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Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility

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This analysis is an initial assessment of the resource potential for applying distributed utility (DU) technologies to meeting load growth on feeders within substations. DU concepts allow major utility investments in transmission and distribution equipment upgrades to be deferred or avoided by applying technologies such as generator sets, fuel cells, battery storage, or demand-side management (DSM) to the building and industrial loads served by the feeder. By applying these technologies at the feeder level, the economic and operational benefits to the utility of reduced need for new generating and transmission capacity can be compounded dramatically. These additional benefits result from avoiding distribution equipment upgrades resulting from load growth and from downsizing feeder equipment during normal replacement cycles.

This assessment of the resource potential of a generic DU technology uses time-series load estimates for about 3000 feeders comprising the entire load of a large utility. The analysis models DU resource purchase and operation using externally derived operating constraints designed to approximate the effect of economic constraints. This first glimpse at utility-wide application of DU technologies shows potential impacts ranging up to 10% of total distribution capacity after 10 years in high growth scenarios, and approaching 100% of *new* distribution capacity at lower growth rates.

The analysis involves a number of simplifications for its initial phase; nevertheless, it is the first comprehensive look at DU potential for a utility system from the level of feeder loads.

Introduction

The purpose of this analysis is to develop an initial assessment of the resource potential of distributed utility technologies for meeting needs for new distribution system capacity. The seminal idea of DU is that utilities can compound savings from DSM investments by focusing them in areas where load growth will soon require increased distribution capacity (Orans, et al. 1992). By targeting programs for specific areas, the need to purchase new distribution system equipment with higher capacity might be deferred for a number of years, or even avoided altogether. The traditional benefits of DSM programs for relief of the generation system are compounded by such deferrals, and there are also benefits to the transmission system. These are in the form of lower line losses and, in special circumstances, the need for new transmission lines (which have become difficult to site) may also be avoided.

The DU concept as derived from DSM has been expanded to include supply-side and storage technologies such as generator sets (gensets), fuel cells, battery storage, and renewables such as photovoltaics and wind (Weinberg, et al. 1992). In addition, because many of these assets are somewhat portable, they provide a hedge against larger permanent distribution system investments that may not be needed if expected growth does not materialize or a major customer leaves. In 1989, investments in the distribution system formed about 50% of all utility capital investment, and with the dramatic reduction in demand for new central generation capacity, the share going to the distribution system is expected to increase to 80% by 1997 (Feinstein, 1993). Cost efficiencies in the distribution system are an increasingly high priority for utilities, particularly in light of increasing deregulation. This is because many utilities see themselves as divesting central generating facilities to third party power producers; if transmission and distribution become the focus of their business, their competitiveness will be much more strongly tied to these aspects of their business.

A number of case studies have focused on the costs and benefits of installing DU to relieve specific problem areas in the distribution system (Orans, et al. 1992) (Shugar,

et al. 1992) (Chapel, et al. 1993). While these support the idea that DU can be a cost-effective alternative to distribution capacity upgrades, they do not provide an overview of how much impact DU might have on utility systems as a whole. This is the fundamental purpose of the initial assessment reported here, which analyzes the technical potential of a generic dispatchable type of DU asset to displace distribution capacity upgrades, albeit on a simplified, non-economic basis. The analysis focuses on time-series load estimates for all the feeders serving the entire territory of a large utility. (The typical distribution substation supplies power through five feeders to the customers in a given area.) By making simplifying assumptions about the uniformity of load growth and how feeder capacities are upgraded, a picture of DU's potential impact is assembled for a range of growth rates and equipment operating assumptions.

Although the analysis necessarily involves a number of gross simplifications for this initial effort, nevertheless it forms the first comprehensive look at how significant DU's potential impact might be and whether further, more detailed investigations are warranted.

Feeder Load Estimates

The basis for the analysis is hourly time-series load estimates for approximately 3000 feeders in calendar year 1990. Estimated loads were used because metered time-series loads from feeders are not available for more than a half dozen feeders. The estimates are constructed by the utility from their customer class load research (CLR) data for 1990, which consist of half-hourly whole-premise consumption data for a stratified random sample of 3500 customers from each customer rate class. The stratification variables include region, average daily consumption (kWh), average monthly peak demand (kW), and Standard Industrial Classification (SIC) code. Each of the metered CLR customers are assigned to cells based on these variables, and the metered loads for the CLR sample cell are averaged to form an average hourly time-series of loads for the cell for a year.

Each of the several million utility customers in the utility service territory is then mapped to a specific feeder and to one of the CLR sample cells. The hourly loads for each customer are then assumed to be well approximated by the average load for the cell scaled to match the actual monthly energy consumption reflected in the customer's billing data. (Actual metered loads are used for the 3500 customers metered as part of the CLR sample, instead of estimates from the cell averages.) Hourly loads for the customers on a feeder are then summed to form hourly customer class loads for a feeder, and typically 6 to 20 feeder class load estimates are summed to form the total feeder load estimate.

It is important to note that this process for estimating hourly loads on feeders produces a time-series of realistic, but not literally real, loads. The class load research data is designed to be used for ratemaking, and the sample is designed to provide 90% confidence at $\pm 10\%$ accuracy. Spot checks of load estimates for five feeders with metered hourly loads indicated a similar level of accuracy was present in the feeder load estimates. For feeders with numerous small customers, this process is likely to be fairly accurate because the presumably random difference between individual loads and the cell average cancel out. However, for specific feeders dominated by one or a few large customers, significantly larger, random errors may be expected unless these customers were part of the metered CLR sample. (Because the CLR sample includes many of the largest consumers, the accuracy of the load estimates is improved considerably.) The feeder class and total load estimates form a very large data set comprised of over one-half billion observations, plus ancillary data on feeder capacities, number of customers, weather data, and monthly breakdowns of feeder load composition by building/business type energy consumption.

Scope of the Analysis

The analysis had a number of specific objectives:

- Develop algorithms to assess the acquisition and utilization of feeder equipment and DU assets located at the feeder supply points, as a function of key operating characteristics and constraints. This is based on a simplified (non-economic) basis for their purchase and operation.

- Simulate the penetration of DU assets into the distribution system, and the impact on feeder equipment utilization, over time under a variety of scenarios. This is based on a range of assumed load growth rates, upgrade factors, and a genset-like DU asset's operating characteristics and constraints.

- Begin the development of an integrated, modular, expandable infrastructure for analyzing DU potential from feeder data that could be used to analyze specific DU technologies. Ultimately, incorporate the economics of feeder upgrades and DU technologies in context with the utility system, as well as more detailed operating characteristics and constraints.

- Conduct a cluster analysis to identify feeders with similar load duration curves and to identify prototypical feeders with which realistic but abbreviated system simulations could be performed for scenario analyses.

The results of our analysis are presented in the remainder of this paper. However, first we discuss the limitations of our analysis in greater detail.

Limitations on Our Characterization of Feeders

A typical utility feeder begins with the bus of a substation transformer and extends in tree-like fashion out to potentially numerous customers (although some feeders serve only one or a few large customers). As the loads served by the feeder grow with time, any one of the feeder components (transformer, wires, etc.) can become overloaded and require upgrading. The capacity of above-ground wires varies seasonally with temperature and wind speed. Our view of a feeder is a very simplistic abstraction of this system. We view a feeder as having a single identifiable capacity (in this case the winter capacity of the first wire leading out of the substation). This proxy for feeder capacity provides a somewhat realistic distribution of the peak feeder loads' proximity to their respective capacities and, hence, the time until upgrades are required.

In our analysis, upgrading a feeder to accommodate new load is a simple matter of increasing the capacity. We do not consider the numerous possible components that might be changed, nor do we consider the literal cost of upgrading. We ignore the varying costs of upgrading transformers (generally the largest cost), voltage changes, and reconductoring of above- and below-ground wires. We also ignore the reconfigurations (shifting of load among feeders adjacent to one another to balance loads) that typically occur before more capital-intensive upgrades are performed, and the fact that eventually new feeders or substations may be required.

We have also assumed that feeder loads all grow at a uniform rate. In fact, loads may grow at a different rate by time of day and time of year, depending upon the type of customers being served. For example, commercial load growth likely will predominantly occur during daytime hours, while residential load growth may concentrate during early morning and evening hours. Further, for lack of better information, we assume that load growth is uniform across feeders in the system, although we know that real growth tends to occur in specific geographic areas. We do vary load growth as a key parameter of the analysis, to determine its effect on DU potential. Actual DU impacts for a given region are probably a composite of the results presented here for uniform growth rates. Subsequent analyses will be conducted using area-specific growth rate projections, but these will necessarily pertain only to the current pattern of growth rate projections for the utility being analyzed.

This view of a feeder, while inadequate for serious distribution system planning, allows us to study the gross potential impacts of various DU technologies and implementation strategies on the utilization of distribution system assets. In one sense, our study provides an upper bound on the potential for DU because it neglects logistical and cost factors that may often prevent the installation of DU in reality. Conversely, utility distribution engineers have pointed out that the capacity of the initial wire leading out of a substation is often not the limiting factor; therefore, more upgrades may be required sooner than we project.

Limitations on Our Characterization of DU

Among the variety of DU assets and/or measures that can be used to defer distribution system upgrades, our study is limited to gensets or other genset-like assets (i.e., those that can provide pure, dispatchable capacity relief such as fuel cells, load control, or interruptible service contracts). As with feeders, our definition of a genset is simplistic. We view a genset as an asset with a specific capacity that can be dispatched at any time. Thus, our analysis does not well characterize assets that have an impact that is not dispatchable (DSM efficiency measures), for which availability is a strong function of the time-series loads (batteries), or for which output is dependent on coincident variables like weather (photovoltaics, wind generators).

However, we do attempt to account for cost-effectiveness to a first order by placing an arbitrary limit on the number of hours a DU asset may operate. A real DU installation—like a gas-fired genset—is generally limited in the number of hours it can cost effectively operate because of the high cost of its natural gas fuel compared to intermediate and base-load central-station generating plants and because of its relatively lower thermal efficiency (heat rate). At some point, its operating cost is high enough that its use to defer a feeder upgrade is no longer justified. Its use may also be limited by local air pollution restrictions. Other studies and distribution planners suggest that a limit of 200 annual operating hours is a reasonable, general surrogate for these effects. Like growth rates, we let this key parameter vary over a fairly broad range in our analysis. To estimate an upper bound on potential without conducting a detailed economic analysis, we install this genset-like DU asset whenever it can meet loads above the feeder capacity.

We also limit the DU asset capacity to 3 MW per feeder in the scenarios we analyze. This limitation also reflects economic reality in that the cost of DU is generally proportional to capacity. Perhaps more importantly, external limits on siting and operating assets like gensets (e.g., obtaining permits and complying with air quality

regulations) probably restrict their capacity to this range (Weinberg, et al. 1992).

DU Simulation

We have developed a system that simulates the operation of the distribution system through a number of years to assess the potential for use of DU assets and to study the effects on the system of various DU implementation strategies. The complexity of the distribution system demands that our model and simulation thereof be simple. This section describes that model and explains the effects it is able to simulate.

Limiting our study to genset-like assets allows a simplification in the characterization of feeders during the simulation. Because gensets can, in principle, produce power whenever necessary, there are no timing constraints in the simulation. That is, we can simply characterize a feeder's hourly loads by producing its load duration curve (LDC), a reverse sorted list of the hourly loads. It is not necessary to know the time sequence of DU needs—only the number of hours DU is usable in deferring peak loads.

Simulation Methodology

The simulation is done feeder by feeder, with no interaction between feeders. Each feeder is hypothetically operated through a number of years (10 in this study) during which its load is growing. At any step (year) in the simulation when a feeder's load exceeds its nominal capacity, it is either upgraded (its capacity increased) or it is fitted with a genset-like DU asset to displace the peak loads. As alluded before, we simplistically assume there is a location on every feeder where a genset can be sited to defer the excess loads. Several tunable parameters, discussed below, determine whether DU or capacity upgrade is selected. Once in place, a DU asset is simulated year by year according to other variable inputs that determine how many and which hours it is to operate. Figure 1 shows the simulation methodology in the form of a flow chart.

The simulation process is further illustrated in Figures 2 and 3. Figure 2 shows four years' load duration curves for an example feeder. The three dotted lines indicate the annual growth of the feeder toward its capacity. In the fourth year a genset-like DU asset is installed. The solid line shows how the feeder is relieved of its peak loads by the distributed generation. Note that the DU asset is assumed to have no capacity modulation capability. When it runs, it displaces a fixed load—in this case somewhat more than is needed to relieve the feeder of its capacity-exceeding peak. The next five years of operation are shown in Figure 3. For two additional years the DU asset is able to maintain feeder loads below capacity; thereafter, the DU asset has insufficient capacity to meet the peak load. In this example, as in all our analyses, we assume the DU asset is removed or otherwise inactivated when it is no longer capable of deferring a feeder capacity upgrade. Another reason a DU asset might be removed is that it would have to exceed its run-time limit to accommodate the feeder's load.

Simulation Inputs

A number of parameters to the simulation can be varied to study their effects on the overall penetration and performance of genset-like DU assets. Feeders are characterized by (1) *capacities*; (2) *growth rates*, which may be specified as annual MW increases or annual percentages; and (3) *upgrade factors*, which determine how much additional capacity is added when a feeder is upgraded. In practice, upgrade factors are typically around 50% to 100%, meaning an additional 50% to 100% of existing capacity is added in an upgrade.

Each DU asset is characterized by (1) *capacity*, which may be specified in MW or as a fraction of feeder capacity; (2) *maximum annual operating hours*, which serves as a surrogate for cost-effectiveness limitations; (3) *modulation ability*, which can be none, full (continuous), stepped, or continuous down to a low cutoff; and (4) *parallel/series allowance*, which determines whether multiple DU devices may operated simultaneously.

Finally, the simulation itself is controlled by several parameters: (1) *years of analysis*; (2) the *maximum DU units per feeder*, which allows for a reasonable upper limit on how much DU can be used to defer feeder upgrades; (3) the *minimum years to deferral*, which prohibits DU installations that would be too soon overtaken by load growth; (4) *additional operation hours*, which specifies hours in addition to the feeder peak hours when DU assets are allowed to operate (e.g., during system peaks or to match some arbitrary load); and (5) an indicator as to *whether the additional operating hours may cause the DU asset to exceed its run-time limit*.

Simulation Outputs

As the simulation proceeds, statistics are gathered. For each feeder, we collect annual feeder capacity (summer and winter if desired), feeder utilization and load factor, number of DU assets installed, capacity of DU assets installed, and DU asset utilization and load factor. For selected feeders, we may collect annual snapshots of the hourly loads to facilitate animated presentations.

We aggregate these feeder-specific data to obtain system-wide DU and feeder installed capacities, feeder asset utilizations, and cumulative upgrade deferral times (feeder-years).

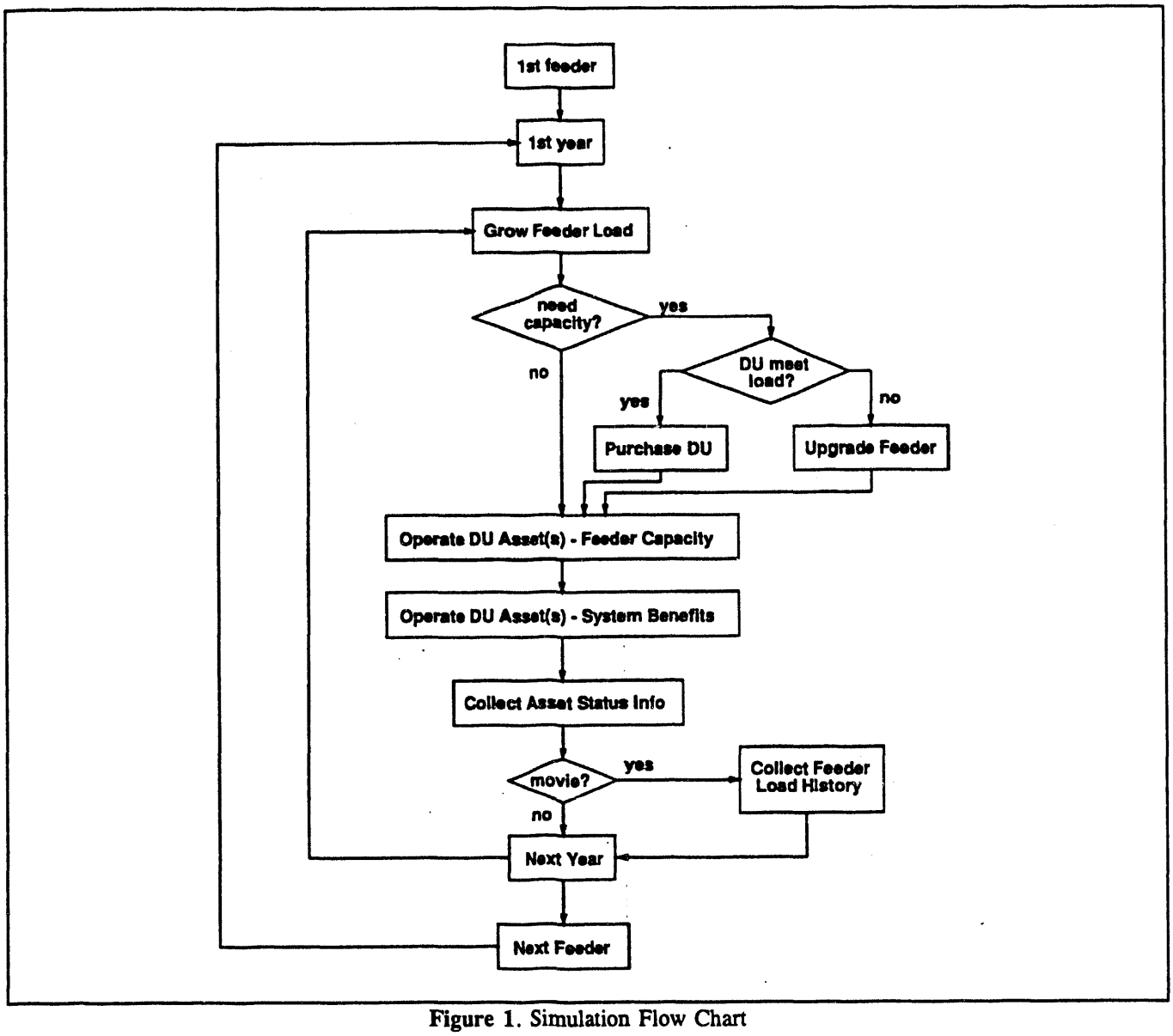

Figure 1. Simulation Flow Chart

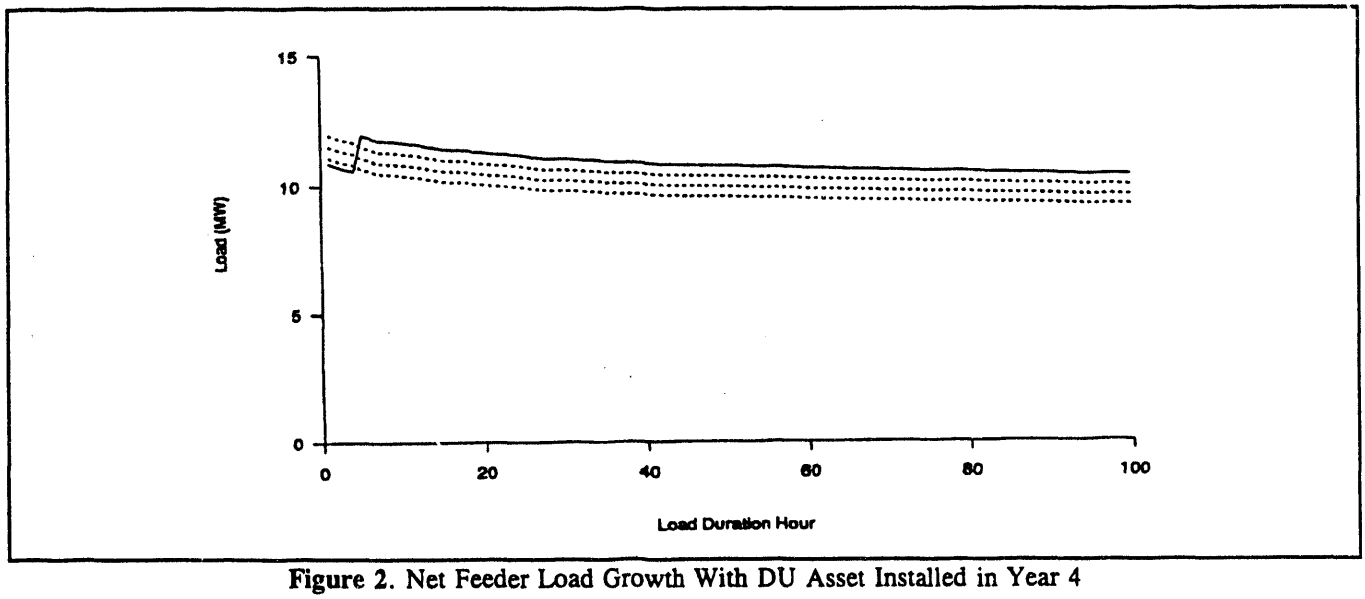

Figure 2. Net Feeder Load Growth With DU Asset Installed in Year 4

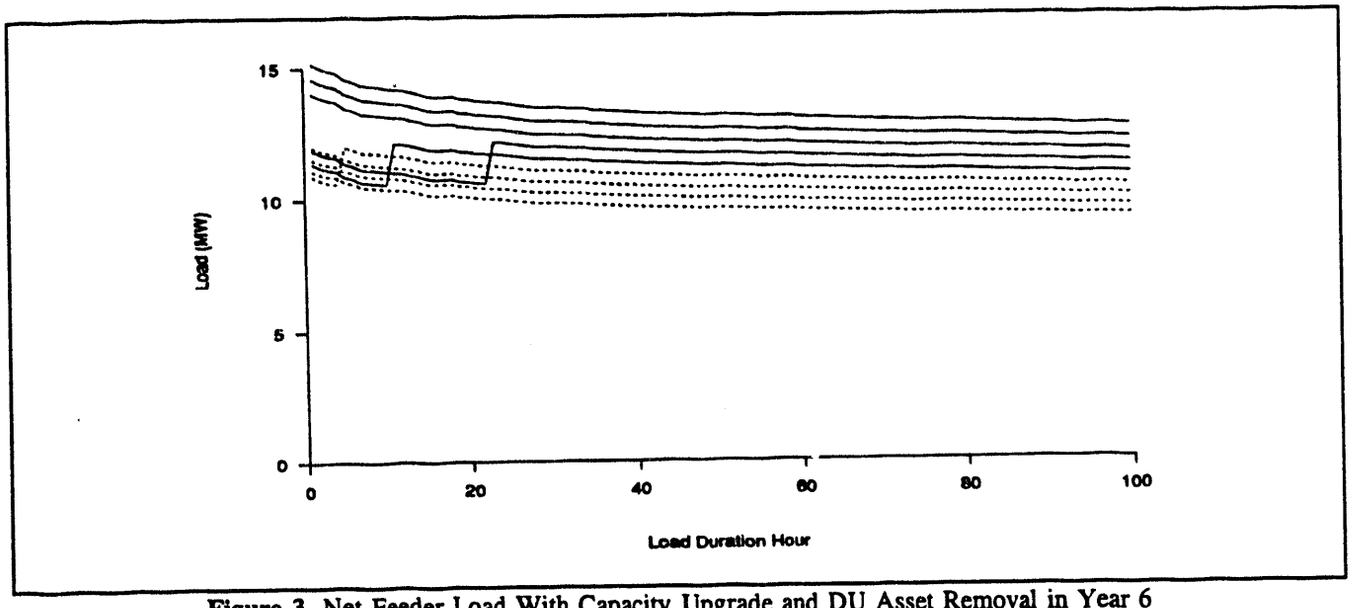

Figure 3. Net Feeder Load With Capacity Upgrade and DU Asset Removal in Year 6

Parameters for Scenario Analysis

We ran the simulation on 30 representative feeders (see next section) under a series of varying operational parameters. The parameters that were fixed for all simulations are shown in Table 1. Parametric simulations were done with the variables shown in Table 2.

Table 1. Fixed Simulation Parameters

Parameter	Value
Years of analysis	10
Maximum number of gensets per feeder	3
Genset capacity	1 MW fixed
Parallel/series operation	Parallel
Capacity modulation	None
Additional operating hours	None
Minimum years deferral	2

Clustering of Feeders

To avoid the necessity of simulating all 3000 feeders, we separated the feeders into groups with common characteristics and identified a representative feeder from each group using cluster analysis. The capacity-normalized load duration curve of each representative feeder was combined with the average feeder capacity from its group in the simulations. The results of the subset simulations were weighted according to the number of feeders in each group.

Table 2. Varying Simulation Parameters

Parameter	Values
Feeder growth rate	2%, 5%, 10% per year
Capacity upgrade factor	25%, 50%, 100% of capacity
Maximum DU operating hours	100, 200, 438, 876 per year

In addition to the benefit of computational efficiency, the cluster analysis offers a couple of additional insights. First, by examining groups of feeders with similar load shapes, we can begin to understand the factors that tend to dictate those shapes. Second, it provides a first-pass assessment of which and how many feeders are good candidates for DU applications. As a final objective, we hope to demonstrate the viability of using cluster analysis to facilitate scenario analyses by comparing our results to a full simulation of all 3000 feeders. However, we do not present this work in progress here.

Clustering Methodology

To identify the groups, we used a statistical technique of hierarchical clustering. The method clusters feeders that are similar to one another based on one or more variables. The variables used here are a selection of important points on the capacity-normalized load duration curves. For our purposes, it is important that all the feeders within a cluster be similar in the proximity of their peak loads to

their capacities and in the general shape of the upper portion of their load duration curves. We used the 1st, 5th, 20th, 100th, 200th, 438th, and 876th hours for our cluster analysis. These seven descriptors capture the important peak hours of the year as well as the hours that are potential run-time limits for reasonable DU implementations. (A limit of 200 annual operating hours is often viewed as a reasonable maximum. A 100-hour limit might be relevant in areas with strict air pollution controls.) The 438th and 876th hours represent run times of 5% and 10% of the hours in a year, respectively.

Although current or anticipated growth rates are also important, those data were not available at the time the clusters were selected. Growth rate is a primary variable for study in our analysis.

The clustering method first calculates the "distances" between all pairs of feeders. A number of metrics can be used to characterize the distance; we used the Euclidean distance, defined as the square root of the sum of the squared differences of the selected points from the load duration curves. Or, if there are N variables V_k, k=1..N, the Euclidean distance between observations i and j is defined as:

$$d_{i,j} = \sqrt{\sum_{k=1}^{N} (V_{i,k} - V_{j,k})^2}$$

Having computed distances between all pairs of feeders, the clustering methodology builds an inverted cluster "tree" by sequentially pairing individual feeders (the "leaves" of the tree) or groups of feeders (the "branches") with the smallest distance between them. This process continues until all feeders have been added to the cluster tree. Thus, the lower the point at which two branches of the cluster tree join, the more similar the feeders represented on those branches are. Any number of clusters may be obtained by cutting the tree with a horizontal line; each separate branch of the tree then forms a single cluster (Becker, et al. 1988).

Clustering Results

Figure 4 shows a graphical representation of the results in the form of a cluster tree. The value on the Y axis at the merger of any two subclusters represents the Euclidean distance between the two. The horizontal dotted line shows a cut through the tree at which 30 subclusters result. A visual inspection of the cluster results indicated there were between 20 and 30 clusters of feeders sufficiently distinguishable from one another to warrant separate investigation.

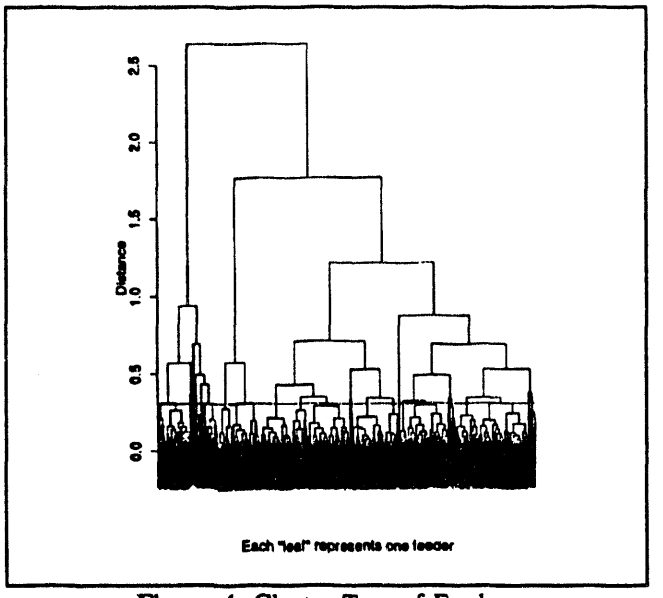

Figure 4. Cluster Tree of Feeders

We selected a single feeder to represent each subcluster by traversing each subtree beginning at its root and repeatedly moving toward the branch having the most members (ties broken arbitrarily) until a single "leaf" (feeder) was identified. We will subsequently weight this feeder's simulation results by the sum of the capacities of all the feeders in the cluster.

Figure 5 shows the representative feeders for four of the 30 clusters. Cluster 3 is a class of feeders with relatively flat load duration curves and peak loads only slightly over 40% of capacity. Cluster 12 is similar, but is at a lower fraction of capacity. Clusters 7 and 14 have load duration curves with relatively steeper slopes at the peak, which makes them more interesting as DU candidates. Cluster 14, in particular, is also quite close to capacity, making the feeders in it represents prime candidates for early DU installations.

Even before simulating the feeders, a few immediate findings are evident from the clustering results. First, the number of feeders with substantial near-term potential for DU installation is relatively small. Clusters representing feeders with peak loads at or above about 80% of capacity account for only 17.5% of the feeders. Only slightly over 7% of the feeders are at 90% of capacity or above. Note that feeders operating at low fractions of capacity are not eliminated as DU candidates—they are simply not candidates in the near term.

Second, the 200-hour limit cited by many as the reasonable upper bound on annual run times of distributed generation assets places a fundamental limit on the fraction of a feeder's load that can be displaced by DU. A large fraction of the feeders we analyzed have load

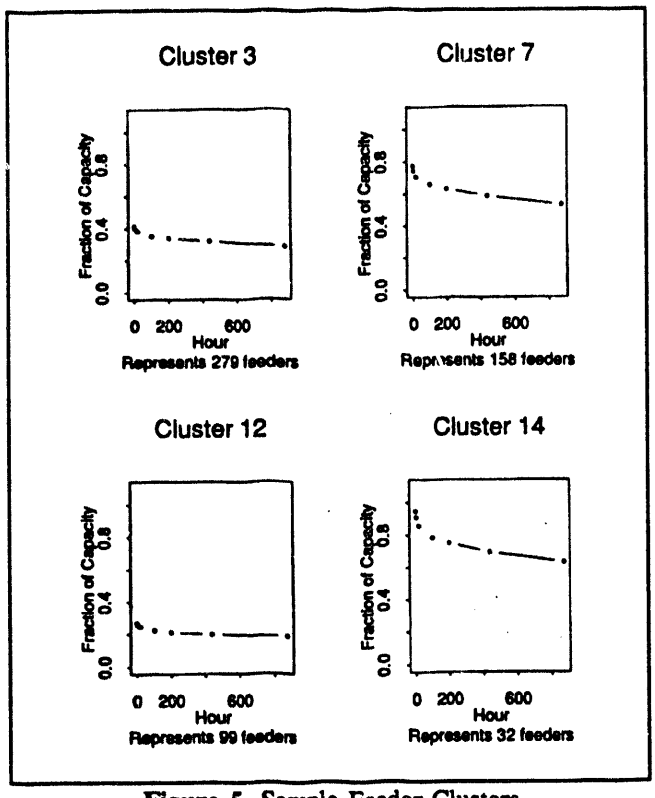

Figure 5. Sample Feeder Clusters

duration curve shapes that limit the potential of DU to around 15% of the total feeder load. Only a small fraction of the feeders have load shapes that would allow DU to displace 20% or more of the loads with a 200-hour limit.

Third, a substantial number of the feeders analyzed have load duration curves with most of the drop from peak loads occurring at or below around 20 to 30 hours. This type of load is a good candidate for other types of DU such as batteries and interruptible power rates, which we have not studied here.

Finally, we note a strong tendency for feeders that have load duration curves favorable to DU installation to serve a single or a few large customers. This is not surprising given the lack of load diversity in such a situation. We mention it nonetheless because it highlights the possibility of locating DU on the customer's premises or even to installation of DU by the customer who might then claim payment for the distribution system benefits.

DU Scenario Analysis

Figure 6 shows the penetration of DU capacity (GW) over time for three different growth rate assumptions for a feeder upgrade factor of 1.25. The solid line at the top of each shaded area represents the total capacity of the distribution system feeder and DU assets combined. The dashed curve at the bottom of each shaded area represents the feeder capacity only. The height of shaded area shows the DU capacity installed at any point in time. Beginning with a distribution system capacity of nearly 25 GW, 10% load growth drives total capacity to nearly 40 GW in 10 years (an increase of over 50%). Over 3.5 GW (almost 25%) of this increase is DU capacity in year 10, when DU begins to approach 10% of the total distribution capacity.

By contrast, at 2% growth, DU capacity in year 10 is only about 0.25 GW (1% of total system capacity), a smaller capital investment by a factor of ten. However, in this case nearly all the capacity added to the system is in the form of DU, suggesting that DU may still be a key

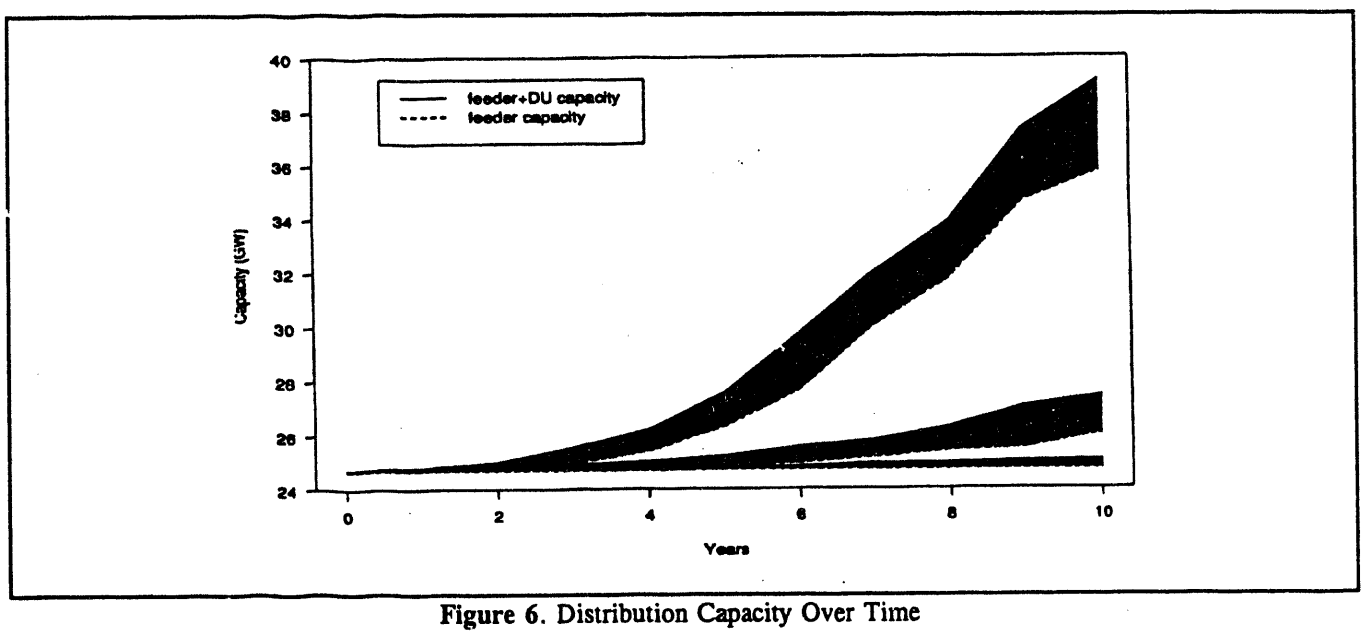

Figure 6. Distribution Capacity Over Time

technology even at low growth rates. The 5% growth scenario impacts are intermediate, with DU comprising more than 50% of new capacity.

The curves of DU capacity penetration over time in Figure 6 are obviously not smooth, proceeding in lumps of capacity that in one case, 5% growth in year 10, is actually less than that in year 9. This is a result of the coarseness of the simulation when only 30 clusters are used, but does not appreciably effect the results. As a result, we will be simulating with more clusters, or more representatives from clusters, in future work. This will be a natural consequence of having real growth rate estimates. Then each load duration curve cluster would contain a range of growth rates and must be simulated with a representative range of growth rates to accurately portray their impact on the feeders in the cluster.

The results of the parametric scenario analysis described in Table 2 are portrayed in Figures 7 through 10. Figure 7 shows the DU capacity installed (in GW) after 10 years, as a function of the operating hours limit for DU assets, growth rate, and feeder upgrade factor. Each family of curves with the same line type indicates the DU capacity for a single growth rate, over the range of feeder capacity upgrade factors. The installed DU capacity is limited by the maximum hours of operation when it is below 438 hours per year (5% of the hours in a year). Shown are modest reductions at 10% growth rates when a 200-hour limit is imposed, and much more severe reductions (on the order of 50%) when a 100-hour limit is imposed. The reason that the DU capacity does not continue to increase as the operating hour limit increases is that the restriction of a maximum DU capacity of 3 MW per feeder becomes the limiting factor as the operating hours restriction is relaxed.

The feeder capacity upgrade factor also is seen to be an important determinant of installed DU capacity. At 10% growth rates, increasing the upgrade factor from 25% to 100% reduces the DU capacity by about one-half. This is because when DU assets cannot supply the additional capacity required without violating asset operating constraints and a feeder capacity upgrade is finally required, we are assuming the DU asset is moved to another feeder. A larger capacity upgrade for the feeder eliminates any need for more capacity and, hence, any opportunity for DU resources to again become needed, for a longer period of time than if the capacity upgrade were smaller. At high growth rates, many feeders may need multiple upgrades within 10 years. At low (2%) growth rates, Figure 7 indicates that upgrade factor has no effect; feeders require only a single, if any, upgrade in a 10-year time horizon at such low growth rates.

At 5% growth, DU capacity is still influenced by upgrade factor, but to a lesser extent. The difference between 50% and 100% upgrade factors is greatly reduced, but significantly higher DU capacities are installed for 25% upgrade factors. These results suggest that lower capacity upgrades are conducive to DU asset installation into utility distribution systems at modest and high load growth rates.

DU capacity in absolute terms, as shown in Figure 7, is specific to the utility being analyzed. To present the impacts in more generic terms, Figure 8 shows the DU asset capacity in year 10 expressed as a penetration, or fraction of the total system capacity. By this metric, potential DU penetration ranges from a high of about 9% at high growth rates to about 1% at low growth rates. Here, the effect of the capacity upgrade factor is magnified because smaller upgrades result in a lower total

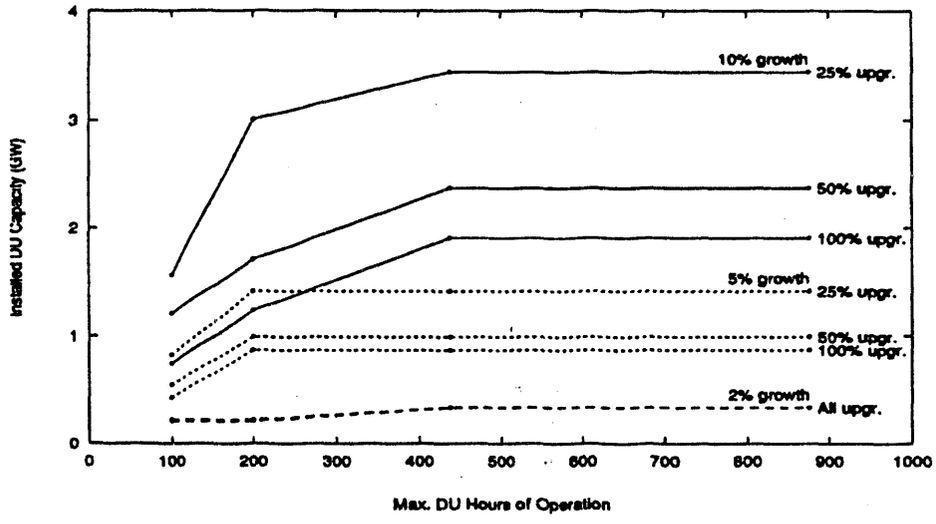

Figure 7. DU Capacity in Year 10

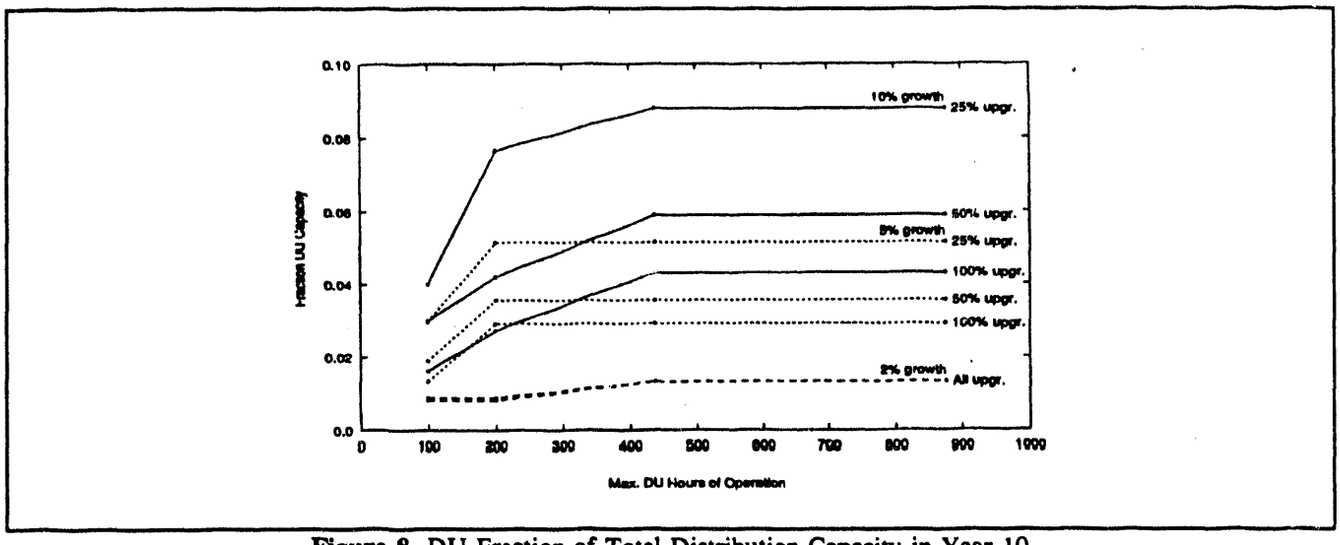

Figure 8. DU Fraction of Total Distribution Capacity in Year 10

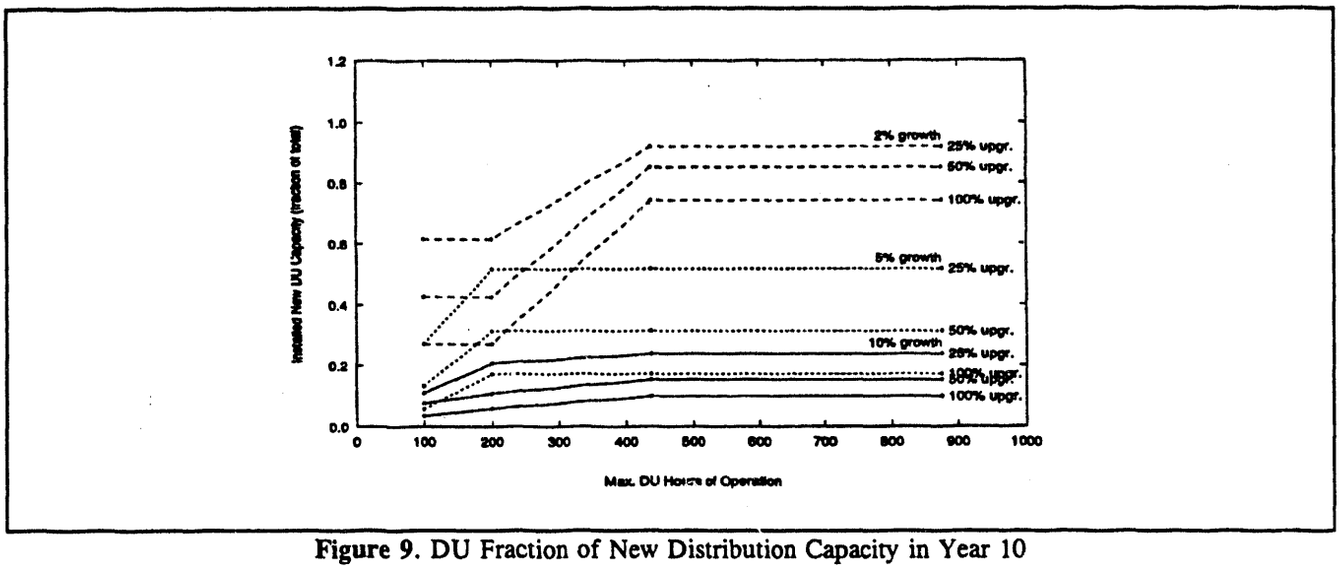

Figure 9. DU Fraction of New Distribution Capacity in Year 10

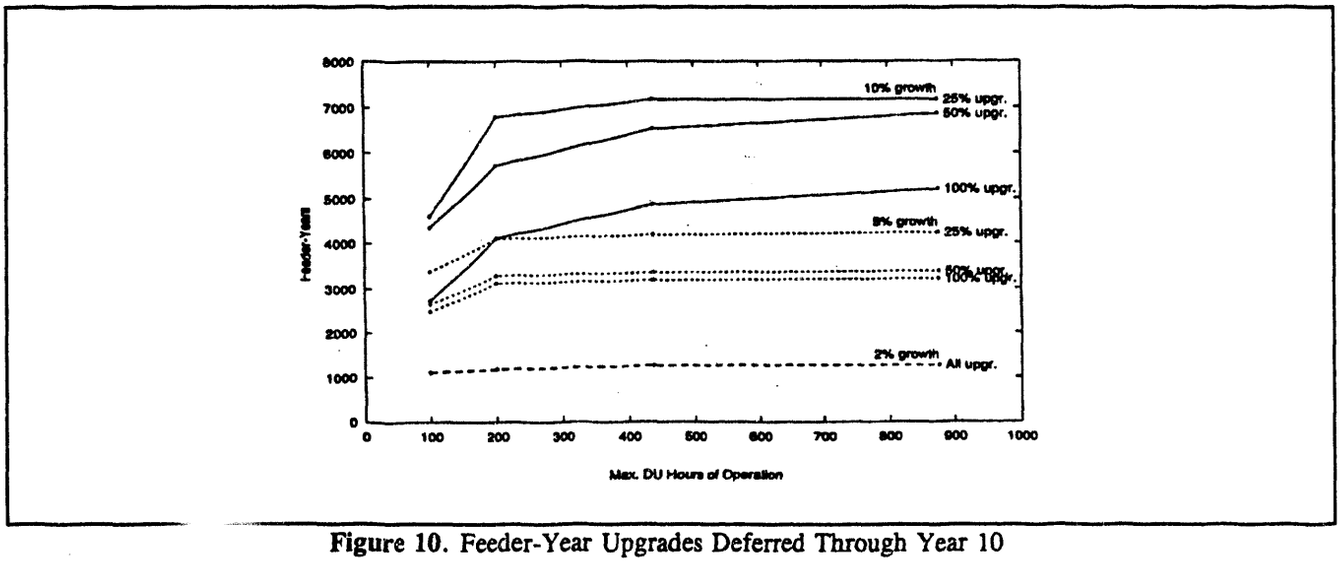

Figure 10. Feeder-Year Upgrades Deferred Through Year 10

distribution capacity. (This is because there is less excess, idle feeder capacity when the system is operated closer to the margin with more frequent upgrades.) The effect of upgrade factor at 2% growth rates is still negligible but causes penetrations at 5% growth and 25% upgrade factors to actually exceed that at 10% growth rates and 100% upgrade factors. It is also important to note that at a 200-hour operating limit, DU's penetration is reduced only slightly from the maximum indicated for any given growth rate and upgrade factor.

At penetrations approaching 10% of total system capacity, DU clearly has the potential to be a significant component of distribution systems in the future. As suggested earlier, however, at low growth rates, the fraction of *new* distribution capacity that is DU as opposed to traditional feeder upgrades is very high. This is illustrated in Figure 9, which shows the fraction of new distribution capacity that is served by DU assets by the end of 10 years. At 2% growth, nearly all new capacity needs are met with DU, while a high (10%) growth rate causes DU's share of new capacity additions to drop to around 10-20%. This is because loads are growing so fast that DU assets cannot stay in place long enough to have much impact before traditional feeder upgrades are required. Upgrade factor is again seen to be important and have effects similar to those discussed previously, except it is significant for 2% growth rates here when it was not for DU penetrations.

The primary economic value of DU to a utility is the deferral of capital investments in the distribution system. (There may be other benefits, such as relief of peak loads on the generating system, increased reliability for customers, reduced risk for the utility, and lower line losses, but these are generally secondary [Weinberg, et al. 1992].) Therefore, a good metric for DU's impact on the utility system for this study is the number of feeders on which upgrades are deferred and the number of years each of those upgrades deferred. We refer to this deferral metric as *upgrades deferred*, in units of feeder-years. The value of a feeder-year upgrade deferral varies with the specific nature of the upgrade deferred. However, as a point of reference, deferral of typical distribution system investments ranging from $0.5M to $10M for a year at a discount rate of 8% is worth about $40K to $800K.

Figure 10 shows the cumulative upgrades deferred over the 10 years analyzed. At 10% growth rates, up to 7000 feeder-years of upgrades are deferred at 25% and 50% upgrade factors. This impact is reduced to 5000 feeder-years if the upgrade factor is increased to 100%, reflecting the reduced opportunity for repeated DU impacts on individual feeders. Significantly fewer deferrals occur for lower growth rates, but still 1000 feeder-years of benefits are accrued at a 2% growth rate. Applying the above range of deferral values, these impacts might range from a minimum of $40M upward to $5.6B.

Combining the information in Figures 7 and 10, it can be shown that at modest growth rates of 5%, more feeder-years are deferred per GW of DU installed. This is because significantly less DU is installed at 5% growth, but the units remain in place (deferring feeder upgrades) for more years before they are unable to meet the load. The same is true for 2% growth rates, but the impact is less dramatic. Thus, DU is likely to be most cost effective (largest impact per unit capacity installed) at modest growth rates like 5% rather than high growth rates. This effect has been noted in previous studies that incorporate detailed economic calculations (Orans et al., 1992).

DU also has the effect of increasing the utilization of feeder equipment by operating it at higher average annual loadings. This is because DU "shaves the peak" from the feeder load, allowing it to operate at or near its capacity for all the hours the DU asset is operating. The upgrade factor is more important than the growth rate in determining these impacts. The initial feeder utilization of 25% is increased by 2 to 8 percentage points in the DU scenarios analyzed. This is another metric for the economic benefits of DU. Given the large current and future investment in the distribution infrastructure, such incremental benefits are likely to be significant.

Future Development

Subsequent analyses would refine and improve the first-cut analysis described above. Such improvements might involve:

- scenario analyses of other key variables such as the effects of DU asset capacities, modulation (load following), parallel operation, and operation to mitigate system peak loads
- more realistic distribution system upgrades, reflecting actual feeder capacity limitations and reconfigurations
- accounting for the economics of traditional and DU technologies for meeting feeder load growth, including displaced system peak and energy costs
- inclusion of specific DU technologies with detailed operating characteristics, constraints, and costs
- incorporation of non-dispatchable DU technologies such as DSM and photovoltaics
- more detailed accounting for load growth by sector and end use across feeders

- extending the cluster analysis to examine whether region, growth rate, and business/building type load shares are associated with the various clusters.

Eventually, metered feeder loads will be readily available, and the uncertainty inherent in estimating the feeder loads will be eliminated. At that point, the advantages of the improvements listed above are greatly compounded, and this analysis system could be used for actual least-cost distribution system planning, as opposed to scoping studies such as we present here.

Conclusions

We have shown that there is significant technical potential for dispatchable distributed utility technologies to defer distribution system feeder capacity upgrades. While detailed economics have not yet been included in the analysis because of the complexities of how feeders are upgraded, this first glimpse at utility-wide application of DU technologies shows potential impacts ranging up to 10% of total distribution capacity after years in high growth scenarios, and approaching 100% of *new* distribution capacity at lower growth rates. We have provided additional evidence that DU may be most cost effective for modest growth rates (like 5%), which combine a fairly near-term need for significant amounts of new distribution capacity, and where each DU installation defers capacity upgrades to a feeder for a number of years before its reasonable operating limits are exceed. By analyzing DU impacts over a range of key parameters, we provide the reader a means of adjusting impact estimates based on an exogenous calculation of cost effectiveness or environmental operating restrictions for DU assets. We show that cluster analysis of feeder load duration curves can provide broad insights into how DU potential may vary from one group of feeders to the next. We also provide evidence that potential economic benefits (indicated by the number and duration of capacity upgrade deferrals and increased feeder equipment utilization) are significant.

Finally, in the course of performing this analysis we have constructed a system for using feeder load duration curves and a simulated load growth to estimate DU potential. This system can be expanded to develop more detailed analyses including specific DU technologies, economic purchase and asset operating decisions, and more feeder capacity upgrade strategies that more realistically follow how distribution planners operate the system.

Endnote

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