**SUPPLEMENTAL INFORMATION**

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

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This document serves as a source of supplemental information for our paper “Diffusion of environmentally-friendly energy technologies: buy vs. lease differences in residential PV markets.” In it we describe in detail the data and methodologies used in the study and present results excluded from the primary publication due to length limitations. For continuity, all figures are located in the appendix. **We assume that the reader is already familiar with the primary publication.**

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1. Data and Methodology

Our basic strategy is to compare the payback period that PV adopters report as having used to evaluate their investment decision with an "objective" model we have built to calculate those same metrics. Actual metrics used by PV adopters in their decision and other related financial and behavioral aspects of their decision-making process were obtained through a survey of PV owners in Texas (see Section 1.2). To enable a comparison, we built a financial model that calculates the lifecycle expected costs and revenues associated with ownership of a residential PV system for the buying and leasing business models (NREL 2009; Kollins et al. 2010). Two factors make our model unique. First, our uniquely comprehensive dataset allows us to make detailed cost and revenue calculations for each respondent (decision maker). Second, our model includes several detailed features of household-level electricity consumption, electricity rates, and PV-based electricity generation, including time-of-day and monthly variations. Our temporal resolution is at the hourly level, aggregated for all days of a month; that is, the given hour represents that hour for all days in that specific month.

1.1 Calculation of Financial Metrics: Cash Flow Model

For each PV adopter in the dataset we calculated a series of monthly expected costs \( C_k \) and revenues \( R_k \) that are incurred every month over the lifetime of the PV system, where \( k \) is the number of months since the PV system was installed. For lessees the system life is the length of the lease contract (typically 15 years) and for buyers it is 20 to 25 years, which is the standard length of warranty coverage on the PV modules. Therefore, monthly cash flows \( CF_k \) in month \( k \) of the investment are:

\[
CF_k = R_k - C_k,
\]

Lifetime cash flow is given simply by \( \sum_k CF_k \). Details of how \( C_k \) and \( R_k \) are calculated are provided below. Using these cash flows we calculate a number of standard financial metrics for each household's investment, including NPV (using a 10% annual discount rate), NPV per DC-kW, and payback period. Further, as we discuss later, we also estimate each individual's unique implicit discount rate.

Next we detail the process of calculating costs and revenues. Let \( c_{ijk} \) be the electrical consumption and \( g_{ijk} \) be the system's generation in hour \( i \) (1–24), month \( j \) of the year (1–12), and \( k \) be the number of months since the system was installed. Note that \( j = k \mod 12 \), but we preserve the index for clarity and to emphasize intermonthly variation. System generation is adjusted by a monthly system loss factor \( l \):

\[
g_{ijk+1} = g_{ijk} \times (1 - l).
\]
Furthermore, $f$ is a function that calculates electricity costs such that $f_{BAU}(c_{ijk})$ is the business-as-usual (BAU) electric bill prorated for period $ijk$ and $f_{PV}(c_{ijk} - g_{ijk})$ is the PV electric bill for the same period. The electricity bill function is numerically calculated based on the individual’s rate plan and electricity tariffs are escalated by an annual growth rate, which is a parameter in the model.

Therefore, revenue associated with system ownership in month $k$ after system installation is:

$$R_k = \sum_{i}^{24} f_{BAU}(c_{ijk}) - f_{PV}(c_{ijk} - g_{ijk}) .$$

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 ($C_{O&M_k}$), and (c) cost of inverter replacement($C_{Inverter_k}$) where:

$$C_k = C_{system_k} + C_{O&M_k} + C_{Inverter_k} .$$

1.1.1 Buyers’ Costs

For buyers, system payments comprise of the system down payment in the first period and any loan payments if the system is financed. The net system cost is calculated as the total installed cost less the utility rebate reported in the program data. Last, 30% of the remaining balance is subtracted to account for Federal Tax Credits (FTC). We assume that buyers will be required to make periodic operation and maintenance-related (O&M) expenses which range from 0%/year to 0.75%/year of the system’s installed cost and are expensed equally each month. Inverters comprise a substantial portion of a system’s installed cost and are assumed to require replacement after 15 years of use. Thus, buyers pay 70¢ to 95¢ per DC-Watt in real costs in the fifteenth year of ownership to represent this cost. In Section 1.3 below we develop a set of scenarios that are used to systematically vary these parameters.

1.1.1 Leasers’ Costs

As defined by their contractual agreement, solar lessees are not obligated to pay O&M or inverter replacement costs. Therefore, the only costs of ownership they incur are either monthly lease payments that escalate by 2.5% a year, or, as in the case of the majority of leases, a single payment incurred in the first period known as a ‘pre-paid lease’. Within the sample, 69% of lessees paid for their lease entirely through a ‘pre-paid’ down payment, 26% through only monthly payments, and 4% through a combination of monthly payments and a down payment. For all 68 leased systems in our dataset we use the actual lease payments being made by the lessees.
1.2 Additional Information on Data Sources

Our analysis uses a new household-level dataset we have built through two complementary data streams: (i) a survey of residents who have already adopted PV and (ii) solar program data for these same PV adopters obtained from electric utilities that administer rebate programs for residential PV. All survey respondents reported residing in Texas and reside in areas of retail electricity choice (fig 1).

1.2.1 Electricity Consumption Profiles

Given the seasonal and hourly variations of both solar generation and electric rate structure, we modeled household electric consumption to include both hourly and monthly factors. Ideally, our model would include the actual time-series of historic consumption patterns to project future consumption for each respondent. This proved infeasible, as we did not have consumption data at that level of resolution. This will be the purview of our future work.

Therefore, the best indication of each respondent’s electricity use was their historic annual electricity consumption in kilowatt-hours (kWh) as provided in the program data. The challenge, however, is to disaggregate annual consumption into hourly intervals of consumption. We make the necessary assumption, given these constraints, that each respondent’s intraday pattern of electrical consumption follows profiles released by the Electricity Reliability Council of Texas (ERCOT) representing average residential consumption patterns in north-central Texas in 2010 (ERCOT, 2010). The ERCOT profiles recognize two types of consumers as defined by the ratio of their peak summer to peak winter consumption. These consumers, Low Winter Ratio (LoWR) and High Winter Ratio (HiWR) respectively, correspond to households using either natural gas or electricity as a winter heat fuel source (fig 2). Based on information from the consumer’s electricity bill, we assigned each consumer a low or high winter ratio consumption profile; where no information was present, a HiWR was assumed.

Furthermore, we assume that profiles of electricity consumption are invariant over the lifetime of the PV system and that each consumer follows the same pattern of consumption. With that assumption, the specific consumption profile for each consumer takes into account their actual annual electricity consumption over the past year. While the ERCOT data was expressed in 15-minute intervals, we aggregated the profiles into an hour-month scale, that is, where all consumption within a given month is expressed in terms of a 24-value vector corresponding to each hour of the day (fig. 3).

Obviously, this is not a robust assumption, per se, since we do not capture household-level patterns of consumption that differ from the average consumption patterns or patterns that evolve over time. But, since the goal is to compare the objective and reported financial metrics, as opposed to evaluating the impact of the
absolute amount of electricity consumed, we believe that this is a robust enough assumption for the purposes of our analysis.

1.2.2 PV Generation Profiles

Calculating profiles for the electricity generated by the photovoltaic system (fig. 3) presents a similar challenge as disaggregating electric consumption, because hourly generation will depend on geography and system orientation characteristics that are unique to each respondent. Orientation of the system is the driving variable in these calculations since it determines the magnitude and profile of generation. Complicating these calculations are factors relating to rooftop availability, angle, and shading factors unique to each rooftop. We employ a generic generation profile for the Dallas-Ft. Worth area taken from the PVWATTS model created by the U.S. National Renewable Energy Laboratory (NREL 2011). Like the consumption profiles, the generation profile is aggregated to an hour-month scale, normalized, and then scaled by the expected annual production of specific PV systems under consideration. The expected, annual system production reported in the program data, which we use here, already incorporates orientation and geographic factors.

Depending upon the specific scenario, purchased systems are assumed to have 20-25 years of production and leased system are assumed to be functional for the length of the lease contract. All systems experience a 0.5% annual loss in system production as the equipment ages. This is the baseline parameter, and as discussed in Sections 1.3 and 3, we also explore the changes in financial return to more pessimistic or optimistic values.

1.2.3 Electricity Rates

PV systems generate value for their owners by reducing electricity expenses during the life of the system. Therefore, the difference between monthly electric bills the owner would have incurred without the system and those with the PV system installed can be thought of as a monthly stream of revenues. The value of these revenues is dependent on the structure and rates of the consumer’s electric bill with the PV system (PV electric bill) as well as the bill the consumer would have paid without the system (Business-As-Usual (BAU) electric bill). We have data regarding each respondent’s electricity rates and bill structure at the time of (just prior to) PV installation. These rates inform the BAU bill calculations; since we assume that in the BAU calculations the customer would have remained on their current electricity rate plan had they not adopted solar for the lifetime of their PV system.

Calculating the PV bill—projections of the electricity bill with PV system installed—is more complicated and requires careful treatment. Within the ERCOT deregulated electricity market customers may freely choose retail electricity service among a variety of providers with varying rates, available bill structures, and percent of electricity sourced from renewable energy sources (TECEP 2012). Standard bill structures such
as flat-rate and tiered-rate plans are prolific as well as plans with a seasonal or a Time-of-Use (TOU) tariff differentiation. More important for solar owners is whether their Retail Electricity Provider (REP) offers a plan that will offer credit for any moment-to-moment excesses of PV generation over consumption that are outflowed to the grid (Darghouth et al. 2011; Mills et al. 2008). Unlike many retail choice states, REPs within the ERCOT market are not required to provide credit for these ‘outflows’ and may set the outflow rate if they choose to offer it (PUCT 2012). Current practice is for REPs to offer at least one ‘solar plan’ characterized by outflows that are credited at a rate below the marginal price of electricity. As an example, a popular ‘solar plan’ is structured as a time-of-use plan with peak (1pm – 7pm), off-peak (7am – 1pm, 7pm – 11pm), and night rates (11pm – 6am) of 21.9¢/kWh, 9.2¢/kWh, and 6.8¢/kWh respectively, and 7.5¢/kWh credited for all outflows.

While it is tempting to assume that consumers will select retail 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 find out which REP provides this greatest value (Conlisk 1996; Fuchs & Arentsen 2002; Gigerenzer & Todd 1999; Goett et al. 2000; Roe et al. 2001; Tversky & Kahneman 1974). For example, is the highest value achieved through a plan which offers the lowest marginal electricity prices but no outflow reimbursement? Or, is it achieved through a TOU plan that has high outflow rates in conjunction with high peak-consumption rates? It is unlikely that consumers will possess sufficient technical expertise, interest, and time to make such a detailed calculation and, therefore, may elect to remain with their current REP as a default option. As discussed below, we account for this dilemma through a set of scenarios.

1.2.4 Electricity Prices

A driving parameter in the projected value of a residential PV system is the expected increase in future retail electricity prices. Excluding unexpected maintenance costs, the financial costs of solar ownership can be well-predicted at the time of purchase. Investment in a PV system, therefore, acts as a hedge against uncertain electricity price increases. Our baseline mode assumes a 2.6% annual increase in electricity, as this was the average increase in residential retail electricity prices in Texas since market deregulation (1990 - 2010). Needless to say, the value of future prices is uncertain. So, a range of plausible annual price escalations from 0% to 5%, were used in a set of scenarios.

1.3 Scenarios

To recognize uncertainty in the values of parameters that drive PV investment profitability (Bergmann et al. 2006; Laitner et al. 2003), we structured our calculations as a series of five scenarios (Very Conservative, Conservative, Baseline, Optimistic, and Very Optimistic) with progressively more optimistic assumptions (i.e., increasing value of solar to the consumer) for the value of the parameters (Table 1). Additionally, it is an insightful exercise on its own to see how the consumer's bottom line might be affected across these scenarios for the buying and the leasing business models. Parameters varied in the scenarios were (i) the annual growth rate in
nominal retail electricity price (0-5%); (ii) lifetime of the system (20 or 25 years); (iii) system loss rate (0.75-0.25%/year); (iii) maintenance costs as a percentage of installed costs incurred per year (0.5 – 0%/year); and (iv) inverter replacement cost ($0.95/W - $0/W). Note that scenarios are not intended to represent likely or unlikely outcomes, but to explore how a consumer’s differing assumptions would affect their evaluation of their investment’s future value.

The final parameter varied across the scenarios is the customer’s retail electricity plan post-installation, which impacts the availability and value of outflow sales. Scenario 1, the most conservative scenario, assumes that the consumer will remain on their current BAU plan for the entirety of their system’s lifetime. This means that they will not be credited for outflows. Scenario 2 assumes that consumers will adopt the ‘solar’ plan if one is offered by their current REP,¹ but will not transfer REPs otherwise even if there is a better solar plan from a different REP. Scenario 3, the baseline scenario, has the additional assumption that consumers will be credited 7.5¢/kWh for outflows if their current REP does not offer a solar plan. Our logic behind this design is our belief that nearly all REPs will offer an outflow credit in the future. Scenario 4 and 5 both assume that consumers will consider plans and REPs beyond their current rate plan and will adopt the plan with the highest overall value (as defined by minimizing their electricity bill post-installation for the life of the PV system) from among their current (BAU) plan and other current solar plans.

2. Additional Results and Scenario Outputs

2.1 Installed Cost and Cost of Ownership

Installed costs ($/W) of lessees (Mean = 8.3, Std. dev. = 0.53) were more than those of buyers (Mean = 6.2, Std. dev. = 1.4)(fig 4) and the mean differences were highly significant (t(201) = 16.08, d = 2.04). Surprisingly, the mean lessees’ costs of ownership ($0.70/W) were substantially less than those of buyers ($2.64/W),² Reflecting this market peculiarity, we found that leased systems had a statistically significant greater NPV per capacity ratio (NPV/DC-kW) than buyers in all but Scenario 5 (fig. 5a-e). Explanation of these results is contained in the primary manuscript.

2.2 Payback Period Comparison

Consistent with previous research (Camerer et al. 2004; Kempton & Montgomery 1982; Kirchler et al. 2008), the majority of respondents reported using payback period as one of the methods used for evaluating the financial attractiveness of their investment (66%) as opposed to NPV (7%), IRR (27%), Net monthly savings

¹ Our data allows us to know who the current REP is for particular households. Therefore, it was possible to determine if each respondent had access to a ‘solar’ plan and, if so, its rate and structure.
² Note that the cost of ownership does not reflect that buyers will operate their system for 25 years, whereas the lease contract typically terminates after 15 years. However, the NPV calculation incorporates this difference in length of cash flows
(25%), or "Other methods" used (6%) (Table 2). 10% of respondents indicated they made no estimate of the financial attractiveness of their investment. Respondents were subsequently asked to report the values of the metrics they used to evaluate their investment. From these responses we are able to compare reported metric values (reported) to the values generated from the financial model (modeled) based on the value of the parameters known for each respondent.

Because most respondents used payback period to assess their investment—and listed the actual value they used, payback proved to be the best financial metric to compare respondent’s reported paybacks to those calculated using the financial model (fig. 6a-e). Further, in order to compare the difference between modeled and reported payback values, we calculated the average absolute difference between reported and modeled payback period values for the entire sample and for buyers and lessees separately, excluding responses more than 3σ from the mean (Table 3). For buyers, Scenario 4 (M = 2.613 years, SD = 2.409) minimized the average absolute difference, followed by Scenario 5 (M = 3.051, SD = 1.918). For lessees, Scenario 3 (M = 1.140, SD = 0.725 ) was the best fit, followed by Scenario 2 (M = 1.296, SD = 0.704). Scenario 1 was a very poor fit overall.

Since the SSE—defined as the sum of squared differences between the modeled and reported payback periods—for buyers is minimized in Scenario 5 (2764.32), this suggests that buyers likely assumed parameters similar to those of Scenario 5 when making their investment valuation. That is, buyers were optimistic or very optimistic when assessing the likely revenues and costs associated with their investment decision. By the same argument, since the SSE for lessees is minimized for Scenario 3 (816.65), lessees were more realistic to slightly pessimistic (conservative) when making their investment decision. The standard deviation of buyers’ mean difference was greater than that of lessees, which indicates that lessees were more precise in their financial evaluation of the PV system. 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.

Thus, our model indicates that leased systems have a lower mean payback period than that of bought systems across all scenarios. However, this statement must be understood in the context that from a financial perspective the two modes of investments operate on different time considerations—for leased system it is 15 years, the length of the lease contract, and for bought systems it is the lifetime of the system i.e. 20 – 25 years. A far better comparison of the financial profitability of the investment is the NPV DC-kW, which incorporates differences in the duration of investment. But, as we have discussed above, a majority of (individual) decision-makers do not use NPV as the evaluation metric.

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Note that because respondents were permitted to indicate more than one metrics the percentages do not sum to 100%.

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2.3 Implied Discount Rate

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 $1,000 more”… (v) “I would not have installed the PV system if it had cost me $5,000 more.” For each question respondents marked ‘Strongly Agree’, ‘Agree’, ‘Neither agree nor disagree’, ‘Disagree’, or ‘Strongly disagree’. One would expect a respondent to reply to this series of questions by increasingly agreeing that they would NOT have installed the PV system as the price increased. For example, one might respond that they would willingly have paid $1000 more, been indifferent to paying $2000 more, but forgone the investment if it had cost $3000 more than they actually paid for their PV system.

Indeed, the real purpose of this question is to ascertain the implicit NPV of the respondent’s investment. Based on the series of responses, we can extrapolate how much more the consumer would have been willing to pay for their system before becoming indifferent to purchasing the system or forgoing the investment—this amount is the implied NPV. In the above example, the implied NPV is $2000.

The difference of normalized implied NPV ($/kW) for buyers (M = 511.16, SD = 308.27) and leasers (M = 447.14, SD = 282.59) was statistically insignificant from zero: t(85) = 1.16, p = 0.249 two-tailed, d = 0.216 (fig. 7). This suggests that, overall, buyers and leasers expected similar (normalized) returns on their investment.

Using the implied NPV, one can determine the consumer’s implied discount rate, since the model calculates an expected series of cash flows. Consider that:

\[ NPV_{implied} = \sum CF_k = \sum \frac{[R_k - c_k]}{(1+r_m)^k} \]

where \( r_m \) is the monthly implied discount rate. Using an optimization routine, we solve for \( r_m \) and annualize it, where \( r \) is the implied annual discount rate:

\[ r = (1 + r_m)^{12} - 1. \]

2.3.1 Discount Rate and 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 (Table 6). Explanation of these results is contained in the primary manuscript.
3. Sensitivity Analysis

A sensitivity analysis was conducted to determine the influence of model parameters on the model-calculated NPV/kW output for the ‘Optimistic’ (Scenario 4), ‘Baseline’ (Scenario 3), and ‘Conservative’ scenarios (Scenario 2). Typically, sensitivity analyses compare the effect that a percentage change in inputs has on the corresponding percentage change in output. Since many of the modeled-calculated NPVs were centered around $0, a small change in parameters produced a modest relative change in NPV, but a large percentage change. That is, suppose changing a parameter increases the NPV from $10/kW to $15/kW—a relative increase of $5/kW, but a 50% percentage increase. Reporting these changes in percentage terms is somewhat difficult to grasp considering that the overall costs of the system could easily exceed $10,000. Therefore, we only consider the relative change in NPV/kW, not the percentage change, as compared to the default NPV/kW for each scenario.

Six variables were tested in the sensitivity analysis: (i) Annual percentage escalation in retail electricity costs, (ii) Annual O&M costs as percentage of gross installed cost, (iii) Inverter replacement cost, (iv) Annual percentage loss in system output, (v) Minimum outflow reimbursement price, and (vi) Lifetime of system (only applicable to buyers). Each parameter was flexed over plausible values and were analyzed for impact on the Conservative, Baseline, and Optimistic scenarios.

Holding all else constant, the NPV/kW is most sensitive to changes in the annual percentage increase in electricity costs, followed by annual O&M costs, and the lifetime of the system. NPV is therefore relatively insensitive to inverter replacement cost, annual production efficiency losses, and the rate credited for outflows. It is interesting that the profitability of the PV system is most dependent on the future costs of electricity, as this is precisely the reason many consumers choose to invest in PV—to hedge against uncertain increases in electricity costs.

4. Additional Discussion

In this paper we report on the economics of decision-making in the adoption of residential solar PV. Using a comprehensive data set comprised of two complementary data sources (survey and program data) for 210 adopters of PV in Texas, we delve into the individual decision-making process. Four main insights emerge from this study. First, a majority of PV adopters report using payback period as the key financial metric they employ in judging the financial attractiveness of investing in PV. This is consistent with other studies of consumer decision-making in a wide range of settings. The use of payback period as a decision criteria is noteworthy given that these early adopters are some of the most sophisticated decision makers—they are far more educated, wealthier, and information savvy than the median household/individual. It also suggests that decision-makers are not nearly as sophisticated as the intertemporal utility optimizer (the rational actor), who at
the very least would base the decision on a net present value (NPV) calculation, if not compare that NPV to alternative investment options.

Second, we compare the reported payback that PV adopters report as having used to evaluate their investment decision with an "objective" model we have built to calculate those same metrics. Our model includes several detailed features of household-level electricity consumption, electricity rates, and PV-based electricity generation, including time-of-day and monthly variations. This comparison of reported and objective metrics allows us to unpack the differences in risk perceptions between buyers and lesasers of PV. Assuming the same annual discount rate (10%) for all adopters, we find that across a range of plausible scenarios buyers are more optimistic in their outlook about the costs and benefits of PV than lesasers.

Third, through optimizing our model to match the reported implied net present value ("How much more would you have paid for your PV system?"), we were able to calculate discount rate for each household (decision-maker) separately. We find that across a range of scenarios, the discount rate for buyers varies between 6-18% and that for the lesasers varies between 20-35%. This further confirms that buyers are in general more optimistic about the value of solar. We do not find any significant variation between buyers and lesasers on any socio-demographic dimension (age, home value, income, etc.).

Taken together, these findings suggest that the leasing model is making PV adoption possible for households with a tight cash-flow situation. 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.

Fourth, and related to the previous two points, we find that for the period of the study (2009-11) cost of leasing appears to be significantly lower than that of buying. We believe that this is due to certain additional benefits such as accelerated depreciation and economies of scale (warrantees and cost of financing) accessible by the leasing companies only through the leasing model, but not the buying model. Further, lesasers typically do not have to worry about maintenance and performance, which are included as part of the contract with the leasing company. For buyers, uncertainties around these represent significant non-monetary costs. Given the apparent cost and informational advantages of the leasing option, then, one would expect decision-makers to opt for the buying option only when their discount rate is very low, or equivalently, when they are very optimistic about the benefits of adopting PV. It is axiomatic that low-discount rate households are vastly outnumbered by households with higher discount rates. This would imply that in the broader market and policy context of 2009-11, leasing models should be the predominant form of PV adoption. Market data, especially from California—the largest PV market in the U.S.—and elsewhere, confirm this.
### APPENDIX A: Tables and Charts

#### 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             | 2.6%/yr          | 2.6%/yr      | 3.3%/yr        | 5.0%/yr           |
| System Life                       | 20 yrs              | 20 yrs           | 25 yrs       | 25 yrs         | 25 yrs            |
| System Loss Rate                  | 0.75%/yr            | 0.5%/yr          | 0.5%/yr      | 0.5%/yr        | 0.25%/yr          |
| Maintenance Costs                 | 0.5%/yr             | 0.25%/yr         | 0.25%/yr     | 0.15%/yr       | 0%/yr             |
| Inv. Replace. Cost                | $0.95/W             | $0.95/W          | $0.7/W       | $0.7/W         | 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 | Adopts plan with max. value among current market solar plans or BAU plan | Same as Scenario 4 |

#### Table 2. Financial metrics used by survey responders to assess the financial attractiveness of their system and the sources of help (if any) used to determine the value of these metrics.

| Source of Information for Metric Calculations | Payback Period | IRR | Net Monthly Savings | NPV | Other | No Metric |
|-----------------------------------------------|----------------|-----|---------------------|-----|-------|-----------|
| Respondents Using Metric (%)                  | 66%            | 27% | 25%                 | 7%  | 6%    | 10%       |
| I calculated it myself                        | 56.9%          | 61.5% | 54.1%   | 72.2% | 42.9% | 8.3%       |
| Contractor/Installer                          | 46.3%          | 47.7% | 32.8%   | 27.8% | 57.1% | 8.3%       |
| I didn't use any of these calc.s.            | 2.5%           | 1.5%  | 13.1%   | 5.6%  | 7.1%  | 16.7%      |
| Online source                                 | 6.9%           | 6.2%  | 4.9%    | 0.0%  | 0.0%  | 8.3%       |
| Utility                                       | 3.8%           | 3.1%  | 3.3%    | 0.0%  | 0.0%  | 4.2%       |
| Neighbor with installed PV system             | 1.9%           | 3.1%  | 0.0%    | 5.6%  | 0.0%  | 0.0%       |
| Family/Friend                                 | 1.9%           | 1.5%  | 0.0%    | 0.0%  | 0.0%  | 4.2%       |
| No Response                                   | 1.9%           | 1.5%  | 11.5%   | 5.6%  | 7.1%  | 54.2%      |

#### Table 3. Mean difference between reported and modeled payback periods for buyers and leasers with ±1σ.

| Variables | Mean Difference In Years Between Reported and Modeled Payback Period |
|-----------|---------------------------------------------------------------|
| All Consumers | Buyers Only | Leasers Only     |
| N          | 141           | 101              | 40          |
| Scen 2: V. Conservative | $24 \pm 19$ yrs | $33 \pm 16$ yrs | $1.8 \pm 1.1$ yrs |
| Scen 2: Conservative       | $6.9 \pm 6.0$ yrs | $8.9 \pm 5.8$ yrs | $1.5 \pm 0.7$ yrs |
| Scen 3: Baseline               | $5.4 \pm 4.6$ yrs | $7.1 \pm 4.3$ yrs | $1.1 \pm 0.7$ yrs |
| Scen 4: Optimistic            | $2.4 \pm 2.1$ yrs | $2.6 \pm 2.4$ yrs | $1.9 \pm 0.9$ yrs |
| Scen 5: V. Optimistic         | $2.9 \pm 1.7$ yrs | $3.1 \pm 1.9$ yrs | $2.3 \pm 0.8$ yrs |
### Table 4. Mean implied discount rate for buyers along income and scenarios with ±1σ.

| Annual Income | All Incomes | $0 – $85k | $85k – $150k | $150k+ |
|---------------|-------------|-----------|--------------|--------|
| N             | 81          | 22        | 37           | 22     |
| Scen 2: Conservative | 6% ±6%     | 6% ±5%    | 6% ±8%       | 7% ±6% |
| Scen 3: Baseline     | 7% ±5%     | 7% ±4%    | 6% ±6%       | 7% ±6% |
| Scen 4: Optimistic    | 13% ±6%   | 12% ±5%   | 13% ±6%      | 13% ±7% |
| Scen 5: V. Optimistic  | 18% ±7%   | 17% ±5%   | 18% ±7%      | 17% ±8% |

### Table 5. Mean implied discount rate for leasers along income and scenarios with ±1σ.

| Annual Income | All Incomes | $0 – $85k | $85k – $150k | $150k+ |
|---------------|-------------|-----------|--------------|--------|
| N             | 81          | 22        | 37           | 22     |
| Scen 2: Conservative | 20% ±15%  | 22% ±19%  | 20% ±14%     | 18% ±12% |
| Scen 3: Baseline     | 21% ±14%  | 23% ±18%  | 22% ±13%     | 19% ±12% |
| Scen 4: Optimistic    | 32% ±17%  | 33% ±22%  | 35% ±15%     | 30% ±14% |
| Scen 5: V. Optimistic  | 35% ±13%  | 29% ±9%   | 38% ±13%     | 36% ±16% |

### Table 6. Student’s t-test comparing mean implied discount rates in baseline scenario for buyers and leasers along sequential income groups. No sequential pair in the baseline scenario was significant

| Scenario 3: Baseline | t     | df | p-value | Mean Difference | Std. Error Difference | 90% Confidence Interval of the Difference |
|----------------------|-------|----|---------|-----------------|-----------------------|------------------------------------------|
|                       |       |    | 1-tailed|                 |                       |                                          |
| Equal Variance Not Assumed |       |    |         |                 |                       |                                          |
| Buy DR(1) > DR(2)   | 0.231 | 49 | 0.409   | 0.003           | -0.019                | -1.51% – 2.17%                          |
| Buy DR(2) > DR(3)   | -0.784| 42 | 0.219   | -0.013          | 0.005                 | -3.40% – 0.85%                         |
| Lease DR(1) > DR(2) | 0.245 | 22 | 0.404   | 0.015           | 0.044                 | -6.62% – 9.64%                         |
| Lease DR(2) > DR(3) | 0.507 | 22 | 0.309   | 0.027           | 0.010                 | -4.28% – 9.61%                         |
Figure 1: Geographic distribution of survey responders. Size of bubble corresponds to the sample size from each zip code.

Figure 2: Monthly variation in residential electricity consumption for northern Texas based on low winter ratio (LoWR) and high winter ratio (HiWR) consumption patterns as compiled by ERCOT
Figure 3: Example consumption, generation, and net consumption profiles for hypothetical consumer during the month of August. Profiles are unique to each consumer and have hourly, monthly, and annual variation.

Figure 4: Distribution of system installed costs ($/W) for buyers and leasers (no rebates). Buyers installed costs ($M = 6.155, SD = 1.387) were significantly less (p = 5.85e-38 two-tailed) than leasers ($M = 8.292, SD = 0.529) though the cost of ownership are the opposite.
Figure 5a: Distribution of modeled system installed costs per W ($/W) for buyers and leasers assuming *most conservative* (Scenario 1) model parameters.

Figure 5b: Distribution of modeled system installed costs per W ($/W) for buyers and leasers assuming *conservative* (Scenario 2) model parameters.
Figure 5c: Distribution of modeled system installed costs per W ($/W) for buyers and leasers assuming baseline (Scenario 3) model parameters.

Figure 5d: Distribution of modeled system installed costs per W ($/W) for buyers and leasers assuming optimistic (Scenario 4) model parameters.
Figure 5e: Distribution of modeled system installed costs per W ($/W) for buyers and leasers assuming *most optimistic* (Scenario 5) model parameters.

Figure 6a: Comparison of payback period calculated by model to the period reported by consumer in our survey using *most conservative* (Scenario 1) parameters assumptions. Mean difference between modeled and consumer payback period: Buyers = 33 yrs; Leasers = 1.8 years.
Figure 6b: Comparison of payback period calculated by model to the period reported by consumer in our survey using conservative (Scenario 2) parameters assumptions. Mean difference between modeled and consumer payback period: Buyers = 8.9 yrs; Leasers = 1.3 years.

Figure 6c: Comparison of payback period calculated by model to the period reported by consumer in our survey using baseline (Scenario 3) parameters assumptions. Mean difference between modeled and consumer payback period: Buyers = 7.1 yrs; Leasers = 1.1 years.
Figure 6d: Comparison of payback period calculated by model to the period reported by consumer in our survey using optimistic (Scenario 4) parameters assumptions. Mean difference between modeled and consumer payback period: Buyers = 2.6 yrs; Leasers = 1.8 years.

Figure 6e: Comparison of payback period calculated by model to the period reported by consumer in our survey using most optimistic (Scenario 5) parameters assumptions. Mean difference between modeled and consumer payback period: Buyers = 3.1 yrs; Leasers = 2.3 years.
**Figure 7**: Difference between implied NPV/kW between buyers and leasers was not significantly different than zero; Both groups implied a mean NPV/kW close to $500.
APPENDIX B: Sensitivity Analysis Results

Baseline Scenario: Relative Change in NPV/kW all else held constant

|                      | All:  | Buyers: | Leasers: |
|----------------------|-------|---------|----------|
| Mean NPV/kW          | $65.68/kW | -$348.1/kW | $929.81/kW |

Annual Percentage Increase in Retail Electricity Costs

|                      | 0%   | 1%   | 2%   | 3%   | 4%   | 5%   |
|----------------------|------|------|------|------|------|------|
| All (n = 210)        | -656.88 | -435.89 | -176.81 | 127.91 | 487.45 | 913.03 |
| Buyers (n=142)       | -759.64 | -505.87 | -205.98 | 149.63 | 572.77 | 1077.95 |
| Leasers (n = 68)     | -442.30 | -289.77 | -115.89 | 82.55 | 309.29 | 568.63 |

Annual O&M Costs as Percentage of Installed Cost

|                      | 0%/yr | 0.1%/yr | 0.2%/yr | 0.3%/yr | 0.4%/yr | 0.5%/yr |
|----------------------|-------|---------|---------|---------|---------|---------|
| All (n = 210)        | 99.28 | 59.57 | 19.86 | -19.86 | -59.57 | -99.28 |
| Buyers (n=142)       | 146.82 | 88.09 | 29.36 | -29.36 | -88.09 | -146.82 |
| Leasers (n = 68)     | 0 | 0 | 0 | 0 | 0 | 0 |

Inverter Replacement Cost ($/W)

|                      | $0/W | $0.2/W | $0.4/W | $0.6/W | $0.8/W | $1/W |
|----------------------|------|---------|---------|---------|---------|------|
| All (n = 210)        | 114.22 | 81.58 | 48.95 | 16.32 | -16.32 | -48.95 |
| Buyers (n=142)       | 168.91 | 120.65 | 72.39 | 24.13 | -24.13 | -72.39 |
| Leasers (n = 68)     | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Annual Percentage Loss in System Output

|                      | 0%/yr | 0.2%/yr | 0.4%/yr | 0.6%/yr | 0.8%/yr | 1%/yr |
|----------------------|-------|---------|---------|---------|---------|-------|
| All (n = 210)        | 69.16 | 41.10 | 13.57 | -13.44 | -39.93 | -65.91 |
| Buyers (n=142)       | 81.66 | 48.49 | 15.99 | -15.83 | -46.98 | -77.48 |
| Leasers (n = 68)     | 43.06 | 25.67 | 8.50 | -8.45 | -25.21 | -41.76 |

Minimum Outflow Reimbursement Price

|                  | 0¢/kWh | 2¢/kWh | 4¢/kWh | 6¢/kWh | 8¢/kWh | 10¢/kWh | 12¢/kWh |
|------------------|--------|--------|--------|--------|--------|---------|---------|
| All (n = 210)    | -92.81 | -68.06 | -43.31 | -18.57 | 12.21 | 61.76 | 118.48 |
| Buyers (n=142)   | -107.98 | -79.19 | -50.39 | -21.60 | 12.47 | 63.39 | 123.41 |
| Leasers (n = 68) | -61.13 | -44.83 | -28.53 | -12.23 | 11.67 | 58.35 | 108.19 |

Lifetime of System (Applicable to Buyers only)

|                  | 20 years | 22 years | 24 years | 26 years | 28 years | 30 years |
|------------------|-----------|----------|----------|----------|----------|----------|
| Buyers (n=142)   | -198.99 | -110.69 | -34.27 | 31.88 | 89.12 | 138.65 |

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### Pessimistic Scenario: Relative Change in NPV/kW all else held constant

| Mean NPV/kW | All:      | Buyers:   | Leasers:  |
|-------------|-----------|-----------|-----------|
|             | -$338.5/kW | -$898.7/kW| $831.44/kW|

#### Annual Percentage Increase in Retail Electricity Costs

|                       | 0%     | 1%     | 2%     | 3%     | 4%     | 5%     |
|-----------------------|--------|--------|--------|--------|--------|--------|
| All (n = 210)         | -560.08| -369.36| -148.79| 106.81 | 403.57 | 748.77 |
| Buyers (n=142)        | -624.00| -412.39| -166.51| 119.83 | 453.96 | 844.67 |
| Leasers (n = 68)      | -426.59| -279.49| -111.78| 79.63  | 298.34 | 548.51 |

#### Annual O&M Costs as Percentage of Installed Cost

|                      | 0%/yr  | 0.1%/yr | 0.2%/yr | 0.3%/yr | 0.4%/yr | 0.5%/yr |
|----------------------|--------|---------|---------|---------|---------|---------|
| All (n = 210)        | 93.10  | 55.86   | 18.62   | -18.62  | -55.86  | -93.10  |
| Buyers (n=142)       | 137.68 | 82.61   | 27.54   | -27.54  | -82.61  | -137.68 |
| Leasers (n = 68)     | 0.00   | 0.00    | 0.00    | 0.00    | 0.00    | 0.00    |

#### Inverter Replacement Cost ($/W)

|                     | $0/W   | $0.2/W  | $0.4/W  | $0.6/W  | $0.8/W  | $1/W   |
|---------------------|--------|---------|---------|---------|---------|--------|
| All (n = 210)       | 155.01 | 122.37  | 89.74   | 57.11   | 24.47   | -8.16  |
| Buyers (n=142)      | 229.24 | 180.98  | 132.72  | 84.46   | 36.20   | -12.07 |
| Leasers (n = 68)    | 0.00   | 0.00    | 0.00    | 0.00    | 0.00    | 0.00   |

#### Annual Percentage Loss in System Output

|                       | 0%/yr  | 0.2%/yr | 0.4%/yr | 0.6%/yr | 0.8%/yr | 1%/yr  |
|-----------------------|--------|---------|---------|---------|---------|--------|
| All (n = 210)         | 69.16  | 41.10   | 13.57   | -13.44  | -39.93  | -65.91 |
| Buyers (n=142)        | 81.66  | 48.49   | 15.99   | -15.83  | -46.98  | -77.48 |
| Leasers (n = 68)      | 43.06  | 25.67   | 8.50    | -8.45   | -25.21  | -41.76 |

#### Minimum Outflow Reimbursement Price

|                     | 0¢/kWh | 2¢/kWh  | 4¢/kWh  | 6¢/kWh  | 8¢/kWh  | 10¢/kWh | 12¢/kWh |
|---------------------|--------|---------|---------|---------|---------|---------|---------|
| All (n = 210)       | 0      | 23.29   | 46.58   | 69.88   | 98.93   | 145.92  | 199.62  |
| Buyers (n=142)      | 0      | 26.64   | 53.28   | 79.92   | 111.45  | 158.57  | 214.12  |
| Leasers (n = 68)    | 0      | 16.30   | 32.60   | 48.90   | 72.80   | 119.48  | 169.32  |

#### Lifetime of System (Applicable to Buyers only)

|              | 15 years | 17 years | 19 years | 21 years | 23 years | 25 years |
|--------------|----------|----------|----------|----------|----------|----------|
| Buyers (n=142) | -273.26  | -152.10  | -47.11   | 43.85    | 122.66   | 190.92   |
Optimistic Scenario: Relative Change in NPV/kW all else held constant

| Scenario          | All:                      | Buyers: $1018.5/kW | Leasers: $1836.1/kW |
|-------------------|---------------------------|--------------------|---------------------|
| Mean NPV/kW       | $1283.2/kW                |                    |                     |

### Annual Percentage Increase in Retail Electricity Costs

| Percentage Increase | All (n = 210) | Buyers (n=142) | Leasers (n = 68) |
|--------------------|---------------|----------------|------------------|
| 0%                 | -1262.62      | -1468.51       | -832.68          |
| 1%                 | -947.93       | -1106.25       | -617.33          |
| 2%                 | -578.92       | -678.10        | -371.82          |
| 3%                 | -144.82       | -170.30        | -91.60           |
| 4%                 | 367.54        | 434.05         | 228.66           |
| 5%                 | 974.19        | 1155.75        | 595.04           |
| 6%                 | 1694.67       | 2020.33        | 1014.62          |

### Annual O&M Costs as Percentage of Installed Cost

| Percentage Increase | All (n = 210) | Buyers (n=142) | Leasers (n = 68) |
|--------------------|---------------|----------------|------------------|
| 0%/yr              | 59.57         | 88.09          | 0                |
| 0.1%/yr            | 19.86         | 29.36          | 0                |
| 0.2%/yr            | -19.86        | -29.36         | 0                |
| 0.3%/yr            | -59.57        | -88.09         | 0                |
| 0.4%/yr            | -99.28        | -146.82        | 0                |
| 0.5%/yr            | -138.99       | -205.54        | 0                |

### Inverter Replacement Cost ($/W)

| Replacement Cost | All (n = 210) | Buyers (n=142) | Leasers (n = 68) |
|------------------|---------------|----------------|------------------|
| $0/W             | 114.22        | 168.91         | 0.00             |
| $0.2/W           | 81.58         | 120.65         | 0.00             |
| $0.4/W           | 48.95         | 72.39          | 0.00             |
| $0.6/W           | 16.32         | 24.13          | 0.00             |
| $0.8/W           | -16.32        | -24.13         | 0.00             |
| $1/W             | -48.95        | -72.39         | 0.00             |

### Annual Percentage Loss in System Output

| Percentage Loss | All (n = 210) | Buyers (n=142) | Leasers (n = 68) |
|-----------------|---------------|----------------|------------------|
| 0%/yr           | 107.56        | 125.92         | 69.20            |
| 0.2%/yr         | 63.91         | 74.77          | 41.24            |
| 0.4%/yr         | 21.08         | 24.64          | 13.65            |
| 0.6%/yr         | -20.86        | -24.39         | -13.49           |
| 0.8%/yr         | -62.09        | -72.58         | -40.19           |
| 1%/yr           | -102.63       | -119.72        | -66.93           |

### Lifetime of System (Applicable to Buyers only)

| Lifetime (years) | All (n = 210) | Buyers (n=142) | Leasers (n = 68) |
|------------------|---------------|----------------|------------------|
| 20 years         | -241.47       | -357.11        | 0.00             |
| 22 years         | -135.27       | -200.05        | 0.00             |
| 24 years         | -42.16        | -62.35         | 0.00             |
| 26 years         | 39.48         | 58.38          | 0.00             |
| 28 years         | 111.05        | 164.22         | 0.00             |
| 30 years         | 173.79        | 257.01         | 0.00             |
APPENDIX C: Sample Survey Questions

2. How much do you agree or disagree with each of these statements?

| Strongly agree | Agree | Neither agree nor disagree | Disagree | Strongly disagree |
|----------------|-------|-----------------------------|----------|------------------|
| I would not have installed the PV system if it had cost me $1000 more | | | | |
| I would not have installed the PV system if it had cost me $2000 more | | | | |
| I would not have installed the PV system if it had cost me $3000 more | | | | |
| I would not have installed the PV system if it had cost me $4000 more | | | | |
| I would not have installed the PV system if it had cost me $5000 more | | | | |

Additional comments:

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3. What type of financial estimate did you use to judge the financial attractiveness of a PV system?
(Please choose all that apply)

- [ ] Net Present Value (NPV)
- [ ] Rate of Return
- [ ] Payback Period
- [ ] Net monthly savings (in the case of leasing)
- [ ] I did not estimate the financial attractiveness of the PV system
- [ ] Other (please explain)

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4. What resulting values from the above financial estimates (Net Present Value (NPV); Rate of Return; or Payback Period) did you arrive at? Please write values for each option selected in the previous question.
(Please write answer in $, years, or %. For example, write “Net Present Value (NPV): $5,000” or “Rate of Return: 10%” or “Payback Period: 10 years”, etc.)

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5. If you received help in making a financial assessment (Net Present Value; Rate of Return; or Payback Period) of your PV system, who helped you? (Please choose all that apply)

☐ Neighbor with installed PV system
☐ Family/Friend (not in your neighborhood)
☐ Contractor/Installer
☐ Independent/3rd-Party online PV investment calculator
☐ Utility
☐ Local non-profit group
☐ I calculated it by myself
☐ I did not make any of these calculations

Other (please explain)
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