Costing Methodology for Electric Distribution System Planning

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The views and opinions expressed here are strictly those of the authors, and may not necessary agree with, state or reflect the positions of those who provided comments and feedback during the report's development.

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Executive Summary

The Opportunity

This report has been prepared for regulators, policymakers, utility managers, distribution planners and engineers. It describes how utilities currently evaluate Distributed Resources (DR) in planning for capital investments in distribution facilities, and suggests a pathway for enhancement of how DR is considered. DR consists of local energy efficiency, load management, or generation. These resources can sometimes delay or eliminate the need for new distribution power lines, substations, and other equipment, at significant cost savings to the utility and consumers.

Distribution costs range significantly between utilities and between locations within utilities. This variation is illustrated below in Figure 1. For the four utilities shown, the system average marginal distribution capacity costs (MDCC) range from $74 to $556 per kW, and individual planning area marginal costs from a low of $0 to a high of $1,795 per kW. [1]

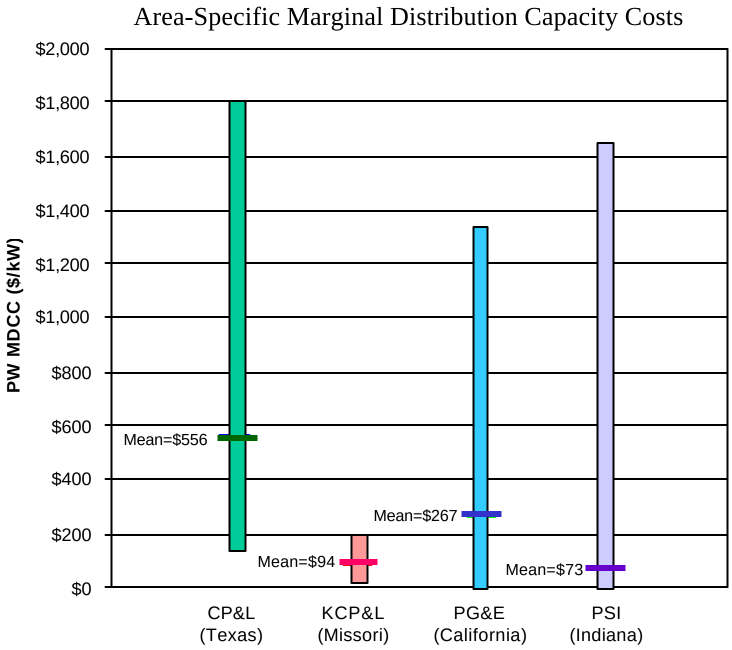

Figure 1. Area-specific marginal T&D capacity costs ($/kW for 1999) using Present Worth (PW) method by planning area for four major electric utilities show tremendous variation. For the PG&E case, several cost-effective DSM and DG alternatives were identified for costs in the mid-range (MDCC~$350-$400 per kW). Zero costs indicate that there are no planned investments over the 20-year time horizon.

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[1] Adapted from Woo, Heffner, Horii, Lloyd (1997), “Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution", *IEEE Transaction on Power Systems*. PE-493-PWRS-0-12-1997.)

Marginal costs also vary significantly by time of day and year. Figure 2 illustrates the marginal costs for each hour of the year for one moderately high-cost planning area, showing that most of the need to invest in new capacity is driven by high energy consumption during a small fraction of the time, driving the marginal cost of distribution capacity to several dollars per kWh.

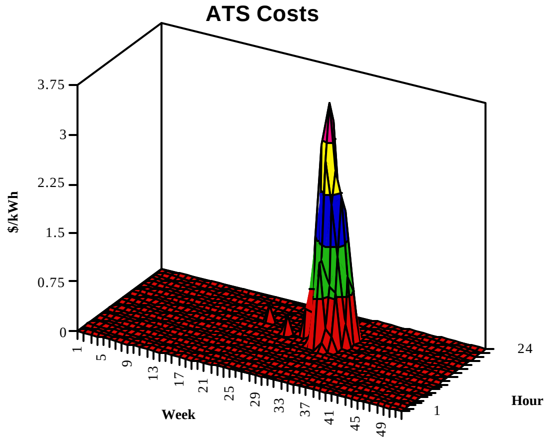

Figure 2. Marginal distribution capacity costs for a single planning area allocated over all 8760 hours of the year. Differentiating by time reveals the critical time periods that necessitate distribution capacity investments.

The findings of this report have profound implications for how utilities, regulators and others should view this part of the industry. Where, and when, marginal distribution costs are high, there are often cost-effective opportunities for local Distributed Resources (DR) to delay or eliminate the need for distribution system investments. DR could significantly impact approximately 10-20% of the annual capital budgets for distribution capacity in the United States.[2]

The “mountain” of costs shown in the Figure 2 is a “mountain of opportunity” to reduce capital costs for distribution companies, potentially enhancing their fiscal stability and moderating distribution rates. With the right regulatory policies, this is also a mountain of opportunities for vendors to provide generation, efficiency, and load management within local communities while reducing distribution costs.

Current Practice

Interest in DR as a tool for meeting distribution system requirements has been intensified by recent DR technological improvements, improved technical understanding and capabilities in the areas of interconnection and controls, as well as regulatory attention on the potential benefits of DR. Utilities vary significantly in the degree to which their existing data, planning processes, and analytic methods are

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[2] Several studies project that DR will provide 10-40% of new electric capacity over the next 5-10 years. However, there are no comprehensive reviews of the potential for DR to offset distribution capacity costs specifically. Many experts in the industry anticipate that 10-20% of these budgets could be impacted by DR.

suitable for considering DR alternatives. In some cases, a paucity of metered data limits the ability to quickly analyze load shapes. Other utilities have sufficient load shape data but limited modeling capability. Few utilities have a well-developed process for considering DR.

Objectives and Strategies for Improving DR Planning

The most important objectives for improved costing methodology are summarized below in Table 1. These objectives drive the best practice recommendations described in the next section.

Table 1: Objectives and Strategies for Improved Costing Methods

	Objective	Strategy
A.	Know where costs are high.	Differentiate distribution costs by location.
B.	Know when costs are high.	Differentiate distribution costs by time of day and year.
C.	Formalize the evaluation process.	Formally compare distribution system improvements to the most promising DR alternatives at the most important locations.
D.	Increase effective lead time.	Consider DR alternatives as early as possible in the planning process.
E.	Ensure effective buy-in.	Consider the financial interests of other parties in calculating the net costs to distribution utilities. Consider mechanisms to cost-share with other parties, and reflect these in estimates of distribution company costs.
F.	Get started with established costs.	Consider the role of societal benefits a lower priority issue.
G.	Include all costs.	Consider factors that are difficult to quantify in making decisions.

***A. Differentiate marginal distribution costs by location*.**

This helps identify areas where DR options are most likely to be beneficial. In doing this, utilities should consider both *costs* for distribution system enhancements, and *revenues* by location. Revenues can vary due to customer mix (and resulting differences in rate level and structure) and load profile. Utilities will discover that the financial impacts of load reduction will vary from site to site based on both costs of service and marginal revenues

***B. Differentiate marginal distribution costs by time of day and year*.**

To select an appropriate DR solution, it is particularly important to understand both when the peak loads that drive distribution improvements are occurring, and what is causing those loads.

C. Formally compare distribution system improvements to the most promising DR alternatives at the most important locations.

DR planning is a significant investment of time and money, and should be pursued where it is most likely to bear fruit. For many systems, most distribution improvements cannot be replaced with DR alternatives because there is not enough time, no DR alternative is available, the distribution system improvement is very inexpensive, or the load shape or other characteristic from DR alternatives does not line up with need. However, if there are questions about applicability, it is important that DR planners take the time to understand the alternatives, and conduct screening analysis to identify potentially beneficial DR applications. Where it is applied, distribution planning should be an iterative process that identifies and compares the costs of several potential options, including DR, to meet distribution system requirements.

D. Consider DR alternatives as early as possible in the planning process.

Some DR alternatives have a longer lead time than typical distribution improvements, which are often planned and installed in less than two years. Efficiency programs, in particular, can take several years to reach maximum benefit. To effectively implement long lead-time programs, utilities may need to use alternative methods to their classical planning tools to “look ahead”. For example, utilities can evaluate load trends at adjacent substations, and focus efficiency programs in areas where there are potential capacity limits several years out. While these long-range planning methods cannot predict the need for capital improvements with certainty, this type of preventative actions can reduce the *risk* of needing “quick solution” capital improvements.

E. Consider the financial interests of other parties in calculating the net costs to distribution utilities.

Other parties, including utility customers, energy service providers, and generators, may gain financial benefits from DR implementation. Where customers are willing to co-invest in efficiency and generation, this reduces the costs of DR alternatives to the utility. Distribution companies should explore these areas of mutual financial interest, but distribution planning should reflect them only as they become practical options.

F. Consider the role of societal benefits a lower priority issue.

Benefits can occur to the public at large, including economic development, less pollution, impacts on land use and visual aesthetics, etc. Many states have in the past created regulatory and rate mechanisms to encourage utilities to pursue energy efficiency to achieve these goals. In some cases multipliers or adders have been established to reflect these values in least-cost planning. Commensurate provisions have also been made in many states to assure that, where utilities fund initiatives that are rendered cost-effective by these adjustments against their own economic self-interest, they have mechanisms to recover costs and (in some states) achieve additional profit.

While an “ideal” planning process would incorporate such benefits, and an “ideal” regulatory process would provide adequate compensation, most utilities should first focus on items A-E, and consider whether societal benefits should be actively incorporated at a later date. This in part reflects a concern that too much of a policy focus and debate on public benefits may obscure the fact *that much DR is profitable to utilities on its own merit*. Additionally, there is ample opportunity to study and experiment with DR within the framework of utility costs and benefits. Finally, the authors recognize that change in distribution planning must move gradually, to assure that the basic reliability and quality objectives are not lost in the maze of new goals. Placing too many objectives for change in the current process will probably lead to justifiable resistance from distribution planners.

G. Consider factors that are difficult to quantify.

It is neither practical nor economical to quantify everything that is important for every proposed capital investment. Progress is likely to be faster if distribution planners and their managers use a decision-making process that explicitly considers both quantifiable factors and "intangibles". The "intangibles" could include political and public relations issues, financial risks that are not formally modeled, environmental and broad economic benefits, and so on as appropriate.

Best Practice

The key elements needed to define a best practice distribution costing methodology are summarized below in Table 2. These recommendations are the specific methods by which the objectives and strategies described in the previous section can best be realized. Not every utility will be able to adopt all aspects of a best practice approach easily due to limited information and resources and some utility-specific considerations such as regulatory constraints or rate freezes. However, some aspects of the proposed methodology can be adopted by most utilities, and can be utilized at least on a pilot basis to the degree that makes sense to each utility and local electricity stakeholders.

Table 2: Best Practice Costing Methodology Summary

Process	Recommendation
Starting Point	Traditional least-cost conventional solution – minimum Revenue Requirement
Review and Iterate	Begin with screening step for alternative solutions Perform detailed analysis of promising solutions
Project Costs	Forward-looking engineering estimates
Marginal Costs	Present Worth method
Location Allocation	Expansion plan by planning area
Time Allocation	Hourly Peak Capacity Allocation Factor
Non-monetary Costs	Clearly identify major items Push for better methods

1) An initial workable solution must first be defined. To establish the recommended methodology and get it into everyday practice, use the costing framework with which planners are familiar and comfortable to provide a reference point against which other alternatives can be compared.

2) Alternatives should be screened with the proposed conventional distribution solution as a benchmark. The alternatives can include DR as well as other innovative conventional solutions.[3]

3) For planning purposes, project costs should be based on forward-looking engineering estimates of identified solutions. Historical costs can be used as a guide for project costs, but should not be used for forecasting areas costs.

4) Marginal costs should be estimated using the Present Worth method described in the report. The method is straightforward, and yields the value of deferring capital investment further into the future due to an incremental decrease in load.

5) Expansion plans should be maintained by planning area so that marginal costs can be computed area by area. Complex econometric models are not necessary.

6) Allocation of costs by time should be performed using the Peak Capacity Allocation Factor method described in the report. The method is computationally simple, but does require area-specific load profile data. Utilities without this data can use estimated profiles to determine whether further metering is worthwhile.

7) Significant costs that are difficult to quantify in monetary terms should be identified, and where possible, valued using established methods. Qualitative assessments should be factored into decision-making where quantitative estimates are not available. The development of new methods to value such costs should be actively pursued.

Where to Start

Not all utilities will be able to implement best practice immediately. In the near-term, utilities should consider the following.

1) Well in advance of need, utilities should review their current and potential future "problem areas" for those with high potential DR benefits. Sometimes this will require using broad indices (e.g., load trends at several contiguous substations), as a complement to more exacting short-term planning methods.

2) Use improved planning and analysis methods on an experimental basis at these high-priority locations.

3) For utilities where data is limited, incrementally improve information on the location and time of distribution loads and costs. Begin to understand the number, size, and shape, of the "mountains". Work towards improved methods to scan the system for locations where detailed examination of DR options is appropriate. Consider how this improved information might ultimately be used

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[3] It is not uncommon that a new lower cost conventional solution has been developed once a lower-cost DR solution has been identified.

to develop price signals which can clearly inform utility economic development staff, efficiency implementers, and potential private sector partners about the potential value in reducing loads, or not increasing them, in certain areas.

It is important to recognize that the process of improving DR planning will be different for each utility. Opportunities for DR vary markedly by utility, based on the existing grid, rates, and customer characteristics. Some utilities may already employ parts of the best practices listed in this report, while for others adopting these best practices would entail a significant change from current planning and costing practices. Altering planning and costing practices is a complex process that requires change at several levels within a utility organization, from the engineers who perform the day to day planning for distribution areas to the managers who make capital budgeting decisions. Changes must occur recognizing that the primary objectives of distribution, to provide power reliably, must remain pre-eminent. Most utilities will make changes gradually, experimentally, and progressively. Although costing methods are an important driver of distribution investments, agreement on methodology is only the first step in changing how distribution companies identify, evaluate and implement distribution capital expansions.

Introduction and Organization

Under any market or regulatory structure, DR offers the opportunity to improve electric utility performance.[4] However, many traditional utility planning processes are not designed to evaluate the potential for cost-effective DR applications in distribution systems. Given the potential impact of DR on distribution loads, costs and revenues, proper consideration of DR in utility planning could mean the difference between financial success and failure for utilities in the next decade.

The first step needed to realize the value that DR can provide is to develop a *valuation methodology* that properly accounts for the features of both conventional "pipes and wires" solutions and DR. The purpose of this report is to develop recommendations on best practices for evaluation of DR in distribution planning.

The remainder of this report is organized into 4 major sections:

1) Overview of Current Utility Practices and Costs;
2) Key Methodological Issues;
3) Best Practices; and
4) Discussion.

Following the Discussion section are several appendices that provide a more technical discussion of the methodological approaches summarized in the main body of the report.

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[4] DR encompasses distributed generation (DG), where energy can be supplied to the grid, and demand side management (DSM), where load can be reduced through a variety of energy efficiency or load management initiatives. Load management includes interruptible power, time-of-day pricing, peak rates, on-site load management, etc.

Overview of Current Utility Practices and Costs

Every utility takes a slightly different approach to making distribution planning decisions. Nevertheless, there is a common process that describes how most utilities select which distribution capacity projects to pursue. This process is illustrated in Figure 3 below.

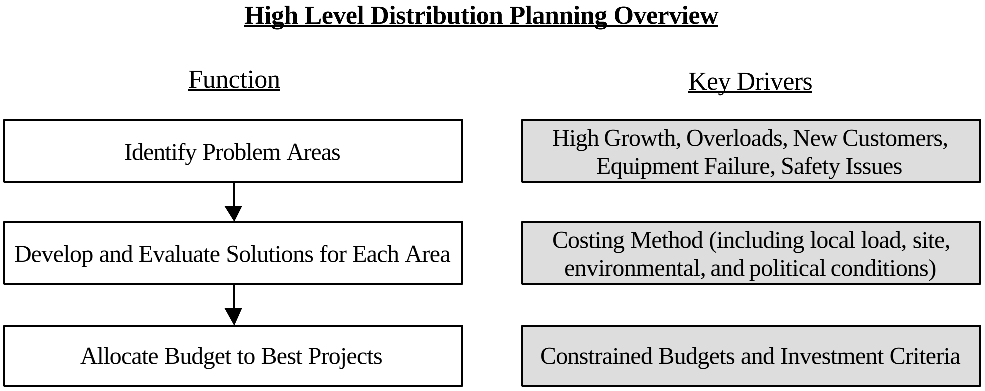

Figure 3: Overview of the Distribution Planning Process

In the first step, engineers and planning staff identify problem areas and develop possible solutions to address them. A capital budget request and justification are developed for each problem area. Planners then formulate their proposed 'best' solution for each problem, resulting in projects that are submitted for consideration in the overall utility capital budget. Capital budgeting then allocates the available resources to those projects deemed to be the most important.

How project costing is performed is critical in determining which projects are eventually implemented. Costing is used to rank different potential solutions for an area, including both traditional and DR alternatives, and ultimately determines which projects are submitted in a request for funding from the capital budget.

Identify Problem Areas

The methods used to identify problem areas are important because they impact the lead times that are available to develop alternative solutions. This is an important issue for DR because some DR solutions[5] require that problems be identified, and solutions begin to be implemented, earlier than would be required for a more traditional wires solution. Typically, the time between deciding that a problem exists on the distribution system and putting new equipment in service is two years or less (one year for feeders, two years for substations). The main drivers for project lead times are 1) the pace of growth , and 2) planner's comfort with the level of loading on lines and transformers.

Slow Growth

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[5] e.g., Efficiency programs with many participants or complex changes to large control systems.

In utilities that have slow, steady growth, problems are typically identified in three main ways.

1. Measurement of loads on feeders with high loading levels.
2. A need is identified as a result of a new large customer or group of customers that request electric service.
3. A failure of equipment.

In utilities with slow, steady growth, area load forecasting studies may not be updated regularly, and are often updated and corrected only once a planning study for a specific feeder is underway (usually less than two years before project completion). For example, one utility began planning a major upgrade on a substation, only to find out in mid-planning that the largest customer was planning to move to a different part of the utility's system. Slow-growth utilities tolerate inaccuracies in the early planning stages because, using traditional methods of meeting capacity needs, there is very little cost until a capital investment decision is made, and small capital improvements do not take long to complete. Planners and engineers typically have one or two years to install additional capacity once they observe high loading on a feeder or substation, or are notified of a new large customer.

High Growth

In utilities that experience rapid growth in areas, planners can also use load forecasting to identify problem areas. When growth is rapid, forecasts of load levels give planners additional lead-time to prepare solutions to potential problems before load levels become critical. Planners and engineers prepare forecasts of the load requirements of the distribution system, and estimate the system capability including peak load carrying capability and any reliability concerns. Those areas with insufficient capacity or reliability when loaded to a level identified in the forecast are identified as problem areas.

Develop and Evaluate Solutions to Problem Areas

Once problem areas are identified, the planners and engineers develop solutions that will mitigate the problem. Typically, these include "traditional" options such as adding transformer capacity, new feeders or circuits, or other measures. Development of technical solutions requires engineering and planning expertise as well as analysis tools (such as load flow models), information on the performance and reliability of existing equipment, and knowledge of the area in question.

Typically, the option that minimizes impact on revenue requirement is chosen and submitted for the capital budgeting process. Some utilities are starting to select among alternatives using other criteria such as net present value of cash flow, rate of return, or a combination of metrics.[6] The most common approach at utilities is to select among projects through a 'total cost' approach (present value of revenue requirement, which includes capital costs and the present value of recurring costs.) As long as the projects have similar reliability once completed, and will be in service

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[6] See Appendix C.

the same length of time, the 'total cost' approach results in the appropriate investment decision from a utility cost point of view[7].

Depending on the utility and regulatory requirements, the preferred plan may be compared with 'non-traditional' distributed resource (DR) solutions. These include DG, DSM, and interruptible-curtailable (I/C) contracts[8]. There is a wide range of sophistication used in the economic analysis of potential alternatives, and there is no method that is consistent across utilities. The analysis of alternatives is conducted to various degrees, and sometimes not at all, depending on the size, budget and sensitivity of the project, whether this type of evaluation is a standard part the utility's planning process, and in some cases, regulatory requirements and the project's public exposure.[9]

Planners and engineers typically view their role as making sure that they build and operate a reliable system. In general, they do not feel as comfortable with DR alternatives as traditional investments because of the their uncertainty regarding if the DR alternative will provide load relief when the system needs it. This impression is based on the different reliability characteristics of DR, and the planners' and engineers' lesser familiarity and experience with DR technologies. [10]

A very important consideration in evaluating DR alternatives is the treatment of reliability. Consistent and appropriate reliability criteria are necessary for proper costing of alternatives. Typical engineering rules stipulate single or double contingency.[11] Such guidelines have worked in the past because historically the capacity and reliability characteristics of different system components have been similar, and because customer expectations regarding power reliability were relatively consistent and moderate. However, they are not meaningful when applied to DR alternatives integrated with the distribution system because the size and characteristics differ substantially. Alternative solutions for problem areas should be evaluated under comparable reliability criteria, and an integrated perspective should be used to appropriately evaluate the reliability of systems with integrated DR. Metrics such as loss of load probability, expected unserved energy, or various reliability indices are increasingly being adopted to better reflect the physical consequences of equipment failures.

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[7] Costing approaches are discussed in more detail later in the report.

[8] For the purposes of this discussion, load management programs, such as site-controlled load management, load management coops, and radio-controlled load management are included in interruptible/curtailable programs.

[9] For some utilities that occasionally evaluate DR alternatives, planners and engineers are assisted with the DR evaluation by separate staff that evaluates the alternatives.

[10] There is not agreement among utilities about which DR options are most effective. In general, planners and engineers tend to be more comfortable evaluating DR options where they have direct experience with their impact. However, experience with DR does not always lead to increased consideration by utility planners. For example, poor persistence in energy efficiency programs has been reported to limit the ability for targeted DSM to avoid distribution capital projects.

[11] Single and double contingency refer to a planning criteria in which the distribution system capability is sufficient when one or two major system components experience an outage.

Allocating the Budget

Capital budgets limitations constrain the number of projects that can be implemented. Most utilities are in a ‘rate freeze’ or face other regulatory pressure and are unable to fund all of the projects that engineers and planners identify.

The methods employed by electric utilities to develop project budgets and to prioritize projects for budgeting vary. Not all costs and benefits are fully accounted for in some cases, and unconventional (or even conventional) alternatives to an initial plan are often given only a cursory analysis. For example, because utilities typically look at the impact on revenue requirements, other categories such as environmental costs, regional economic benefits, customer benefits, or social issues may not be explicitly evaluated. Also, DR alternatives may not be considered, or not considered fully, because it is not standard practice to include a cost comparison of non-traditional technologies at most utilities.

Key Methodological Issues

There are three main methodological issues related to distribution costing.

1) Calculation of project costs.
2) Calculation of marginal costs.
3) Prioritization and project selection.

Figure 4 illustrates in more detail the process steps for developing distribution system expansion plans. Typical current practice potentially misses many cost-saving opportunities by not identifying area- and time-specific marginal costs, and by failing to evaluate alternatives to the base case plan.

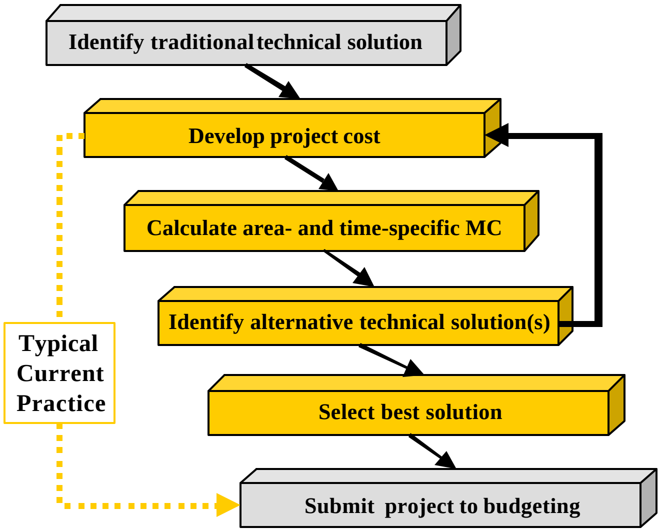

Figure 4: Costing steps in distribution expansion plan development

The two key cost concepts relevant for distribution system planning are project costs and marginal costs. These are not different costs, but different modes of comparison.

Project costs are measured in dollars. Traditionally these include all direct costs required to meet the new demand at a specified level of reliability. The least cost alternative(s) for each problem area is usually selected as the base case "best" plan (other approaches for selecting alternatives are addressed later).

Marginal costs ($/kW) reflect the change in cost associated with a change in demand. They are derived from the least cost "base case" expansion plans determined from the project costs. Marginal costs are used by planners to compare new alternative solutions to the base case investment plan on a more comparable basis: alternative solutions with lower marginal cost would improve the cost-effectiveness of the investment plan.[12]

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[12] As discussed later in this section, the calculation of marginal costs for distribution planning may require a different approach than marginal costs calculated for the purposes of ratemaking.

Both total project costs and marginal costs can vary significantly with where and when capacity is added. Hence, good costing methodologies will allocate costs by location and time.

For utilities that make an effort to consider several alternative solutions to a distribution problem, planning and costing is an iterative process. The starting point is to move through the planning process once using a base case design developed from experience and engineering judgement. After the base case is developed, planners then develop alternative solutions, which are compared to the base case plan in subsequent iterations of costing process.

Develop Project Costs

Developing project costs is the first step after technical solutions are identified. Cost estimates can be based on either historical or forward-looking costs. Historical costs can provide a gauge for possible future costs. However, distribution costs are very site specific, and engineering estimates of what actually must be done to effect each solution are a more accurate estimate of future costs. Changes in demand can alter what constitutes the best expansion plan looking forward, and therefore project cost estimates should be forward looking. Representative cost data for typical distribution system hardware are provided for reference in Appendix F.

Cost projections can be augmented by using a competitive bidding process, which can provide creative alternatives that utility planners may have missed and competitive incentives for least cost alternatives, and can leverage engineering manpower. However, bidding does require time to issue requests for proposals and to evaluate them, and requires detailed data that may be proprietary. Furthermore, markets are effective at setting costs only once a number of competitors are available to provide a product at the scale, location, reliability level, specifications, and time frame needed to meet distribution planning needs. The newness of many DR technologies limits the available market infrastructure. Until there is significantly more volume of activity in a local market, bidding may not be an effective pricing mechanism.

Cost effectiveness of new alternatives is measured relative to the base case expansion plan. Cost-effective DR alternatives can be uncovered using the traditional costing framework with which utility distribution system planners are familiar and comfortable, and which have already been agreed to by utilities, environmental advocates, ratepayer advocates, and regulators.[13] This report recommends a *methodology* for determining the magnitude of the costs of service *where* and *when* they are incurred. This methodology can and should be adopted by individual utilities (to the degree that they have the data and resources) in order to move forward with identifying and implementing cost-effective DR pilot projects. The debate about which cost perspective is most appropriate in the long-run (e.g., utility, ratepayer, societal) can be contentious. Resolving this issue in a permanent way may not be essential to building constructive experience with DR planning. Utilities can begin to use this methodology, focusing on net costs to the utility, to identify cost-saving DR investments in distribution systems. While this approach may not capture many

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[13] The major cost perspectives are discussed in detail in Appendix A.

significant societal costs and benefits, it is sufficient to justify many DR projects and gain further experience. It will also help re-enforce the direct value of DR to utilities.

Different types of costs and benefits are included in utility cost estimates, depending on the agreed-upon practices in each jurisdiction. The table below summarizes the features of the major cost categories, including costs that are often overlooked or excluded due to difficulty of quantification. Appendix B discusses these costs in more detail.

Table 3: Categories of Costs

Ease of Quantification	Type of Cost	Description	Comments
Readily Quantifiable	Direct costs	Hardware, labor, design, services, permits, customer costs, and avoided costs	Include all lifecycle costs. Consistent accounting.
	Time Value	Accelerated savings, deferred investment	
Difficult to Quantify	Environment	Air emissions, land use, water, noise, and landscape impacts not reflected in permitting or other regulatory costs	Use method accepted in jurisdiction. Explore improved methods
	Reliability	Outage costs, reliability metrics	
Very Difficult to Quantify	Quality	Waveform, harmonics, transients, droop	Note important aspects. Explore quantifiable metrics.
	Risk	Project risk, cost risk, demand risk	
	Strategic	Flexibility, real options, active management	
Subjective but Important	Intangibles	Public relations, political, learning	Highlight. Can be showstoppers or "must do" flags.

Readily Quantifiable: Costs and timing derived using generally accepted engineering and accounting practices.
Difficult to Quantify: Some components are quantifiable, but others require monetizing non-market attributes.
Very Difficult to Quantify: Relatively simple concepts that require advanced analytics to estimate.
Subjective: No accepted practical method to estimate.

Formal costing should be complemented by an effort to describe and provide relative priority for variables not considered in the costing model. As illustrated below, these factors can be few or many, depending on the extent of the costing analysis and the situation for the particular site.

1. Some analyses consider customer value of power quality and availability, but most do not. If a feeder includes a very quality-sensitive customer with significant load, power quality may be important. If the customer is willing to pay a premium rate, or may move if not satisfied, that impacts utility revenues, and could also have implications for costs for other customers.

2. A DR alternative may use up remaining available permits in an airshed with a cap on emissions. This could have significant effects on the local economy. Alternatively, a clean DR alternative may reduce emissions from central plants in the airshed, making more pollution permits available under an emissions cap.
3. An efficiency program may provide significantly more job-years per kW than a substation, and may also reduce customer costs, helping to foster industrial growth in an economically disadvantaged area.

While these issues will not fit easily into a formal costing framework, they will have significant impacts on the political situation of the utility and on the health of the local environment and economy. Many such unconventional benefits are important only in certain situations. It is more effective to scan for them using a checklist than to try to consistently incorporate them into models. Where they are important, these values will impact approval of a distribution improvement whether planners consider them formally or not. Efforts to discount or ignore such factors are likely to result in more political conflicts and may delay important projects or have a negative impact on utility profits.

To minimize conflict, planners need to explicitly balance these “fuzzy” variables against conventional ones, focusing on the situations where they weigh heavily, and highlighting those that have the most potential impact.

Derive Marginal Costs

To compare among alternatives that have different time horizons, install significantly different amounts of capacity, and result in very different systems, such as DR solutions, a comparison based on marginal costs (i.e., cost/kW of capacity) is a useful alternative approach. If done correctly, it will result in the same decision as the total cost method but is easier to implement. For example, it is possible to compare the total costs of installing a series of distributed generators, interruptible – curtailable rates, and targeted DSM to serve an area (maybe $10 million dollars present value) with the cost of a new substation to serve the area (maybe $12 million dollars present value). Under a total cost approach, care is needed to insure that the projects would serve the area for equivalent time periods, and would both provide adequate reliability. Alternatively, the analyst could compare the marginal costs of the DR plan (maybe $400 per kW) with the substation plan (maybe $420 per kW) to make the same selection.

Marginal costs also have the advantage that they are useful for benchmarking. Areas can be quickly evaluated to see if they are ‘high cost’ or ‘low cost’. DR program marginal costs can be developed in advance and then compared to the marginal cost derived from the distribution expansion plan in order to screen sites to identify those that merit more detailed analysis.

When calculating marginal costs, it is important to use an appropriate method. Utilities routinely use marginal costs for two different purposes, rate-making and project evaluation. It is important to distinguish between the two purposes, because not all methods for calculating marginal costs are necessarily appropriate for both tasks. Distribution marginal costs for rate-making are almost always system-wide (there are some a notable exceptions) and are used to allocate the relative amount of revenue requirement to be collected in distribution rates. Some methods for calculating the distribution marginal costs for rate-making are backward looking at investments that have already been made, and some are based on replacement costs of the system. There are good policy reasons why these approaches may be applied to develop the distribution rates, but their results do not reflect actual avoided costs if specific projects are deferred, and therefore are not as useful for planning purposes.

The purpose of deriving marginal costs for planning is to reflect as accurately as possible the incremental costs of investments in distribution system capacity associated with changes in demand. Marginal costs offer a comparable basis on which to evaluate alternative investments that may have different total project costs. There are several methods that can be applied to calculate marginal costs. Regardless of the method, critical elements in developing marginal costs are 1) definition of which costs are included, and 2) where and when the costs are incurred. Area- and time-specific marginal costs (ATSMC) serve as a benchmark by which alternatives to a base case plan can be compared. The basic steps required to calculated ATSMC are illustrated in Figure 5.

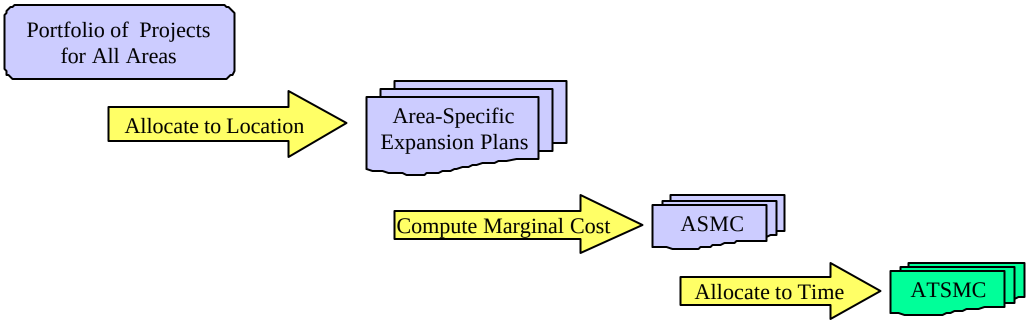

Figure 5: Area- and Time-Specific Marginal Cost Calculation Process

MARGINAL CAPACITY COST

There are several basic methods in use for deriving marginal capacity costs for distribution systems, described in detail in Appendix D. For distribution costing, the present worth method (PW) reflects a good estimate of forward-looking marginal costs against which new alternatives can be compared, and is straightforward to compute. The PW method estimates marginal cost as the opportunity cost of planned capital expenditures from a permanent increase in load. This cost is reflected in the savings associated with shifting the system expansion plan cost stream into the future, sometimes referred to as deferral value[14]. The PW method yields a MC estimate that varies by planning year, reflecting the greater marginal costs when investment is imminent. The PW method has been utilized for the examples that follow.

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[14] The PW numerator is sometimes presented with a distribution cost inflation index (DCI) and the actual cost of capital or interest rate r_{cc} rate such that

$$MC_{PW} = CRF \times \frac{\left(\sum_{t=1}^{N} \frac{I_t}{1+r_{cc}}\right) \times \left(1 - \left(\frac{1+DCI}{1+r_{cc}}\right)^{\Delta t}\right)}{\Delta L}$$

LOCATION

Costs vary by location due to geography, customer density and demographics, weather, proximity to urban centers, level of development, and several other location-specific factors. Knowing where the cost of providing distribution service is high is critical for knowing where DR has potential to save the most money.

The simplest approach to differentiate costs by location is to develop distinct area-specific capital expansion plans. This approach requires maintaining separate budgets for each planning area. There are also methods to allocate shared facilities when separate costing is difficult. The two major approaches are econometric methods and shares of demand indices, described in Appendix D. Deriving forward-looking plans differentiated by zone during the planning process provides a reasonable degree of differentiation with a minimum of added analytical complexity. To the degree that differences in customer revenues per kW or customer value is known by area, the costs and benefits should be reflected in area-specific cost tests.

Locational variation of marginal distribution costs has been analyzed for several utilities using the recommended methodology in this paper. This approach reveals large variations in the marginal costs of providing electric distribution system service both between utilities and across planning areas within a single utility. The results for four such utilities spanning from California to Indiana are illustrated in Figure 6.

TIME

The effectiveness of any DR solution in replacing or delaying a distribution system investment depends on the ability of the DR to reduce loading at the time that it is driving the need for new investment.

Methods to allocate costs across time fall into two categories: (1) Peak Block Shares, which lump costs into pre-defined peak periods, and (2) Allocation Factors, that assign cost responsibility to the hours most responsible for triggering distribution system investment. Peak block share methods are useful for determining costs attributable to different users of shared facilities during the peak period. However, they provide only rudimentary time differentiation, as they allocate all costs to the peak period and zero to all other times.

Allocation factors take the allocation of costs over time much further than the peak block approaches, allocating a share of the costs to each hour of the year. Because DSM tends to effect more hours, this approach better reflects the value of DSM measures. The specific methods are described and discussed further in Appendix E.

In looking at DSM opportunities, the way that timing of costs are expressed can be problematic. For example, peak costs may be on the three hottest days of the year, but which days will those be in 2002? A DSM measure has value if it reduces load on the 45 days most likely to be the hottest day, because those *include* the three hottest days. Additional benefits, such as extended distribution equipment life, lower losses, and improved efficiency, are provided by reducing loads on other days.

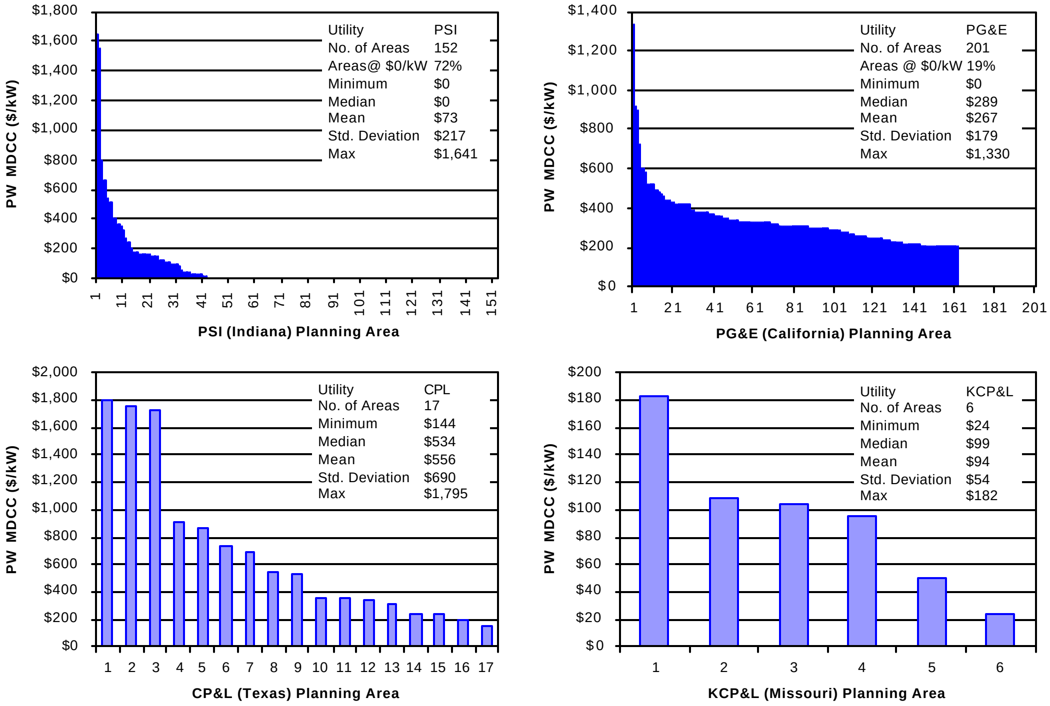

Figure 6: 1999 MDCC ($/kW) by Utility: Area-Specific MDCC. Marginal T&D capacity costs ($/kW for 1999) by planning area for four major electric utilities show tremendous variation. For the PG&E case, several cost-effective DSM and DG alternatives were identified for costs in the mid-range (Delta: MDCC~$350-$400 per kW). Zero costs indicate that there are no planned investments over the 20-year time horizon. [15]

In contrast, an interruptible program will reduce load on a certain number of hot days, consistent with the terms of the contract. This has a different value. A method which focuses exclusively on peak-day benefits will not pick up this difference.

The recommended method is the Peak Capacity Allocation Factor (PCAF). PCAF yields an approximation of the contribution of the load during each hour to the need to invest in distribution capacity. PCAF for each hour is calculated as the share of incremental load in the peak period divided by the total incremental load in the peak period. PCAF is computationally straightforward. It does require hourly load data (preferably a forecast but usually conducted with historical data). Because of the improved capability over other methods, the PCAF method has tremendous advantages. If only time-of-use period data is available (not hourly), PCAF can be easily applied, as well. If no load shape data is available at all, load shape estimates based on customer mix and typical average load shape by customer can provide a good proxy, identifying specific time dependence and revealing areas that may warrant further metering or analysis.

The impact of time differentiation is illustrated in Figure 7, based on a single utility from the study shown in Figure 6. The system average marginal distribution costs

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[15] Adapted from Woo, Heffner, Horii, Lloyd (1997), "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution", *IEEE Transaction on Power Systems*. PE-493-PWRS-0-12-1997.)

over time of use periods (chart on left side of figure) shows tremendous variation. However, moving to hourly PCAF allocation for a single summer afternoon peaking area (chart on right side of figure) dramatically highlights the critical times of the year, and the scale jumps from cents per hour to dollars per hour.

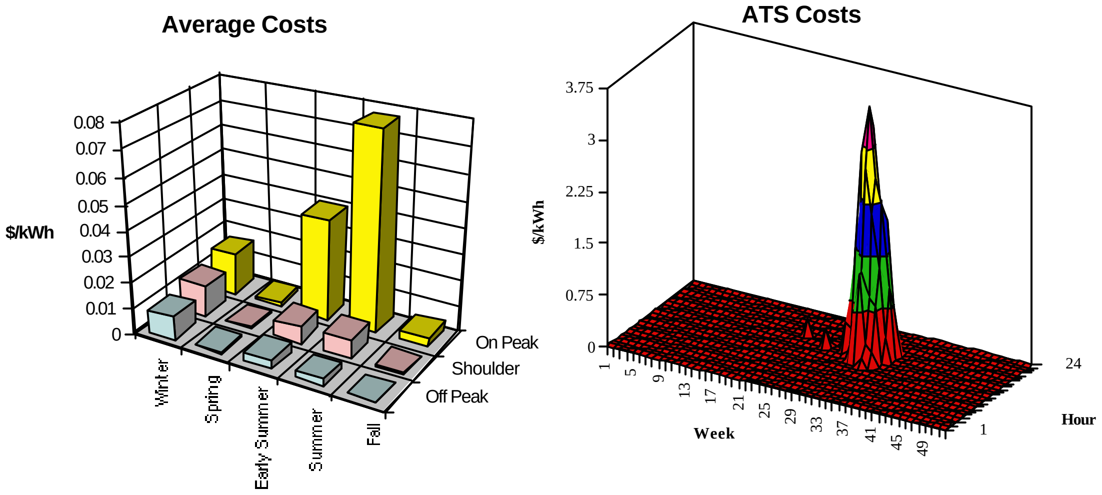

Figure 7: Marginal distribution capacity for (a) the entire system by time of use periods and season, and (b) a single planning area allocated over all 8760 hours of the year. PCAF reveals the critical time periods that necessitate distribution capacity investments.

Prioritize and Select Solutions

Determining which projects are actually implemented requires a method to measure project value, and an approach for project selection. Several typical measures for ranking investments are summarized in Table 4, and are discussed in detail in Appendix C. Before any of these measures are used, projects must be technically feasible, legal, and within the available budget. In addition, cost effectiveness tests, such as the utility cost test, ratepayer impact test, or societal cost test, for example, can serve as constraints or as ranking criteria: they represent the perspective of different coalitions that need to “buy-in” to alternatives to make them happen.

Table 4: Measures of Project Value

Method	Description	Metric
Present Value of Cost - PVC	Yields magnitude of cost only, no reflection of benefit or return on investment.	$
Net Present Value - NPV	Yields magnitude of gain but not return on investment.	$
Levelized Cost	Present value expressed in annualized payment.	$/year
Internal Rate of Return - IRR	Yields return but not magnitude of gain.	%/year
Payback Time	Yields neither return nor magnitude - only when investment breaks even.	years
Benefit-Cost Ratio - BCR	Cost effectiveness test measures return. Ratio of incremental gain to incremental cost.	Ratio

Method	Description	Metric
Engineering Standards	Simple guideline. No reflection of costs other than budget constraint. Treats units as direct measure of benefit.	e.g. kW or LOLP[16] reduced
Unit Costs	Treats units as direct measure of benefit, but reflects cost. A variant on BCR.	e.g. kW or LOLP reduced per $
Combined Preference Function	Most thorough, but requires most effort. Development of function is problematic, but is used.	Unitless or "$ equivalent"

Approaches for project selection are summarized in Table 5 in order of increasing complexity. The value and capability of experience and judgement should not be shortchanged, as all aspects of ranking and selection mechanism can not be captured in a fully quantifiable mechanism. Nevertheless, it is valuable to use a project selection approach that incorporates cost analysis. For most utilities, simply moving to consistent application of individual project ranking (option 2) would represent a substantial improvement in how distribution investment decisions are made. For utilities that have already adopted a consistent costing method for prioritizing distribution projects, adopting a portfolio perspective for evaluating groups of potential distribution investments can create additional value.

Table 5: Project Selection Approaches

Approach	Basis	Comments
1. Senior Management Decision	Experience and Judgement	Prevalent current practice.
2. Individual Project Ranking	Single alternative from each project proposed. Projects selected in rank order according to cost test results until budget exhausted.	Need clear criteria for ranking. May miss optimal combinations.
3. Simple Portfolio	A few alternatives for each project are proposed. Alternatives selected to achieve combined best set within budget.	Captures optimal combinations. Requires more extensive initial analysis. Misses synergies.
4. Interdependent Portfolio	Same as above, but interactions between projects are included.	Captures synergies. Requires yet more initial analysis to identify interdependencies.
5. Dynamic Programming	Incorporates uncertainty and actions contingent on resolved information.	The most comprehensive method. Requires probability estimation of drivers and development of contingent plans. Most useful at strategic level than at the distribution planner level.

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[16] Loss of Load Probability.

The quantitative methods (options 2-5) should serve as a decision support tool, not a prescription. Utilities with systems that exhibit a greater degree of project interaction and interdependence will gain value in moving toward evaluating all projects in an interdependent portfolio, but those that exhibit few such cases gain little by moving away from treating each project independently.

Best Practice

As discussed in the previous sections, there are several methodological issues that must be addressed to define a distribution costing approach. The key elements of a "Best Practice" methodology are summarized below in Table 6. Not every utility will be able to adopt all aspects of a best practice approach easily due to limited information and resources and some utility-specific considerations such as regulatory constraints or rate freezes. However, some aspects of the proposed methodology can be adopted by most utilities, and can be utilized at least on a pilot basis to the degree that makes sense to each utility and its constituents.

Table 6: Best Practice Costing Methodology Summary

Process	Recommendation
Starting Point	Traditional least-cost conventional solution – minimum Revenue Requirement
Review and Iterate	Begin with screening step for alternative solutions Perform detailed analysis of promising solutions
Project Costs	Forward-looking engineering estimates
Marginal Costs	Present Worth
Location Allocation	Expansion plan by planning area
Time Allocation	Hourly Peak Capacity Allocation Factor
Non-monetary Costs	Clearly identify major items Push for better methods

Starting Point

Good costing methodology meets technical requirements at minimum cost. This objective is consistent with typical distribution planning practice as currently applied for developing conventional "wires" solutions for identified problem areas. The traditional goal of selection solutions which minimize revenue requirement provides a reference point against which other alternatives can be compared. There can be much debate around which cost perspective (e.g., utility, ratepayer, societal) is appropriate for developing project costs. In order to establish the recommended methodology and get it into everyday practice, planners should begin by using costs with which they are familiar and comfortable.

Review and Iterate

With a reference workable solution established, planners should begin with a screening step that can quickly identify which potential alternative solutions could be competitive, and follow on with more detailed analysis of promising solutions. Establishing a simple screening tool facilitates incorporation of unconventional alternatives earlier in the planning process, increasing their applicability and competitiveness. Some U.S. utilities have begun to screen for DR solutions as a matter of routine.

Expansion Plan Costs

Project costs should be based on forward-looking engineering estimates to meet load, including for DSM, DG, and I/C alternatives. These costs may be developed in-house or via a bidding process, or a combination of both. This approach yields cost estimates that reflect the closest proxy for the actual costs that will be encountered given the information available to the utility.

Marginal Capacity Costs

Marginal capacity costs should be calculated using the Present Worth method. For distribution costing, the PW method reflects the savings associated with an investment deferral associated with a decrease in demand. It reflects a reasonable estimate of forward-looking marginal costs against which new alternatives can be compared and is simple to compute.

Cost Allocation

A guiding objective is to allocate costs as closely as possible to how costs are actually incurred. Best practice should include the development of area and time specific marginal costs that reflect costs by planning area and time. Location should be accounted for by developing expansion plan costs on a planning area basis. The peak capacity allocation factor (PCAF) method for allocating costs over time is computationally straightforward, and yields an approximation of the contribution of load during each hour to the need to invest in distribution capacity. Because of the improved capability over the binary peak block methods and simplified computational mechanics relative to the LOLPAF method, the PCAF method has tremendous advantages.

Data

Where customer-side alternatives are considered, utilities need to have reasonable data on customer load shapes for the affected end-uses (which are meaningful for the locations considered), and reliable data on program lead time, potential penetration, and likely savings. This includes consideration of the diversified impacts of programs with many customers (this also applies to generation alternatives with many customers).

Difficult to Quantify Value Elements

Where accepted procedures are in place to quantify the value or costs associated with risk, flexibility, the environment, or other difficult to quantify concepts, the distribution planner should use those procedures, and the utility, regulators, and advocates should work together to continue to improve both the methodology and documentation procedures. The rationale is to use what has already been agreed to, but to actively pursue improved accuracy, transparency, and ease of implementation.

Formal costing should be complemented by an effort to describe and provide relative priority for variables not considered in the costing model. These factors can be few or many, depending on the extent of the costing analysis. While these issues will not fit easily into a formal costing framework, they will have significant impacts on the political situation of the utility and on the health of the local environment and economy. Many such unconventional benefits are important only in certain situations. It is more effective to scan for them using a checklist than to try to incorporate them into models. To minimize conflict, planners need to explicitly balance these “fuzzy” variables against conventional ones, focusing on the situations where they weigh heavily, and on those that have the greatest impact.

Discussion

The best practices discussed in the previous section present a preferred approach to valuing distribution investment alternatives. These best practices serve as a guide, not a prescription. This section discusses several major implementation issues, and highlights several closely related issues that are interdependent with costing methodology, but are not addressed directly by costing methods.

Implementation and Transition

For many utilities, the proposed best practices differ substantially from current practices, and immediate and full implementation of these practices is not practical. However, there are concrete steps that utilities can take to adopt the elements of the recommendations that are practical, and thereby move toward improved distribution costing. These initial steps consist primarily of evaluating current status and developing a vision and roadmap for improving costing practices.

- *Status*. One of the core aspects of the recommended costing methodology is evaluating current costs differentiated first by location and second by time. Initial implementation of area- and time- specific costing makes most sense for areas in which additional investments are anticipated in the not-too-distant future. Most utility planners know which areas of their system are likely to require these investments. A utility can begin, at the very least, with a review of the variability of distribution costs by planning area within their territory. Allocation of these costs by time can be accomplished to the degree that area-specific annual load profiles are known. In many utilities these load shapes are not known, but can only be estimated. The initial assessment can yield insight as to where it is worth the expense to gather additional load information. To carry out the status evaluation and any follow-on data gathering, utilities must be able to recover the costs of these endeavors.
- *Screen - do not overanalyze*. Some utilities may apply a screening approach to identify sites where more detailed analysis of DR alternatives may prove fruitful. The screening could incorporate rough analysis of marginal costs along with a checklist approach to identify local problems or opportunities that may make DR initiatives more attractive.
- *System configuration*. Application of the recommended costing methods and tools needs to reflect utility system in which it is implemented. For example, some methods for cost allocation are more difficult to apply to highly networked systems than to radial circuits.
- *Empowerment*. It is critical to recognize that change is difficult to manage, and successful implementation depends strongly on the improvements coming from within the utility. The planning personnel are the most valuable resource for making such improvements, and they need to be empowered to effect change on a realistic schedule and with a style that is consistent with the culture.
- *Perspectives*. Utilities may need to explore the incorporation of different perspectives on a pilot basis to “get it right” before incorporating them in routine analyses. Furthermore, many types of costs and benefits are important only for

selected sites (e.g., customers with high reliability needs, or environmental issues within a regulated airshed). Costing methodology itself does not resolve the debate about which perspectives should be included in cost data. How the different cost perspectives are incorporated into the distribution planning process will vary from jurisdiction to jurisdiction.

Closely related issues that costing does not fix

Costing is only one part of addressing the incorporation of DR into utility operations. Although it does provide an opportunity to unleash some of the capital budget to facilitate DR projects, there are several closely related issues that costing does not solve. Although beyond the scope of this project, some of the important issues are summarized below, and serve as a springboard for further discussion moving forward.

- *Timing*. An improved costing methodology by itself will not solve the problem of having insufficient time in many cases to consider unconventional alternatives. However, evaluation time can be reduced significantly by making the review and screening process standard practice, thereby increasing the chances that longer lead-time alternatives could be implemented. Furthermore, utilities may decide to experiment in using a less formal "look ahead" process to decide whether and where to target efficiency programs. This process can look at early signs of future need for expanded capacity, including load trends on coincident feeders, areas with strong commercial growth potential, etc.
- *Load forecasting*. Load forecasting is an important issue that is not addressed in detail here. Different methods introduce biases and can miss important features, introducing significant errors into the forecast. Increases in customer-sited DG and new technologies for facility load control can impact the effective load to which the utility must build.
- *Customer initiated DG.* In the wake of this summer's capacity crises, many states are experiencing a flood of customer-generated proposals for on-site generation. While it is difficult to predict how many will be built, these proposals are significant for three reasons:
    1. They may significantly reduce substation and feeder loads, but the certainty of completion and the reliability and availability of power may not meet utility standards. Ignoring the impact of customer initiated DG could result in significant utility investment with very uncertain consequent revenues.
    2. They may have significant environmental impacts that could affect the ability of utilities to site or encourage other local generation.
    3. The sponsors may view utilities as "competition" for providing DR if efforts are not made to integrate utility and customer DR interests and plans.
- *Customer-utility partnerships*. Customer initiatives that are coordinated with the utility may represent opportunities for the utility to reduce uncertainty and costs. For beneficial customer applications, utilities could support, financially and through other means, the customer investment and help customers develop environmentally acceptable solutions.

- *Uncertainty and risk*. Some of the methods discussed provide tools for addressing uncertainty, but risk can also be evaluated, starting with the load forecast. Two significantly different approaches that utilities may wish to consider are highlighted below.
    1) *Probabilistic planning*. This approach would attempt to forecast, five to seven years in advance, areas that have a high chance of causing the need for distribution system expansion. These would identify both locations and industrial sectors. Industries such as telecom and internet businesses have created explosive growth in distribution system requirements nationwide. Because growth in these areas is only "likely" and may be several years off, costs would need to be adjusted for both time and probability. However, in areas with high intrinsic costs for distribution expansion (environmentally sensitive, congested and high-property value areas), there may be value in pursuing customer-side actions that either delay or reduce the odds that distribution expansion will be needed.
    2) *Subscription*. An alternative approach would be to change the way in which capacity is provided. Rather than building to an uncertain load, customers (especially larger ones) could subscribe to a capacity level. The utility would then build to order rather than to what might be ordered. This approach cannot apply to every customer, but applied to aggregated groups and larger users, the uncertainty in peak load could be reduced.
- *Clean DR*. A key objective for many stakeholders is to accelerate the deployment of environmentally friendly distributed resources. An improved cost method will identify areas where the distributed resources are most valuable, but experience so far is that the least cost distributed generation alternatives are rarely the cleanest technologies, even when incorporating societal costs. Without proper safeguards and special efforts to find the economic niches for clean DR, costing methods adopted with clean DR as objective could result in the perverse outcome of accelerating the deployment of small but not-so-clean distributed generation.
- *Incentives and policy.* Public policy should aim to design incentives for the utility and the customer to better align their perspective with social objectives wherever it is possible and practical. A move to internalize the differences inherent in the different stakeholder perspectives will serve to allow costing to effect socially desirable outcomes. The costing methodology itself only serves to select projects based on the existing guidelines and information.

Appendices

The following technical appendices are organized around the key questions that define a distribution costing methodology. Appendices A-C address project costs, while D and E address area- and time-specific marginal costs, and F provides some representative equipment costs for reference.

The key questions to address in determining a project costs are:

A. What is included?
B. How are they accounted for and what are the drivers?
C. How are projects prioritized?

The key issues for estimating area and time-specific marginal costs are:

D. How are marginal capacity costs estimated?
E. How are costs allocated by location and time?
F. What are typical equipment costs?

A. Cost Tests and Perspective: *What is included?*

One aspect of valuation is the identification of the cost perspectives under which the evaluation is performed. Perspectives that can be considered include the utility, non-participating and participating consumers, and society at large. Industry restructuring, especially the disintegration of vertically integrated utilities, changes how some types of cost tests reflect values. Energy efficiency programs, for example, have traditionally been evaluated with respective to benefits they provide in generation markets. Distribution planning focuses on capacity impacts, not energy, hence how cost tests evaluate benefits for distribution planning should be carefully applied and understood relative to their traditional uses for vertically integrated utilities. This appendix discusses costing methods generally. However, their application should be thought of in the context of industry structure in which they are applied.

There are five standard cost perspectives by which utility projects are judged. These tests are typically applied on a project-by-project basis, but may also be applied to a portfolio of projects taken as a whole. The term "costs" should not be confused with "cost effectiveness". Costs include relevant net changes in economic outflows. Cost effectiveness takes a step further, assigning the net changes from different categories as project *costs* or as project *benefits* (relative to a base case project alternative). Different cost and benefit assignments depend on the cost test perspective, changing the magnitude and makeup of both the numerator and denominator for a cost/benefit ratio. The basic definitions of the five cost tests are as follows.

Utility Cost Test (UCT) - The utility cost test includes as costs all expenses that impact a utility's ratebase. The perspective is that of all of the ratepayers (both participants and non-participants in DSM or customer-owned DG).

Rate Impact Measure (RIM) - The RIM test is from the perspective of ratepayers (non-participants in the case of DSM or DG). The RIM test includes as costs all expenses that impact a utility's rates. Since a reduction in revenue due to implementing a given alternative will affect the ultimate rates of all customers, revenue loss is computed as a cost of the program.

The difference between UCT and RIM is subtle but important. Rates are determined by the ratebase divided by sales. Therefore, project alternatives that reduce sales rank lower on the RIM test than UCT. From the wires company perspective, generation costs that are passed on to the customer are not included in the UCT and RIM tests because generation savings do not affect the ratebase or rates of the utility.

Total Resource Cost (TRC) - The TRC test is from the perspective of the utility and the customer as a unit. Incentives paid by the utility to a participating customer and any bill reductions the customer might receive as a result of the DR cancel out because they are a transfer between customer and utility.

Societal Cost Test (SCT) - The societal cost test is similar to the TRC test described above, but it also captures the externality effects that the DR has on society in addition to its direct costs.

Participant - The Participant cost test is specific to programs in which customers participate such as DSM or customer-sited DG, and reflects the net out-of-pocket costs incurred by the participating customer, including their direct costs, bill reductions, and incentives received from the utility or other programs. Net customer costs include all costs and savings net of incentives.

The relevant cost components included for each test are summarized in Table 7.

Details for non-wires distribution system alternatives are provided in Table 8.

Table 7: Cost elements relevant for different cost tests.

	UCT Vertical	UCT Wires	RIM Vertical	RIM Wires	TRC	SCT	Participant
Generation: Energy & Capacity	●	-	●	-	●	●	-
Losses	●	-	●	-	●	●	-
Transmission	●	○	●	○	●	●	-
Distribution	●	●	●	●	●	●	-
Administration	●	●	●	●	●	●	-
Incentives Utility to Customer	●	●	●	●	-	-	●
Revenue	-	-	●	●	-	-	●
Outage Cost	-	-	-	-	●	●	-
Externalities	-	-	-	-	-	●	-
Customer net cost	-	-	-	-	●	-	●

● Included ○ Possibly included - Not included

As a guide to understanding the cost tests, Table 9 provides sample perspectives from participants who focus more on societal values versus utility and customer business needs. Of course, individual groups may have very different perspectives than those listed here, but many of the most common arguments have been included.

For a project to enjoy buy-in by all interested parties, it will need to pass several different cost tests. Minimum criteria could include:

- The project does not exceed the allowable budget.
- The societal cost test indicates a net gain or impact only to a level determined acceptable by regulators.
- Non-participant ratepayers are at least as well off or impacted only to a level determined acceptable by regulators, or have a reasonable chance to participate over the next several years.
- If non-utility participants are involved, (e.g. customer-owned energy efficiency), the participant perspective is needed to ensure that there is adequate incentive and to balance the non-participant perspective.

A "best" solution is likely to be a compromise in which no single cost perspective is always the determining factor.

Table 8: Cost test components for each cost test and program type

Program Type		Cost Test UCT - Vertical	UCT - Wires	RIM - Vertical	RIM - Wires	TRC	Societal	Participant
Failure Replacement DSM	*Benefits*	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	G, TD Def, ICAP, Env	K, Rev
	Costs	k, Admin	k, Admin	k, Rev, Admin	k, T&D Rev, Admin	C, k, Admin	k, Admin	$C (DSM)
Early Replacement DSM	*Benefits*	G, TD Def, ICAP	T&D	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	G, TD Def, ICAP, Env	K, Rev
	Costs	K, Admin	K, Admin	K, Rev, Admin	K, T&D Rev, Admin	C, K, Admin	K, Admin	$C (DSM)
Interruptible / Curtailable DSM	*Benefits*	TD Def	TD Def	TD Def	TD Def	G, TD Def, ICAP	G, TD Def, ICAP, Env	Incent
	Costs	Incent, Admin	Incent, Admin	Incent, Admin	Incent, Admin	Admin	Admin	$C (DSM)
Fuel Switching DSM	*Benefits*	G, TD Def, ICAP	TD Def	G, TD Def, ICAP, Alt. Fuel Rev	TD Def, Alt. Fuel Rev	G, TD Def, ICAP, Conv Device	G, TD Def, ICAP, Conv Device	Incent, Rev, Conv Device
	Costs	Inc, Alt. Fuel Cost, Admin	Inc, Alt. Fuel Cost, Admin	Inc, Rev, Alt. Fuel Cost, Admin	Inc, T&D Rev, Alt. Fuel Cost, Admin	Inc, Alt Fuel Cost, Admin, Alt Device	Inc, Alt Fuel Cost, Admin, Alt Device	Alt Device, Alt. Fuel Rev
Behind the Meter DG	*Benefits*	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	G, TD Def, ICAP, Env	Rev, ICAP, Incent
	Costs	Incent, Admin	Incent, Admin	Inc, Rev, Admin	T&D Rev, Admin	Admin	Admin	$C (DG)
Merchant Plant DG	*Benefits*	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	TD Def	G, TD Def, ICAP	G, TD Def, ICAP, Env	G, ICAP, Incent
	Costs	Incent, Admin	Incent, Admin	Incent, Admin	Incent, Admin	Admin	Admin	$C (DG)

Symbol Definitions		Symbol Definitions	
$C (DSM or DG)	Customer Cost of DSM or DG	ICAP	Generation Marginal Capacity Price (ICAP Market Price)
Admin	Administration Costs of the Program	Incent	Incentive Payment from the Utility (if any)
Alt Device	Purchase for Alternative Fuel Device	k	Incremental Cost of Efficient Unit
Alt. Fuel Cost	Marginal Cost of Providing Alternative Fuel	K	Total Cost of Efficient Unit
Alt. Fuel Rev	Revenue from Customer for Alternative Fuel	Rev	Change in Total Bill (Energy and T&D)
Conv Device	Avoided Purchase of Electrical Device	T&D Rev	Change in T&D Bill
Env	Environmental Externality	TD Def	Transmission and Distribution Deferral Benefits
G	Generation Marginal Energy Price (Market Energy Price)		

Table 9: Sample Perspectives on the Cost Tests

Test Name	Societal Focus	Business Perspective
UCT – Utility Cost Test	This test looks only at real cash transfers the utility gives and receives, and does not include externalities so it undervalues environmental programs, customer economic benefits, regional economic benefits, social issues, and impacts on the generating and transmission utility. This test offers more favorable evaluations of efficiency programs than the RIM test because revenue loss is not included as a cost.	This test is the status quo at most utilities whose goal is to minimize revenue requirement. However, most utilities do not traditionally consider alternatives that reduce sales. If they did, they would use RIM to make investments for reasons discussed below.
RIM – Rate Impact Measure	This test unfairly looks only at non-participants in the program and does not include the benefits to the participants. Utilities should look at benefits to customers as a whole (within moderation). This issue is important if utility-side alternatives are compared to customer-side alternatives	This test measures the impact on the utility rates. This is a very important test since rate increases affect all customers and reflect the ability of the utility to increase sales and thereby increase profits. With recent upward pressures on energy prices, this is particularly important. Why should non-participants pay for bill reductions that only participants are receiving?

TRC – Total Resource Cost	This test is more acceptable, subject to its limitations. It looks at the costs from a broader perspective that includes both all the utility costs (including transmission and generation) and any costs a customer might pay. However, it is too limited because it ignores non-cash cost differences that have very important ramifications to society.	This cost test does not really apply to anyone. If a program passes, who is better off? This cost test does not give us the answer. Rates may go up, and participants may be subsidized by non-participants. You can do a better job at making investments by looking at the more specific cost test perspectives of non-participants through RIM and the Participant Test.
SCT – Societal Cost Test	This test results in the projects with the least total cost to society. This is the right set of projects to focus on.	Using the societal cost test to make investment decisions will result in a selection of much more expensive projects that will probably increase rates and ratebase. This is only acceptable as long as it is an explicit public policy choice and the utility is allowed to seek recovery through increasing rates or some other mechanism such as using public purpose funding.
PCT – Participant Cost Test	This is a valuable, but fragmentary perspective. Care must be taken to capture all of the reasons a customer may or may not want to participate when you develop your costs and benefits.	This test is an important part of developing a marketing plan for a program. There is no point in developing a program that will in all likelihood have very little participation.

B. Elements and Drivers: How are they accounted for? What matters?

Typology of Value Elements:
How are they accounted for?

Elements of value that are relevant for distribution system include:
- direct initial and ongoing costs,
- timing (deferral or acceleration of cash flows),
- environmental consequences,
- power quality and reliability,
- risk management (reducing variance and extremes in performance),
- option value (flexibility to respond to uncertain conditions), and
- intangibles (i.e. learning, political necessity or public relations/goodwill).

Not all of these components are easily estimated, and some are difficult to convert to monetary units. Costs relevant from the broader societal perspective also include environmental externalities and customer outage costs, which do not directly impact the value to the utility, but directly impact other stakeholders and may indirectly affect the utility. In general, value is measured relative to a "business as usual" or, if feasible, a "do nothing" reference case.

Readily Quantifiable: Costs and timing derived using generally accepted engineering and accounting practices.

> Direct costs include initial investment, such as capital equipment purchase, finance charges, site preparation, permit fees, and land, as well as ongoing operating cost streams for fuel, maintenance, spare parts, and repairs. Accurate accounting also includes avoided costs as a credit. Impacts on utility margins that reflect the impact of changes to sales to customers from different rate classes would also be included as direct costs.
>
> Timing refers to changes when cash flows (costs) are incurred, which impacts the present value of the cash flow stream. The most relevant of these is commonly referred to as "deferral value", which is realized by delaying an investment that otherwise would have been required and thereby shifting the associated cash flows and gaining the interest on the investment less any inflation of the costs. Likewise, accelerating cost reductions or revenue increases has timing value.

Difficult to Quantify: Some components are readily quantifiable, but others require monetizing non-market attributes.

> Environmental consequences impact cash flows directly because of permitting requirements, especially if some alternatives are within a "non-attainment area", if there is an active emissions trading market, or if there is special rate treatment such as net metering, for example. Quantification of environmental externalities is necessary for SCT, and is normally accomplished by assigning costs per pound of air emission or adders per kWh of energy.

Power quality refers in general to waveform specifics such as voltage or frequency abnormalities, harmonic distortion, or distortions from a sinusoidal shape. Reliability of electrical service refers to adequacy and security of the distribution system: whether the waveform is there or not, due to equipment outages or involuntary load curtailments, and if not, how often, how long, how much load, and how many customers are affected. Quality and reliability provide value for the utility in many cases: when there is threat of bypass in response to poor service, where there are reliability or quality-differentiated rates, and where costs of repair are significant, for example. Utility outage costs include loss of revenue from customers not served, loss of customer goodwill, loss of future potential sales due to adverse reaction, and increased expenditure due to maintenance and repair. Customer outage costs imposed on industry include lost manufacturing, spoiled inventory, damaged equipment, extra maintenance, and overtime. Costs imposed on residential customers include spoiled frozen foods, substitute heating and lighting costs, and inconvenience. Customer outage costs are typically estimated by a customer value per kWh or per outage and duration, multiplied by expected outages in either kWh or frequency and duration for different customer classes. Studies suggest that these costs vary widely, are susceptible to biases in estimation, and are not necessarily linear[17]. Often, reliability is treated as a constraint rather than considered explicitly as a cost, requiring that the system meet specific loss-of-load probability (LOLP) or other reliability index criteria, and in fact many utility projects are driven by meeting these requirements rather than capacity adequacy. Quantification of customer outage costs is used for SCT in either case to account for differences in reliability level between projects.

Very Difficult to Quantify: Relatively simple concepts that require advanced analytics to estimate.

Risk management is a relatively new concept for a historically regulated monopoly business. Estimating the value of risk management features of projects requires moving beyond expected value measures, looking for reduced variance and extremes in financial performance. These can be incorporated into costs through risk-adjusted discount rates or asset pricing models, or compared using other metrics such as standard deviation, value at risk, or worst-case scenario value. Much of the business world has adopted tools and procedures to value risk, but few utilities or utility regulators have reached agreement on acceptable methods.

For example, some customer-side approaches are modular and easily scalable over time, while some distribution-side investments (e.g., a new feeder) need to be made once, requiring a commitment to a single forecast of growth. The modularity provides risk management or flexibility value.

Effective risk planning requires (1) scanning for uncertain, but high cost-impact events (e.g., Where would grid growth have the highest cost and lowest revenue

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[17] Like environmental cost estimation, outage cost estimation is an entire field unto itself. A good discussion of customer outage costs can be found in R. Billinton and R. Allan, Reliability Evaluation of Power Systems, Plenum Press 1996, or for more in-depth analysis see C.K. Woo and R.L. Pupp, Costs of Service Disruptions to Electricity Customers", *Energy*, v12n2, 1992, pp 109-126.

increment? Where are loads most unstable? Where are distribution-side investments binary, as opposed to scalable?), (2) estimating the probability based on the best available information, and (3) estimating costs. This information then can be used both in conventional analysis and to consider risk mitigation strategies that incorporate DR.

"Option" value or "strategic" value is related to but distinct from risk management, and derives from the flexibility to respond to uncertain conditions as information is realized, rather than committing to a course of action in advance of the facts. Examples of such option value are the option to wait to see what kind of load growth actually happens (possible with short response-time and modular projects) or the option to cancel a project should load not materialize or fuel costs or technology not meet expectations. Methods used for estimating strategic value include "real options" or contingent claims analysis, financial derivatives, dynamic programming, and decision analysis. Where strategies involve reactive behavior with other market participants, these tools are sometimes combined with game theory.

Subjective: No accepted practical method to estimate.

Intangibles include political necessity, public relations, or learning opportunities (e.g. trying a new technology as a pilot demonstration), or other such categories that clearly have value but are difficult (or controversial) to quantify. These costs can sometimes be agreed upon through a usually confrontational regulatory process. Efforts have been made to quantify such intangibles by applying marketing tools (focus groups, surveys, contingent valuation or conjoint analysis) and decision analysis, but there is no accepted methodology. Engaging decision makers in understanding these features and their implications for each project is important even if they are not quantifiable.

Typology of Independent Variables and Area Attributes: *What are the drivers?*

Underlying drivers of value include basic features specific to the location, load growth rate relative to capacity, load shape, characteristics of existing equipment and operational details of possible alternatives, financial parameters, synergies, power quality and reliability features of the area, environmental considerations, uncertainty, and opportunities or requirements related to intangibles. Many of these drivers exhibit complex interactions and are by no means mutually exclusive.

Location: Many drivers of cost can be characterized broadly by distinctions such as Remote vs. Urban, Constrained vs. Unconstrained, and Mild vs. Extreme Climate. Once costing analysis has been completed, the groupings can be more aptly categorized as high or low incremental cost.

Load Growth: The fundamental need for distribution system investment derives from the adequacy of the existing system to deliver forecasted peak demand requirements. The load growth rate therefore determines the amount of time before a capacity shortage is likely to be experienced. The magnitude of the growth relative to capacity sets both the timing and the magnitude of action required, and with it scales the magnitude and timing of investment. Customer-sited generation growth will impact the load seen by the utility as well, and may become an important element to consider in load forecasting.

Customer-sited generators can be significant decrements to loads, and failure to consider future plans can lead to unnecessary generation construction. Most generators will not be considering utility reliability in their plans and may not be planning to provide service in a way or at a level of reliability that is consistent with utility responsibilities. The best forecasting in some cases may consist of efforts to "firm up" customer plans and work with them to provide generation in a way that meets both utility and customer needs. This may require that utilities develop channels for investing in utility-focused upgrades to customer-planned generation.

Load Shape: Distribution systems serve loads at all times, but are built to have adequate capacity defined by the highest (peak) load periods. Areas with sharp peaks exhibit different dynamic loading characteristics for distribution equipment than for those with fairly flat load profiles. Distribution project alternatives that have time-varying load carrying capability must correlate with the peak periods in order to provide any value, so the load factor and peak timing have an impact on net cost. For example, a daytime peaking distributed generator or a curtailable load management program that allows load curtailment up to 75 hours per year could have value when the peak load is during the day, or if most of the peak is in a 75-hour time period in the load duration curve, but achieves very little with a high load-factor (fairly flat load profile).

Equipment Characteristics: The vintage, performance, and specifications of the equipment already in place represent both opportunities and constraints for feasible solutions.

Operational Details: Likewise, the availability, cost, maintenance and service requirements, spare parts issues, and reliability features of new equipment alternatives determine the technical and economic capabilities for possible solutions.

Financial Parameters: Available incentives, the possible methods of financing, taxes, and budget constraints set or alter some costs and benefits, and may dictate some of the project priorities. A capital budget may not be allowed by regulators to be spent on vegetation management, for example, even if it is the more cost-effective than undergrounding a feeder to meet reliability constraints. Perhaps the most contentious parameter in many analyses is the discount rate used for valuing future investments in current dollars, especially when valuing difficult-to-quantify societal costs. Although accounting for risk using risk-adjusted discount rates is conceptually straightforward, different theoretically sound methods lead to significantly different results. Higher discount rates favor least first-cost solutions, and the net benefit or cost-benefit ratio can be very sensitive to the discount rate -- slight adjustments can in many cases flip the ranking of two alternatives.

Synergies: If there are interactions between two projects such that two projects together are more valuable than the individual projects considered separately, then looking only at individual projects alone will miss possibly important cost savings opportunities. Synergies generally require that two problem areas be physically connected by the grid, resulting in the fact that inter-planning area synergies are rare. However, intra-planning area synergies are not as rare and can easily be overlooked.

Environmental Considerations: Direct costs can depend significantly on the attainment or non-attainment area status of the location and local permitting regulations and fees. An emissions permit trading program, for example, provides a quantifiable value for the utility for costs that are otherwise more difficult to quantify.

Power Quality and Reliability: Quality and reliability levels in the area depend not only on equipment (above) but also vegetation and climate. The realized customer outage costs further depends on the local customer value of service and customer demographics.

Uncertainty: Uncertainty in data, forecasting, regulatory climate, and cost estimates drive risk and strategic value, but also lead to risk averse behavior by planners due to fear of being wrong (e.g. slightly overbuilding or over-forecasting as a slight over-capacity has fewer repercussions than slight under-capacity). Forecasts are by nature always wrong, the question is really, "How much and in what direction?" When uncertainty is low, point-forecast methods may be adequate. Significant levels of uncertainty require the use of expected values, scenario analysis, distributions of possible costs and loads, value at risk, variance, or worst case results.

Intangibles: Are there opportunities or requirements related to public relations, goodwill, learning, political necessity, etc.? If so these may limit or pre-specify particular actions or at least include particular projects in the budget process regardless of quantifiable cost considerations.

C. Ranking and Selection: *How are alternatives and projects prioritized?*

There are two levels of prioritizing and selection that are relevant for distribution planning: selection of the best alternative for each problem area to propose for funding from the capital budget, and selection of which proposed projects are to be funded and which are not. These processes are not necessarily mutually exclusive. This section describes the criteria, constraints, and ranking approaches to select projects and alternatives within projects.

Criteria

Specifying the objective has two components: what perspective and which metric? The perspective determines what costs and benefits are included, discussed earlier (RIM, SCT, PCT). The common measures used for ranking alternatives include: present value of cost, net present value, levelized value, internal rate of return, payback time, benefit-cost ratio, engineering standards, various incremental measures such as load reduced per dollar spent, or a multivariable approach that converts a host of measures to a single number using a "utility function" that represents decision maker preferences. Any of these measures can be recast into the various cost perspectives. Each is discussed briefly below.

<u>Present value of cost - PVC</u>. Present value analysis is a tool for measuring and comparing costs and savings that take place at different times on a consistent and equitable basis for decision making. It represents a dollar value that if invested today which earned interest at rate d could match the cash flows of the project. For PVC, only the costs are considered. Each cost element is multiplied by a present worth factor equal to $(1-d)^{-t}$, where "d" is the discount rate and "t" is the time relative to some reference point. In traditional "minimum revenue requirement" mode with projects reviewed in isolation from each other, the dominant approach had been to select the alternative for each project with the lowest cost, usually based on the PVC, using the utilities cost of capital or allowed return on investment as the discount rate. In a broader view, cost savings may be included. For considering other perspectives, not only are different costs and benefits included, but a different discount rate is appropriate, as well.

<u>Net present value - NPV</u>. Net present value is identical to PVC, except that costs, savings, revenue impacts, and other benefits are included. Net present value is the difference between the present value of benefits and the present value of costs. A positive NPV indicates that there is a net benefit in present value terms. The same caveats for perspectives and discount rate apply as for PVC.

<u>Levelized cost</u>. Levelized cost or levelized value is a constant annual cost or savings over the lifetime of a project that has the same present value as the project. It is useful for comparing alternatives with different lifetimes, such as a transformer that lasts 30 years versus substituting fluorescent lights for incandescent lights that are replaced every 6-10 years. Levelized value is calculated from the present value by multiplying by a levelizing factor $LF=(d(1+d)n)/((1+d)n-1)$, where "d" is the discount rate and "n" is the project lifetime in years.

Internal rate of return - IRR. IRR is the discount rate that makes the NPV equal to zero. It provides a benchmark for performance per dollar of investment. Neither the IRR nor NPV tell the whole story about return on investment - they need to be evaluated together for a more complete picture. Its calculation requires no discount rate assumptions.

Payback time. Payback period is the time required for savings to recoup the initial investment. The period can be computed in either actual or present value terms. Payback time is rarely used formally in formal planning criteria, but sometimes used informally as another perspective, especially in situations where cash flow concerns are imminent.

Benefit-cost ratio - BCR. BCR is usually expressed in present worth terms so that BCR=PVB/PVC. If BCR is greater than one, there is a net benefit. BCR is a valid metric to compare alternatives within one project or program, but applying it for comparing options across project boundaries can lead to less than optimal spending decisions, particularly with budget limitations. BCR ranks cost effectiveness, whereas NPV ranks net benefit, with similar caveats mentioned above under IRR. To obtain the maximum benefit for a set of projects (each with several alternatives) with a limited budget, the marginal benefit-cost ratio MBCR is the metric of interest, which is the incremental increase in benefit per incremental increase in cost over the next least costly alternative.

Engineering standards. Another practice is to rank projects by engineering measures. These criteria fall into two general categories: cause (overload) and effect (what happens to customers and the system). The first can be quantified in terms of the amount of normal or emergency overload reduced or the amount of reserve capacity provided. The second can be measured by changes in loss of load probability (LOLP), outage duration and frequency indices (SAIDI, SAIFI, CAIDI, CAIFI, etc.), expected unserved energy (EUE), or other engineering reliability metrics. This can be extended to the customer value of service or outage costs, which then becomes a cost or benefit issue rather than strictly an engineering criteria.

Incremental measures. An extension of engineering standards is to rank projects by unit costs such as overload reduced per dollar invested, or change in reliability level per dollar invested. Both the engineering standards and incremental measures have some appeal because of their ease of implementation, and both can incorporate costs in the denominator from different perspectives. However, both have the drawback that they take into account only the benefit of meeting the engineering criteria and may in many cases select projects with zero or negative net benefits.

Utility function. Some utilities have moved toward incorporating a wide range of measures for each project and each alternative, and assigning value to the utility for all of the different attributes of each project that reflect the preferences and values of the corporation (or at least of its upper management). These may include the impacts on cash flows, reliability, customer satisfaction, fairness, environment, uncertainty, risk, politics, and so forth. This criteria is the most comprehensive and therefore most complex and difficult to compute. Methods that can be applied along these lines include decision analysis, value-based budgeting, analytical hierarchy process, and conjoint analysis. The details of this approach are beyond the scope of this study.

Feasibility - Constraints

Distribution planners face a number of technical financial, regulatory, and social limitations that limit the alternatives that are feasible. Furthermore, when DR alternatives are considered where investment by others (e.g. customers or third parties such as independent power producers or energy service companies), they will only be embraced if the participant is better off by joining in. Some constraints are binding, meaning that the project must be funded (e.g. a mandate), but still the utility must select exactly how to go about doing it. The final set of projects must meet all of these constraints and still provide the most favorable outcome.

Technical. Planning engineers design to standards, generally guided by meeting specific normal and emergency overload conditions, specified differently in different regions of the country. These are usually zero, single, and double contingency limitations, meaning that under normal conditions or if the single largest or two largest components (or any single or two components) are out of commission, that all anticipated load can still be met. Some areas are moving more toward using reliability metrics rather than "n-1" criteria for design[18]. Of course, all designs must meet all local technical codes, standards and regulations.

Budget. With no budget limitations, the alternative for each project with the greatest gain (as determined by which criteria is selected) would be pursued and all projects with a net gain would be funded. The ranking may differ depending on the cost effectiveness test perspective. The world of unconstrained budgets is rare (some say science fiction). "Unconstrained" does not mean unlimited amounts of money, only that the proposed "best" projects fit within the proposed overall budget. If this collection of alternatives exceeds the budget, then how does one go about selecting less expensive alternatives or which projects to not do at all? The best total set of projects is not necessarily the same as all of the highest-ranked individual projects that fit into the budget. There may be project interactions that can further impact the total value cost of the project portfolio. Another complication is that different kinds of projects fall into different budgets - such as "reliability", "capacity", "vegetation management", with no ability to "cross-fund" projects from different budgets.

Regulation. Environmental laws, zoning rules, building or fire codes, or other regulatory mandates may restrict specific alternatives or combinations of alternatives. Prohibited alternatives should of course be excluded from the cost analysis from the beginning.

Social and political. Similarly, there are groups and coalitions that can render particular alternatives or sets of projects infeasible even though they are perfectly legal. These can include considerations such as fairness or low-income aid, environmental, high visibility, privacy, or simply "not in my backyard".

Participants. Alternatives that require investment by those other than the utility must be incentive-compatible: they will only participate if they are better off by doing so. This generally requires that the participant cost test result in a BCR of at least one for a project to be feasible.

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[18] For discussion of reliability indices see for example R. Billinton and R. Allan, Reliability Evaluation of Power Systems, Plenum Press, New York, 1996.

Ranking Approaches

The ranking and selection quandary is a classic operations research portfolio optimization problem with the caveat that sometimes some of the components are difficult to quantify. Possibly the most difficult part is defining the appropriate objective. Ranking approaches range from a simple ranking "rule of thumb" to complex decision models. Each method is applicable to any of the criteria listed above. The different quantitative methods should serve as a decision support tool, not a prescription. Utilities with systems that exhibit a greater degree of project interaction and interdependence will gain value in moving toward evaluating all projects in an interdependent portfolio, but those that exhibit few such cases gain little by moving away from treating each project independently.

Senior Management Decision. The most common method is completely opaque to the distribution planner. A set of alternatives for all potential projects are submitted, and both experience and judgement are applied to determine which of the submitted projects is to be funded. The value and capability of experience and judgement should not be shortchanged because all aspects of ranking and selection mechanism can not be captured in a fully quantifiable mechanism. When implemented by experienced staff with the appropriate incentives this may be the best approach.

Independent Projects. The alternative for each project that best matches the criteria (lowest PVC, highest NPV, highest BCR, etc.) is selected for each project, then each project is funded in rank order until the budget is completely allocated. The method is simple, but very often does not lead to the optimal set of projects.

Simple portfolio. The set of projects that best matches the criteria that matches the budget and other constraints is selected, with flexibility as to which alternatives to select for each project. This approach selects the alternatives and projects simultaneously. The method used is "0-1 integer programming", and is straightforward but not necessarily easy. Value based budgeting, is a variant of simple portfolio analysis that employs a multivariable "value" function as the overarching criteria.

Interdependent portfolio. This approach requires information about project interactions that are not commonly addressed in most distribution planning. It uses the same basic mathematical method as the simple portfolio approach, but does require more effort on the part of planners to consider more complex project interdependencies. For example, if a reconductoring alternative for one area enables a load transfer to solve an overload in a different area that is otherwise not possible, then this synergy can be accurately accounted for.

Stochastic dynamic programming (SDP). SDP takes into account uncertainty in the various underlying drivers of distribution planning, usually load growth and cost, but can extend to any number of variables that the analyst is willing to model. SDP also takes into account the ability to adapt to information about these variables as it is revealed over time. For example, if load grows more slowly or more quickly than the simple average forecast, then the optimal plan given the actual load could be different. By addressing this flexibility or "real option" value, SDP adds a degree of sophistication, elegance, and realism to the mathematical model of managing the distribution system. However, the analytical complexity can be enormous (depending on the degree of complexity adopted), as the data requirements shift to estimating probability distributions of future variables instead of mean estimates, and the number of contingency plans and alternatives also usually increases. Properly applied, SDP can provide additional insight into strategic flexibility and optimal timing of investments under uncertainty, but as a planning tool needs to be pared down to the simplest possible implementation. SDP simultaneously identifies which alternatives for each project are to be funded when and under what circumstances.

D. MCC Estimation: *How are marginal capacity costs estimated?*

Most of the costs in distribution systems are fixed and the investments are large and discrete (lumpy). Incremental costing methods are employed because the strict interpretation of the term "marginal" as a slope of the cost versus demand curve becomes meaningless, cycling between zero most of the time and instantaneously infinity when investments are made. Typical practice is to use one-year time increments, but other increments may be used in any of the methods descried below. For completeness, the non-capital variable cost should be added to the capital-based MC formulations described below or included in the investment stream. Load or demand is usually defined as a coincident peak load or a coincident peak load modified by a diversity factor, as distribution systems are designed to carry peak, not average, loads.

The methods commonly in use and described below[19] are summarized in Table 10.

Table 10: Marginal Costing Methods

Marginal Costing Method	Description	Comments
Total Investment Method - TIM	Discounted capital budget cash flow divided by additional peak demand.	Longer time horizon appears less expensive. Cannot compare areas with different timing.
Discounted Total Investment Method – DTIM	Discounted capital budget cash flow divided by discounted additional peak demand.	Equivalent to constant $/kW payment needed to match cash flow. Does not capture avoided cost of a kW saved.
Present Worth – PW	Deferment value from shifting optimal capital plan in time due to change in peak demand from base case.	Captures avoided cost of a kW saved.
Regression Method (NERA) – RM	Slope of linear regression based on historical and forward-looking cost vs. demand.	Historical costs skew results. Does not capture avoided cost of a kW saved.
Replacement Cost New – RCN	Average cost based on cost to replace. Marginal cost based on "engineering elasticity" derived from simulation.	Does not reflect actual costs.

Each of these methods produces an estimate of marginal capacity costs. Many of the methods have been developed for ratemaking. TIM is rarely used and included mainly for completeness: it does not change value if investment timing changes.

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[19] These methods relate to first order to different definitions of marginal cost: TMC - textbook marginal cost, TLRIC - textbook long-range incremental cost, PWSIC - present worth of system incremental cost, AIC - average incremental cost. For a discussion of these concepts see R. Orans, Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs, Ph.D. Dissertation, Stanford University Dept. of Civil Engineering, 1989, or R. Saunders, J Warford and P. Mann, "Alternative Concepts of Marginal Costs for Public Utility Pricing: Problems of Application in the Water Supply Sector", Staff Working Paper, Washington D.C., World Bank, May 1977.

DTIM is responsive to investment timing, but remains constant if the load and cost both move by the same increment in time and thereby does not reflect any cost savings associated with a deferred investment due to a decrease in demand. Present worth reflects the savings associated with such an investment deferral, but assumes that the existing plan changes only in timing. This assumption is reasonably valid for relatively small load changes, but the overall plan could change significantly if relatively large changes are encountered. Regression provides an accurate historical account of marginal cost, but the forward-looking component has the same problems as DTIM. RCN has been employed mainly for ratemaking, designed to reflect *value* of service and thereby does not reflect the actual costs that must be incurred in response to changes in demand. For distribution costing, the PW method reflects a good estimate of forward-looking marginal costs against which new alternatives can be compared, and is straightforward to compute.

TIM - Total Investment Method

The TIM computes an arithmetic average by dividing the undiscounted total investment during the planning horizon by the undiscounted total load growth during the same period. The resulting unit marginal cost is then annualized using a Real Economic Carrying Cost (RECC) factor[20].

$$MC_{TIM} = RECC \times \frac{\sum_{t=1}^{N} I_t}{\sum_{t=1}^{N} L_t}$$

where

I_t = Capital investment in year t
L_t = Additional load in year t
N = The number of years in the planning horizon
$RECC$ = Real economic carrying cost

DTIM - Discounted Total Investment Method

DTIM is an extension of the TIM, except that DTIM discounts both the expenditures and the load growth. DTIM computes a marginal cost by dividing the present value of the planning period's investment by the present value of the load growth. The ratio is annualized using a RECC factor.

$$MC_{DTIM} = RECC \times \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t}}{\sum_{t=1}^{N} \frac{L_t}{(1+r)^t}}$$

where

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[20] RECC levelizes a stream of future payments to an annualized real cost. It measures the per dollar savings of deferring an investment one year, taking account of the stream of replacement investments.

I_t = capital investment in year t
L_t = additional load in year t
r = real discount rate
N = number of years in the planning horizon
RECC = real economic carrying cost

The rationale for discounting both the numerator and denominator is to normalize all investments and loads to a single time period. The intuitive reason for this is that the discounted load makes it so that DTIM accurately represents a constant price that if paid for the load as it occurs would exactly match the present value of the investment stream.

PW - Present Worth Method

The PW method estimates marginal cost by the opportunity costs of planned capital expenditures from a permanent increase in load. This cost is reflected in the savings associated with shifting the system expansion plan cost stream into the future, sometimes referred to as deferral value[21]. The PW method yields a MC estimate that varies over time, reflecting the greater marginal costs when investment is imminent.

$$MC_{PW} = CRF \times \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t} - \sum_{t=1}^{N} \frac{I_t}{(1+r)^{t+\Delta t}}}{\Delta L} = \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t}\left[1-\left(\frac{1}{1+r}\right)^{\Delta t}\right]}{\Delta L}$$

where
I_t = capital investment in year t
Δt = incremental change in peak load divided by the estimated annual change in peak load
ΔL = incremental change in peak load
r = real discount rate
N = number of years in the planning horizon
CRF = capital recovery factor[22]

RM - NERA Regression Method

National Economics Research Associates, Inc. (NERA) developed a linear regression technique used by some utilities and jurisdictions. The NERA regression methodology obtains a marginal unit capital cost by regressing the cumulative changes in investment with cumulative changes in load. The analysis usually uses a combination of historical and forecast period data. The marginal unit is annualized using the RECC factor. The calculation consists of estimating the coefficient "b" for the equation:

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[21] The PW numerator is sometimes presented with a distribution cost inflation index DCI and the actual cost of capital or interest rate r_{cc} rate such that $MC_{PW} = CRF \times \frac{\left(\sum_{t=1}^{N} \frac{I_t}{1+r_{cc}}\right) \times \left(1-\left(\frac{1+DCI}{1+r_{cc}}\right)^{\Delta t}\right)}{\Delta L}$

[22] The capital recovery factor levelizes a stream of future payments to an annualized real cost.

$$I_t = a + b \times L_t$$

where

I_t = capital investment in year t
L_t = additional load in year t

whereby the resulting marginal cost estimate is

$$MC_{RM} = RECC \times b$$

RCN - Replacement Cost New Method

RCN reflects the estimated cost to reproduce the existing facilities at prevailing prices. The total RCN cost of the system is usually estimated by collecting historical asset value data (differentiated by location and component type), and then converting to current values. The RCN per unit of load served (can be measured as non-coincident peak, coincident peak, diversified peak, "equivalent demand", or others) estimates the average cost of meeting demand, the rationale being that it reflects the appropriate opportunity cost. This part of the calculation is based only on historical data. The average cost is then converted to a marginal cost by multiplying by an "engineering elasticity" or elasticity of capital cost with respect to demand. This elasticity is usually derived using a forward-looking load and project projection, deriving the % change in RCN with % change in load based on forecast values. A typical formulation follows.

$$RCN = \sum_{Current\ Assets} I_t \times DCI_t$$

$$MC_{RCN} = RECC \times \frac{RCN}{NCD \times DF} \quad e = \frac{RCN}{DD}\left(\frac{\%\Delta RCN}{\%\Delta DD}\right)$$

where

I_t = capital investment in year t
DCI_t = distribution cost index (usually $(1+i)^{T-t}$ where i is inflation rate]
RCN = replacement cost
ΔRCN = incremental change in replacement cost
ΔDD = incremental change in diversified peak demand
NCD = non-coincident peak demand
DF = diversification factor
DD = diversified peak demand
ε = engineering elasticity [$(\Delta RCN/RCN)/(\Delta DD/DD)$]
$RECC$ = real economic carrying cost

E. Cost Differentiation: *How are costs allocated by location and time?*

The value that distribution system investments offer may vary by location and time. There is significant variation in distribution system *costs* from one location to another and the timing of new load additions (or reductions)[23]. Differentiating costs by location and time provides an improved benchmark against which specific project alternatives can be gauged.

Furthermore, potential solutions can affect *demand* differently over the time. Adding a wire increases capacity essentially uniformly from season to season, day to day, and hour to hour (although it adds a little less capacity when it is very hot and after being heavily loaded for a period of time). An investment in energy efficient street lighting reduces demand (adds "negawatts") during the evening hours when there is already adequate capacity. A photovoltaic panel located at the customer end of a daytime-peaking distribution circuit lowers demand when it is most needed.

The purpose of deriving area- and time-specific costs is to as accurately as possible reflect the <u>contribution</u> to the need to invest in distribution system capacity that includes where and when the demands are incurred. This section summarizes the approaches for allocating costs over location and time. The methods have been developed primarily for area- and time-specific marginal costs (ATSMC), but can in most cases be applied to expansion plan and individual project costs also. The key required steps are development of an area-specific expansion plan, assigning costs related to shared facilities, and evaluating the time dependence of distribution system costs. A utility may wish at the very least to review their current status to understand the degree of variability within their territory.

Area-Specific Expansion Plan

The most accurate method of differentiating costs by area is to develop a local distribution system supply plan. This requires that accounting and engineering databases be interrelated. The degree of granularity that is possible depends on the degree to which budget categories can be matched with specific engineering-defined boundaries. Finer distinctions become difficult partially because it requires finer load forecasts which become statistically less robust as the areas shrink. Also, area definitions are most appropriately specified by the physical boundaries defined by circuitry, whereas capital budgets are often arranged by other boundaries. At best, the degree to which the link between engineering and accounting information exists is by planning area, and more typically is that costs are not identified easily by location except through a labor-intensive research process. In the near-term, the best a utility can do is to categorize projects into specific zones to the degree that they are known using project plan documentation, but in the long-run an effort to improve the geographic information embedded in the planning process may could well be worth the effort.

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[23] For example, the marginal distribution capacity costs were evaluated for four utilities in G. Heffner, C.K. Woo, B. Horii, and D. Lloyd-Zannetti, "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution", *IEEE Transactions on Power Systems*, v13n2, May 1998, pp 560-565. Results are presented graphically in the Executive Summary and the Key Methodological Issues section.

Shared Facilities

There will still be variation in costs within the zones that define expansion plan boundaries. Both within and outside of these zones three are numerous shared facilities that are not clearly assignable directly to any single zone or sub-area within a zone. Appropriately assigning the contribution to peak capacity for shared facilities is important in further refining the cost allocation.

Several econometric methods for allocation of time-varying shared facilities costs have been developed in the peak-load pricing literature[24]. The general econometric approach uses accounting data to estimate a neoclassical, long-run production function of the utility's entire electric power system to determine the costs structure, economies of scale, technological progress, and so on. Econometric methods and engineering approaches are both couched in a cost minimizing framework, but in any situation where the physical engineering constraints of the system are binding, there is a need to include reliability evaluation, and costs are forward-looking, it is important to an engineering specification that captures these elements.

Engineering methods of assigning responsibility for shared facilities to different users involve computing a share based on fraction of some index. The simplest is the fraction of total demand measured at the instant of peak demand (coincident peak). This approach raises the questions as the when that instant is - is it the peak for the specific shared facility, instant of total system demand, or something else? A second index employed is ratio of a single user's peak demand to the sum of all of the users' individual peak demands. This approach tends to over-allocate the cost of the system to off-peak users. One correction to the non-coincident peak index is to apply a diversification factor based on the average load shape for the area or customer class. Any of these methods can be extended to a different definition of peak demand period from being instantaneous to a "peak block" such as the highest 100 hours of use or highest 10% of use. This alternate method begins to delve into time-differentiation simultaneously with area differentiation, and is discussed more fully in the next section. There are four main indices in use and in the literature.

1. Coincident peak (individual demand at the system peak divided by aggregate system peak demand).
2. Non-coincident peak (individual peak divided by the sum of all the individual peaks).
3. Diversified peak (coincident peak modified by a "diversification factor").
4. Less common is the “correlated peak” (uses the average load at the peak plus a term that is proportional to the user variability and its correlation with the system peak demand).[25]

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[24] See for example work by Scherer, Estimating Electric Power System Marginal Costs, Amsterdam, North Holland (1977) , and Bohn, Caramanis and Schweppe, "Optimal Pricing in Electric Networks Over Space and Time", *The Rand Journal of Economics* (1984), whose approaches employed at least some degree of engineering constraints in an economic model and found significant locational variation in efficient prices. This topic is reviewed in more depth in Orans (1989) [Op cit].

[25] Diversified peak and correlated peak are similar, but the coefficients are derived differently. Diversification factors typically originate from a typical load related with a customer class, whereas correlated peak originates from actual hourly load data for individual customers or groups of customers.

Area loads served by a distribution system are by nature statistical and uncertain - exact timing of the annual peak is not predictable. The average index approach above does not capture the contribution of individual users or groups of users to the variability in load. A group of French economists and engineers developed a statistical method that quantifies this contribution to better ascertain the costs of serving specific nodes in a network that captures this effect[26]. The approach can be applied at a single instant in time or differentiated into time blocks. The share for each user's contribution to the need for distribution investment is their average capacity need at the time of the peak plus a term that is proportional to their variability and correlation with the circuit variability. Formally, the total demand on the system (q^0) is expressed as an average capacity requirement at the time of the peak ($\bar{q}$) and the "irregularity margin", equal to the product of the engineering margin (λ) and the random irregularity of collective demand at the time of the peak (σ)[27].

$$q^0 = \bar{q} + l\, s$$

Each area or user provides a contribution that includes a correlation term k_i. Low values of k_i describe a tendency for the uncertainty in one customer's demand to be offset by the uncertainty in another customer's demand. High values indicate a higher probability that a single area or user's demand will be higher when the aggregate usage is also higher.

$$q_i^0 = \bar{q}_i + l\, k_i s_i$$

The aggregate demand can then be computed as

$$q^0 = \sum_i \bar{q}_i + l\, k_i s_i = \sum_i q_i^0$$

The share for area or user *i* is

$$S_i^0 = \frac{q_i^0}{q^0}$$

The method enables allocating the share of the costs attributable to different areas that share a common facility, but requires fairly extensive load information. Although the approach is computationally intensive, it is straightforward when applied to a radial system but very difficult to apply to a networked grid because the interactions are so many and complex

All of the methods to address shared facilities require extensive hourly load data. Basing these statistics on historical data may not reflect the future use for which the incremental equipment is being built to serve. Utilities vary significantly in their current data sets; some can readily apply this approach, while others needs special metering studies to obtain any data other than non-coincident peak.

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[26] Boiteaux, and P. Stasi, "The Determination of Costs of Expansion of an Interconnected System of Production and Distribution of Electricity" (1951), translated in J.R. Nelson's Marginal Cost Pricing in Practice, Prentice Hall, 1964.

[27] The term λ is described as a typical engineering margin established by each planner.

Reasonable DR costing and planning often requires significant enhancements to load data, because DR options, especially DSM options, can impact peak loads of specific customer end-uses in ways with complex interactions with utility peak. Additionally, significant data is required on customer demographics and program performance. Performance data includes lead time, reliability, and potential saturation. This data tends to be more available from utilities that have extensive existing DSM programs and are subject to rigorous evaluation requirements as part of their regulatory oversight.

Time Dependence

Allocation of costs over time (the different hours in the year) can be accomplished in two ways:

1. Using "peak block" shares, or
2. Applying allocation factors.

Peak block shares define costs attributable to a specified peak period or block (e.g. the top 100 hours or all hours above a threshold level), and assign costs based on fractions of specific indices.[28] This time allocation is usually binary -- all the costs are incurred in the peak period, and zero the rest of the time.

Allocation factors take the allocation of costs over time much further than the peak block approaches. The two key allocation factors are the loss-of-load-probability and the peak capacity above a threshold level. These two methods allocate a share of the costs to each hour of the year.

Time allocation methods are summarized in Table 11.

Peak block share methods are useful for determining costs attributable to different users on shared facilities during the peak period. They provide only rudimentary time differentiation, as they allocate all costs to the peak period and zero to all other times. The coincident and non-coincident peak block methods are computationally simple. Non-coincident peak tends to overestimate the contribution of users whose peak use takes place during lower demand portions of the peak period. Diversified and correlated peak correction factors require more extensive statistical analysis. Diversification factors are usually based on generic average customer types, whereas correlated peak is a more detailed analysis of correlation of the load profile of specific users or groups of users with the system load during the peak period.

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[28] For example, 50% of the costs for a substation could be allocated to the loads on feeder x, and 100% of those costs could be allocated to the 100 hours with the highest loads. To further this example, those loads might be between 5 and 7 PM on August weekdays, from 6-8 AM on December Mornings, and 10 AM to 6 PM on the three hottest days of the year.

Table 11: Methods for Cost Allocation over Time

Method	Description	Comments
Peak Block Shares		Costs lumped into peak period.
Coincident Peak	Fraction of usage during system peak period.	Smoothes out use from instantaneous coincident peak.
Non-coincident Peak	Non-coincident peak during peak period.	Overestimates contribution by spiky off-peak users.
Diversified Peak	Non-coincident peak modified by diversity factor.	Diversification factor usually based on customer type.
Correlated Peak	Fraction of usage, adjusted for correlation with system peak, during peak period.	Requires extensive statistical load data and analysis.
Allocation Factors		Costs assigned to each hour.
Loss of Load Probability - LOLPAF	Hourly fraction based on contribution to annual LOLP	All hours are allocated some cost. Requires extensive reliability model.
Peak Capacity - PCAF	Hourly fraction based on load above threshold level.	Hours below threshold level are assigned no cost.

Allocation factors provide a much finer time scale, assigning shares hour-by-hour. The LOLPAF method is the most sophisticated, and yields a measure most closely associated with the motivation to build new capacity. However, it becomes computationally complex quickly as systems become large, and its is subject to the quality of the outage statistics assumptions. The PCAF method is computationally straightforward. Both LOLPAF and PCAF require hourly load data (preferably a forecast but usually conducted with historical data). PCAF yields an approximation of the contribution of the load during each hour to the need to invest in distribution capacity. PCAF is sensitive to the specification of the threshold level. Because of the improved capability over the binary peak block methods and simplified computational mechanics relative to the LOLPAF method, the PCAF method has tremendous advantages.

Peak Blocks

The "snapshot" approaches for allocation of costs by location discussed above basically define the peak period as a single instant in time. The first step in extending from this simplification is to designate an on-peak period, defined by a specific duration (e.g. the top 100 hours of demand[29]) or all hours above a threshold level (e.g. within 10% of the instantaneous peak). With these definitions, the percentage of average demand or the other instantaneous indices (described above) during the peak period provide means to allocate area-specific costs to two different time periods, but basically assigns all peak load cost to the on-peak period and zero costs to the off-

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[29] Swisher & Orans, "A New Utility DSM Strategy Using Intensive Campaigns Based on Area-Specific Costs, *ECEE 1995 Summer Study* (1995), cite 60-100 hours for allocating area-specific MDCC.

peak period. Using the average load during the peak hours as an example, the cost share S^i attributable to the peak load period for area or user *i* is determined by

$$S^i = \frac{\sum_{Peak\ hours}\left(Load_h^i\right)}{\sum_{Peak\ hours}\left(Load_h^0\right)}$$

The longer peak period definition used spreads out the impact of using the instantaneous coincident peak. The non-coincident peak can overestimate the contribution by spiky off-peak users. The diversification factor is usually based on customer type, requiring more extensive statistical analysis if more specific information is applicable. The correlated peak method can be extended, but the data and computational complexity issues discussed earlier are amplified.

Allocation Factors

Two key methods have been posited for extending the concept of time-dependent costs beyond the "on-peak is responsible or all costs and off-peak is zero" paradigm. The first estimates each time period's share of costs to its contribution to the loss of load probability (LOLP), which serves as a measure of why the distribution system is built to begin with[30]. The second takes a simpler approach to develop hourly "peak capacity allocation factors" (PCAF) that measure the average share of demand during the hours that the system is above a specific threshold level, a different but more easily estimated measure of the "appropriate" level of distribution system capacity[31].

LOLPAF: Loss of load probability for an area is first calculated as a function of total load using a computer model of the network. This LOLP function can then be combined with either the load duration curve or the full 8760-hour load profile for the area. The total LOLP for the area is the sum of the individual hourly contribution to LOLP, designated by h_j . The resulting LOLP allocation factor for each hour is then computed as

$$LOLPAF_j = \frac{h_j}{LOLP} = \frac{h_j}{\sum_{k=1}^{8760} h_k}$$

The LOLPAF requires a fairly robust reliability model. However, LOLP can be approximated using simpler higher-level models. Each hour is assigned some level of costs, as there is always some non-zero probability of a failure. The cost allocation is of course only as good as the reliability data and model, and to be most useful for planning should be as close as possible to the forecasted behavior, not historical.

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[30] For detailed description see J. Vardi et al, "Variable Load Pricing in the Face of Loss of Load Probability", *The Bell Journal of Economics*, v8n1, Spring 1977, pp. 270-288. For treatment of LOLP as a measure of capacity needs, see Crane, A. and R. Roy, "Competition, Trading and Reliability of Electric Power Service", *Annual Review of Energy and the Environment*, v17, pp. 161-186.

[31] See for example, G. Heffner et al (1997): Footnote 23 [Op cit].

Also, when a new project affects the reliability of the system (which is nearly always the case), the allocation could change significantly for each potential alternative.

PCAF: The peak capacity allocation factors allocate costs to hours in proportion to that hour's contribution to the need to add capacity. PCAF for each hour is calculated as the share of incremental load in the peak period divided by the total incremental load in the peak period. The peak period is specified by a *Threshold* peak period cut-off value, typically defined as the load level one standard deviation down from the historical single hour peak, but definitions can vary. PCAF for each hour is calculated as follows.

$$PCAF_i = \frac{max\{(Load_i - Threshold), 0\}}{\sum_{h=1}^{8760} max\{(Load_h - Threshold), 0\}}$$

Hours below threshold level are assigned no cost using PCAF and the results are sensitive to the choice of threshold level. However, the PCAF method provides a good balance of providing an equitable allocation of cost to time periods and computational ease. The measure should also be forward-looking. It is more easily iterated with different alternatives that impact capacity timing than the LOLP is to incorporate reliability changes.

F. Typical Distribution System Hardware Costs

Equipment	Lower Cost Examples	Higher Cost Examples
Lines	50 k$/mile: 46 kV wooden pole subtransmission	1,000 k$/mile: 500 kV double-circuit construction with 2,000 MVA capacity ($.50/kVA-mile).
Feeders	Overhead: $10-15 per kW-mile. Rule of thumb for 3-phase overhead wooden-pole cross-arm type feeders of normal large conductor (about 600 MCM per phase at ~12.47 kV) runs about $150,000 per mile. Range is $55,000 to $500,000 per mile.	Underground: $30-50 per kW-mile.
Laterals	Overhead: $5-15 per kW-mile.	Underground: $5-15 per kW-mile (direct buried) $30-100 per kW-mile (ducted)
Substation	Rural substation: 69 kV feed to 5 MVA transformer serving 4 MW load: ~$90,000 (includes all fuses and poles and buswork) or ~$23/kW.	Suburban/urban substation: 2x138 kV lines feeding 2x40 MVA 138kV to 12.47 kV transformers, each with 4x9 MVA feeders for ~$2,000,000. Serving a peak load of about 60 MVA this is $33/kW. If serving a tighter utilization, could be about $25/kW.
Miscellaneous	Mainline, conduit - $90/ft Mainline, D.B. - $38/ft Lateral, conduit - $63/ft Install transformer - $2,698 Change out transformer - $2,822 Install - 3 switch - $20,871 Replace - 3 switch - $11,203 Install - 1 fuse switch - $11,367	Replacing cable: 1 - $180/ft. 3 - $360/ft. Capacitors (installed) Substations: $ 9/kVAR Line: $ 5.5/kVAR Padmounted: $ 21/kVAR
Connection	Connection cost per customer ~$300 (or $60/kW of coincident load)	
Single-phase padmount transformers (installed)	<u>12.5 kV (loop feed)</u> 25 kVA: $2,552 50 kVA: $2,986 75 kVA: $3,591 100 kVA: $4,972	<u>34.5 kV (loop feed)</u> 25 kVA: $3,119 50 kVA: $3,931 75 kVA: $4,725 100 kVA: $5,728
Three-phase padmount transformers (installed)	<u>12.5 kV (loop feed)</u> 75 kVA: $7,749 150 kVA: $9,450 300 kVA: $11,718 500 kVA: $13,608 750 kVA: $21,357 1000 kVA: $25,515 1500 kVA: ------- 2500 kVA: -------	<u>34.5 kV (loop feed)</u> 75 kVA: $10,584 150 kVA: $11,605 300 kVA: $15,574 500 kVA: $20,034 750 kVA: $21,377 1000 kVA: $28,350 1500 kVA: $40,824 2500 kVA: $50,841

NOTE: above costs include necessary cable terminations, pads, misc. material and transformer, but no primary or secondary cable.

Sources:

Willis, H. and W. Scott, Distributed Power Generation: Planning and Evaluation, Marcel Dekker, New York, 2000.

Burke, J., "Hard to Find Information About Distribution Systems", May 1997, http://www.pti-us.com/pti/consult/dist/papers/hardfind/costs.htm