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Distribution system costs associated with the deployment of photovoltaic systems

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ABSTRACT

The broadening of our energy system to include increasing amounts of wind and solar has led to significant debate about the total costs and benefits associated with different types of generators—with potentially far-reaching policy implications. This has included debate about the cost associated with integrating these generators onto the electric grid. For photovoltaics (PV), this encompasses costs incurred on both the bulk power and distribution systems, as well as the value provided to them. These costs and benefits, in particular those associated with integrating PV onto the distribution system, are not well understood. We seek to advance the state of understanding of "grid integration costs" for the distribution system by reviewing prior literature and outlining a transparent, bottom-up approach that can be used to calculate these costs. We provide a clear delineation of costs to integrate PV in to the distribution system within the larger context of total costs and benefits associated with PV generators. We emphasize that these costs are situationally dependent, and that a single "cost of integration" cannot be obtained. We additionally emphasize that benefits must be considered when evaluating the competitiveness of the technology in a given situation.

1. Introduction

The cost of photovoltaic (PV) modules and systems are increasingly well known. However, the costs associated with integrating PV into the bulk power and distribution systems are not well understood, especially for very high penetration levels. Bulk power systems consist of centralized energy generators and high-voltage (≥ 69 kV) transmission lines that carry power from these generators over long distances. Distribution substations reduce the voltage from transmission lines and transfer power to the distribution systems, which consist of medium (typically 4–46 kV) and low voltage lines and constitute the final stage of energy delivery to the end user. There are multiple ways in which the presence of PV can affect both of these systems, potentially incurring a cost.

As penetrations of distributed PV (DPV) increase, uncertainty about the potential system impacts and their associated costs, in addition to concerns about utility business model disruption and cost-shifting of fixed costs associated with maintaining the electric grid from solar to non-solar customers, have contributed to debates around interconnection rules, net metering, and feed-in tariffs taking place across the globe. An enhanced understanding of the costs associated with—and value provided by—DPV is required to support the design of fair and efficient electricity tariffs, create policies that avoid market distortions, encourage low-cost solutions, help utilities plan more effectively for increasing penetrations of DPV, and compare different energy sources. An improved, more transparent approach for assessing these costs is also critical for reducing the uncertainty and cost of the interconnection process, which, in some cases, has presented a major hurdle to financing PV projects.

The costs associated with integrating PV into bulk power and distribution systems are both commonly referred to as "grid integration" costs; however, in general, modeling the cost of each of these systems involves distinct challenges. For the bulk system, past efforts to understand the costs and benefits of PV have highlighted "why calculating integration costs is such a difficult problem and should be undertaken carefully, if at all" ([1], pg. 1), largely due to complex, system-wide interactions. While system interactions at the distribution level are still quite complex, the localized nature of certain costs may make the definition of some distribution integration costs more tractable. Nevertheless, most past efforts in this area have been system-specific and have not attempted to extract generalizations. We begin to address this gap by surveying past work on PV integration costs at the distribution-level and then attempting to distill a more transparent and generalized framework for such evaluation.

Up to a certain penetration level, called the hosting capacity, PV may be incorporated onto the distribution system without requiring

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Table 1
Summary of prior work on distribution system costs associated with DPV.

Citation (year)	Scale and location	Methodology	Data included	Penetration levels	Key insights
[4] (2013)	Country, for a set of 11 countries in the EU	Imperial College distribution network planning tools	Distribution line costs, costs associated with distribution line losses	Varies between 2% and 18% (annual PV energy/annual energy demand), determined by projected levels for 2020 and 2030 scenarios in each country	● Costs associated with distribution line upgrades and losses may be positive (PV deployment results in a net cost compared to their base case) or negative (PV deployment results in a net benefit compared to their base case). ● Calculated costs of distribution lines with PV compared to the base case range from − 25 €/MWh to 9 €/MWh. ● Distribution line costs per MWh are not a monotonic function of PV penetration level; however, the highest cost per MWh does occur at the highest penetration level. ● Costs associated with distribution losses range between − 7.5 €/MWh and 1.8 €/MWh. ● When PV is present in the distribution system, the use of demand response results in lower distribution line costs as well as lower line losses.
[5] (2014)	Distribution circuit (feeder and substation), United States	Reported data from 90 SGIP reports for 3 utilities and one regional transmission operator	Total cost of mitigation and interconnection facilities required to safely and reliably connect PV	Varies, penetration in MW PV system sizes ranged from 2 to 20 MW, with most of them in the 2–10 MW range	● Costs for interconnection plus mitigation ranged from ~ \$0/W to over \$1.4/W. 50% identified total connection costs were less than \$0.689/W ● Overvoltage impacts were the least expensive to mitigate, with almost half of the cases incurring no additional cost to the utility. Costs associated with mitigating voltage deviation and thermal overload effects (when present) were much higher, comprising 19–70% and 4–72% of total interconnection costs, respectively. ● Protection impacts were the most common, and, when present, cost 9–69% of total interconnection cost to mitigate.
[6] (2015)	Feeder, for 20 feeders in Atlantic City Electric Grid in the United States	PV impact study via hosting capacity analysis on the feeder level	Distribution system upgrade costs, including those associated with phase balancing, capacitor redesign, reduced voltage, dynamic voltage control, fixed power factor (PF) control, and battery storage	0–336.7%, depending on the feeder; (% PV capacity/ gross peak load)	● Every feeder has a different hosting capacity ● Distribution system upgrade costs per MW depend significantly on the feeder, loading, and PV placement. Costs ranged from ~ \$0.23/kW to \$118.7/kW. ● Distribution system upgrade costs are not necessarily higher for feeders with higher PV penetration levels. The feeder with the highest level of PV penetration had much lower cost than the feeder with the lowest non-zero penetration level ● Advanced communications and controls for dynamic Volt-Var operation will be required in some cases and for high penetrations ● Advanced inverters provide good, low-cost solutions, but uncertainty remains about their behavior at high penetrations

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Table 1 (*continued*)

Citation (year)	Scale and location	Methodology	Data included	Penetration levels	Key insights
[7] (2009)	Feeder, for two RNMs in three case studies in the Netherlands, Germany, and Spain	RNM brownfield/expansion planning model (PECO model)	Investment, maintenance, and loss costs for low, medium, and high voltage lines and substation equipment, depending on the scenario	Netherlands: up to 600%, Germany: 0–37%, Spain: up to 67% (as a % of contracted demand) Considered both large and small PV systems, depending on the network	● The shape of the incremental €/kW curve with penetration level was very different for each scenario examined (Netherlands: concave, Germany: linear, Spain: convex) ● Cost drivers vary significantly depending on the network ● Total network costs may be positive or negative, with negative costs resulting from reduced line losses ● Incremental network investment costs ranged from ~ 50€/kW to 600€/kW depending on the scenario and penetration level
[8] (2015)	Feeder, for prototype networks designed using greenfield RNMs [19], European and U.S. network designs	Set locations of PV on the networks, two different load scenarios, use brownfield RNM model (PECO model)	Distribution infrastructure costs, distribution loss costs	0–30% for some analysis and 0–40% for other analysis (in annual PV electricity output/annual load) Considered both large and small PV systems	● Calculated total network costs associated with U.S. network designs were lower than that associated with the European network designs ● Average total network costs tend to increase as a function of penetration, but incremental costs per watt do not necessarily – depends on network type ● Extra network costs are lower in places with higher capacity factors (higher solar insolation) ● The use of storage can decrease network reinforcement cost, but demand response and curtailment may be more efficient alternatives
[10] (2013)	Feeder level, for a real medium voltage grid in Germany	● Hosting capacity (minimum) ● Use of root mean square (rms) models in PowerFactory	Breakdown of total costs by category (annuity laying, annuity cable, opportunity costs for PV, network losses). Absolute cost numbers not provided	Additional 5 MVA PV capacity beyond the hosting capacity Appears to be for larger PV systems only (5 systems for 5 MVA added capacity)	● All investigated control strategies can reduce annuity costs and total costs (annuity + network losses) compared to the base scenario, where there is no active participation by DPV and only grid reinforcements are used ● Network losses are the largest cost categories for all scenarios ● Use of automated voltage limitation significantly reduces annuity for cables and laying of cable, but increases the opportunity costs for the PV generators
[9] (2013)	Feeder level, for a real low voltage grid in Germany	● Hosting capacity (minimum) ● PCCs randomly selected ● Discount their costs (5% interest rate and 40 year lifetime) ● Use of root mean square (rms) models	2011 costs, including OLTC, cable costs, feed-in tariff, reactive power compensation, transformer cost (including installation), and network losses	50%, 100%, and 150% increase in installed kW over a base case of 120 kWp (the minimum hosting capacity) For smaller systems ≤ 30 kW	● Costs depend significantly on the strategy used to integrate the PV. Costs vary from ~ 7 to 60 €/(kWp*yr), depending on the penetration level and mitigation strategy selected ● Specific costs for PV grid integration in €/(kWp*yr) decrease with increasing penetration of PV ● Use of static reactive power provision, automatic voltage limitation by dynamic active power control, automatic voltage limitation by combined dynamic reactive/active power control, or distribution transformers with OLTC can provide significantly lower costs compared to the use of grid reinforcement or limitation of PV active power feed-in. ● Costs associated with the use of an OLTC are sensitive to the OLTC cost which can vary widely (1000–15,000 €/unit)

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Table 1 (*continued*)

Citation (year)	Scale and location	Methodology	Data included	Penetration levels	Key insights
[11] (2015)	Real low voltage network in the UK with 6 3-phase feeders and 351 single-phase loads	• Hosting capacity (Probabilistic Impact Assessment methodology), but only looking at voltage violations	Costs associated with network reinforcement and on-load tap changers (OLTC) with local or remote control	0–100% of houses on the feeders with DPV systems (penetration levels on all feeders are assumed to be the same) For smaller, residential PV systems	• OLTC costs are mostly fixed as a function of penetration level, while network reinforcement costs increase non-linearly as a function of penetration level • It is cheaper (in £) to address voltage violations with network reinforcement for penetrations up to 60% and with an OLTC with remote control for penetrations above 70%.
[18] (2013)	Southern California Edison (SCE) territory in the United States, 13 feeders selected to represent the entire service territory	• Perform power flow simulations on the feeder (with Milsoft and CYME) • Integration costs include cost to integrate all DERs: 90% PV and 10% biomass • Interconnection costs represent average costs for SCE	Distribution system upgrade and interconnection costs for 3 scenarios with different amounts of DER installed at rural and urban locations	2400 MW, 4800 MW, and 6000 MW Considered both large and small PV systems	• The cost of integrating PV onto the distribution system varies significantly depending on locational factors, including PV size, location, and degree of clustering, in addition to feeder characteristics • Carefully siting PV systems can significantly reduce distribution system integration costs • Integration costs are higher in rural areas than urban areas. Longer feeders, particularly those with low voltage and/or light loading are associated with higher integration costs. Integration costs are higher when the PV is further from the substation. • High penetrations of DER may require sophisticated communication and control systems to better manage impacts and reduce integration costs (advanced communications and controls not considered in this study) • Depending on project size, location, and the degree to which DER were clustered together, estimated integration costs ranged from $190 to $270/kW installed capacity for adding 4800 MW of DER to SCE's distribution system
[49] (2017)	Feeder level, for 75 sample/representative circuits in California (30 in SCE territory, 20 in PG&E territory, and 25 in SDG&E territory)	• Perform power flow simulations on the feeder	Distribution system upgrade/integration costs for mitigating voltage violations, thermal loading, and reverse power flow	0–160% of peak load Considered impacts in cases where larger stand-alone PV systems are deployed, by integration costs are for small rooftop installations with (2 kW/system)	• Modeled distribution integration costs ranged from $0.01/W to $0.51/W. • Costs were significantly lower (between $0.01/W and $0.03/W) when DPV was evenly distributed throughout the feeder than when DPV was clustered near the end of the feeder ($0.03/W–$0.51/W). • The use of advanced inverters could enable a $0.15/W, $0.01/W, and $0.30/W reduction in distribution integration cost for PG&E, SCE, and SDG&E, respectively • Costs can be low or zero up to high penetration levels (20–100%, depending on the circuit and DPV locations) • Where traditional mitigation measures couldn't be used to mitigate DPV impacts, storage was the major cost driver • Proactive upgrades could potential result in total cost savings

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Table 1 (*continued*)

Citation (year)	Scale and location	Methodology	Data included	Penetration levels	Key insights
[50] (2016)	Feeder level, for 9 sample/ representative feeders in California (SCE territory)	• Perform power flow simulations on the feeder in CYME • Compare results with different time-series simulation approaches	Distribution system upgrade/integration costs for mitigating voltage and protection violations	0–100% of feeder thermal rating Includes other DERs besides just PV (energy efficiency, combined heat & power, demand response, electric vehicles, and energy storage)	• For most cases, the use of advanced inverters significantly reduced costs • Assumed widespread reconductoring was required in the steady-state case, but that voltage regulation devices were sufficient to mitigate voltage issues without reconductoring when dynamic load and generation behavior was considered • Implementation of some of the studied integration solutions requires system-level communications investments not included in these cost estimates. • Energy storage can be effective at addressing overvoltage issues if operated to mitigate these violations • Protection costs were a significant portion of overall costs for one third of the circuits modeled. Voltage issues dominated in the other cases. • Integration costs generally increase with penetration level. At 100% of feeder thermal rating, costs ranged from \$1.088 million to \$5.016 million, depending on the circuit
[51] (2016)	Feeder level, for 14 sample/ representative feeders in Virginia (Dominion Virginia Power's distribution system)	• Perform power flow simulations on the feeder • Compare results with different time-series simulation approaches	Distribution system upgrade/integration costs	0–100% of feeder thermal rating	• Costs vary significantly depending on the specific feeder • Costs vary significantly depending on the location and size of the DPV. DPV at the end of the feeder tends to have higher costs. Costs for large DPV in a limited number of locations tend to be more than for smaller units spread throughout the feeder. (This study assumes DPV is distributed evenly throughout the circuit without clustering) • High penetrations of PV may require additional system-wide upgrades for communications, protection, and controls which are not included in this study • Energy storage can be very effective at mitigating violations but may not currently be cost-competitive with other options • Integration costs generally increase with penetration level. At 100% of feeder thermal rating, costs ranged from approximately \$2–\$10 million, depending on the circuit and scenario

changes to the infrastructure or prematurely wearing out equipment [2]. Beyond the hosting capacity, DPV may affect the operating conditions of the distribution system, as detailed in [2,3]. In order to mitigate these effects and maintain reliable grid operation, it may be necessary to replace or modify communications and controls equipment, change control and protection schemes, upgrade the rating of devices on the distribution circuit, and/or upgrade distribution lines. We refer to the costs associated with these modifications *distribution system upgrade costs*. Notably, the presence of DPV may also enable deferral of line or other system upgrades.

Some prior analysis been performed on distribution system costs [4–12]. However, inconsistent terminology and sparse underlying information on how costs were obtained make it difficult to interpret and compare results from the literature. A standardized set of cost metrics has not emerged. Some studies also combine the effects of DPV with other distributed energy resource (DERs), including biomass, storage, and wind. This is further complicated by the fact that true variability in costs is high, and depends heavily on several factors, including: the location of PV systems on the feeder; feeder and substation characteristics (including network type, existing equipment on the grid, electrical characteristics, length, peak load, number of customers, etc.); and the selected integration approach, which is itself influenced by multiple actors within utilities and regulatory bodies. Even utilities, who are privy to much more cost information than most researchers or the general public, struggle to accurately predict costs associated with incorporating very high penetrations of DPV.

In this work, we seek to advance the state of understanding of grid integration costs for the distribution system through the following contributions:

- Reviewing prior literature and the current understanding of distribution system costs associated with DPV,
- Introducing of a transparent framework for assessing costs of distribution system upgrades required for maintaining grid reliability in the presence of PV,
- Identifying the key drivers of distribution system upgrade costs,
- Proposing a consistent set of terminology for distribution system costs that recognizes the lack of a single standard set of costs, and
- Clarifying the difference between distribution upgrade costs and interconnection costs, as well as the difference between the cost to integrate PV onto the bulk power and distribution systems.

Overall, this effort aims to clarify issues, terms, and concepts in order to facilitate support for utility and policy decision makers.

Section 2 reviews prior literature related to distribution system costs. Section 3 presents a taxonomy of distribution system upgrades that may be required to integrate PV and outlines a bottom-up approach for calculating distribution upgrade costs on a specific feeder as a function of penetration level. In Section 4, these costs are discussed in the context of prior work as well as the total costs and benefits associated with PV and other energy generators.

2. A review of prior cost analysis on distribution system costs associated with DPV deployment

Prior work related to distribution system costs has generally fallen into one of three categories: 1) analysis of distribution system costs for specific feeders or regions, typically for one or several DPV penetration levels, 2) examination of the potential for different low-cost solutions to expand the hosting capacity of specific distribution systems, without explicitly calculating the cost of these upgrades, and 3) development of general frameworks for analyzing distribution system costs associated with DPV. In the following sections, we review work falling into each of these categories.

2.1. Prior work on distribution system costs associated with DPV

Table 1 provides an overview of prior work that estimated distribution system costs associated with the presence of DPV. The SGIP study [5] presents empirical data from interconnection reports on the total cost of mitigation and interconnection facilities required to safely and reliably connect DPV to several different grids in the United States. It is of note that information on distribution system costs from interconnection reports is reflective of costs to interconnect larger DPV systems—hundreds of kWs to tens of MWs in size—rather than smaller systems installed on residential or small commercial rooftops. All other analyses involve simulating the effects of DPV on the distribution system, and then using the results as a basis for determining required system modifications and calculating cost. Heuristics have been used to select approaches for mitigating operational violations. Generally, analyses have either used the hosting capacity approach [6,9,10] or network planning tools [4,7,8]. Some of these studies consider potential impact of smaller rooftop DPV systems as well. Where information on the size of systems assumed was available, this is given in Table 1.

Work in this area has focused on networks in either in European countries or the United States (U.S.). It is of note that distribution systems in the United States and Europe have different configurations and characteristics. For example, European low voltage (LV) networks typically provide 3-phase, 220–240 V service to dozens or hundreds of customers from a single transformer. In the United States each secondary (low to medium voltage) transformer serves only a few customers, and most residential and small commercial loads are served with single-phase 120 V supply, while higher voltage, 3-phase service is provided to large commercial and industrial loads. The single-phase loads are often provided by extensive single-phase medium voltage (MV) laterals not found in European systems. The mounting of distribution lines can also be different, with many MV networks in Europe buried and LV networks mounted on buildings. Additionally, utilities are subject to different regulations in different countries. These factors can contribute to differences in the cost of integrating DPV. The MIT Future of Solar study estimated costs for both European and U.S. network designs, and found a significantly lower increase in distribution costs compared to a no-PV scenario for U.S.-type networks [8]. Literature on distribution system costs associated with DPV deployment in countries outside of Europe and the United States is lacking. Grid integration costs for other Organization for Economic Co-operation and Development (OECD) countries were published in reference [13], but distribution system costs were only separated out for Germany, and it was unclear what costs the authors included in this category or how the results were obtained.

We found a direct, quantitative comparison between results shown in Table 1 to be difficult for several reasons:

- Inconsistency in costs that were included in each study, as well as inconsistent terminology used for different cost categories.
- Inconsistency in units used for both integration cost and penetration, with insufficient information included to convert between units. In some cases, integration costs represented marginal costs, whereas in others, they appeared to be average costs. Additionally, the cost equations vary, with some authors discounting lifetime equipment costs back to present values, while others simply summing all upfront capital costs.
- Variation in the methodology and assumptions, including: assumptions about DPV system sizes and distributions, loads and load profiles, the solar resource, and treatment of hosting capacity, among others. In many cases, little data were provided on the underlying methodology and assumptions. Consensus in the literature is that results can be sensitive to these factors.
- Information on how input cost data are obtained is often missing from most prior work. Some sources [5,9,11] include unit costs data for a few specific upgrades, but this data is not typically published.

In some cases, papers state that this is due to the proprietary nature of much of this data. This makes it difficult to unpack cost drivers or build off of prior literature to analyze costs in other scenarios, or with even greater penetrations of PV.

Although we could not draw a quantitative comparison of prior results, several common themes have emerged:

- Costs incurred on the distribution system vary significantly depending on locational factors, loads, the status of the rest of the power system, and strategies used to integrate DPV. In effect, the shape of the curve illustrating costs versus penetration level is not consistent between different scenarios. Accordingly, a generalized cost of distribution integration for DPV cannot be obtained.
- Distribution system costs are higher when PV systems are clustered together and located further from the substation. They also tend to be higher in rural areas, which are currently more likely to be lightly loaded, have a lower rated capacity, and host larger PV systems located further from the substation than urban grids.
- Careful siting of PV systems can significantly reduce the impact on the distribution grid and associated costs.
- Increased flexibility in the distribution system, achieved through the expanded use of demand side management or distributed storage, could significantly reduce distribution systems costs, especially at high penetrations.
- Advanced communications and controls, which are still being developed, will likely be required for low-cost integration at very high penetrations of PV, in part because of their ability to increase the flexibility of the system.

While several studies pointed to increased flexibility or the use of advanced communications and controls as potentially low-cost options, prior works have explored the cost of these strategies in-depth or considered the full suite of potential options. There has been other cost-benefit research on smart grids as a whole that has included information on advanced communications and control costs [14], but costs triggered specifically by increased penetration of PV, versus other system drivers, are not clearly identified or allocated. Additionally, because advanced communications and controls for smart grid applications are still being developed, and solutions are often customized, significant uncertainty around these costs exists.

As shown in Table 1, the Imperial College of London study [4] reports negative numbers in their range of possible integration costs. This is because this study defines total integration cost as the cost incurred on the grid due to the presence of PV minus the benefit provided by the PV to the grid. In this case, the benefit was provided in the form of reduced distribution line losses and deferral of distribution line upgrades. Notably, DPV could provide several monetizable benefits to the distribution and/or bulk power systems including reduced generation capacity costs, deferral of transmission line upgrades, reduction of transmission line losses, hedges against future fuel prices, and improved resiliency of the power system, for example during natural disasters [15] (although the ability of PV to improve resiliency of the current power system is still subject to debate). Like cost, benefits are highly dependent on the scenario and assumptions, and are not generalizable. Inconsistency in what costs and benefits are included in the calculation of grid costs makes it difficult to compare prior work. Keeping track of which parties realize these benefits (and incur the costs) is also critical for understanding competitiveness of a given generator. Additional prior analyzes that have attempted to assess the benefits or value, but not cost, of DPV to distribution systems include [15–17].

The costs in Ref. [18] represent the costs to integrate all DERs into the distribution system; 90% of the DER is assumed to be DPV, while 10% is assumed to be biomass. In scenarios where multiple DERs are present or there are multiple motivations for upgrading distribution systems (e.g. advanced communications and controls that improve reliability of service or allow for the use of time-of-day pricing, in additional to allowing for the successful integration of DPV), it may be difficult to attribute costs to DPV specifically. This is discussed in more detail in Section 3.

2.2. Prior work on expanding the hosting capacity of DPV

Multiple papers have explored the potential for expanding the hosting capacity of DPV via the use of advanced or “smart” inverters for real and reactive power control [2,20–28]. The potential for using dynamic curtailment to expand the hosting capacity of a mix of DERs—including DPV—on European distribution systems was also studied in [29,30]. There is general agreement among the literature that these solutions could enable expanded hosting capacity; the degree of expansion possible is dependent on loads, the location of the DPV, the presence of voltage regulators in the distribution system, electrical and physical feeder characteristics, and the control algorithms used (e.g. fixed power factor (PF) versus voltage-dependent PF schemes). This would allow for the incorporation of higher penetration of PV onto the distribution system while avoiding the need for distribution system upgrades. Because voltage regulation capability has been previously required in some countries (e.g. Germany), and advanced inverter features are typically already integrated into most inverters for sale worldwide, the use of advanced inverters typically does not change customer capital or O&M costs. The use of advanced inverter capabilities can, however, impact distribution system losses, and in some situations may require decreasing real power production from PV, both of which can impact utility operations costs. Curtailment of real power output would also effectively increase the levelized cost of energy or LCOE for the DPV generators. However, prior work [29,30] has found that dynamic curtailment of DER output by less than 5% could expand the hosting capacity significantly, so increases in LCOE may be small. Currently, for customer- or third-party-owned, rooftop PV, the ability of the utility to curtail output may be limited by regulations, thus modified regulations may be required to enable use of curtailment across a greater number of systems.

Prior work has also demonstrated that the hosting capacity of DPV is sensitive to the location of the DPVs in the distribution system [2,27,31–35]. Thus, controlled siting of DPV generators could allow for the incorporation of higher penetrations of PV while minimizing grid costs. Currently, grid integration costs that can be incurred by PV developers in the interconnection process may influence the decision to site some DPV at certain locations; however, there is currently no mechanism that allows utilities to choose whether or not DPV is placed at specific locations, and this would require the development of new policy frameworks.

Finally, several papers have examined potential for the use of on-load tap changers (OLTC) [11,21,26] or modified OLTC controls schemes for mitigating voltage violations and expanding the hosting capacity of DPV. Such devices are common in the United States, but less so in Europe. These studies found that the use of an OLTC could expand the hosting capacity, but that the degree of expansion depends significantly on characteristics of the network and distribution transformer, and on uncertain information about loads profiles and the distributions system models. Kolenc et al. [21] also found that increasing the size of the MV/LV transformer could also expand the hosting capacity. As discussed in Table 1, [11] showed that the cost-competitiveness of this option compared to network reinforcement (or reconductoring) depends on the PV penetration level. Per unit, OLTC and distribution transformers are significantly more expensive than the expected cost of enabling advanced inverter features.

While only [11] explicitly calculates costs, this body of work provides simulation of the hosting capacity (below which no distribution system costs are incurred) on a diverse set of networks, illustrates how costs could vary significantly depending on the choice of mitigation solution, and demonstrates the potential of several low-cost options for expanding the hosting capacity. Research on the best control schemes for voltage regulation is ongoing, and it may be possible that new algorithms could lead to greater expansions in the hosting capacity using these approaches in the future.

2.3. Development of frameworks for calculating distribution system costs associated with DPV

Electric Power Research Institute (EPRI) has recently published a description of a general framework for calculating distribution system costs associated with DPV, but has not yet published cost modeling results using this approach [36]. Their framework involves simulating the impact of PV on a distribution feeder, determining violations to grid operating conditions, selecting approaches for mitigating these violations, and then calculating the total cost of mitigation. This is similar to the approach used in some prior work cited in Table 1, including [9,18]. EPRI proposes selecting a set of feeders to represent the full distribution system, for example via clustering analysis [18,28,37]. The authors additionally point out that the presence of DER increases the interaction between the distribution and transmission systems, and that constraints on each of these systems should be aligned when conducting analysis. This work includes guidance on integrating distribution and transmission system models, as well as incorporating distribution system costs into a comprehensive cost-benefit analysis of PV.

These works contribute significantly to the development of procedures that can be used to better assess the costs and benefits of DPV to the distribution system—and in the case of the ERPI study, society more broadly—and begin to coalesce around a common categorization for distribution system costs. However, they do not include definitions of standardized cost metrics, underlying unit cost data, or guidance on how to allocate the cost of system upgrades that have multiple motivations for adoption (e.g. new communications systems, energy storage—see Section 3 for discussion).

2.4. Gaps in prior work

The study of DPV distribution grid integration costs is relatively new, with most prior work published within the last three years. The literature has helped to clarify the challenges associated with calculating these costs, illustrated some potential cost drivers, and demonstrated that the cost of integrating DPV onto the distribution system can vary widely depending the mitigation strategies selected, the characteristics of the network, load profiles, DPV energy production, and the location of generators on the feeder. However, there are still significant gaps in the literature that need to be addressed in order to fully understand distribution grid integration costs. One issue is the lack of published information on underlying cost assumptions. As discussed above, the proprietary nature of certain cost and network data often make these data difficult to publish. Without information on the unit costs of different mitigation strategies, it is very difficult to unpack cost drivers or to compare different mitigation strategies. Additionally, this increases the “barrier to entry” for conducting this type of analysis, because data must be obtained from utilities or other sources for each study; this can be difficult for newcomers to the field, and is a time-consuming effort often requiring the use of a non-disclosure agreement (NDA). The California Public Utilities Commission (CPUC) did release a database of costs per unit for components often required to integrate PV into California utility systems in September 2016, with the goal of increasing transparency and decreasing costs and uncertainty associated with the interconnection process [38]. This database represents a step towards addressing this data gap. However, this database only contains information on strategies currently employed by California utilities when incorporating larger PV into their systems; both unit costs and mitigation strategies employed will vary depending on PV system-size, utility, state, and country, and new options for mitigating the impacts of DPV are emerging.

A consensus on terminology and metrics for analyzing the costs and benefits of DPV to the distribution system has also not yet emerged from the literature. There is not a standard definition of distribution grid integration costs, including what costs should be categorized under this heading or how this cost should be calculated. The metrics and units used for grid integration costs (e.g. $, $/kW, $/kWh) also vary, with insufficient data provided to convert between units. This inconsistency makes it very difficult to interpret and compare prior work.

Additionally, while some studies [6–8,11] calculated costs on individual feeders over a wide range of penetration levels, the literature is limited and very high penetration levels are not often considered. Prior cost analysis has also only considered a limited set of possible options for incorporating DPV, and we do not yet have a clear and complete picture of the relative cost of all available options. To our knowledge, analysis of costs associated with the use of advanced communications and controls strategies has not been published. Validation of the ability of cost models to accurately estimate cost is also not generally available. Finally, as discussed in Section 2.1, all prior cost analysis has focused on distribution systems in the United States or Europe, and very little is known about what these costs might be in other countries.

3. Proposed approach

In this section, we outline an approach that begins to address some of the gaps in prior work identified in Section 2.4, proposing a standard set of cost metrics (terminology, equations, and units), as well as guide for categorizing and allocating different costs. This approach is intended to improve the ease, transparency, and consistency associated with calculating distribution grid integration costs as a function of penetration level on a given feeder, without being overly prescriptive about methods and assumptions.

There are many components to distribution grid integration costs. As discussed above, these costs may be positive or negative, with negative cost representing a net benefit to the grid. In general, the distribution grid integration costs are split into three domains, illustrated in Fig. 1:

1) *The (near) zero cost domain*: A domain where costs are near zero, corresponding to penetrations below the hosting capacity, although the hosting capacity itself depends on uncertain input assumptions, including customer loads and the spatial distribution of the DPV. Non-zero costs in this domain could include interconnection costs or the cost of any changes in distribution line losses; these two costs are explicitly defined in Section 3.1.
2) *The quantifiable cost domain*: A domain where modifications to the distribution system (feeders and substations) equipment or controls (and/or the use of advanced inverters by DPV generators) are required specifically for mitigating the impacts of DPV on distribution system operations. In this regime, distribution grid integration costs can be clearly defined and are quantifiable. However, costs will be dependent on the mitigation strategy selected and the specifics of the feeder, loads, PV resource, etc.
3) *The fuzzy cost domain*: A domain where system-wide upgrades are undertaken, which may improve the ability to host DPV on the distribution system, but which would also provide additional benefit to utilities (at either the distribution or bulk power system level) and/or consumers, and whose adoption is motivated by multiple factors. These system-wide upgrades could include, for example, changes to the communication infrastructure or supervisory control and data acquisition (SCADA) software, the use of distributed storage, or other smart grid upgrades. It is likely that distribution upgrade costs will be much more difficult—maybe even impossible—to attribute to DPV especially as the overall power system modernizes and interaction between bulk power and distribution systems becomes more complex. While these costs are shown in the high penetration region, system-wide upgrades may occur at lower

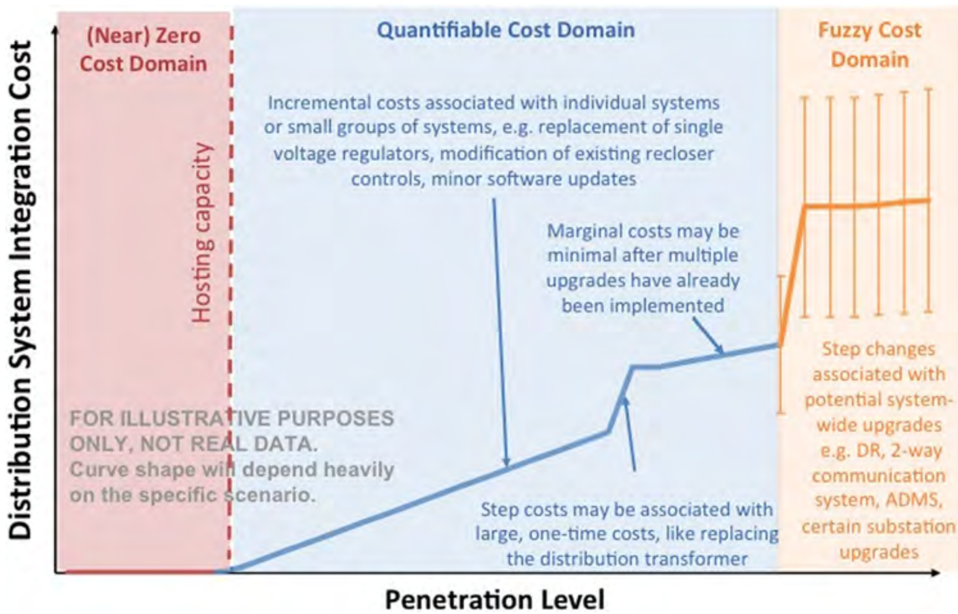

Fig. 1. Illustration of the three regions of PV integration costs: (near) zero cost (hosting capacity), increasing, quantifiable costs, and difficult to disaggregate system-level effects in the fuzzy cost domain. Note that fuzzy costs may also occur at lower penetration levels, and that it is possible for the quantifiable cost domain to extend to very high penetrations. Curve is shown for the purposes of illustrating potential cost drivers only, and is not based on real data; the shape and magnitude of the curve will be highly dependent on the specific scenarios.

penetration levels as well, for example if pre-emptive or forward-looking upgrades are undertaken, or if the utility decides to upgrade its system at lower penetration levels for other reasons (e.g. to improve system visibility and reduce outage times).

As discussed in Section 2, there is a substantial body of literature on approaches for computing the hosting capacity and understanding the zero-cost domain. In Section 3.1, we outline a cost analysis approach applicable for domain 2). In Section 4, we discuss possible options for calculating costs in domain 3), and highlight associated challenges.

3.1. Calculating distribution system integration costs in the quantifiable cost domain

3.1.1. Distribution system integration cost breakdown

The total distribution system cost, C_{DS}, can be defined as follows:

$$C_{DS} = C_{DU} + C_{IC} + C_{DL} \tag{1}$$

where C_{DU} is the cost of any upgrades to the distribution system equipment or controls required for maintaining grid operating conditions and reliability, C_{IC} is the cost of interconnection, and C_{DL} is the cost associated with distribution line losses. C_{DS} is a *net cost* in the sense that it should be compared to a reference case without DPV, and may be higher or lower than the costs in that reference case; C_{DS} could be lower in the case with DPV if, for example, the presence of DPV enables line upgrade deferrals or substantially reduces distribution system losses. All of these costs are a function of both DPV penetration level and time for a given feeder and scenario. Ideally, calculation of C_{DS} would eventually be integrated with analysis of other DPV costs and benefits, as discussed in Section 4.

C_{IC} includes the cost of equipment required to physically link the DPV to the distribution system as well as the soft costs associated with the interconnection process (e.g., interconnection feasibility, system impact, and facilities studies, if required). Interconnection cost may be borne either by the PV system owner or the utility, depending on the market. As discussed above, the soft costs of interconnection are sometimes already included in calculations of LCOE [39], and care should be taken to avoid double counting these costs. Typically, interconnection soft costs have been collected via interview or by examining project cost data from utilities and/or project developers [39,40]. These will be project specific, and could vary depending on several factors, including how easily utilities can assess the potential impact of DPV, and if certain projects are fast-tracked for approval; new approaches are currently being developed to reduce the soft cost associated with the interconnection process, and these costs may come down over time [38,40,41]. The cost of installing any new distribution lines or other hardware required to physically link a DPV system to the grid would also be included in C_{IC}; these can be calculated by determining the distance between the proposed DPV site and the nearest distribution circuit (if any), the required size of the connecting conductor, and then multiplying by the materials and installation cost per length of that conductor type. The net present value (NPV) of these interconnection costs as a function of penetration, p, can be calculated according to Eq. (2):

$$C_{IC}(p) = \sum_{n=0}^{N} \sum_{i(p)} \frac{ONC_{IC,\ i}}{(1+d)^n} \tag{2}$$

where:

- n is the year index.
- N is the planning horizon or planning period, in years.
- d is the discount rate.
- $ONC_{IC,i}$ is the total overnight capital cost of interconnection associated with generator i.

C_{DL} will depend on the behavior and status of the bulk power system. The change is power losses can be readily calculated by comparing the time series power flow with and without DPV present at each penetration level, as previously outlined in [19,36,42]. The NPV of C_{DL} can be defined as:

$$C_{DL}(p) = c_{Loss} \cdot \left(\sum_{n=0}^{N} \frac{P_{PV}(p) - P_{ref}}{(1+d)^n} \right) \cdot \Delta t \tag{3}$$

where:

- c_{Loss} is the cost of loss compensation, in \$/kWh.
- $P_{PV}(p)$ are the total power losses within the distribution grid with DPV at penetration p, in kW.
- P_{ref} are the total power losses within the distribution grid in a reference case without DPV, in kW.
- Δt is the time step of the time series power flow simulation.

The remaining challenge is then to calculate distribution system upgrade costs (C_{DU}) as a function of penetration level for a specific scenario and set of assumptions, which we dedicate the remainder of this section to.

One challenge with understanding the cost of integrating PV has been selecting a reference case for comparison. While a PV system may trigger certain distribution system upgrades at the time of install, it may allow for the deferral of other distribution system upgrades in the future, or required upgrades may provide additional value for other technologies (e.g., other DERs) in the future. Because of this, we propose the definition of C_{DU} on a specific feeder at a given penetration level, p, as the net present value (NPV) of the difference between the total distribution system upgrade cost with and without DPV over a specific planning horizon:

$$C_{DU}(p) = \sum_{n=0}^{N} \frac{ONC_{DU,PV}(p, n) + O\&M_{DU,\ PV}(p, n) - ONC_{DU,ref}(n) - O\&M_{DU,ref}(n)}{(1 + d)^n} \tag{4}$$

where:

- $ONC_{DU,PV}(p,n)$ is the total overnight capital cost of all distribution system upgrades in year n with the presence of DPV at penetration p, in \$.
- $O\&M_{DU,PV}(p,n)$ is the total operations and maintenance (O&M) cost associated with distribution system equipment upgrades that are required with the DPV at penetration p, plus any changes in O&M costs of existing equipment due to the presence of the DPV, in \$. For example, any increase in regulator or load tap changer (LTC) operations sufficient to trigger maintenance or replacement would be included here.
- $ONC_{DU,ref}(n)$ is the total overnight capital cost of any distribution system upgrades that would be required in a reference case without PV in year n.
- $O\&M_{DU,ref}(n)$ consists of any O&M costs that would be incurred in a reference case without PV in year n.

Capital and O&M costs include all hardware, software, and/or labor required. This metric captures both the cost and value of PV with respect to distribution system upgrades, without blurring the distinction between these during the calculation. Upgrades that should be made regardless of the presence of DPV, even if the utility only discovers the need for the upgrade in the course of the PV impact analysis, would be included in both the DPV and reference case and thus cancel out.

Under most current U.S. regulations, the project developer can be responsible for some or all of the costs associated with required distribution upgrades. In these cases, the project developer's discount rate should be used for the costs that the developer is responsible for, and the utility's discount rate should be used for costs that the utility is responsible for.

3.1.2. Normalized distribution system integration costs

Distribution system integration costs can also be normalized by either capacity (e.g., watts) or energy production (e.g. kWh). Normalizing these costs makes it easier to compare between studies on distribution system costs, and/or to common metrics for the cost of the generation, including overnight capital costs (\$/W or \$/W$_p$) and LCOE (\$/kWh). There are several capacity-based metrics that are most useful for different purposes:

$$\text{Average cost per watt} = \quad \hat{C}_{DS,\ a} = \frac{\sum_p C_{DS}(p)}{\sum_{i(p_{max})} P_i} \tag{5}$$

$$\text{Average overnight capital cost per watt} = ONC_{DS,a} = \frac{\sum_p ONC_{IC}(p) + ONC_{DU,PV}(p) - ONC_{DU,ref}}{\sum_{i(p_{max})} P_i} \tag{6}$$

where P_i is the rated DC power output (under standard test conditions) of generator i at the maximum penetration level, p_{max}, and thus $\sum_{i(p_{max})} P_i$ is the sum of the rated power output for all DPV units on the distribution system at the maximum penetration level. $\hat{C}_{DS,a}$ is more useful for comparing the total calculated distribution system costs associated with DPV across different cost analyses, while $ONC_{DS,a}$ is more useful when comparing to the overnight capital costs of PV systems or other generators.

The marginal levelized cost per kWh at penetration p, which we call LCDS$_m$, is:

$$LCDS_m(p) = \frac{C_{DS}(p)}{\sum_{n=0}^{N} \sum_{i(p)} \frac{E_{n,i}}{(1 + d)^n}} \tag{7}$$

where $E_{n,i}$ is the estimated energy production in year n of generator i, and $i(p)$ is the set of all generators present at penetration level p. The average, levelized cost of distribution system upgrades, $LCDS_a$, is then simply:

$$LCDS_a = \frac{\sum_p C_{DS}(p)}{\sum_{n=0}^{N} \sum_{i(p_{max})} \frac{E_{n,i}}{(1 + d)^n}} \tag{8}$$

Costs normalized by either capacity or energy production could ease comparison between studies and generator costs, but because of the number of assumptions that go into calculating energy production of each generator, and the additional computations required, the capacity-based normalizations may be preferable for comparing between different studies on distribution system costs specifically.

Of course, the cost incurred by specific DPV systems that are born by either utilities or PV project developers are also of interest for evaluating economic competitiveness under current interconnection rules. Economic competitiveness is discussed in more detail in Section 4.

3.1.3. A taxonomy of distribution upgrade costs

We saw in Section 2 that variation in the costs included in the calculation of grid integration costs, as well as variability in the mitigation solutions considered, can make it difficult to interpret results from prior work. In Section 3.1.1, we clarified the costs that fall under C_{IC} and C_{DL}. Distribution system upgrades that may be required to maintain grid operating conditions as DPV penetration increases are shown in Table 2. This table should serve as an initial guide for the types of costs to include in C_{DU}. Components below the solid line are considered advanced solutions, and are not widely employed when integrating DPV today, but could be required for very high penetration levels. The cost of each type of component is dependent on several of different parameters (e.g., voltage and current ratings for transformers, relays, and reclosers; latency and number of endpoints for communication networks, VARs supplied for capacitor banks; and ground or pole-mounted configuration). Not all of these components will be required in every scenarios — only a subset of these will be selected to mitigate any observed impacts of DPV. In Section 3.1.4, we will discuss common mitigation strategies employed today.

A few items in Table 2 deserve additional discussion. Of special note are communication networks, since coordinated control of PV systems may prove to be a particularly effective mitigation at very high PV penetrations. This could include expanded control of utility owned equipment by expanding current SCADA systems or integration of advanced distribution management systems (ADMS) [43]. It could also include support for direct to PV communication through a wide range of communication channels including advanced metering infrastructure

Table 2
Distribution system upgrade costs related to DPV.

Communication networks (wireless, fiber-optic, power line)*
Communication modules*
Communication bridges for field and substation devices*
Line sensors (voltage, current)
Recloser
Recloser controller
Relay
Relay controller
Fuses
Capacitor banks
Capacitor bank controller
Static VAR compensator
Modifications to or replacement of existing electronic controllers (for relays, reclosers, capacitors, etc.)
Load tap changer/Voltage regulator
Modify settings on load tap changer
Substation transformer
Distribution transformer
Grounding transformer
Smart meters and advanced metering infrastructure (AMI)*
Distribution supervisory control and data acquisition (SCADA) software or upgrade*
Conductor (for the distribution network)
Cost to integrate new systems with existing infrastructure*
Software for demand response*
Smart breaker panel*
Li-ion battery systems (including smart control system)*
Software and hardware for dynamic PV curtailment
Any additional software required for system re-optimization and protection
Applications for Volt/VAR optimization*
Solar resource and output modeling and forecasting software
PV monitoring and fleet management applications: Other
Distributed energy resources management system (DERMS) software or upgrade*
Distribution management system (DMS) software upgrade*
Data management solutions*
Phasor measurement units and accompanying software
Advanced substation controller*

Starred (*) components in could have multiple motivations for adoption. Components below the solid line are considered advanced solutions and are not widely employed today.

(AMI), customer owned internet, cellular modems, third-party PV owner fleet-wide management systems, etc. In some cases, existing communication networks may be leveraged to implement advanced functionality at no extra cost. In other cases, increased bandwidth, reduced latency, or deployment of additional routers may be required.

Communication networks or upgrades, as well as several other components listed in Table 2, could provide additional functionality beyond the integration of distributed PV. These components are indicated with a star (*) in the table. For example, these components could also be used to manage other DERs and/or provide other value to the utility (e.g. improved resilience, outage management, or customer satisfaction). In other words, the presence of DPV would be only one of several motivations for purchasing these components, and the DPV would only "use" part of each component for grid integration. When these components are indeed utilized for multiple purposes, only a portion of their cost should be allocated to C_{DU}. This portion should correspond to the relative use of the component for DPV integration. For example, for the communication system, the total costs might be multiplied by the fraction of devices using the network. The relative-use fraction for DPV will be more difficult to determine for other components, and will require subjective approximations. The difficulty of this assignation may push such communication costs and benefits into the fuzzy cost domain. Moreover, advanced automation and control are undergoing active product development and are likely to see changes in their functionality, performance, and cost over time.

Other difficult to quantify costs include those for integration and engineering costs arising from the need for interoperability between individual systems on the distribution network. This can be a significant cost and is very difficult to predict; in our interviews, costs associated with achieving interoperability ranged from less than 10% of other project costs (for cutting-edge demonstrations) to over 100%. One source suggested that these costs could be up to 10 times higher than total project costs. However, the interoperability provided by these larger efforts will likely enable other value beyond integrating DPV; if this is the case, this cost should also be allocated according to relative use as discussed above.

Furthermore, penetrations of DPV will increase over time, and as time passes, learning and availability of more interoperable systems is expected to drive down this cost. Thus, when computing a relationship between integration cost and penetration, it would be prudent to capture possible reductions in these costs as penetrations increase; however, there is insufficient data to be able to predict this decrease at this time, and this represents a significant uncertainty in this type of analysis.

3.1.4. Mitigation approaches

Once penetration levels exceed the hosting capacity and distribution system upgrades are required, a key assumption is which mitigation approaches to consider, particularly because they vary by utility practice and regulatory regime. A set of different mitigation strategies commonly employed today could be compared, in order to evaluate the relative cost-effectiveness of different choices. Based on interviews, review of available reports, and published literature, we compiled information on what mitigation schemes are typically employed by utilities today (Table 3). Table 3 can serve as a heuristic guide for selecting mitigation strategies for initial cost analyses. Eventually, other emerging solutions discussed in Section 3.1.3 could also be considered as cost data and best practices for allocating the costs of system-wide upgrades (those falling into the fuzzy cost domain) become available.

It is of note that no clear relationship between penetration level and mitigation strategies employed could be drawn from our review. Currently available solutions have been used to successfully integrate PV at penetrations (measured as installed PV capacity/peak load) of up to 100%, and many examples of using these solutions to integrate very high penetrations of DPV exist [44].

3.1.5. Overcoming data challenges

The major challenge with quantifying distribution system integration costs in this way is the need for detailed data about the distribution network and unit cost of different upgrades to incorporate into the power system simulation. However, without such detailed data and power system analysis, cost results will be inaccurate and potentially misleading, particularly because of the strong dependence of results on specific feeder and DPV characteristics discussed in Section 2.

In Section 2.4, we discussed how much of this required data is not publicly available. Data that is available is specific to limited geographic regions (mostly California) and largely focused on larger system interconnections. A key area of future research is to develop open datasets for these costs. In on-going work by the authors, we are working to create a database of costs of distribution system upgrades in Table 2. To circumvent issues associated with disclosure of proprietary information, such research typically requires collecting cost data from a large number of sources such that the data can be aggregated and anonymized, and only statistics of the costs of each part released publicly.

3.1.6. Other considerations

There are many assumptions that need to be made in simulating the impacts of DPV on the grid, including assumptions about load profiles, PV system outputs, and the location of DPV systems on the circuit. Significant uncertainty exists around each of these input assumptions. Sensitivity or Monte Carlo analysis may be performed to assess the possible implications of these uncertainties.

In prior economic analyses, people have used either stochastic [32] or behavioral economic [45] models to determine where DPV is

Table 3
Common mitigation approaches employed today.

Violation	Mitigation approaches	Notes
Overvoltage	• Advanced inverters • Modification of voltage regulator equipment or increased use of voltage regulators (LTC, SVC, capacitor banks) • Modifications to voltage regulator controls equipment • Energy storage	Advanced inverters are most commonly used for power factor (PF) control. Energy storage is employed much less frequently.
Undervoltage	• Addition of capacitors • Modification of capacitor controls	
Voltage stabilization	• PF control via inverter • Modification of capacitor bank control settings • Reconductoring	Reconductoring is not a preferred solution due to expense, employed only if necessary
Overload	• Transformer replacement • Reconductoring • Energy Storage	Energy storage may provide a cost-effective alternative to major transformer or line replacements, even at current prices
Protection	• Change fuse size • Installation of additional reclosers, relays, or fuses or change the location of these devices on the circuit • Update substation protection schemes • Use of advanced relay controls/functions	
Harmonics	• Harmonic filters	
Device movement	• Change low-frequency trip settings of the PV inverter to reduce frequent tripping during frequency drops	
Anti-islanding	• Built-in inverter functionality • Direct Transfer trip • Coordinating tripping of PV systems	

deployed on the distribution system. As discussed in Section 2.1, clustered DPV tends to have a larger impact on operating conditions, particularly when located far from the substation; prior research has indicated that such clustering may occur, for reasons including the existence of neighboring systems and spatial correlations in environmental, policy, and socio-economic conditions [46]. Thus, a range of customer adoption models should be considered in order to capture a spectrum of potential costs.

4. A holistic view of PV: distribution system costs in context

In general, economic competitiveness of a product is defined by the difference between its benefits (also referred to as value or utility in the literature) and costs, and is relative to a particular actor in the market. For example, PV may be economically competitive for a homeowner if their electricity bill savings exceed the cost to purchase the PV system, but not economically competitive for the utility if the costs they incur for integrating the system into the grid exceed value provided to the grid, or if the costs cannot be recovered by increasing consumer prices. Economic competitiveness depends on a complex set of market, policy, cost, and technical factors; EPRI provides a discussion of relevant metrics for different parties in reference [36].

Taking a comprehensive view, the total costs and benefits associated with PV (or any energy generator) are comprised of four elements:

1. The lifetime cost of the generator itself, typically represented by the LCOE.
2. The costs and benefits incurred at the bulk power system level when the generator is added to the system.
3. The costs and benefits incurred at the distribution level when the generator is added to the system.
4. Externalities associated with the production, installation, operation, decommissioning of the generator, as well as delivery of its energy to the consumers. While methodologies and assumptions vary widely, prior analysis has indicated externalities associated with PV represent a net benefit compared to the most likely non-renewable energy sources for a given scenario [52–55].

In this work, we have focused on advancing the understanding of one of these elements (number 3) specifically for DPV systems (rather than centralized PV installations connected to the transmission system). It should also be noted that all energy generators, not just DPV, have associated interconnection and grid integration costs [1]. However, the uncertainty and variability in output of PV systems in general (as well as wind, and other variable renewable energy resources), along with the distributed nature of DPV, pose unique challenges.

As mentioned in Section 1, costs in both 2) and 3) are often referred in the literature to as "integration" or "grid integration" costs. However, in general these systems are modeled using different approaches and represent distinct challenges. The best practice for bulk power system analysis involves conducting unit commitment and economic dispatch analysis for cases with and without PV, and then comparing the total system costs in each case. This analysis can be conducted under a range of assumptions about fuel prices, existing generators and line capacities on the system, loads, and weather conditions. However, it is difficult to define an integration cost on the bulk power system, and isolating the costs and benefits may be impossible or misleading. For example, if fuel costs are included, then adding PV to the system will always reduce total system cost; these fuel savings from displaced generators dominate the cost of any grid upgrades required to integrate the PV. Selecting an appropriate base case for comparison is also difficult. An understanding of how to satisfactorily calculate and express bulk power system integration costs is still being developed, and a consensus on whether or not this can or should be done at all is yet to be reached. Milligan et al. [1], Agora Energiewende [47], and Denholm et al. [42] provide an overview of the challenges that have been encountered in analyzing total grid integration costs associated with PV and wind.

At high penetrations of PV, additional flexibility in the power system may be required to deal with the variability of the PV resource. Flexibility can be added on either the bulk power or distribution systems, or both. In these situations, it may be difficult to separate analysis of the cost and benefits associated with these two systems. For example, the addition of DPV plus storage to a feeder may enable deferral of transmission line upgrades, or reduced capacity and fuel costs associated with generators on the bulk power system. Understanding these complex interactions requires increased coordination on the development of more integrated or complementary analysis tools between utilities and research groups. The use of standardized terminology among analysts is also critical.

The costs and benefits in all of the categories listed above have some dependence on penetration level, although this dependence is often non-linear, complex, and involves a multitude of factors. The dependence also differs between each category. For example, costs and benefits incurred on a distribution feeder are often dependent on the percent of PV capacity installed as a fraction of load. Additionally, as PV penetration increases, the marginal economic value of PV could decrease due to overproduction during the day [48]. However, installed PV system prices and thus LCOE have decreased as function of the total amount of installed PV capacity, due to experience effects. It is very important to keep track of the costs and benefits that are incurred by different parties to be able to understand the competitiveness of different energy sources and design good policies and markets.

Externalities are dependent on characteristics of the generators and systems, and therefore coupled with assumptions and models for LCOE, distribution integration costs, and transmission system configuration (note that externalities may be accounted for qualitatively or quantitatively, wherein they are assigned an economic valuation using a variety of techniques, e.g. as in [56]). The costs and benefits in all four categories listed above can be strongly influenced by market design, market conditions, and policy. If subsidies are included in the analysis of total costs and benefits, for example in the LCOE calculation, an additional cost representing the cost of the subsidies to the government should be included to capture the full economic cost. Subsidies exist today for multiple renewable and non-renewable energy sources, depending on the location.

5. Conclusion

The review of prior literature has identified the need for a more transparent and standardized approach for assessing grid integration costs associated with PV systems. We have presented an approach for assessing distribution system upgrade costs, and discussed this in the context of total costs and benefits associated with PV. We have identified three major challenges to understanding these costs at high penetration levels: the interaction between the distribution and bulk power systems, the ability of certain required distribution upgrades to provide other benefits to utilities or customers that are difficult to quantify, and the uncertainty in the cost of advanced solutions and their interoperability as a function of time. We also find that costs are dependent on a number of assumptions, and no generalized “cost of grid integration” for PV can be obtained.

Next steps involve applying this methodology to compute distribution upgrade costs on a set of select feeders under different assumptions. These case studies will serve to validate this approach and identify difficulties with implementing it in practice. Significant future work is also required to integrate models of DPV impacts on the distribution system, bulk power system, and society, and obtain a complete, holistic view of PV costs and benefits.

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