Solar Project Return Analysis for Third Party Owned Solar Systems

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EXECUTIVE SUMMARY

1.1 UNDERSTANDING THE SITUATION

Navigant conducted an analysis to evaluate the Third-Party Owned (TPO) solar PV (solar) leasing business model, which has emerged as the dominant business model in Arizona (AZ) and throughout the country. Customers with solar TPO systems receive solar-generated power without the high up-front cost of purchasing a system or the responsibility of system monitoring or maintenance. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar TPO lease rate (lease rate)[1] for the term of the agreement.[2] The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate. Our analysis focuses on quantifying solar TPO providers' project returns in utility service territories across AZ and California (CA).

1.2 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.[3]
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from $0.087/kWh to $0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on page 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

[1] For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

[2] In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis.

[3] Utility offset rates ($/kWh) are defined as the dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. It is the amount of their bill that is "offset" for each kWh generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

2. SOLAR PROJECT RETURN ANALYSIS

2.1 THIRD-PARTY OWNED SOLAR BUSINESS MODEL

Third-Party Owned solar systems, as compared with customer owned systems, has emerged as the dominant distributed solar business model throughout the country. Solar TPO providers offer customers the option to adopt solar power with no upfront costs. Customers sign a long term contract for solar electricity and the solar TPO provider owns and maintains the system. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar lease rate[4] for the term of the agreement.[5]

The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate.

2.2 ARIZONA SOLAR MARKET

Navigant obtained data from ArizonaGoesSolar.org[6] and used those data to characterize the 2015 residential solar market. The data revealed that the solar TPO business model dominates the Arizona market with a handful of large national players comprising the majority of the solar market share. For UNSE, the market is dominated by one national player, SolarCity, and a handful of regional companies. Navigant observed the same trends in other service territories – dominance of the solar TPO business model and SolarCity followed by other national and regional players.

2.2.1 Arizona 2015 Solar Data

Since not all utilities report data to ArizonaGoesSolar.org denoting whether a system is solar TPO or a customer purchased system, Navigant looked at data from APS, the utility with the largest residential solar market, to quantify the market share of solar TPO systems in the overall residential market. In 2015, APS territory comprised 81 percent of the solar PV installations across the Arizona utility territories examined in this report (UNSE, Arizona Public Service (APS), Sulphur Springs Valley Electric Cooperative (SSVEC), and Tucson Electric Power (TEP)). Given the large percentage of solar PV installations in APS's service territory, relative to other Arizona utilities, Navigant assumed the ownership type split in APS's service territory reasonably represents the Arizona market. These data indicate that solar TPO is the dominant business model in the residential sector. Figure 1 shows that 72 percent of systems 10 kilowatts and smaller installed in the APS service territory in 2015 were TPO. This aligns with the U.S. Solar Market Insight Q3 2015 report, which reported that third party providers owned 77-80 percent of new residential installations in Arizona in 2015.[7]

[4] For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

[5] In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis.

[6] Arizonagoessolar.org, http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx, Accessed January 12, 2016.

[7] GTM Research and Solar Energy Industries Association, U.S. Solar Market Insight, Q3 2015, December 2015.

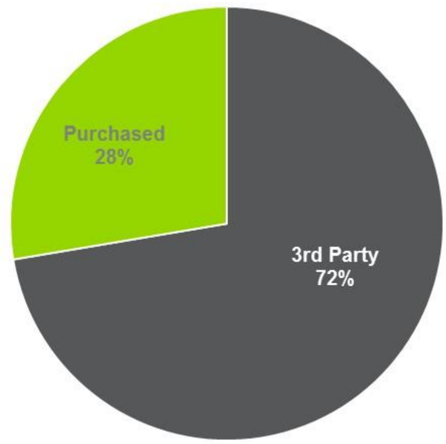
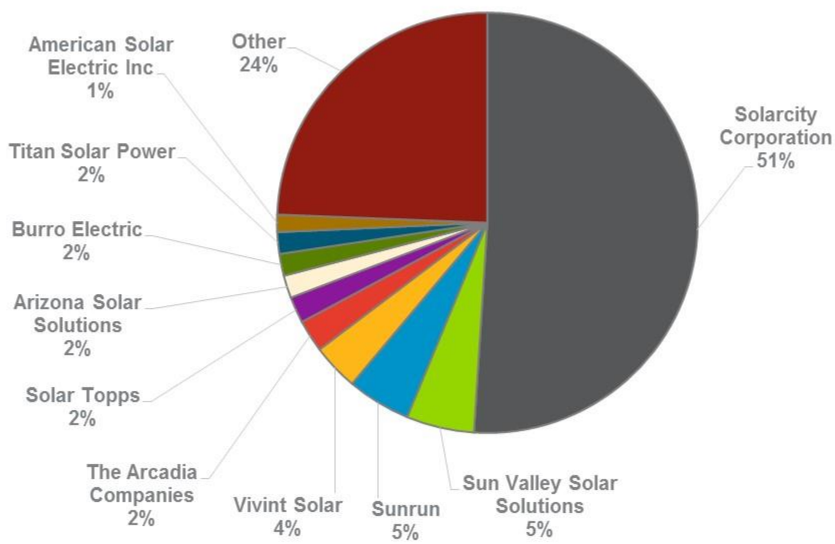


Figure 1. Arizona Residential Solar APS 2015 Ownership Type[8]

ArizonaGoesSolar.org data indicate that SolarCity is the dominant solar player across all Arizona utilities, comprising approximately 50 percent of the residential market in 2015, as shown in Figure 2. SolarCity is also the dominant player in UNSE territory with around 32 percent of total installed residential systems in 2015.



* Other includes all other installers in the Arizona examined service territories.

Figure 2. Arizona (APS, TEP, UNSE, and SSVEC) Residential Solar Market Share, Leading Installers[9]

Based on the dominance of solar TPO and SolarCity, Navigant used solar TPO and SolarCity data to represent the Arizona solar market.

[8] APS market share installation data for systems <10kW in 2015, as other utilities do not report ownership type.
[9] Installation data for systems <10kW in 2015.

2.3 LEASE PRICING VS. UTILITY OFFSET RATES

Navigant obtained lease data from leading solar TPO companies in states with high penetration of distributed solar PV, benchmarking this information through industry interviews and market research. Solar TPO providers reported that their residential lease rates are typically 5 to 20 percent below residential retail rates.[10] Navigant's research indicates that third party providers choose to operate in jurisdictions where they can undercut utility offset rates. Further, Navigant's research found that the solar TPO pricing strategy is such that jurisdictions with higher offset rates are likely to see higher solar TPO lease prices without direct cost-causation. Table 1 lists the lease rates and utility offset rates used for this analysis.

Table 1. Lease Rates and Utility Offset Rates[11]

State	APS	UNSE	TEP	SSVEC	PG&E	SMUD
Observed Lease Rate (Year-1) – Jan 2016 ($/kWh)	0.105	0.095	0.093	0.110	0.162	0.109
Observed Lease Rate (Year-1) – Dec 2015 ($/kWh)	0.105	0.087	0.090	0.105	0.150	0.109
Lease Rate Annual Escalation	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Utility Offset Rate ($/kWh)	0.133	0.103	0.108	0.122	0.234	0.137

2.3.1 Lease Rate Pricing

In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production in kWhs. One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis. In other jurisdictions, the contract might entail a rate directly specified on a $/kWh basis, often referred to as a power purchase agreement (PPA) rate. For simplicity, we refer throughout this document to the lease rate, as though it is analogous to a PPA rate. Residential customers usually enter 20-year lease agreements with the solar TPO provider that often include a year-one lease rate and an annual escalator.

Navigant accessed publicly available lease rate pricing data for the six utilities listed in Table 1 from SolarCity's website and benchmarked them through interviews and market research. In some utilities, lease rates have increased from 2015 to 2016, consistent with public disclosures and comments from leading players such as SolarCity and SunRun.

- SolarCity reported on its Q3 2015 earnings call that in 2016 the company would focus on cost reduction and value, with less emphasis on growth. They reported that pricing would increase in Q1 of 2016 to correspond with escalation in utility rates.[12]

[10] Navigant interviews with industry experts.
[11] Sources: Energy Information Administration Average Utility Rates, System Advisor Model – National Renewable Energy Laboratory, SolarCity website https://go.solarcity.com/#/my-home/zip-nearme, Navigant Modeling (Rates: APS: Residential TOU ET2; SSVEC: Residential Service; TEP: R-01; UNSE: Residential-RES-01; PG&E: E-6 TOU Region R; Residential TOU Option 1)
[12] SolarCity Corp (SCTY) Earnings Report: Q3 2015 Conference Call Transcript, http://www.thestreet.com/story/13345540/1/solarcity-corp-scty-earnings-report-q3-2015-conference-call-transcript.html, Accessed January 28, 2016.

- SunRun reported on its Q3 2015 call that cost structure improvements are a primary focus. For a significant portion of their current markets, SunRun is currently pricing on a per kilowatt hour basis at 25 percent or more below utility rates, even before anticipating future increases in utility rates. They reported that because of strong consumer demand, they have begun to and will selectively raise prices.[13]

2.3.2 Utility Offset Rates

Utility offset rates ($/kWh) are defined as dollar value reduction to a customer's utility bill for each kWh generated by the customer's solar system. In other words, it is the amount of their utility bill that is "offset" for each kWh of solar generated. Navigant calculated the offset rate for each utility using residential tiered rates and time of use rates. Consistent with net metering rules, Navigant sized the system to meet 80 percent of customer load over the course of the year, such that the system never over generates on an annual basis and generation exported to the grid is credited to the customer at a retail rate rather than a wholesale rate.

Navigant benchmarked these offset rates using National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) and the average residential rates published by the Energy Information Administration (EIA). Both the Navigant and NREL SAM models rely on TMY3 weather data and OpenEI data for average hourly residential building load profiles.

2.3.3 Rate Comparison

Consistent with the findings from the 2015 Lawrence Berkeley National Laboratory (LBNL) Tracking the Sun VIII report, Navigant found that solar TPO vendors pursue value-based pricing strategies by undercutting the utility offset rate, which is evidenced by the positive correlation between lease pricing and the offset rate.[14] Figure 3 shows that offset rate increases across utility territories correspond with lease rate increases.

[13] Transcript of SunRun earnings conference call or presentation 12-Nov-15, http://finance.yahoo.com/news/edited-transcript-run-earnings-conference-032845202.html, Accessed January 28, 2016.

[14] "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Lawrence Berkeley National Laboratory, 2015. https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf

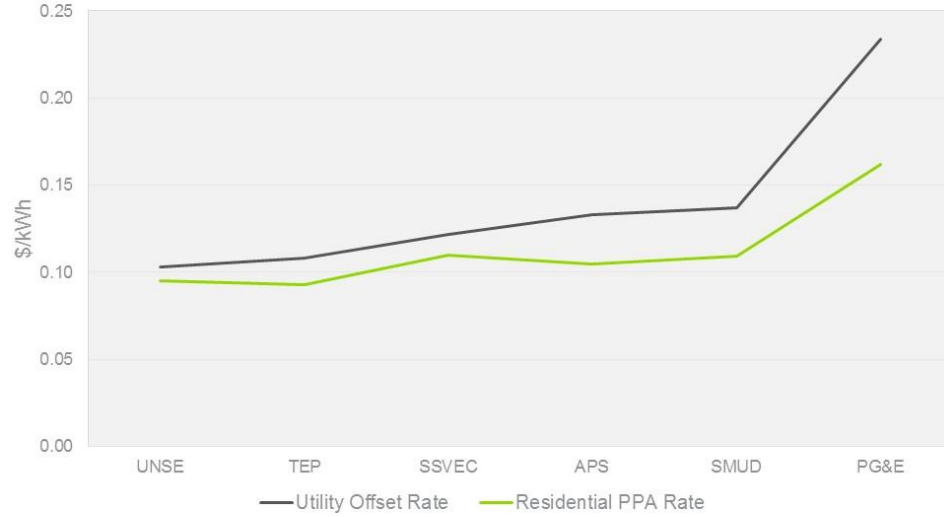


Figure 3. Utility Offset Rate vs. Lease Rate – Line Graph

In Figure 4, the dashed grey line represents the points at which the residential solar lease rate equals the utility offset rate. Along this line customers would be paying the same for grid and solar generated electricity. Points below the line indicate where lease rates are undercutting utility offset rates. However, while solar TPO providers are undercutting utility offset rates, the analysis needs to consider the impact of locational factors such as solar insolation, installed system cost, state income tax rates and state incentives to correctly compare lease rates across different service territories and locations. We will present these jurisdiction specific factors in the following section.

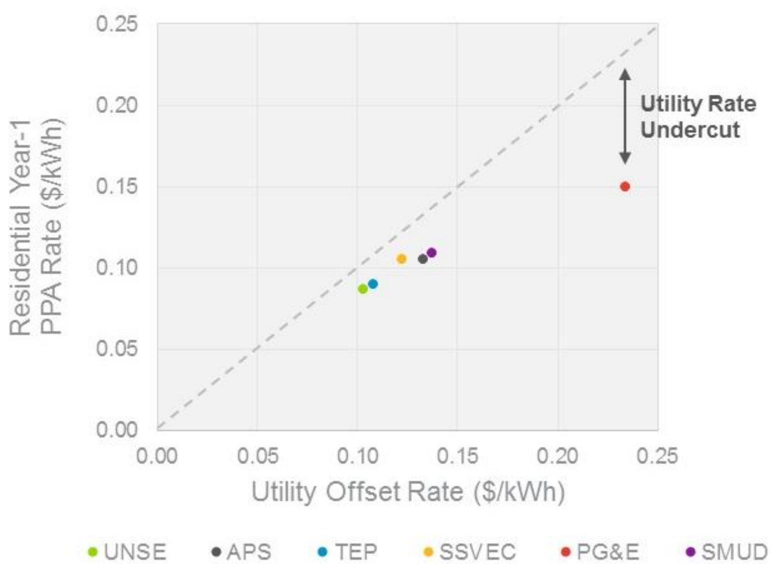


Figure 4. Utility Offset Rate vs. Lease Rate – Scatter Plot

2.4 PROJECT RETURN ANALYSIS

2.4.1 Project Return

This section presents Navigant's jurisdiction-specific analysis of solar TPO lease pricing. Navigant used its proprietary Renewable Energy Market Simulator (RE-Sim™) discounted cash-flow analysis model to calculate a leveraged project return on invested capital on a project-specific basis.

Consistent with standard economic practice, we define the project return on invested capital (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero. Navigant's analysis estimates the project return assuming a solar TPO provider both owns and installs the system, consistent with the dominant solar PV business model. We calculate total project return independent of the breakdown of possible recipients of the project return (i.e., whether an equity investor, a tax equity investor, or the third-party provider itself is the recipient of the project return on invested capital).

In this report, Navigant defines the *project return on invested capital* (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero.

The cash flow streams accounted for in this analysis include:

- Initial capital outlay, inclusive of all system component costs, installation costs, and an allocation of overhead costs
- Operation and maintenance (O&M) costs, inclusive of inverter replacement
- Debt-financing cash inflow and interest payments
- Federal Investment Tax Credit (ITC) benefits
- Incentives (where applicable)
- Accelerated depreciation for tax purposes (MACRS and Bonus Depreciation)
- Federal and State corporate income taxes
- Lease revenue, including lease rate escalation and accounting for system output degradation

Navigant's model is a discounted-cash-flow optimization model, whose objective function is to minimize the lease rate, a decision variable in the optimization, subject to constraints on the input project return and minimum debt service coverage ratio.[15] Another decision variable in the optimization is the debt ratio, which is an output of the optimization rather than an assumed input, as with some more simplistic analyses. The reason we calculate the debt ratio rather than assume a debt ratio is that higher lease rates afford the opportunity for a provider to have greater leverage (i.e., a higher debt ratio), while still being able to service its debt. Having greater leverage offers the potential for higher project returns on invested capital, since for a given revenue stream the required capital outlay is lower. As such, a rigorous analysis must calculate the debt ratio rather than take it as an input.

[15] Navigant's model can also calculate the effective project return given an input lease rate.

2.4.2 Financial Assumptions

As described above, Navigant conducted a discounted cash flow analysis to calculate the project return for projects across various service territories in AZ and CA. While several assumptions were fixed across utility territories, as detailed in the Appendix, locational assumptions varied by service territory where applicable. Locational assumptions that varied by service territory include: the installed system cost ($/Watt), capacity factor, PV production, local taxes, and incentives. These locational assumptions are detailed in Table 1 and Table 2 and are explained in the following sections.

Table 2. Locational Financial Assumptions

	APS	UNSE	TEP	SSVEC	PG&E	SMUD
Installed Cost ($/W-DC)	2.76	2.76	2.77	2.77	2.87	2.88
First Year PV Production (kWh/kW-DC)	1,684	1,718	1,718	1,692	1,591	1,469
State Income Tax Rate	6.00%	6.00%	6.00%	6.00%	8.84%	8.84%
Incentives	-	-	-	-	-	$500/system

2.4.2.1 PV System Costs

Navigant developed detailed cost estimates for residential solar PV systems installed in 2015 based on a system size of 7.00 kW. As displayed in Figure 5, Navigant's bottom-up estimate for the national average installed system cost in 2015 is $2.82/W. Navigant adjusted installed system costs for each utility service territory accounting for changes in key cost components such as direct labor and sales tax.

While some components of the installed system costs can vary significantly by location, the overall impact of locational cost differences is small. For example, direct labor is a leading cost component that changes by location. Navigant adjusted direct labor costs by utility service territory and, while costs may differ by as much as 30-35 percent between high cost locations in CA and low cost locations in AZ, the overall impact on the total installed system cost is relatively low, as direct labor costs only account for around 10-15 percent of the total installed system costs.[16,17]

[16] Quarterly Census of Employment and Wages - Bureau of Labor Statistics
[17] Electrical Cost Data - RSMeans

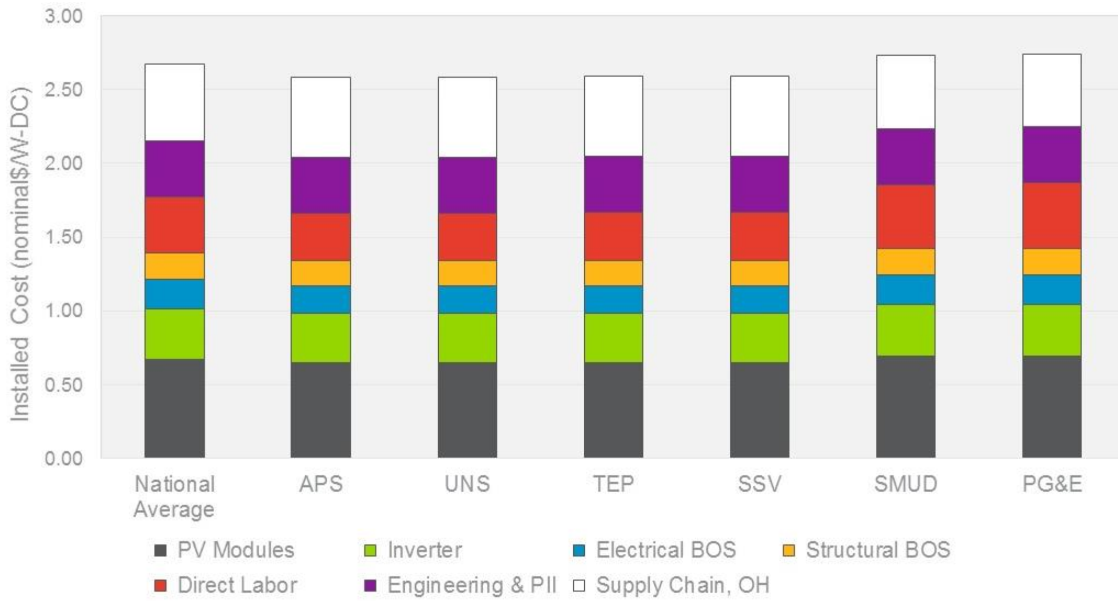


Figure 5. 2015 Installed System Costs, Residential

Over the coming years, system costs are expected to decline further as published in the solar market leaders' three-four year cost reduction roadmaps. In December 2015, SolarCity reiterated its cost goal of $2.25/W by mid-2017 and $2.00/W by 2019.[18] This cost reduction roadmap is part of a broader initiative by SolarCity to improve profitability over focusing on pure growth. Key elements of the cost reduction roadmap include: the use of higher efficiency panels, hardware cost reductions and sales and operations cost reduction. Other industry leaders have also published cost reduction roadmaps. For example, SunRun is projecting 2016 cost declines to follow 2015 cost decline trends.[19]

2.4.2.2 Solar Resource

Navigant used NREL's SAM model to calculate system performance across all regions. System design assumptions were fixed, though the solar resource assumptions changed for each service territory. This methodology accounted for the variance in locational solar resource, and therefore capacity factor and system generation, while keeping system design constant.

2.4.3 Policy Adjustments

Solar project economics are currently driven by federal incentives including the investment tax credit (ITC), accelerated depreciation, and bonus depreciation. During 2015, federal incentives included the ITC and accelerated depreciation, as bonus depreciation had expired at the end of 2014. However, in December 2015, the ITC benefit was extended through 2022. Additionally, bonus depreciation was also extended

[18] SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3.compressed-min.pdf

[19] SunRun Q3 2015 Q3 Earnings Conference Call Presentation, November 12, 2015. http://investors.sunrun.com/phoenix.zhtml?c=254007&p=irol-calendar

through 2019, retroactively impacting 2015 project economics. [20,21] Federal incentives currently driving the solar market include:

- **Investment Tax Credit**: The ITC has recently been extended allowing solar system owners to take advantage of this benefit until 2022. The revised policy allows for 30 percent ITC through 2019, 26 percent in 2020, 22 percent in 2021, and 10 percent in 2022, after which the ITC is set to remain at 10 percent.[20] The ITC benefits solar TPO providers by directly reducing providers' tax liability in the form of a tax credit, effectively reducing the cost of acquiring the asset.[22]
- **Accelerated depreciation:** Qualifying solar energy equipment is eligible for an accelerated cost recovery period of five years.[23] This accelerated depreciation is a significant benefit to solar TPO providers compared with normal depreciation of a capital asset for tax purposes, which would require depreciating an asset over its useful lifetime (e.g., 20-30 years). Since depreciating an asset reduces a firm's tax liability, accelerating the depreciation improves a firm's after-tax income in the early years. Since a dollar today is worth more than a dollar tomorrow, due to the time value of money, this benefits solar TPO providers and/or investors.[24]
- **Bonus depreciation:** The bonus depreciation benefit has been re-introduced and is currently 50 percent through 2017, after which it is reduced to 40 percent in 2018, 30 percent in 2019, and zero percent from 2020 onward.[21] The benefits of bonus depreciation are similar to those described for accelerated depreciation, except that they result in even greater depreciation of an asset in the first year of a capital investment. For instance, with a 50 percent bonus depreciation, one can essentially depreciate an additional 50 percent of the asset's value in the first year.

2.4.4 Locational Adjustments

As described above, observed variations in residential solar lease rates alone do not determine project return, as factors such as PV production and systems costs, among others, also need to be considered in the calculation. In our analysis, Navigant used the lowest project return calculated as a comparative benchmark for project returns by solar TPO providers in other jurisdictions. For the six utilities analyzed in 2015, UNSE service territory had the lowest observed lease rate of $0.087/kWh and a project return around 40 percent.

Navigant then made adjustments to account for key drivers such as solar production, system costs, incentives, and tax rates to calculate a lease rate required to achieve the same 40 percent return in other service territories, as presented in Figure 6.

In PG&E's service territory, a 40 percent project return would result in a calculated lease rate around $0.10/kWh, which is about 33 percent lower than the observed $0.15/kWh lease rate in PG&E territory in 2015. In APS's service territory, a 40 percent return would result in a calculated lease rate around

[20] HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 303

[21] HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 143

[22] A tax credit is a dollar-for-dollar reduction in the income taxes that a solar TPO would otherwise have to pay the federal government.

[23] SEIA, Depreciation of Solar Energy Property in MACRS, http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs, Accessed February 1, 2016.

[24] The significant tax benefits from the ITC, accelerated, and bonus depreciation require a "tax appetite" to monetize these benefits (i.e., one must have sufficient tax liability to take advantage of these tax breaks). Thus, it is not surprising that tax equity investors (which can provide the tax appetite required) constitute a substantial portion of solar TPO providers' financing.

$0.090/kWh, yet observed lease rates in APS service territory in 2015 were around $0.105 (Figure 6). This shows the calculated project return in one service territory vastly differs from the project return in other service territories.

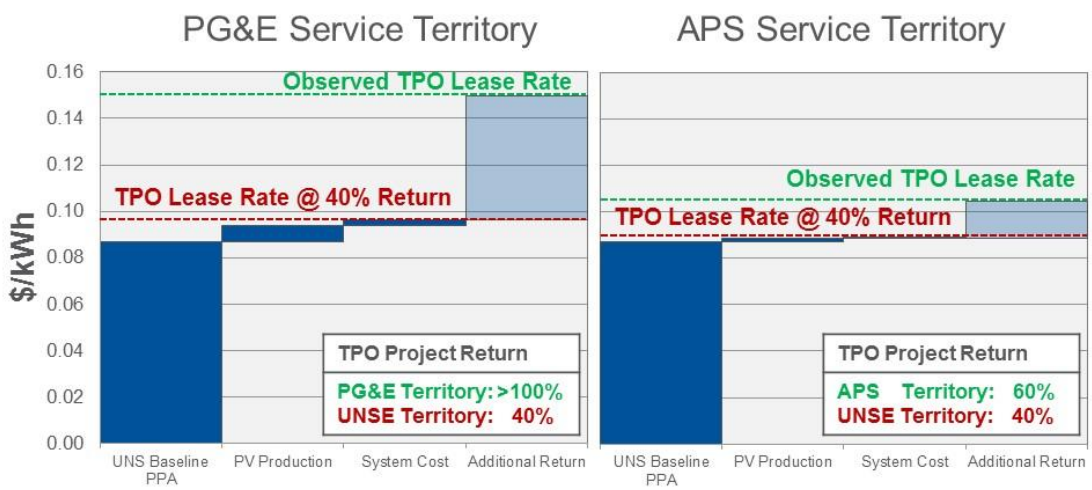


Figure 6. Impact of Locational Factors on Solar TPO Project Return, 2015[25]

Figure 7 plots the observed solar TPO lease rates in each of six jurisdictions in AZ and CA (represented by the green dots) on the same graph as what lease rates would be if instead solar TPO providers achieved a benchmark 40 percent project return in those jurisdictions, accounting for locational differences (represented by the red dots). These red and green dots on Figure 7 correspond with the red and green dotted lines in Figure 6, respectively. The positive difference between the observed solar TPO lease rates and the TPO lease rates at 40 percent project return, shown as the green shaded area in Figure 7, represents an opportunity for solar TPO providers to achieve "additional return" in those service territories.

As is evident in Figure 7, solar TPO project returns increase with increasing utility rates, which cannot be accounted for by variations in locational factors. In other words, calculated project returns vary by utility and are positively correlated with the utility rates.

[25] Prior to retroactive bonus depreciation.

Figure 7. Project Value Analysis across six utility service territories in AZ and CA

Navigant conducted this analysis for lease rates in 2015 and 2016. We found that in four out of the six utility service territories analyzed, SolarCity, for example, increased their lease rates in 2016. This occurred despite declining system costs and favorable policy re-introducing the 50 percent bonus depreciation allowance. The chart above clearly illustrates that solar TPO providers have headroom in many jurisdictions, including UNSE's service territory, to reduce solar TPO rates while still achieving project returns at or above those achieved in UNSE's service territory in 2015 (when lease rates were lower, and when bonus depreciation had not yet been re-introduced, as is discussed in further detail in the next section).

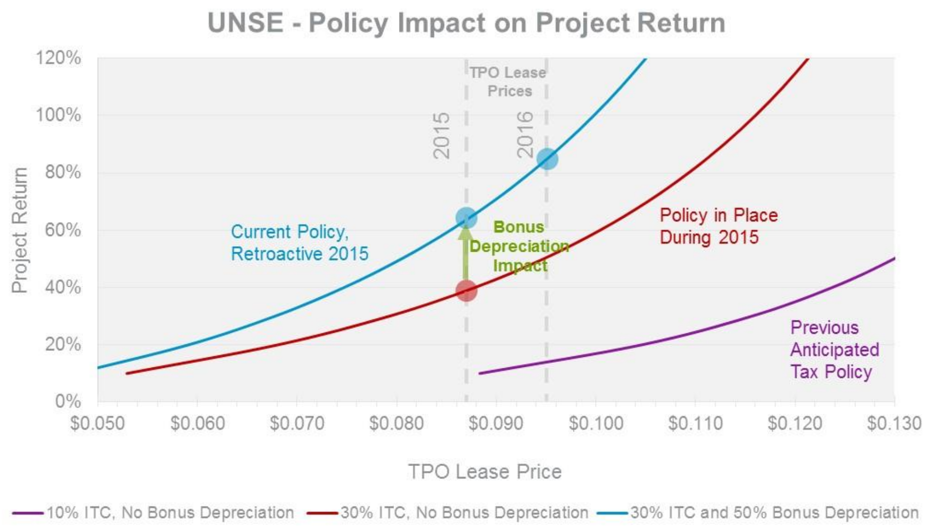
2.4.5 Impact of Policy

Figure 8 shows how the ITC and bonus depreciation policy impact project returns in UNSE and APS territories for various solar TPO lease prices. Throughout 2015 bonus depreciation did not exist for solar systems. However, in December 2015, bonus depreciation was reintroduced and retroactively applies to all 2015 projects. [26] In Figure 8, the red line reflects policy in place during 2015, which has been replaced by current policy (blue line) as of December 2015 and applies retroactively to 2015 projects. Following the favorable bonus depreciation change, solar TPO project returns increased significantly. For example, if lease rates were held constant at $0.087/kWh, project return in UNSE service territory for systems installed in 2015 would have retroactively increased from 40 percent to 60 percent. Similarly, solar TPO providers in APS's service territory experienced project return increases from 60 to 110 percent for systems installed in 2015 due solely to the re-introduction of bonus depreciation.

Simultaneously, UNSE customers have seen increases in lease rates from 2015 to 2016. These lease rate increases are consistent with multiple residential solar players announcing plans to raise lease prices at the end of 2015.[31] As shown in Figure 8, UNSE customers have seen a 9 percent increase in solar TPO lease rates, representing a further project return increase from 60 percent in 2015 to 80 percent in 2016.

[26] UBS, Global Research – "SolarCity Corp, Getting a Bigger Policy Boost", 16 December, 2015

In contrast, the purple line reflects previously anticipated 2017 policy -- 10 percent ITC and no bonus depreciation. Before these recent policy changes, solar companies would have had to compete along the purple line as of Jan 1st, 2017, yet now they are operating along the blue line.



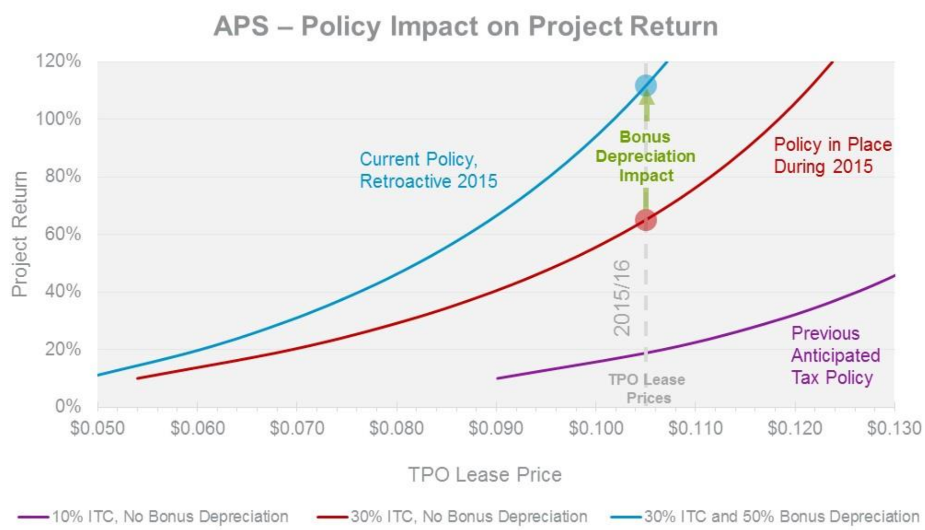


Figure 8. Incentive Impact on Project Return, APS and UNSE Service Territories

The analysis above suggests that the combined impacts of the re-introduction of bonus depreciation and the increase of lease rates from 2015 to 2016 offer headroom for solar TPO providers to reduce lease rates and adjust to changing rate structures while still enjoying the same project returns achieved in 2015. For instance, in 2015 in UNSE's territory, SolarCity, the leading solar TPO provider, could earn a project return of 40 percent with solar TPO prices set at $0.087/kWh. With the re-introduction on bonus depreciation, this should permit SolarCity, the leading solar TPO provider in UNSE service territory, to earn 40 percent return with lease rates of about $0.075/kWh, which differs substantially from current observed lease rates of $0.095/kWh. The headroom available in other service territories appears to be even greater, based on our analysis indicating that service territories with higher offset rates tend to have larger project returns. The above analysis is presented in a slightly different format below in Table 3.

Table 3. Policy Impact of Project Returns, 2015 and 2016[27]

	2015 policy		2015 retroactive change to bonus depreciation		2016 policy	
	in place through Dec 2015		in place after Dec 2015		in place after Dec 2015	
	2015 Solar Lease Rate ($/kWh)	Project Return	2015 Solar Lease Rate ($/kWh)	Project Return	2016 Solar Lease Rate ($/kWh)	Project Return
UNSE	0.087	40%	0.087	60%	0.095	80%
APS	0.105	60%	0.105	110%	0.105	110%

Navigant notes that project return calculations can be sensitive to certain input assumptions. Since project returns grow exponentially as lease rates increase (see Figure 8), this sensitivity is most notable when lease rates and corresponding project returns are high. The robustness of this analysis is in its *comparative* nature, such that minor uncertainties in inputs are applied equally across all jurisdictions, and across comparative policy and lease price changes. As a result, the conclusions of this analysis are driven primarily by the relative values of the calculated project returns across service territories and over time. Furthermore, Navigant makes no assertions regarding whether any individual project return is deemed to be acceptable, too high, or too low.

Although these calculated project returns are high, we note that we have made several conservative assumptions in our analysis that would actually tend to understate, rather than overstate, true project returns. These conservative assumptions include:

- **Cost of debt**: Our analysis used a cost of debt of 6 percent throughout the analysis. Some sources indicate that this cost of debt could be as low as 5 percent.[28]
- **Lease term and residual value**: The analysis uses a 20 year contract term with no residual value for contract renewal and no residual value for the system at the end of life. The typical system life is longer than 20 years and the system is expected to have a residual value at the end of the lease term.
- **Markup assumed for the ITC and depreciation basis**: We used a 35 percent markup on system cost to calculate the value of the system for the purpose of ITC and system depreciation benefits. This value is also known as the fair market value (FMV). Using FMV as the basis for tax credits and depreciation benefits would effectively result in a solar TPO developer reporting a system value of $3.74-3.87/W-DC to the Internal Revenue Service, which is still lower than observed system sales prices that typically range from $4.20-$4.75.[29,30,31] The ability of PV providers to

[27] Project returns are influenced by several key factors including: installed system cost, ITC, bonus depreciation, accelerated depreciation.
[28] UBS Solar, US Alternative Energy & YieldCos, 4Q15 Playbook: Giving Solar 'Credit,' January 2014.
[29] Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.
[30] "A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax Treatment in the Residential PV Sector", Lawrence Berkeley National Laboratory, June 2015
[31] SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3.compressed-min.pdf

markup cost to something more akin to a price, or system value, when calculating tax credits and depreciation is a key driver in the favorable economics for solar TPO providers. [32, 33]

2.5 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.[34]
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from \$0.087/kWh to \$0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

[32] "Evaluating Cost Basis for Solar Photovoltaic Properties", U.S. Treasury Department. https://www.treasury.gov/initiatives/recovery/Documents/N%20Evaluating_Cost_Basis_for_Solar_PV_Properties%20final.pdf

[33] "Valuation of Solar Generating Assets", Solar Energy Industries Association, http://www.seia.org/sites/default/files/Valuation-of-Solar-Generation-Assets.pdf

[34] Utility offset rates (\$/kWh) are defined as dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. In other words, it is the amount of their bill that is "offset" for each kWh generated (hence the term).

APPENDIX A.

Financial Assumptions		
System Specifications	Asset life/investment horizon (Years)	20
	Installed cost ($/W-DC)	Varies by location
	Total asset size (kW)	7.00
	Annual capacity factor (%)	Varies by location
	Annual degradation (%/year)	0.50%/year
	Fixed O&M ($/kW-year)* [35,36]	20.00
	Fixed O&M escalator	1.90%
Financing	Cost of equity	Model output
	Cost of debt	6.00%
	Percentage of cap structure – equity	Model output
	Percentage of cap structure – debt	Model output
	Debt amortization period (Years)	20
	Residual Value	$0.00
	Target Debt Service Coverage Ratio	1.30
Taxes and Incentives	Federal income tax	35.00%
	State income tax	CA: 8.84%; AZ: 6.00%
	Investment Tax Credit	30.00%
	Depreciation type	MACRS, Bonus where applicable
	Discounting convention	Mid-year[37]
	System Cost Markup for Tax and Depreciation	35.00%
	State incentives	None
	Local incentives	None (SMUD: $500/system)
Other	Lease rate	Varies by location
	Lease escalation rate	2.90%

*O&M costs include all O&M components as well as inverter replacement.

[35] National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014.
[36] National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html, Accessed February 1, 2016.
[37] A mid-year discounting convention is a standard assumption about when cash flows occur throughout the year for the purposes of a discounted cash flow analysis. The problem with an end-of-year discounting convention is that it discounts the future value too much. It assumes that the entire cash flow for a given year comes at the very end of that year, and therefore should be discounted accordingly. This is often inaccurate, since cash flows typically occur in each month of the year. The mid-year discounting convention better represents the time-value of these monthly cash flows than an end-of-year convention. The mid-year convention assumes that all the cash comes in halfway through the year, which averages out the time differences between the individual monthly cash flows. http://www.wallstreetoasis.com/finance-dictionary/what-is-mid-year-discount