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THE DISTRIBUTED UTILITY: A New Electric Utility Planning and Pricing Paradigm

Charles D. Feinstein
Department of Decision and Information Sciences, Santa Clara University,
Santa Clara, California 95053

Ren Orans
Energy and Environmental Economics, 353 Sacramento Street, San Francisco,
California 94111

Stephen W. Chapel
Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto,
California 94304

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ABSTRACT

The distributed utility concept provides an alternate approach to guide electric utility expansion. The fundamental idea within the distributed utility concept is that particular local load increases can be satisfied at least cost by avoiding or delaying the more traditional investments in central generation capacity, bulk transmission expansion, and local transmission and distribution upgrades. Instead of these investments, the distributed utility concept suggests that investments in local generation, local storage, and local demand-side management technologies can be designed to satisfy increasing local demand at lower total cost. Critical to installation of distributed assets is knowledge of a utility system's area- and time-specific costs. This review introduces the distributed utility concept, describes an application of ATS costs to investment planning, discusses the various motivations for further study of the concept, and reviews relevant literature. Future research directions are discussed.

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INTRODUCTION

Over the past 20 years, electric utilities have been challenged by economic, regulatory, institutional, and technical developments. As they continue to respond to these challenges, utilities can be expected to alter the way they conduct their business, including the way they operate, the way they plan, and possibly even the way they are structured. This review explores a possible path of evolution for electric utilities that entails a response to these challenges and adopts a nontraditional approach to investment planning. The essential feature of this path is that utilities may evolve into what we refer to as distributed utilities. The purpose of this review is to describe the distributed utility (DU) concept and discuss some research that suggests that the concept has merit.

THE DISTRIBUTED UTILITY CONCEPT

United States electric utilities had become highly centralized and vertically integrated companies by the mid-1960s. The economic justification for the vertically integrated utility has not changed for more than 100 years: Economies of scale in central generation plants permit utilities to supply energy at an ever-decreasing cost per kWh to customers connected to an ever-expanding transmission and distribution system. The increasing cost of fuel, the inflation of the 1970s and 1980s, a reduction of central generation station economies of scale, increasing environmental mitigation costs, and the failure of the nuclear power industry to deliver inexpensive power, in combination, perhaps with other factors, led to an increase in the real cost of generating electricity. Further, deregulation studies and changes in state and federal regulations identified the need for and encouraged the development of competition in the generation supply market. Therefore, the justification for the centralized, vertically integrated utility may be weakening.

Two other developments are of interest. First, in 1989, the capital investment, over the entire industry, in transmission and distribution systems equaled the investment in generation for the first time. Increasing transmission and distribution investment is expected to continue. In 1985, the fraction of total annual investment allocated to generation was 69%, and the corresponding proportion for transmission and distribution investment was 27%. By 1994, the fraction of total annual investment required for generation was 38%, but the share for transmission and distribution had increased to 51% (1). In 1993, for three California investor-owned utilities, the annual capital expenditures were approximately equally divided between generation and the combined cost of transmission and distribution [Federal Energy Regulatory Commission (FERC) Form 1, analysis provided by F Graves]. Predictions that extrapolate the observed trend indicate that the transmission and distribution share of the total utility construction outlays may increase to 80% after 1997 (2).

Second, various new generating technologies are approaching commercial viability. Although the costs of these technologies (such as photovoltaics, small diesel engines or gensets, and fuel cells) have decreased appreciably, further reductions will be required before these technologies become competitive. Commercialization of these alternatives requires using the economies of mass production to bring down their costs and thus entails the simultaneous evolution of markets and the technologies themselves. Rather than delaying introduction until improvements in both the technologies and equipment manufacturing decrease total costs, commercializers may be expected to exploit high-value market applications for the current generation of technologies. Such early applications will stimulate both the natural development of the technologies and the manufacturing techniques used to produce them. This development process should accelerate as new opportunities for these technologies are identified. As the cost of generation decreases, new applications become possible; thus, the technologies and the markets evolve jointly.

These conditions—increasing costs, exhaustion of central station economies of scale, environmental considerations, increased competition, changes in capital investment patterns, and development of alternate technologies—suggest that there are economic benefits to be gained if modular generation or storage units are placed in the local transmission or distribution system close to selected loads. Further, since the transmission and distribution system is designed to meet infrequent but large peak loading, the assets that account for the major portion of the current and forecasted capital investment are not often utilized to capacity. Although such capital investment may be optimal given the available alternatives and the constraints that guide the traditional utility planning process, there may be an opportunity to shift capital if other alternatives are considered. Recent studies (3–6) suggest that modular generation or storage units, augmented by specially designed demand-side management (DSM) programs, can be used to reduce these infrequent peaks and to do so with cost savings when compared to the cost of reinforcing or expanding the local transmission and distribution system. If intelligent controllers and switches are added, it might even be possible for these local generation, storage, and load control capabilities to be dispatched for system-wide needs as well.

The idea that generation, using modular and perhaps renewable technologies, modular storage facilities, and specially designed DSM programs, can be distributed throughout the transmission and distribution system and serve as an alternative to planned central generation investment and transmission and distribution system expansion is fundamental to the concept of the distributed utility. In 1992, a group that included research and academic institutions, government agencies, and electric utilities was formed to study the distributed utility concept (7, 8). This was not the first time the concept was addressed. Earlier reports measured the benefits of siting small-scale dispersed storage and generation assets in a utility's transmission and distribution system (9–21). Those benefits included reduced capacity requirements of the transmission and distribution system, improved reliability, and lowered losses. Under the distributed utility (DU) concept, the central station assets are still likely to provide the majority of the energy needs of all customers, but the distributed elements will meet local-area transmission, substation, and feeder peaks when and where most useful. The latter idea is the distinguishing characteristic of the DU concept. Planning under the DU concept highlights transmission and distribution costs and how distributed assets can affect those costs, compared with the kind of planning practices that tend to ignore the impacts on the distribution system and focus mainly on generation. Indeed, when the costs of transmission and distribution are taken into account, expansion strategies can change greatly.

AN EXAMPLE OF DU PLANNING

PG&E's Livermore-Pleasanton Planning Area

Pacific Gas and Electric Company (PG&E) is the largest investor-owned utility in California. PG&E serves customers in 201 planning areas distributed over nearly the entire length and breadth of the state, from Santa Barbara in the south to beyond Eureka in the north; service areas extend to the Sierra in the east and to the relatively sparsely populated areas in the south-central part of the state as well as to the urban population centers of San Francisco and San Jose and to the neighboring suburban areas.

PG&E's Livermore-Pleasanton (LP) planning area is located about 40 miles southeast of San Francisco. The area encompasses the Interstate 680 corridor in the San Ramon valley from south of Danville past Interstate 580 through Pleasanton. Expansion planning in the area was based on an estimate of the expected value of the peak load growth rate of 12.3 MW per year, or 9.2%, per year, of the maximum area load, which was 133 MW in 1990. PG&E's system-wide growth rate was approximately 2% per year at that time. The LP area is composed mainly of residential and small commercial customers (58% and 33%, respectively, of the peak load), with a smaller number of industrial and agricultural customers (9% of the peak load). The relatively large growth rate is due to the expected increase in the commercial and residential classes, resulting from individuals and companies relocating from San Francisco and the San Francisco peninsula to the more affordable locations in the San Ramon valley.

Using conventional planning approaches, PG&E proposed an upgrade of the 230-kV and 60-kV lines that served seven substations in the area. The plan included construction of a 230-kV transmission line to one of the substations (Vineyard). That part of the plan attracted attention when Pleasanton residents learned that the line would be built overhead across the mountain range that separates Pleasanton from San Francisco. The residents requested that the last few miles of the line be underground to avoid site pollution associated with the overhead line. PG&E began to investigate other approaches in order to avoid the cost of the underground line. A revised plan was approved by the California Public Utilities Commission that included construction of a 90-MVA transformer at another substation, which deferred the 230-kV underground line until 2001. This expansion plan is depicted in Figure 1. The present value of

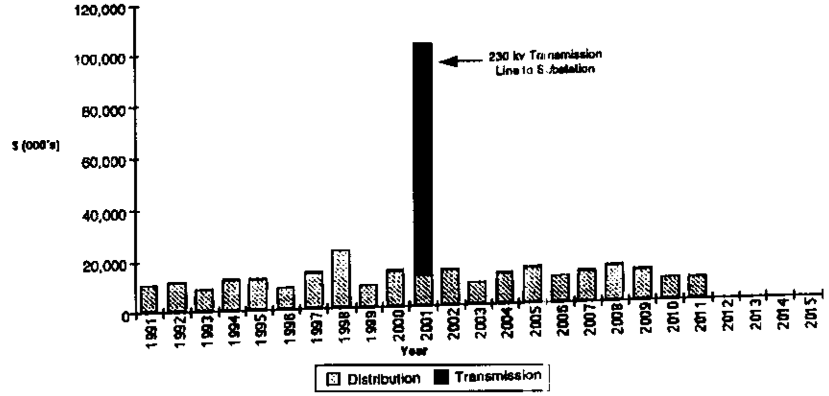


Figure 1 Conventional expansion plan costs for LP area.

this plan is $355 million. This amount includes all direct and indirect costs required to support expected load growth over the 20-year planning period.

A natural question to ask is whether it is possible to modify this plan and still satisfy the needs of the planning area. The conventional planning criteria used to develop the expansion plan shown in Figure 1 determine plans that provide high levels of reliability while meeting the load in the area. Therefore, the conventional solution to the planning problem is to expand the capacity of the transmission and distribution system in the area so that local peak demand is satisfied, using central generation capacity to supply the needed energy. Thus, the following observation is immediate and fundamental: The costs of transmission and distribution capacity expansion can be attributed to very few hot or cold hours of the year, depending on the season of the peak demand. The observation is immediate because capacity expansion is needed only if peak load exceeds existing capacity. The observation is fundamental because it is the analysis of these few peak hours in each planning area that determines the structure of alternatives to conventional planning. Finding such alternatives is the basis of the distributed utility planning process. Therefore, it is necessary to identify the high-cost areas and hours for a utility. These areas and hours can be found through a process that decomposes a utility system's costs into so-called area- and time-specific (ATS) costs (22).

Although the purpose of this section is to discuss an example, some background may be of interest. In PG&E's 1993 General Rate Case, PG&E became the first vertically integrated, investor-owned utility to have regulatory approval for the use of area- and time-specific (ATS) costs for rate making and resource planning. [Other utilities may be expected to apply for similar approval. The Federal Energy Regulatory Commission has adopted a more flexible pricing policy for transmission services (23).] The resource planning applications included targeting demand-side management (DSM) programs and installing generation and storage assets locally, in the high-cost areas, as measured by the ATS costs, to lower the cost of transmission and distribution (T&D) expansion. As noted above (see The Distributed Utility Concept), lowering T&D costs by meeting local peak demand using local generation, storage, or DSM programs is what characterizes planning under the distributed utility concept.

Prior to 1993, PG&E and the Electric Power Research Institute (EPRI) collaborated on a series of four studies that addressed such local investment planning. The first project focused on the siting of a 500-kW photovoltaic plant connected to a primary distribution feeder from PG&E's Kerman substation (5). The study used ATS costs and hourly load analysis to site the facility optimally and to develop estimates of both bulk-system and local benefits. The results indicated that the photovoltaic plant was not cost effective. Nevertheless, the study estimated that the local benefits of this investment were on the order of the more traditional system energy and capacity benefits. The second study, applied to PG&E's Delta district, addressed the optimal integration of DSM programs with a local conventional T&D expansion plan. The study applied ATS marginal costs and estimates of load by area, customer segment, and end-use. The result was an integrated (conventional investments plus DSM) expansion plan that was approximately 30% less expensive than the original, conventional expansion plan. In fact, PG&E built the Kerman photovoltaic facility (as a demonstration of the technology rather than as a cost-effective investment) and implemented the first two years of the integrated plan in the Delta District (4). The third study in this series addressed the Livermore-Pleasanton area (24). That study added locally sited generation and storage devices to the set of possible investments, and it is the source of the example under discussion. (The fourth collaborative study constructed an integrated planning process that combined existing models of generation, transmission, and distribution planning. The report describing that study is not yet available.)

The integrated expansion plan shown in Figure 2 was found for the LP area by applying ATS costs and integrating DSM and locally installed generation and storage assets into the conventional expansion plan. The integrated plan deferred the transmission upgrade to 2009, which changed the present value of the upgrade from $94 million to $55 million. The present value of the distribution investments was also reduced owing to deferral, and it decreased to $178 million from the original value of $261 million. Thus, the original plan had conventional investments with a present value of $355 million; deferral reduced the present value of those investments to $233 million. The deferrals were created

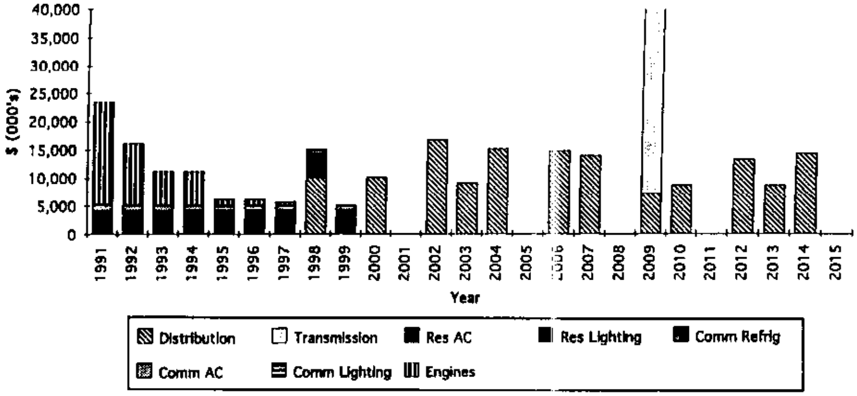


Figure 2 Integrated expansion plan costs for LP area.

Table 1 Comparison of net present values of the original expansion plan and the integrated expansion plan for LP area

	Original plan	Integrated plan
Transmission upgrade	94	55
Distribution investments	261	178
Conventional investments (total)	355	233
DSM investments		41
Locally sited engines		48
Avoided generation capacity and avoided energy costs		(160)
Net present value (total)	355	162

by investing in DSM and locally sited engines. The present values of those investments were $41 million and $48 million, respectively. Further, the benefits of avoided energy costs (due to DSM) and avoided generation capacity costs (due to locally sited engines) were, together, $160 million. Therefore, the net present value of the integrated plan was $162 million (55+178+41+48−160). The savings due to integrated planning was $193 million, or over 50% of the original present value. These results are presented in Table 1.

ATS Costs in Livermore-Pleasanton

The ATS cost in a local area is the sum of three components: avoided generation capacity cost, avoided energy cost, and avoided local transmission and distribution cost. The avoided generation capacity cost is the value to the system of not having to supply generation capacity to a local area at a particular time. This cost is a function of the cost of a combustion turbine, the expected system unserved energy, and the hourly load on the system. The main idea in the computation of hourly avoided cost is that the cost is greatest when the system is under stress, i.e. serving a peak load. The avoided generation capacity cost for hours that are not likely to be system peak hours is zero. Figure 3 exhibits the avoided generation capacity cost for the PG&E system. The system peaks at about 4:00 P.M. each day. July, August, and September contain all the high-load hours. The maximum hourly cost is about $6.50 per kWh, in July. This may appear to be a large value. The purpose of the analysis is to assign the cost of serving the peak load to the hours in which the peak load is likely to occur. It is natural to observe relatively large costs over relatively few hours. The avoided energy cost is based on the system-wide forecast of hourly energy costs. An environmental adder is included, in this case, to account for pollution reduction that results from reduced load on central generation units that emit pollution. The environmental adders may vary by season. The average marginal energy

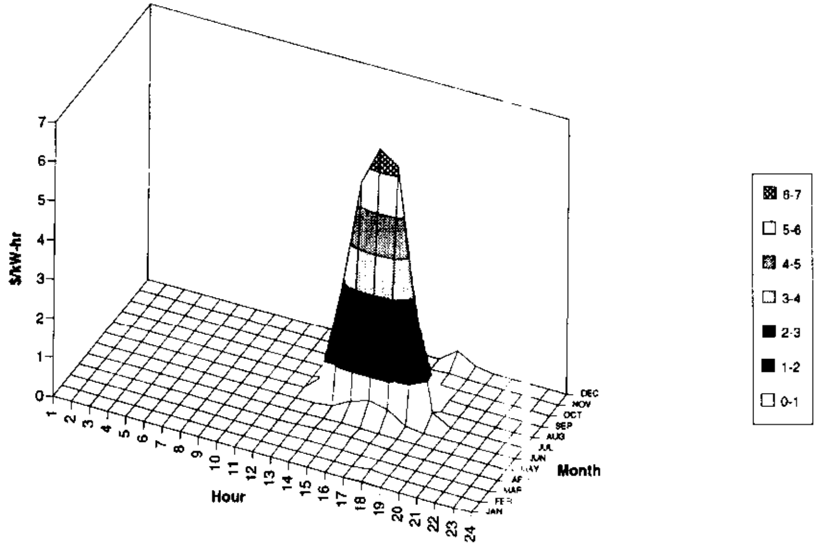


Figure 3 Hourly marginal generation capacity costs in $/kWh.

cost was $.0236 per kWh, and the average environmental adder was $.0114 per kWh. These costs are multiplied by energy loss factors to account for transmission energy losses. The avoided energy cost can be presented in a figure similar to Figure 3 but is not shown here. For the PG&E system, the marginal energy costs are greatest in December, when they are about $.065 per kWh between 8:00 A.M. and 8:00 P.M. In July, August, and September, the marginal energy costs are approximately $.035 per kWh between 2:00 P.M. and 6:00 P.M.

The avoided local transmission and distribution cost is not based on system behavior. Instead, that avoided cost is equal to the difference between the present value of the conventional expansion plan, as presented in Figure 1, and the present value of this plan when it is deferred for some time. For example, suppose an investment of $1.00 to be made now could be deferred for n years. The present value of that deferred investment is $1.00 $(1+i)^n/(1+r)^n$, where i is the annual inflation rate and r is the appropriate annual discount rate. The avoided cost associated with deferring this planned investment is $1.00 $[1-(1+i)^n/(1+r)^n]$. This avoided cost can be allocated hourly by various approaches. In the present case, the cost was allocated over the 100 hours corresponding to the largest local loads, using a weighted average over the aggregate load in those hours. (This allocation was based upon the spiky load-duration curve observed in this case. Figure 9, below, indicates that a typical

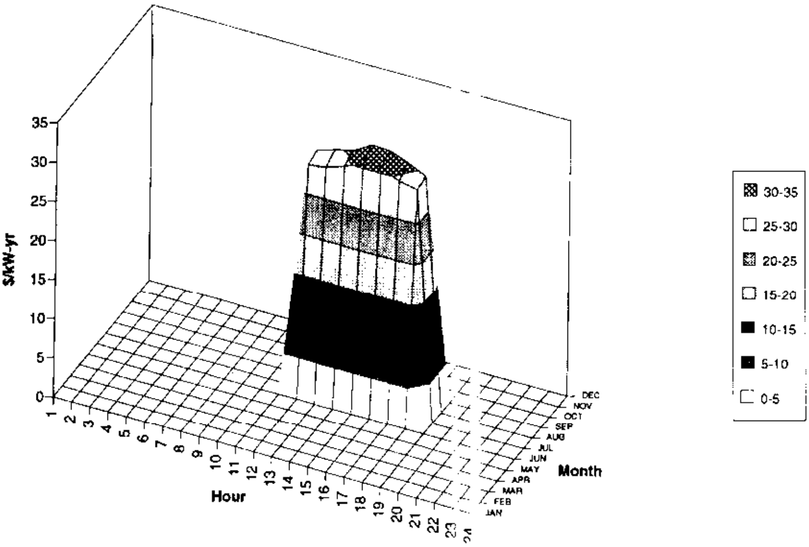


Figure 4 Hourly marginal local T&D capacity costs in $/kW-year.

distribution planning area load-duration curve is more peaked than a system-wide load-duration curve. There is relatively little load diversity in a local planning area.) Figure 4 exhibits these costs. The hourly costs are largest between noon and 7:00 P.M. during July and August. The peak value is about $1.10 per kWh at 3:00 P.M. in August.

One way to relate these costs to local-area conditions is shown in Figure 5. In all three graphs, the independent variable is the local hourly load, shown in decreasing order from the local peak of 133 MW; the hour is implicit. The top graph shows that the avoided local T&D cost is a decreasing function of the local load. This is a consequence of the allocation scheme described above. After the load drops below 109, no avoided cost is assigned, because the load drops below 109 after the one-hundredth hour. The middle graph describes the avoided cost of generation for the local area. This curve is not monotonic because the local-area peaks do not coincide with the system-wide peaks. The system-wide peak hours have the greatest avoided generation costs. The middle graph is another representation of the data in Figure 3. The third, bottom, graph shows the marginal energy cost assigned to each of the loads in the local area. Again, this graph is not monotonic because the peak local-load hours do not correspond to the hours at which the system energy cost is largest.

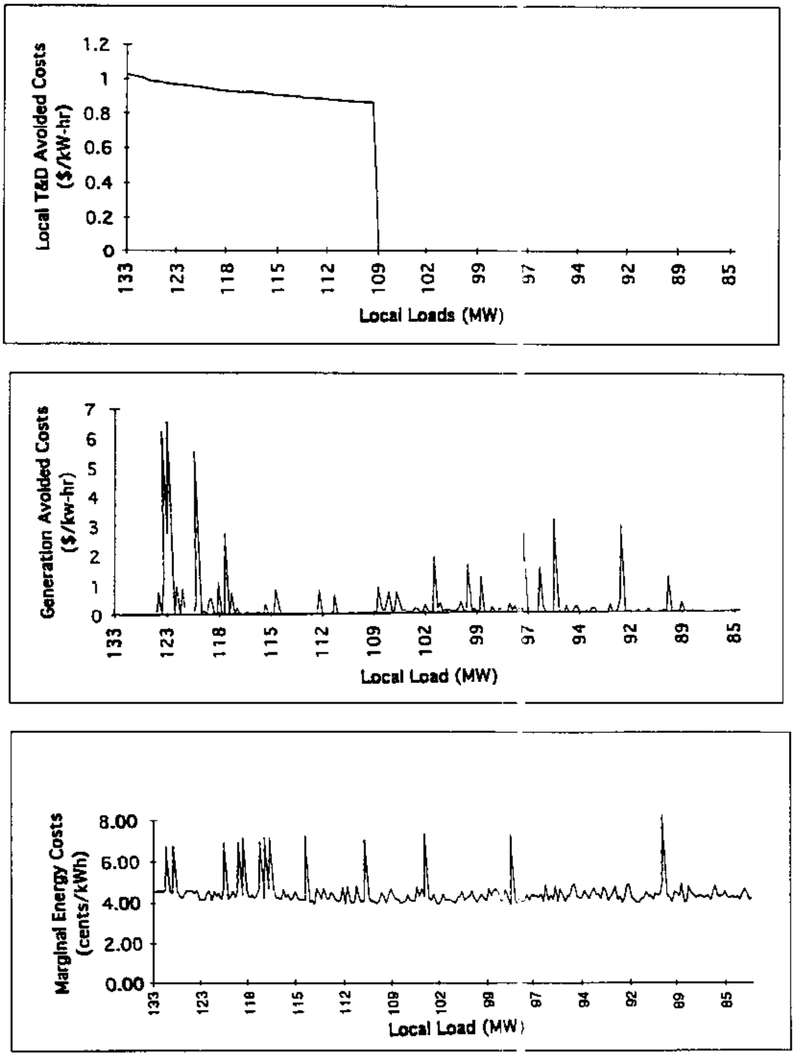


Figure 5 Local hourly avoided costs (determined by local peak load) for transmission and distribution, generation, and energy.

Modifying the Conventional Expansion Plan

The ATS costs indicate the hours during which local-load reduction would be most beneficial. The next step, then, is to identify cost-effective investments, such as DSM programs, locally sited engines and batteries, that can reduce the load in those high-cost hours. The question of which investments to make, when to make them, and how to dispatch them to minimize the net present value of the integrated expansion plan can be formulated as a dynamic optimization problem (4, 25). The essential aspects of the solution technique are as follows.

An investment will be integrated into the expansion plan if its operating benefits are greater than its life-cycle costs over the planning horizon. The benefits are measured by the avoided costs associated with the optimal dispatch of the investment. The life-cycle costs are given by the initial capital investment and the following stream of operating and maintenance costs, determined by the dispatch of the investment, and a salvage value, as appropriate. Note that the calculation of ATS costs, benefits, optimal dispatch, and life-cycle costs must be done dynamically, over the planning period, as new investments are brought into the plan. Clearly, the dispatch of a particular technology depends on what other technologies are present in the plan, when those technologies were installed, and how they are dispatched.

The alternatives considered in the LP area were phosphoric acid fuel cells, grid-connected single axis tracking photovoltaics, standard lead acid batteries, and gas-fired generator sets. Capital costs (including installation), operations and maintenance costs, degradation costs, and performance characteristics were collected for each technology for the 0.5, 1.0, and 5.0 MW sizes. Table 2 contains the data that describe each alternative. Columns A–G in Table 2 describe the alternate technologies. The remaining columns will be discussed immediately below. The notes in Table 2 explain further how each value was found.

The variable operating cost of each technology can be used to find the maximum number of hours that it would be beneficial to operate the technology, for a given set of ATS costs. For example, Table 2 indicates that the variable operating cost of the 0.5 MW fuel cell is \$.0521 per kWh (column F). The cost-duration curve (Figure 6) indicates that the avoided cost is greater than or equal to \$.0521 per kWh for more than 200 h. A more accurate observation cannot be made from the figure because of the scale of the graph. The actual number of hours on the cost-duration curve that corresponds to that variable operating cost is 977 h (column H). Similarly, the variable operating cost of the 1-MW photovoltaic unit is \$.0165 per kWh, which corresponds to over 4000 h on the cost-duration curve. Therefore, both technologies could be operated over the high–ATS cost hours. The hours of operation of the 2-h battery are restricted because of the capacity limitations defined by the amp-hour rating and the state

Table 2 Technology cost data and analysis for LP area distributed technologies

Column A	B	C	D	E	F	G	H	I	J	K
	Initial capital costs (\$/kW)[a]	Fixed M&O (\$/kW-yr)	Variable M&O (cents/kWh)	Fuel costs (cents/kWh)[b]	Variable operating cost (cents/kWh)[c]	Heat rate (Btu/kWh)	Number of hours dispatchel per year	Present value of fixed M&O (\$/kW)[d]	Present value of variable M&O (\$/kW)[e]	Life cycle costs for 20-year life (\$/kW)[f]
2-hour flooded lead acid battery										
500 kW	1,418	2.80	1.30	0.00	10.30		36	31	5	1,454
1000 kW	1,080	2.80	1.30	0.00	8.20		36	31	5	1,116
5000 kW	845	2.80	1.30	0.00	6.74		40	31	6	882
Tracking PV[g]										
500 kW	8,700	0.00	1.10	0.00	2.20		4,410	0	535	9,235
1000 kW	8,286	0.00	0.61	0.00	1.65		4,410	0	296	8,582
5000 kW	7,365	0.00	0.50	0.00	1.42		4,410	0	243	7,608
Low speed generator set[h]										
500 kW	1,542	7.00	1.80	2.74	8.59	11,400	222	77	111	1,730
1000 kW	1,105	5.50	1.60	2.71	7.22	11,300	291	61	138	1,304
5000 kW	996	2.80	0.75	2.42	5.74	10,100	694	31	242	1,269
High speed generator set[h]										
500 kW	1,157	7.60	2.50	2.91	10.37	12,300	195	84	116	1,357
1000 kW	911	6.00	2.20	2.83	8.94	11.800	220	66	122	1.099
5000 kW	841	3.00	1.70	2.71	7.90	11,300	249	33	121	995
Phosphoric acid fuel cell[i]										
500 kW	5,156	31.00	2.50	1.89	5.21	7,885	977	342	473	5,970
1000 kW	4,971	18.00	2.50	1.89	5.17	7,885	1,010	198	489	5,658
5000 kW	4,603	10.00	2.50	1.89	5.10	7,885	1,064	110	515	5,228

[a] Data in columns B, C, D, E and G taken from unpublished PG&E Technology Report. Column B equals capital cost in Technology Report increased by 9.6% and then multiplied by 0.84.

[b] Column G × fuel cost of 240 cents per MBtu where M = 1,000,000.

[c] (Columns D + E) + degradation factor × (Columns B + I) × 100. Battery variable operating cost does not include cost of recharging from the grid.

[d] Column C discounted at 6.5% over 20 years where 6.5% = 10.5% cost of capital − 4% inflation.

[e] (Columns D + E) × Column H/100 discounted at 6.5% over 20 years where 6.5% = 10.5% cost of capital − 4% inflation.

[f] Equals columns B + I + J.

[g] Assumed capacity factor of 28%.

[h] Natural gas or deisel-fired reciprocating engine.

[i] Initial capital costs include the costs of stack replacement every two years.

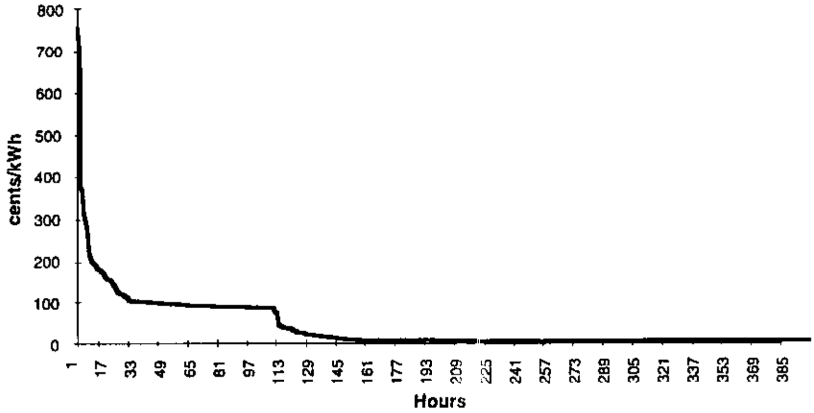


Figure 6 Total avoided costs for LP area: cost-duration curve.

of charge characteristics. These physical constraints restricted use to only 40 h for the 5.0-MW battery and 36 h for both the 1.0-MW and the 0.5-MW batteries, overruling the economic considerations (which would otherwise permit even the most expensive battery to operate for more than 200 h).

The maximum hours of operation provide a bound on the benefits that can be achieved by each technology. These benefits must be compared with the life-cycle costs (column K), which include capital (column B), fixed operating and maintenance costs (column I), and variable operating and maintenance costs (which depend on the actual hours dispatched; column J). The life-cycle costs listed permit a comparison of the technologies studied in this example.

The most cost-effective investments in the LP area are engines and batteries. They would be dispatched for relatively few hours and therefore cost relatively little to operate. Their life-cycle costs are dominated by their capital costs. The photovoltaic technology is the least cost effective. Although it is beneficial for the photovoltaic technology to be dispatched for more than 4000 h, the capital cost is too great for the technology to be cost effective in this application. Indeed, the sum of the avoided costs over the more than 4000 h of operation, given by the integral of the cost-duration curve, is no more than 35% of the life-cycle cost for any of the photovoltaic alternatives in this example. Applying insolation constraints that decrease the number of hours the photovoltaic technology could be dispatched—the maximum possible value is approximately 2700 h—would make the results even worse. For the engines, the sum of the avoided costs is more than the life-cycle costs, even though the engines are dispatched for relatively few hours. Hence, it is worthwhile to use engines to reduce the load in the LP area. The steepness of the cost-duration curve suggests that most of the benefits are achieved by operating engines over relatively few hours. The additional hours that the photovoltaics can operate are not worth very much in terms of ATS costs. The conclusion for fuel cells is similar. Although fuel cells can be economically dispatched for approximately 1000 h, at relatively low operating cost, the capital cost is the major component of the life-cycle cost, and that cost is far greater than the integral of the cost-duration curve over the operating hours. The batteries have capital costs comparable to the engines and are cheaper to operate than the engines. The two-hour limitation prevented them from being cost effective. A battery or storage device with sufficient energy to follow the distribution peak loads might be as cost effective as an engine in the LP area.

This analysis is suggestive of the way that the expansion plan would be modified. The actual method that integrates the technologies with the conventional plan is a dynamic algorithm that specifies the integrated plan based on hourly and yearly changes in ATS costs. (In the form it was implemented to modify the LP plan, the algorithm does not necessarily find the true dynamically optimal solution. It does converge to a solution that improves upon the conventional plan.) As technologies are added to the plan and dispatched in the years of the planning period, the ATS costs change. In particular, the avoided T&D cost varies as investments are deferred. This variation introduces an opportunity for the integrated plan to be improved by targeting the technologies not only to high–avoided cost hours but also to high–avoided cost years. That is, the cost effectiveness of a technology can vary by year. In the LP area, the batteries became cost effective in the year immediately preceding the large transmission upgrade, which was originally scheduled for 2001. (The engines are still preferable to the batteries, and the fuel cells and the photovoltaics remain uneconomical choices, but the dynamic variation in cost effectiveness is a component of the analysis.)

DSM alternatives are also candidates for integration into the expansion plan. In the LP area, cost-effective DSM programs included residential air conditioning, residential lighting, commercial refrigeration, commercial air conditioning, and commercial lighting. Fourteen DSM alternatives were introduced, but only these five were cost effective. Selection of cost-effective DSM programs for integration into the plan was based on the presence of appropriate end uses in the high-cost hours. The application of the dynamic algorithm developed the integrated plan described above, in Figure 2. The only technologies integrated into the plan are DSM and engines.

MOTIVATION FOR STUDYING THE DISTRIBUTED UTILITY CONCEPT

The distributed utility concept may be defined as a planning approach that replaces planned investment in central generation, transmission, and distribution

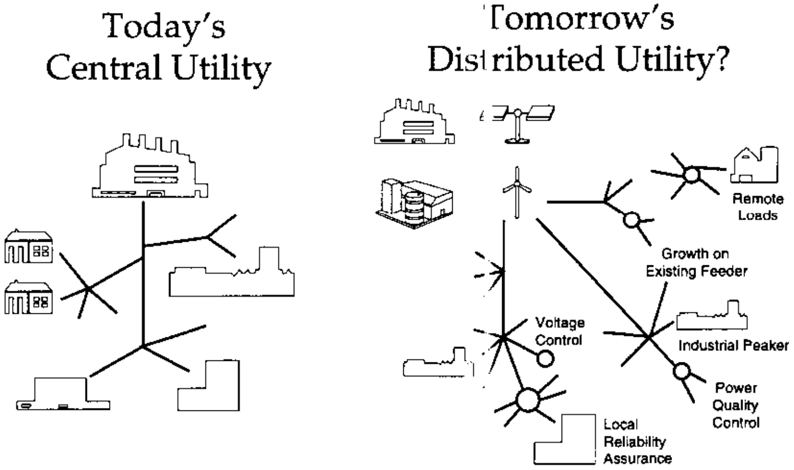


Figure 7 Structural comparison of the central station model utility and the distributed utility.

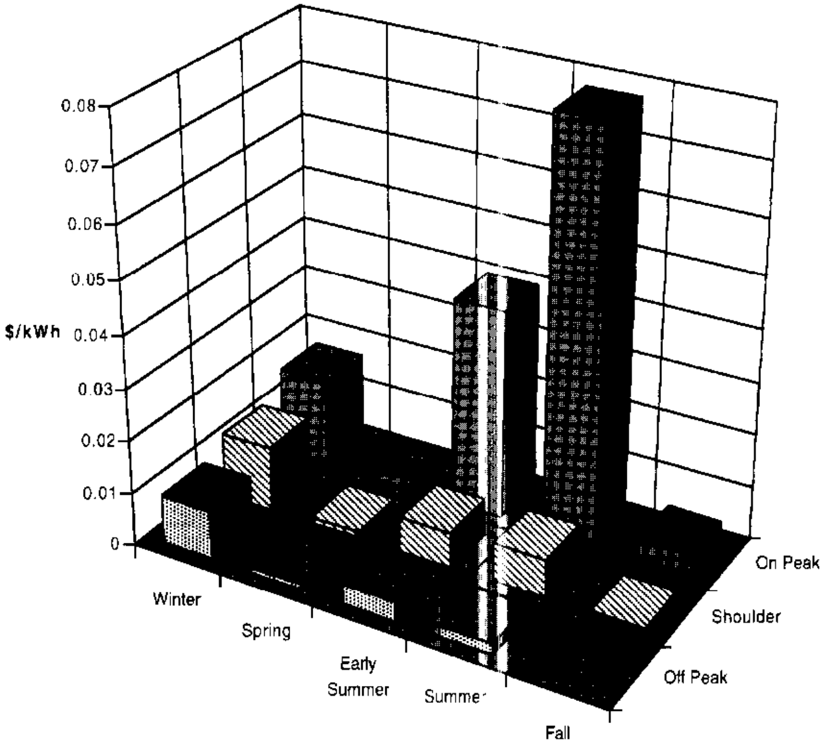
system assets with locally cited generation, demand-side management, and storage technologies, under certain local conditions. The difference in structure between a central utility and a utility that would expand according to the DU concept is illustrated in Figure 7. The central hub generation and spoke transmission and distribution, on the left side of the figure, has been the typical pattern adopted by utilities to generate and supply electric energy. On the right side, a schematic of the possible structure of a future distributed utility is presented. The schematic indicates that central station power plants will be integrated with distributed generation and storage devices. In certain cases, utility and third party-owned or operated modular generation technologies can serve remote loads that are too expensive to connect to the utility grid. What might motivate a utility to adopt this kind of evolutionary planning practice? The DU concept appears to be of interest from several points of view. There are economic, regulatory, institutional, and technological considerations that motivate further study of the DU concept.

Economic Considerations

COST OF SERVICE Economically efficient planning and operation of the modern utility ought to be based on the total cost of electrical service, which includes the costs (investment and operating) of all links between the power sources and the customer. Currently, utility planners direct most of their attention to the cost of installing a central generation plant and, to a lesser extent, the associated transmission and distribution investment costs of delivering the additional power demanded. Since transmission and distribution costs have been small compared to generation costs and were viewed as unavoidable because of existing assumptions about system structure and connectedness (as illustrated in Figure 7), utility planners viewed the cost of service as being driven by the cost of central generation. This observation is supported by the fact that planning models for electric utilities have almost exclusively focused on the efficient operation and expansion of the generation system. Basic transmission and distribution expansion planning models were not available prior to the development of the DU concept. It has become increasingly important, in part because of the advent of competition in the industry, to base investment decisions, pricing decisions, and operating decisions on the costs of all the components of service to customers: generation, transmission, and distribution.

If structural assumptions are relaxed, it is possible to imagine a utility that augments centralized production with modular local generation, targeted local demand-side management programs, and modular local storage distributed throughout the system. The total cost of electricity would then be a function not just of the traditional elements—central generation, bulk transmission, and local transmission and distribution—but also of the distributed elements. Taking into account the possibility of applying system-wide demand-side management programs and large centralized storage, the total cost of service depends on the joint effects and costs of all of these items. In particular, the cost of implementing distributed technologies at the local level, as an alternative to other expansion plans, should be compared to all and not just some of the costs avoided by such implementation. These avoided costs, which will almost surely vary by location, include the avoided costs of generation, transmission, and distribution.

The DU concept recognizes that the true cost of local transmission and distribution (T&D) capacity is a function of location and time. In the past, utilities have tended to price on the basis of the average cost of T&D capacity. The average cost hides the important variation in costs that exists from area to area, as well as the temporal variation in costs over the course of an expansion plan. The application of area- and time-specific (ATS) T&D costs, as illustrated in the LP planning example discussed above, demonstrates that it is necessary to decompose T&D costs in order to identify high-value applications of distributed generation technologies. The average costs of T&D capacity cannot indicate the true value of such applications. In the top half of Figure 8, the results of a typical-system average "marginal" costing study for a utility located in the southwestern United States are shown. Costs are estimated by time-of-use period. The average cost of peak-period summer consumption is nearly $0.08 per kWh. In the bottom half of the same figure, the ATS costs are estimated on an hourly basis, for a single year, in an isolated fast-growth area of the same utility



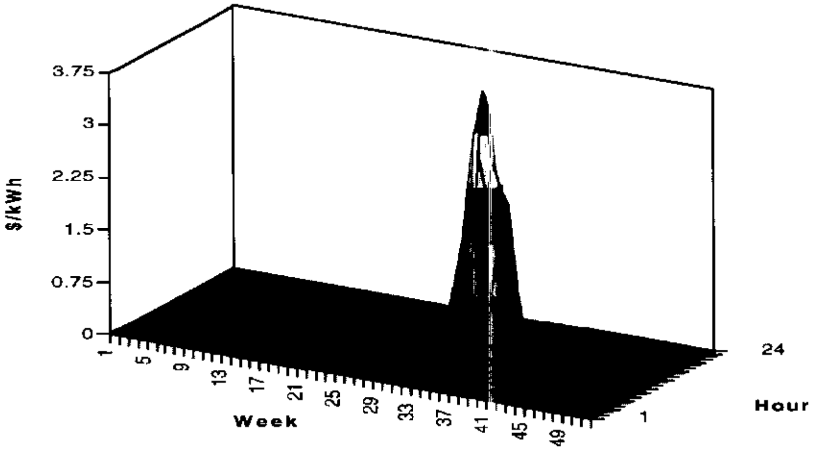


Figure 8 Comparison of system average ("marginal") costs and ATS costs.

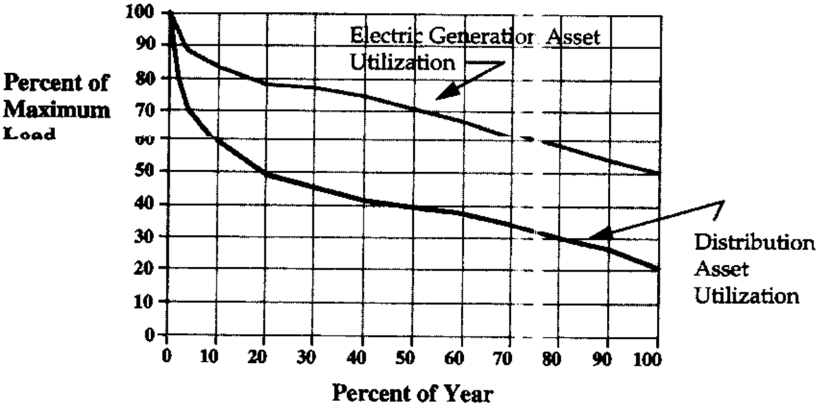


Figure 9 Comparison of annual load duration curves for a typical PG&E distribution feeder and the entire PG&E generation system.

system. There are hours during the year that actually cost the utility nearly $3.00 per kWh.

CAPITAL ASSET UTILIZATION One motivation for considering the effects of distributed elements in the total system can be illustrated by two load-duration curves observed in the PG&E system. Figure 9 indicates that PG&E's generation assets are being used at 70% of capacity or more about 50% of the time. A typical distribution system feeder is being used at 70% capacity or more less than 10% of the time. Generation assets never fall below 50% utilization, while the typical feeder is utilized at 50% of capacity less than 40% of the time. This difference occurs partly because feeder systems are sized to meet intermittent local-area peak loads, whereas the generation system is sized to meet the entire system demand. Since the local-area peak loads occur at different times and at different magnitudes throughout the system, they do not coincide in a system peak; the entire system demand is, in general, less sharply peaked than local-area demand.

Since transmission and distribution investment is becoming the major capital item for the industry as a whole, as discussed above, reducing the magnitude of the transmission and distribution peaks would have an important effect on industry capital requirements. Implementing targeted area-specific demand-side management programs, adding modular local storage, and adding local generation are among the ways to reduce local peak demand. It is possible that such approaches are cost effective and thus a preferred investment for the utility, because planned expansion of the transmission and distribution system could be delayed by such measures. This delay may provide a considerable financial benefit. An added benefit of this approach is that less central generation capacity would be needed, so the utility could move towards a more constant level of utilization of both central generation and transmission and distribution assets over time, while changing its pattern of capital investment.

Whether the utility can or should change its pattern of capital investment is the main issue. The appropriate choice for a utility is not obvious. In particular, the utility must weigh the impact on service quality of changing the way it invests in distribution capacity. For example, if the utilization of distribution system assets were increased, there might be important consequences for reliability because failure rates would tend to increase. Such considerations are central to the distributed utility concept. One way of expressing the DU planning perspective is that the objective is to find the mixture of central and distributed generation, central and distributed storage, and central and distributed load management that will improve utilization of both central generation and transmission and distribution assets, reducing the need for capital investment, without sacrificing service quality.

Regulatory Considerations

UNCERTAINTY Regulatory agencies have responded to uncertainty in load growth forecasts by discouraging large central station investments. The long lead times and lumpy capital flows of such investments can be replaced by much shorter lead times and much smaller incremental investments typical of the distributed utility approach. The distributed utility concept provides increased flexibility in expansion planning, the possibility of making decisions contingent upon future conditions, the ability to delay large capital commitments, and the ability to match capacity changes to load changes. Hence the distributed utility concept may be successfully applied to the problem of planning under uncertainty (26). Further research is required to validate the importance of such flexibility.

COMPETITION AND NATURAL MONOPOLY ARGUMENTS As noted above, deregulation studies and changes in state and federal regulations have identified the need for and encouraged the development of competition in the generation supply market. It is possible that the increase in competition will create opportunities for smaller-scale generation, at or below 5 MW capacity. This possibility is enhanced by any decreasing difference in cost between large central station generation and smaller-scale technologies, such as photovoltaics, fuel cells, and generator sets. If small-scale modular technologies can be cost-effective generation alternatives under some conditions, utilities could reduce the costs to rate payers if such technologies were integrated into the systems.

Alternatively, under performance-based regulatory schemes that index prices or revenues, reductions in costs could increase the utility's earnings.

Although generation is moving toward greater deregulation, it is possible, if not likely, that the utility will retain a natural monopoly in transmission and distribution. Ruff (27) argues that the transmission and distribution assets form a "physical infrastructure" monopoly. The fundamental question for such a "gridco" is whether to purchase additional power from a generation "poolco," add T&D capacity, add small-scale generation, or conserve. The distributed utility concept provides an approach to answering this question. As regulatory interest in local transmission and distribution issues is increasing, it is not unreasonable to expect that future regulations will address transmission and distribution planning functions. If cost-effective opportunities for distributed technologies are found, it is not unlikely that some form of incentives or other regulations, including broadened least-cost planning requirements, will be developed that encourage the application of these technologies. An alternative view is given by Morse (28). Morse argues that as vertical unbundling proceeds, it is inconsistent for a regulated utility to own distributed generation assets. He presents a scenario under which the distribution monopoly is broken by competitive distributed generation (on the customer site). Nevertheless, the considerations fundamental to the DU concept form the basis of the argument. The fundamental question, for Morse, is what entity owns the distributed assets, not whether there will be any.

We can suggest three conditions that would tend to promote consideration of the DU concept. First, if prices increase, customers might be motivated to invest in distributed generation on their side of the meter. This presupposes that the prices charged will reflect the true costs of service. Second, if there is active rate-of-return regulation that judges the prudence of local-area investments, utilities might be motivated to investigate the application of the DU concept. This investigation requires the use of appropriate planning tools to reveal what investment strategies are least cost over time. Third, if performance-based regulation is structured so that there are incentives to minimize the cost of delivered energy, then utilities might find that the DU approach is valuable.

ENVIRONMENTAL CONSIDERATIONS Finally, many technologies, such as photovoltaics, solar thermal, wind, and fuel cells, are viewed as more environmentally benign than central station alternatives. The "green" movement that began in the 1970s and continues to grow in the 1990s is a force that regulatory bodies and utilities will surely have to consider as they plan the evolution of their systems. The preferences of regulators for environmentally benign generation technologies has been expressed as environmental adders and higher returns on equity for clean or renewable generation investments by utilities.

These incentives can create niche opportunities for appropriate technologies distributed to relieve local peak loads (29).

LOCAL INTEGRATED RESOURCE PLANNING The forum for discussion of these opportunities is shifting from utility-integrated resource planning proceedings to local transmission and distribution siting cases. State regulators are beginning to bring pressure on utilities to develop local integrated resource planning processes that seek to defer transmission and distribution investments cost effectively or to avoid them completely if they are found to be unneeded (30). State public utility commissions (PUCs) are beginning to require utilities to file studies that demonstrate that there are no cost-effective alternatives to transmission facilities. This trend should continue and will motivate utilities to adopt planning processes that focus on the remaining portion of their natural monopoly assets, the T&D system. It is not currently known how integrated resource planning will fit into the new competitive environment, but it has been clearly recognized that "IRP at the T&D level . . . has resulted in major reductions in T&D costs" (31, p. 27).

Institutional Considerations

INTEGRATED PLANNING METHODOLOGY A fundamental issue is how the utility will plan for integration of small-scale modular technologies. Most current planning tools begin by projecting system-wide energy demand and then calculating the size of the central station plant needed to meet the projected demand. Cost-effective system increments are typically at least several hundred megawatts. This approach routinely ignores specific needs at the local transmission and substation level (and below), which can use modular distributed generating sources of no more than a few megawatts. Also typically ignored are the increasing costs of transmission and distribution and the impact of such increasing costs on the marginal cost of service. It is possible that the utility of the future will derive its most important planning data from the substation level and below. Planners will benefit from feeder information on customer mix, demand and consumption by customer type, outage history, and the value customers place on reliable service. Planning models that address these issues are under development. EPRI has supported many of the modeling efforts for DU planning, giving particular attention to planning under uncertainty (32, 33), modifying existing expansion strategies by incorporating distributed technologies (4, 25), and applying ATS costs to determine how best to integrate DSM into the investment plans (34, 35, 38). Other methodology developments have been directed at reducing the amount of data required to make investment decisions (36, 37).

DIFFERENTIATED CUSTOMER SERVICE Customer-specific information is important not only for planning purposes but also because the utility of the future may well be delivering a product to a customer rather than delivering an undifferentiated commodity—power—to all customers. In order to compete, a utility will have to provide differentiated services to customers, based on customers' needs, at the lowest possible cost. In addition to requiring changes in planning procedures and models, providing such service will also require operational changes. It is natural to expect that a utility's assets will have to be used more effectively to attract and keep customers, by responding to customers' particular demands and not simply providing a generic service. It may be that these required planning and operational changes can be achieved cost effectively with the expected flexibility provided by the distributed utility concept.

RESTRUCTURED UTILITY It is also possible that availability of modular distributed generation and storage technologies that can be sited economically throughout the transmission and distribution system will cause utilities to change their structures. This scenario represents an alternative to the natural monopoly argument regarding transmission and distribution. The future utility may partition itself such that each planning area becomes a mini-utility or profit center.

A planning area typically contains system elements that are strongly connected. The connection across planning areas is relatively weak. Ideal planning areas also have homogeneous load growth and types of customers. Typical rural planning areas are comprised of a single primary distribution substation and a set of radial feeders, and they range in size from several MW to less than 100 MW. Suburban areas often have multiple substations and more highly interconnected feeder systems. The LP area discussed above is an example of a suburban planning area. Urban areas can sometimes have as many as 10 networked substations. Since T&D planning is currently performed ad hoc, many utilities do not even know what their planning areas are. The more advanced utilities, however, maintain expansion plans by area for the purpose of forecasting their capital budgets. This information is often very useful for decomposing T&D costs and for determining the value of small-scale generation and storage technologies by area.

Each profit center can purchase bulk power from the backbone transmission system and combine it with available power at the planning area level and below. The amount of power generated locally will depend on the relative costs of such local generation compared with the "imported" power from the bulk system.

In such a partitioned or "distributed" structure, the concept that the utility is providing differentiated products to customers, as discussed above, instead of a generic service to all, is natural. Time-varying pricing at each substation would be possible, if not likely. Each profit center could "package" power for each customer within the substation service territory. Each package could be characterized by price, time of day, quality, voltage, quantity, and reliability, since the distributed elements should provide as much control over those attributes as necessary to allow the utility to deliver the exact service the customer requires.

Technological Considerations

FOCUS ON THE DISTRIBUTION SYSTEM Most fully integrated utilities have substantially separate generation, transmission, and distribution resource planning organizations. Generation and bulk transmission projects are typically large single investments that are closely scrutinized by upper management and regulators. Distribution planners, often located in operating divisions physically removed from company headquarters, typically respond to outside needs rather than having their technology and budgets driven by strategic planning focused on the distribution system directly. For example, demand-side management programs are often designed centrally for overall system relief rather than being motivated by local problems that could be solved by targeting such programs at the high-cost hours.

The status of distribution planning is becoming increasingly troublesome for at least three reasons. First, distribution has the greatest impact on utility customers' perceptions of the value of utility services and products, since the distribution system is responsible for nearly all outages, power quality problems, and other drivers of customer satisfaction. Second, as noted above, the distribution system, for most utilities, currently requires a larger annual investment of utility capital than transmission and generation projects. Data from three California utilities indicate that distribution costs accounted for approximately 20% of the average cost per kWh in 1993. That fraction is increasing. Also, approximately 20% of the distribution costs come from operating and maintaining the system, with capital investment costs accounting for the remainder. For example, in 1993, PG&E's costs for distribution were $1.53 billion, of which $0.27 billion was attributed to operating and maintaining the system, out of a total cost of $6.47 billion for generation, transmission, and distribution (FERC Form 1, analysis provided by F Graves). Therefore, the distribution system is naturally becoming an increasingly important driver of corporate planning. Third, with industry restructuring, the distribution business may be separating from both generation and transmission. It is reasonable to expect that customers will be offered alternatives to purchasing energy from a local distribution company. Therefore, business success will depend on distribution investment planning to a far greater degree than it has in the past.

EXISTENCE OF DISTRIBUTED RESOURCE TECHNOLOGIES Some distributed generation has been added to many utility systems. For example, wind generation has been added to PG&E's system. BC Hydro has recently developed standards for the interconnection of independent power producers rated up to 5 MW on 12.5-kV feeders and 10 MW on 25-kW feeders.

Successful integration of these assets into their respective systems serves as motivation for further penetration. The technologies likely to be installed in the utility system of today to meet local needs are dispatchable DSM programs (load control and real-time pricing), small gas-fired generators, and, potentially, storage batteries. Photovoltaics, solar thermal dishes high-efficiency fuel cells, and small super-conducting magnetic energy storage devices are technologies that hold promise for distributed applications but may not become cost effective until further developed. Hybrid systems, which would include more than one technology, such as batteries and a generator set with photovoltaics for a standalone installation, appear especially interesting and flexible.

THE DISTRIBUTED UTILITY PLANNING PARADIGM

The distributed utility concept embraces more than the use of small-scale local generation and storage technologies coupled with demand-side management programs to lower the utility's total cost of delivered power. The concept implies a decomposition of the power production and delivery system into three separate functions: generation, transmission, and distribution. This decomposition motivates new approaches to planning since, to some degree, each function has the ability to replace all or a portion of any other through investment, pricing, or conservation. The broad view of the DU concept is that it suggests that the solution to the planning problem is to determine the most efficient integration of the decomposed functions. This solution concept is clearly different from the traditional, top-down approach to expansion planning, which gives primacy to central generation planning.

The emerging competitive bulk power market will separate the generation function from the rest of the system. But the existence of bulk-generation competition is not sufficient for total cost reduction, because local-level competition is surely necessary to reduce the cost of energy for users. It seems that efficient pricing at the local level, as part of the (decomposed) distribution function, is essential to achieve the benefits of competition. How, then, can efficient pricing be determined in order for competition to be encouraged?

In the past, the difference between the capacity costs of large-scale central station generation and smaller-scale generation plants compensated the vertically integrated utility for the costs of transmission and distribution. As this difference decreases, accompanied by increasing costs of transmission and distribution, the cost-effective applications of small-scale generation plants will increase. These small-scale plants can be either renewable or nonrenewable technologies. To the extent that the current cost trends continue, vertically integrated utilities could transform into distributed utilities. The distributed utility would purchase a portion of their power from a competitive bulk power market, provide their own power through a combination of small generation and local storage, and apply targeted demand-side management programs to modify the load that must be served.

Thus, the DU technologies augment the purchases from the bulk generation market. The particular cost and load characteristics of each utility system determine when, where, what type, and how much of a particular DU technology is cost effective. Utilities with excess generation capacity that also have well-defined areas of continuing growth may find that the costs of transmission and distribution capacity in certain areas are greater than the costs of providing generation capacity and energy. Moreover, to the extent that existing transmission and distribution planning criteria are designed to provide very high levels of reliability over local planning areas, the costs of transmission and distribution capacity expansion can be attributed to a few very hot or cold hours of the year. Decomposing a utility system's costs into area- and time-specific (ATS) costs identifies these high-cost areas and hours. These costs determine the appropriate DU technologies and efficient pricing strategies.

The evolution of the electric utility into a form that incorporates DU technologies or creates a viable outside market implies an important endorsement from regulators and utilities for the transformation from average costing and rate making to ATS costing and rate making. This transformation will require that the role of utility regulation be weighted more toward the promotion of efficiency than equity. Such weighting is inconsistent with the history of regulation of electric utilities in the United States. The important relationship between a utility's ability and willingness to determine and reveal ATS costs and the identification of niche DU applications places the utility in a curious position. Planning based on ATS costs can lead to more competitive, lower costs of service and potentially higher earnings for the utility. At the same time, the publication of ATS costs invites third parties to develop and own sources of generation that may be competitive with portions of the T&D grid.

There are fundamental issues associated with ATS costing and rate making and ownership of the distributed assets as the electric utility industry evolves and becomes more competitive. One future scenario has the regulated vertically integrated utility withering away as competitive central generation becomes completely unbundled and transmission and distribution become common carriers serving the competitive generation market (39). Distributed generation and storage can then be used by "wires" companies to avoid T&D expansion. Regulators may find this situation undesirable because of the cross-subsidies that may result. In particular, regulators and competing retail providers may be very concerned that avoided upgrades could be used by competing providers to reach new customers. Alternatively, a retail provider may be able to collect T&D savings by installing distributed resources near potential customers (28,40). The benefits of competition under this scenario are then local, with respect to pricing, as a result of decomposing the prices of generation, transmission, and distribution.

CONCLUSIONS AND FUTURE RESEARCH DIRECTIONS

Conclusions

This review has described the distributed utility concept, an approach to utility expansion planning that identifies cost-effective niche applications of distributed generation and storage technologies. The two main aspects of this approach are that (*a*) the various technologies are sited (distributed) throughout the system so that they are physically close to the peak loads they are relieving, and (*b*) the approach identifies the area- and time-specific costs associated with planned transmission and distribution investments.

There is debate about the extent of penetration of distributed technologies, and assessments of the market have been made (41,42). Currently, mainly because of capital cost variations among the technologies, the largest opportunity exists for targeted dispatchable DSM and low-cost engines. These niche applications could extend to both batteries and photovoltaics as the performance and costs of these technologies change in the future. Fuel cells offer the possibility of bypassing the T&D system entirely or in part—some imagine a fuel cell in the basement of a home—but require performance and cost improvements before becoming a competitive technology.

Although there has been an increasing amount of research directed at the DU concept, much is still unknown. There are open questions about both economic analysis and engineering feasibility. In addition, the changing conditions in the structure of the industry will almost surely affect the degree to which the DU concept guides planning. If a true paradigm shift were to occur, what may happen to the regulated utility itself is not yet clear. Despite such uncertainties, the basis of the DU concept, which is that the increasing costs of T&D expansion can be reduced by nontraditional investments in generation and storage guided by purely local economic and load considerations, seems to offer a perspective that will be important under many different future scenarios.

Future Research Directions

RELIABILITY CONSIDERATIONS The DU evaluation studies reviewed assume that the reliability of the utility's delivery system will remain unchanged with the incorporation of DU assets. This appears to be a reasonable assumption, if the aggregate capacity of the installed distributed technologies is relatively small compared to the capacity of the utility's system. There are two interesting cases where there can be substantial changes in reliability of the delivery system. In the first case, the distributed investments actually replace rather than defer a large facility like a transformer bank. This will decrease the reliability of the distribution system. The utility T&D system is designed to serve load at any location for a specified period of time with a single contingency fault. Since the designed failure rate of each component is extremely low, the majority of these faults are not related to equipment failure. Since some of the DU technologies (generators, for example) have higher failure rates than less dynamic T&D components, the use of a DU device as a replacement will increase the probability of an outage. In the second case, the distributed technology is located very near the load, perhaps at a customer site. This reduces the impact of uncontrollable events such as inclement weather and collisions into power poles (the most frequent causes of distribution outages). The effects of installing distributed technologies on system reliability requires further analysis (43).

ANALYSIS UNDER UNCERTAINTY The models applied to the DU planning problem make assumptions about the future and typically treat those forecasts as deterministic. The solutions thus determined will be optimal if the assumptions about the future environment are actually realized. Aspects of the future environment, such as load growth, regulatory restrictions, technological change, fuel costs, environmental conditions, and other variables, have been captured as forecasts in the model. The variation in the optimal solution as a function of the departure from forecast values of the variables is not a priori known. It is important to learn which variables cause the most variation in the solution and to determine a strategy that permits the utility to react to such departures from forecast values. Without the ability to react to new information, the utility will make non-optimal decisions. The objective of uncertainty analysis is to determine whether uncertainties in the forecast variables are important and, if so, how best to respond to such uncertainties

Uncertainty analysis provides several benefits that are not readily achieved by deterministic analysis alone. These benefits include the specification of a contingent strategy, the measurement of the value of the option to delay, and the value of modularity. Brief explanations follow. Since the values of sensitive variables can change the optimal solution, the actual optimal solution should be contingent on and thus responsive to the future observed values of the sensitive variables. An important benefit of the distributed utility concept is that the utility can delay building large central generation stations or upgrading transmission and distribution systems, unless and until it becomes clear that such large investments would be worthwhile. DU technologies provide short-term alternatives for satisfying growing demand. The option to delay larger investments has value that can be revealed by an analysis of uncertainty. Finally, since distributed utility alternatives are characterized by short lead times and relatively small capacities, they are both flexible and modular. Short lead times and the ability to implement only as much capacity as needed provides the utility the responsiveness that a large central generating unit or large transmission line does not provide. The utility is better able to match load, use resources more efficiently in the short term, and lower short-term costs and rates. The benefits of flexibility and modularity associated with a particular distributed generation investment have been measured (44). Current efforts are aimed at developing models for DU planning under uncertainty (26, 32, 33, 45; CD Feinstein, PA Morris & SW Chapel, submitted).

DYNAMIC ANALYSIS The models that are used in utility planning are essentially static models, evaluating or optimizing decisions at a particular point in time. Although it is clearly recognized that investment planning is a dynamic problem, the treatment of intertemporal tradeoffs requires improvement.

For deterministic models, the planning problem should be reformulated as an optimal control problem or a mathematical programming problem. Standard algorithms can then be applied to the formulation to determine the optimal solution (25). Current practice in solving a dynamic problem entails either an unrelated or loosely coupled set of static problems or applies a limited look-ahead algorithm that is almost surely suboptimal. For stochastic formulations, the model should be based on stochastic dynamic programming so that the dynamic behavior of the system is captured in the formulation (33; CD Feinstein, PA Morris & SW Chapel, submitted). Current research is directed at dynamic formulations for both deterministic and stochastic problems.

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