Solar Value Analyses: Generic Concepts And Terms

While utilities have a long history of valuing resources over a longer time horizon, they are currently faced with the need to assess distinct impacts that accompany increased levels of distributed generation. Solar-value analyses, therefore, become important tools to better align rates with the net impacts of solar DG. Utilities and other solar stakeholders are mutually aware that decisions about how to formulate and apply solar-value analyses will affect the evolution of solar pricing policies for years to come.

3.1 | TERMS FOR ANALYSIS IN NEM POLICY REVIEWS

In recent years, NEM-policy reviews have been conducted on behalf of state regulatory commissions, utilities, stakeholder groups, and others. While these studies vary in their methodology, scope, and assumptions, some categorical agreement has emerged regarding the terms for the analysis. This section describes the broad set of value categories commonly used in assessing solar DG costs and benefits, with ratemaking implications. Note that for this discussion, the term "impact" is often used instead of value, in order to underscore that these are *net* values, which may be positive or negative, within each category or in aggregate.

The categories discussed here represent a broad, but not necessarily comprehensive, list of the components of solar value, and not all studies evaluate each component. This is due largely to the fact that each state determines acceptable terms and methods, usually based on their use in general rate case proceedings and mandated energy plans. Another important limitation is the quality of available data. Utilities often have relatively little available data on some components of avoided cost, and approximations may or may not be useful. The table at right provides a summary of the common value categories found in the literature for determining the solar-DG impacts.

Throughout this paper the term *value* includes both prospective costs and benefits and does not bias or imply that either costs or benefits exist exclusively in any one or all areas of analysis.

The solar value components described in this section represent the performance of a fleet of distributed solar PV systems distributed throughout a utility's service area. This approach

TABLE 3.1 COMMON VALUE CATEGORIES FOR DETERMINING NEM SOLAR IMPACTS

Utility Energy Purchase/Generation Impacts
Utility Capacity Purchase/Generation Impacts
T&D Line Loss Impacts
Net Impacts on T&D Investments and O&M
Environmental Impacts
Fuel Price Hedge Impacts
RPS Compliance Impacts
Gross Lost Revenues
NEM Excess Generation Payments
Program Administration Budget Impacts
Power Quality and Other Ancillary Services as Another Line

reflects cumulative and dynamic impacts that would be missed in an analysis based on a single "average" system analyzed in isolation. For example, the aggregate amount of fleet hourly and annual solar generation would reflect the value from avoided energy and generation capacity at the margin (i.e., \$/kWh and \$/kW) *and* the magnitude of that value (i.e., number of kWh and kW avoided at the marginal price). This could be consequential, if the fleet were large enough not only to avoid the marginal source (and price) of generation, but also the impact to generation dispatch for the utility. Evaluating the energy and generation-capacity savings from the fleet also would capture any value provided by the geographic dispersion of systems throughout the additional flexible generation capacity to integrate solar generation and/or utility service area. By the same token, any need for additional flexible generation capacity to integrate solar generation and/or upgrades to distribution infrastructure to account for system impacts would be assessed in relation to the fleet rather than to a single system.

Ideally, a solar cost-of-service study would look at impacts on each utility circuit, with different solar penetrations, and only then assess fleet-wide impacts. In the discussion below, that approach is applied sparingly, to address specific circumstances. It would also consider whether solar installations utilize inverters with embedded capabilities to resolve power quality issues or whether the inverter might introduce power quality challenges to the grid. However, for most utilities, that level of analysis is not practical today.[31] If the analysis were intended for a rate review, another limitation would be the focus on the test year, rather than taking into account the dynamic impacts upon the utility of growing solar market penetration and other planned system changes. Some regulators may request additional analysis that takes a longer view, if only to provide context.

A summary of the value categories of solar in DG applications, and sub-sets of these categories where applicable, are as follows:

- **Utility Energy Purchases/Generation Impacts.** Solar DG reduces the on-site energy requirements of the utility customers who employ these systems. As the number of solar DG systems increase, sufficient energy may be generated by these systems to offset utility purchases of energy or utility generation. This value is generally calculated by multiplying the hourly output of the PV system by the utility's marginal cost of energy for the corresponding hour of PV generation and would be performed for each hour of the year that the PV system is generating, and then summed to derive annual energy-cost impacts. Embedded in this value are the net economic impacts associated with avoided fuel purchases and the net impacts on generation plant O&M costs.
- **Utility Generation Capacity Impacts.** In addition to purchasing and/or generating energy, utilities may also have to purchase or monetize generation capacity. Valuing the impacts of DG on utility generation capacity costs is a very utility-specific analysis and depends heavily on two factors: when the utility shows a need for incremental generation, and what capacity value they assign to solar PV.

  For example, utilities with excess capacity in the near-term would assign little to no value to incremental generation such as DG systems, because they are not avoiding or deferring generation additions until those years when load growth or retirements are forecast to establish a need for incremental generation capacity. For utilities that do show a need in the near term, DG systems could be attributed with deferring that incremental capacity; however, the actual amount deferred is contingent upon how well solar PV aligns in that utility's territory with its load curve.

  Multiple methods exist for determining this correlation, which provides a proxy for the percentage of a new generation asset that could be avoided/deferred with increased DG penetration (i.e., its capacity value or credit).[32]

Further, as utilities integrate a broad range of solar resources into their portfolios the capacity value provided by solar may change. Several utility IRPs have demonstrated that solar resources, including DG, ultimately at high penetrations have diminishing contributions towards system peak load. However, as forecasting load becomes more accurate, it may be possible to better determine capacity-like benefits provided by solar DG coincident with utility peaks.

- **Transmission and Distribution Line Loss Impacts.** Distributed solar projects generate energy at the point of use, reducing consumption of energy from the utility grid. In reducing grid energy requirements, the localized distribution feeders and transmission lines serving the utility experience reduced line losses. Transmission and distribution (T&D) line-loss impacts are typically calculated separately from each other, as the values differ for each system and even more by individual distribution-system feeder (inasmuch as data is available). T&D line loss impacts are typically calculated hourly, based on the marginal cost during the hours of PV production. In some deregulated wholesale power markets, marginal transmission costs are embedded in the locational marginal prices. In such cases, analysts would be careful to avoid double counting transmission line-loss impacts.

  In considering distribution-level impacts, analysts might consider that DG systems export power to the distribution grid when solar generation exceeds load. Ultimately power-flow studies are required to determine the value of DG on line losses as those impacts differ from dense to sparse territories and from low solar penetration to high solar penetration.

- **Net Impacts on Transmission and Distribution Investments and O&M.** Solar DG systems often impact the capacity levels on T&D systems, either by decreasing the capacity requirements during periods when distributed solar is being consumed on-site, or by increasing the capacity on the lines when excess power is exported to the grid. Capacity impacts are largely a function of the penetration of solar DG within individual feeder lines and within the overall service area as well as the operational characteristics and timing alignment between the solar and the specific circuits hosting the resource.

  As solar DG penetration increases, there may be feeder circuits where the utility could defer or eliminate capital investments in the system because the solar output coincides with peak demand on that circuit. Some utilities highlight tension with this potential value, relaying that reliance on DG resources to ensure the utility meets it regulatory requirements for reliability and safety is a practice that is shouldered with uncertainties and yet evolving with regulators. Other utilities and utility-published studies report that this situation is theoretically realizable, but currently rare in practice. The situation is most likely to occur where there is relatively high solar penetration on circuits that experience a peak that can be offset by solar, combined with low- or flat-load growth. A different impact might occur as reduced line loads decrease system wear, potentially resulting in deferral of replacement. In general, deferrals—to the extent achievable—have value due to the "time value of money," where money spent today has a higher cost than money spent in out years.

  One method for assessing T&D deferral value is equal to the expected long-term T&D system capacity upgrade cost, divided by load growth, times the financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.[33]

  There may also be utility capital costs associated with adding distributed solar to the grid. As market penetration of DG systems increases, utilities must prepare the grid to accept this variable generation, and to perform well with two-way power flows. Costs of such grid preparation include technical and operational investments and expenses. In some cases, analysts must be careful not to double-count grid upgrade costs that are accounted for as utility "smart grid" engineering upgrades, or as part of regularly scheduled system infrastructure upgrades. DG systems also may have infrastructure O&M impacts, including possible savings or costs. While the ratemaking process is focused on the test year, regulators also might want to note whether impacts will be sustained, or whether they have to do with system upgrades that can serve the utility for a given number of years at increasing solar market penetration.

- **Environmental Impacts.** Solar, and distributed solar within that broader category, is associated with a number of environmental impacts. Some of these occur as solar displaces conventional generation and related pollutants. A few occur as utilities increase their use of (typically natural gas) generators that can respond quickly to variable solar generation. In addition, there may be impacts on O&M costs for associated pollution control equipment. Because solar market penetration is just becoming consequential for a few utilities, the calculation of these impacts is subject to different assumptions and methodologies. A full, net accounting may be complex.[34] Analysts must be careful to avoid double-counting benefits that are embedded with costs in other categories.
- **Fuel Price "Insurance".** Electricity generation from solar resources has an embedded fuel price hedge-like value, since its cost of generation is known with reasonable certainty over the expected system life. This hedge-like value remains in place for the full life of the solar resource and as such can be referred to as fuel-price insurance, a known price for a defined outcome. Many utilities hedge against future fuel price uncertainty through the purchase of commodity futures, though state regulators may prescribe a particular approach and most often these hedging practices are short-lived (e.g., three to five years in duration). The generation output of a fleet of distributed solar systems provides insurance against future fuel price uncertainty equal to the annual generation of the fleet, but adjusted for any increase in fossil fuel use needed to ensure that these conventional plants can ramp up or down as needed to accommodate the intermittent nature of solar production.
- **RPS Compliance Impacts.** RPS targets are typically measured by accumulating renewable energy certificates (RECs), where one REC equals the renewable energy attributes of one MWh of renewable energy generation. Many utilities require transfer of the REC or solar REC (SREC) ownership from solar customers to the utility in exchange for some type of payment (e.g., a credit or rebate). To determine the SREC value of solar DG generation for a specific utility, the analyst would calculate the difference between the alternative cost of compliance (e.g., the prevailing SREC market price or the price of an alternative compliance payment) and the current unit cost of SRECs acquired from solar DG customers. If the alternative cost of RPS compliance is higher than the cost of acquiring SRECs from solar-DG customers, then the value of the solar DG SRECs is positive. If the compliance cost is lower, the solar DG SREC value is negative. In some jurisdictions (e.g, California), rooftop solar output does not directly count in furtherance of a utility's RPS. There may be an indirect, fractional benefit, because the amount of load for which the utility must procure renewable supplies is lower.
- **System Reliability Impacts.** A fleet of distributed solar systems may impact utility system reliability either positively or negatively. Examples of potential system reliability benefits range from the value of preventing blackouts and brownouts, to that of providing back-up power to critical customers, to the value of providing ancillary services and reactive power support to the grid.

Studies have recognized that these reliability impacts could be designed into DG system deployment, but since these implementations remain largely theoretical, they treat them in a qualitative manner. A CPUC order describing solar value calculation methodologies has described these as reliability benefits yet to be characterized and currently sets their value at zero.[35] There are also impacts of intermittent generation on system reliability such as islanding, voltage drops, etc. These impacts are reported by utilities as specific to individual electric system characteristics; some such costs are borne by the customer deploying the DG resource while other costs are socialized.

- **Gross Lost Revenues.** As discussed previously, solar-DG customers reduce their energy bills through use of the on-site generation, at times exporting energy to the grid and receiving credits for those kWh. This reduces utility energy sales, and it reduces gross utility revenues. For utility rate classes with flat retail energy rates, the calculation is merely the annual generation of the DG fleet multiplied by the retail energy rate. For utility rate classes with demand charges, seasonal differentials, time-of-use, and/or inclining block rates, the calculation becomes more complex. In these instances, an hourly analysis may be required.
- **NEM Excess Generation Payments.** Typically, DG customers who generate excess energy above their on-site energy requirements through NEM rates receive a billing credit for this unused generation, which is carried over into other hours or subsequent months. In some states, a periodic "true up" event occurs, wherein any excess generation by the customer for the period is quantified, and the customer is compensated. The rate and level at which customers are compensated varies, ranging from full retail rate compensation, to the average annual utility avoided cost of energy, with many variations in between. Perspectives have differed between solar stakeholders and utilities on the level of compensation that is most appropriate. Most states cap excess generation compensation to a percentage (typically 10-20%) above the annual energy requirements of the customer's facility. In this case, any excess generation above the cap would not be compensated. Regardless of how the customer is compensated, payments for excess billing credits are often considered a cost to the utility, depending on how the cost and value of this energy compares to the alternative the utility would have undertaken.
- **Program Administration Budget Impacts.** This is the total utility cost for running the solar-DG program. It may include costs of utility personnel to manage and market a distributed solar program, to process incentive applications, to conduct engineering reviews for interconnections, to inspect customer systems, and other program related costs. It may also include costs for NEM billing. Program administration costs are typically defined by the utility's program budget and are subject to the same type of regulatory review as other program costs.

The above inputs used in determining solar value are based on the most common categories of PV DG monetary impacts found in published literature. However, even in the literature, the application of these inputs varies widely. Table A1, in the Appendix was developed by the Vermont Public Service Department[36] and illustrates these differences. Analysts may have many reasons for using certain value categories and not others, but their reasons often relate to the perspective used in the analysis (e.g., TRC, RIM, etc.). They also may rely on categories and inputs that are prescribed by state commissions or suggested by state energy agencies.

The bottom line is that when these inputs are used in a given cost-effectiveness test, they estimate the value of a solar fleet within the jurisdiction analyzed. Results are not necessarily comparable or transferable. As with any benefit-cost analysis, a value greater than 1.0 indicates a positive value and value less than 1.0 indicates a negative value.

For example, in conducting a RIM test with the above inputs (or sub-set of inputs), if the resulting value were greater than 1.0, then the distributed solar fleet would be considered to have positive impact on rates; while a benefit-cost ratio of less than 1.0 would indicate that the fleet is having a negative impact on utility rates overall. Either way, rate equity questions may be raised. Indeed, the cost effectiveness test may result in a value greater than 1.0 for some classes of service and less than 1.0 for others.

While benefit-cost tests from various perspectives are commonly used in DG-related proceedings they do not provide the value of solar in terms of net unit costs or benefits (i.e., $/kW or $/kWh). These net unit costs are useful for comparative analysis, both in DG-related proceedings and in broader policy discussions. The same input values detailed in the above summary could be used to calculate the net unit value of a DG fleet. The analysis could be done for a single test year, or for multiple years, to capture the lifecycle benefits of a fleet of customer-DG systems.

This calculation provides additional granularity to the traditional benefit-cost tests. It might be used in adjusting solar DG/NEM rates and terms, to better meet policy objectives. For example, if it were determined that the net $/kWh value of solar is positive or negligible, then a status quo program would typically be acceptable. Conversely, if a program were determined to have a significant net negative or net positive impact, then changes to the program, in terms of incentives, DG/NEM participant retail rates, or some other adjustments, might be used.

3.2 | PRACTICAL USE OF SOLAR VALUE CALCULATIONS IN UTILITY DG AND NEM RATE DESIGN

A number of factors can have significant impacts on the results of a solar-value analysis. The first is the number of inputs that are used in the analysis. An analysis that includes only four input categories would likely provide different results than an analysis that includes eight input categories.

The second factor is the determination of assumptions used in calculating a specific input value or the determination of assumptions that bound the entire analysis. A clear example of how varying the assumptions would impact results is found in the literature on expected PV system life. Research studies commonly cited assume expected PV system life in the range of 20 to 30 years, while one study (cited by the Vermont commission staff in Table A1) assumed a system life of 30 years, and also proposed a "bonus system life" of an additional 10 years.[37] Varying system life from 20 to 30 years would, by itself, significantly impact the results, due to the discrepancy of 10 years worth of PV generation and associated costs and benefits. Other assumptions about the technology and orientation of systems, degradation in system efficiency, the pace of deployment, rates applied, and economic parameters, such the discount rate, greatly affect outcomes.

Despite the potential for differences, there is a trend running through recent published studies. Disregarding extreme outliers in the results and assuming the same number and type of inputs, the majority of studies in the literature value solar DG within a reasonably tight range when reflected over a levelized 20-year resource life. However, with the experience of European installations over the past decade, and even US installations over the past few years, there is a growing acceptance that with proper maintenance, solar DG systems can reasonably be expected to last 20 years or more. Utilities and stakeholders continue a critical review of whether the prevailing analyses will prove out, as growing solar market penetration affects the benefit/cost equation.

The above discussion on distributed solar rate impacts is based on the most common categories of benefits and costs found in the literature. However, some studies also include other input values. Some of these could be applied to a broader societal perspective, depending on acceptance by a particular regulatory commission. However, there is an active debate regarding the elements of value (costs and benefits) that should be included or reflected in utility rates. Thus, the following items should be considered as useful for consideration, but not necessarily reflective of a view that utility customers do or should pay rates that reflect these items. Stakeholders are generally aligned that to the extent that these impact areas are determined to have positive value and worthy of financial support there are various means of support, such as tax incentives (which exist today) and other economic stimuli.

"...there is an active debate regarding the elements of value (costs and benefits) that should be included or reflected in utility rates..."

Some of these additional impacts are defined below:

- **Market Price Impact.** This value comes into effect as a fleet of distributed solar systems impacts energy and capacity requirements region-wide. As increasing solar affects the amount of energy and capacity the utility purchases, the supply curve shifts, and the market-clearing price (or marginal cost of energy) will fall (or rise). Over time, as distributed solar market penetration increases, market price impacts could be significant.[38] For example, a high penetration of solar DG could lower the demand impacts on a utility system, which would move the supply curve to the right and result in a reduced marginal cost of energy and/or capacity for the hours that solar DG is operational. Yet, analysts must be wary about this anticipated impact. It is possible that higher solar market penetration might move the system peak hours to later in the day, without significant impact on daily peak demand costs. In that case, as more PV systems are added, the marginal impact on peak pricing from these systems would decrease.
- **Economic Development Value.** Some studies address the impacts of local economic development that stem from distributed solar installations. These studies assert that more jobs are generated from distributed solar installations than from conventional power generation. Other studies indicate that while solar provides short-term construction jobs, the long-term job impact for solar O&M is minimal. (One response might be to suggest that it will take many job-years for solar installers to reach full market penetration.) Regardless of the exact scenario, any job creation from solar projects could provide a net benefit to all taxpayers, due to increased tax revenues resulting from these jobs. In addition, benefits would accrue from the multiplier effects of local workers spending money within the local economy. This type of analysis, to the extent demonstrated, is nevertheless seldom accepted in the utility ratemaking process.
- **Other Environmental Impacts.** As noted previously, the environmental impact of NEM is not completely assessed by only looking at the utility's cost reductions. Reduced pollution, water usage/temperature rises (due to less combustion turbine cooling), and certain health impacts have been enumerated in studies. For utilities, these costs are not typically covered in rates; thus, some analysts have noted that it may be necessary to enact laws that charge for these costs, rather than justifying NEM, in part, on these externalities.

Some studies have suggested additional impacts, such as the market transformation impacts of PV systems (e.g., contributing to the creation of a robust and competitive market for renewable energy products). To date, these additional input categories have only been recognized as qualitative benefits, and they have not been documented in analyses before regulatory commissions.

3.3 | VARIATIONS IMPOSED BY DIFFERENT MARKETS AND UTILITY STRUCTURES

A number of specific considerations influence the impacts of solar projects in DG applications, including whether the utility obtains power within deregulated wholesale markets, whether the utility itself is regulated, and whether the distribution utility operates within a retail deregulated market. Each of these market structures will dictate different terms for the utility cost-of-service study and DG/NEM rate impact analysis or solar-DG deployment plan.

In the case of utilities that purchase wholesale power in deregulated markets, the methodology for determining the avoided cost of energy and capacity is generally the same as in regulated markets. However, the source of the generation and pricing mechanisms are likely to be different. For example, regulated utilities may obtain wholesale power from their own generation resources, supplemented by power purchase contracts with well-defined costs for energy and capacity. In contrast, utilities purchasing wholesale supplies in deregulated markets may experience more uncertainty at the margin on an hour-to-hour basis, depending upon regional load conditions and planned or forced outages of power units serving the particular supply node. There may also be fixed "take-or-pay" in power purchase agreements that will impact a utility's costs and therefore its rates to customers. In general, avoided costs of energy and capacity are calculated in a similar manner in regulated and deregulated markets, but the necessary calculations are more complex in deregulated markets.

Another consideration is the nature of the distribution utility—whether it is a regulated investor-owned utility, a public power utility, or an electric cooperative. Investor-owned utilities are almost always directed by regulatory guidelines. Their solar-impact and rate analyses would have little latitude, in terms of what input variables to include or how to assess them, until they receive approval from their state regulatory commissions. Public power utilities that are locally regulated often have fewer barriers (in addition to a non-profit business structure) which may provide a quicker path to innovations. They may decide locally which input variables to include and how to shape their solar-value analyses. This is one reason why public power utilities (e.g., Austin Energy) have included certain impacts in their tariff designs that are not typically considered in regulatory rate case proceedings. Notably, early consideration of solar-value analysis, virtual net metering for community solar projects, and alternative, FIT-based rates was also initiated in public power utilities (including at Sacramento, United Power, and Gainesville, respectively).

In some areas of the country, the impact of deregulated retail markets must be considered.[39] Retail competition presents a number of issues and concerns related to solar DG applications. Generally, in deregulated retail markets, an energy services provider sells power to individual customers. However, as billing involves the local distribution utility, and because the solar DG system may outlive the customer's relationship with a particular energy services provider, regulators have found it beneficial to promote consistency in DG programs statewide.