Fuel Cells for Dispersed Generation

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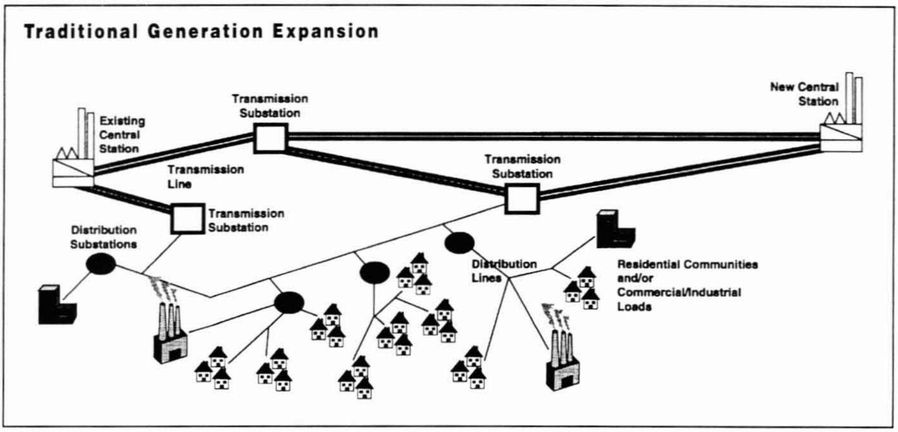
DISPERSED VS TRADITIONAL GENERATION

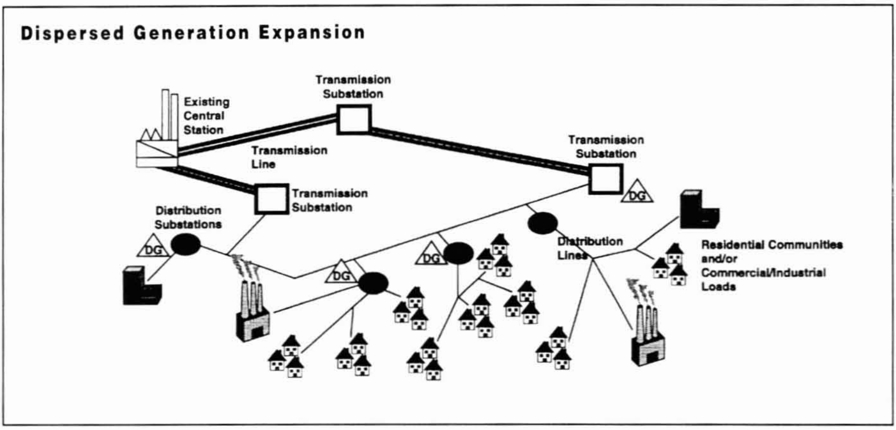
New technologies are going to have a significant impact on the electric utility industry in the coming years. Successful commercialization of advanced power supply technologies will usher in "dispersed generation" or DG as an alternative to the conventional central station power plants that now dominate the electric utility industry.

A DG power supply expansion strategy will allow siting of many smaller generating units close to the load. In fact, these remotely dispatched, unmanned generating units will probably be located right at the substation and look more like substation equipment than generating facilities.

The ability to site small-scale DG units close to the customer can improve the reliability of delivered service and promises new options for managing industrial and commercial loads through tailored energy services. These will be important factors for rural electric systems, especially those that are experiencing load growth at the end of long feeders, or those trying to attract new commercial or industrial loads with special power quality needs.

Locating small DG units near or in an existing distribution substation could also defer costly transmission and distribution upgrades and improve the efficiency, operation, and management of the distribution system by facilitating load shifting and providing voltage and power quality support.

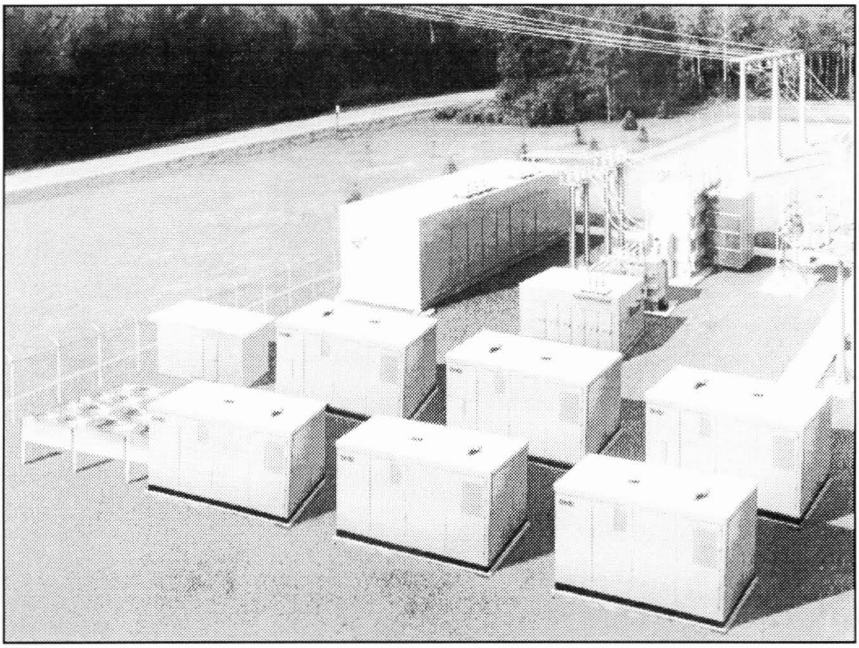




TODAY'S DG TECHNOLOGIES

A number of technologies will find their way into dispersed generation applications. Internal combustion engines, gas turbines, photovoltaics, and wind power are all candidates. In fact gas engines, diesels and gas turbines are already widely used for *peaking* and *intermediate* service applications. But the most exciting development with regard to the viability of dispersed generation in the utility industry is the emergence of fuel cells as *baseload* power plants in small sizes ranging from 200 kW to 2 MW and perhaps larger.

Tremendous technical strides have been made in the last decade



A "Concept" Illustration—Six 200-kW Fuel Cell Units are Arranged in a 1.2 MW Distributed Generation Configuration.

in the development and commercialization of fuel cells. In fact, today small phosphoric acid fuel cells (PAFC) rated at 200 kW may be purchased from International Fuel Cells (IFC), a division of United Technologies Corporation.

These units are fully warranted by ONSI, IFC's manufacturing corporation for operation on either natural gas or propane. The market entry price is $3000/kW, but IFC's goal is to offer $1500/kW or less within three years. It is a realistic goal that is predicated upon the expected production increase as well as modest engineering improvements. These fuel cells offer high efficiency, compact size, very low emissions, modular factory construction, short power plant lead times, and good load-following capability.

NRECA's RER program has signed an agreement to purchase a 200 kW model PC25C fuel cell power plant from IFC's ONSI corporation. Delivery will be in March of 1996, and the unit will be rotated among four RER member systems over the next several years for an evaluation of dispersed generation in actual co-op applications.

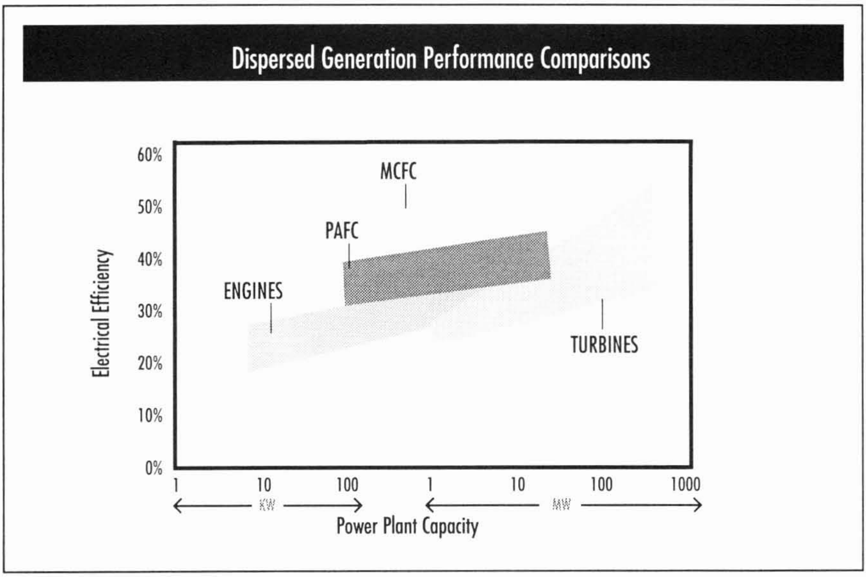
ADVANCED TECHNOLOGIES

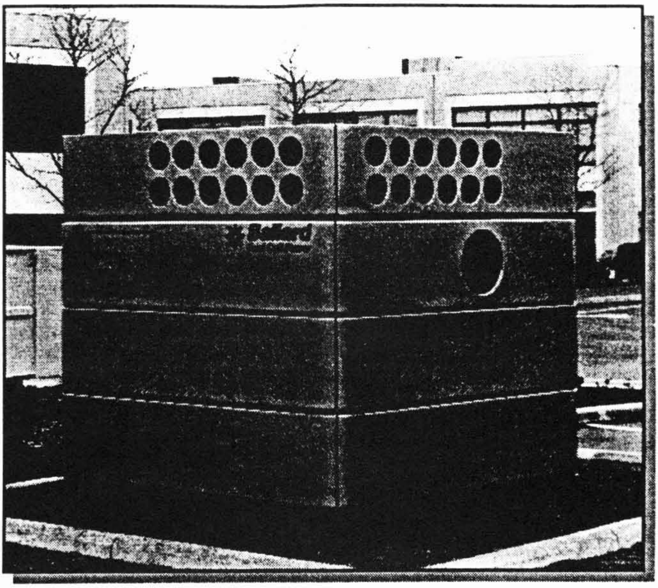
Just around the corner are more advanced versions of fuel cell power plants that will be coal compatible and will offer the highest efficiency and lowest emissions of any coal-fired option. Among these are the molten carbonate fuel cell (MCFC), which is expected to enter the commercial market by the end of the decade. It is a more efficient fuel cell, offering potentially lower cost than the phosphoric acid technology. But its economics favor a larger size—in the range of 2 MW.

Two suppliers, MC Power and Energy Research Corporation, are competing to introduce the molten carbonate fuel cell power plant. Cost is expected to be around $1000/kW for natural gas-fueled power plants. This technology is presently in the demonstration stage of its development. NRECA's RER program, EPRI, and six other sponsors are funding a 2-MW demonstration of the ERC power plant at the City of Santa Clara Municipal Utility in California. Construction completion and power plant commissioning are expected by the end of 1996, with operation for two years beginning early next year.

Also, toward the middle of this next decade, we expect to see the third generation of fuel cell power plants become commercially available. This is the solid oxide fuel cell, which potentially offers the highest efficiency and lowest cost of the three. Under development by Westinghouse, it is envisioned to serve the utility market in the 10- to 50-MW size range. Westinghouse is now at the point of talking to utilities, and to the RER program in particular, about participation in a demonstration project The relative efficiencies of the various options are compared in the figure.

And the idea of a fuel cell power plant small enough to provide electricity and hot water to an individual residence cannot be dismissed. Ballard Power Systems in Vancouver, British Columbia, is developing a proton exchange membrane (PEM) solid polymer fuel cell that is currently being evaluated by Daimler-Benz AG as the power plant for buses and minivans. Ballard has developed a 10-kW PEM system that uses natural gas and might ultimately be suitable for residential or multifamily dwellings. Commercialization is moving ahead with the help of Dow Chemical and a number of other industrial partners.





Ballard Power System's 10-kW Proton Exchange Membrane Solid Polymer Fuel Cell.

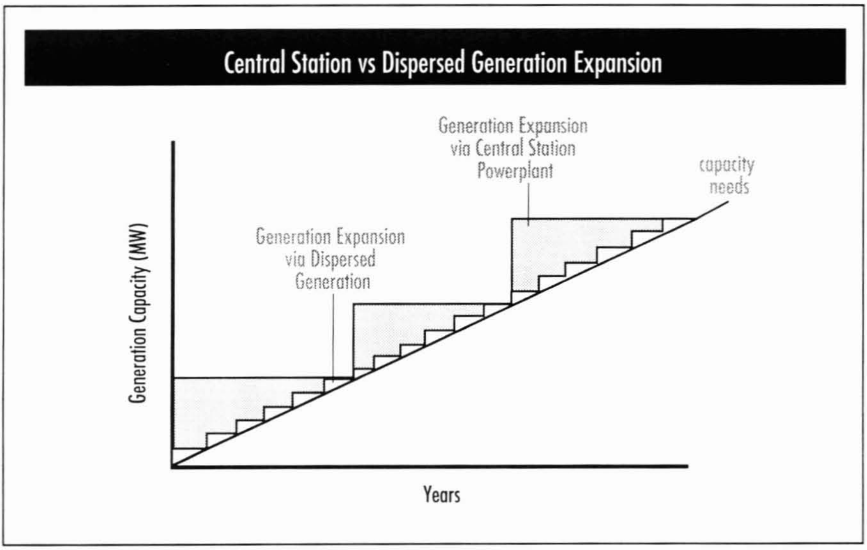
DG LOWERS FINANCIAL RISK

One key point should be emphasized with regard to the benefits of fuel cell power plants in rural electric applications. Whereas other DG technologies have for the most part been used for *peaking* or *intermediate* service, fuel cells will be highly efficient *baseload* units that can be ordered from the factory in increments ranging from 200 kW to several megawatts. That will permit co-ops to work their way up the load growth curve in small steps.

Compare the advantages of this approach with our past challenge of buying increments of power in the several hundred-megawatt range and then trying to manage the excess capacity economically until it is needed. As shown by the shaded areas in the figure, the critical source of most of the rural electric program's past financial problems could be eliminated.

DG AVAILABILITY

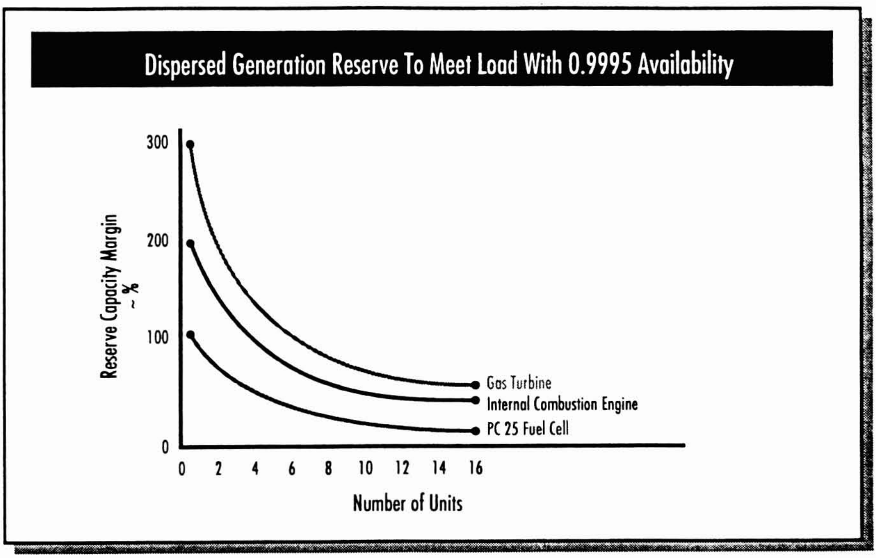
There is an important point to keep in mind with regard to distributed baseload generation. Large central station baseload power plants are designed to meet load with a certain availability level.



That will also be true with baseload DG units as well. To date, the PC25 fuel cell power plant operating history has demonstrated that on an annual basis the lost hours caused by forced and maintenance outages is no more than 2 percent. The comparable data for internal combustion engines has been 7 percent and that for gas turbines 11 percent.

The low unscheduled outage hours result in a high overall power plant availability from installation of PC25 power plants since the probability of multiple units being down at any one time is quite small. From a system point of view, the low unscheduled outages mean that smaller reserve capacity margins are needed to provide a level of power availability to a specified load.

The impact of this is illustrated in the figure, which plots the reserve capacity margin versus the number of installed units. Reserve capacity margin is defined as the reserve or excess generating capacity that must be installed to meet the power availability requirement divided by the generating capacity that must be installed just to meet the required load. The curve is plotted for outage factors of 0.02, 0.07, and 0.11 representative of the PC25 fuel cell, internal combustion engines, and gas turbines in DG applications. For this example, specified power plant availability is 99.95 percent, which corresponds to less than four hours per year that the units would not meet load.



An important observation from this graph is that conventional generation equipment such as internal combustion engines and gas turbines in DG applications will require higher reserve capacity margins in order to meet the specified availability level. Alternatively, the figure shows that for a given reserve capacity margin, one will need a greater number of installed gas turbines or engines compared to the fuel cell to meet the desired availability.

Consider a reserve capacity margin of 100 percent as an example. The figure shows that approximately one PC25 power plant would be required to achieve the 99.95 percent availability. But, on the other hand, approximately four internal combustion engine or about six gas turbines would be necessary to realize the same 99.95 percent availability. When viewed in this way, as a total DG system with normal baseload power plant availability requirement imposed, the higher cost per kW of the fuel cell power plant is not as significant as one might initially think.

DG DEFERS COST

Distributing generation throughout the utility system can offer the benefit of reducing transmission and distribution (T&D) costs by deferring capital expenditures for distribution system equipment and upgrading or reconductoring of power lines. Generation distributed through the system in this manner often will reduce the infrastructure requirements between the DG unit and central station generation. Often, much of the benefit can be accomplished by siting the distributed generator at the substation if the principal deferrals are at the substation (transformers, switch gear, etc.) or in the transmission or subtransmission system.

The additional benefits associated with these savings can be added to avoided generation costs to build a picture of the true value of siting generation in a distributed manner. Even a one-year deferral on the distribution system capital expenditure is likely to reduce the present worth of that expenditure by roughly 10 percent, even after inflation is taken into account. Two recent studies published by Sandia National Laboratories and the Electric Power Research Institute (EPRI) illustrate the potential value of distributed generation.

One study with Plains Generation and Transmission evaluated alternatives to upgrading a 36-mile long 24.9-kV distribution line for one of Plains' distribution cooperatives, Navopache Electric Cooperative. The problem was that the feeder was experiencing voltage drops greater than REA voltage regulation guidelines. The upgrade would have required a new line with a voltage of 69-kV. The cost of this upgrade was estimated to be $4.2 million. In this case, the alternative evaluated was a 100-kW photovoltaic (PV) system installed near the load, which would have deferred the need for a line extension by three years. The overall benefits, including externalities, for this application were calculated to be $9,000/kW. A large part of that benefit was due to the three-year deferral of the line extension. A 200-kW fuel cell may have deferred that line extension by more than six years.

Another part of the analysis involved the value of moving the distributed generator to another location on the system after the line had been upgraded. The study found that, if three additional moves could be made for applications with 30 percent of the benefits mentioned above (after all costs for removal and installation were considered), the value of the benefit for the distributed generator increased by $2,000/kW. The total potential value for the distributed unit was greater than $11,000/kW.

Another study with Arizona Public Service Company analyzed the benefits of a 1-MW PV plant to defer budgeted substation and distribution feeder upgrades for the Cocopah Substation in Yuma, Arizona. The deferred benefits for that application were found to be almost $3,500/kW. The traditional utility benefits for energy, generation, and deferred T&D expenses were $2,430/kW. The soft benefits from increased reliability, environmental mitigation, and other benefits were estimated, using accepted values for avoided emissions, at about $1,000/kW.

Most of the benefits attributed to the PV systems are also applicable to natural gas fuel cells. The two exceptions are the benefits associated with avoided energy (including fuel) and avoided CO_2 emissions. PV uses no fuel and produces no emissions when generating electricity. A fuel cell operating on natural gas uses a fuel and produces CO_2 as a by-product of steam reforming the natural gas to produce the hydrogen-rich gas stream required by the fuel cell stack for power generation. Therefore, these two benefits are lower for the fuel cell than for the PV system.

An Oglethorpe Power Corporation study done with RER and

EPRI evaluated the benefits of installing molten carbonate fuel cell and diesel generation to avoid or delay substation and distribution system upgrades for 10 years. One case centered on upgrading a 46-kV subtransmission line ending at a substation that served a distribution cooperative. The line had experienced frequent and prolonged outages and required replacement to maintain a reliable level of service. The load served by the substation has a variable growth rate of between two and five percent per year. Over 10 years, and in stages, 12 MW of generation were installed at the substation and compared with the cost of upgrading the subtransmission line. The impact of those 12 MW of generation deferred between $1,585/kW and $1,900/kW in avoided T&D upgrades, avoided energy and demand charges, increased transmission capacity, and reduced energy losses. The size of the benefits depended on the rate of load growth over those 10 years.

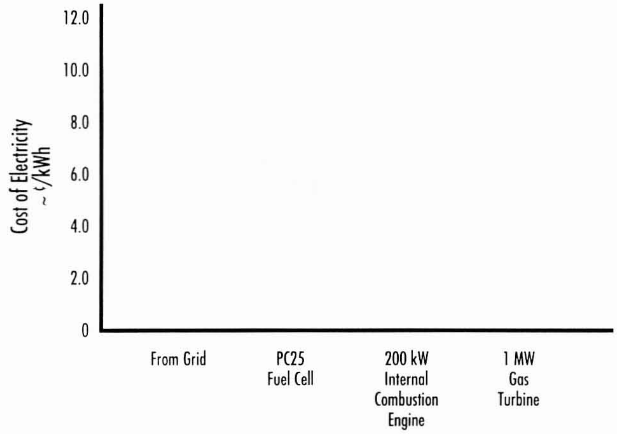
DG ELECTRICITY COSTS

Cost of electricity from distributed generation facilities can vary widely depending upon the particular site, fuel cost, how financing is arranged, etc. And as previously described, there are can be some substantial added value for DG installations when deferral of transmission or distribution capital expenditures is considered. However, even without consideration of these related benefits, DG systems can often provide cost of electricity at the busbar comparable to or even lower than conventional generation.

A recent DG power supply study was carried out in some detail for providing electricity to a remote community electrical load via the PC25C fuel cell power plant fueled by propane which would be transported to the site. The resulting busbar electricity costs calculated for meeting the load requirements with PC25C fuel cell power plants, 200 kW internal combustion engines, and a 1 MW gas turbine are compared to the present electricity costs from grid supplied power at the point of use in the figure.

The cost range shown by the shaded area in the figure for the fuel cell case reflects the projected reduction in the O&M costs over the twenty year planning period, as well as the potential for heat recovery. The operating cost advantage of fuel cells can be signifi-

Dispersed Generation Cost of Electricity Comparisons



cantly enhanced at local sites if heat recovery is possible. It was assumed that only fifty percent of the heat could be recovered in calculating the cost reduction shown by the shaded area.

CONCLUSIONS

Traditional generation expansion plans typically involve construction of a new central station power plant of several hundred megawatts along with new transmission lines to serve growing load centers.

Now that true baseload power plant technology is beginning to enter the market in sizes ranging from a few hundred kilowatts up to several megawatts, there are some real opportunities to serve small but growing loads in a more cost effective manner than with the traditional power supply approach. Co-ops will be able to construct power generation facilities that can be dispersed among growing load centers perhaps at a substation location, or at the consumer site where the power is being used.

A dispersed generation power supply expansion strategy could help co-ops be more competitive providers of power by avoiding or delaying for many years the need for constructing a new central station power plant, along with costly transmission lines and substations.

ABOUT THE AUTHOR

John W. Neal, P.E., is Director of Research for the National Rural Electric Cooperative Association (NRECA). In that capacity he manages the Rural Electric Research (RER) program, and represents electric cooperatives on research and technology policy matters. John is based at NRECA headquarters in Arlington, VA.

Prior to joining NRECA, Mr. Neal directed the Member Relations Program of the Electric Power Research Institute (EPRI), where he worked with member utilities to help them realize the benefits of their research investment. In that role he was also the EPRI liaison to NRECA and the Rural Electric Research program.

His previous experience included serving as Deputy Director, Office of Coal Utilization in the U.S. Department of Energy. There he was responsible for the federal R&D program for utilization of coal, with such projects as fuel cells, fluidized-bed combustion, coal gasification combined cycle power plants, coal-oil and coal-slurry fuels, and advanced coal cleaning.

Mr. Neal had a key role in forming the Fuel Cell Commercialization Group (FCCG). As a member of the original Board of Directors of FCCG, he represented America's 1,000 consumer-owned rural electric cooperatives. His technical background in advanced electric utility power systems, along with a thorough understanding of technology transfer requirements, are uniquely relevant to FCCG's goal of commercializing molten carbonate fuel cells (MCFC) in small dispersed power applications. Rural electric distribution systems are a key potential market for early applications of MCFC technology.