florida case law, for a valid fee or assessment. If not a valid fee or assessment, the charge is a tax and requires general law authorization. If not a tax, the fee or assessment's imposition is within the constitutional and statutory home rule power of municipalities and counties.

When analyzing the validity of a home rule fee, judicial reliance is often placed on the type of governmental power being exercised. Generally, fees fall into two categories. Regulatory fees, such as building permit fees, inspection fees, impact fees, and stormwater fees, are imposed pursuant to the exercise of police powers as regulation of an activity or property. Such regulatory fees cannot exceed the cost of the regulated activity and are generally applied solely to pay the cost of the regulated activity.

In contrast, proprietary fees, such as user fees, rental fees, and franchise fees, are imposed pursuant to the exercise of the proprietary right of government. Such proprietary fees are governed by the principle that the fee payer receives a special benefit or the imposed fee is reasonable in relation to the privilege or service provided. For each fee category, rules have been developed by Florida case law to distinguish a valid fee from a tax.

Local governments may exercise their home rule authority to impose a franchise fee upon a utility for the grant of a franchise and the privilege of using a local government's rights-of-way to conduct the utility business. The franchise fee is considered fair rent for the use of such rights-of-way and consideration for the local government's agreement not to provide competing utility services during the term of the franchise agreement. The imposition of the fee requires the adoption of a franchise agreement, which grants a special privilege that is not available to the general public. Typically, the franchise fee is calculated as a percentage of the utility's gross revenues within a defined geographic area. A fee imposed by a municipality is based upon the gross revenues received from the incorporated area while a fee imposed by a county is generally based upon the gross revenues received from the unincorporated area.

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[12] The following discussion of franchise fees is based on materials contained in Nabors, Giblin & Nickerson, P.A., Primer on Home Rule & Local Government Revenue Sources (June 2014).

In Fiscal Year 2012-13, 343 municipal governments in Florida collected $656.5 million in franchise fee revenues, of which $546.5 million (83.3 percent) was from electricity franchise fees. Electricity franchise fee revenues accounted for 1.7 percent of total municipal government revenues for that fiscal year. In Fiscal Year 2012-13, 13 county governments in Florida collected $160.3 million in franchise fee revenues, of which $139.0 million (86.7 percent) was from electricity franchise fees. Similar to the municipal governments, the electricity franchise fee revenues accounted for 0.4 percent of total county government revenues. Summaries of prior years' franchise fee revenues as reported by local governments are available on the Office of Economic and Demographic Research's (EDR) website.[13]

Public Service Tax

Municipalities and charter counties may levy by ordinance a public service tax on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service.[14] The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed 10 percent of the payments received by the seller of the taxable item. Services competitive with those listed above, as defined by ordinance, can be taxed on a comparable base at the same rates; however, the tax rate on fuel oil cannot exceed 4 cents per gallon.[15] The tax proceeds are considered general revenue for the municipality or charter county.

All municipalities are eligible to levy the tax within the area of its tax jurisdiction. In addition, municipalities imposing the tax on cable television service, as of May 4, 1977, may continue the tax levy in order to satisfy debt obligations incurred prior to that date. By virtue of a number of legal rulings in Florida case law, a charter county may levy the tax within the unincorporated area. For example, the Florida Supreme Court ruled in 1972 that charter counties, unless specifically precluded by general or special law, could impose by ordinance any tax in the area of its tax jurisdiction that a municipality could impose.[16] In 1994, the Court held that Orange County could levy a public service tax without specific statutory authority to do so.[17]

The tax is collected by the seller of the taxable item from the purchaser at the time of payment.[18] At the discretion of the local taxing authority, the tax may be levied on a physical unit basis. Using this basis, the tax is levied as follows: electricity, number of kilowatt hours purchased; metered or bottled gas, number of cubic feet purchased; fuel oil and kerosene, number of gallons purchased; and water service, number of gallons purchased.[19] A number of tax exemptions are specified in law.[20]

A tax levy is adopted by ordinance, and the effective date of every tax levy or repeal must be the beginning of a subsequent calendar quarter: January 1st, April 1st, July 1st, or October 1st.

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[13] http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm
[14] Section 166.231(1), F.S.
[15] Section 166.231(2), F.S.
[16] Volusia County vs. Dickinson, 269 So.2d 9 (Fla. 1972).
[17] McLeod vs. Orange County, 645 So.2d 411 (Fla. 1994).
[18] Section 166.231(7), F.S.
[19] Section 166.232, F.S.
[20] Section 166.231(3)-(6) and (8), F.S.

The taxing authority must notify the Department of Revenue (DOR) of a tax levy adoption or repeal at least 120 days before its effective date. Such notification must be furnished on a form prescribed by the DOR and specify the services taxed, the tax rate applied to each service, and the effective date of the levy or repeal as well as other additional information.[21]

The seller of the service remits the taxes collected to the governing body in the manner prescribed by ordinance.[22] The tax proceeds are considered general revenue for the municipality or charter county. As previously mentioned, taxing authorities are required to furnish information to the DOR and the Department maintains an online database that can be searched or downloaded.[23]

In Fiscal Year 2012-13, 327 municipal governments collected $864.1 million in Public Service Tax revenues of which $686.3 million (79.4 percent) was from public service taxes on electricity. Electricity public service tax revenues made up 2.1 percent of total municipal revenues in that fiscal year. Also in Fiscal Year 2012-13, 12 charter county governments collected $255.8 million in Public Service Tax revenues, of which $224.1 million (87.6 percent) was from public service taxes on electricity. Similar to the municipalities, the electricity public service taxes made up 0.8 percent of the counties total revenues in that fiscal year. Summaries of prior years' revenues reported by county and municipal governments are available on EDR's website.[24]

Regulatory Assessment Fees

Section 366.14, F.S., provides that each regulated company under the jurisdiction of the PSC must pay a fee based on its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives, or any combination. Statutorily, the rate for investor-owned utilities that supply electricity can be no greater than 0.125 percent, and the rate for municipal electric utilities and rural electric cooperatives can be no greater than 0.015625 percent. PSC Rule 25-6.0131, F.A.C., establishes the fee on investor-owned electric utilities at 0.072 percent and municipal and rural electric cooperative utilities at the statutory maximum 0.015625 percent.

II. FISCAL ANALYSIS & ECONOMIC IMPACT STATEMENT

Section 100.371(5)(a), F.S., requires that the Financial Impact Estimating Conference "…complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative."

As part of determining the fiscal impact of this amendment, the Conference held four public meetings:

- Public Workshop on April 10, 2015

21 Section 166.233(2), F.S.
22 Section 166.231(7), F.S.
23 http://dor.myflorida.com/dor/governments/mpst/
24 http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm

- Principals’ Workshop on April 24, 2015
- Formal Conference on May 6, 2015 and May 7, 2015

A. FISCAL ANALYSIS BACKGROUND

Requested Information from State Entities and other Organizations

The following table provides a summary of information gathered from several state entities and other organizations that presented information to the FIEC. Information specific to tax revenues that was provided by the Department of Revenue (DOR) is addressed separately under the “Tax Treatment of Solar Equipment and Energy in Florida” section of this report.

Presenter	Date	Summary of Information
Public Service Commission (PSC)	April 10th April 24th	Commission staff indicated that implementation costs are unknown at this time. Staff provided information on Regulatory Assessment Fees, which are designed to cover the costs of utility regulation. The revenue reductions associated with the amendment will depend on the degree of displacement of traditional utility activity. At a minimum, rule-making would be necessary to change the Regulatory Assessment Fee rate.
Department of Revenue (DOR)	April 24th	The key to implementation is voluntary compliance – payment of Gross Receipts Use Tax. DOR did not identify specific implementation costs but indicated the need to work with various stakeholders to facilitate voluntary compliance methods.
Florida League of Cities	April 10th April 24th	The impact will depend on the degree to which the amendment incentivizes additional solar activity. There are two scenarios that could impact the franchise fee revenues. The first is a reduction in the gross revenues of an electric utility due to increased generation of local small-scale solar-generated electricity. The second is the potential termination or renegotiation of franchise fee agreements. Costs associated with the permitting process for building/installing solar may have to be re-evaluated in the event of an expansion of solar. Net metering agreements and insurance requirements on interconnections to the grid may also have to be re-evaluated.
Florida Association of Counties	April 24th	Public Service Tax collections will likely be reduced. Franchise fee agreements would likely be terminated, in which case the agreements would have to be re-negotiated, probably at a loss to the affected counties.

The PSC, Florida League of Cities, and Florida Association of Counties all believe that there will be costs to implement the amendment. However, those costs are currently unknown. The Florida League of Cities and Florida Association of Counties believe that the Public Service Tax and franchise fees will likely see reduced collections, but the amount is unknown. The Regulatory Assessment Fee imposed on the municipal electric utilities and rural electric cooperatives is already at the statutory maximum rate. If the amendment's implementation results in a future reduction to the gross operating revenues of municipal electric utilities and rural electric cooperatives, it is possible that the Florida Legislature would consider a statutory rate increase in order to prevent a potential future revenue loss to the Public Service Commission. The Regulatory Assessment Fee currently imposed on the investor-owned utilities is not at the maximum rate, so there would be flexibility to adjust that rate to the extent needed, if the amendment results in changes to gross operating revenues of the utilities.

Solar Business Models

The following table describes five different solar business models. The first four were identified by Floridians for Solar Choice, and the fifth was identified by the FIEC. Models A and B are permitted under current law, while models C, D, and E are not.

	Business Model Description	**Allowable Under Current Law?**
A	A property owner contracts for the purchase and installation of solar equipment that provides energy to the property.	Yes
B	A property owner enters into a lease for the installation of solar equipment on the property with the solar energy being consumed on the property. The property owner pays the company for the use and maintenance of the solar equipment.	Yes
C	A property owner allows a company to install equipment on the property and purchases some, but not necessarily all, of the solar energy from the company. The solar energy system may be financed through a PPA which requires the purchaser to pay a monthly charge to the solar supplier based on the amount of solar electricity used at the property.	No
D	A property owner provides solar-generated electricity to itself and also sells it to contiguous property owners.	No
E	Multiple contiguous property owners purchase solar-generated electricity from a centrally located solar-panel hub owned by someone other than an electric utility.	No

Tax Treatment of Solar Equipment and Solar Energy in Florida

The following table and explanatory notes were prepared by the Department of Revenue (DOR) and present six scenarios related to potential solar energy financial arrangements. The table presents the sales tax and gross receipts tax implications of each scenario. Scenarios III. and VI. are permitted under current law, while Scenarios I., II., IV., and V. are not.

	Scenario	Purchase of Solar System	Use of self-generated electricity		Sale of excess electricity to neighbor (or utility in III. and VI.)	
		Sales/Use	Sales/Use	Gross Receipts	Sales/Use	Gross Receipts
I.	**A residential household buys or leases a solar system then sells excess electricity directly to a neighbor without going through the local utility/grid.**	exempt	exempt	use tax	exempt if neighbor is residential; taxable if neighbor is commercial and not otherwise exempt	arguably taxable
II.	**A residential household buys or leases a solar system then sells excess electricity directly to a neighbor using another entity's distribution system.**	exempt	exempt	use tax	exempt if neighbor is residential; taxable if neighbor is commercial and not otherwise exempt	arguably not taxable
III.	**A residential household buys or leases a solar system, sells the excess electricity to the local utility under a net-metering agreement. The local utility then sells the electricity to the household's neighbor.**	exempt	exempt	use tax	exempt as a sale for resale	exempt as a sale for resale
IV.	**A commercial business buys or leases a solar system, then sells the excess electricity directly to a neighbor without going through the local utility/grid.**	exempt	use tax	use tax	exempt if neighbor is residential; taxable if neighbor is commercial and not otherwise exempt	arguably taxable
V.	**A commercial business buys or leases a solar system, then sells the excess electricity directly to a neighbor using another entity's distribution system.**	exempt	use tax	use tax	exempt if neighbor is residential; taxable if neighbor is commercial and not otherwise exempt	arguable not taxable
VI.	**A commercial business buys or leases a solar system, then sells the excess electricity to a local utility under a net-metering agreement. The local utility sells the electricity to the commercial business's neighbor.**	exempt	use tax	use tax	exempt as a sale for resale	exempt as a sale for resale

In the last column of the table above, some of the scenarios are categorized as "arguably" taxable or "arguably" not taxable. The uncertainty stems from the definition of "distribution company." The Gross Receipts Tax is imposed on "distribution companies." Section 203.012(1), F.S., defines the term "distribution companies" as meaning: "… any person owning or operating local electric or natural or manufactured gas utility <u>distribution facilities</u> within this state for the transmission, delivery, and sale of electricity or natural or manufactured gas. …" [emphasis added] The term "distribution facilities" is not defined in statute. Arguments both for and against someone being considered a "distribution company" could be made. The spectrum of fact patterns that one can envision would range from a power producer like a traditional large investor-owned utility to a future wherein neighbors share electricity they produce through wiring that they install and maintain.

B. FISCAL ANALYSIS CONCLUSIONS BY THE FIEC

There are numerous favorable and unfavorable factors affecting the adoption of solar technology to produce electricity in Florida. The amendment will likely induce more solar electricity generation than would have occurred in its absence. In this regard, the conference agrees with the following statement in the joint memorandum from Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company (the Utilities) dated April 22, 2015: "The express purpose of the proposed Initiative is to 'encourage and promote local small-scale solar-generated electricity' (Section (a) of the proposed Initiative) and to facilitate its sale to electric consumers in Florida. Those sales will necessarily displace sales of electricity currently made by the Utilities, as well as by municipal utilities and electric cooperatives." The items discussed below are influenced by this premise.

Regulatory Assessment Fees
State Impact: Reduction in Revenue

1. The relevant impact is limited to state government.
2. Current revenues are likely to decline due to sales by traditional utilities displacing sales by local solar electricity suppliers.
3. The Public Service Commission has the ability to act to generate additional dollars.
    - i) For Investor-Owned Utilities, the assessment rate is not at its statutory maximum.
    - ii) For Municipal and Rural Electric Cooperative Utilities, the assessment rate has reached its statutory maximum.
    - iii) Section 350.113(3), F.S. reads in part: "The fee shall, *to the extent practicable*, be related to the cost of regulating such type of regulated company." [emphasis added]

Municipal Utility Revenues
Local Impact: Probable Revenue Loss to Local Governments

1. Payments by customers to the municipally owned utilities are local government revenues that are used to operate the utility and in some cases to finance the general operations of government.
2. To the extent that production and sale of electricity by local solar electricity suppliers displaces municipal utility sales, local government revenues will be reduced.
3. It is unknown how local governments will respond to the loss of revenue.

Local Government Franchise Agreements
Local Impact: Probable Revenue Loss to Local Governments

1. Since franchise fees are calculated based on the gross sales of electricity by utilities, each reduced or eliminated sale by a utility results in a reduction in the amount of fees collected.
2. The conference agrees with the following statement in the joint memorandum from Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company dated April 22, 2015: "There is no question that those franchise fees would *not* be paid on LSES [Local Solar Electricity Suppliers] sales. This is because the agreements pursuant to which utilities pay franchise fees are bilateral contracts between the specific utilities and the counties and municipalities that the utilities serve. There is no counterpart to those franchise agreements for LSES sales."
3. Renegotiation of local government franchise agreements resulting in lower rates than would have occurred in the absence of the amendment is also likely. However, the timing of such reduction is unclear. Whether it occurs as a result of outright cancellation or upon the expiration of current agreements is unknown. At a minimum, local governments will experience a loss in bargaining strength and will be at a disadvantage in future negotiations.
4. In public and written testimony provided on April 24, 2015 to the FIEC, representatives of the Florida League of Cities and the Florida Association of Counties expressed concerns that current electric utility franchise agreements may be impaired.
5. It is unknown how local governments will respond to the loss of revenue.

Ad Valorem Taxes
Local Impact: Probable Initial Revenue Gain to Local Governments

1. The installation of more solar energy systems on non-residential properties than would have occurred in the amendment's absence will increase ad valorem revenues to local governments at current millage rates.
2. Over time, the Ad Valorem Taxes paid by electric utilities may be lower than otherwise as their need for additional generating capacity is reduced by expanded solar electricity production.
3. It is unknown how local governments will respond to the changes in revenue.

Public Service Tax
Local Impact: Probable Revenue Loss to Local Governments

1. The Public Service Tax does not have a "use tax" provision; consequently electricity produced but not sold by local solar electricity suppliers is not subject to the tax.
2. To the extent that the electricity produced by local solar electricity suppliers reduces sales of electricity, tax collections will be reduced.
3. It is unknown how local governments will respond to the loss of revenue.
4. It is possible—but cannot be deemed probable—that the Legislature would act to change the basis of this tax to capture additional kinds of sales or impose a use tax.

Gross Receipts Tax
State Impact: Probable Revenue Loss to State Government

1. In regard to (a) the use of self-generated electricity and (b) sales that are not reliant on the grid for transmission, the use tax provisions associated with the Gross Receipts Tax rely on voluntary compliance, which is overall less effective than traditional tax collection methods.
2. In regard to sales of excess electricity that use another entity's distribution system, the sales are arguably not taxable, but the consumer of that electricity is subject to use tax.
3. In regard to sales of excess electricity through net metering agreements with electric utilities, the sales are exempt as sales for resale; however, the sale by the utility to a customer is taxable.
4. It is unknown how state government would respond to the loss of revenue.
5. It is possible—but cannot be deemed probable—that the Legislature would act to increase enforcement of use tax provisions or to otherwise broaden the taxable base.
6. It is probable that the Department of Revenue would act to increase voluntary compliance in some manner, but the outcome is uncertain and likely to be less than 100 percent effective.

Sales Tax
State and Local Impact: Probable Revenue Loss to State and Local Governments

1. In regard to self-generated electricity for commercial purposes, the use tax provisions associated with the Sales Tax rely on voluntary compliance, which is overall less effective than traditional tax collection methods.
2. In regard to sales of excess electricity for commercial purposes that use another entity's distribution system, the sales are taxable.
3. In regard to sales of excess electricity through net metering agreements with electric utilities, the sales are exempt as sales for resale; however, the sale by the utility to a customer is taxable.
4. It is unknown how state and local governments would respond to the loss of revenue.
5. It is possible—but cannot be deemed probable—that the Legislature would act to increase enforcement in some manner.
6. It is probable that the Department of Revenue would act to increase voluntary compliance in some manner, but the outcome is uncertain and likely to be less than 100 percent effective.

Implementation and Compliance Costs
State and Local Impact: Probable Minor Costs to State and Local Governments

1. The Public Service Commission is likely to incur one-time administrative costs related to the implementation of the amendment, particularly in regard to rule-making activities.
2. The Department of Revenue is likely to incur administrative costs related to the implementation of the amendment, particularly in regard to rule-making and compliance activities.
3. To the extent that current administrative practices are changed, local governments are likely to incur costs related to the implementation of and compliance with the amendment. Some of these costs will likely be offset by fees.
4. All of these costs are expected to be minor.