Distributed Generation

Who Benefits?

In the first of three articles, experts at Oak Ridge National Laboratory examine the technical obstacles, deployment, and economic issues surrounding distributed generation.

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The existing electric power delivery system is a critical part of this country's economic and societal infrastructure, and proposals to increase the role of distributed energy resources (DER) within this system are welcomed by few in the utility industry. Such resistance to change in our electrical power system is not new.

Utilities view DER as a potential threat because it tends to reduce utility revenues. More important, many utilities view DER as a source of safety and protection problems, especially as the amount of DER connected to the circuit grows. For example, an energized DER system can continue to feed short-circuit faults, such as a tree shorting a distribution circuit, and can therefore pose a safety problem for utility crews. In addition, DER can feed back into the distribution circuit, offsetting the circuit current feed during a fault and possibly fooling existing protection schemes. In spite of these issues, the potential societal benefits of widespread DER, especially cogeneration, which includes cooling applications, are beginning to be recognized. These include:

- Improved generation efficiency due to local use of waste heat;
- Reduced transmission and distribution losses;
- Increased energy security;
- Localized voltage and reactive power support; and
- Overall environmental improvements.

However, an interest in the common good is seldom sufficient justification for such a large investment. Investment in DER is more often based on an assessment of measurable cost savings and a consideration of other, less tangible advantages, such as improvement in local power quality. A number of publications have discussed the traditional cost-benefit analysis for a customer-owned DER installation.[1,2] But many DER benefits—including reduced electric line losses; reduced upstream congestion; grid investment deferment; improved grid asset utilization; improved grid reliability; and ancillary services such as voltage and reactive power support, contingency reserves, and black start capability—have no clearly assigned value in today's markets. In fact, one report was dedicated to an assessment of just how difficult it is to calculate these values.[3]

Why is it important to define the economic value of all these DER benefits? First, a comprehensive examination of the benefits can be used both to attract new DER owners and to highlight those market and technical factors that could be improved by DER deployment. Second, given that utilities traditionally have considered DER a revenue-reducing competitor, we need to quantify the benefits to utilities that could counter that point of view. Third, we need to go beyond the fuzzy descriptions of societal benefits that have been used to date (such as greener power and increased efficiency). A well-founded quantification of those benefits will be much more effective in attracting public and industry support for the technology. This information also will be useful in prioritizing future research, development, demonstration, and deployment programs into those areas where the future payoff is clear and significant.

Responding to these needs, the U.S. Department of Energy (DOE) Distributed Energy (DE) program commissioned a focused examination of DER benefits that would both improve understanding of all the issues and put hard numbers on the benefit values wherever possible. This study began by gathering available data for a large number of DER sites and talking to many of the owners or opeators. A few case studies that are more detailed were collected as part of this initial effort. The examination then progressed to a load-dispatch study for a selected region and a parametric evaluation of central station displacement—with particular attention to the question of whether DER displaces current and future combined-cycle plants.[4,5,6] This article focuses on the results from the initial review and the associated case studies.

The initial review was designed to query a broad spectrum of current DER users/owners about the benefits they derive from their DER systems. Although we do not claim that our review was a statistically representative sample of the DER population, it did cover 162 installations with a variety of equipment types and ownership classes located as shown in Figure 1. Forty-nine of these installations were subsidized technology demonstration units, typically fuel cells or microturbines. These installations have provided invaluable performance data for the newer technologies but were less useful in this examination of DER benefits. The remaining 113 installations were used to extract the information discussed in this article. Figures 2 and 3 provide an overview of the technology types and ownership classes covered in the review. As expected, most of the facilities use either a gas turbine (alone or in a combined-cycle configuration) or a reciprocating engine (fueled by either diesel or natural gas). Utilities and third-party generators made up the bulk of the installed capacity in the review, but there were also 60 customer-owned DER sites producing a total of 600 MW. As Figure 2 indicates, 21 of the records were incomplete in that they failed to report either the technology used, the installed capacity, or both. As indicated in Figure 3, the ownership of the DER unit was not specified for 10 sites.

Some of these installations fall into the "early adopter" category, such as customers with loads that are extraordinarily sensitive to the quality and continuity of their energy service. These customers included the usual suspects: computer server centers, where power quality problems or brief outages can cause extensive business disruptions; hospitals, where back-up generators already are required to protect human lives; and types of industrial plants (*e.g.*, electronics, food) in which a process interruption can result in significant product loss and cleanup. One unexpected customer in this class was a zoo, where animal lives were at risk because of local power problems. The more conventional customers ranged from a car wash to a convention center, along with industrial sites, hospitals, and college campuses.

Review

We asked many system operators why they had installed a DER system, using this response as an indicator of the perceived benefits. Note that the electricity market rules in most of the United States today do not permit DER operators to participate in the ancillary services market, and so there are no price signals to reveal the value of ancillary services that are available from DER (*i.e.*, serving as spinning reserve, supplying variable reactive power to the system). Thus these would not be included in any customer's list of DER benefits, although they might be appreciated by a utility owner. The answers covered a broad range, as shown in Table 1.

These results were examined with respect to ownership category, as shown in Figure 4. The third-party category and customer classes were strongly influenced by the opportunity to use cogeneration and reduce costs. Some of the third-party systems were older ones installed under Public Utility Regulatory Policies Act (PURPA) regulations. Others were newer systems that were installed and operated by service companies on the customers' sites, typically providing a combination of thermal and electrical energy to the customers.

In addition to using cogeneration, customers were focused on improving reliability. Approximately 10 percent of the customers cited the need to meet peak demand, guard against variable energy prices, and increase their generation capacity. Some of the customers installed their DER systems as a part of an overall increase in plant capacity, or as a part of a broader renovation project required to meet environmental regulations or to upgrade or expand the plant. Some of the customers realized additional savings by switching to lower-cost interruptible rate schedules, relying on their DER unit for power during any such interruptions.

Utility owners were most strongly motivated by four major reasons: meeting peak demand, improving reliability, protecting themselves from price instabilities, and meeting grid constraints. Many of the utilities' peak-demand installations were classed as emergency generators, and they were often leased units. Other utility-owned units were located at customer sites, providing back-up power to those customers but dispatchable by the utility to meet operational needs. In a few cases, customer-owned units were controlled by utilities in a similar fashion.

Because the larger review focused on the DER system owner/operators, it could not reveal benefits to other parties. Therefore, four in-depth case studies were conducted to explore benefits that are typically outside the scope of a DER cost-benefit analysis. For each of these cases, the DER technology, load, and alternative utility choices were characterized. The system costs, including both capital and operating expenses, were examined. Associated risks, such as the uncertainty of future fuel supplies or shifting environmental regulations, were explored. Considering all these factors, the benefits to the system owner/operator, to local utilities, and to other ratepayers were addressed.

The first case study described a narrow coastal island where summer vacationers increase the population by a factor of six for two to three months per year, and the summer peak load during most years is about 250 percent of the average daily peak. Exacerbating this seasonal load swing is a weather cycle that leads to a peak every third year that is about 50 percent higher than the peak during the other two years. An aging subtransmission system used to serve this island, composed of five 23-kV submarine cables, was very near its maximum load during these summer peaks; and contingency requirements could not be met with the existing wire system.

The proposed wire system upgrade included replacing the 23-KV subtransmission system with an extension to the 69-kV transmission system and upgrading one of the island substations to match this greater voltage, at a total estimated cost of $10 million, or about $90/kVA. Considering the annual load profile and the customer classes (*i.e.*, few, if any, pay demand charges), the return on this transmission and distribution investment was limited. Therefore, two DER solutions to these challenges were explored in the case study—utility-leased and customer-owned DER.

Based on the expected load growth, the utility-leased DER option offered financial benefits and enhanced reliability and was more flexible than the alternative wire solution. A cash-flow analysis showed that the subtransmission wire solution could be deferred for six to seven years, saving approximately $1 million. The local installation of DER would also increase the reliability of service to this island location, and additional units could be quickly installed to meet unexpected growth or additional contingency requirements. Alternatively, if the growth was less than expected, the low-cost leased units could extend the deferral time before the wires needed to be replaced. If the existing wire system failed prematurely, necessitating early replacement, the leased units could be used elsewhere in the system, or the lease could be terminated.

The customer-owned DER option on this island could offer financial advantages to a resident with a thermal load sufficient to justify a cooling, heating, and power (CHP) system.[7] However, for these circumstances, this option offered few if any benefits to the utility. The location of the DER was critical if it were to offer useful relief to the island's distribution system; it is unlikely that there would be a sufficient number of suitable CHP applications in the relevant locations. In addition, although a customer-owned DER system would decrease the island's peak load, it would be attractive only to year-round residents. It would therefore decrease the already small load during the non-summer periods, making the utility's low load factor during that part of the year even worse, along with lowering its revenues.

Looking at Cogeneration

In a second case study, we examined a cogeneration plant, built primarily in response to PURPA regulations. The plant provided steam to a food processing facility in Idaho and was connected to the local utility, Idaho Power, at the transmission level. For PURPA installations, societal environmental and energy conservation benefits typically are balanced against slightly higher costs for ratepayers. Since this plant was located in a region with a traditionally sufficient supply of lower-cost power, the 10-MW gas-fired unit has not offered any advantages to Idaho Power, which is contractually obligated to purchase power from the cogeneration unit for approximately $50/MWh. Nor was the Idaho Power system in need of voltage support or reliability services at this location. However, for the unusual utility economics (marginal prices reached $250/MWh and higher) that occurred during the time period under study, this plant also contributed profits to the local utility.

The third case study examined a CHP application at the Brookfield Zoo in Chicago. This case study demonstrated a system where DER was able to meet high reliability requirements unavailable from the existing local distribution grid. This same case was also a compelling example of the efficiency and cost-saving opportunities associated with cogeneration.

Following an extended power outage that nearly led the zoo to move its dolphins to Florida, the zoo installed two natural-gas–fired engines with waste heat recovery and an emergency backup diesel-fired engine. The two gas-fired engines operated daily in a cogeneration mode, and the system was projected to have a positive cash flow of more than $700,000 over 10 years. The three engines operating together were sufficient to meet 100 percent of the zoo's load, thereby providing the desired reliability in the event of another utility outage.

Commonwealth Edison (Com Ed) did not participate in the case study, but information garnered from industry sources indicated that the zoo's DER installation may indeed have provided benefits to the utility system.[8] The Com Ed system was under such strain during this period that it was asking local fire departments to cool overloaded transformers, offering a curtailment program to business customers, and paying cash rebates to interrupted customers.[9] An extensive maintenance program was instituted to improve reliability, but not until four years after the zoo's critical outage. During this same time frame, Com Ed leased a large number of mobile generators to help meet its peak demand.[10] Possible benefits to Com Ed therefore included deferral of distribution system upgrades and a reduction in very expensive power purchased at peak periods. The cost to Com Ed was the lost revenue from the daily power generation provided by the zoo's cogeneration engines.

The fourth case study was a review of a relatively large DER installation at Vanderbilt University. Vanderbilt's power plant produced all the steam required on campus and at the medical center in Nashville, Tenn., and a portion of the complex's electric power needs. This plant included units fired by coal, oil (for the emergency back-up units), and natural gas. The Vanderbilt plant, including four generating units with a total capacity of 17 MW, was sufficient to meet 100 percent of the steam needs (including steam used to power five absorption coolers) and 50 percent of the electricity load. This enabled the university to take advantage of a limited interruptible power contract for half of its demand, while using the more traditional firm-demand contract for the remaining 50 percent. With this contract, the university was able to operate its DER system to match its steam loads rather than its electrical demand, because any power needed beyond the firm-demand contract amount was purchased at a greatly reduced price. The fuel flexibility of the DER installation enabled Vanderbilt to negotiate lower fuel prices and so has reduced utility rates and fuel costs, saving the university approximately $2.1 million in the year preceding this study. As the study was under way, Vanderbilt increased the generation capacity from 17 MW to 27 MW and added two new heat-recovery boilers.

FIGURE 2 **DISTRIBUTION OF DER TECHNOLOGY TYPES IN THE REVIEW**

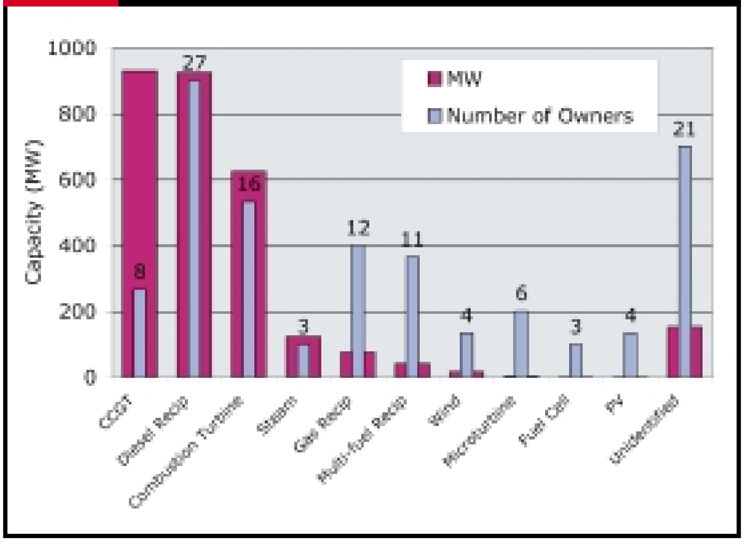


FIGURE 3 **DISTRIBUTION OF OWNERSHIP CATEGORIES IN THE REVIEW**

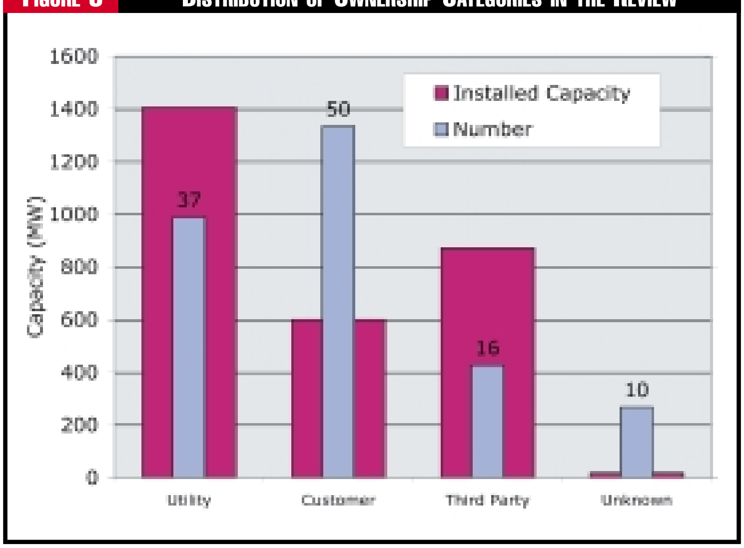
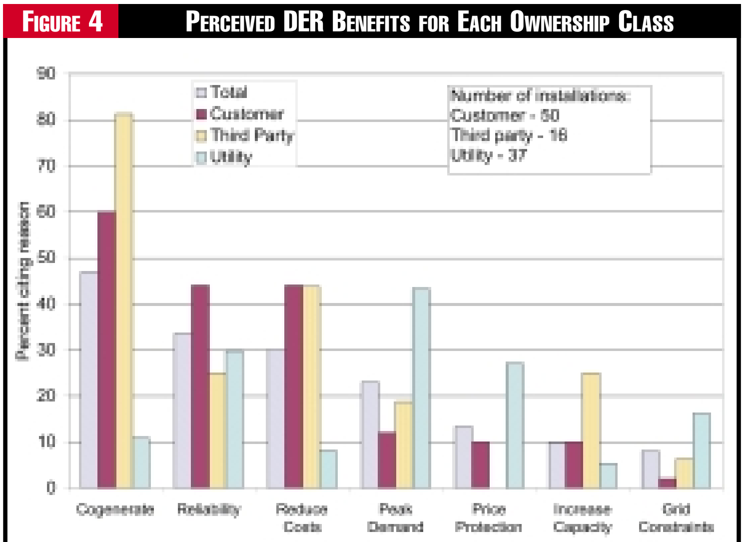


FIGURE 4 **PERCEIVED DER BENEFITS FOR EACH OWNERSHIP CLASS**



The DER system provided an element of reliability for the university, and especially for the hospital. It also enhanced the reliability of the local distribution system, as was demonstrated in 1998. At that time, the local electric system suffered a short period when a number of distribution lines were loaded near capacity and therefore experienced low voltage and were close to tripping. To circumvent a power outage to the entire Nashville Electric Service system, the utility asked Vanderbilt and other DER customers to generate as much power as they could and reduce their load to the utility. The system collapse (tripping of lines on overloading) was averted, at least partially because of these DER resources. The utility recognized that its system benefited from the DER installations during this occurrence. However, the utility felt that the benefits would have been greater had they had control over these DER generators, such as their location, size, and operation.

This final case study clearly demonstrated that DER can provide critical peak load support to a grid-constrained system and thus prevent outages to a localized region that extends beyond the DER system owner's boundary.

This overview has identified two major categories for DER. Many systems were installed to meet base-load growth or replace central generation; these typically employed cogeneration and were recognized as reducing overall energy costs. Others were installed to meet peak loads, sometimes by a customer to avoid peak demand charges and sometimes by a utility to meet peak demand and defer transmission system reinforcement. Reliability benefits were cited by many DER owners in both categories. Economic benefits to society are indicated by the frequent discussion of using DER to achieve a measure of price stability and by the overall economic efficiency reflected by these significant investment decisions. Environmental benefits are complex and may not occur in the same geographical location as the DER. They depend on the selected DER technology, fuel, and efficiency; the displaced central production technology, fuel, and efficiency; and the relative locations of these two competing power sources.

The case studies demon- *(Cont. on p. 61)*

management tool box. Each has its own attributes and each complements the other. Efficiency and conservation can result in load reductions on peak, but likely cannot be dynamically controlled. Demand response offers dynamic control and "dispatch" but, while likely not resulting in increased usage, may not always result in a large conservation effect.

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Endnotes

1. Our review included, either directly or indirectly, more than 200 pilot or large-scale programs carried out by government or utility sponsors between 1975 and 2004.
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12. Braithwait, Steven. "Peak Demand Impacts of TOU Rates and Customer Access to Usage Data," California Energy Commission Demand Response.

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strate the difficulty of determining the value of DER benefits that accrue to anyone other than the owner. Most current market structures are incapable of reflecting the ancillary benefits that DER can supply. The case studies also demonstrate a reluctance on the part of utilities to recognize or acknowledge the benefits to their systems, even when there is clear evidence of a grid deficiency or when a DER operator increases its output in response to a utility's request. In addition, utility input is crucial in determining the value of location-specific transmission and distribution deferrals due to DER installations. In the next stage of this project, a regional model, with a census of available power plants and a comparative technology database, is used to assign market values to both reliability and environmental benefits.

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TABLE 1 — REASONS CITED FOR INSTALLING DER

Reason	No.	Reason	No.
Cogeneration	53	Environmental sensitivity	6
Cost reduction	34	Fuel flexibility	3
Reliability	38	Reduction in emissions	4
Peak demand	26	Upgrade plant	6
Price protection	15	Market speculation	2
Capacity increase	11	Grid constraints	9
Burning of waste product	6	Power quality	3
Rate structure	7	Unknown	4

Endnotes

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2. F. William Payne, Ed., Cogeneration Management Reference Guide, Fairmont Press, Inc., Lilburn, GA, 1997.
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4. W. P. Poor, *et al.*, Connecting Distributed Energy Resources to the Grid: Their Benefits to the DER Owner/Customer, Other Customers, the Utility, and Society, ORNL/TM-2001/290, Oak Ridge National Laboratory, March 2002.
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