BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 12-11-005 (Filed November 8, 2012)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE ASSIGNED COMMISSIONER'S RULING REGARDING THE ESTABLISHMENT OF A NET ENERGY METERING TRANSITION PERIOD

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I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides these reply comments on *The Assigned Commissioner's Ruling Regarding The Establishment Of a Net Energy Metering Transition Period*, released on November 27, 2013 (Ruling). As explained in detail below, a balanced transition period that provides customers with a reasonable opportunity to recover their "investment"[1] in solar, but does not lock-in current net energy metering (NEM) rules and the associated cost-shift for decades, makes the most sense for **all** customers.

The 17 sets of parties that filed opening comments presented grandfathering proposals that break down into four groups:

1. The 2020-2022 Proposals. Consumer advocates, TURN and ORA, sought a transition period of 2020 and 2022 respectively.

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1 Most residential customers are now participating in third party owned projects that require little or no upfront investment, and almost always promise savings from Day 1. However, for convenience PG&E will use the term "investment" throughout this document to refer to both host owned and third party owned projects.

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2. The 2023 Proposals. The three investor-owned utilities proposed a slightly longer transition, 2023 for existing projects. SDG&E and PG&E proposed a shorter transition for projects that come on line after the grandfathering decision in 2014.
3. The 2037-2047 Proposals. One party[2] proposed 20 years and several others proposed 30 years, either from the date of interconnection, or from 2017.[3]
4. The 2062+ Proposals. Other solar groups sought the entire actual "life of the facility", not limited by any period of years.[4] Many parties noted that solar systems can last 40-45 years or longer.[5] For simplicity, we call this the 2062 Proposal, for 45 years after 2017, even though these parties actually seek perpetual grandfathering.

The CPUC should rely on three key considerations to guide its selection and adoption of a proposal for the NEM transition period. First, the statute gave a specific directive to the CPUC. It directed the CPUC to set a transition period for existing customers to move to NEM 2.0, not to let them keep NEM 1.0 forever. It also directed the CPUC to consider "reasonably expected payback period," which means repayment of investment, and not expected additional savings over the several decades that will follow the system payback. This immediately eliminates from consideration proposals that are based solely on life of system. Second, the overwhelming evidence is that the reasonably expected payback period for commercial and residential systems installed recently is less than ten years. Third, in developing AB 327, the legislature intended to protect non-participating customers from being unduly burdened by NEM-related cost-shift. It would be unfair to set a lengthy transition period that will shift literally billions of dollars of costs to nonparticipating customers to maintain a subsidy that is not needed to sustain a vibrant solar industry.

2 The California Center for Sustainable Energy (CCSE).

3 California Farm Bureau Federation, The Alliance for Solar Choice (TASC), California Solar Industries Association (CalSEIA), Interstate Renewable Energy Council (IREC), California Climate and Agricultural Network (CalCAN) and Solar Energy Industries Association and Vote Solar Initiative (SEIA/Vote Solar), and the City of Benicia et al, calling themselves the Net Energy Metering Public Agency Coalition (NEM-PAC).

4 The Agricultural Energy Consumers Association (AECA), California Energy Storage Alliance (CESA), Charles Hewitt, and Recolte Energy (Recolte).

5 CalSEIA stated that warranty periods (often 25 years) "are more akin to a half-life than an expected lifetime. It would not be unreasonable to define the expected lifetime at 40 years or more." CalSEIA p. 6. Other studies have also concluded that the life span of solar systems can exceed 45 years. For example, a number of solar web sites cite to the study by Andy Black stating that the first solar panels manufactured about 40 years ago are still creating power at about 80% of their original power. See http://www.brightstarsolar.net/2010/06/life-expectancy-of-solar-photovoltaic-panels/.

The CPUC's recent report to the legislature on the cost shift associated with net energy metering[6] provides an excellent source of relevant, independent, commission-validated data for the CPUC to analyze the impact of various alternatives on cost-shift. As explained in detail below, the choice of a transition period can result in literally billions of incremental dollars of cost being shifted to nonparticipating customers over many decades. The long-term extension of the NEM subsidy is generally not needed to protect the customer's ability to recover its investment and to continue to enjoy savings. These subsidies are also not needed to support a continuing and vibrant solar business. Rather than unnecessarily perpetuating the existing subsidies, the CPUC should adopt PG&E's balanced proposal which gives at least 10 years of grandfathering to all projects installed before April 1, 2014, with a reduced period after the grandfathering and NEM 2.0 rules are established. This strategy will provide a smooth and sustainable path from NEM 1.0 to NEM 2.0 for the industry participants and utility customers, while ensuring that customers continue to receive value from their systems after transitioning to NEM 2.0.[7]

II. DISCUSSION

A. The Transition Period For Existing Projects Should Be Based On Reasonably Expected Payback Period, Not The Life Of The System

Many parties argued that the CPUC should adopt the life of the system (either expected or actual) as the transition period. These proposals are counter to the Legislature's intent and direction to the CPUC. Setting a transition of the actual life of the facility results in no transition at all, as those systems would **never** transition to NEM 2.0.[8] The CPUC is simply required to allow customers a transition period to recover their investment, and then develop a NEM 2.0

[6] CPUC California Net Energy Metering Ratepayer Impacts Evaluation dated October 2013 (E3 Report).

[7] Alternatively, the Commission should adopt one of the proposals put forward by the Consumer Groups – TURN or ORA – which are reasonable proposals that provide certainty to NEM customers and appropriate protection for non-adopters.

[8] Some solar parties agree that the notion of a perpetual grandfathering is at odds with the statute. See, for example, IREC's statement that "instead of allowing customers to operate NEM systems indefinitely…, the transition period contemplated by AB 327 seeks to establish a firm end point…" IREC p. 5.

paradigm that provides the opportunity to continue to accrue value. Further, adopting these proposals would unfairly extend billions of dollars in unnecessary subsidies to NEM customers at the expense to non-participating customers.

1. "Payback" Means Recovery Of The Costs Spent on The System, Not Recovery of Every Penny That Might Be Saved Over The Life Of The Facility.

The Legislature determined the CPUC should consider "a reasonable payback period" for customers who install renewable generation during the transition period. A number of parties define "payback period" as meaning "all expected savings or returns."[9] However, that is simply not what the word "payback" means. As explained in the Ruling, payback means recovery of cost spent on the system, not all the savings a customer might hope or plan to receive, long after the customer's investment has been repaid.[10] Both the TURN and SDG&E opening comments contained a number of citations to financial textbooks showing this is the established meaning, and many dictionaries provide similar authority.[11] In contrast, none of the parties seeking to redefine "payback" included any references to any reputable linguistic, economic or financial authority, or other legislative history.[12]

Instead, as shown in opening comments, the Legislature considered proposals to insert protection for the life of the facilities into the legislation, and rejected them.[13]

2. Fairness To NEM Customers Requires A Transition Period No Longer Than That Needed To Permit Customers To Recover Their Investment

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9 See, for example, CalSEIA comments p. 2.

10 See Ruling footnote 7, defining "payback" as "the initial system installed costs divided by the dollar value of saving per year, with no modifications for inflation or time value of money."

11 See TURN, p. 3, fn. 5, SDG&E, page 2. In addition, the Merriam-Webster Dictionary defines "payback" as "a return on an investment equal to the original capital outlay; also : the period of time elapsed before an investment is recouped."

12 Some relied on the Governor's signing statement. However, as TURN lucidly explained, the Governor's signing statement did not revise or define the words in the statute or bind the CPUC in how it should exercise the decision-making authority mandated by the statute. TURN p. 4.

13 See citations in PG&E Opening Brief p. 12, fn. 7; see also SCE p. 13 and TURN p. 5.

A number of parties argued that basic fairness requires the CPUC to ensure that customers recover not only the cost of their investment, but also 100% of the value that they expected to receive at the time they made their investment decision.[14] PG&E acknowledges that its current NEM customers have made good faith investments in renewable, self-generating projects, and has proposed a lengthy transition period intended to allow customers to recover this investment. However, the claim that this protection should continue for decades after payback has been achieved is unrealistic and inappropriately burdens non-participating customers.

As with any other financial investment, investments in renewable distributed generation include many uncertainties that customers should be aware of. Whether a customer elects to install renewable self-generation through a self-financed or a lease or PPA arrangement, they are making an investment decision that is dependent on conditions that are expected to evolve over many years and therefore, they must consider the associated risks. As some of the solar parties themselves argued, utility rates change every year, insolation varies from year to year, and the customer's own usage pattern will change over the life of the system. While PG&E is not in a position to know what information is provided to customers, system providers should help their customers understand that, as with any long-term financial investment, there is risk associated with investments in renewable energy generating systems.[15]

As a practical matter, under PG&E's proposal, affected customers can expect to recoup their investment, and then continue to accrue bill savings for the next decade or more. This expectation will not change under NEM 2.0. Some parties indirectly suggest that NEM 2.0 will result in no bill savings for customers with renewable generation. This is simply not true.[16]

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14 See, for example, AECA, which argued against "Pulling the rug from under businesses that made good faith investments…" AECA p. 2.

15 Many of the solar parties make clear in their comments that while they ask the utilities to provide NEM protection of 30 years or longer, they are not willing to give performance guarantees of more than 25 years. CalCAN p. 4;CalSEIA pp. 4-5. Similarly, they noted that most PPAs are for less than 25 years. Recolte argues that customers are provided with cash flow statements that cover a 25 year life, but asks for NEM protection for the entire system life, admitting that it seeks protection long after "the payback period, warranted life, or expected life…" Recolte pp. 3, 5.

16 See also ORA pp. 9-10.

While not expected to be as lucrative as the current NEM 1.0, there is every reason to expect that NEM customers will continue to enjoy savings on their energy bills under the new tariff.

3. Basic Fairness To All Customers Requires The CPUC To Use Payback Period To Determine Grandfathering

The CPUC has a responsibility to all customers, not just NEM customers. The CPUC's selection of a transition period will result in dramatically different levels of costs being shifted from NEM customers to non-participating customers, with longer transition periods resulting in markedly higher cost burdens for non-participants. The basic principle of fairness requires that the CPUC limit the impact on non-participants by requiring a transition period no longer than "reasonably expected payback period." The Legislature directed the CPUC to specifically address the impact on non-participating utility customers, and was well aware the updated ratepayer impact analysis study would be available to inform the CPUC's development of NEM 2.0 and any transitional program. The CPUC must balance NEM customers' reasonable recovery of their investment costs with the mitigation of the cost shift on other customers.

The CPUC's recent evaluation of the costs and benefits of NEM found significant cost shifts from participating customers to non-participating customers.[17] It found that over three-fourths of NEM customers do not pay their full cost of service.[18] These costs must be borne by other utility customers.

Building on the Commission's own study, PG&E has provided an estimate below to demonstrate how the cost-shift to other customers is affected by the various NEM grandfathering proposals. These estimates depend on a) the projected MW of NEM that would be subject to grandfathering b) the cost-shift per MW for each year of grandfathering, and c) the number of years of grandfathering past the July 1, 2017 date in which NEM 2.0 would otherwise apply.

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17 Energy and Environmental Economics, Inc., "California Net Energy Metering Ratepayer Impacts Evaluation", prepared for CPUC, October 2013. Also, see NEM-PAC, page 7, "Prior to AB 327, California law evidenced a clear intent to provide a subsidy to NEM customers with full recognition that non-NEM customers would bear these costs." (Emphasis in original.)

18 E3 report, page 105.

First PG&E considered the projected volume of NEM that would be subject to transition. All parties suggesting the CPUC use life of system rather than payback period to set the transition period propose NEM 1.0 be available for any customer interconnecting before July 1, 2017. PG&E assumes for purposes of the information below that these proposals will result in a "gold-rush" as system providers and customers seek to lock-in the generous subsidies under NEM 1.0. As a result, PG&E assumes that the full 5% NEM cap (i.e. 2,409MW[19]) will be achieved by July 1, 2017 in its calculation of cost-shift associated with these 20+ year transition proposals. On the other hand, most parties proposing the CPUC adopt a transition period based on a reasonable payback period also include a transition period ramp-down mechanism intended to mitigate such a "gold-rush". So, PG&E uses the adoption curve from the E3 report as the basis for its calculation of cost-shift associated with the IOU, ORA and TURN proposals. These amounts are shown in column (b).[20]

Next, PG&E calculated the annual cost-shift associated with each MW of volume that would be transitioned. According to the E3 study, the cost shift for PG&E customers in 2017 is projected to be $448 Million annually for projected adoption of 1,760 MW, or effectively $255,000 per MW.[21] NEM 2.0 reforms would substantially mitigate this cost shift upon implementation on July 1, 2017. Grandfathering effectively "locks-in" this cost shift, delaying the ability for non-participating customers to benefit from NEM reform.

Finally, PG&E applied the annual cost shifts to the number of years past the July 1, 2017 transition date included in the various parties' proposals. Column (a) includes the number of

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19 The 2409 MW figure is from AB 327. Additionally, for PG&E and SDG&E, MWs installed between April 2014 and December 31, 2015 have a shorter transition period, and NEM customers installing after that will be not be grandfathered after July 1, 2017

20 Note, where transition dates occur in partial years (e.g. July 1, 2017), the projected volumes were interpolated between the adjacent year-end values in the E3 workbooks. For example, the July 2017 values are the average of 1,525 and 1,760 MW, the year-end projections for 2016 and 2017, respectively.

21 This amount is derived from the 2017 "Snapshot Calculations" from the E3 Models and stated in nominal (2017\dollars), as opposed to the 2020 results stated in 2012 dollars reported in the text of the final E3 report. Further, as described in PG&E's opening comments, PG&E believes that E3 understated the magnitude of the cost shift.

years past the July 1, 2017 transition date. [22] Column (c) shows the total cumulative cost shift from the grandfathered period of the various proposals.

The illustrative results below show that the proposals from parties advocating system life would incur $25.7 (column c =$27.7-$2) Billion more cost-shift than PG&E's payback period proposal during the grandfathered period.

Illustration of Cumulative Cost-Shift Incurred Under Alternative Transition Proposals

	(a)	(b)	(c)
	Years Post 2017	MW Grandfathered	Cumulative PG&E Cost Shift During Proposed Grandfather period ($Millions)
TURN	**3**	**1,640**	**$1,300**
ORA	**5**	**1,640**	**$2,100**
PG&E, SDG&E		**1,310**	**$2,000**
Through Q1 2014	*7*	*970*	*$1,700*
Through YE 2015	*4*	*340*	*$300*
SCE	**7**	**1,640**	**$2,900**
CCSE	**20**	**2,410**	**$12,300**
Most solar parties	**30**	**2,410**	**$18,400**
Other solar parties	**45**	**2,410**	**$27,700**

Notes:

1) Calculations rely on Cost-Shift per MW per year in 2017 of $255,000 from E3 workpapers; (c) is calculated as (a) * (b) * 0.255.

2) Projected volumes in (b) are from E3 workpaper projections of year-end volumes, with partial year values interpolated; however, proposals for CCSE and solar parties are set at PG&E's NEM Cap of 2409 MW.

It is not yet known how much of the projected cost-shift would be mitigated by NEM 2.0 reforms. Recognizing that NEM reform may not totally eliminate the cost shift, the actual impact on cost shift (i.e. the difference in cost shift during the transition period between customers on NEM 1.0 and NEM 2.0) of the different proposals may be less than what is shown, but should nonetheless be substantial.

In addition to the above analysis, PG&E also did some simple calculations to determine the per-customer impact of a proposal to extend NEM 1.0 to all customers installing before July 1, 2017 for the life of their system. Making the same simplifying assumptions as in the earlier

[22] Note, PG&E's proposed transition period would end in the first true-up period after December 31 or its transition year, so in effect, NEM customers would on average transition in the middle of the subsequent year.

analysis, the impact on each non-adopting customer of the transitioned cost-shift would be $7,400.[23] This result is clearly unnecessary and unfair. Allowing a lengthy grandfathering period would result in the continuation of large subsidies that the Legislature and CPUC's own report have established are not cost-effective and that market data suggests is unwarranted.[24]

B. PG&E's Study Shows That The Transition Periods Proposed By The Utilities Will Permit The Vast Majority Of Customers To Recover Their Investment Before Transitioning To NEM 2.0

PG&E contracted with Navigant Consulting, Inc. (Navigant) to examine the customer economics and assess the payback period for both host-owned and third-party-owned (TPO) PV systems across the residential and commercial customer segments. The methodology varied by system ownership type, as described briefly below. The Navigant analysis drew from public, transparent sources such as the California Solar Initiative (CSI) Database and the workpapers in the CPUC's recently issued NEM Cost Effectiveness Evaluation prepared by its consultant E3 ("the E3 report"). Navigant's report is attached as Appendix A. The analysis shows median payback periods of less than 10 years for recently installed residential and commercial projects.

Navigant calculated payback times for thousands of individual host-owned systems using actual installation data obtained from the CSI PowerClerk database. Navigant then aggregated these results to calculate the probability distribution of expected payback times. Data on system size, installation costs, estimated annual production, and other key inputs were obtained from a variety of sources that are described in Appendix A of its analysis. For the Residential Sector, Navigant used a sample of 6,601 residential host-owned systems, representing roughly 20% of the host-owned systems in PG&E's service territory that received a CSI incentive. The quantity of systems analyzed provides a representative distribution of the payback times given the large sample sizes. Navigant examined 100% of the CSI systems installed in the Commercial/Industrial sector, representing 1,367 systems in PG&E's territory.

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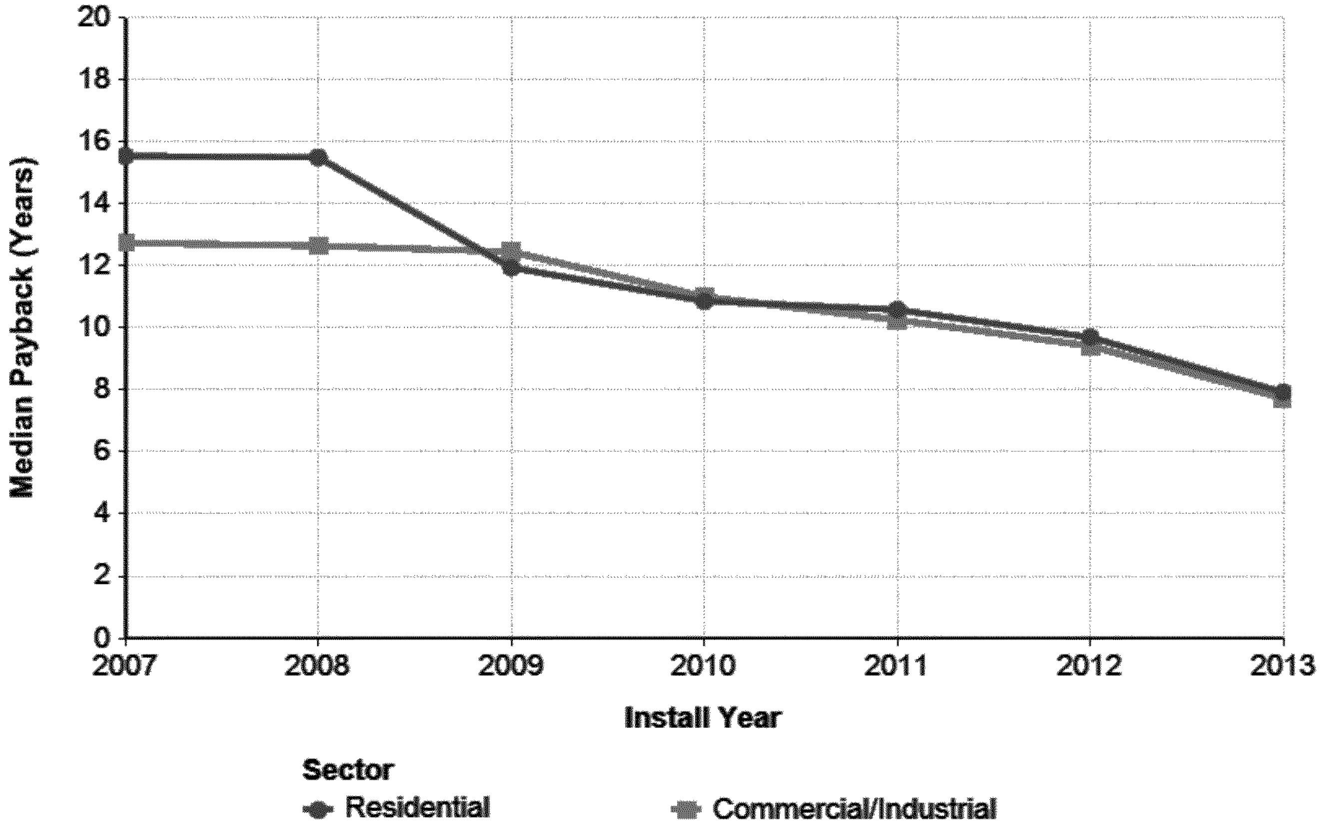
23 $26 billion cost shift divided by approximately 3.5 million non-CARE non-adopting customers. CARE customers enjoy substantial protection from cost shifts.

24 E3 report, page 113.

Payback Period for Residential and Commercial/Industrial Customers with Host -Owned Solar PV Systems by Vintage



This analysis is conservative. It substantially discounts customers' bill savings by only accounting for the after-tax impacts (e.g., for every $100 of reduced electric expenses, a taxable commercial customer only saves about $60 because it could have deducted that $100). Also, the modeled customer costs come from the CSI database and are based on reported pricing, which is often higher than system costs.[25]

C. Other Information Submitted On Solar Payback Supports A Transition Of No More Than 10 Years For Existing Projects.

Other parties also filed comments supporting a modest payback calculation, many with transition periods shorter than those proposed by PG&E. For example, TURN included detailed

25 Feldman, D. et al., "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections", SunShot, U.S. Department of Energy, PR-6A20-60207, July 16, 2013.

information supporting its much shorter transition proposal.[26] Additional material was supplied concerning customer understanding of payback. For example, ORA presented citations to various authorities supporting a payback expectation of ten years or less.[27] PG&E's opening comments also provided data on payback estimates made available in the public domain, and a review of online reports, news coverage, and company statements put most in the 5- to 10-year range in California.

Parties proposing a longer transition period offered little or no evidence on reasonable payback period. Instead, most of them requested that the CPUC should abandon calculation of a reasonable payback period, arguing it is the wrong test, or that it is too complicated.[28] However, the Legislature did not require the CPUC to provide a specific payback for each and every customer, rather that the CPUC set one or more grandfathering periods that allows customers a reasonable payback period. All of the proposals based on payback rather than system life achieve this goal.

D. Third Party Ownership With Little or No Customer Payment Upfront

A number of parties discussed the availability of third-party ownership (TPO) financing, many correctly noting that these arrangements now make up an increasing majority of all new systems installed.[29] Some parties argue that if their proposed term of "at least 30 years" is not adopted, at the very least, the CPUC should set a transition term equal to the life of the power purchase agreement or contract with the NEM owner.[30] However, these arrangements often have an immediate payback period, as the TPO systems are offered to host customers for no money down, and provide bill savings immediately.[31]

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26 TURN, pp. 2, 8-10.

27 ORA pp. 3-4, esp. text and citations at fn. 7

28 IREC argued against setting over 200,000 different transition end dates. IREC p. 13.

29 See, for example, CESA p. 5.

30 See CESA p. 5.

31 For example, NEM-PAC, after arguing for protection for the life of the PPA, admitted that the projects of its members were built under PPAs "without having to expend out-of-pocket capital funds." NEM-PAC p. 10.

AB 327 provides no guarantee to the suppliers of renewable distributed generation systems that entered into such arrangements, and is instead focused on the customer economics. PG&E believes the Commission should focus its evaluation on the impact of NEM reform on customers not third-parties. In any event, companies providing TPO arrangements were well aware of, and have disclosed in their public financial statements,[32] the uncertainties inherent in owning and operating long-lived energy generating assets that are dependent on ever-changing rates and tariff structures.

Navigant also analyzed the economics of third party arrangements, and concluded that under third party financing, customer payback would be achieved within ten years for the vast majority of residential and commercial/industrial projects.[33] No conflicting data has yet been submitted as part of this proceeding.

E. A Shorter Transition Period For Projects Coming On Line After 2014 Will Reduce Costs, Avoid A Gold Rush, and is Appropriate, Since The Industry Knows Change Is Coming.

Very few parties addressed the question of whether a different transition period should be adopted for projects coming on line after the NEM grandfathering decision, or after the rules for NEM 2.0 are established in 2015. SDG&E agreed with PG&E about the benefits of a shorter transition period for such projects, and both SCE and TURN addressed the risks of a huge "gold rush."[34]

PG&E proposes that projects installed from April 1, 2014 to December 31, 2015 receive a transition period of 6-7 years before transitioning to NEM 2.0. This will provide sufficient certainty to customers, allowing them to receive a substantial amount of the value of their investment through NEM 1.0. In fact, due to the recent rapid drop in solar prices, and the

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32 Solar City 2012 10K Filing, March 27, 2013, p. 15: "Federal, state and local government regulations and policies concerning the electric utility industry, and internal policies and regulations promulgated by electric utilities, heavily influence the market for electricity generation products and services. These regulations and policies often relate to electricity pricing and the interconnection of customer-owned electricity generation. In the United States, governments and utilities continuously modify these regulations and policies".

33 See Appendix A, pp. 23 and 33.

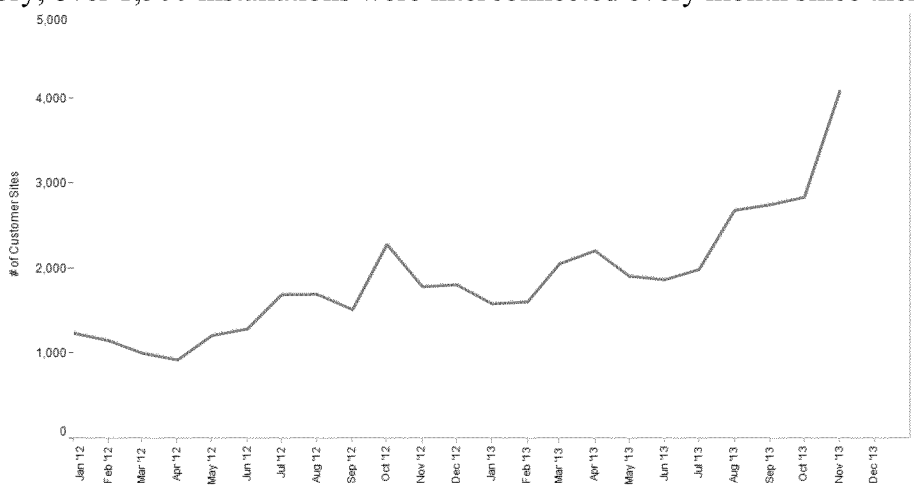
34 See SCE p. 10, TURN p. 11.

transition period, these customers may earn much or all of their payback prior to transitioning to NEM 2.0. Further, these customers will also continue to enjoy benefits under the NEM 2.0 tariffs after the transition date.

Customers installing renewable generation between January 2016 and July 2017 are less likely to be surprised by the NEM 2.0 changes than those already interconnected, since those rules will have been set in 2015. They should be transitioned to NEM 2.0 in July 2017.

F. The Proposed Transition Periods Will Not Unduly Affect The Market

Some parties claim that the grandfathering of NEM 1.0 based on anything other than expected system life will harm the market.[35] This is an exaggeration for which parties provide no support. NEM has always had an overall legislative cap, and since May 2012, when the CPUC passed the NEM cap decision[36] calling for a study of and possible suspension of NEM, the market has been aware that NEM may not go on forever as it currently exists. For over a year, the solar market has known that NEM is likely to change in order to mitigate the cost shift. During that time period, solar installations have continued to increase in California. In PG&E's service territory, over 1,500 installations were interconnected every month since then.



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35 See, for example, AECA pp. 2, 4, and CalSEIA p. 2, arguing that any change in net metering would "discourage future investment in solar generation."

36 D.12-05-036. Although that decision was vacated by the CPUC, this did not occur until after AB 327 was enacted. See D.13-11-026, issued in November 2013.

In addition, the drop in solar prices has been dramatic, meaning that customers installing solar no longer need the significant cost-shift subsidy they have been receiving from other customers. So long as customers receive current information, including uncertainties,[37] the market should remain healthy during the transition period.

G. Eligibility For NEM 1.0 Grandfathering Should Run With The Customer Of Record, Not The Equipment

Several parties suggest that the eligibility for NEM 1.0 should attach to the equipment, not the customer.[38] This means if there is a change of ownership during the grandfathering phase, the new homeowner will receive the benefit of grandfathering. There is a fundamental difference between the customer of record who originally installed the equipment and the prospective buyer of his or her home. The first did not know about the changes to NEM 1.0, or the likely terms of NEM 2.0 at the time they installed their equipment. The CPUC can ensure that the seller has an opportunity to recover its original investment. On the other hand, the prospective buyer knows exactly what the market conditions are at the time of the sale and can negotiate the home price accordingly. PG&E agrees with SDG&E and SCE, who concluded that when the customer of record changes, the NEM 1.0 grandfathering should end for that installation.[39]

H. Projects That Have Been Materially Modified Should Not Be Grandfathered.

Most solar parties agreed that any substantive additions to the original systems made after July 1, 2017 should be covered by NEM 2.0.[40] PG&E agrees. They also argued that customers with existing systems should be able to repair or replace those systems without impacting its eligibility for the NEM tariff. PG&E agrees as to repairs or replacements of equipment of the

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37 See ORA, p. 1.

38 See, for example, Alliance for Solar Choice pp. 15-16.

39 SDG&E p. 9; SCE p. 8, n. 16.

40 SEIA/Vote Solar p. 6; Recolte p. 6. IREC and NEM-PAC argued that any additions to a project should be grandfathered for the life of the system. IREC p. 12; NEM-PAC p. 12.

same size, but believes that any material modification or addition to the existing system would not be eligible for the NEM transition program. However PG&E would support giving the customer a choice about how this would be implemented, either moving the entire facility onto NEM 2.0, or electing to add the new generation consistent with the multiple tariff treatment, NEM-MT option in the NEM 1.0 tariff.[41]

III. CONCLUSION

PG&E appreciates the opportunity to provide these comments and requests that the Commission adopt these recommendations.

Respectfully submitted,

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41 CESA also asks the CPUC to address issues of energy storage coupled with NEM eligible generation. CESA p. 7. That issue is pending elsewhere at the CPUC, and is beyond the scope of the Ruling here.

Appendix A

NAVIGANT

Net Metering Grandfathering Analysis for the Residential and Commercial/Industrial Market Sectors

Prepared for:

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December 23, 2013

NAVIGANT

Table of Contents

SB_GT&S_0393181

NAVIGANT

List of Figures and Tables

Figures:

Tables:

Executive Summary

Navigant was retained by PG&E to develop a model that illustrates customer economics and the potential impact of different net energy metering (NEM) grandfathering options by market segment and system vintage. This report presents the results of the analysis for both host-owned and third-party (TPO) systems for the Residential and Commercial/Industrial (taxable) market sectors.[1]

This project is largely driven by the need to analyze potential grandfathering arrangements for existing NEM customers as required by Assembly Bill (AB) 327.[2] Today, the vast majority of customers with NEM (99%) have installed solar PV systems.[3] Thus, to conduct this study, Navigant examined participants in the California Solar Initiative (CSI).

The timing for CPUC decisions on grandfathering the existing NEM tariff and the details of a future tariff (NEM 2.0) differs, making it difficult to fully assess the potential impact of different grandfathering alternatives. The CPUC is required to determine the length of the grandfathering period by March 31, 2014. However, decisions on subsequent changes to NEM rules and tariffs may not occur until December 31, 2015. Therefore, it is important to note that the focus of this report is only on grandfathering of existing systems and not the potential impact of NEM 2.0 rate scenarios.

Methodology

Navigant examined the customer economics for both host-owned and TPO systems. The methodology varied by system ownership type, as described briefly below and in more detail in Section 2 of this report. Both annual production and the utility offset rate[4] were disaggregated by whether generation was produced and consumed onsite (i.e., during periods where consumption was greater than or equal to production) or exported (i.e., during periods where consumption was less than production). Assumptions regarding utility offset rates (onsite versus exported) as well as the percentage of generation assumed to be exported (by sector) are provided in Appendix A.

Host-Owned System Payback Methodology

Navigant calculated the median payback times for thousands of host-owned systems in the Residential and Commercial/Industrial market sectors using actual installation data obtained from the CSI PowerClerk database.[5] Navigant also calculated the probability distribution of expected payback times.

For the Residential sector, Navigant pulled a sample of 6,601 residential host-owned systems, representing roughly 20% of the host-owned systems in PG&E's service territory that received a CSI

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[1] The Government/Non-profit (non-taxable) market segment is not included in the scope of this report.

[2] Bill Text - AB-327 Electricity: natural gas: rates: net energy metering: http://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml

[3] http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

[4] The utility offset rate is the amount a PV customer's bill is reduced for each kWh produced by the PV system. Its calculation is described in Appendix A. Values used are the same for host-owned and TPO systems.

[5] http://www.californiasolarstatistics.ca.gov/current_data_files/. The CSI Working Data set through November 27, 2013 was used in this analysis.

incentive. The quantity of systems analyzed provides a representative distribution of the payback times given the large sample sizes. Navigant examined 100% of the CSI systems installed in the Commercial/Industrial sector, representing 1,367 systems in PG&E's territory.

Third-Party Owned (TPO) System Payback Methodology

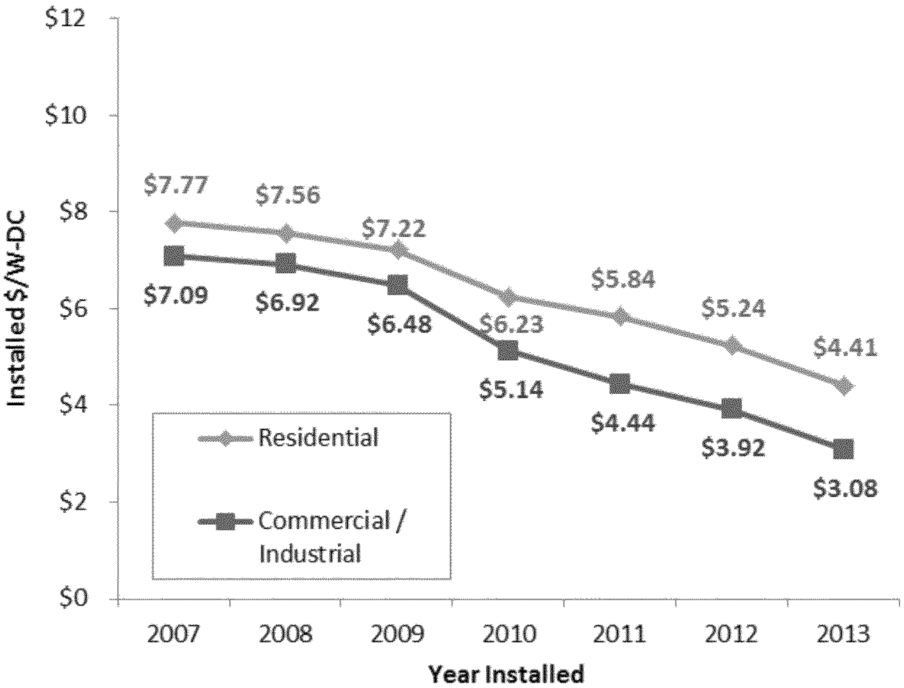
Payback times for TPO systems were calculated very differently than those for host-owned systems. As many TPO systems (e.g., via solar leases or power purchase agreements [PPAs]) provide immediate bill reductions and are often offered with little or no down payment, the concept of a "payback" time is more abstract than for host-owned systems. Given the requirement in AB 327 that the CPUC "consider a reasonable expected payback period," this analysis included a modified payback calculation for TPO systems. In short, the "net system cost" was assumed to be the present value of the lease or PPA obligation over the duration of the entire contract period (e.g., 15 or 20 years). The time it would take to pay back the lease or PPA obligation was then estimated using a modified payback calculation.

The sample sizes for the TPO analysis are much smaller than those in the host-owned analysis, resulting in a greater degree of uncertainty in the analysis of TPO systems. The TPO analysis required that Navigant staff manually extract contract terms from a sample of TPO contracts for CSI customers in PG&E's service territory. Contract terms and conditions where then used to calculate the levelized cost of electricity (LCOE) of each contract over the duration of that contract. We term this LCOE the "Effective Lease or PPA Rate ($/kWh)." As contract terms typically require transfer of the Federal Investment Tax Credit (ITC) and utility incentives to the third-party provider, these benefits are fully rolled into the calculated LCOE and therefore do not need to be re-accounted for in the payback analysis.

Results

The results of the analysis are largely driven by rapidly declining prices in solar systems under the CSI Program. Figure 1 shows the average reported system cost for systems installed each year by sector based on the CSI PowerClerk data.

Figure 1. Annual Average Reported Cost for Installed Host-Owned CSI Systems ($/W$_{DC}$)



Note: Costs are nominal $ as reported to the CSI Program. Residential numbers are based on a representative sample (n=6,601) of host-owned systems listed in CSI PowerClerk data.
Source: PowerClerk Working Data, November 27, 2013

Table 1 below provides a summary of the median paybacks for host-owned participants in the CSI Program across all three sectors. As displayed, the median payback is roughly 8 years for systems installed in 2013 for the Residential and Commercial/Industrial sectors. As displayed, the median payback times for these two sectors have decreased dramatically since the CSI Program's inception in 2007.

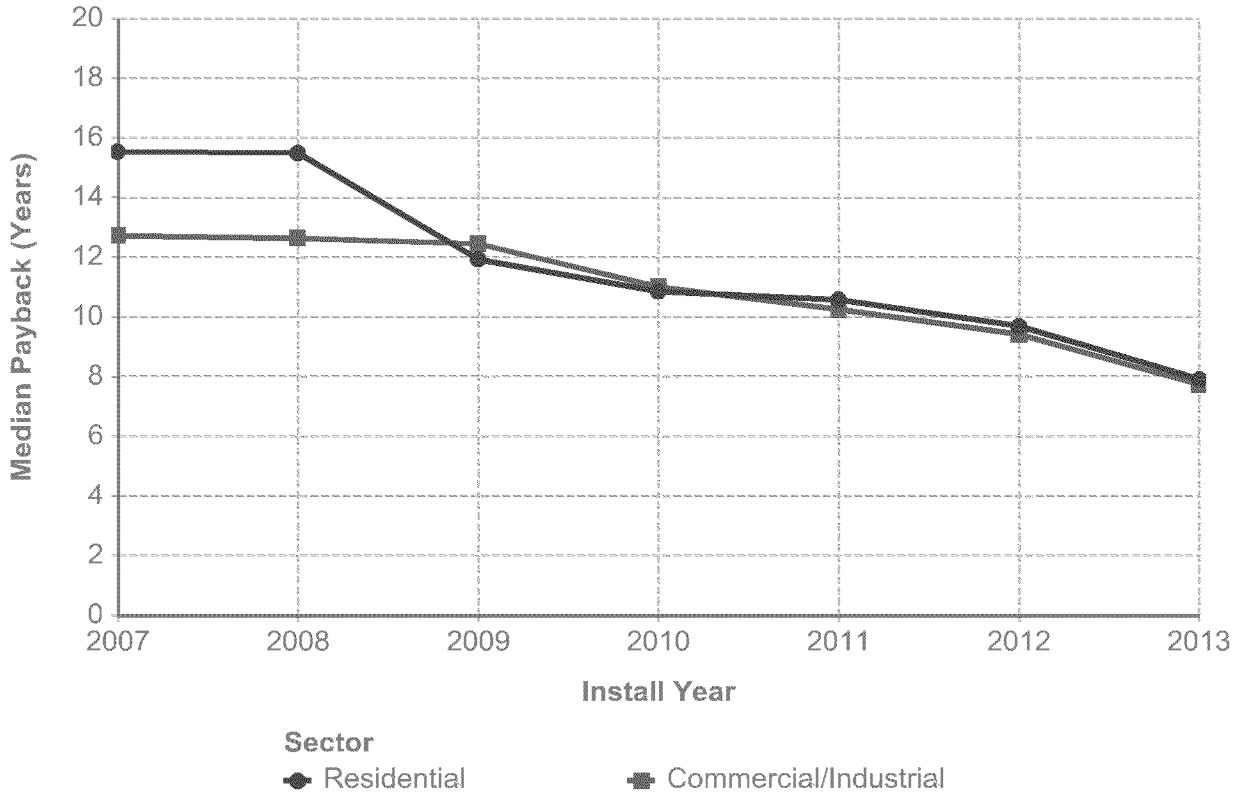
Table 1. Median Payback by Sector and System Vintage for Host-Owned Systems (Years)

Sector	Year of System Installation						
	2007	2008	2009	2010	2011	2012	2013
Residential	15.5	15.5	11.9	10.9	10.6	9.7	7.9
Commercial/Industrial	12.7	12.7	12.5	11.0	10.3	9.4	7.8

Note: Residential numbers are based on a representative sample (n=6,601) of host-owned systems listed in CSI PowerClerk data. Commercial/Industrial numbers include all reported systems.
Source: Navigant analysis, based on a sample of CSI PowerClerk data

Figure 2 displays these calculated median payback times by market segment and year of installation.

Figure 2. Median Payback of CSI Systems by Market Sector



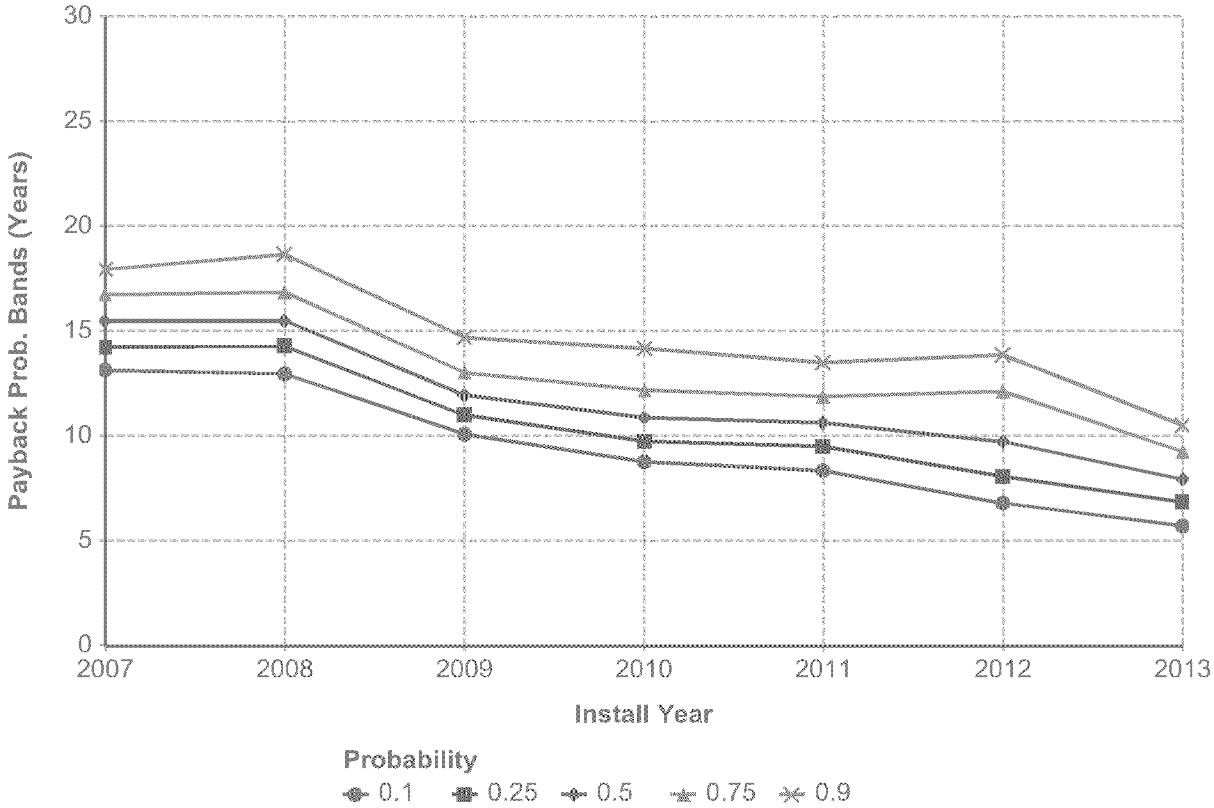
Note: Residential numbers are based on a representative sample (n=6,601) of host-owned systems listed in CSI PowerClerk data. Commercial/Industrial numbers include all reported systems.
Source: Navigant analysis, based on a sample of CSI PowerClerk data

Residential Sector Results

Host-owned Residential Systems

Navigant estimates that median payback times were greater than 15 years in 2007, but dropped to eight years by 2013, driven largely by reductions in system installation costs. Figure 3 shows the payback probability bands for each year of installation. For instance, for systems installed in 2007, the figure shows that roughly 10% of the systems had payback times of less than about 13 years, whereas 90% had payback times of less than about 18 years. By 2013, however, 10% of installed systems had payback times of less than 5.7 years, whereas 90% of systems had payback times of less than 10.5 years.

Figure 3. Payback Probability for Residential Host-Owned PV Systems

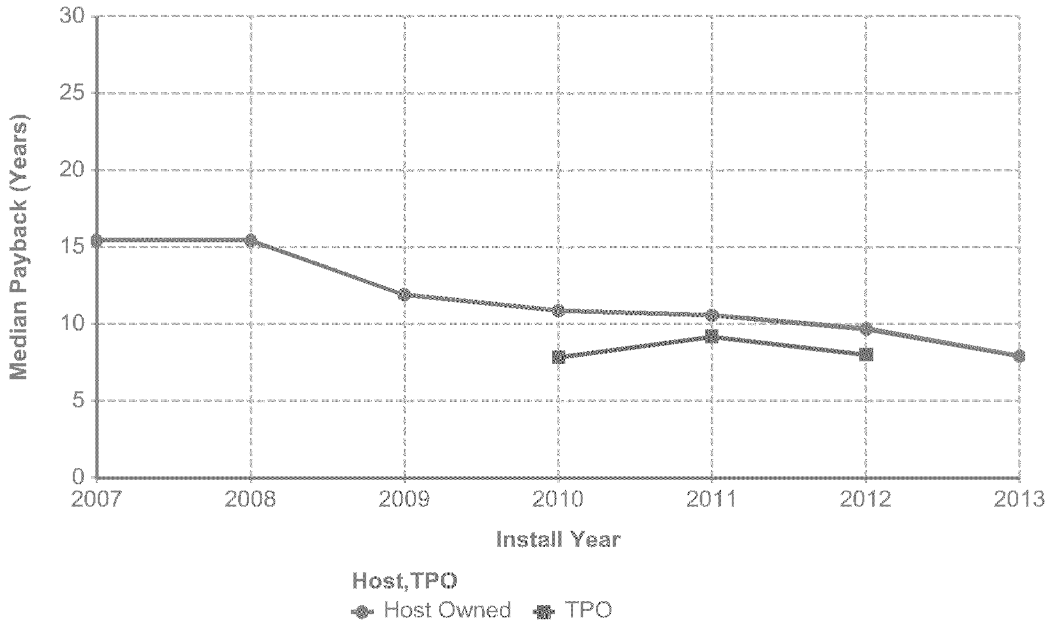


Source: Navigant analysis, based on a sample of CSI PowerClerk data

Third Party-Owned (TPO) Residential Systems

Figure 4 compares payback times of host-owned systems with those of TPO systems. As shown, payback times tend to be lower than those calculated for host-owned systems. A likely explanation for this is that a third-party owner, which is a commercial entity, is able to monetize the benefits associated with capitalization and accelerated depreciation of the PV system asset, whereas a residential customer is not able to do so. That said, other confounding factors (e.g., possible pricing strategy differences between TPO and host-owned systems) may also contribute to this apparent difference.

Figure 4. Median Payback Times for Residential Host-Owned & TPO PV Systems

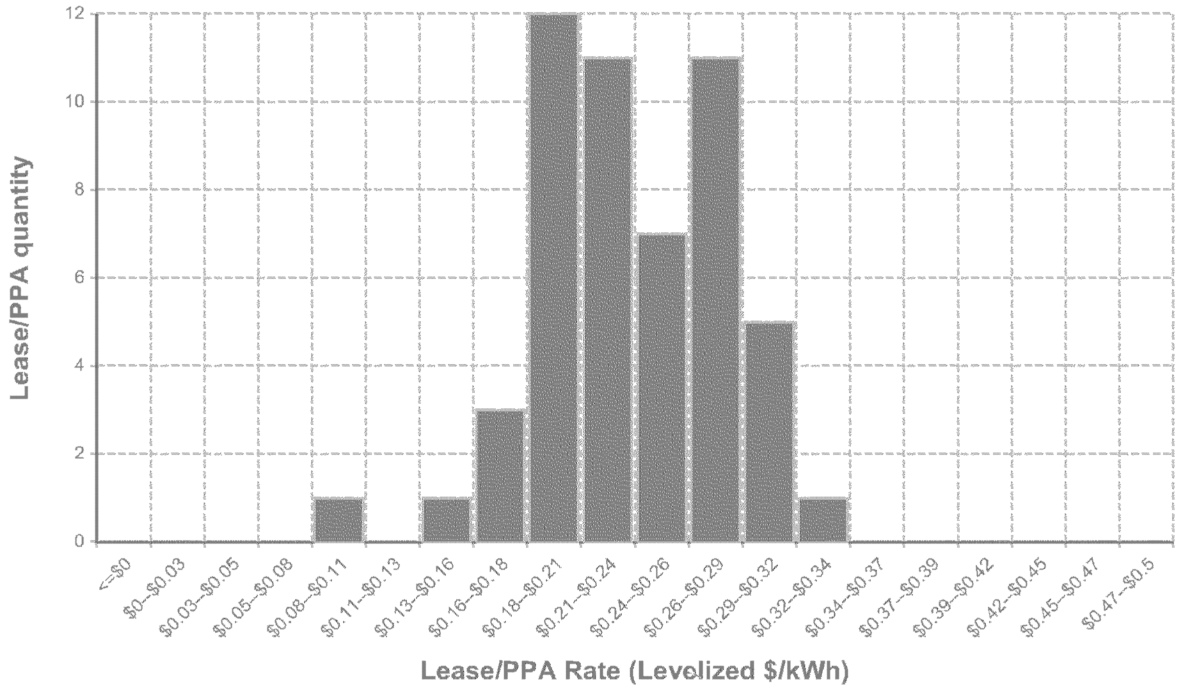


Source: Navigant analysis, based on a sample of CSI PowerClerk data

Figure 5 provides a histogram of the calculated effective lease or PPA rates (levelized $/kWh) for 52 systems installed in 2012. The quantity of leases/PPAs analyzed is on the y-axis, and the effective lease or PPA rate is on the x-axis. Navigant calculated the effective lease/PPA rates by manually extracting relevant contract terms from a sample of TPO contracts and then performing a levelized cost of energy calculation for each contract. To ensure an apples-to-apples comparison, only contracts with 20-year terms are shown in this figure.[6] The figure below focuses on 2012 due to having the largest sample size in the residential sector in that year.

[6] One residential system had a 25-year contract term and was excluded from this histogram, as levelized costs of electricity are only comparable if analyzed over the same length of time.

Figure 5. Effective Lease or PPA Rates (Levelized $/kWh) for Residential TPO Contracts in 2012

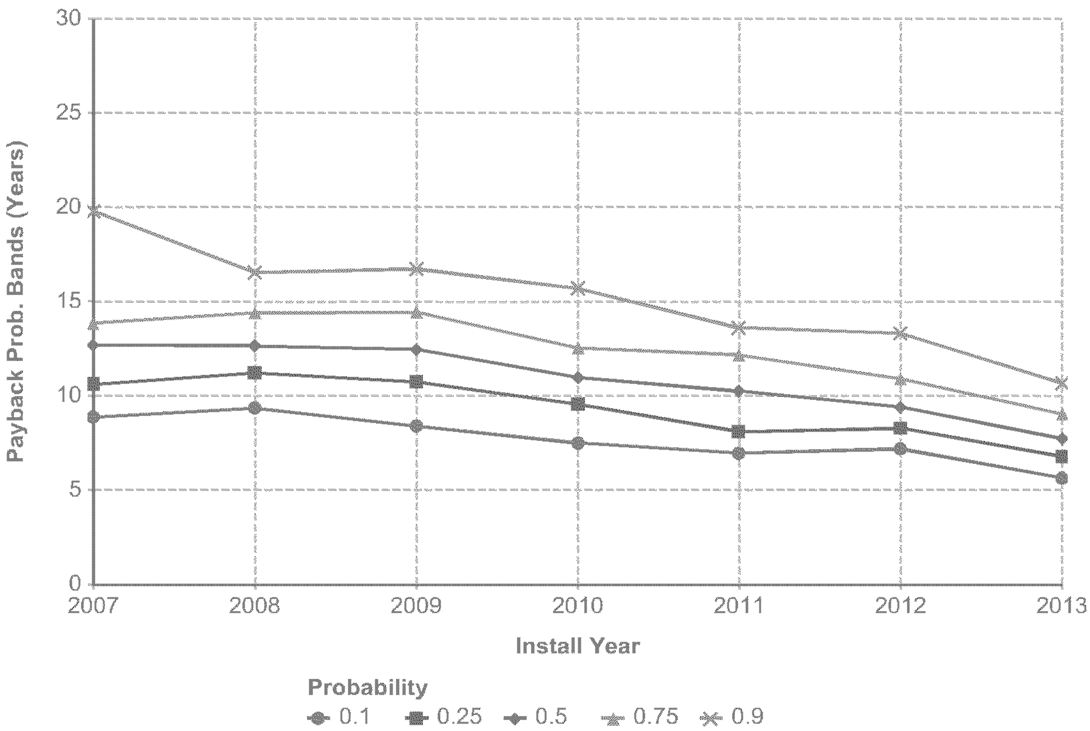


Source: Navigant analysis, based on a sample of TPO contracts from CSI PowerClerk data (n=52)

Commercial/Industrial Sector Results

For the Commercial/Industrial sector, Navigant estimates that median payback times were roughly 14 years in 2007, but dropped to eight years by 2013, again driven largely by reductions in system installation costs. Figure 6 shows the payback probability bands for commercial systems for each year of installation. For systems installed in 2013, 10% of installed systems had payback times of less than 5.8 years, whereas 90% of systems had payback times of less than 11.1 years.

Figure 6. Payback Probability Bands for Host-Owned Commercial/Industrial PV Systems



Source: Navigant analysis, based on a sample of CSI PowerClerk data

1. Introduction

Navigant is pleased to present the results of our research to assess estimated payback periods for existing net energy metering (NEM) customers in PG&E's service territory. This report presents the results of the analysis for both host-owned and third-party-owned (TPO) systems for the following two market sectors:

- Residential
- Commercial/Industrial (taxable non-residential)[7]

1.1 Background

Net energy metering has been instrumental in helping to drive the market for distributed solar in California. The state's NEM policy was designed to encourage customers to install distributed generation facilities to offset part or all of their electrical needs. For the purposes of this project, NEM means measuring the difference between the electricity supplied through the electrical grid and the electricity generated by an eligible customer-generator that is then fed back to the electrical grid over a 12-month period.[8]

1.1.1 Assembly Bill 327

This project is largely driven by the need to analyze potential transition periods (i.e., grandfathering) for switching existing NEM customers from the current NEM tariff to a future NEM tariff, as required by Assembly Bill (AB) 327.[9] Key provisions of AB 327 include:

- NEM grandfathering rules will be determined by the Commission by March 31, 2014.
- Rules adopted by the Commission shall consider a "reasonable expected payback period" based on the year the customer initially took service under the tariff or contract.
- Allowance of significant changes in future electric rate reforms, including application of fixed charges.
- A new NEM tariff (NEM 2.0) will be designed to begin at the earlier of July 2017 or once existing NEM capacity reaches 5% of aggregate demand among the state's investor owned utilities.
- NEM 2.0 should ensure that:
    - Renewable distributed generation (DG) continues to grow sustainably.
    - Total benefits of NEM approximately equal its total costs.

It is important to note that the timing for decisions on the grandfathering period and future NEM 2.0 rules differs, thereby making it difficult to fully assess the potential impact of different grandfathering alternatives. As listed above, the CPUC is required to determine the length of the grandfathering period by March 31, 2014. However, subsequent decisions about the changes to the NEM rules and tariff may

[7] The Government/Non-profit (non-taxable) market segment is not included in the scope of this report.
[8] This definition is consistent with the language in AB 327.
[9] Bill Text - AB-327 Electricity: natural gas: rates: net energy metering: http://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml

not occur until December 31, 2015. The focus of this report is limited to an analysis of potential grandfathering periods for existing systems; it does not fully explore the potential impact of different NEM 2.0 scenarios.

1.1.2 PowerClerk Data Analysis

Today, the vast majority of customers with NEM (99%) have installed solar photovoltaic (PV) systems.[10] Thus, to conduct this study, Navigant developed a customized model to assess the expected payback of customers who have participated in the California Solar Initiative (CSI) program. Since the program began in 2007, the majority of the customer-sited solar PV systems installed in PG&E's service territory have received a CSI incentive. Navigant utilized the publicly available PowerClerk Working Data set to conduct its analysis of host-owned systems. To assess the economics of TPO systems, we used PG&E's access to non-public PowerClerk data to extract the terms and conditions from a sample of 123 third-party contracts for customers in PG&E's service territory.

1.1.2.1 CSI Database Summary Statistics

Prior to launching into the results, it is important to provide an overview of the PowerClerk data that the team analyzed. We pulled data on CSI systems installed through November 27, 2013. Summary statistics on the total capacity installed and system costs are provided below.

1.1.2.2 Total Capacity Installed

As stated previously, Navigant utilized the publicly available PowerClerk Working Data to conduct this analysis. The total installed capacity for the Residential and Commercial/Industrial sectors, broken out by ownership type, is illustrated in Figure 1-1 and Figure 1-2, respectively. From 2007 through November 27, 2013, TPO systems represented roughly 43% of cumulative installed capacity in the Residential sector and 37% of cumulative installed capacity in the Commercial/Industrial sector.

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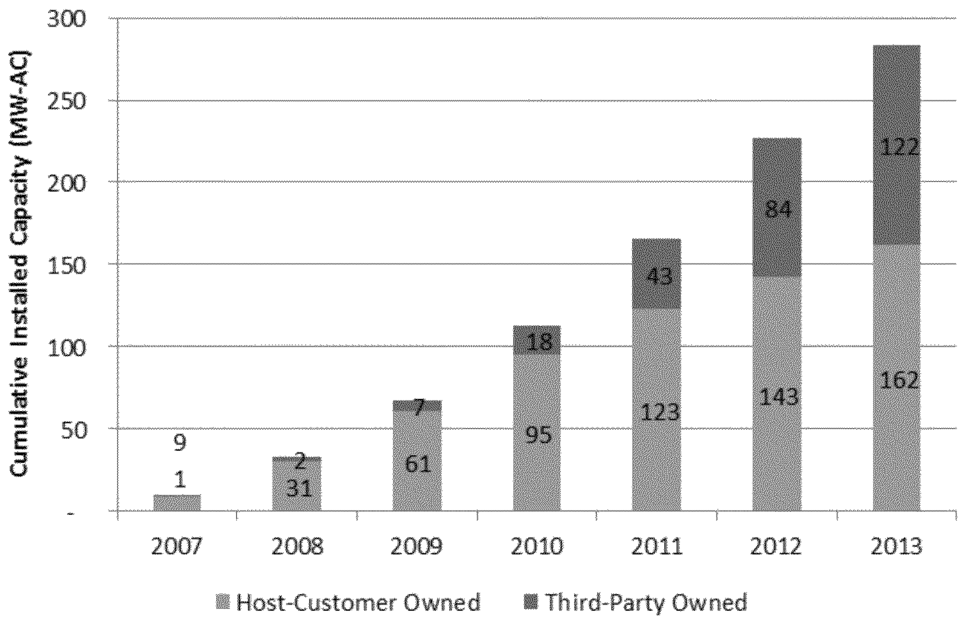
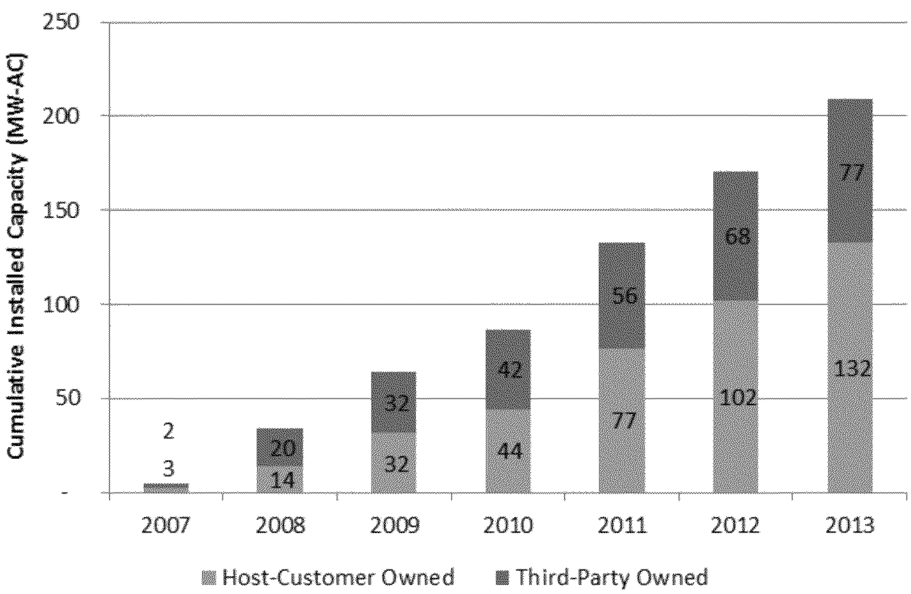
[10] http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

Figure 1-1. Residential Sector – CSI Cumulative Installed Capacity (MW-AC)



Source: PowerClerk Working Data, November 27, 2013

Figure 1-2. Commercial/Industrial Sector – CSI Cumulative Installed Capacity (MW-AC)

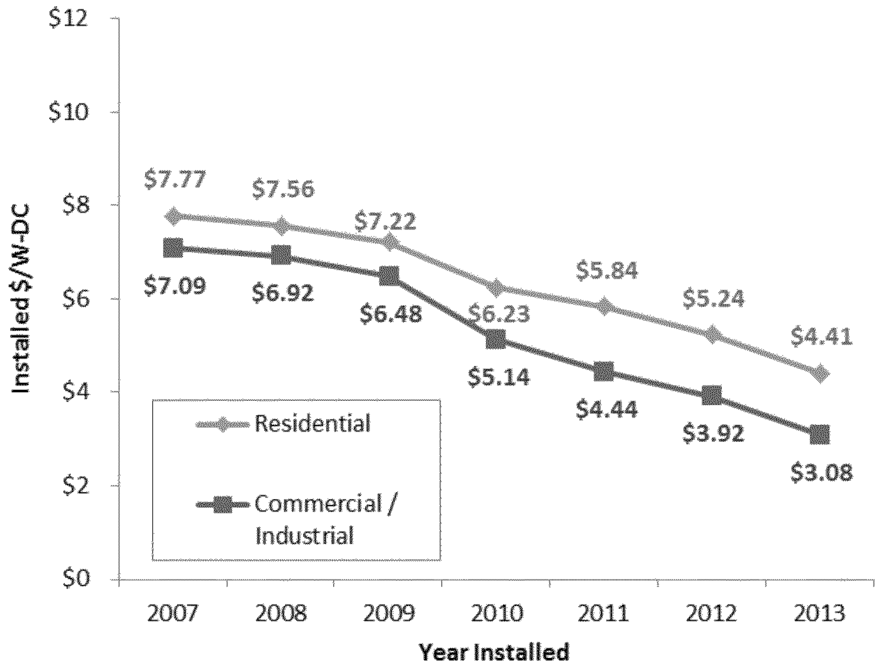


Source: PowerClerk Working Data, November 27, 2013

1.1.2.3 *Installed Costs for Host-Owned Systems*

System costs for solar systems have decreased dramatically since the inception of the CSI Program. These declining costs have led to increased customer adoption and, as will be discussed below, shorter payback periods. Figure 1-3 illustrates the annual average installed cost for the systems included in Navigant's analysis.

Figure 1-3. Annual Average Reported Cost for Installed Host-owned CSI Systems ($/$W_{DC}$)



Note: Costs are nominal $ as reported to the CSI Program. Residential numbers are based on a representative sample (n=6,601) of host-owned systems listed in CSI PowerClerk data.
Source: PowerClerk Working Data, November 27, 2013

1.2 *Organization of Report*

The remainder of this report is organized in the following sections:

- Section 2: Overview of Approach and Methodology
- Section 3: Residential Sector Results
  - Host-owned
  - Third-party owned
- Section 4: Commercial/Industrial Sector Results
  - Host-owned
  - Third-party owned
- Appendix A – Data Sources & Assumptions

2. Overview of Approach/Methodology

This section provides a high-level overview of Navigant's approach to calculating payback times for host-owned and TPO solar PV systems. Additional detail regarding specific calculations can be found in the accompanying payback model that Navigant provided to PG&E with this report.

2.1 Calculation of Payback Times

Navigant calculated payback times separately for host-owned and TPO systems. Section 2.1.1 discusses the payback methodology for host-owned systems, and Section 2.1.2 discusses the payback methodology for TPO systems.

2.1.1 Host-Owned System Payback Methodology

Navigant calculated payback times for thousands of individual host-owned systems in the Residential and Commercial/Industrial sectors using actual installation data obtained from the CSI PowerClerk database.[11] Navigant then aggregated these results to calculate the probability distribution of expected payback times. Data on system size, installation costs, estimated annual production, and other key inputs were obtained from a variety of sources that are described in Appendix A. The Residential and Commercial/Industrial sectors were each treated differently in the payback calculations due to differences in each sector's ability to monetize the Federal Investment Tax Credit (ITC) and other tax benefits (e.g., accelerated depreciation).

For host-owned systems, the basic payback calculation is shown below.

where:

and,

[11] http://www.californiasolarstatistics.ca.gov/current_data_files/. Working data set through November 27, 2013 was used in this analysis.

Below, we describe how each sector (Residential versus Commercial/Industrial) was treated differently in the above payback equations.

Federal ITC

The Federal ITC (30% of the cost basis) was assumed to apply to the Residential and Commercial/Industrial sectors. Additionally, in the Residential sector, we applied the maximum tax credit of $2,000 for systems installed prior to 2009.[12] For Residential customers, the cost basis for determining the ITC was reduced by the amount of the EPBB incentive. The cost basis was not reduced by the EPBB incentive for Commercial/Industrial customers since Federal taxes were assumed to be paid on the EPBB incentive (per below), obviating the need for a reduction in the cost basis for purposes of calculating the ITC.

Tax Paid on EPBB Incentive and Taxes Paid on PBI

Federal (not State) taxes were assumed to be paid on the EPBB incentive and PBI by Commercial/Industrial customers only.[13]

Annual After-Tax Bill Savings

For Commercial/Industrial customers, energy expenses can be deducted from taxable income. As such, only the after-tax bill savings were included in the denominator of the payback equation (i.e., Bill Savings * (1 – Combined Effective Tax Rate).[14] See Appendix A for tax rate assumptions. Bill savings (pre-tax) were calculated per the equation below.

Both annual production and the utility offset rate were disaggregated by whether generation was: produced and consumed onsite (i.e., during periods where consumption was greater than or equal to production) or exported (during periods where consumption was less than production).[15] Assumptions regarding utility offset rates (onsite versus exported) as well as the percentage of generation assumed to be exported (by sector) are provided in Appendix A. The appendix also describes the methodology used to calculate utility offset rates for PG&E.

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[12] Source: Federal Residential Incentives: DSIRE website: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F. The same adjustment shown here also applies to treatment of operation and maintenance expenses, which are also after tax.

[13] See 17138.1 in the following link: http://www.leginfo.ca.gov/cgi-bin/displaycode?section=rtc&group=17001-18000&file=17131-17157

[14] The effective combined Federal/State tax rate, in this case 40.75% (or State Tax Rate + (1 – State Tax Rate) x Federal Tax Rate. See Appendix A for tax rate assumptions.

[15] The utility offset rate is the amount a PV customer's bill is reduced for each kWh produced by the PV system. Its calculation is described in Appendix A. Values used are the same for host-owned and TPO systems.

Avoided Taxes due to Depreciation
For Commercial/Industrial customers, avoided taxes due to depreciation were added to the assumed annual savings.[16] The cost basis for depreciation was reduced by 50% of the Federal ITC. Additionally, for State depreciation, the cost basis was also reduced by the EPBB incentive (since the EPBB was assumed to be taxed at the Federal level but not at the State level).

2.1.2 Third-Party Owned (TPO) System Payback Methodology

Payback times for TPO systems were calculated very differently from those for host-owned systems. As many TPO systems (e.g., via solar leases or power purchase agreements [PPAs]) provide customers with immediate bill reductions and are often offered with little or no down payment, the concept of a payback time is more abstract than for host-owned systems. Given the AB 327 requirement that the CPUC "consider a reasonable expected payback period" (see Section 1.1.1), this analysis included a modified payback calculation for TPO systems. In short, the net system cost was assumed to be the present value of the lease obligation over the duration of the entire contract period (e.g., 15 or 20 years). Then, the time it would take to pay back the present value of the lease obligation was estimated using the equation below.

Where:

and,

To calculate the effective lease or PPA rate (levelized $/kWh), Navigant extracted the terms and conditions from a sample of 123 TPO system contracts. As this step required manually extracting

[16] See Appendix A for assumed Federal/State depreciation schedules, which include "Bonus" depreciation for some installation years.

[17] Recall that with host-owned systems, Navigant used after-tax values for annual savings due to energy bill reductions. That is also the case for TPO systems; however, this effect cancels out since both lease/PPA payments for energy and the associated bill reductions are tax deductible.

contract terms (as opposed to being able to pull large quantities of data rapidly from the CSI PowerClerk database), the sample sizes for the TPO analysis are much smaller than those in the host-owned analysis, resulting in a greater degree of uncertainty in the TPO system analysis. The number of sampled data points, by sector and installation year, is summarized in Appendix A; it also appears in Table 2 below for context. Due to the high degree of uncertainty that would result from only a few data points being available for a given stratum (by year and sector), the output tables and figures in this report only include those stratum where 10 or more TPO contract data points were available.

Table 2. Number of TPO Contracts Reviewed

Year Installed	Residential	Commercial/ Industrial	Total
2007	0	0	0
2008	1	0	1
2009	2	0	2
2010	**12**	3	15
2011	**29**	**12**	41
2012	**53**	**10**	63
2013	0	1	1
Total	97	26	123

Note: Only sector/year combinations with ten or more data points (highlighted in bold) were used in the analysis.

Source: CSI PowerClerk non-public data sampled by Navigant

Navigant then used contract terms and conditions to calculate the levelized cost of electricity (LCOE) of each contract over the stated term of that contract (usually 15 years or 20 years). We term this LCOE the "Effective Lease or PPA Rate ($/kWh)" in the equations above. As contract terms typically require transfer of the Federal ITC and utility incentives to the third-party provider, these benefits are fully rolled into the calculated LCOE and therefore do not need to be re-accounted for in the payback analysis.

3. Residential Sector Results

This section provides the results for both host-owned and TPO systems in the Residential sector.

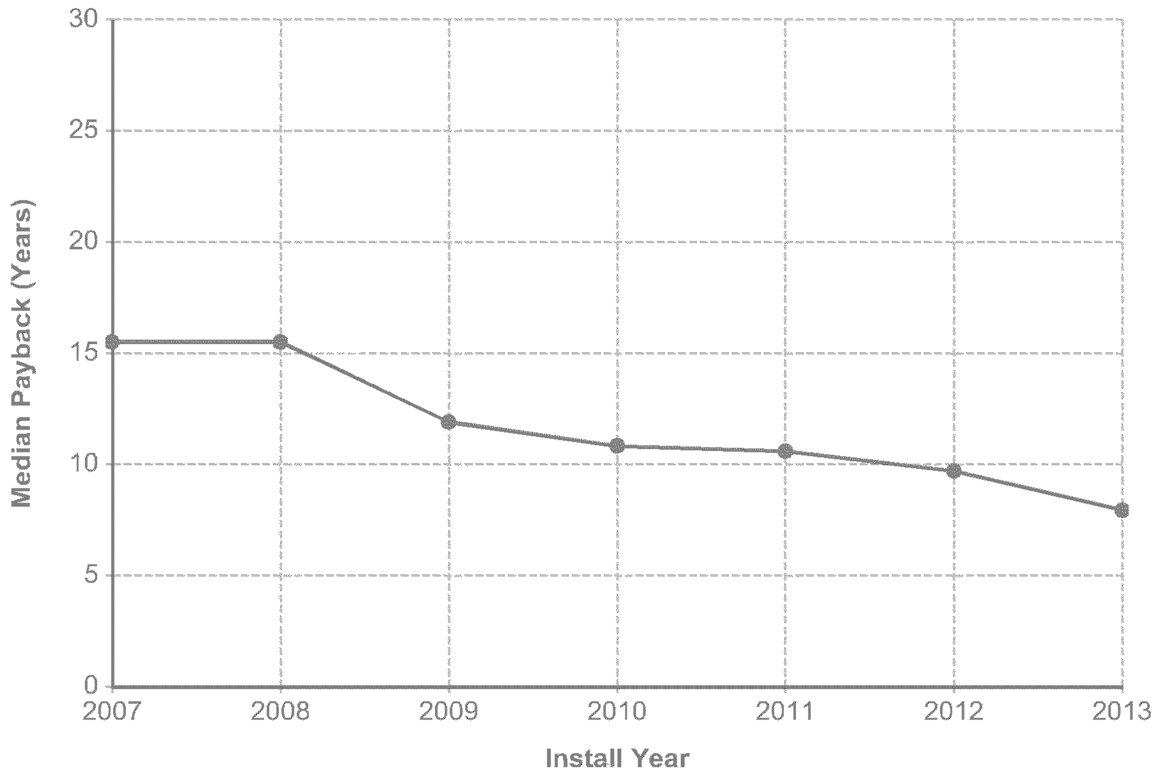
3.1 Residential Host-Owned Systems

This sub-section provides the results only for host-owned systems. Section 3.2 provides the results for TPO systems.

3.1.1 Median Payback

Figure 3-1 illustrates the median payback time for the 6,601 residential systems analyzed (with installation dates from 2007 through 2013), using the assumptions outlined in Appendix A. As can be seen below in Figure 3-1, payback times were roughly 15.5 years in 2007, but dropped to eight years by 2013, driven largely by reductions in system installation costs (see Figure 1-3).

Figure 3-1. Median Payback Times for Residential Host-Owned PV Systems



Source: Navigant analysis, based on a sample of CSI PowerClerk data

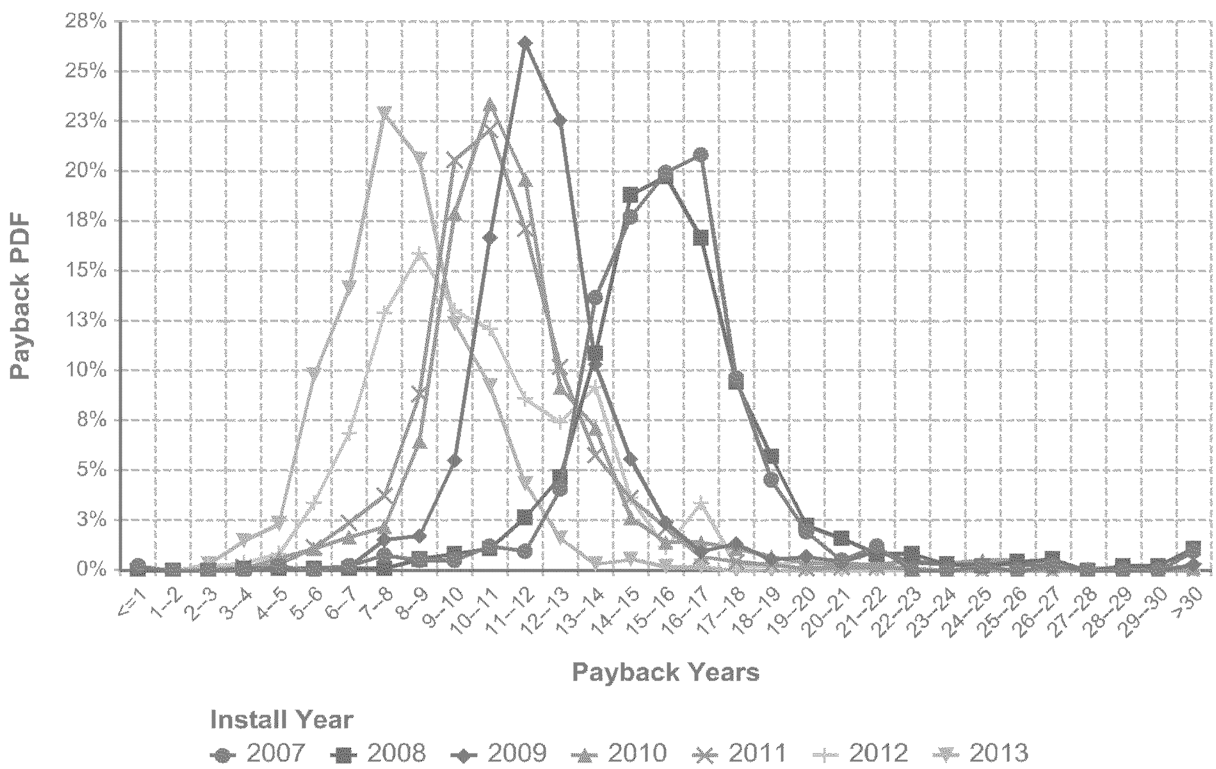
3.1.2 Payback Probability Distributions

As noted previously, Navigant conducted analysis of a sample of several thousand installed PV systems using data from host-owned systems listed in the CSI PowerClerk database.[18] This representative sample allowed the Navigant team to also calculate various probability distributions around payback times, which are illustrated in this section.

3.1.3 Payback Probability Density Function

Figure 3-2 illustrates the probability density function (PDF) for the payback times of 6,601 systems installed in the Residential sector. As noted in Appendix A, these represent about 20% of the host-owned systems (PG&E service territory only) available for analysis in the CSI PowerClerk database. Navigant pulled a random sample for the Residential sector to better facilitate scenario analysis and to permit reasonable model run times. The quantity of systems analyzed provides a very representative distribution of the payback times given the large sample size.

Figure 3-2. Payback Probability Density Function for Residential Host-Owned PV Systems



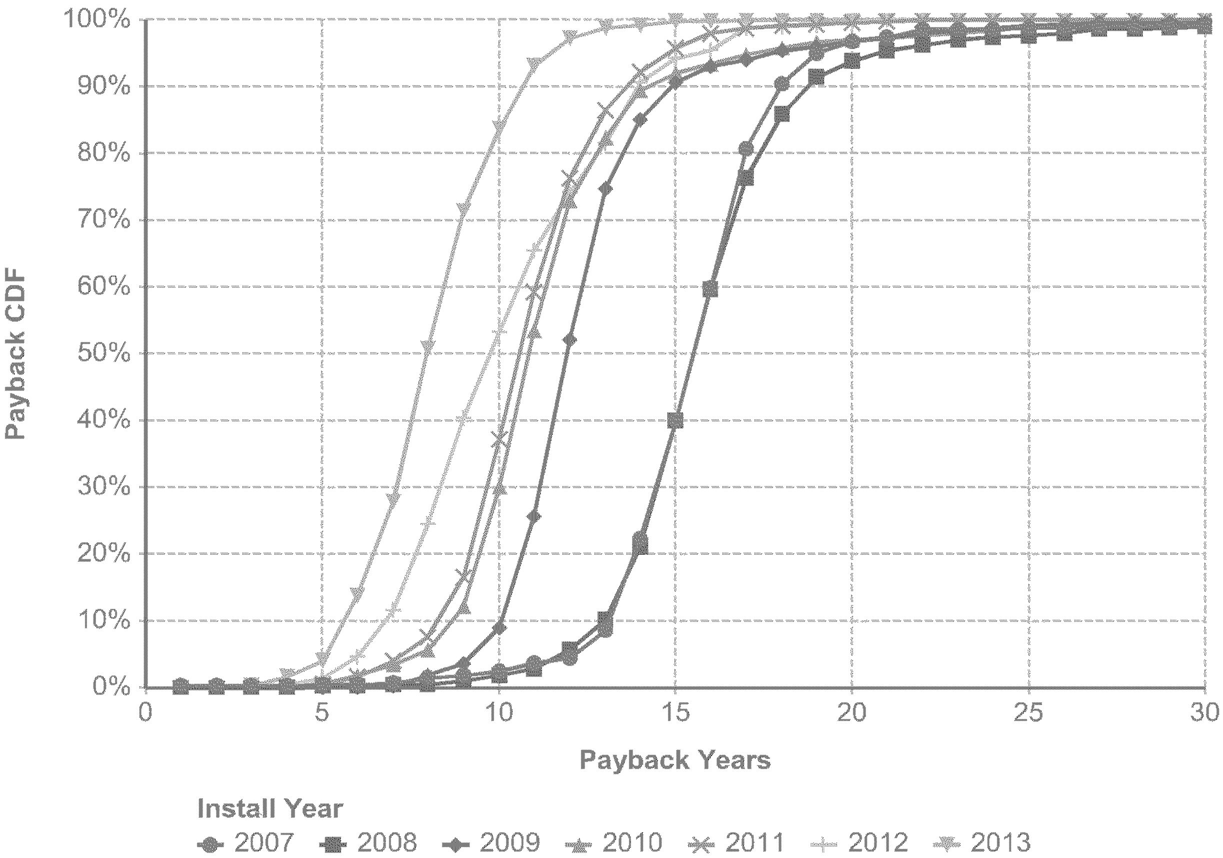
Source: Navigant analysis, based on a sample of CSI PowerClerk data

[18] See Appendix A for data assumptions and sources, including a breakdown of the number of data points by installation year and sector.

3.1.4 Payback Cumulative Distribution Function

Figure 3-3 provides the cumulative distribution function (CDF) for the residential systems analyzed. This curve is simply an integration of the PDF in Figure 3-2 and represents the likelihood (shown on the y-axis) that any given system has a payback time of less than that shown on the x-axis. For instance, the figure shows that in 2007, 90% of systems installed had payback times of less than roughly 18 years, whereas in 2013, 90% of systems installed had payback times of less than roughly 10.5 years.

Figure 3-3. Payback Cumulative Distribution Function for Residential Host-Owned PV Systems



Source: Navigant analysis, based on a sample of CSI PowerClerk data

3.1.5 Payback Probability

Figure 3-4 is similar to the CDF shown in Figure 3-3, except that it shows specific percentiles of the CDF for each year of installation. For instance, for systems installed in 2007, the figure shows that roughly 10% of the systems had payback times of less than about 13 years, whereas 90% had payback times of less than about 18 years. By 2013, however, 10% of installed systems had payback times of less than 5.7 years, whereas 90% of systems had payback times of less than 10.5 years.

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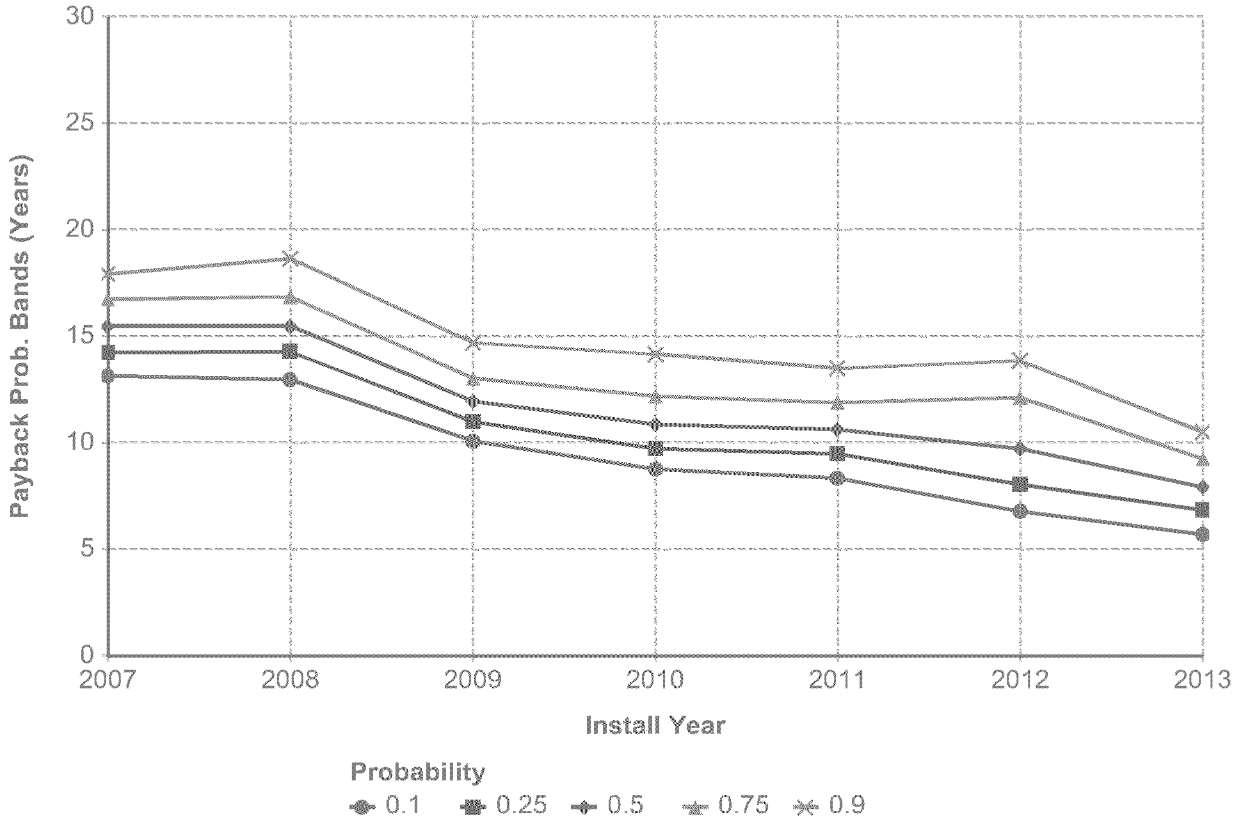
Figure 3-4. Payback Probability for Modeled Residential Host-Owned PV Systems

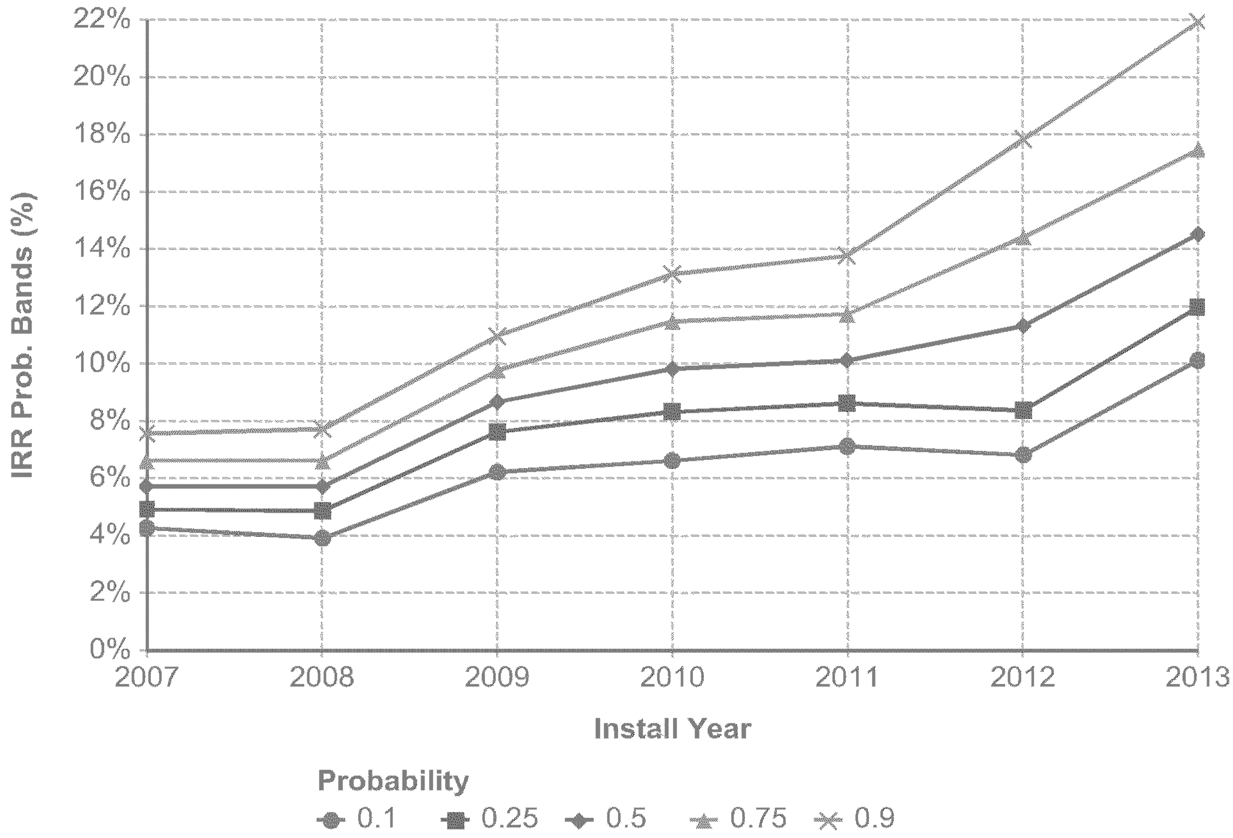


Source: Navigant analysis, based on a sample of CSI PowerClerk data

3.1.6 Internal Rate of Return

In addition to payback times, Navigant also calculated the effective internal rate of return (IRR) for a customer installing a host-owned PV system. The IRR is defined as the discount rate at which the net system cost is equal to the present value of the stream of annual savings over the assumed system lifetime (assumed for this IRR analysis to be 30 years). As can be seen below, IRRs were relatively high in 2013, ranging from about 10% (at the 10^{th} percentile) to 22% (at the 90th percentile), with a median value of 14.6%.

Figure 3-5. Internal Rate of Return of Modeled Residential Host-Owned Systems



Source: Navigant analysis, based on a sample of CSI PowerClerk data

3.1.7 Payback vs. IRR

To provide a better understanding of how payback times relate to IRRs for residential systems, Navigant also plotted the median payback against the IRR for each year of installation. This relationship is illustrated below in Figure 3-6.

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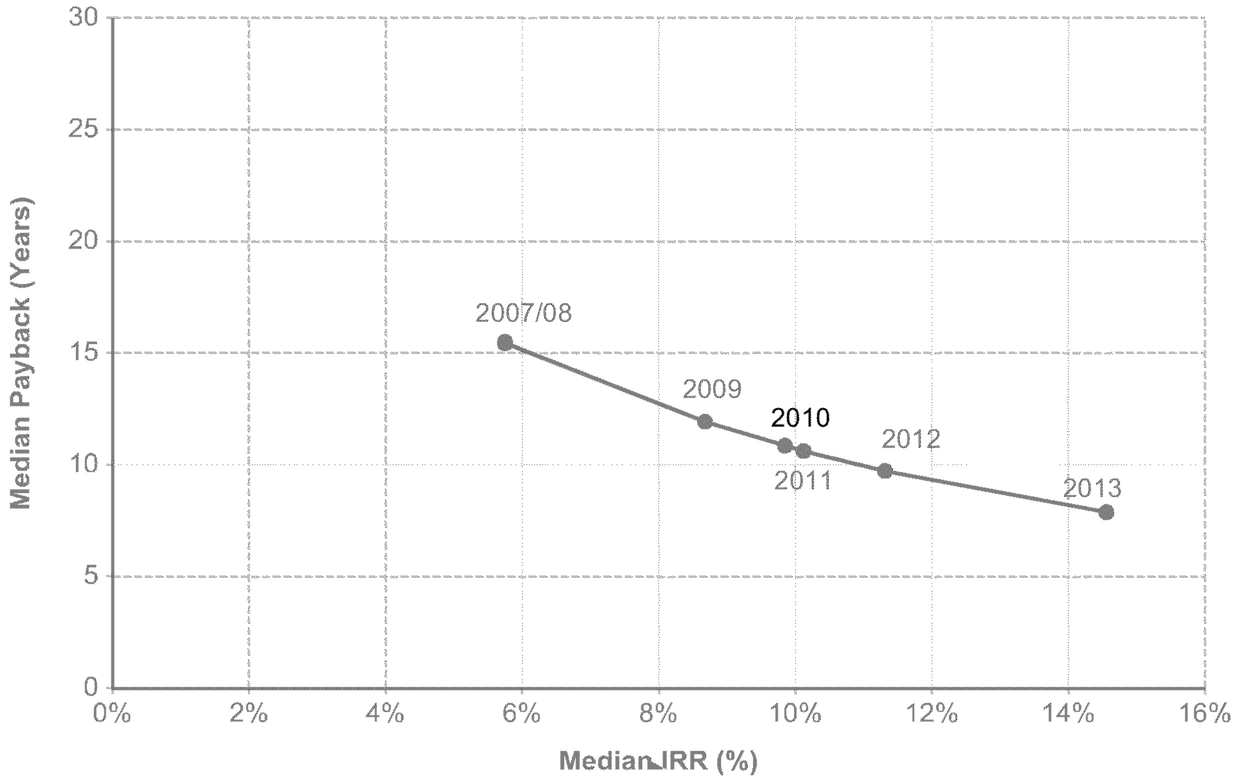
Figure 3-6. Payback Time versus IRR for Residential Host-Owned PV Systems



Source: Navigant analysis, based on a sample of CSI PowerClerk data

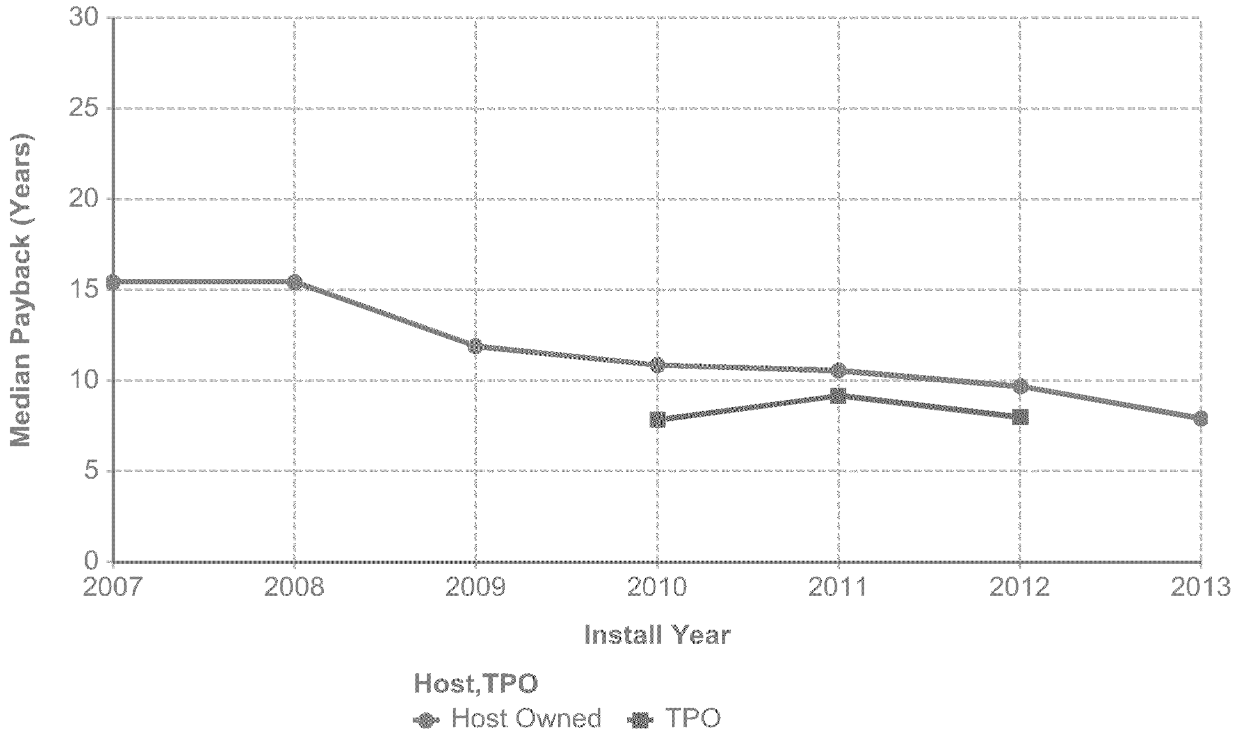
3.2 Residential Third-Party Owned Payback

This section provides the analysis results for residential third-party owned (TPO) systems.

3.2.1 Median Payback

The figure below compares payback times of host-owned systems with those of TPO systems. As shown, payback times (calculated as described in Section 2.1.2) tend to be lower than those calculated for host-owned systems. A likely explanation for this is that a third-party owner, as a commercial entity, is able to monetize the benefits associated with capitalization and accelerated depreciation of the PV system asset, whereas a residential customer is not able to do so. That said, other confounding factors (e.g., possible pricing strategy differences between TPO and host-owned systems) may also contribute to this apparent difference.

Figure 3-7. Median Payback Times for Residential PV Systems – Host-Owned versus TPO



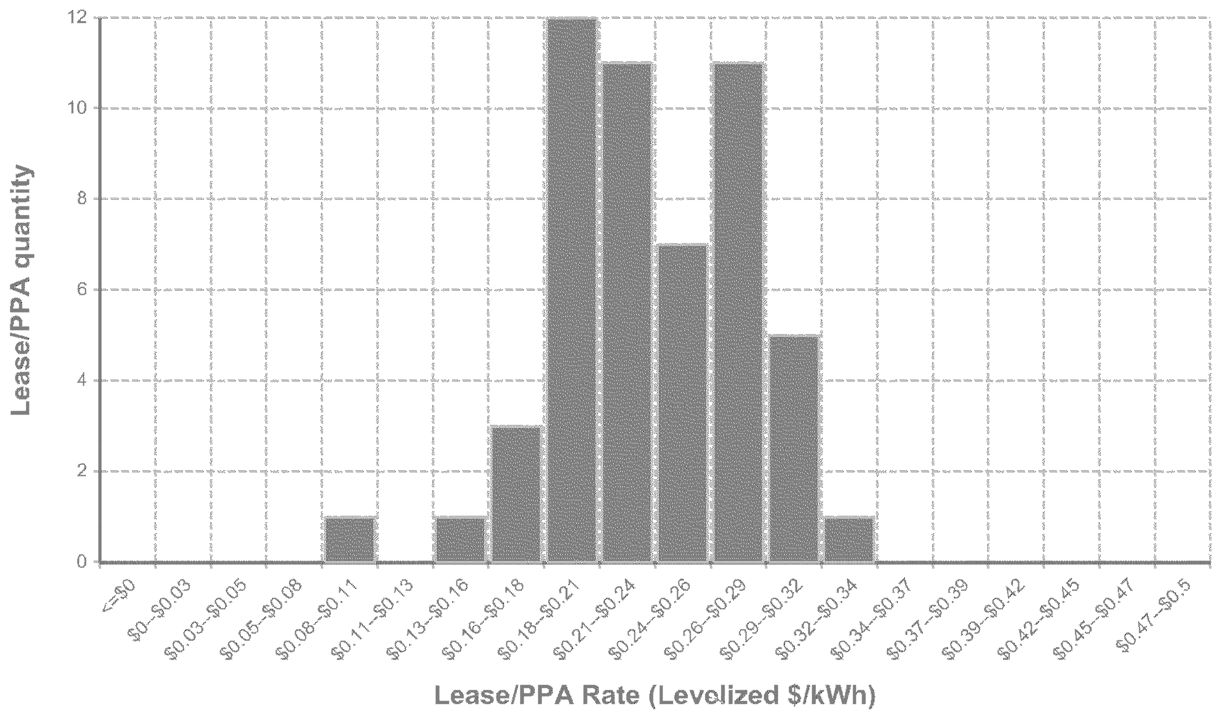
Source: Navigant analysis, based on a sample of CSI PowerClerk data

3.2.2 TPO System LCOE (Effective Levelized $/kWh)

Figure 3-8 provides a histogram of the calculated effective lease or PPA rates (levelized $/kWh) for 52 systems installed in 2012. To ensure an apples-to-apples comparison, only contracts with 20-year terms are shown in this figure.[19]

[19] One residential system had a 25-year contract term and was excluded from this histogram, as levelized costs of electricity are only comparable if analyzed over the same length of time.

Figure 3-8. Effective Lease or PPA Rates for Residential TPO Contracts from 2012



Source: Navigant analysis, based on a sample of TPO contracts from CSI PowerClerk data (n=52)

The effective lease or PPA rate (levelized $/kWh) is, by definition, a levelized value that is constant over the life of the contract. Since utility offset rates escalate over time, today's utility offset rate is therefore not comparable with the effective lease rate illustrated above. One must also levelize the offset rate to make comparisons between the two. Figure 3-9 illustrates this comparison, providing the results for all installation years and contract periods. The effective lease or PPA rate is shown by the red dots, while the average levelized utility offset rate is shown by the blue dots; both values were calculated for every TPO record analyzed. If the red dot falls below the blue dot for a particular record, it implies that the PV customer is effectively saving money (or making a profit on each kWh produced from PV), since he/she is paid more by the utility for a kWh generated by the PV system than he/she pays the TPO lease or PPA provider.

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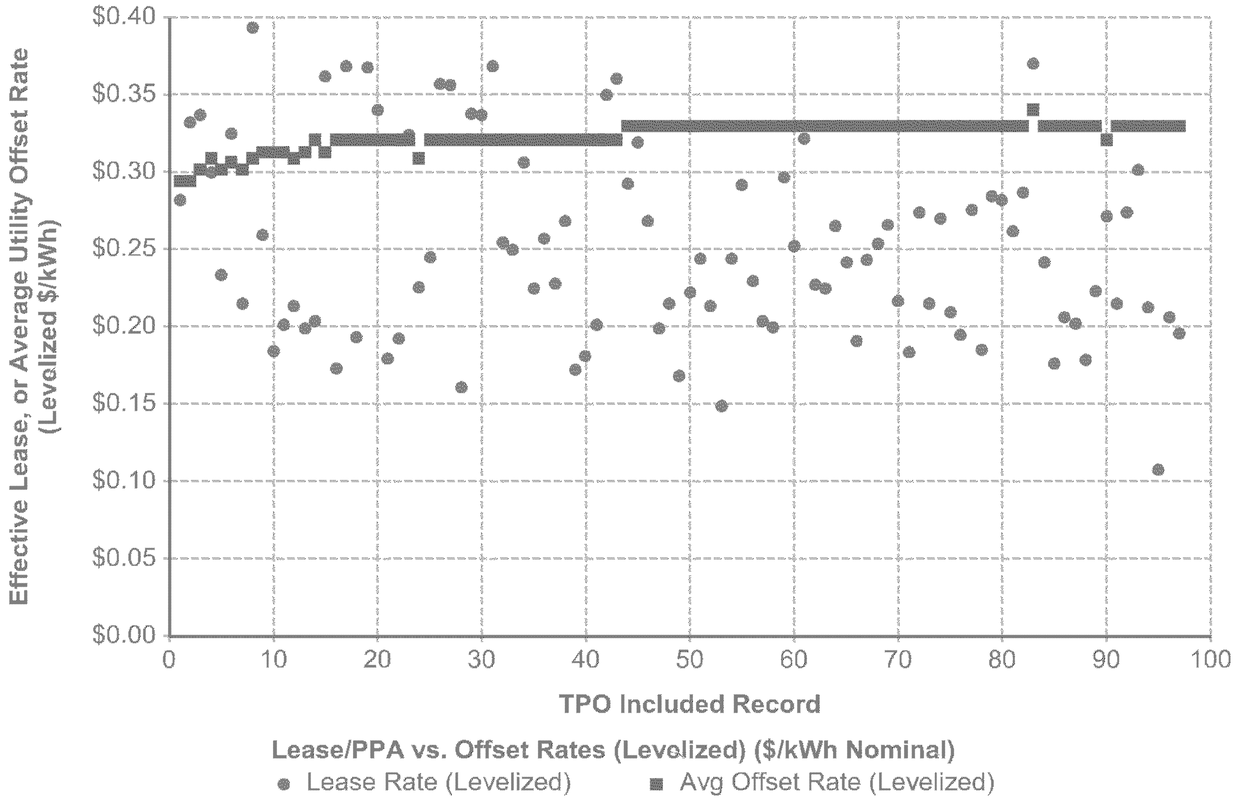
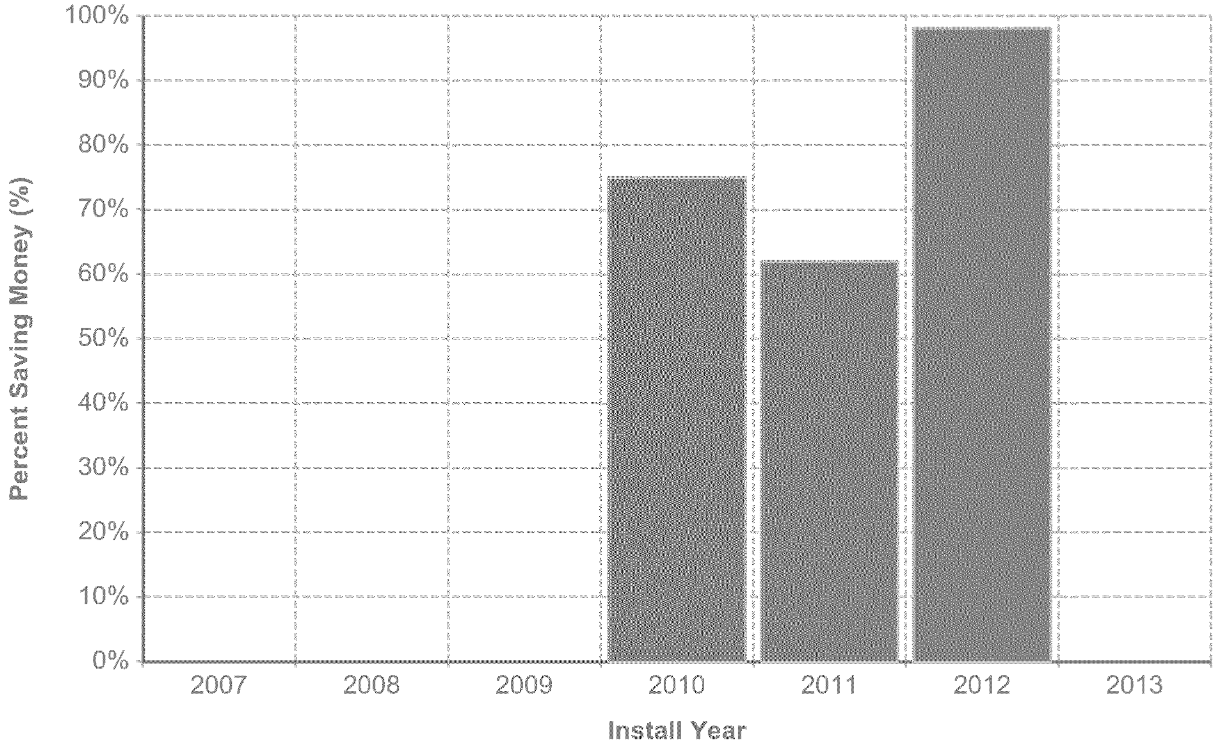
Figure 3-9. Effective Lease or PPA Rates (Levelized $/kWh) for Residential TPO Contracts



Source: Navigant analysis, based on a sample of TPO contracts from CSI PowerClerk data (n=97)

It is also interesting to calculate, by year of installation, the percentage of TPO systems analyzed that are, effectively, saving money by having a TPO lease/PPA agreement (i.e., the percentage of records analyzed, in the figure above, where the red dot is below the blue dot). This result is shown below in Figure 3-10.

Figure 3-10. Percent of Residential TPO System Customers who are "Saving Money" based on a Sample of Contracts from CSI PowerClerk Data



Source: Navigant analysis, based on a sample of TPO contracts from CSI PowerClerk data (n=97)

4. Commercial/Industrial Sector Results

This section provides the results for both host-owned and TPO systems in the Commercial/Industrial sector.

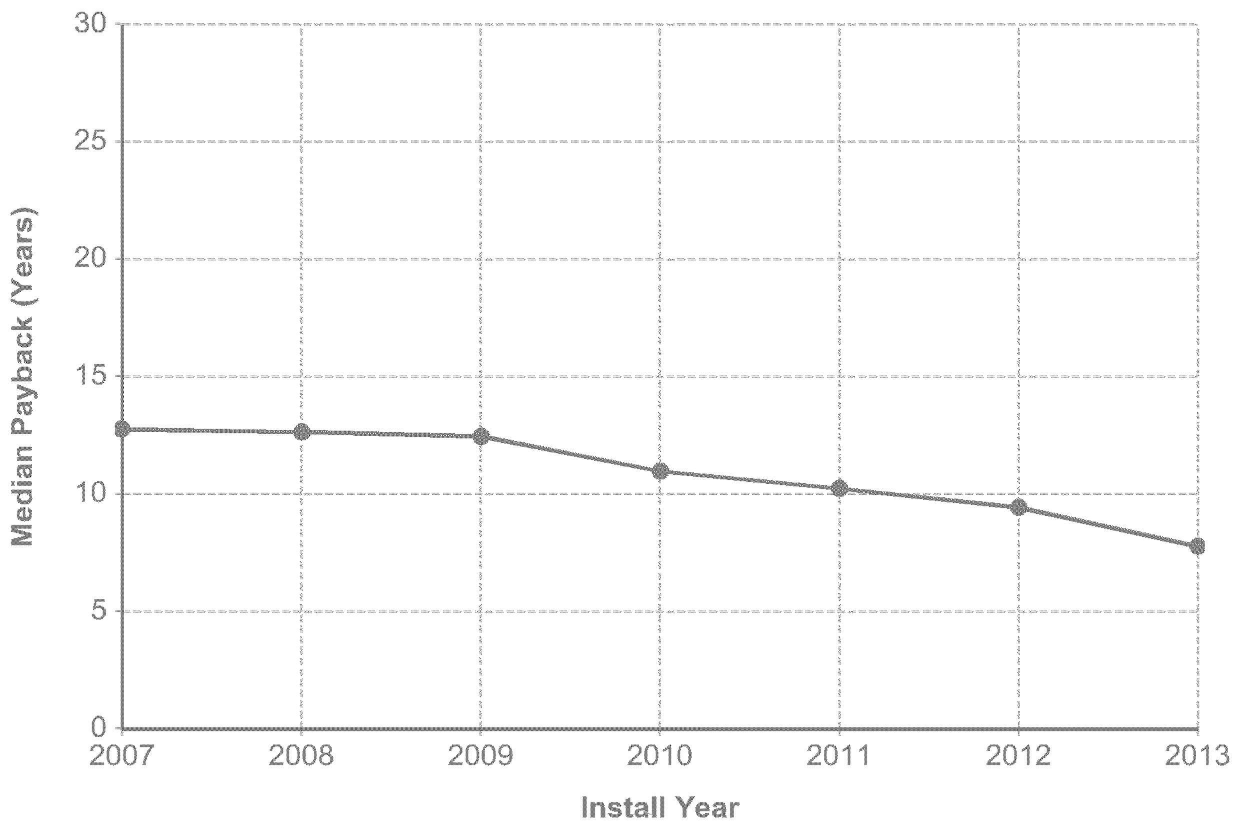
4.1 Commercial/Industrial Host-Owned Systems

This sub-section provides the results only for host-owned systems. Section 4.2 provides the results for TPO systems.

4.1.1 Median Payback

Figure 4-1 illustrates the median payback time for Commercial/Industrial systems from 2007 through 2013, using the assumptions outlined in Appendix A. As can be seen below, payback times were roughly 13.6 years in 2007, but dropped to eight years by 2013, driven largely by reductions in system installation costs (see Figure 1-3).

Figure 4-1. Median Payback Time for Host-Owned PV Systems in the Commercial/Industrial Sector



Source: Navigant analysis, based on CSI PowerClerk data

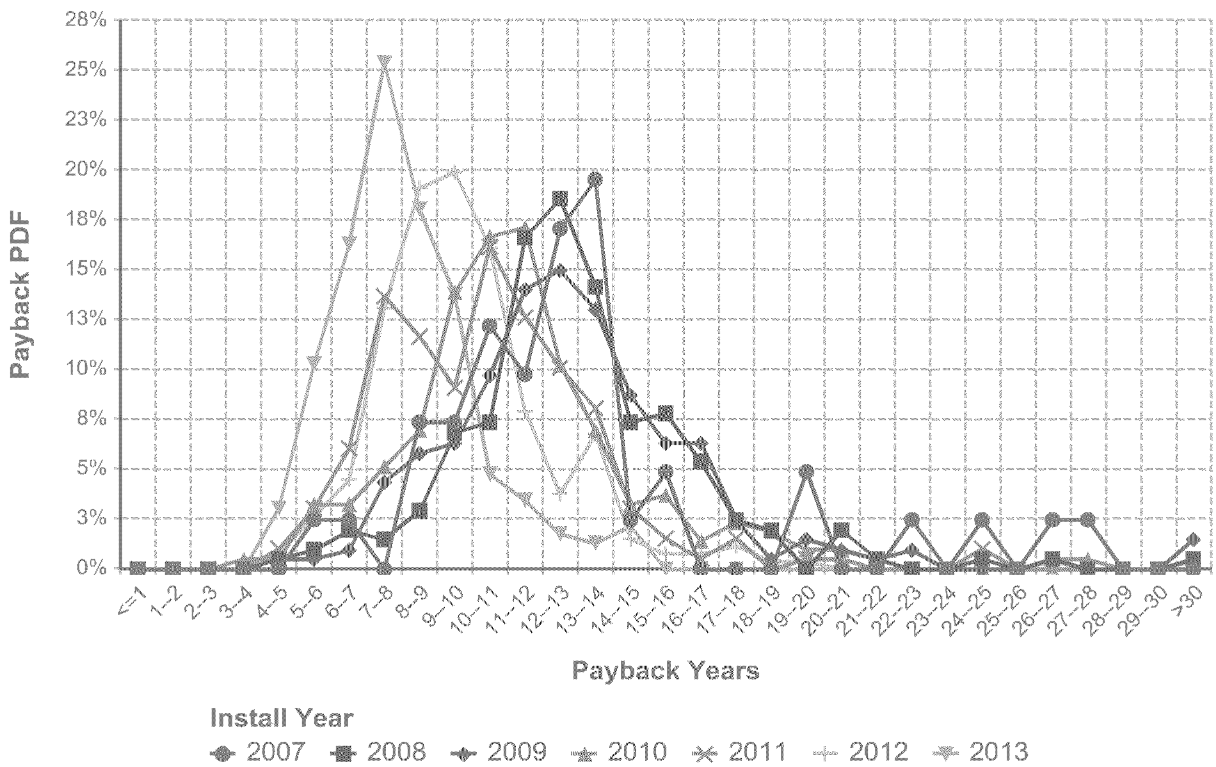
4.1.2 Payback Probability Distributions

For the Commercial/Industrial sector, Navigant analyzed 100% of PV systems installed from 2007 through late 2013 (N=1,367 systems) in PG&E's service territory, using data from specific host-owned PV installations in the CSI PowerClerk database.[20] As with the Residential sector, Navigant calculated various probability distributions around modeled payback times, as illustrated in this section.

4.1.3 Payback Probability Density Function

Figure 4-2 illustrates the probability density function (PDF) for the payback times of the 1,367 systems installed in the Commercial/Industrial sector from 2007 through late 2013.

Figure 4-2. Payback Probability Density Function for Host-Owned PV Systems in the Commercial/Industrial Sector



Source: Navigant analysis, based on CSI PowerClerk data

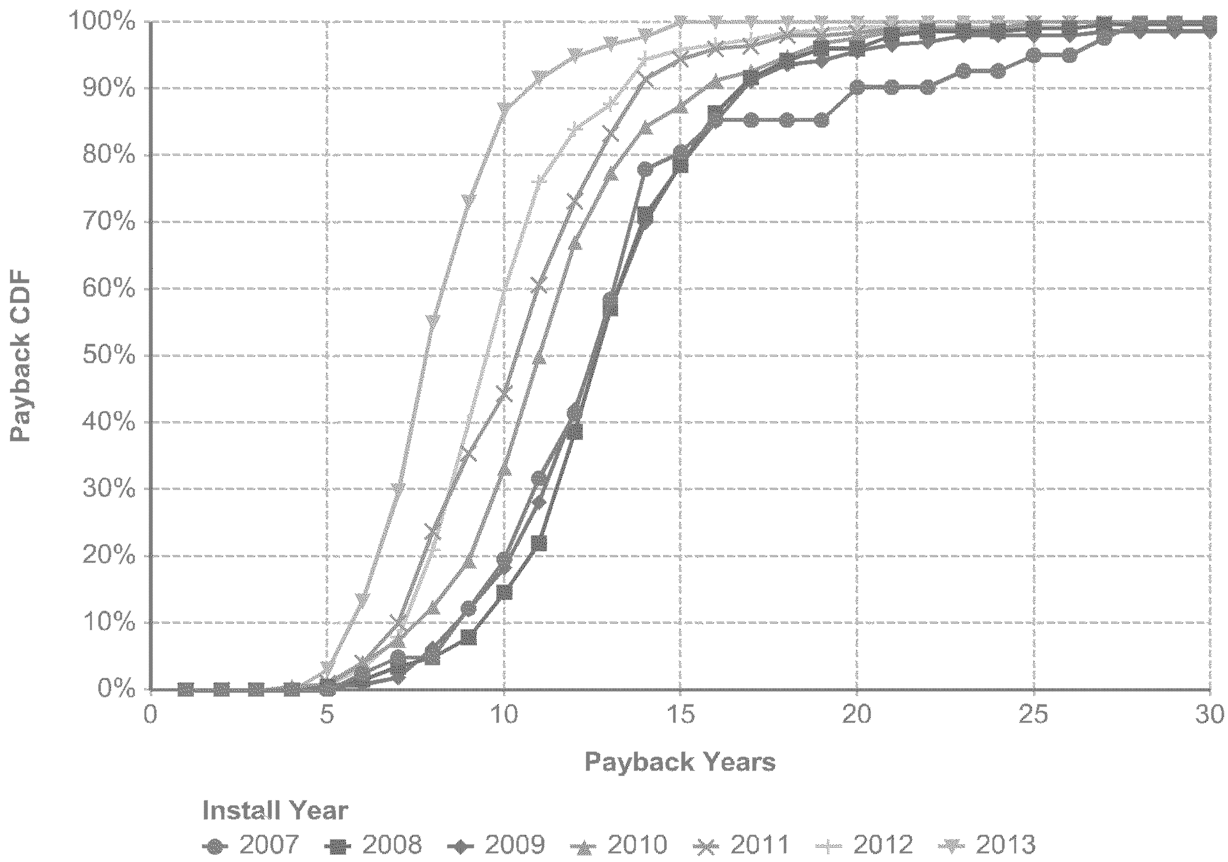
4.1.4 Payback Cumulative Distribution Function

Figure 4-3 provides the cumulative distribution function (CDF) for the Commercial/Industrial systems analyzed. This curve is simply an integration of the PDF shown in Figure 4-2 and represents the likelihood (shown on the y-axis) that a system has a payback time of less than that shown on the x-axis. For instance, the figure shows that 90% of systems installed in 2008 had payback times of less than

[20] See Appendix A for data assumptions and sources, including a breakdown of the number of data points by installation year and sector.

roughly 17.4 years, whereas 90% of systems installed in 2013 had payback times of less than roughly 11 years.

Figure 4-3. Payback Cumulative Distribution Function for Host-Owned PV Systems in the Commercial/Industrial Sector

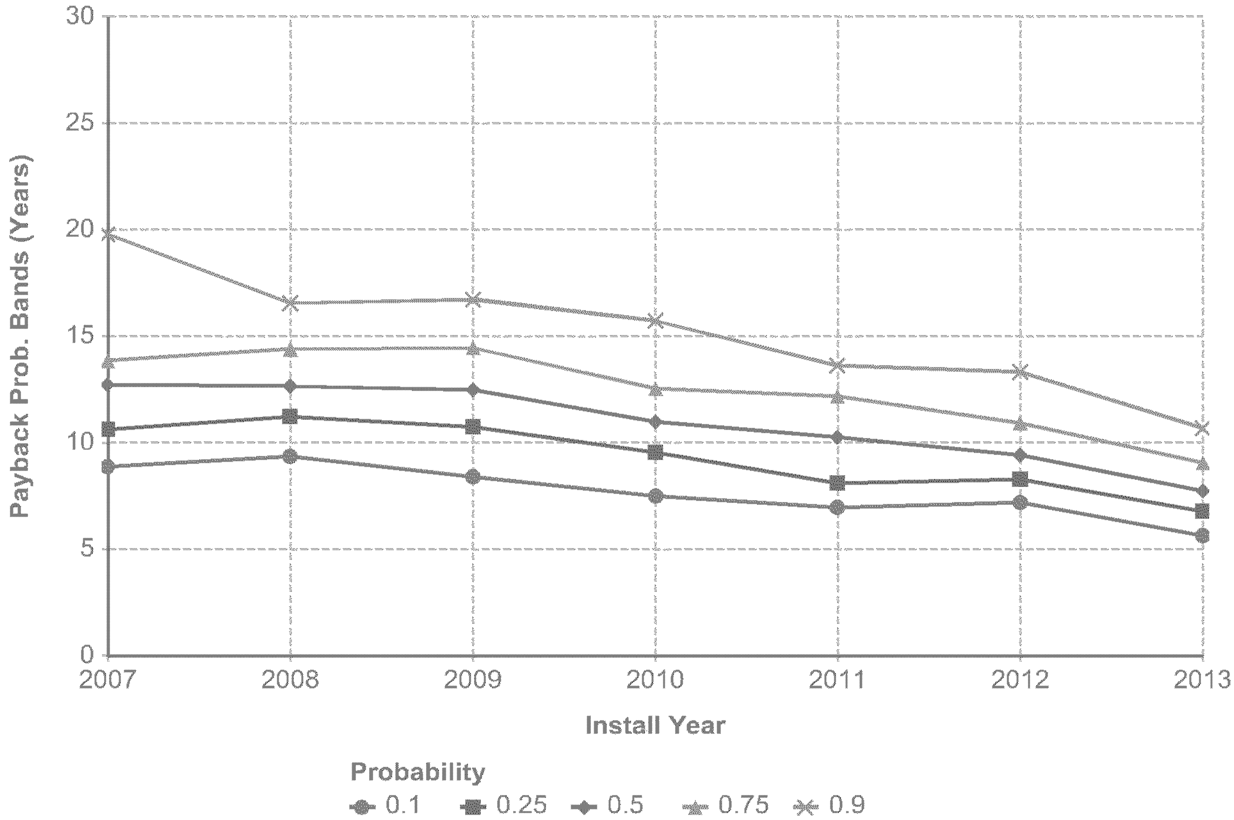


Source: Navigant analysis, based on CSI PowerClerk data

4.1.5 Payback Probability

Figure 4-4 is similar to the CDF shown in Figure 4-3, except that it shows specific percentiles of the CDF for each year of installation. For instance, for systems installed in 2008, one can see that roughly 10% of the systems had payback times of less than about 10 years, whereas 90% had payback times of less than about 17.4 years. By 2013, however, 10% of installed systems had payback times of less than 5.8 years, whereas 90% of systems had payback times of less than 11.1 years.

Figure 4-4. Payback Probability for Host-Owned PV Systems in the Commercial/Industrial Sector

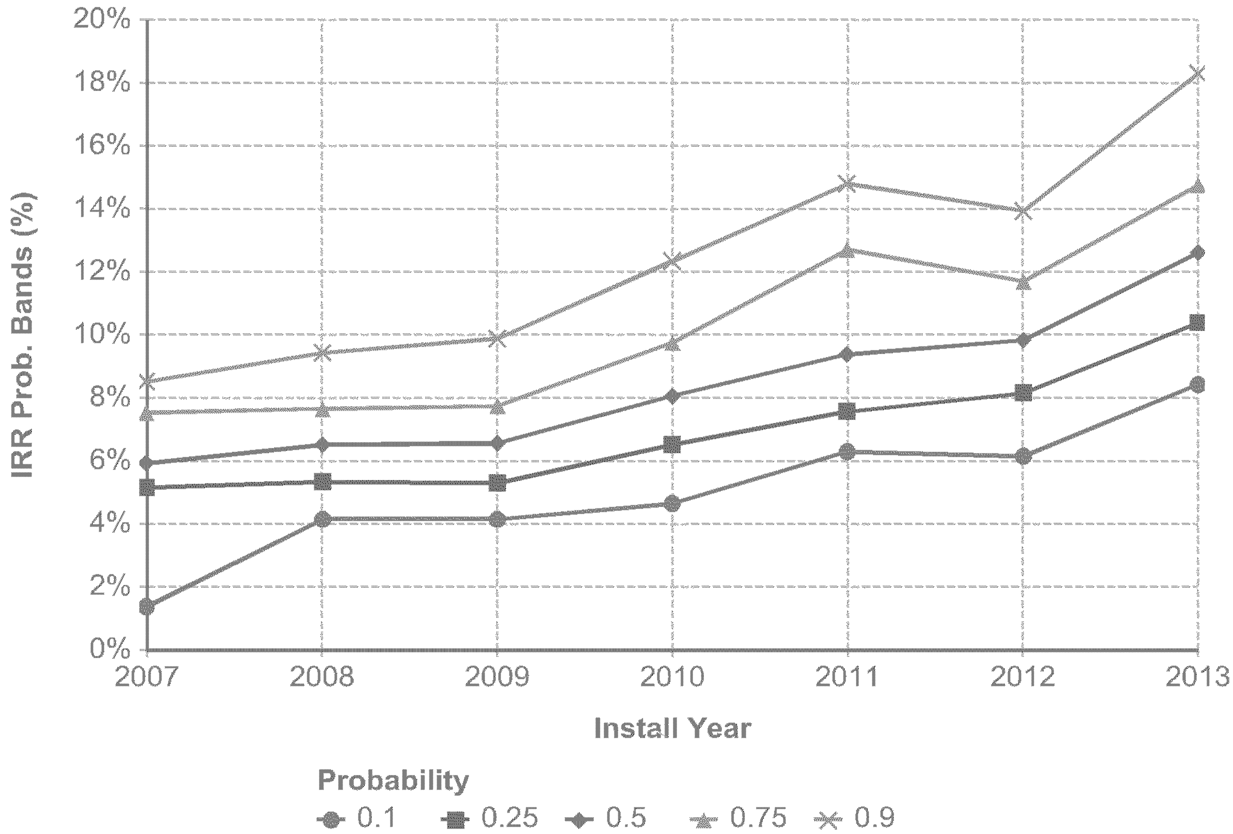


Source: Navigant analysis, based on CSI PowerClerk data

4.1.6 Internal Rate of Return

Navigant also calculated the effective internal rate of return (IRR) for a Commercial/Industrial sector customer installing a host-owned PV system. The IRR is defined as the discount rate at which the net system cost is equal to the present value of the stream of annual savings over the assumed system lifetime (assumed for this IRR analysis to be 30 years). As shown in Figure 4-5, IRRs in 2013 ranged from about 8% (at the 10^{th} percentile) to 18% (at the 90th percentile), with a median value of about 12%.

Figure 4-5. Internal Rate of Return for Host-Owned PV Systems in the Commercial/Industrial Sector



Source: Navigant analysis, based on CSI PowerClerk data

4.1.7 Payback vs. IRR

To provide a better understanding of how payback times relate to IRRs for Commercial/Industrial systems, Navigant also plotted the median payback against the IRR for each year of installation. This relationship is provided below in Figure 4-6.

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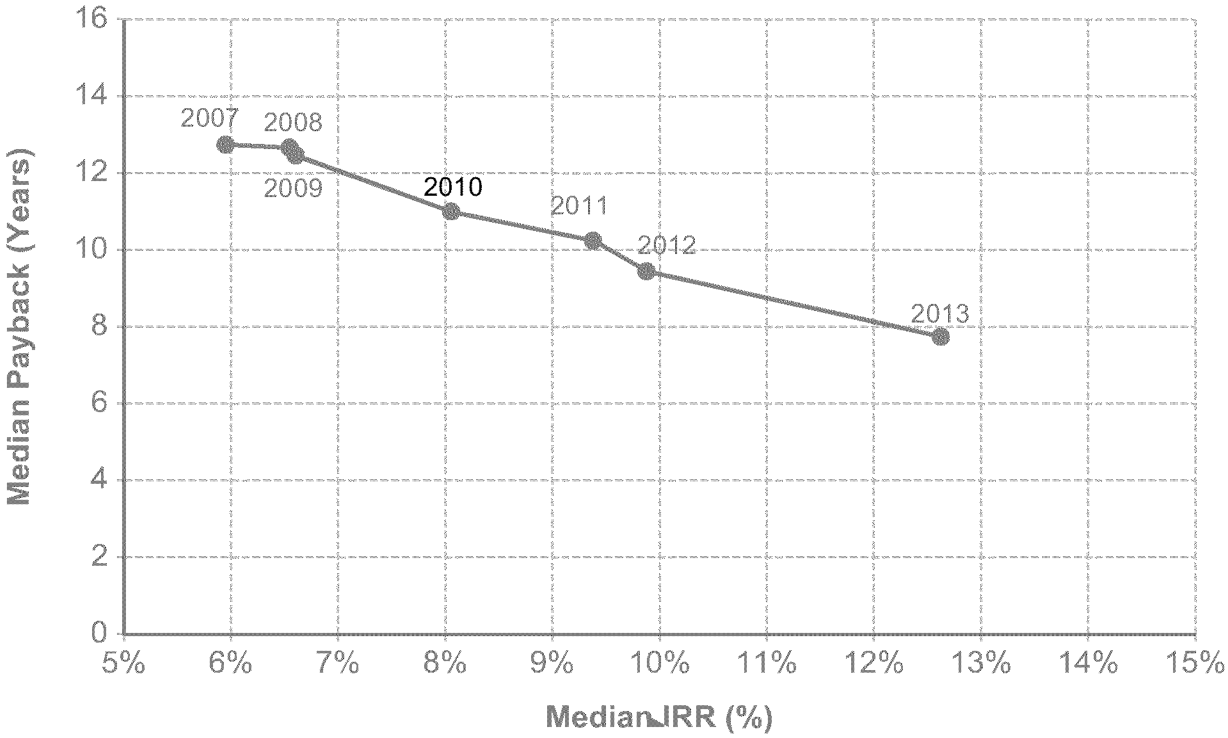
Figure 4-6. Payback Time versus IRR for Host-Owned PV Systems in the Commercial/Industrial Sector



Source: Navigant analysis, based on CSI PowerClerk data

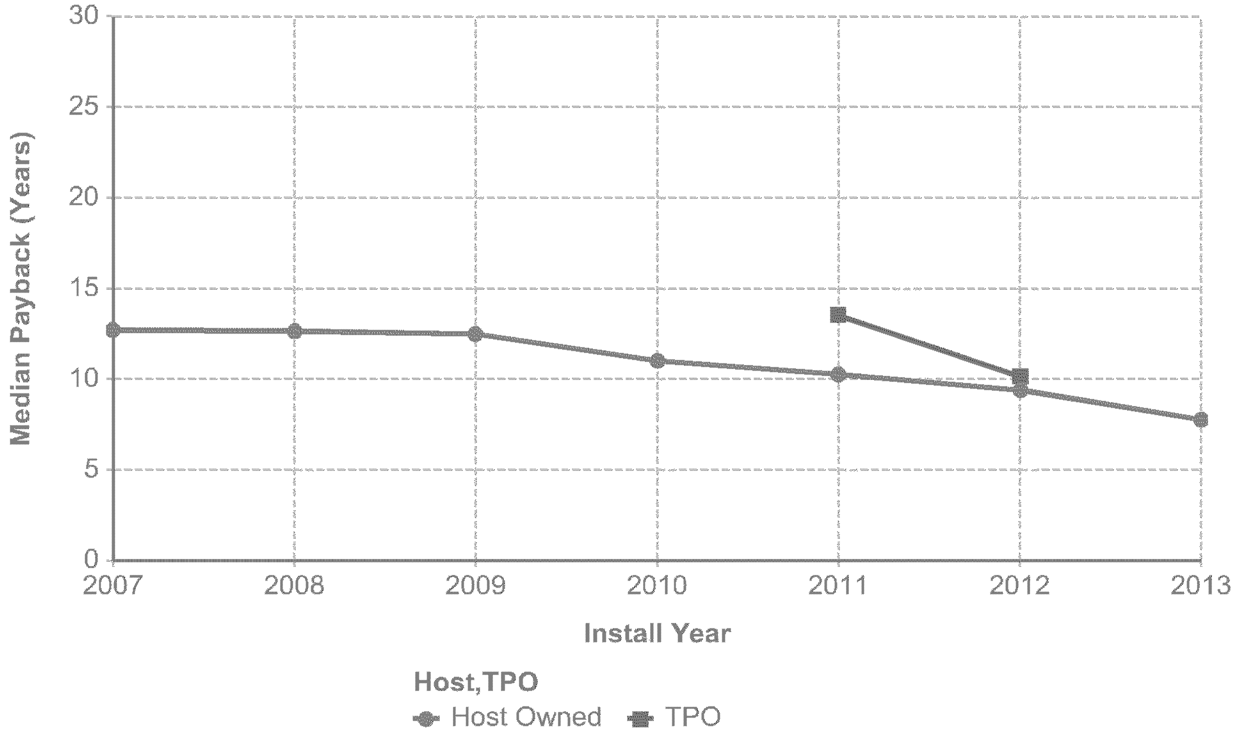
4.2 Commercial/Industrial Third-Party Owned Payback

This section provides the analysis results for Commercial/Industrial third-party owned (TPO) systems.

4.2.1 Median Payback

Figure 4-7 compares payback times of host-owned systems with those of TPO systems. Unlike with residential TPO agreements, where payback times tended to be lower than those for host-owned systems, Commercial/Industrial system payback times for TPO systems are on par with (in 2012) or somewhat higher then (in 2011) host-owned systems. Note, however, that the number of data points for this TPO analysis was limited (n=13 in 2012 and n=13 in 2011) due to the effort required for extracting terms from CSI's PowerClerk database and the time constraints for this study. As such, there is significant uncertainty in these values. That said, the results are consistent with expectations that Commercial/Industrial sector payback times for TPO systems would not be lower than for host-owned systems, unlike in the Residential sector. Commercial/Industrial customers, unlike Residential customers, can already take advantages of the tax benefits of monetizing the PV system asset and applying accelerated depreciation (as can a TPO provider). As such, there is no inherent financial advantage in changing ownership to a third-party provider for a Commercial/Industrial customer.

Figure 4-7. Median Payback Times for PV Systems in the Commercial/Industrial Sector: Host-Owned versus TPO



Source: Navigant analysis, based on a sample of CSI PowerClerk data

Appendix A. Data Sources and Assumptions

This appendix summarizes key data input assumptions and sources used in Navigant's payback model, which was separately provided to PG&E.

A.1 Total Systems Analyzed

Payback distributions and statistics were calculated within the Navigant payback model from nearly 8,000 individual PV systems that were installed between 2007 and 2013. The number of systems evaluated in this analysis is summarized in Table A-1 (host-owned) and Table A-2 (TPO). For the residential sector, 20% of the records were randomly sampled from the CSI PowerClerk database, whereas 100% of the records were used from the Commercial/Industrial market sector.[21] Sampling the residential sector facilitated scenario analysis and resulted in faster model run times while still providing a very large sample that results in a representative distribution of installations.

Table A-1. Number of Host-Owned Systems Analyzed from CSI PowerClerk Data.

Year Installed	Residential	Commercial/ Industrial	Total
2007	417	41	458
2008	946	205	1,151
2009	1,254	207	1,461
2010	1,300	216	1,516
2011	1,128	198	1,326
2012	861	267	1,128
2013	695	233	928
Total	**6,601**	**1,367**	**7,968**

Source: CSI PowerClerk Working Data set, November 27, 2013

[21] http://www.californiasolarstatistics.ca.gov/current_data_files/. Working data set through November 27, 2013 was used in this analysis.

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Table A-2. Number of TPO Systems Analyzed

Year Installed	Residential	Commercial/ Industrial	Total
2007	0	0	0
2008	1	0	1
2009	2	0	2
2010	**12**	3	15
2011	**29**	**12**	41
2012	**53**	**10**	63
2013	0	1	1
Total	97	26	123

Note: Only sector/year combinations with ten or more data points (highlighted in bold) were used in the analysis.

Source: CSI PowerClerk Non-Public Data Sampled by Navigant

A.2 Utility Offset Rate Assumptions

The bill-savings value that a distributed PV system provides is calculated from offset rates that were calculated from E3.[22] Table A-3 summarizes the offset rates used within the Navigant payback model. Due to current NEM rules and the effect of existing rate structures, the offset rate for PV generation consumed on-site is different from the offset rate for PV exported to the grid. The offset rates were also forecasted for future years using the E3 assumptions for electricity price inflation.[23]

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[22] Calculations were performed on data from E3NEMSummaryTool.xlxs, developed by E3 and located at: http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm. California Net Energy Metering Rate payer Impacts Evaluation, 2013.

[23] E3 forecasted electricity prices to 2039. Navigant extrapolated E3's forecast to 2042.

Table A-3. Base Case Offset Rate Assumptions, in Nominal Dollars per kWh-AC

Year	Residential ($/kWh-AC)		Non-Residential ($/kWh-AC)		Year	Residential ($/kWh-AC)		Non-Residential ($/kWh-AC)	
	Onsite	Export	Onsite	Export		Onsite	Export	Onsite	Export
2007	$0.303	$0.197	$0.171	$0.132	**2025**	$0.452	$0.293	$0.254	$0.197
2008	$0.295	$0.192	$0.166	$0.129	**2026**	$0.460	$0.298	$0.259	$0.200
2009	$0.313	$0.203	$0.176	$0.136	**2027**	$0.469	$0.305	$0.264	$0.204
2010	$0.308	$0.200	$0.173	$0.134	**2028**	$0.479	$0.311	$0.270	$0.208
2011	$0.309	$0.200	$0.174	$0.134	**2029**	$0.491	$0.319	$0.277	$0.214
2012	$0.325	$0.211	$0.183	$0.142	**2030**	$0.504	$0.327	$0.284	$0.219
2013	$0.333	$0.216	$0.188	$0.145	**2031**	$0.513	$0.333	$0.289	$0.223
2014	$0.347	$0.225	$0.195	$0.151	**2032**	$0.523	$0.340	$0.295	$0.228
2015	$0.367	$0.238	$0.207	$0.160	**2033**	$0.533	$0.346	$0.300	$0.232
2016	$0.378	$0.246	$0.213	$0.165	**2034**	$0.544	$0.353	$0.306	$0.237
2017	$0.392	$0.255	$0.221	$0.171	**2035**	$0.555	$0.360	$0.312	$0.242
2018	$0.403	$0.261	$0.227	$0.175	**2036**	$0.565	$0.367	$0.318	$0.246
2019	$0.417	$0.270	$0.235	$0.181	**2037**	$0.576	$0.374	$0.325	$0.251
2020	$0.427	$0.277	$0.240	$0.186	**2038**	$0.588	$0.382	$0.331	$0.256
2021	$0.425	$0.276	$0.239	$0.185	**2039**	$0.599	$0.389	$0.337	$0.261
2022	$0.432	$0.280	$0.243	$0.188	**2040**	$0.611	$0.396	$0.344	$0.266
2023	$0.439	$0.285	$0.247	$0.191	**2041**	$0.622	$0.404	$0.351	$0.271
2024	$0.443	$0.288	$0.250	$0.193	**2042**	$0.635	$0.412	$0.357	$0.276

Source: Navigant analysis of E3NEMSummaryTool (2013).

A.3 Tax Rates

Table A-4 shows the assumed tax rates that Navigant used in its payback model.

Table A-4. Tax Rate Assumptions

Sector	Marginal State Tax Rate	Marginal Federal Tax Rate
Residential	N/A	N/A
Commercial/Industrial	8.84%	35%

Source: https://www.ftb.ca.gov/forms/2013_california_tax_rates_and_exemptions.shtml

A.4 Depreciation Schedules

Several Federal and State depreciation schedules were used in the Navigant payback model. These schedules are shown in Table A-5.

Table A-5. Depreciation Schedules used in the Navigant Payback Model

Year	Bonus Depreciation (100%)	Bonus Depreciation (50%)	MACRS Depreciation Schedule (5-yr)	State Depreciation Schedule for PV (12-yr)
1	100%	60%	20%	8.33%
2	0%	16%	32%	15.28%
3	0%	9.60%	19.20%	13.26%
4	0%	5.76%	11.52%	11.99%
5	0%	5.76%	11.52%	10.73%
6	0%	2.88%	5.76%	9.47%
7	0%	0%	0%	8.21%
8	0%	0%	0%	6.94%
9	0%	0%	0%	5.68%
10	0%	0%	0%	4.42%
11	0%	0%	0%	3.16%
12	0%	0%	0%	1.89%
13	0%	0%	0%	0.63%

Sources: Depreciation schedules were obtained from the Internal Revenue Service (IRS), the California Franchise Tax Board (FTB), and the Database of State Incentives for Renewable Energy and Energy Efficiency (DSIRE).[24]

[24] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F

The specific federal depreciation schedule that is applied to each PV system depends on the year of the PV installation. Table A-6 shows the depreciation schedule assumed for each installation year considered within the payback model.

Table A-6. Depreciation Type by Year of PV System Installation[25]

Install Year	Depreciation Schedule
2007	MACRS Depreciation Schedule (5-yr)
2008	Bonus Depreciation (50%)
2009	Bonus Depreciation (50%)
2010	Bonus Depreciation (50%)[26]
2011	Bonus Depreciation (100%)
2012	Bonus Depreciation (50%)
2013	Bonus Depreciation (50%)

Source: IRS

A.5 System Costs

A summary of average installed costs by year and host sector used within the payback model is provided in Table A-7. Installed costs from individual systems (from the CSI PowerClerk database) were used as the input for the payback model. Thus, the values presented in Table A-7 are outputs of the model, rather than assumed inputs. Installed cost values for individual systems evaluated within the payback model can be found in the input tables in the actual model file.

Table A-7. Weighted Average Installed Cost ($/W$_{AC}$) of Host-Owned PV Systems in PG&E Territory

Customer Sector	Year System Installed						
	2007	2008	2009	2010	2011	2012	2013
Residential	$9.54	$9.28	$8.86	$7.65	$7.17	$6.43	$5.41
Commercial/ Industrial	$8.36	$8.16	$7.65	$6.06	$5.23	$4.62	$3.64

Source: Average of PV systems analyzed in Navigant's payback model, using data from the CSI PowerClerk database.

[25] Depreciation schedules were obtained from the Internal Revenue Service (IRS), the California Franchise Tax Board (FTB), and the Database of State Incentives for Renewable Energy and Energy Efficiency (DSIRE). http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F

[26] Though the last quarter of 2010 also was able to take advantage of 100% bonus depreciation, we only used 50% bonus depreciation for 2010 since this was an annual model and for conservatism on calculated payback times.

A.6 PV Production, Exported Generation, and Performance Ratios

Tables in this subsection describe assumptions for PV system production (Table A-8); proportions of system generation exported to the grid (Table A-9); and PV system performance ratios (Table A-10).

Table A-8. Assumed Energy Production Ratio by Host Customer Sector

Host Sector	kWh-AC/kW-DC
Residential	1,462.1
Commercial/Industrial	1,536.6

Source: Derived from E3 data [27]

Table A-9. Proportion of PV Generation Consumed On-Site Versus Exported to the Grid

Host Sector	Percent of PV Generation Exported to the Grid	Percent of PV Generation Consumed On-Site
Residential	52.46%	47.54%
Commercial/Industrial	41.22%	58.78%

Source: Derived from E3data [28]

Table A-10. DC-to-AC PV Performance Ratio and Annual Degradation by Host Customer Sector[29]

Host Sector	Performance Ratio	Annual PV Degradation
Residential	81.50%	1%
Commercial/Industrial	84.80%	1%

Source: Derived from E3 data

A.7 Operation and Maintenance

Annual PV system operation, maintenance, and inverter replacement cost data for the payback model were obtained from a 2012 report Black and Veatch completed for the National Renewable Energy Laboratory that detailed comprehensive cost and performance data for various power generation

[27] Calculated using the E3NEMSummaryTool.xlxs, developed by E3 and located at: http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm. California Net Energy Metering Rate payer Impacts Evaluation, 2013.
[28] Ibid.
[29] The performance ratio is also known as the DC-to-AC derate factor. It is only used in the model for purposes of calculating O&M costs, which were available on a $/kWDC basis. Ibid.

technologies.[30] Table A-11 summarizes the input data used within the Navigant payback model. These costs were converted from 2009 dollars to nominal dollars by applying the same inflation factor assumed in the E3 NEM Summary Tool.[31] Since, O&M data were provided in five-year increments. Navigant interpolated to derive an annual dataset for use within the payback model.

Table A-11. Annual Operation and Maintenance Cost, in Nominal Dollars

Year	Residential ($/kW-DC)	Non-Residential ($/kW-DC)	Year	Residential ($/kW-DC)	Non-Residential ($/kW-DC)
2007	$49.41	$49.41	2025	$58.96	$58.96
2008	$50.98	$50.98	2026	$59.47	$59.47
2009	$50.40	$50.40	2027	$60.03	$60.03
2010	$50.82	$50.82	2028	$60.57	$60.57
2011	$52.00	$52.00	2029	$61.13	$61.13
2012	$52.65	$52.65	2030	$61.64	$61.64
2013	$53.10	$53.10	2031	$62.18	$62.18
2014	$53.64	$53.64	2032	$62.76	$62.76
2015	$54.27	$54.27	2033	$63.36	$63.36
2016	$54.90	$54.90	2034	$63.96	$63.96
2017	$55.57	$55.57	2035	$64.56	$64.56
2018	$55.06	$55.06	2036	$65.14	$65.14
2019	$55.70	$55.70	2037	$65.71	$65.71
2020	$56.34	$56.34	2038	$66.29	$66.29
2021	$56.91	$56.91	2039	$66.86	$66.86
2022	$57.43	$57.43	2040	$67.43	$67.43
2023	$57.94	$57.94	2041	$68.00	$68.00
2024	$58.45	$58.45	2042	$68.57	$68.57

Source: Adapted from Black and Veatch, 2012

[30] Black and Veatch (2012). "Cost and Performance Data for Power Generation Technologies." Prepared for the National Renewable Energy Laboratory. Available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

[31] Calculated using the E3NEMSummaryTool.xlxs, developed by E3 and located at: http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm. California Net Energy Metering Rate payer Impacts Evaluation, 2013.