STUDIES ON THE TIME AND LOCATIONAL VALUE OF DER

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ABSTRACT

Electric utilities are changing how they plan and operate their facilities as a result of policy incentives, technological improvements, and consumer choices that promote the increased use of distributed energy resources (DER). DER integration policies in New York and elsewhere will require utilities to more inclusively account for distributed resources and to identify where DER can be best integrated to provide the greatest benefit to the entire electric system. This paper describes the technical results of a study with Consolidated Edison of New York that demonstrated methods for valuing the temporal and spatial impacts of DER on network distribution systems.

INTRODUCTION

The role and operation of the U.S. electric power system is changing as a result of policy incentives, technological improvements, and consumer choices in technology and service. Consumers have increasing choice and control over their electricity service with increasing accessibility to on-premises generating systems, such as solar photovoltaic (PV), energy storage, wind, combined heat and power, and energy efficiency measures to manage when and how they consume grid-supplied electricity. Collectively these demand-altering measures are referred to as distributed energy resources (DER).

Regulatory initiatives in New York are developing distributed energy resource integration policies that will require utilities to more inclusively account for distributed, customer-owned resources and to establish planning processes that will identify where DER can be integrated to provide the greatest benefit to the entire electric system.

This paper describes the results of a study with Consolidated Edison of New York that demonstrated methods for valuing the temporal and spatial impacts of DER on a network distribution system [1]. This study is distinctive in that it focuses first and foremost on portraying how DER impact distribution, which is where the DER are interconnected, while illustrating the complexity and implications of incorporating DER to address capacity issues arising from load growth. The results suggest that the value of DER is not uniform across a distribution system, and cannot be simply determined by applying generalities about feeder characteristics.

NETWORK DISTRIBUTION SYSTEMS

An important factor in studying DER impacts is the type of system being modeled. New York City and other densely populated urban areas are served by extensive, urban, low-voltage networks. These low voltage networks are characterized by a meshed low voltage network that is served by numerous medium voltage feeds and MV/LV transformers, see Figure 1. These network systems are typically designed to withstand two coincident failures without interrupting loads providing reliability up to two orders of magnitude better than achieved with radial systems. Additionally, momentary interruptions, common on radial systems, are rare on urban low-voltage networks.

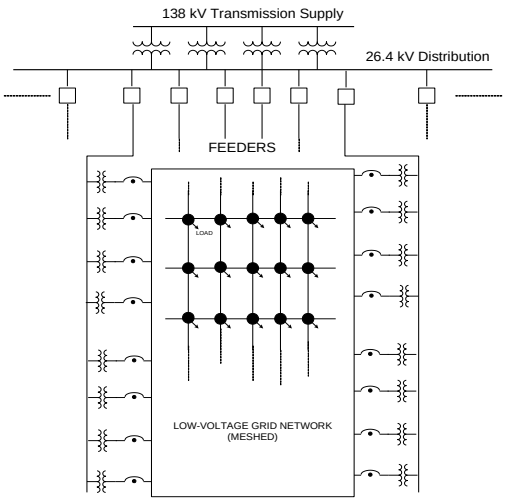

Figure 1. Typical Urban Network Distribution System

Siting and assessing DER impacts on network systems, however, can be more challenging compared with radial systems. As there are multiple pathways for energy to flow in a network system, the power injected by the DER can be quickly dispersed by the multiple junctions in the meshed grid. Consequently, the ability for DER to provide relief to an overloaded asset depends both on the system configuration and the DER location within the network. While DER installed electrically near an overloaded component will generally have greater impact on relieving overloads than DER installed father away, detailed planning assessments are required to evaluate the true extent of the relief provided.

Urban, low-voltage distribution networks also require different modeling capabilities. Networks are large and the

physical topology requires a mesh solver rather than a radial circuit solver to model power flow. One approach to modeling network system impacts is to employ analytical tools that were originally developed for modeling the transmission grid, which is also a meshed grid. However, these tools typically assume a balanced system and, therefore, do not capture any imbalance associated with the single phase load and generation.

For the purposes of this study, Consolidated Edison selected the Williamsburg network, which serves about 100,000 commercial and residential customers in their Brooklyn-Queens region. The network is comprised of 20 primary feeders operating at 27 kV serving low-voltage meshed networks through multiple transformers that have total capacity of approximately 500 MVA The peak demand is about 270 MW.

APPLYING SCENARIO-BASED ANALYSIS TO STUDY DER IMPACTS

Approach and Objective

The EPRI Integrated Grid Framework [2] served as the foundation for modeling the time and locational impacts of DER. It provides objective and substantive insights into the methods that are needed to evaluate the physical and economic implications of DER on the distribution system. The Framework, depicted in Figure 3, begins by specifying the core assumptions of the study: market conditions, DER adoption rates, and system assumptions, which are used to define a base case and scenarios that portray possible future outcomes.

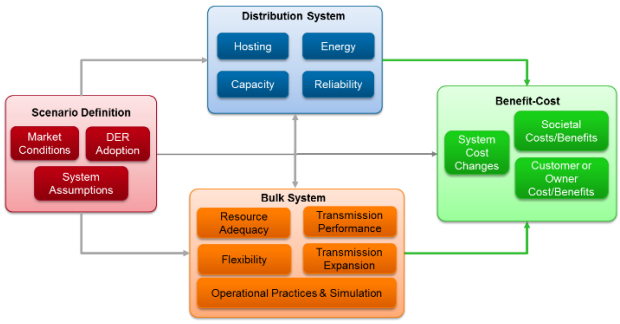

Figure 3. The EPRI Integrated Grid Framework

Energy, capacity, and reliability analyses are undertaken to identify approaches that take advantage of the DER benefits while avoiding adverse reliability impacts. Illustrated in Figure 4 are the power system criteria that are considered in this modeling study. Utilizing these criteria, distribution planners can assess DER interconnection impacts as well as how the system's operation may change over time [3]. The Benefit-Cost step accumulates all impacts and computes net benefits [4]. It requires a reference case to establish a basis for comparing DER interconnection scenarios.

A scenario-based analysis was then applied with an objective to investigate how a portfolio of DER, strategically located on the system, can be utilized as a means for meeting load growth requirements in lieu of traditional utility investments. The study identifies important characteristics that a DER portfolio must deliver in order to achieve an equivalent level of availability, dependability, and durability as provided by traditional system upgrades. Additionally, the consequences (net costs and benefits) of DER that are connected to the distribution system are also evaluated in the study.

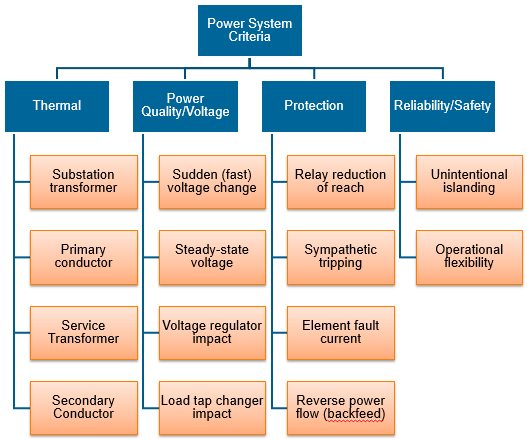

Figure 4. Power System Criteria for Impact Studies

The scenario-based analysis has two parts. The base case conducts simulations to identify the timing and location of system violations (overloads, voltage, and protection) that result from load growth and specifies how those violations would be mitigated using established utility planning processes – adding utility assets such as transformers or cables for example. This was performed over a 10-year planning horizon with mitigations being identified for each year. These results serve as a basis for comparing DER as an alternative.

In the second part, DER were added systematically, to individual loads or load aggregations (nodes), to resolve the violations. Potential DER locations were selected and raked in descending order based on their contribution to eliminating the violation, with the goal of minimizing the amount of DER deployed. In order to reasonably distribute the DER and account for potential siting constraints, the amount of DER that could be assigned to a node was limited based on assumed constraints. Repeating this for all violations over the study period provided a consolidated and consistent way to compare the cost of the DER alternative to employing conventional asset upgrades.

Study Area - Williamsburg Network

Temporal variation in system demand is an important factor to consider when examining alternatives to meeting load growth. The 24-hour demand during the 2015 summer peak day is plotted in Figure 5. As shown, the network load reached the peak level in the mid-afternoon hours and remained at or near the peak until late evening – a total of 8 hours. Consequently, using DER to replace or defer an asset upgrades must be able to offset the load over this extended period. This suggests that portfolios of multiple and diverse DER technologies would be needed to reliably meet this load-carrying requirement.

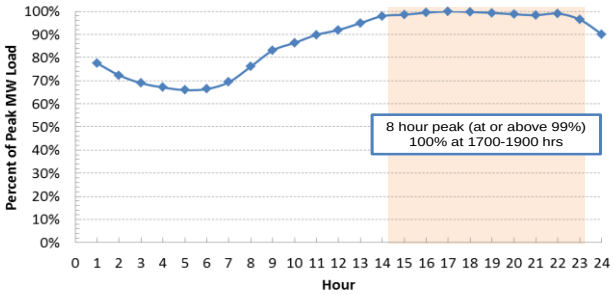

Figure 5. Normalized 2015 Peak Day Profile

DER PORTFOLIO DESIGN

In order to provide an effective alternative to traditional distribution assets, non-wires alternatives must achieve equivalent characteristics of the asset it is replacing. Thus, a portfolio of DER, rather than a single resource, was assembled with an eye toward supply diversity. Resource diversity is essential because of the uncertainty about when DER will be needed to provide essential distribution services and the degree of their availability and reliability when these services are needed the most and their durability over time.

The base-case simulations revealed system violations associated with the hours of the distribution system peak load. Different types of DER reduce the circuit's peak hourly demand in different amounts, based on their power output (or avoidance) coincidence. In addition, DER measures are subject to factors beyond the control of the utility, such as customer behavior that results in varying load patterns and what DER customers are willing to have installed on their premises. DER can include a broad range of technology, including energy efficiency, demand response, solar PV, and various types of distributed generation and energy storage. Some of these technologies may be attractive for reducing distribution peak demand (and therefore supporting the deferral of traditional investments) but may be less likely for customers to implement in a non-controlled scenario.

For this study, Con Edison constructed a portfolio of DER based on DER performance characteristics, customer characteristics and estimates of DER costs from previous deployments. The portfolio composition is illustrated in Figure 6. The simulations deployed the DER portfolio to nodes as a normalized (kW) resource. For consistency, well-defined rules direct the DER allocation in a manner consistent with the study objectives.

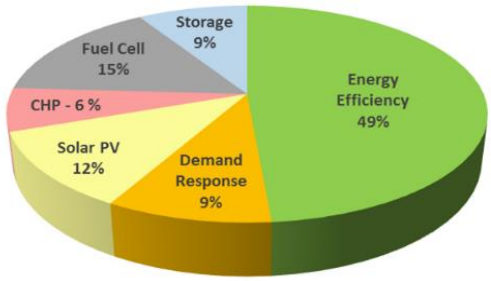

Figure 6. Con Edison Case Study Portfolio

STUDY FINDINGS

Locational sensitivity in network topologies

The effectiveness of DER to provide deferral benefits is highly dependent upon the location of the DER relative to the system constraint, and these considerations vary by system topology. The location of projected system violations (due to load growth) needing remediation and the load points where DER can be installed to alleviate them are key drivers to how much DER is required, and hence the economics of DER as a system asset.

Network systems are characterized by complex and multi-directional power flows, so the effect of DER located electrically "close" to a violation become dispersed. In some cases, dispersion is so significant that the DER may only deliver a fraction of its nameplate capacity toward mitigating a violation.

To illustrate, the example shown in Figure 7 depicts a 63 kVA violation of the flow limit on a network transformer. The total amount of DER required to eliminate the overload is shown for each node downstream from the transformer, assuming the DER is only located at that node. When DER are located directly at the site of the constraint (the transformer secondary), the required amount of DER in this case (125 kW) is already twice the size of the 63 kVA overload.

Moving two node points further away (where 240 kW of DER is required) the ratio increases to about 4:1, and increases to over 8:1 (520 kW) at the farthest node. This example illustrates how the impact of DER disperses in a network system. As illustrated, the effectiveness of DER contributions decrease significantly moving from the area substation down into local distribution assets.

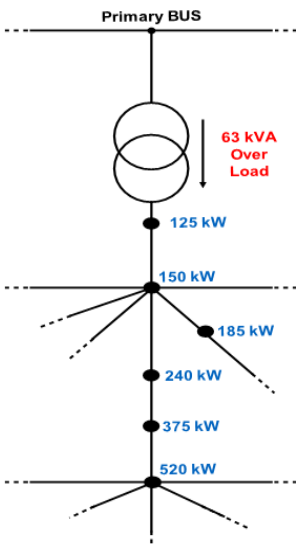

Figure 7. Total DER Output required at Each Node (blue) to Provide by Itself 63 kVA of Load-Relief to the Target Transformer

Though the numbers presented in this example cannot be universally applied for every network transformer, less DER is generally required if it can be located at nodes nearer the location of the constraint. This is not always feasible, however, due to many limitations that are extraneous to the electric power system – availability of distributed generation fuel sources, above-ground limitation on DG footprint, potential for energy efficiency and customer participation, etc.

Scenario Analysis

The base case analysis revealed multiple thermal overload violations occurring during at different points along the 10-year planning timeframe. Each of these conditions required remediation through traditional upgrades such as cable replacements, transformer replacements, etc. Both traditional utility-side mitigation options and DER solutions were identified using the analysis approaches previously discussed.

For this analysis, the amount of DER allocated to a node was not allowed to exceed the node's peak load to prevent backfeeding the network protector. Because the analysis also assumes that DER can be physically placed at the designated node locations, the required DER amounts can be regarded as the most optimal solution as it is the minimum amount of DER that resolves the system constraint.

The placement methodology assigns DER in relatively small increments, permitting violations to be resolved in a precise manner. In contrast, traditional utility-side investments generally result in additional capacity (headroom) to accommodate unanticipated load growth and growth beyond the planning period. Distribution planners aim to build headroom (typically 10%) into system upgrades to avoid having to resolve the same constraint each successive year in order to meet incremental annual load growth on the system. For example, 20-30% headroom was achieved with the network transformer upgrades in the traditional remediation solution. This approach is consistent with utility system practices and to some extent results from the nature of electric system equipment that is available only in relatively large capacity increments. To provide a more meaningful comparison of the DER and utility-side solutions, two DER alternatives were investigated – one with the minimum amount of DER needed to resolve all violations and a second providing an additional 10% headroom.

The total amount of DER required over the study period for the two DER alternatives is summarized in Figure 8. The analysis indicates that 12.1 MW of DER are required to eliminate violations due to load growth without any headroom and three times as much (36.2) MW of DER are required to achieve a 10% headroom margin.

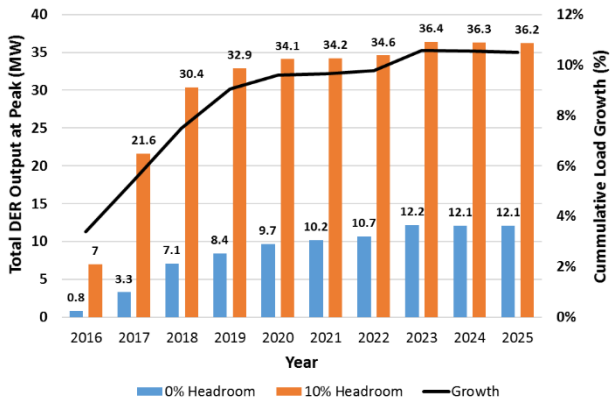

Figure 8. Total DER Output Required to Eliminate All Violations

Two factors combine to drive the large increase in required DER – the limitation on how much DER can be located at a node and dispersion of injected power across the network. Nodes are assigned DER starting with one that provides the greatest relief. As nodes reach their DER limits, more distant nodes are required to alleviate the violation. As noted previously, the efficacy of DER to relieve a particular violation declines as its electrical distance from the violation increases due to dispersion in the mesh network.

An economic assessment was conducted to summarize the results in a consistent and comparable way employing EPRI's benefit-cost methodology. Results are summarized two-fold, both allowing a comparison of the base case and the DER scenarios on an equivalent net benefit basis. Cost and benefits are first converted to a societal cost measured as the net present value of costs incurred over the study

period. The societal cost was then converted to a levelized cents/kWh using the load growth kWh as the denominator.

For the base case (no DER), the estimated societal cost of serving load growth includes five categories: distribution equipment cost; consumed energy cost; cost of losses - growth; social cost of carbon emissions; and bulk power system capacity cost. For the DER alternative cases, traditional distribution equipment costs are replaced (avoided) by the customer capital cost and ongoing expenses associated with the DER. The methodology also captures energy produced by the DER, the avoided capacity, and net change in losses, and carbon impacts.

Summarized in Figure 10 are the results of the economic analysis, illustrating net societal and levelized costs to serve load growth on the Con Edison network. Comparing traditional upgrades to employing DER, the societal costs are comparable, $118M and $126M, respectively. To provide the 10% headroom typically provided by conventional utility assets, the total societal cost was $160 million, about 36% ($42 million) more than the base case cost. Figure 9 also summarizes cost to the distribution system, comparing the traditional distribution equipment costs in the base case with the customer capital cost and ongoing expenses associated with the DER in the alternative cases.

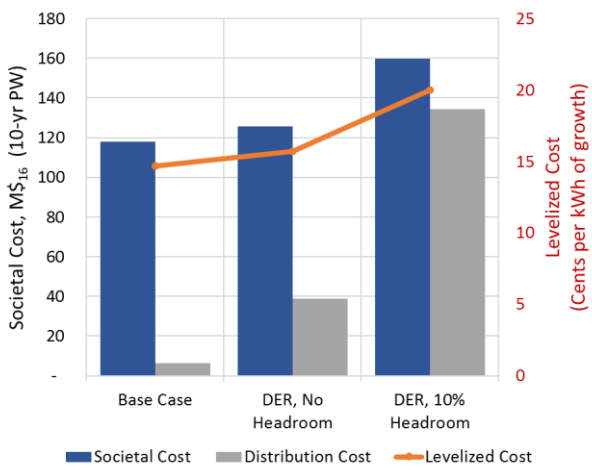

Figure 9. Cost to Meet Load Growth – Utility Solution (Base Case); DER Solution (No Headroom); and DER Solution (10% Headroom)

CONCLUSIONS

This study illustrated the complexity and implications of incorporating DER into the distribution system to address distribution loading issues and provide capacity relief. DER impacts on distribution can be either beneficial or adverse, depending on a wide variety of contextual circumstances.

Distribution systems are geographically and electrically distinct, and their characteristics vary from utility to utility and within each utility. The results from this study suggest that *the value of DER is not uniform across a distribution system, and cannot be simply determined by applying generalities about feeder characteristics like MW served, or any other single performance metric.* Comprehensive, objective, and transparent methods are required for consistent and sensible results.

The net benefits of employing DER as an alternative to conventional grid upgrades depends on a complex set of parameters. The study revealed the importance of the physical characteristics of the feeder in valuing DER and the complexity of substituting portfolios of DER for traditional distribution equipment. *The most cost-effective choice is significantly influenced by multiple parameters, including local-area load-growth rates, peak-day load profile, types of available DER and capabilities, power system design, the time and location of the grid upgrades, and customer-adopted DER.* DER may provide benefit in some instances; but it may not always be the best alternative.

The effectiveness of DER to provide deferral benefits is highly dependent on the location of the DER relative to a system constraint and the topology of the system. Individual DER, and a portfolio comprised of multiple DER technologies, have different and complex interactions with the system. Engineering analyses can establish the DER attributes needed for resolving a system capacity constraint, and this study reveals the importance of location and system topology for DER solutions to be effective.

ACKNOWLEDGMENTS

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