ELECTRIC POWER RESEARCH INSTITUTE

Technology Review and Assessment of Distributed Energy Resources

2005 Benchmarking Study

1010525

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Technical Update, January 2006

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NOTE

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This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Technology Review and Assessment of Distributed Energy Resources: 2005 Benchmarking Study, EPRI, Palo Alto, CA: 2005. 1010525.

PRODUCT DESCRIPTION

The investigators reviewed and assessed the current status of distributed generation (DG) in the U.S. as it applies to smaller-scale installations (residential, commercial, and light-industrial buildings—generally under 1,000 kW capacity), and benchmarked the prospects for significant market impacts over the next 5 – 7 years. This study serves as an update to EPRI's *Assessment of Distributed Resource Technologies,* completed in 1999 [EPRI 1999].

Results & Findings

While there have been incremental improvements in the cost, efficiency, and reliability of many DG technologies over the past six years, there have been no breakthroughs that change the fundamental barriers to DG identified in the 1999 study. The investigators do not anticipate DG market changes over the next 5 – 7 years that would significantly alter the current mix of DG and centralized electricity generation used by residential, commercial, and light-industrial end-users. While not specifically addressed under this investigation, the use of DG in combined heat and power (CHP) applications is unlikely to significantly improve DG economics enough to change the conclusions reached. This is because a) thermal energy has a much lower value than electricity, and b) thermal loads in these market segments are not always coincident with the need for electricity. Furthermore, upcoming emissions mandates for stationary generation in non-attainment areas will be difficult to meet for many DG technologies (with the exception of fuel cells).

Challenges & Objectives

The results of this investigation will be of interest to those in the electric utility industry responsible for:

- Strategic and corporate technology planning
- Anticipating customer demand and the associated implications for generation, transmission, and distribution requirements
- Ensuring a reliable and high-quality power supply to customers
- Integrating DG within their service areas
- Developing regulatory policy

Periodic review and assessment of DG technologies is important to understand if and when these options will play a significant role in providing power to residential, commercial, and light-industrial end users. Despite the limited prospects for DG over the next 5 – 7 years, significant development efforts funded by the public and private sector continue, which may change the attractiveness of decentralized generation in the long term. The primary technical challenge facing DG is the need to achieve electric generation efficiencies that are significantly higher than achieved by the grid (accounting for generation, transmission, and distribution losses) while maintaining high reliability.

Applications, Values & Use

As discussed above, DG technologies are not likely to significantly alter the sources of electricity for U.S. residential, commercial, and light-industrial end-users over the next 5 – 7 years. The longer-term attractiveness of DG may change, however, if ongoing efforts to develop and refine technologies (especially solid-oxide fuel cells, phosphoric-acid fuel cells, and IC engines) are successful. Again, the key technical challenge is achieving high electric generation efficiency relative to the grid, while maintaining high reliability.

EPRI Perspective

While DG technologies are unlikely to significantly impact the sources of electricity for the vast majority of residential, commercial, and light-industrial end-users over the next 5 – 7 years, DG may still play an important strategic role in niche applications to help ensure reliability and quality of the power supply in areas where the electric grid is stressed, especially if electric rates reflect the difficulty of meeting demand (such as in New York City and Los Angeles).

Furthermore, while this report focused only on small generation technologies, continued research is need to re-evaluate the social benefits and how utilities can make a business case for decentralized resources in general including the combination of energy efficiency, load management, DG, distributed energy storage, and distributed renewables. In 2006, EPRI expects to conduct research to quantify the value and business case for a "distributed utility" in both competitive and regulated markets.

Finally, the cost & benefits of distributed systems needs to be continually evaluated given the high probability that the "delivered cost" of electricity is anticipated to rise significantly over the next 5-10 years.

Approach

The investigators reviewed the development status of each major DG technology, including planned activities over the next 5 – 7 years, and related analyses of performance, cost, energy savings, and economics. Sources included:

- EPRI's 1999 *Assessment of Distributed Resource Technologies*, which was written by many of the same investigators who conducted the current investigation. The 1999 study served as a baseline for the current investigation
- Recent studies and analyses completed by TIAX LLC and other investigators
- Recent DG conference proceedings
- Selected interviews with technology developers
- Limited additional analyses completed as part of this investigation and not otherwise published.

The investigators solicited outside review of draft materials from technology developers and electric industry experts to identify any gaps or omissions.

Keywords

Distributed generation
Distributed energy resources
Distributed resources
Decentralized energy
Combined heat and power

EXECUTIVE SUMMARY

The key objective of the present investigation was to review and assess distributed generation (DG) technology developments in recent years, as well as ongoing development efforts, to identify trends, gaps to market, and specific technologies that could have significant market impact over the next 5 – 7 years. The investigators focused on smaller-scale applications (residential, commercial, and light-industrial), which generally have generation capacities under 1,000 kW. The technologies considered included one baseline technology (IC engines) and six developmental technologies (PEMFC, SOFC, MCFC, PAFC, microturbines, and Stirling engines). Assessments are based on current natural-gas and electric rates.

While there have been incremental improvements in the cost, efficiency, and reliability of many DG technologies in recent years, there have been no breakthroughs that change the fundamental barriers to DG. The investigators do not anticipate DG market changes over the next 5 – 7 years that would significantly alter the current mix of decentralized and centralized electricity generation used by residential, commercial, and light-industrial end-users. While not specifically addressed under this investigation, the use of DG in combined heat and power (CHP) applications is unlikely to significantly improve DG economics enough to change the conclusions reached. This is because a) thermal energy has a much lower value than electricity, and b) thermal loads in these market segments are not always coincident with the need for electricity. Furthermore, upcoming emissions mandates for stationary generation in non-attainment areas will be difficult to meet for many DG technologies (with the exception of fuel cells).

Technology-specific observations are summarized below.

IC Engines: IC engines are by far the most common technology used in the U.S. today for DG applications of less than 1,000 kW. Its key advantages are that it's a proven technology and it achieves relatively high electric generation efficiencies (generally on par with, or higher than, those achieved by the grid). Increasingly stringent emissions mandates pose a particularly challenging hurdle for IC engines.

PEMFC: While there has been significant investment in PEMFC for automotive applications, these efforts do not address the relatively low generation efficiencies of natural-gas-fired PEMFC systems. In addition to efficiency, life, durability, and reliability remain significant challenges for PEMFC in DG applications.

SOFC: Significant development will be required to produce reliable, long-life, and cost-effective SOFC DG systems. As such, market impacts over the next 5 – 7 years will not be significant. However, if current development targets are met, SOFC DG systems may prove very attractive due to their inherent high electric generation efficiencies, very low emissions, and relatively modest fuel-processing requirements.

MCFC: MCFC has demonstrated many of the performance attributes needed for DG. However, key challenges remain, such as reducing costs and extending stack life.

PAFC: PAFC has been used far more in the field than any other fuel-cell technology. Like MCFC, remaining challenges include reducing costs and extending stack life. UTC Power has placed renewed emphasis on PAFC, showing their confidence in the technology. An advanced lower priced product is anticipated for 2008.

Microturbines: With a few thousand units in the field, there is a considerable amount of experience with microturbines. The key advantage of microturbines is low emissions without after-treatment of exhaust gases. However, low generation efficiencies remain a key barrier, and are the target of DOE-supported microturbine R&D efforts.

Stirling Engines: Stirling Engines are unlikely to achieve the efficiency and life characteristics needed for most DG applications.

While IC engines will remain the most common prime mover for DG applications over the next 5 – 7 years, the investigators recommend that EPRI track future developments with particular emphasis on:

- SOFC systems (including hybrid plants), because of their high electric efficiency, very low emissions, and relatively modest fuel-processing requirements
- MCFC systems, because of their demonstrated performance attributes
- PAFC, focusing on UTC Power's commercial roll out (planned for 2009)
- Microturbines, focusing on DOE-sponsored development of advanced microturbines in the 200 – 500 kW range.

It is anticipated that electric rates may change dramatically in the future, and the investigators recommend a re-evaluation of the economic attractiveness of DG technologies. Furthermore, while this report focused only on small generation technologies, continued research is needed to re-evaluate the social benefits and how utilities can make a business case for decentralized resources in general including the portfolio of energy efficiency, load management, DG, distributed energy storage, and distributed renewables.

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BACKGROUND

EPRI commissioned a study, completed in 1999 and entitled *Assessment of Distributed Energy Resource Technologies* that served as the baseline for this investigation [EPRI 1999]. The key objective of the present investigation was to review and assess distributed generation (DG) technology developments since 1999, as well as benchmark ongoing development efforts, to identify trends, gaps to market, and specific technologies that could have significant market impact over the next 5 – 7 years. The investigators focused on smaller-scale applications (residential, commercial, and light-industrial), which generally have generation capacities under 1,000 kW. Technologies considered include:

- Fuel Cells:
  - Proton-Exchange-Membrane Fuel Cells (PEMFC)
  - Solid-Oxide Fuel Cells (SOFC)—both tubular and planar
  - Phosphoric-Acid Fuel Cells (PAFC)
  - Molten Carbonate Fuel Cells (MCFC)
- Microturbines
- Stirling Engines
- Internal-Combustion (IC) Engines.

This investigation focuses on DG that is intended to compete with power from the electric grid at the retail level in U.S. residential, commercial, and light-industrial sectors, based on current natural-gas and electric rates. It specifically excludes back-up power applications (which some consider to be DG) that have low equipment duty cycles. We consider only applications in which the primary objective is energy-cost savings. While there are niche applications for other fuels, natural gas is the predominate fuel available for DG throughout the nation and, hence, is the focus of this investigation. While this investigation does not specifically address combined heat and power (CHP), previous analyses conducted by TIAX demonstrate that CHP generally provides only incremental improvements in the economics of DG. While CHP can improve energy savings by 30 – 40 percent relative to DG, capital costs tend to rise by almost as much [WEEC 2004].

2
COST/PERFORMANCE REQUIREMENTS

Overview: Distributed Generation Economics

We first examined the cost and performance requirements for large market impacts. Generally speaking, DG systems must provide power at a cost lower than the grid purchase price, accounting for the impacts of utility rate structures (such as demand charges and time-of-use rates). In some applications there are benefits of DG that are not addressed here, such as power quality/reliability, and transmission and distribution support. However, economic benefit based on energy-cost savings will be the key driver for most applications. We also do not account for government or utility incentives that may be available (rebate programs, tax benefits, special gas rates, etc.). On the other hand, we do not consider utility stand-by charges, siting/permitting issues, or grid-interconnection difficulties, which may also confront the DG end user.

The Cost of Electricity (COE) from a DG system depends on:

- The cost of fuel (natural gas) used by the DG technology
- O&M costs, which include both routine maintenance and the amortized cost of major overhauls and subsystem replacements
- The initial cost of capital to install the system, the cost of money, and the useful life over which it must be amortized.

Figure 2-1 provides an example of the COE breakdown for a DG system using cost/performance characteristics of an IC engine (currently the most common technology choice for DG systems below 1,000 kW). The cost performance characteristics assumed were:

- Capital Cost: $700/kW installed, paid with a five-year loan at 7% interest rate
- O&M Cost: $0.02/kWh (including periodic overhauls)
- Generation Efficiency: 35% (LHV)
- Capacity Factor: 50% (4,380 kWh per year per kW of installed capacity)
- Useful Life: 60,000 hours of operation (13 – 14 years, assuming on/off operation)
- Natural Gas Cost: $8.29/MMBtu (2003 national average for commercial customers).

The above parameters are consistent with current good practice for DG packages in the 100 kW to 1,000 kW capacity range.

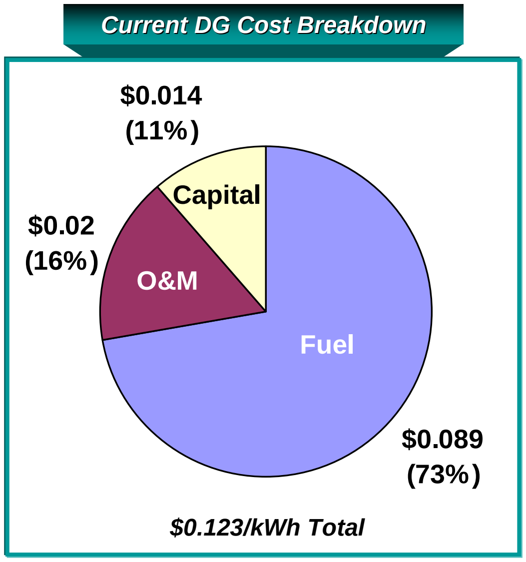


Figure 2-1
Current Cost of Electricity for Typical DG System (National Average)

Figure 2-1 indicates several important issues relative to the current cost structure of electric energy from DG:

- The cost of fuel (73 percent) is by far the single largest factor in determining the COE based on current conversion efficiencies. The fuel costs have become increasingly important in recent years as natural gas prices have increased. Between 1999 and 2004, commercial gas prices increased by 74 percent and industrial prices increased by 105 percent. Prices are forecast to remain high compared to historical levels (dropping only about 20 percent over the next five years) [AEO 2005]. The importance of fuel costs in the overall cost structure places even more importance on electric conversion efficiency than has heretofore been the case.
- O&M costs are also significant, representing about 16 percent of the COE. The O&M cost assumed is typical for good IC-engine practice using an efficient maintenance infrastructure and is still considered one of the major barriers to widespread use. O&M requirements have additional financial implications not captured in the direct O&M cost. For example, the down time required for maintenance functions (both scheduled and unscheduled) can have significant financial impacts particularly if it impacts the ability to avoid utility demand charges.
- The COE for this example is about $0.12/kWh, which is well above the current nationwide average for grid-purchased electricity ($0.0798/kWh for commercial buildings in 2003). As a result, the implementation of DG with the assumed characteristics would be considered primarily in selected applications having higher than average electricity rates, lower than average fuel costs, and/or that attach significant value to other system attributes (heat recovery, backup power capability, etc.).

Figure 2-2 extends this simplified analysis to a state-by-state analysis based on 2003 state average commercial gas and electric prices. States are grouped in three categories:

- Grid Most Economical: COE for DG is more than $0.015/kWh above grid electricity price
- Borderline Economics: COE is within $0.015/kWh of grid electricity price
- DG Most Economical: COE is more than $0.015/kWh lower than grid electricity price.

In establishing these ranges, we added $0.015/kWh to state-average commercial grid electricity prices to roughly account for the fact that DG can be operated preferentially during daytime hours when the price of grid electricity is higher than average values would suggest. In other words, we account for the fact that DG displaces electricity that would otherwise be purchased at a price higher than the average price.

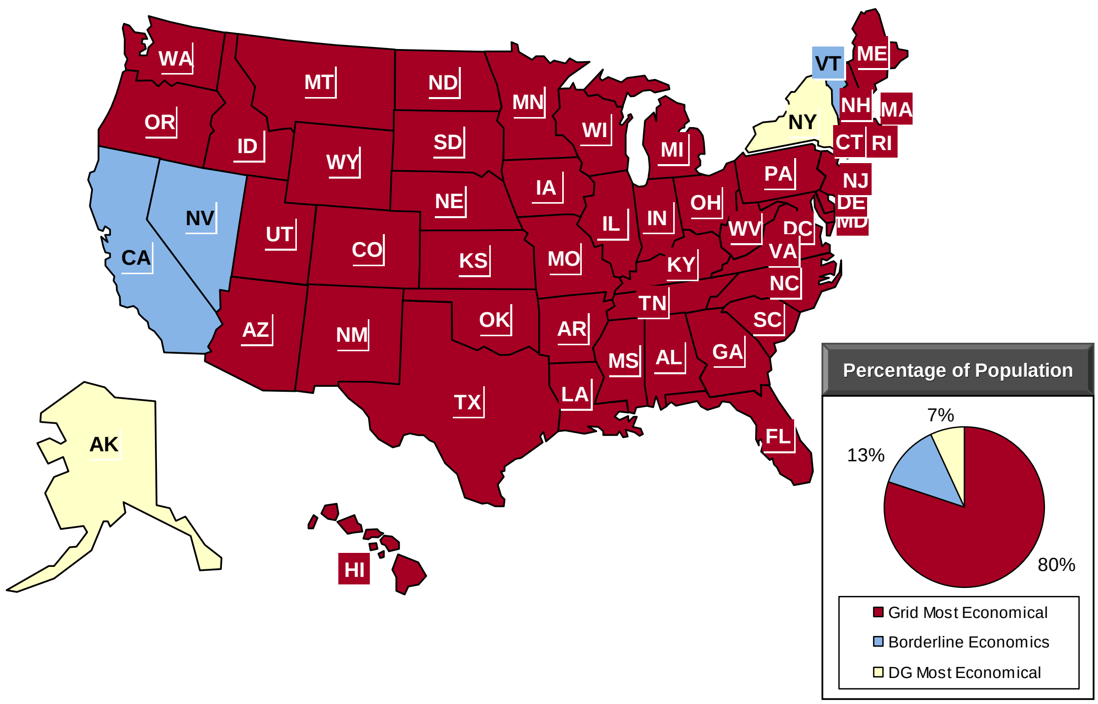


Figure 2-2
Current Cost of Electricity for Typical DG System (State by State)

As indicated by the above simplified analyses, the COE for current DG technology is not widely competitive with grid-supplied power, consistent with the current limited market for such systems.[1] For DG to capture large markets, the cost as measured by COE must be significantly lower than grid-supplied power to account for uncertainties and risk factors associated with investments of this type.

[1] I this study we did not forecast the anticipated escalation of retail rates due to rising cost of natural gas for central station power. Also there is a general belief that retail rates will increase dramatically over the next 7-10 years as power generators shift to clean coal technologies.

The implications of the above are, for DG to experience large market growth, the cost/performance characteristics must improve significantly compared to currently available IC-engine technology.

Ongoing R&D programs are expected to advance IC engine technology over the next 5 – 7 years, improving the performance and O&M requirements of IC-engine-based systems, but with some modest capital cost increases. Figure 2-3 shows the COE breakdown for an advanced DG system based on the same national average commercial gas price. Assumptions for Figure 2-3 are:

- Capital Cost: $735/kW installed, paid with a five-year loan at 7% interest rate
- O&M Cost: $0.015/kWh (including periodic overhauls)
- Generation Efficiency: 40% (LHV)
- Capacity Factor: 50% (4,380 kWh per year per kW of installed capacity)
- Useful Life: 60,000 hours of operation (13 - 14 years, assuming on/off operation)
- Natural Gas Cost: $8.29/MMBtu (2003 national average for commercial customers).

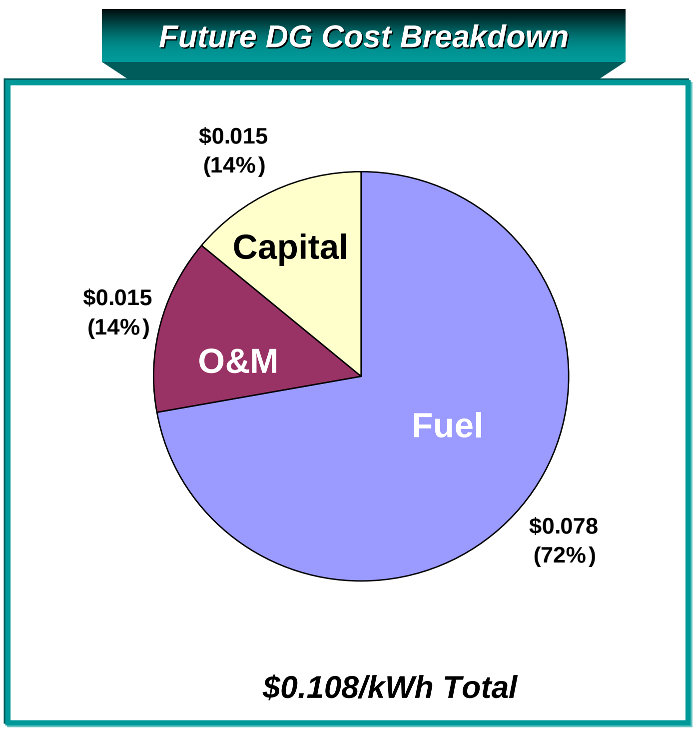


Figure 2-3
Future Cost of Electricity for Advanced DG System (National Average)

The technology advancements assumed reduce the COE from about $0.12/kWh to about $0.11/kWh. Figure 2-4 illustrates where the cost improvements occur. Most of the improvement in COE is associated with the efficiency improvement. Figure 2-5 extends this analysis to a state-by-state analysis, suggesting that the COE is attractive in less than 20 percent of the country, even with the advanced technology characteristics.

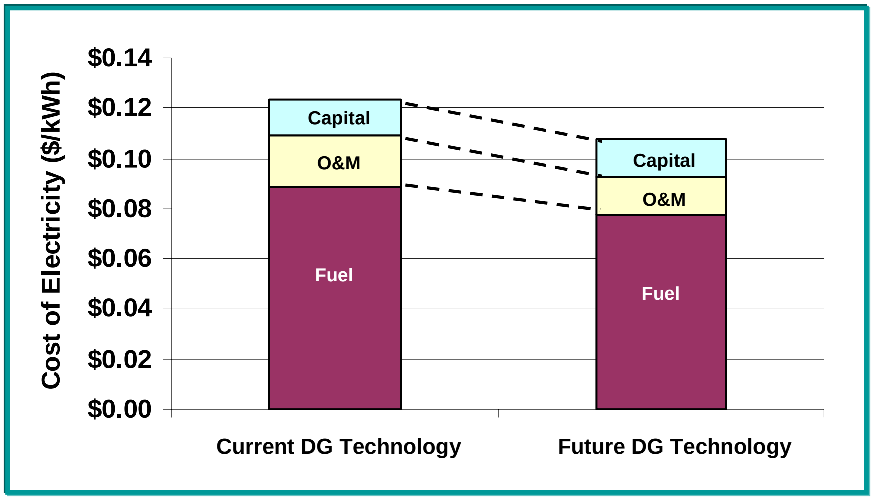


Figure 2-4
Cost-of-Electricity Comparison for Current and Future DG Systems (National Average)

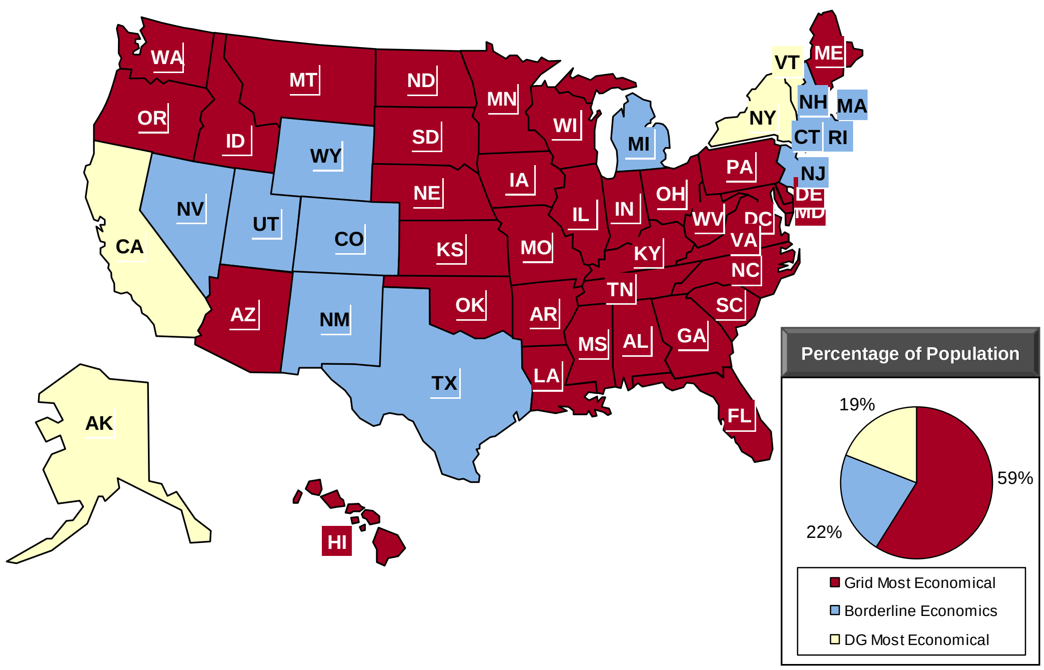


Figure 2-5
Future Cost of Electricity for Advanced DG System (State by State)

A more detailed study of large office buildings, large hotels, and hospitals that accounts for hourly building load variations and actual utility rate structures produced similar results, with payback periods for advanced commercial DG and combined heat and power (CHP) systems ranging from two to three years in Los Angeles and New York City, but exceeding five years in

Chicago, Miami, and Phoenix [WEEC 2004]. Interestingly, using CHP typically did not lower simple payback periods appreciably. The higher capital costs of CHP systems tended to offset their incremental impact on energy costs compared to DG systems.

Cost/Performance Targets

Overview

Table 2-1 indicates cost/performance targets that need to be achieved by DG systems for widespread market penetration and acceptance. As used herein, we mean "market penetration" relative to the U.S. residential, commercial, and light-industrial building stock (rather than relative to the current market for DG systems). The ranges indicated correspond to favorable economics when compared with utility rate structures covering roughly 50 percent of the population. There are tradeoffs among the cost/performance parameters—for example, achieving the high end of the efficiency range might allow for higher capital costs while still remaining in an overall favorable cost/performance range.

Table 2-1
Cost-Performance Targets for DG Technologies

Parameter	Target Range	Comments
Efficiency (LHV)	35-50%	Low end of range may require large, steady thermal loads that are partially met by heat recovery (i.e., CHP)
Non-Fuel O&M Cost	\$0.01-\$0.015/kWh	
Capital Costs	\$400-\$600/kW	Equipment cost only (corresponding installed costs are typically 50%-100% higher for straightforward installations
Useful Life	40,000-60,000 hours	Corresponding to roughly a ten-year life
Availability/Reliability	92%-98% Availability	
Emissions		
Non-Attainment	0.07 lb NO_x/MWh	From California ARB for 2007
National	0.3 lb NO_x/MWh	From RAP Model, Phase 2, 2008

The rationale for each of the target parameters is discussed in more detail in the following sections.

Efficiency

Particularly with rising natural gas prices the efficiency of converting gas into electricity is becoming of increasing importance in determining the economics of DG systems. The target range for efficiency is 35 to 50 percent (LHV). Reasons for this aggressive efficiency target range include:

- DG efficiencies will need to be at least 34-35 percent (LHV) just to "break even" with grid supplied power on a primary energy basis i.e. there is minimal national energy savings benefit at the lower end of the target efficiency range. This lack of energy-savings benefit may result in little public policy support for DG implementation for low-efficiency systems. The consistent use of waste heat (i.e. CHP architectures) can bias the efficiency target to the lower end of the range indicated; but with corresponding restrictions on market access to a relatively narrow market segment.
- Per Figure 2-6 the "fuel only" cost of power generation exceeds the retail cost of power if DG generation efficiencies fall below the 35 to 45 percent (LHV) range for utility rates covering 50 percent of the country. The targets can vary depending on details of utility rate structures (demand charges, etc.) but not sufficiently to change the basic issue, i.e., high generation efficiencies will be required for DG to have widespread market acceptance.

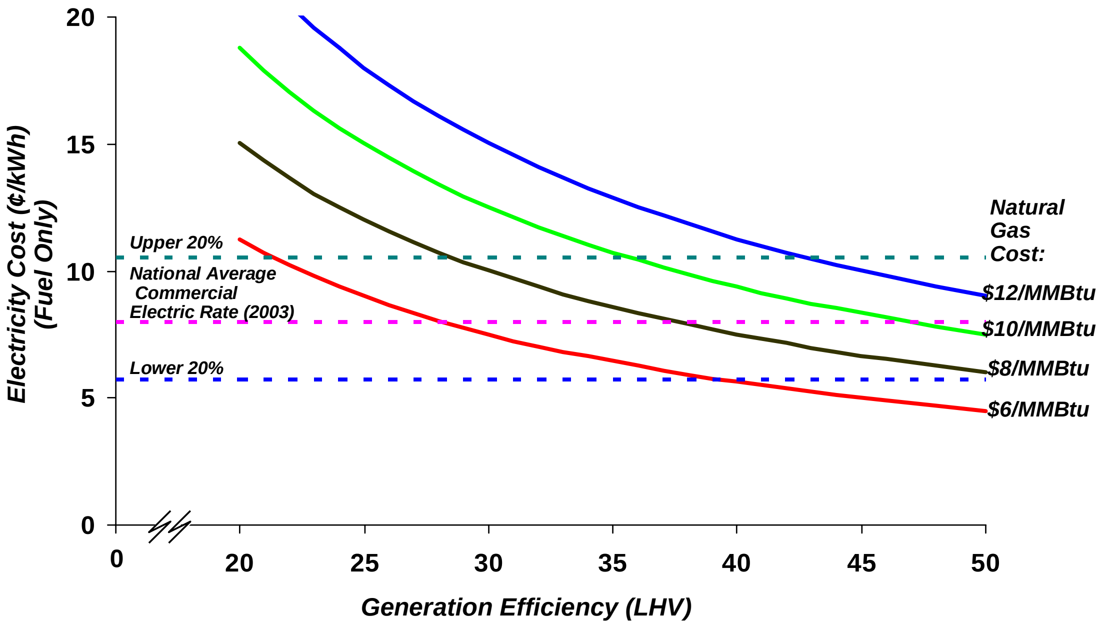


Figure 2-6
"Fuel Cost" of DG

The above does not suggest that technologies having efficiencies lower than these targets cannot have significant markets in some DG type applications (such as backup generators or low-duty-cycle systems focusing on demand charge savings). However, in such limited applications, the operating hours are low and capital costs dominate over fuel costs, greatly reducing the impact of efficiency on user benefits.

O&M Costs

The non-fuel O&M costs of well developed IC-engine-based DG systems is typically in the \$0.015 to \$0.03/kWh range depending on factors such as system capacity and duty cycles. This O&M cost range often represents 15% to 30% of the retail cost of power, which can significantly impact the economics of DG. The negative impacts of O&M costs on DG economics are widely recognized and often cited as one of the important reasons that DG has not had wider market acceptance. The developers of advanced technologies often assert that one of their important advantages will be inherently lower O&M costs than IC-engine-based systems. As discussed in Chapter 3, for the most part these assertions have not yet been verified by long-term system operation.

The target O&M costs indicated are $0.01 to $0.015/kWh, which is on the very low end of that achieved by IC engines—of course even lower values would be highly beneficial. O&M costs include both routine maintenance (oil changes, etc.) and planned, periodic, replacement of subsystems subject to predictable degradation (fuel-cell stacks, etc.).

Capital Costs

Capital costs are particularly important in DG systems due to the stringent requirements placed by buyers on economics (for example, very short payback periods). Recent EPRI research has shown that many end-users require simple paybacks on the order of less than two years [EPRI 2005]. As a result, the target capital cost range on an **installed** basis is $600/kW to $1,200/kW—with the high end corresponding to systems having high efficiencies. Business models that tolerate longer paybacks (e.g., utility-owned and rate-based DG) could allow higher installed capital costs.

Value-chain analyses indicate that equipment costs typically represent 30 to 50 percent of the final installed cost, even for well packaged systems designed to facilitate installation, resulting in a target equipment cost range of roughly $400/kW to $600/kW.

Useful Life

In high-duty-cycle DG applications the equipment will be in operation for 4,000 hours to 6,000 hours per year depending on operational strategies and maintenance time requirements. A ten-year operational life would, therefore, correspond to 40,000 to 60,000 hours. During this time some level of major O&M can be performed on selected subsystems (which must be accounted for in the O&M costs), but, for new technologies, achieving (or approaching) such extended useful lifetimes presents a major challenge.

The very long useful lifetimes that are required for DG applications complicate the development and commercialization of advanced technologies. The development process must include long-term equipment testing over periods of time that are significant compared to the ultimate life requirements—perhaps 10,000 hours as a minimum—before either developers or buyers will make large-scale commitments. The overall testing process, taking into account the inevitable problems that will arise, can take several years and tends to be very costly.

Availability/Reliability

Availability refers to the hours when the system is either operating or available to be dispatched (even if the dispatch strategy does not require operation). Availability is influenced by forced outages due to equipment problems (i.e., reliability issues) and the need for scheduled shutdowns for planned O&M. Having very high levels of availability is usually critically important for DG in the commercial and light-industrial sectors where demand-charge savings are an important part of the economic benefit. Many utility rate structures result in a loss of a month or more of demand-charge savings by being down even an hour during peak-demand periods.

The target range for availability is 92 to 98 percent—even these high levels of availability imply that the system is unavailable for operation for 170 hours to 700 hours a year, which in some applications might be unacceptable.

Emissions

The prior cost/performance parameters are driven by the requirement that DG systems provide economic benefit to the end users. The issue of emissions is fundamentally different in that the acceptable values are driven by regulation. As such, there is no acceptable "range" at any given location. Two general sets of emissions targets (requirements) are indicated:

- Those that include particularly stringent emission-control requirements that apply in non-attainment areas for specific pollutants, such as southern California
- Those that apply more broadly across the country.

Regulations covering emission levels address a multiplicity of regulated pollutants including NO_x, SO_x, CO, particulates, volatiles, etc. Table 2-2 indicates typical expected emissions mandates. Emission regulations are in a continuous state of change, with the trend always toward more rigorous standards. This trend poses an additional risk for both users and equipment manufacturers with the practical effect of biasing decisions toward those technology options that can robustly meet current and probable future emission standards.

Table 2-2
Likely Near-Term Emissions Mandates Applicable to Small-Scale DG

Region	Representative Proposed Regulation	NO_x (lb/MWh)	Particulate Matter (lb/MWh)	CO (lb/MWh)
Non-Attainment Areas	California Air Resources Board (ARB) Emissions Standards, January 1, 2007[a]	0.07	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/scf	0.10
Other US Regions	Regulatory Assistance Project (RAP) Model, Phase 2, 2008	0.3	0.07	2

a) ARB will permit a credit for packaged combined heat and power systems that have a minimum overall efficiency of 60 percent. Effectively, the credit allows useful thermal output to be added to electric output, after converting to MWh.

It should be noted that a different set of DG performance and cost-requirements exists <u>if</u> state policies were to change to “incent” distributed systems as part of helping meet broader energy efficiency and demand reduction goals.

3

STATUS: DISTRIBUTED GENERATION TECHNOLOGIES

Overview/Summary

Table 3-1 provides an overview of the current status of technology options either available or under active development for DG applications. We compare and contrast the current status of each technology with the cost/performance targets that are outlined in Chapter 2 above.

Table 3-1
Overview: Distributed Generation Technology Status

	IC Engines	PEMFC	SOFC	MCFC	PAFC	Microturbines	Stirling Engines
Efficiency	◒	○	●	●	◒	○	○
O&M Costs	◒	N	N	N	◒	◒	◒
Capital Costs	●	○	○	○	○	◒	◒
Useful Life	●	○	○	○	◒	◒	○
Availability/Reliability	◒	N	N	N	●	◒	N
Emissions:							
Non-Attainment Areas	○	●	●	●	●	◒	◒
National	●	●	●	●	●	●	●

● Meets requirements

◒ Close to meeting requirements

○ Does not meet requirements

N Insufficient information

The table suggests several broadly based observations on the status of DG technology:

- The current baseline technology is IC Engines—this technology option meets several of the requirements including capital costs, useful life, and even emissions in many areas of the country. However, IC engines are still only marginally acceptable relative to several important parameters including efficiency, O&M costs, availability/reliability, and emissions in non-attainment areas. The relatively low market penetration of IC-Engine DG is due, in large part, to the fact that IC-Engine DG is only marginally acceptable compared to grid power, as indicated by these key cost/performance attributes. Furthermore, increasingly stringent emissions mandates may limit future potential for IC engines in non-attainment areas.
- None of the developmental technologies has verified the very long life and high reliability characteristics required by DG applications—those that are furthest along include PAFC and microturbines.
- UTC Power has shown a renewed commitment to PAFC, and is planning commercial rollout in 2009. Significant challenges remain, however, in achieving cost reductions and stack-life improvements.
- PEMFC, microturbines, and Stirling engines have not yet achieved the needed efficiency levels. As indicated in the next sections this may be for fundamental reasons that cannot be easily circumvented.
- Two fuel-cell technologies, SOFC and MCFC, can achieve high efficiency, which is one reason they could be particularly attractive for DG applications. These technologies have, however, not achieved several other key cost/performance characteristics (such as long life/reliability) needed for widespread market acceptance.
- All the fuel-cell technologies can achieve the very low emission levels needed to be used in all areas of the country, while microturbines and Stirling engines are close to doing so. Achieving low emission levels removes one large area of potential uncertainty and will help facilitate rapid market expansion if other cost/performance targets can be met.

Since the preparation of the 1999 EPRI report on DG technologies significant progress has been made on all the technologies under consideration [EPRI 1999]. Nevertheless, none of the advanced technologies has progressed to the point that it meets the stringent requirements for large DG market penetration. Several systems, such as microturbines, MCFC, and PAFC, have been implemented in DG applications, but usually under special conditions not present in the broader markets—for example, where government-supplied credits and other forms of financial support are available.

An important objective of this study is to provide insights to the utility industry as to which, if any, of the developmental technologies (including improved IC Engines) are likely to advance over the next five-to-seven years such that their cost/performance characteristics will become compelling for DG applications. The following sections provide brief overviews for each technology option, including current status, major development issues, and identification of milestones that would indicate a fundamental change in prospects for the technology.

Technology Discussions

PEMFC Technology

PEMFC technology is the subject of multiple R&D programs on a worldwide basis due, in large part, to its being the only fuel-cell technology being actively considered for automotive propulsion. In addition, PEMFC technology is amenable to operation over a wide power range so there are active developments for its use for portable power (less than 100 W) and stationary applications in the 1 kW to 100 kW power range. As a result there are over 20 major PEMFC technology development programs worldwide addressing a multiplicity of applications as listed in Table 3-2. Those directed toward automotive applications dominate both government and corporate funding, which is roughly estimated to be in excess of $500 million annually.

Table 3-2
Sample Key Players in PEMFC Technology Today

FC Company	Automotive	Stationary
General Motors	✓	
Diamler Chrysler	✓	
Ford	✓	
Nissan	✓	
Honda	✓	
Toyota	✓	
Volkswagon	✓	
Peugeot	✓	
Mitsubishi Motors Corporation	✓	
UTC Fuel Cells	✓	
Ballard Power Systems	✓	
Hydrogenics		✓
Nuvera Fuel Cells		✓
Plug Power		✓
Nippon Oil		✓
Kyocera		✓
Tokyo Gas		✓
Matsushita		✓
Idatech		✓
Relion		✓

Automotive Applications

As a result of the high level of industry activity there are now over 500 fuel-cell test vehicles in operation worldwide and industry participants project significant fuel-cell vehicle markets in a post-year-2010 time frame. The large industry commitments are motivated, in part, by analysis that indicates that automotive fuel-cell power plants might approach costs of commercial interest, assuming ongoing R&D programs are successful. TIAX has undertaken much of the independent cost analyses for the US Department of Energy (DOE), the results of which indicate manufacturing cost potential of under $300/kW (operating on fossil fuels) or under $150/kW (operating on hydrogen) for systems of about 100 kW at automotive production levels. The industry recognizes, however, that there are multiple technical challenges remaining to develop systems with the reliability and performance required by automotive applications and that success is by no means assured.

Stationary Applications

Most of the PEMFC systems being developed for stationary power today are sub-10 kW systems targeted for residential combined heat and power (CHP) applications (primarily in Japan) and telecom back-up power. Japanese and Korean companies are developing 1 kW PEMFC systems that operate on liquid fuels (LPG or kerosene) for home CHP use. The Japanese Government has in place several initiatives to help subsidize the technology and, hence, support demand. The target price for a 1 kW unit in Japan today to obtain Government subsidies is equivalent to $20,000, with the Government subsidizing up to $10,000 per unit. These units are being developed to run on natural gas, LPG or kerosene. In contrast, PEMFC systems for telecom back-up are primarily being developed by US companies with a focus on hydrogen-fueled systems. Several companies, notably Plug Power, have provided over 150 units (approximately 5 kW each) for this less demanding application. The current cost of such a system is in the range of $2000 – $4000/kW. Current focus on telecom back-up is, in part, driven by the less stringent demands on efficiency, cost, life/durability, and fuel processing.

Applicability of Automotive PEMFC Technology to DG

A potentially important issue for PEMFC technology is the extent to which the large R&D resources and future production volumes associated with automotive applications can be utilized in DG. Certainly the low production cost projected for automotive fuel-cell systems would be sufficient to raise this question. Independent analyses indicate, however, that the transfer of automotive technology to DG applications is complicated by fundamental differences in the fueling and usage requirements, including:

- *Fuel:* Both the industry and government have now determined that the most effective route to fuel-cell vehicles is to fuel them with on-board-stored hydrogen and, hence, hydrogen technology and infrastructure developments are an integral part of fuel-cell vehicle programs. Stacks designed to operate on hydrogen are different in many respects (catalyst composition, loading, etc.) from those operating on reformate as required by DG applications where the predominant fuel is natural gas. As a result of the focus on hydrogen-fueling, there is relatively less R&D focus on the development of fuel-cell stacks operating on reformed hydrocarbons, fuel processors, and associated balance of plant (BOP) components. An important R&D area not receiving the required attention is cost-effective membrane electrode assemblies (MEAs) capable of long-term operation on reformate which invariably includes some level of carbon monoxide and other gases that reduce MEA performance and life. Limited experience to date suggests little likelihood that current technologies can achieve the needed life using reformate within the next 7 years.
- *Life and durability:* The required operating life of an automotive power plant is on the order of 5000 hours, which represents less than one year of operation in most DG applications and is only 10 – 20 percent of that assumed here. Specifically, the target performance degradation rate for automotive PEMFC power plants is roughly two percent per 1000 hours in the near term (DOE targets). The degradation rates are higher in current practice. It is not clear how

PEMFC technology would be modified to address the much longer life/durability requirements of DG applications given the developmental status of the technology (and the fact that achieving even automotive life requirements has not been verified). The changes would likely include some combination of increased catalyst loadings, thicker or different membrane materials—all leading to higher cost structures.

- *Duty-cycle performance:* Automotive fuel-cell power systems are being rated at full power where they operate at lower voltages and higher power densities. At rated capacities the fuel-cell power systems also operated at lower efficiency levels—the high efficiencies of fuel cells (operating on hydrogen) are achieved at 20 – 50 percent of rated power consistent with automotive driving cycles. By contrast, in DG applications the power system will operate at or near rated capacities most of the time and must be sized to achieve high efficiencies during such operation. The net result is that an automotive power plant would have a lower output when rated for DG applications than for automotive applications, with associated higher cost implications.
- *Costs:* Analyses for automotive PEMFC systems, do not include the power electronics, energy storage for load-following capability, and packaging that would be required by a packaged DG system capable of interfacing with the load and utility power—these subsystems would significantly increase the cost structure.

As indicated above, it is not clear that automotive PEMFC technology can be readily adapted to stationary DG applications and that the cost estimates associated with automotive systems would have to be modified significantly (with a strong upward cost bias) when applied to PEMFC-based DG. However, the highly funded automotive R&D activities will certainly provide a strong base for adapting PEMFC technology for DG and, possibly, some level of production support for selected materials and components. As indicated subsequently, even with a significant crossover from automotive, it is unlikely that PEMFC technology will meet critical efficiency and life requirements within the 5-7 year time frame examined in this study.

Technology Status - Gap Analyses

As shown in Table 3-3, PEMFC technology has made good progress in verifying several important characteristics needed for DG applications including low emissions and low noise/vibration levels. It is also likely that PEMFC technology could achieve (or approach) the capital-cost targets if automotive applications continue at current projections. However, there are three key performance parameters that PEMFC technology is unlikely to meet over the time frame of interest for fundamental reasons associated with technology characteristics. These are discussed below:

Efficiency

The limited operational experience with natural-gas-fueled PEMFC systems indicates system-level efficiencies of well under 30 percent (LHV)—these efficiency levels are consistent with other independent analyses based on the developmental status of the field units. Analyses also indicate that more refined units that push the limits of practical operating voltages (0.8 V as compared to 0.65 to 0.7 V for current systems), and that incorporate other measures to increase system-level efficiencies, would still achieve efficiencies in the 30 – 35 percent (LHV) range. Achieving such efficiencies would, however, require significant cost increases and possibly decreased reliability due, in part, to the current questionable ability of MEAs to operate for long periods at elevated voltages. In addition, achieving the higher end of the efficiency range would require significant reductions in the parasitic power of the BOP equipment such as pumps and blowers. The higher "potential future" efficiencies are consistent with good IC-engine practice, but not sufficient to significantly modify the overall DG market.

Table 3-3
Summary of Current and Expected Performance/Cost Parameters for PEMFC Technology in DG Applications

Parameter	Current Status	Potential Future	Notes
Efficiency	< 30% on reformate ~ 55% on H_2	< 35 % on reformate ~ 60 % on H_2	Efficiency improvement requires operation at high cell voltages. Current technology has poor power density and enhanced degradation at high cell voltages
Cost	~ 3000 – 10000 $/kW for 80 kW – 1,000 kW systems	~ 300 $/kW for 80 kW ref. based systems ~ 125 $/kW for H_2 based 80 kW systems	Costs of current systems vary over a wide range because of uncertainties in R&D costs accounting. Current costs are high because of low-volume production. The future costs are estimated for high-volume production associated with automotive application
Life	5,000 – 10,000 hours in single cell and mini stacks	TBD	Information on life/durability of current PEMFC technology is scarce. Developers are projecting achieving the automotive target of 5,000 hours, but none of the developers to date are claiming to be able to achieve 40,000 hours in a reasonable time frame
O&M costs	NA	NA	There is little information today on the O&M costs for PEMFC technology. However, it is clear that stack replacement costs will dominate O&M costs—currently the stack is the most expensive and least reliable component in the fuel-cell system.
Noise	< 65 dBA at 1 m	Similar	Current status values are measured for a 1 kW PEMFC system
Emissions	~zero	~zero	

Life/Durability/Reliability

These three related parameters are discussed together since a common set of fundamental technology issues impacts them. PEMFC and MEA developers report extended durability testing of stacks and MEAs, achieving 10,000 hours operating on hydrogen and up to 5000 hours operating on reformed natural gas. Information needed to validate these claims, such as test conditions, MEA characteristics, or air purity levels, are not readily available. Even with these caveats, the industry assertions indicate good progress in improving the durability characteristics of PEMFC technology. However, the experience to date is still a long way from assuring the needed lifetimes of 40,000 hours with minimal degradation. These questions arise due to a concern for MEA stability when exposed to trace impurities in hydrogen supply and ambient air. When using reformate, the life the issue of MEA degradation becomes even more serious. To further exacerbate the situation, there is relatively little R&D taking place to address the long-term durability of PEMFC technology when operating on reformate, given the current focus of most major developers on hydrogen-fueled systems. Significant efforts are focusing on the development of new catalysts and membranes (facilitating higher temperature operation) to reduce system costs and improve system performance. However, the life/durability of these newer developments will not be established in the time periods of interest for this study (5 – 7 years).

Cost

It is unlikely that system costs will be reduced from today's values to those necessary for DG applications over the next 5 – 7 years. Although PEMFC system costs in high-volume production could be competitive, achieving the required levels of sales (500,000 units/yr.) will not be accomplished in this time frame. (These levels of production are plausible only for automotive PEMFC systems, which operate on hydrogen.)

Water Self-Sufficiency

Sourcing water is a practical issue facing stationary PEMFC applications. During operation, PEMFC stacks require saturated fuel and air streams to keep the membrane hydrated. Under most conditions, the system produces more water than is needed for hydration, which can be recovered to maintain water self-sufficiency. However, under hot (above 90°F) and dry ambient conditions, recovering water from the exhaust will prove energy-intensive. The cell performance would degrade and over prolonged periods of low hydration, and the membrane could experience catastrophic failure. The hydration issue can be addressed by providing an external source of water—this water must, however, be purified, which introduces additional system complexities, cost and O&M. These complexities are rarely discussed in the literature.

R&D Focus

Significant R&D programs are being funded by both Government and industry worldwide. The DOE and US industry are focusing on hydrogen-fueled PEMFC. The primary areas of R&D focus are on the fuel-cell stack and include:

- Development of high-temperature membranes
- Development of membranes for low-humidity operation
- Reduced loadings of precious-metal catalysts, and non-precious-metal catalysts

- Understanding of degradation processes
- Improving life/durability of MEAs and stacks.

Of the above R&D focus areas, developments that will impact most the attractiveness of PEMFCs for DG applications are high-temperature membranes and improved cell performance at high cell voltages. High-temperature membranes could potentially:

- Improve durability of the MEA by increasing tolerance to impurities in the reformate
- Improve cell power density
- Reduce the fuel-processor complexity
- Reduce parasitic power associated with heat removal.

Improved cell performance and durability while operating at high cell voltages (over 0.8 V) would directly enhance system efficiency.

Summary Observations

It is not clear that current or developmental PEMFC technologies will achieve the efficiency and life/durability/reliability requirements of DG applications. The prospects for use of PEMFCs in stationary applications would be enhanced by the ongoing and significant investments in PEMFC for automotive application by helping reduce the cost of key components, eliminating some aspects of performance degradation, development of new membrane and catalyst materials, reducing catalyst loadings, etc. However, none of these developments will improve the efficiency of natural-gas-fueled PEMFC systems. Also, the relatively limited activities focused on natural-gas PEMFC systems are unlikely to resolve the outstanding issues within next 5 – 7 years.

SOFC Technology

SOFC technology is receiving increased attention from industry, capital resources, and government—the reasons for this include a combination of the following:

- SOFC technology has the potential to achieve efficiency levels of 50 percent (LHV) or more in simple-cycle configurations and over 65 percent in combined cycles. The potentially high-efficiency operation of SOFC is of increasing value and visibility particularly with increasing natural gas costs.
- Developments in materials and electrode/electrolyte architectures that enable low-temperature (600^{o}C to 800^{o}C) stack operation allowing the use of use of low-cost materials. The higher-temperature operation of early SOFC designs required the use of exotic materials for overall stack (e.g., ceramic interconnect materials) and system (e.g., treated Inconel® alloys for recuperators) construction and complicated achieving needed life and reliability requirements.

- Analyses undertaken by developers and TIAX (on behalf of the DOE) indicate that SOFC technology has the potential to achieve performance characteristics and manufacturing costs consistent with the cost targets of large-scale DG markets and for other markets for which SOFC is being considered[2].

In this section we provide an overview of:

- *Key SOFC technologies under development*: For the discussion that follows, it is useful to classify the current SOFC technologies as either tubular or planar. Each of these technologies has advantages and disadvantages, and is at a different stage of development.
- *The major government-industry program for SOFC technology development:* In the US, the Solid State Energy Conversion Alliance (SECA) program is spearheading SOFC technology development. The projected technology development timeline of this program provides a guideline as to when SOFCs will be available for DG applications.
- *Current status of development:* More than 20 companies are active in SOFC development today. In this section, we will describe the key attributes of the technology that have been demonstrated, and those that are yet to be demonstrated.
- *R&D developments that will enhance the applicability of SOFC technology for DG:* SOFC technology faces multiple technical problems that are the focus of current R&D efforts. We describe below some key areas of R&D focus and how they might impact the applicability of SOFC technology for DG.

Main SOFC Designs

As indicated in Table 3-4 there are currently over 20 firms worldwide pursuing the development of SOFC technology for auxiliary power units (APUs) (3 – 10 kW), small stationary DG systems (3 – 10 kW), and larger systems for stationary power (over 100 kW). The SOFC technologies being pursued by these companies can be classified primarily by the stack architecture into tubular and planar and, a further classification into the typical operating temperature range (as shown in Figure 3-1).

[2] See TIAX reports available on SECA website at: http://www.seca.doe.gov/

Table 3-4
Sampling of Companies Developing Fuel-Cell Systems and their Key Areas of Focus

SOFC Company	APUs	Small Stationary	Large Stationary
Siemens-Westinghouse			X
SOFCo	X	X	
Delphi	X	X	
General Electric		X	X
Versa Power	X	X	
Acumentrics	X	X	
Ceramic Fuel Cells Limited		X	
Mitsubishi Heavy Industries		X	X
Nissan Motor Co.	`X		
Mitsubishi Materials Corporation		X	
Tokyo Gas		X	X
Kyocera Corporation		X	
Rolls Royce			X
Ceres Power	X	X	
Haldor Topsoe		X	X
Webasto	X		
Wartisilla			X
ZTek		X	X
Ion America		X	
United Technologies		X	X
Jpower			X
Fuel Cell Technologies		X	
Evogy		X	X

Table 3-5
Summary of the key SOFC Stack Technologies being Developed Worldwide Today and the Characteristic Operating Temperature of the Stack Technology

	<600°C	700 - 800°C	850 - 950°C	900 - 100°C	
	Metal supported	Anode supported (Thin-electrolyte)	Electrolyte supported (Thick-electrolyte)	Cathode supported	Ceramic support
Tubular		- Acumentrics - Evogy		- Siemens-Westinghouse - Toho	- MHI - Rolls Royce
Planar	- Sanyo - Ceres Power	- Delphi - GE - Versa Power - Nissan - Mitsubishi Materials - NTT	- Cummins/ SOFCo - Versa Power - Kyocera - Tokyo Gas? - MHI		

Tubular

In the tubular architecture, the active fuel-cell elements are in shape of tubes with the reactant flows both inside aroind on the tube exterior[3]. The advantages of the tubular configurations include:

- Tubular shapes are less prone to mechanical damage caused by thermally induced stresses, which can be an issue with planar configurations.
- The stacks can be configured to eliminate or reduce the need for sealing between the reactant flows, which is difficult (at best) due to the high temperatures involved.

The major disadvantages of the tubular configurations include:

- Relatively low power densities (180 – 250 mW/cm^2), primarily due to high ohmic resistance associated with current collection. A consequence of low power density is the high stack costs.
- Complex fabrication processes for S-W but maybe not for others that increase the manufacturing costs.

[3] For the purpose of the discussion here, we include several variants of the tubular technology including the Siemens-Westinghouse technology (older circular cross-section technology, newer flat-tube technology, and very recent triangular cross-section technology), the Rolls Royce cascaded cell technology, and the Acumentrics anode-supported tubular technology.

Planar

In planar architectures the active ceramic elements are in the form of thin plates sandwiched between separator plates that provide both the flow passages for the reactants and electrical conduction paths. The planar architectures can be further classified into electrolyte-supported and anode-supported designs. As indicated in Figure 3-1 the anode-supported (thin-electrolyte) designs typically operate at 700 – 800ºC, whereas the electrolyte-supported designs operate between 800 – 900ºC. The electrolyte-supported designs have been in development for over two decades now; in contrast significant development of anode-supported technology has taken place only in the past six years.

Advantages of the planar configurations include:

- The potential for higher planar and volumetric power densities (relative to tubular designs), which reduce material content and lead to compact configurations needed for many applications. The ohmic resistance in the planar configurations is expected to be much lower than that in the tubular configurations, permitting the higher power densities.
- Relatively simple fabrication techniques for the active ceramic elements, which reduces manufacturing costs.
- Specifically for the anode-supported designs, the lower operating temperature permits the use of cheaper metallic interconnect materials. In addition, lower stack operating temperature also implies potentially lower costs associated with balance-of-plant components such as the high-temperature recuperators.

The primary disadvantages/technical challenges of planar configurations at this time include:

- The complexity of providing seals to separate reactant flows when dealing with temperatures where no compliant materials are available.
- Maintaining low contact resistances between the active ceramic elements and the separator plates so that the high-power-density potential of the technology is achieved in practice.
- The potential for mechanical damage to the active ceramic elements due to either mechanically or thermally induced stresses.
- Poisoning of the cathode by chromium from the interconnect. Interconnects currently used for planar SOFCs (either anode-supported or electrolyte-supported) contain chromium, which vaporizes in the presence of trace levels of water vapor in air and poisons the cathode.
- In addition to the above issues, planar anode-supported designs do not tolerate repeated exposure of the anode to reduction and oxidation cycles. Essentially, the significant volume changes that the anode experiences with reduction and re-oxidation cause it to crack, thereby catastrophically damaging the cell.

Notwithstanding the above problem areas, as indicated in Figure 3-1 above, planar configurations are the focus of most of the development programs. This is primarily owing to the expectation of low stack and system costs because of the potentially high stack power density, and the lower operating temperatures that could facilitate the use of inexpensive interconnect materials and inexpensive system components such as recuperators.

Government-Industry Partnerships

Several government-industry partnerships worldwide have been established to drive the development of SOFC technology. The largest among them is the US Department of Energy's Solid State Energy Conversion Alliance (SECA) program.

SECA Program Strategy and Participants

SOFC technology development in the US is driven primarily by the Solid State Energy Conversion Alliance (SECA), which has an annual budget of about $50 million that is spread among six vertically-integrated industrial teams (Table 3-5) developing complete SOFC systems and a core-technology program that is supporting the resolution of key technical issues faced by the industrial teams. The central strategy of the SECA program is to use mass-produced, nominally 3 – 10 kW, SOFC stacks and systems in a wide range of applications. The target factory cost for these systems is $400/kW in high-volume production. Targeting diverse markets is expected to help achieve significant economies of scale, even during the initial stages of market penetration when individual-market sales volumes might be modest. The development path includes use of the core technologies in a multiplicity of applications, such as auxiliary power units (APUs), residential/commercial CHP, and portable power to reduce commercial risk and provide near-term markets as the technology evolves in both cost and performance.

The SECA program has as its longer-term goal the development of SOFC technology modules that can be used to construct super-efficient multi-megawatt power plants using a multiplicity of fuel inputs. The system-level electrical efficiency target for a combined-cycle system exceeds 65 percent (LHV) with a cost target of $400/kW. Independent analysis indicates that both the efficiency and cost goals are consistent with technology characteristics assuming key power density and other performance attributes can be achieved.

The six SECA industrial development teams (listed in Table 3-5) each have a unique approach to stack design. All but two (Accumetrics and Siemens-Westinghouse) are based on a variant of planar architectures.

Table 3-6
Summary of the Key Approach and Target Markets for each of the Six SECA Industrial Teams

Prime Contractor	Other Team Members	SOFC Technology	Target Applications
General Electric		Anode-supported planar	Stand-alone power plant or integrated into larger systems
Delphi	Batelle	Anode-supported planar	Automotive and truck APUs, DG applications & military
Siemens-Westinghouse	Fuel Cell Technologies, Blasch Precision Ceramics, Ford, Eaton	Cathode supported tubular	Stationary DG and automotive applications
SOFCo-Cummins	Ceramatec, Inc. and Advanced Refractory Technologies	Electrolyte-supported planar	APUs and stationary power generation
Versa Power	MSRI, University of Utah, GTI, EPRI, Dana Corporation, and PNNL	Anode-supported planar	Small stationary power and military applications
Acumentrics	—	Anode-supported tubular	Communications, residential, military, APUs for heavy-duty trucks and automotive

The SECA program was initiated in late 2001 / early 2002. The development schedule (indicated in Table 3-6) involves three distinct phases with significant demonstrations of key system performance and cost attributes at the end of each phase. The key performance attributes are scheduled to be experimentally verified by mid-year 2005 to 2006, along with evaluation of the potential for the architectures to meet the stringent cost goals. If the development schedules are met, systems meeting DG needs would be developed and verified by the end of 2009. The evaluation against SECA goals will take place first at the developer's site followed by performance evaluation at the National Energy Technology Laboratory's (NETL's) site in Pittsburg.

As of mid-2005 two of the development teams had initiated aspects of Phase 1 testing, with the other teams expected to do so starting in 2006. None of the teams have reported their progress as of mid-2005 relative to achieving their Phase 1 system-level goals.

Table 3-7
Summary of the SECA Program Plan

	Phase I	Phase 2	Phase 3
End-date[a]	2005-2007	~ 2009	~ 2012
Demonstration at the end of the Phase	A prototype system that satisfies the following metrics	A packaged system that satisfies the following metrics	Field testing of the packaged system that satisfies the following metrics
System capacity	3 – 10 kW	3 – 10 kW	3 – 10 kW
System efficiency	Mobile: 25%, Stationary: 40 %	Mobile: 30 %, stationary: 40 %	Mobile: 30 %, stationary: 40 %
System cost[b]	800 $/kW	600 $/kW	400 $/kW
Durability	< 4 % degradation/1000h, 80% availability in 1500h test	< 2 % degradation/1000 h, 85% availability in 1500h test	< 1 % degradation/1000 h, 90% availability in 1500h test
Thermal Cycling	10 cycles	50 cycles	100 cycles
Fuel	Commercial fuel (NG, diesel, gasoline) or suitable surrogate	Commercial fuel (NG, diesel, gasoline)	Commercial fuel (NG, diesel, gasoline)

[a] The range for the end-dates is associated with the different start-dates for the various developers.
[b] System factory cost estimated for high-volume production of the technology at the end of each phase.

Another major Government-Industry partnership was unveiled in 2005. GE was awarded a 10-year, three-phase project with DOE valued at US$83 million. In this project, GE Energy's Hybrid Power Generation Systems business will design and demonstrate an integrated gasification fuel cell (IGFC) system that incorporates a hybrid SOFC/gas turbine as the primary power generation unit. Primary objectives of this program include:

- Develop a design for a 100-megawatt IGFC power plant
- Design and demonstrate a proof-of-concept (POC) system
- Resolve obstacles associated with the development of SOFC, and develop and demonstrate an SOFC building block stack for multi-megawatt system applications

Key milestones for the three phase project are:

- Phase I will begin in October of 2005 and will focus on system design of the IGFC power plant, IGFC and POC system cost analyses, and SOFC technology advancement
- Phase II will further advance the design of the IGFC and POC systems and will extend through 2010
- Phase III, beginning in the fifth year of the program, will culminate in the demonstration of the POC system at an integrated gasification combined cycle (IGCC) power plant.

Technology Status - Gap Analyses

Several of the key cost/performance attributes needed for large-scale DG applications of SOFC technology have been verified (see Table 3-7) including:

- The potential for very high efficiency over a wide power range (from 5 kW to multiple thousands of kW)
- Low emissions that meet all regulatory requirements
- Potential to meet the low manufacturing costs needed for large markets.

The efficiencies and costs listed in Table 3-7 reflect a combination of reported measurements and estimates:

- *Current systems:* Efficiencies are in a large part based on developer assertions. The costs for the current systems are very rough estimates.
- *Future systems:* Efficiency for the future systems were estimated from simulation results published by developers and also estimated in previous studies by TIAX. The potential costs for future systems were taken from the SECA program targets. Previous TIAX analysis indicated that the planar anode-supported technology could meet the $400/kW factory cost in high-volume production with improvements in stack power density.

The likely developmental status of SOFC technologies for DG applications over the next 5 – 7 years can be summarized as:

- *Efficiency:* Meeting the efficiency targets of the SECA program (listed in Table 3-7) by 2012 appears likely based on progress demonstrated to date.
- *Emissions:* SOFC should readily meet foreseeable emissions mandates.
- *Capital Cost:* The cost target of the SECA program ($400/kW by 1012) is based on high-volume production (on the order of 500,000 units/year by a single manufacturer). Developers will strive to meet this cost target, however, it is not clear that markets of sufficient volume will develop in the next 5 – 7 years to support this cost target. At lower production volumes, costs will be higher, but may still be attractive for niche DG applications.
- *Life/Durability/Reliability:* DG applications require stack life on the order of 40,000 hours with less than one percent degradation in power output per 1000 hours. Currently, stacks that have performance consistent with meeting cost targets have higher degradation rates and have not been tested for 40,000 hours. The SECA 2012 target is 1500 hours of stack operation with negligible degradation. It is not clear that stack designs consistent with cost targets will meet life requirements for DG applications within the next 5 – 7 years.
- *O&M Costs:* O&M costs will depend primarily on stack life. As discussed above, it is not clear that stack life requirements will be met within the next 5 – 7 years.

Table 3-8
Summary of Current and Future Performance Attributes of SOFC Systems

Parameter	Current	Future	Notes
Efficiency	~ 35 %, 3- 10 kW ~ 50 % > 100 kW	~ 35 -45 %, 3- 10 kW ~ 55 % > 100 kW ~ 65 % > 3000 kW	Efficiency is primarily dictated by the cell voltage, the fuel utilization, and the BOP parasitic losses. There is insufficient information to distinguish between planar or tubular architectures in simple cycle systems However, the higher operating temperature of tubular cells may support higher efficiencies in combined cycle operation.
Cost of complete systems if fabricated in high-volumes	> 1000 $/kW	~ 800 $/kW (by 2007) ~ 400 $/kW (by 2012)	Costs of current systems vary over a wide range because of uncertainties in R&D costs accounting. Current costs are high due to low power density and materials choice The future costs are taken from the SECA program milestones
Life	Tubular: ~ 80,000 hours on single cell, and ~ 20,000 hours on 100 kW system Planar: ~ 3000 hours on mini stacks	SECA targets: APU: 5000 hours DG: 40,000 hours	Information on life of Siemens-Westinghouse tubular technology (circular cross-section) is well-tabulated; Long life of planar stacks/or systems not demonstrated yet
O&M costs	NA	NA	There is little information today on the O&M costs with SOFC technology. However, it is clear that stack replacement costs will dominate O&M costs – currently the stack is the most expensive and least reliable component in the fuel cell system.

The developmental status issues for SOFC differ somewhat between the tubular and the planar configurations. These are discussed separately below.

Tubular - Status and Development Issues

There is considerable long-term operating experience with stacks/systems using tubular technology by virtue of the program at Siemens-Westinghouse. The tubular architecture is the furthest along in terms of demonstrating large-scale systems for stationary applications. Siemens-Westinghouse has demonstrated multiple systems (as indicated in Table 3-8). This program has been funded by DOE for over 15 years and in resulted in over 100,000 hours of system-level testing with up to 20,000 hours on one 110 kW experimental system (see Table 3-8).

A major accomplishment of the Siemens-Westinghouse tubular SOFC program is the demonstration of the compatibility of the basic materials used in today's SOFC technology. Stable performance of single cells with less than 0.1 percent degradation per 1,000 hours, even after 20,000 hours of testing, has been demonstrated with conventional cell electrode and electrolyte materials.

However, the requirement for all the current tubular technologies to operate at temperatures higher than 900°C complicates achieving life/reliability targets. As indicated in public presentations from Siemens-Westinghouse, failure modes of several of the systems in field tests were centered on high-temperature balance-of-plant (BOP) components rather than the stacks themselves.

Table 3-9
Summary of Current Demonstration Activities Based on the Siemens-Westinghouse Tubular Stack Technology

Net AC Power (kW)	Electrical Efficiency (% on LHV basis)	Operating time (hours)	Test Period
110	46	20,400	1997-2002
176	52	3,200	2000-2002
192	40	1,130	2003-present
3	39	3,100	2003-present

An even more fundamental issue with tubular configurations is that some have low power densities using current technologies and materials. These low power densities result in material-intensive architectures. Furthermore, most of the materials are electronic-grade ceramics requiring complex processing. TIAX cost analyses for one of the tubular configurations suggest stacks/system production costs will exceed $800/kW even in significant production quantities.

Because of these and other factors, Siemens-Westinghouse is exploring alternate designs to enhance the stack power density. More-recent presentations from Siemens-Westinghouse indicate novel architectures aimed at reducing the ohmic voltage losses (Figure 3-2). In addition, Siemens-Westinghouse is developing novel cathode/electrolyte interlayer materials to reduce the electrochemical reaction losses associated with the cathode.

Several early stage companies e.g. Evogy are developing novel tubular designs which may exhibit both high power density and require less complex tube fabrication and electrode processing steps. However, given the current stage and scale of development many of these early stage companies are not anticipated to have products which could impact electric utilities within 5 years.

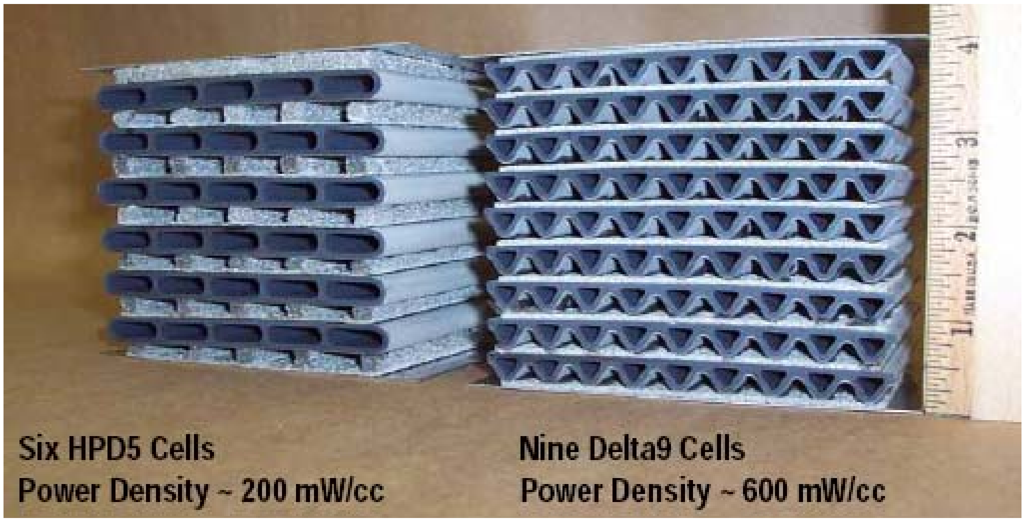


Figure 3-1
Recent Developments in the Siemens-Westinghouse Tubular Cell Design Aimed at Reducing Ohmic Losses

Planar - Status and Development Issues

As shown in Table 3-7 above, if planar technology meets its power-density potential the cost structure of stacks/systems will be consistent with large-scale DG markets. The central issue with planar architectures is achieving the life and reliability requirements that are, in turn, needed to address availability and O&M cost goals. To date, the experience with extended testing of planar configurations is far more limited than with tubular configurations:

- *Planar electrolyte-supported designs:* Completely integrated systems (about 1 kW capacity) have been built and tested based on planar electrolyte-supported configurations. Key developers conducting system-level demonstrations with electrolyte-supported technology are and Ceramic Fuel Cells Limited (CFCL) and SOFCo. . Note that Sulzer Hexis recently terminated their SOFC activity.
- *Planar anode-supported designs:* There have been fewer demonstrations of completely integrated systems. GE Energy, Delphi, Mitsubishi Materials, and Versa Power have tested complete systems. However, performance data on tests with fully integrated systems are scarce.. GE Energy has reported to EPRI the successful operation of a 5 kW SOFC system developed under the Phase I DOE SECA Program. They have reported overall system efficiencies of 40.6% LVH fuel to dc power.

Several technology challenges remain for planar configurations:

- Few stacks are able to withstand frequent thermal cycling and reasonably fast startup that would be required in most DG applications. In many cases performance drops off significantly after only a few thermal cycles (1 to 10).

- Only limited extended durability testing is taking place, with few of the developers reporting more than a few hundred hours of testing on full-sized units—certainly a long way from the 10,000-hour-plus testing required to establish minimal credibility.
- The performance of stacks is usually much lower than that which would be projected based on single-cell test data (and lower than that needed to achieve cost targets), even during initial operation, and tends to degrade thereafter.
- An issue that has not been adequately addressed by most developers is the strategy for scale-up of SOFC stacks for multi-MW or even 100 kW systems. The development of cost-effective large SOFC systems (100 kW – multi-MW capacity) would require larger stacks (both cell area and number of cells per stack) so as to minimize the piping and the number of electrical interconnections in the system. However, most of the stack developers today are pursuing small-scale cells (~100 cm^2 active area). An exception might be GE, who displayed large area (~1000 cm^2) cell at a recent SECA workshop. However, performance data on the large area stack has not been published.

Extensive analyses at TIAX and discussions with government and industrial organizations involved in fuel-cell development indicate several fundamental reasons for the life/reliability problems being exhibited to date including:

- Difficulty in sealing the reactant flows from one another given the lack of material compliancy at SOFC operating temperatures—the issue of seals capable of undergoing repeated thermal cycles has long been a problem.
- Relative motion of the separator plate and ceramic electrode/electrolyte, resulting in high contact resistances that vary due to thermal cycling, complicates the sealing issue, and can cause mechanical damage to electrode surfaces.
- Basic material incompatibility issues that are exacerbated by the high temperatures involved. One of the more persistent issues is the presence of chromium in many of the separator plate materials, which can poison the cathode.
- High contact resistance between the interconnects and the electrodes, which reduces the stack power density.

The above and other issues impacting life and reliability are well known, and are being addressed through multiple government and private sector programs. The certainty and timing of their resolution is still, however, uncertain.

R&D Focus

As indicated previously, several research programs are focusing on overcoming the technical challenges in SOFC technology. R&D areas that are being addressed by the developers that will directly impact the applicability of SOFCs for DG applications are.

- Metal Interconnect: highest cost element in planar stack; durability issue

- *Increase in stack power density:* The stack costs are driven by the power density that is obtained under practical conditions of high fuel utilization. Developers are working to improve the power density of both the tubular and planar stacks:
  - For the tubular stacks the primary cause of low power density is the ohmic loss associated with the cell current collection and poor cathode performance. As described above, Siemens-Westinghouse is developing novel stack structures to overcome the ohmic loss limitations
  - For planar architectures, high contact resistance is a major reason for poor stack power density. In addition, specifically for anode-supported designs, diffusion resistance to hydrogen at high fuel utilization in the anode also reduces the power density. Materials to reduce the contact resistance and better engineering of the anode are being pursued to improve the power density. To meet the SECA cost targets requires that the stack power density exceed 500 mW/cm^2 for anode-supported planar technology at high fuel utilization
- *Lower temperature stack operation:* The operating temperature of the stack impacts costs associated with the BOP components. The higher the operating temperature of the stack, the more exotic (hence more expensive) the materials used in BOP components such as recuperators. For a 5 kW system, the recuperator could represent more than 10 percent of the total system cost
- *Sulfur tolerance:* SOFC anodes currently used in both tubular and planar designs have very low tolerance to sulfur. By some estimates sulfur levels in the anode feed gas above two ppmv can significantly reduce cell performance. Given that most fuels likely to be used for DG applications would contain sulfur, either the development of effective sulfur traps or the development of sulfur-tolerant anodes is critical to achieving high stack power densities when operating on realistic fuels
- *Scale-up of power*: Most of the planar SOFC effort currently is focused on sub-10 kW stacks. Larger-scale systems would require strategies to scale-up today's sub-10 kW SOFC stacks. Issues associated with manifolding a larger number of stacks will have to be resolved.

Summary Observations

If successfully developed, SOFC technology could be attractive for DG applications. Demonstrations to date have shown that it would be possible to achieve high system efficiencies for both simple cycle and hybrid fuel cell cycles. Analysis undertaken by TIAX and others indicate that if the power density targets were attained then at high volume production the costs of the SOFC systems would be acceptable for large DG markets. However, life, reliability, and the performance needed for low costs are yet to be demonstrated. R&D efforts are being focused on overcoming these technical challenges through significant Government-industry collaboration. The US-DOE's SECA program provides one guide for the timeline of SOFC development. If the development schedules are met, systems meeting most of the DG needs would be developed and verified by the end of 2009. EPRI should continue to closely follow developments in this area, with particular focus on some of the novel developments by smaller companies. EPRI should also closely follow advanced in SOFC hybrids as they have the efficiency and size attributes of relevance to utilities and power generators.

PAFC Technology

PAFC technology has received limited interest from government and industry over the last few years—leading vendors are UTC Power in the U.S., and Fuji and Mitsubishi Electric in Japan. Recent announcements by UTC Power, however, indicate a renewed commitment to PAFC for DG applications that will result in the expanded R&D, marketing, production, and deployment for this technology.

PAFC technology has the most extensive track record for operational experience of any of the fuel-cell technologies with over 300 systems (mostly 100 kW to 200 kW) installed worldwide (over 15 countries, with most in Japan and the U.S.). The UTC Power systems alone have accumulated over "one billion kilowatt hours", which far exceeds the experience with any other fuel-cell technology. The reasons for the reduced interest in PAFC that occurred in the 2002 to 2004 time period (notwithstanding respectable operating experience) included some combination of the following:

- A widely held view that PAFC is inherently more costly than alternatives under development such as PEMFC and, to a lesser degree, SOFC and would, therefore, be made obsolete by these technologies. In the case of PEMFC this view was reinforced by the potential for PEMFC to benefit from the huge investments being made in automotive PEMFC technology.
- Limited potential for increasing efficiency levels above the 35 – 40 percent (LHV) range currently achieved, which is marginal for many DG applications.
- Questions about reliability and life due, in part, to the use of a liquid electrolyte, which complicates maintaining stable stack conditions.

The renewed interest in PAFC reflects, in large part, recent developments with the other fuel-cell options, including:

- The shift of automotive PEMFC developments to use hydrogen so that little R&D is taking place for natural-gas-fueled PEMFC needed for DG.
- Continuing questions as to whether PEMFC technology would have adequate efficiency and life characteristics when operating on fuels reformed from natural gas.
- The difficulties encountered in developing SOFC and MCFC technologies with the reliability, life, and cost structures needed for DG.

Technology Status - Gap Analyses

The experience of UTC Power is representative of the technology status as summarized below:

- Individual units have operated for as long as 40,000 hours with minimal degradation.

- Over 7 million operating hours on the "fleet" with average availability of over 95 percent on the latter-generation systems.
- Operating efficiency levels averaging about 35 to 38 percent (LHV), with the pressurized 10 MW system in Japan achieving 41 percent.
- Emission levels meeting all regulatory requirements (including CARB 2007 Emission Standards).
- Equipment costs in excess of $3,500/kW—as a result, almost all the systems have been installed with some form of government subsidy (direct grants, tax credits, etc.).

PAFC is at least close to meeting most of the technical performance characteristics needed for widespread DG applications. The big issue has been and continues to be the potential to significantly reduce capital and O&M costs by some combination of increased production levels and technology improvements. Several observations on the cost structure of PAFC stacks and systems follow.

Capital Costs

As indicated above, the equipment costs for PAFC systems are in excess of $3,500/kW and have not come down over the last few years. These costs are much too high to lead to substantial DG markets even with the highly respectable technical performance characteristics. Several observations follow on the current high costs:

- The balance of plant (BOP) cost for PAFC systems should not be higher than that for PEMFC—in fact, the fuel-processing requirements of PAFC are somewhat less than for PEMFC since the operating temperature of PAFC is 200°C, thereby obviating the need for additional CO cleanup steps required for PEMFCs. As such, cost analyses undertaken for the BOP of PEMFC systems should be, in large part, applicable to PAFC, assuming similar production levels.
- A primary contributor to the high current costs of PAFC is the fuel-cell stacks. Reasons for the high stack costs include a) their relatively low power density (about 150 mW/cm^2 as compared to PEMFC at over 300 mW/cm^2), and b) the machined, high density, graphite separator plates, which require multiple high-temperature processing steps in their fabrication. There has been little change in the separator-plate materials or designs over the last 20 years.

UTC Power has recently announced focused programs for cost reduction that they project will reduce costs to a level where the technology becomes "a standard energy resource that secures power availability, improves efficiency, and reduces environmental impact" (UTC Power Press Release; May 4, 2005).

The separator-plate materials being developed for use in PEMFC stacks cost only a fraction as much (on a per-unit-area basis) as those used in PAFC stacks. Drawing, in part, on PEMFC technology experience, UTC Power has developed new composite materials capable of operation under PAFC conditions (more harsh than in PEMFC stacks) and consistent with low-cost fabrication (molding, etc.) techniques to greatly reduce the cost of separator plates and gas diffusion layers used in stack construction. The new material combinations are currently undergoing extensive performance and endurance testing in small stacks.

Life/O&M Costs

Life and O&M costs are directly related when assessing PAFC economics since a major portion of levelized O&M costs is associated with periodic replacement of the stack subsystem and, to a lesser degree, the frequency of routine maintenance such as replacement of fuel-processor catalyst and sulfur-control materials. The 40,000 hours of stack life demonstrated for PAFC is still at a threshold level of acceptability—although far superior to that of any of the other fuel-cell technology options. Both Fuji and UTC Power have announced that they expect to achieve 60,000 to 80,000-hour stack life on their next-generation fuel-cell systems. As discussed below, life and O&M are the key focus of ongoing R&D efforts.

R&D Focus

The strategy being pursued by UTC Power includes a combination of:

- Reduced average stack operating temperature (by about 20°C) to both increase material life and facilitate liquid electrolyte loss control strategies.
- Increase the capacity of fuel-processor catalyst and sulfur-control-bed materials to extend maintenance intervals.

If stack costs and life goals are achieved, the resultant O&M costs would likely be reduced to levels consistent with targets established here.

Summary Observations

PAFC technology has verified many of the key technology performance parameters via operation of hundreds of field systems, which have improved over the last decade as better models have been introduced. The primary issues are now a) achieving major cost reductions, and b) extending life of the costly stack subsystem to levels consistent with DG applications. UTC Power asserts that by virtue of the ongoing cost-reduction programs the technology will become consistent with an installed cost goal of $1500/kW, which is in the target range for commercial viability. UTC Power is making significant investments towards meeting this aggressive goal. The development time line is to verify the advanced technology package via testing of a "Model C" system designed to meet cost targets (in sufficient production quantities) in 2007 in preparation for a commercial rollout in 2009.

MCFC Technology

Currently there is only one developer/manufacturer of MCFC technology in the U.S. (Fuel Cell Energy), several in Japan (Ishikawajima-Harma Heavy Industries, IHI and Mitsubishi), and one in Europe (Ansaldo Fuel Cell). The developments at FCE are the most advanced as measured by the number of units deployed and associated operational experience and, therefore, the developments at FCE will be the focus of the following discussion.

The developments at FCE have been supported, in part, by the DOE for over 15 years and continue at reduced levels as FCE enters into the field deployment and commercialization phases of its technology.

Technology Status - Gap Analyses

FCE currently has 40 units in the field with capacities ranging from 250 kW to 1,000 kW. The target applications have been high value CHP functions in applications such as hospitals, universities, and hotels having large, steady, electric and thermal loads allowing high duty cycle operation; reliable power applications such as credit card operations; and conversion of bio-gas to electricity at land-fills, sewage treatment plants, and other sites generating organic waste such as breweries. The current costs of the systems are high (over $4,000/kW) so that installations focus on applications which value emission reductions and power quality as well as energy cost reductions. All system installations are supported by some form of financial incentives provided by various government programs.

The technology has many of the attributes required for widespread commercial applications, which is also indicated by the multiple commercial alliances on a worldwide basis with such companies as MTU in Germany, Marubeni Corporation in Asia, Caterpillar, PPL Energy Plus, and Chevron Energy Solutions in the United States, and Enbridge in Canada. There are several important cost/performance issues which must be addressed for the technology to meet the needs of large markets.

Manufacturing Costs

Over the last eight years FCE has reduced the cost of the system package by over 50% from about $10,000/kW in 1997 to the current cost of about $4,800/kW, which is still far above that needed for large scale, unsubsidized, markets. The high cost of the technology is due to several factors, including:

- A low power density (about 130 mW/cm2), which results in the requirement for large surface areas.
- The extensive use of relatively costly nickel or high temperature alloys for electrodes, flow-fields, interconnects, and BOP components (e.g., manifolds, piping, recuperator).
- A relatively complex balance of plant much of which must operate at 600C limiting the selection of materials.
- Limited levels of production so that production economies of scale are not yet achieved.

Increased production levels would tend to decrease cost structures somewhat by allowing for increased automation of some manufacturing/assembly processes. However, independent cost analyses indicates that the high material intensity of the technology in its current form results in a major challenge for the technology in approaching even the high end of the target cost range for the equipment package ($1,000/kW).

Life/Durability

FCE has an excellent record of operating full size fuel cell systems for significant periods of time measured in many thousands of hours on single units. There are still questions, however, as to whether the technology in its current form can meet the particularly stringent life (and associated reliability) requirements of DG. The operating environment of MCFC with molten carbonate at 600°C is well known to be a particularly aggressive potentially impacting the stability of all materials with which it is in contact.

If stack lifetimes do not approach (or exceed) the lower end of the target range (40,000 hours) the more frequent stack replacement schedule will need to be accounted for in the levelized O&M cost structure and would likely result in O&M costs well in excess of the target range.

O&M Cost:

There is still insufficient operation experience to have a track record on O&M costs. In 2003 FCE claimed an operating life of 3 years with replacement stacks projected to have a life of 5 years or greater. For a 2003 assessment of MCFC technology, an analysis was performed to look at the impact of stack life, capital cost, fuel cost, and the stack percentage of the system cost on the cost of electricity [EPRI 2003]. This analysis is still valid and is shown in Figure 3-3. To understand the implications of system cost on cost of electricity, a few basic concepts and relationships were defined. The cost of electricity (COE) includes:

- *Recovery of capital cost* (for simplicity here represented as total installed equipment cost multiplied by a capital recovery factor divided by number of hours of equivalent full-capacity operation per year).
- *Non-fuel operating and maintenance cost* - For fuel-cell systems, most of this cost-component is related to the replacement of stacks. Hence this component depends strongly on the stack cost and the stack life. Thus it is linked to the installed system cost as stack costs are projected to represent 40% of the system cost. It is also assumed that the rest of the system has a much longer life (e.g. 20 years) and even though some BOP components (notably catalyst and filter costs) need periodic replacement, their contribution to O&M cost is minimal.
- Fuel cost (depends on fuel price and system efficiency).

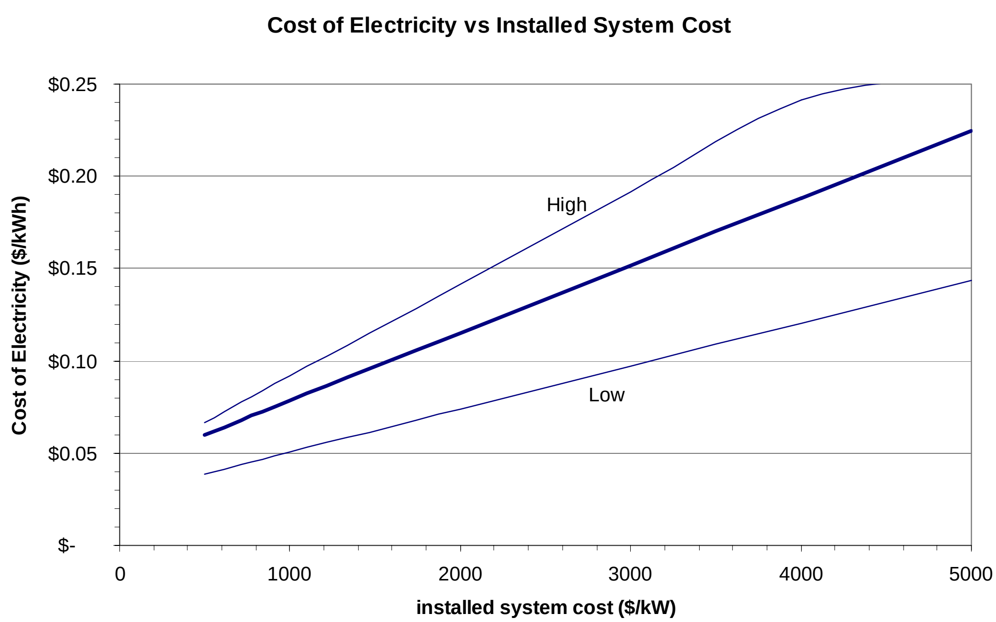
The cost of electricity was calculated for three baseload power production scenarios (i.e., high, intermediate, and low) with the assumptions for each case listed in Table 3-9.

Table 3-10
Cost of Electricity Scenario Assumptions

Cost Scenario	Stack Percentage of System Cost	Stack Life (years)	Fuel Cost ($/MMBTU)
High	60%	3	5
Intermediate	60%	5	5
Low	40%	10	3
Common Values: Hours of Operation – 6000; Non-Replacement O&M - $0.005/kWh; Efficiency – 47%; Capital Recovery Factor – 0.1			

At the time, FCE indicated that the split between fuel cell and BOP costs was 50:50 and that stack life was three years. They indicated in the future these values would be 40:60 and five years respectively. An electrical efficiency was selected on the basis of reported performance of FCE demonstration units, while the non-capital portion of the O&M costs was set equal to $0.005/kWh based on our experience. A capital recovery factor of 0.1 was chosen on the assumption of the availability of favorable financing, but could double under less favorable conditions.

Based on these assumptions, installed capital cost of the system would have to be between $2,000 and $4,000 per kW in order to be able to achieve a cost of electricity of around $0.13 per kWh, as shown in Figure 3-3.



Note: Low- and high-cost scenarios represent range of fuel prices, stack life, and number of operating hours.

Figure 3-2
Cost of Electricity versus Installed Equipment Cost

Further cost reduction to around $1500/kWh would have to be achieved to attain an unsubsidized COE of $0.10 per kWh. Achievement of a five-year stack life is critical to attaining cost targets.

Higher electrical efficiency of the FCE technology relative to other fuel cell technologies provides some tolerance for high capital equipment costs. The impact of stack replacement cost on the cost of electricity is significant under the assumptions used above. In fact, O&M cost is the single biggest component of the total COE. This emphasizes the importance of reducing stack replacement cost further, which again points towards increasing power density and increasing stack life.

One strategy that might be considered to address the afore-discussed limited stack life is to replace the stack at more frequent intervals in the early years while R&D is undertaken to extend basic durability characteristics. As indicated in the figure, this strategy would result in high O&M costs (on a levelized basis) beyond those acceptable in most applications unless the stack replacement schedule increases well beyond 20,000 hours (as a minimum).

R&D Focus

Per public pronouncements of FCE, much of their attention is focused on continuing cost reduction via a combination of design refinements, engineering, procurement improvements, vendor relations, and technology improvements. The goal is 20% to 25% cost reductions on an annual basis, which, if achieved, would result in a system cost of about $2,000 in a 3 to 4 year time period. Further cost reductions would probably require significant technology advances in such areas as power density given the high material intensity of the current technology.

All the developers of MCFC continue to address basic material issues associated with stack degradation and associated limits on useful stack life—little information is available on the strategies being pursued and progress being made.   Progress on this issue will be important for the technology to have overall cost/performance characteristics consistent with large markets.

Summary Observations

MCFC technology has already demonstrated many of the performance attributes needed for DG. The key issues have been and remain the ability to reduce costs and extend stack life to the levels required for large market acceptance. EPRI should continue to monitor and assess field demonstrations and seek to obtain data on stack durability and life.

Microturbine Technology

Microturbines are pre-packaged combustion turbine systems having capacities in the 60 kW – 500 kW output range. Although the technology base for microturbines has been available for over 25 years, the emergence of serious industry commitment to their development started in the early 1990's due to the growing interest in DG. Figure 3-4 shows a typical microturbine installation.

Figure 3-3
Microturbine Installation at DeAnza College, Cupertino, CA (Courtesy of Capstone Turbine Corporation)

In the late 1990's there were six industry participants in the microturbine area—AlliedSignal Power Systems, Bowman Power Systems, Capstone Turbine, Elliot Energy Systems, NREC (Ingersoll-Rand), Turbec (Volvo/ABB). The industry has grown to include the nine participants listed in Table 3-11. Over 3000 units have been shipped, although mostly from one manufacturer, Capstone [Capstone 2005]. Similarly, the level of development efforts has also grown. Developers are focused on higher capacity units—around 200 kW, on higher efficiency—30+% (LHV), and on integrated combined heat and power (CHP) packages. This departure from initial focus on sub-100 kW units targeted primarily for electric-only applications is driven by several factors, including:

- Better project economics with higher efficiency
- Better matching to commercial and light-industrial applications
- Potential higher reliability and lower cost facilitated by lower rotating speeds
- Lower "transaction costs" (legal, sales, permitting, etc. costs) on a per-kW basis as capacity increases
- Performance improvements possible at larger scale.

Despite the shift in focus and the level of activity, capital and O&M costs remain stubbornly high, well above early projections.

Table 3-11
Current Microturbine Developers

	Products	Comments
Bowman Power Systems	3 CHP packages w/ 80 kW_e core, over 125 units shipped	Bowman Power Group Ltd., Hampshire, UK
Capstone Turbine Corporation	Several 30 kW_e and 60 kW_e units (over 3000 units shipped); integrated 60 kW_e CHP recently introduced, 200 kW_e in development under DOE Advanced Microturbine Program	Public Corporation, NASDAQ-CPST Preliminary spec. electric efficiency 32.5% (LHV) for 200 kW unit. Further beta testing planned, but commercialization date not yet announced.
Elliot Energy Systems	100 kW_e integrated CHP package, over 125 units shipped	Wholly-owned by Ebara Corp., Tokyo Electric efficiency 29% (LHV)
GE Global Research	175 kW_e unit in development under DOE Advanced Microturbine Program	Target electric efficiency 35% (LHV); test results not yet available
Honda R&D, Wako Research Center	42 kW_e unit in development	Spec. electric efficiency 26.7% (LHV); demonstrated efficiency less than 26% (LHV), but further improvements expected
Ingersoll-Rand Power Systems	70 kW_e and 250 kW_e integrated CHP packages, over 80 units shipped	Spec. electric efficiency 29% (LHV) for 250 kW unit
Turbec	100 kW_e integrated CHP package, over 150 units shipped	
UTC Power	Joint development with Capstone of a combined cycle using two Capstone 200 kW_e microturbines and UTCP organic Rankine cycle (ORC) for 480 kW_e generation capacity target.	Demonstrated combined cycle electric efficiency of 38% (LHV); microturbine alone is 33% (LHV)
Hitachi, Ltd.	150 kW_e unit in development	Partially funded by the New Energy and Industrial Technology Development Organization in Japan. Target electric efficiency 35% (LHV); demonstrated 32%, which is expected to increase with addition of inlet air cooling and moist air injection.

Note: Shipment Data: Current for Capstone; for others based on an 11/2002 survey by E SOURCE Distributed Energy Service presented at ASME Turbo Expo Technical Congress, June 2003.

Microturbines hold two key advantages over their primary competition, internal combustion engines:

- Very low emissions without any after-treatment is the primary advantage. Microturbines use premixed, staged combustor technology similar to that used in large combustion turbines, known as Dry Low NO_x (DLN) combustors. The NO_x emissions level achievable by microturbines without after-treatment is far lower than can be currently achieved with natural-gas internal-combustion engines (3 to 6 lb/MWh) [Caterpillar 2005]. At full load, many microturbines emit less than 9 ppm of NO_x @ 15% O_2 (<0.49 lb/MWh). Some units emit as much as 25 ppm of NO_x @ 15% O_2. Tightening DG emissions regulations in California for 2007 are restricting NO_x emissions to less 0.07 lb/MWh. Improved combustor designs alone are not likely to meet pending NO_x restrictions. However, California will allow the useful thermal output to be added to the electric output provided the total system efficiency is greater than 60 percent at full load. Meeting the NO_x limit in California means DG systems must be offered as factory-integrated CHP packages. All product development efforts are headed in this direction.
- Easier to attenuate sound and vibration compared to IC engine gensets. Microturbine generator systems have noise ratings ranging from 70 dBA at 1 m (for Bowman Power Systems TG80RC-G-R CHP package at 0.041 kW/kg) to 70 dBA at 10 m (for Capstone's C60 generator at 0.053 kW/kg). A comparable IC engine generator system, such as Caterpillar's GEP83-3 genset with sound attenuating enclosure, has a noise rating of 72 dBA at 7m, but is a much heavier system with a specific power of only about 0.03 kW/kg. Microturbine systems can achieve the same level of sound attenuation as IC engine systems with less added cost and less added physical space/weight.

Technology Status - Gap Analyses

There are over 3,000 microturbine systems operating throughout the world with most in the U.S., Europe, and Japan. Annual sales, dominated by Capstone, are estimated at between 150 and 200 units per year (estimate based on Capstone's backlog March 2004). Although significant, the sales of microturbines are far below early projections by their developers of over 10,000 units per year. As discussed subsequently, the modest sales reflect issues of current technology in meeting DG requirements relative to efficiency, life / reliability, and costs.

Efficiency

Large turbine generators (20-250 MW), such as GE Frame 5, 7, and 9 heavy-duty gas turbines, have electric efficiencies ranging from 28.3 to 36.9 percent (LHV). Whether large or small, turbine generator efficiency is driven by the temperature and pressure of the gases flowing through the turbine's expander. For microturbines with their single-stage centrifugal compressors, pressure is limited to about 4 atm. For larger turbines with multi-stage axial compressors, pressure ranges from 4 atm to 10 atm. While pressures in large turbine are much higher than in microturbines, the temperature flowing through the turbine's expander, referred to as the turbine inlet temperature (TIT), has the greatest impact on efficiency. Efficiency increases as turbine inlet temperature increases. However, turbine inlet temperature can only increase within the limits of high-temperature materials. Large turbines push turbine inlet temperature beyond material limits by employing active cooling of components that are exposed to the highest temperatures, such as flowing air or steam inside turbine nozzles / blades. For microturbines, employing such active cooling schemes is beyond the capability of the simpler radial compressors and expanders used. As a result, current microturbine system level efficiencies are in the range of 27 to 29 percent (LHV) at standard rating conditions. In practice, as with all combustion turbines, efficiencies are lower at ambient air temperatures above the nominal 59°F rating-point temperature, dropping 0.07 to 0.08 efficiency points per degree of ambient air-temperature rise, or about three percentage points at 95°F. Microturbines in development are pushing nominal efficiency as high as 33 percent, using advanced ceramic components. Although advanced ceramics can support higher temperatures and increased efficiency, they raise significant questions regarding reliability, life and cost. Until microturbines using advanced materials are demonstrated to have sufficiently long life at reasonably cost, microturbines at their current electric efficiency levels do not meet DG requirements established here for power-only applications. This is recognized by the industry and, therefore, increasing efficiency levels is a high priority R&D objective.

Capital Costs

Energy project case studies report current equipment costs are in the $800/kW – $1100/kW range with corresponding installed costs, including a heat recovery unit (HRU), in the $2000/kW to $2500/kW range[4]. Capstone's FY 2004 annual report indicates unit costs of about $700/kW, which would represent factory standard cost, leaving $100-$400/kW margin for distributors and project developers. Interestingly, this standard cost is consistent with early cost analyses by TIAX staff for manufacturing at 1000 units per year [EPRI 1999; Table 1-12]. Those same analyses showed then that, at volumes of 10,000 units per year, factory standard costs would drop below $600/kW. However, such an increase in production volume is not expected.

Additionally, EPRI's early analyses were for a recuperated microturbine operating with a 1700^{o}F turbine inlet temperature, which resulted in a net generation efficiency of 26 percent (LHV). Actual turbine inlet temperatures were estimated to vary from 1500°F to 1700°F, which can account for about a three percentage point difference in electrical efficiency (23 to 26 percent). However, increasing turbine inlet temperature increases material fatigue, placing a limitation on the actual performance benefit that may be realized. To achieve the electric efficiencies in the low-30's percent range requires more exotic metal alloys and ceramics for the combustion liner and the expander, and both exotic alloys and higher effectiveness (over 90 percent), meaning more surface area for the recuperator. These advanced materials and designs will drive up factory costs and are presently driving a significant percentage of development costs.

Life/Reliability/O&M Costs

While there is an increasing body of information from field experience relative to these interrelated parameters, available data are not sufficient to assess actual lifetimes and O&M

[4] Costs from developers presentations at DOE / CETC Workshop on Microturbine Applications 2004

costs. Recent case studies report operating hours of 4,000 to 6,000 hours and availabilities generally well over 90%[5]. O&M costs reported in these studies range widely from $0.008/kWh to $0.19/kWh and nearly all note that these costs exclude hot-end component replacement. It appears that the variation in O&M costs stems from several sources: 1) on the low end, Capstone has/had offered as a sales promotion a backstop warranty of $0.008/kWh, 2) on the high end, lack of experience in the specific application for all parties involved, and 3) reliability of fuel compressors/boosters and electrical components. While expensive hot-end components, such as the recuperator, may not have been replaced given the number of operating hours, O&M costs in some cases are above the requirements set in the present study for DG applications.

R&D Focus

DOE's Advanced Microturbine Program, within the Distributed Energy Program, is a 6-year program for fiscal years 2000-2006 with government investment of more than $60 million. Activities are focused on meeting the following performance targets:

- Electrical efficiency of 40 percent (LHV) by 2008—demonstrated, not necessarily commercialized
- NO_x emissions on natural gas less than 0.15 lb/MWh by 2008 (but which is still above the CARB 2007 requirement of 0.07 lb/MWh)
- Mean time between overhauls of 11,000 hours
- Service life of 45,000 hours
- System cost less than $500/kW (manufacturer's selling price for equipment only)
- Fuel flexible options for diesel, ethanol, landfill gas, and biofuels.

Five teams, led by Capstone, GE, Ingersoll-Rand, Solar Turbines, and UTC Power, have been involved in the program. Only two teams remain—UTRC[6] / Capstone and GE. Ingersoll-Rand pulled out. Capstone purchased Solar Turbine's recuperator technology and brought recuperator production in-house. Capstone and UTC Power combined forces when United Technologies bought a portion (4.9 percent) of Capstone.

Technology approaches being pursued under the DOE Advanced Microturbine Program include:

- Ceramic hot sections
- Novel cooling schemes
- Advanced heat exchangers and materials
- Electronics cooling

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[5] O&M costs from developers presentations at DOE / CETC Workshop on Microturbine Applications 2004 and National Resources Canada 5th Annual Microturbine Applications Workshop.

[6] United Technologies Research Center (UTRC) supports UTC Power and other United Technologies companies.

- Magnetic bearings.

In addition, UTRC is pursuing a combined-cycle approach (using an organic Rankine cycle bottoming cycle) to boost generation efficiency.

DOE may sponsor further microturbine development, but, if so, it will likely be as part of a broader program focusing on integrated energy systems for buildings.

Summary Observations

The key advantage of microturbines is low emissions without after-treatment of exhaust gases. Low generation efficiencies remain a key barrier, and are the target of ongoing R&D programs. However, improving efficiency presents trade-offs with emissions and reliability/life. Current focus is on 200 to 500 kW_e systems packaged for CHP applications. EPRI should continue to follow the development and advances of these larger systems, given their longer-term potential to serve the commercial sector in building heating and cooling applications.

Stirling Engines

Stirling engines have been under development for decades for a wide variety of space, solar, vehicle-propulsion, and DG/CHP applications. Stirling engines use a basic thermodynamic cycle whereby the alternate heating and cooling of a gas is used to produce power. The flow of gas between hot and cold zones is controlled by piston motion. There are two basic architectures for Stirling engines:

- Free-Piston Stirling Engines (FPSE) where the pistons are contained in cylinders with their relative motion controlled by gas flows without mechanical linkages. Power is extracted via linear alternators built into the piston and cylinder walls.
- Kinematic Stirling Engines (KSE) where piston motion is controlled by kinematic linkages similar to those in conventional IC Engines.

Both architectures use external heat inputs (a high intensity burner with natural gas) and almost all use helium or hydrogen for the working gas. As listed in Table 3-11, there are multiple Stirling engine developments worldwide for both architectures.

Table 3-12
Summary of Stirling Engine Developers

Country	Manufacturer/ Developer	Technology	Fuel	Capacity Range	Generation Efficiency Range (LHV)	Target Applications	Commercialization Status
New Zealand	Whisper Tech	KSE	Natural gas Propane Gasoline Diesel Alcohols	About 1 kW	11% for DC 800 W unit,	Marine generator Residential CHP	Commercially available
US Athens, OH	Sunpower	FPSE	Natural gas Alcohols (can adapt to solar, electric heater)	1 & 3 kW	23%		Developers who license technology to manufacturers (see Microgen Energy below)
England	Microgen Energy LTD (Licensing Sunpower technology)	FPSE	Natural gas Alcohols	1 kW		Residential CHP	Plan to commercialize 2007
US Phoenix, AZ	Stirling Energy Systems	FPSE	Solar	60,000 kWh/year /dish		Submarines Residential CPH	Manufactures for Kockums Submarines, field tested by Southern California Edison for 175,000 hours
US Athens, OH	Stirling Technology, Inc.	FPSE	Natural gas Agro-byproducts	about 4kW		Residential CHP Water pumps Compressors	Commercially available
US Ann Arbor, MI	STM Power	KSE	Natural gas Biogas	55 kW	30%	Digester gas- and Landfill gas-fueling	Commercially available
US Kennewick, WA	Infinia (formerly Stirling Technology Corporation) [Infinia 2005]	KSE		To 3 kW			Prototype

Technology Status - Gap Analyses

Stirling engine technology meets several of the performance requirements for widespread DG applications including low emissions, low noise/vibration levels, and, possibly, acceptable cost structures with substantial production levels. Two key issues associated with Stirling engines in DG applications are discussed below.

Efficiency

The system level efficiency of Stirling engine technology ranges from about 15 – 20 percent (LHV) for smaller (1 kW) systems to 25 – 30 percent (LHV) for larger kinematic engines. It is possible to achieve somewhat higher efficiencies, but so doing usually requires increasing heat-input temperatures to levels requiring more costly materials. Also, increasing heater head temperatures above about 600°C complicates maintaining low emission levels due to the associated high flame temperatures involved.

Life/Durability/Reliability

The internal working space of Stirling engines cannot be lubricated—this significantly complicates achieving the long lifetimes required by DG applications. A primary advantage of FPSE configurations is that they can be designed so that the side forces on the moving parts (basically two pistons) are minimized to allow unlubricated operation over extended periods of time (up to 50,000 hours), as verified in some specialized configurations developed for space power applications. Several of the systems developed for residential CHP systems have demonstrated up to 5,000 hours of operation.

Achieving long life operation with KSE configurations is complicated by the kinematic linkages and associated seals between engine working spaces and the external drive train. KSE configurations are now achieving operating times in excess of 5,000 hours with further improvements expected. However, the inherent loadings on unlubricated pistons and seals associated with KSE architectures have long been a problem in achieving the very long lifetimes required for DG.

R&D Focus

The focus of FPSE developments is on residential CHP systems with capacities on the order of 1kW—primarily in Europe. Much of the KSE engine developments over the last few years have focused on solar power applications supported by both government and industry for capacities on the order of 25 kW. These developments are also being applied to DG applications.

Summary Observations

Overall, there is limited potential for large improvements in Stirling engine characteristics. Incremental improvements are being pursued by all developers primarily via engineering refinements as exemplified by:

- Lower-cost, more-efficient, linear alternators (applies to FPSE only)
- Improved combustor/heater-head designs
- Improved shaft seals
- New materials for sliding surfaces (piston rings, seals, etc.).

It is unlikely that these ongoing incremental improvements will lead to Stirling engines with the efficiency and life characteristics needed for DG.

IC Engine Technology

Use of internal-combustion (IC) engines in DG applications is summarized as follows:

- IC engines are used widely in DG applications worldwide over a broad capacity range—in fact, almost all US DG in the capacity range of interest is currently based in IC engine technology.
- IC engines represent a well-known and mature technology served by a multibillion dollar global industry. Commercially available IC engines for power generation (including DG, CHP, standby power, and peak shavers) range from 0.5 kW to 6,500 kW and engage such major players as Caterpillar, Cummins, Deutz, Generac, Honda, Kohler, Waukesha , ABB, MAN, GE Jenbacher, and Wartsila.
- IC engines represent the largest installed base of DG in the world, with millions of units in operation. IC engines dominate the marketplace below 1,000 kW and have a substantial market share for part of the market up to 10,000 kW. New units are installed principally as backup units, but peaking and cogeneration units are also being installed.
- IC engines are unique in their capability for rapid (and reliable) startup and shutdown, which is important in many applications—for example, for backup generators or for peak-power reduction.
- IC engine cost/performance characteristics have been improving incrementally over the last decade.

However, in many significant market segments of the DG industry, the cost of producing power with the existing suite of natural-gas engines is still not adequate for achieving large market penetrations in commercial and light-industrial applications. Consequently, engine-based DG remains a niche market, with the niche being applications below 1,000 kW where they dominate other prime movers.

Technology Status – Gap Analyses

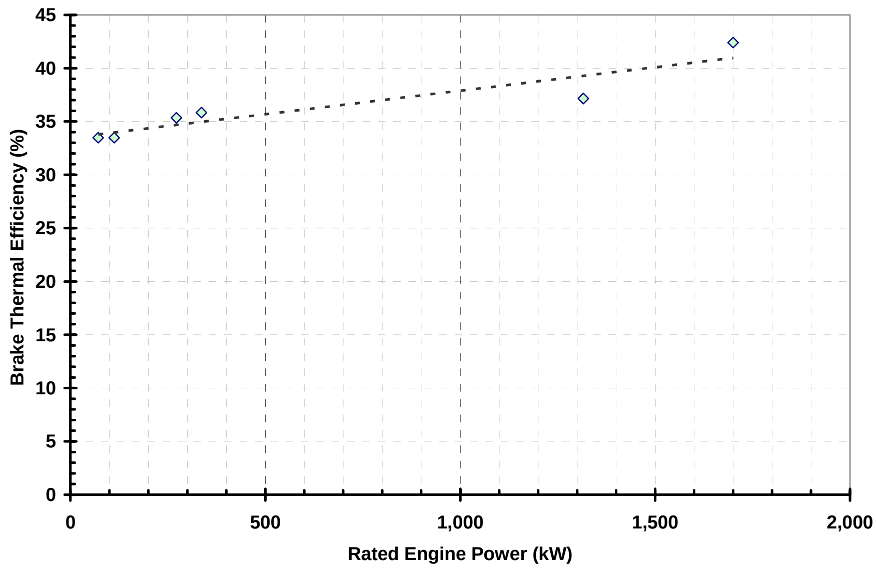
As detailed in Section 2.1 above, the rough, order-of-magnitude, cost-performance characteristics of a state-of-the-art IC-engine/generator package for DG applications operating 4,000 to 5,000 hours per year for 13 – 14 years (representative service life of the IC engine) is:

- Fuel cost 73 percent (based on natural-gas prices as of early 2005)
- Maintenance cost 16 percent
- Capital cost (installed cost), amortized 11 percent.

As indicated below, IC-engine technology is close to meeting DG application requirements established for the present study, but needs improvements in efficiency, maintenance, and possibly emissions characteristics to significantly expand markets.

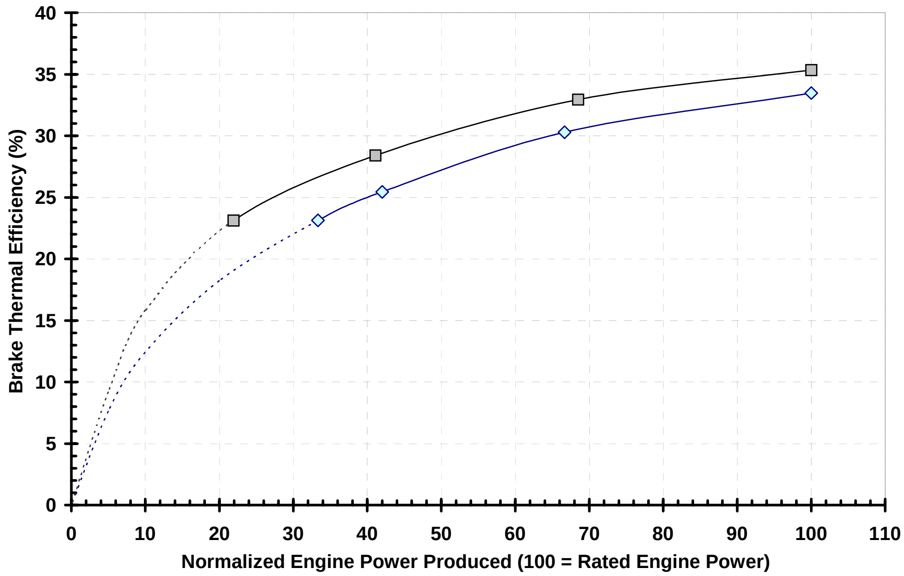
Efficiency

The typical peak efficiency of conventional IC-engine technology used in stationary applications is currently in the 35 – 40 percent range (not including generator inefficiencies) when operating on natural gas and at maximum (rated) power in DG applications (see Figure 3-5). However, the efficiency drops to 25 – 35 percent if the power produced by the engine is turned down to half load (half the rated power) (see Figure 3-6). These efficiencies represent a modest improvement over the last 10 years, but are still only marginally acceptable in DG applications.



Source: Spec. sheets and product catalogues from Caterpillar, and Wartsila

Figure 3-4
Peak Efficiency of Selected Representative Natural-Gas IC Engines for Stationary Applications



Source: Caterpillar spec. sheets

Figure 3-5
Impact of Engine Load on Efficiency for Two Representative Caterpillar Natural-Gas IC Engines for Stationary Applications

O&M

The O&M costs (including overhauls) of larger IC engines (over 100 kW) are typically in the range of $0.015 to $0.030/kWh (high end of acceptable). The most frequent routine O&M elements include oil and oil filter changes, spark-plug replacement, and air-filter cleaning or replacement ranging from a few times per year up to monthly intervals. There is an infrastructure in place to implement O&M functions, which is essential to controlling costs and ensuring rapid response. Nevertheless, the current O&M requirements (both frequency and cost) for IC engines are considered to be a major barrier to wider marker acceptance in DG—particularly in more modest capacities often associated with applications in the commercial-building sector.

Emissions

The emissions from IC engines meet regulatory requirements in most parts of the country. However, in regions designated as “non-attainment”, regulatory requirements are becoming stricter for pollutants such as NO_x. After-treatment technologies, such as Selective Catalytic Reduction (SCR), are available for larger lean-burn engines to dramatically reduce NO_x levels, albeit with increases in costs and operating complexity. For widespread DG markets, the near-term emissions-controls solution for IC engines is stoichiometric operation (often referred to as rich burn in the IC-engine DG business, or chemically-correct mixture) resulting in exhaust oxygen concentrations of less than 0.5 percent, combined with three-way catalysts (TWC) for simultaneous reduction of NO_x and oxidation of CO and HC in the engine-out exhaust stream.

This combination (stoichiometric mixture and TWC) is currently the best available control technology for spark-ignition IC engines, and very low stack-emission levels (compliant with all current emissions mandates) can be achieved. However, although stoichiometric operation combined with TWC can bring spark-ignition IC engines into compliance even in non-attainment areas, it is generally accepted that improvements in the efficiency, integration, and robustness of these systems are required. Furthermore, this approach will not ensure compliance with future mandates (such as the California Air Resources Board Emissions standards that go into effect on January 1, 2007).

TWC, which is lower cost relative to SCR, can be applied to lean-burn engines by using exhaust-gas recirculation to reduce exhaust oxygen concentration to that require by the TWC catalyst. This approach has only recently emerged from the laboratory, and has been implemented at only a limited number of field sites.

Looking further out (10 – 20 years), it may be viable to simultaneously improve the emission and fuel-efficiency characteristics of IC engines beyond that achievable with stoichiometric operation and TWC by using some combination of advanced technologies such as Homogenous Combustion Compression Ignition (HCCI) and after-treatment catalysts.

Active efforts are also underway to develop exhaust heat-driven steam-reforming systems that convert some of the natural-gas fuel to hydrogen. The high flammability limits of hydrogen would allow operation at increased air/fuel ratios, which decrease NOx formation. Steam reforming also increases the calorific value of the fuel stream, resulting in incremental improvements in electrical efficiency.

Capital Cost

The equipment capital cost for natural-gas-fueled, IC-engine-based DG systems is in the range of \$400 – \$600/kW. The installed costs are typically in a range of \$1200 – \$1700/kW, which reflects the need for site preparation, electric utility interface, thermal interfaces (if heat recovery utilized), and application-specific engineering. The latter issue reflects current status that most installations are customized rather than based on standard packages.

Life

Major engine overhauls typically include complete engine rebuilds (bottom and top ends) every six to eight years (50,000 – 70,000 hours) combined with periodic top-end (cylinder head) replacement at half that interval (every 3 – 4 years). These lifetimes meet the requirements established in the present study for DG systems.

R & D Focus

Notwithstanding the above mostly favorable (and improving) characteristics, IC-engine technology has had only limited success in addressing broad-based DG (particularly CHP) applications in the U.S. (with the exception of standby generators). Key reasons for this include:

- Marginal economics based on energy-cost savings due to the relatively low costs for utility power in most parts of the country. The marginal generation efficiency of the IC-engine systems exacerbates this situation.
- Increasing O&M/service-plan costs (and hassle factor) as capacities decrease into the range applicable to most commercial buildings (and certainly residential), since O&M functions are relatively insensitive to capacity (i.e., the O&M cost/frequency for a 200 kW system is about the same as for a 500 kW system).

Additional reasons, although of less importance, are:

- Concerns over emissions based both on perceptions (odors, etc.) and possible legal problems with both current and potential future regulations (varies greatly by location).
- The reality and perception of relatively high noise/vibration levels, which limit their placement and applications (particularly in buildings) without adequate enclosures.

Government programs have supplemented and focused industry-funded development efforts. Federally and/or state-supported IC-engine R&D programs for DG applications, focus primarily on improving the efficiency and lowering O&M costs and emissions. In particular, two publicly co-funded and coordinated R&D programs are currently underway:

- The US Department of Energy Advanced Reciprocating Engine Systems Initiative (ARES), funded through the Distributed Energy (DE) Program
- The California Advanced Reciprocating Internal Combustion Engines (ARICE), collaborative funded through Public Interest Energy Research Program (PIER).

Both programs (ARES and ARICE) were launched in 2001. They are competitively funded, multiple participant arrangements targeting engine output power roughly in the 500 to 6,500 kW range. Ultimate program goals include:

- 50 percent (LHV) generation efficiency (80 percent overall efficiency, or higher, with CHP)
- NO_x emissions of 0.1 g/bhp-hr (ARES) and 0.01 g/hp-hr (ARICE)
- Installed capital costs of \$400 to \$450/kW_e
- Maintenance costs of \$0.01/kWh.

ARES consists of three phases, with the final phase expected to be completed in 2009 – 2010. Research themes include:

- Advanced materials.
- Improved fuel and air-handling systems
- Advanced ignition systems
- Advanced combustion systems, including homogeneous charge compression ignition (HCCI)
- Emissions control catalysts
- Lubricants.

In partnership with the Department of Energy (DOE), ARES participants include:

- National Laboratories (Argonne, Oak Ridge, Sandia, Lawrence Berkley, Brookhaven, and Pacific Northwest).
- Engines Manufacturers (Caterpillar, Cummins and Waukesha Engine).
- Universities (Colorado State University, Massachusetts Institute of Technology, Michigan Technology University, Purdue, University of Southern California, University of Texas, West Virginia University, University of Tennessee, and Ohio State University).

ARICE participants also include National Laboratories and engine manufacturers. Currently, there are three active ARICE projects scheduled to be completed in 2006:

- Laser Ignition Systems – Argonne National Laboratory
- HCCI combustion – Lawrence Livermore National Laboratory
- Improved efficiency and reduced emissions of exhaust-gas recirculation/TWC combustion systems – Waukesha Engine, Dresser Inc.

In summary, both ARES and ARICE are focusing on two of the issues that currently impede wider spread use of IC-engine-based DG:

- Increased efficiency is being pursued by multiple approaches, including:
  - Miller cycle
  - Turbo-compounding
  - HCCI.
  - Friction mitigation
  - Chemical recuperation of exhaust heat to reform the fuel
- Improved O&M characteristics including:
  - Advanced ignition systems (including laser ignition)
  - Advanced lubricants.

Each of these examples is discussed further below.

Miller Cycle

One specific technology area that is being investigated by all three engine manufacturers within the ARES programs as a near-to-medium term (5-10 years) efficiency improvement is the use of variable-valve timing (VVT) for late intake-valve closing (LIVC). This approach, often referred to as the Miller cycle[7], allows the effective compression ratio to be decreased while the nominal

[7] Strictly speaking, the Miller Cycle is an over-expanded turbocharged engine cycle, where the over-expansion is achieved by late or early intake-valve closing. It was developed as a more practical alternative to the Atkinson Cycle, which is a fully expanded (down to atmospheric pressure) naturally aspirated cycle. With the Atkinson Cycle, the need to expand down to atmospheric pressure "in-the-cylinder" leads to excessively long stroke lengths and, therefore, "bulky" engines. In contrast, the Miller Cycle does some over-expansion in the cylinder (but not down to atmospheric pressure) and attempts to capture the rest of the available expansion work by expanding the exhaust gas through a turbocharger. Over the years, the Miller Cycle has become a liberally used term to represent

expansion ratio is maintained. At very light loads, some throttling will still be necessary since LIVC cannot be used very late in the compression stroke. As shown in Figure 3-6, the use of the Miller cycle for load control in a spark-ignition engine can be expected to significantly improve part-load efficiency relative to the same engine using a conventional throttle. Therefore, the use of VVT to implement the Miller cycle can serve as a near-to-medium-term (5 – 10 years) enabling technology for improving the economics of IC-engine-based DG.

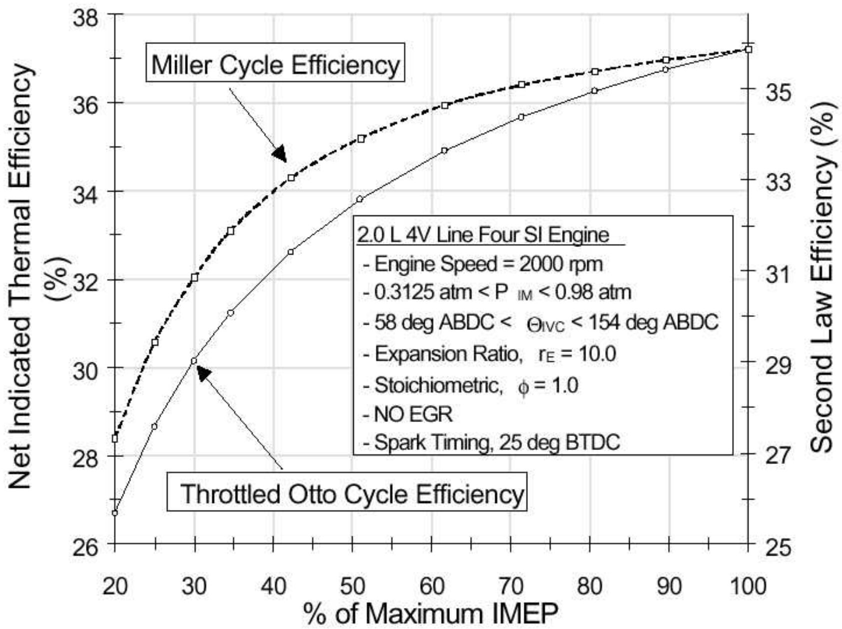


Figure 3-6
Part-Load Efficiency Comparison between the Miller Cycle and Throttled Otto Cycle based on the First and Second Law of Thermodynamics [Anderson 1998]

Turbo-Compounding

Another alternative approach being investigated within ARES that may serve as an enabling technology for improved IC-engine DG economics is the use of turbo-compounding (electric or mechanical) for exhaust waste-heat recovery. In the electric turbo-compounding concept, power electronics and a motor-generator is coupled to a turbocharger to enable excess exhaust thermal energy to be captured and converted into electricity. This electric energy can be added to the electric energy generated by the engine crank-shaft, thereby improving the overall system fuel-to-electricity thermal efficiency. Early estimates suggest that this use of the technology could result in five percent lower fuel consumption [Algrain 2003].

exhaust gas through a turbocharger. Over the years, the Miller Cycle has become a liberally used term to represent intake-valve throttling in general (by late or early intake-valve closing), with or without turbocharging. We are using the term as such here.

O&M Cost Reduction

TIAX is currently performing research for National Energy Technology Laboratory (NETL) on the possibility of increasing spark life by reducing the ignition energy. The reduced ignition energy is possible due to the supplementation of the engine intake air charge with a small fraction of hydrogen. This project and the lessons learned from it, coupled with other research avenues such as alternative ignition sources, are commercially viable within the 5-7 year timeframe. Sparkplug-free sources, such as HCCI, are not expected to be available in that time frame, as much more controls development work is needed.

With respect to O&M costs, areas that are being researched within the ARES and ARICE programs are the less-than-perfect reliability and high maintenance requirements of spark-ignition systems. These continue to present important technical and cost barriers to significantly increased penetration of spark-ignited natural-gas engines in these market segments. Spark-plug life for standard electronic coil ignition systems is typically on the order of 1,000 to 1,500 hours for lean-burn applications, and 1,500 to 3,000 hours for stoichiometric (rich-burn) applications, depending on operating conditions. The replacement interval is largely dictated by erosion-related spark-gap growth and, although adjustment (re-gapping) is possible, it is generally more economical to discard the worn spark plug. Incremental improvements in spark-plug life are of little value to engine operators due to the necessity to synchronize replacement with regular service intervals. For example, if the engine oil must be changed every 1,000 hours of operation then the plug life must be increased from 1,000 hours to 2,000 hours to be of value, since it is not economical to schedule a service visit only to replace spark plugs. Furthermore, since spark-plug failure inevitably results in a forced outage and unscheduled maintenance, it is absolutely essential that the plugs are replaced well before the end of their service life unless some form of real-time diagnostics can be used to reliably monitor the spark-plug condition and trigger preventive maintenance at the next scheduled service visit when needed.

The problem of spark-plug life is only getting worse because of the drive toward increased engine power output (higher brake mean effective pressure, BMEP), which generally leads to more plug erosion. This creates the motivation for research on advanced, long-life spark plugs and ignition-system designs as well as initiatives to eliminate spark plugs altogether (as in laser ignition or HCCI).

HCCI

The concept of homogeneous charge compression ignition (HCCI) deserves special attention since it could overcome most of the limitations of conventional engine-based DG systems:

- Step-wise improvement in cost and energy efficiency
- Engine efficiencies as high as 45 percent or higher
- Virtually zero emissions of nitrogen oxides (NO_x) and particulate matter (PM)
- No spark plugs needed.

The discovery of HCCI was first published in 1979. Since then, the promise of low engine-out emissions and excellent fuel economy has led to much research interest from engine manufacturers, universities, and research firms. Table 3-12 lists selected developers, most of whom are focused on automotive applications—only the ARICE/ARES programs are specifically focused on stationary applications.

Table 3-13
Partial List of HCCI Developers

Developer	Key Activities
ARICE/ARES Programs	ARICE HCCI development, led by Lawrence Livermore Laboratories, is focused on optimizing HCCI for stationary power generation. ARES has a similar research focus.
Honda	Demonstrated HCCI gasoline two-stroke engine in a pre-production motorcycle, placing fifth in the Granade-Dakar desert race.
GM/Bosch	In 2005 announced a three-year, $2.5 million program to expand the development of HCCI.
Toyota	Produced an HCCI-like engine in early 2000. This is based upon a diesel engine system and uses two-stage fuel injection to produce the HCCI-like combustion, with the second injection triggering the heat release from the early fuel injection.
Nissan	Nissan introduced a Modulated Kinetics (MK) engine that was used to obtain homogeneous diesel combustion by using retarded fuel injection, heavy Exhaust Gas Recirculation, and high in-cylinder swirl. This causes the combustion to occur after the fuel is injected, differentiating it from diesel and thus making it a form of HCCI, but not true HCCI. This engine is still used traditional diesel hardware, and went into production in 1998.

There are technical challenges that must be overcome to make this technology viable for practical energy-conversion applications and, consequently, to capitalize on the potential benefits. Specifically, controlling the start of combustion and transient operation in HCCI engines need to be addressed. Unlike in the spark-ignition engine, where combustion starts when the spark plug fires, or a diesel engine, where combustion occurs a short amount of time after fuel injection, there is no direct actuating mechanism to precisely and reproducibly initiate combustion in an HCCI engine. In recognition of this challenge, both the ARES and ARICE programs include efforts to develop novel and robust HCCI controls approaches. If successful, HCCI could make engine-based DG both cost- and energy-efficient alternatives to central power generation. However, overcoming the technical challenge of controlling HCCI cost-effectively will require significantly more research and development, which will put their introduction after the 5 – 7 year timeframe. While the ARES/ARICE programs call for demonstration of HICCI in stationary applications within the next 5 – 7 years, commercial availability will take significantly more time. TIAX is currently involved with novel low-cost start of combustion monitoring methods that will, if successful, allow feedback based control of HCCI engines. This research is sponsored by the Department of Energy Small Business Initiative Review (SBIR) program.

Summary Observations

A combination of the above technologies shows potential for IC-engine architectures that more robustly meet the needs of DG applications. The development time scales are consistent with initial commercial availability in a 5 – 7 year time period.

4

CONCLUSIONS AND RECOMMENDATIONS

We reviewed and assessed one baseline DG technology (IC engines) and six developmental technologies (PEMFC, SOFC, MCFC, PAFC, microturbines, and Stirling engines). The key focus was on smaller (less than 1,000 kW), natural-gas-fired applications for residential, commercial, and light-industrial buildings, and the prospects for significant market impact (relative to the current building stock) over the next 5 – 7 years. Assessments are based on current natural-gas and electric rates.

While there have been incremental improvements in the cost, efficiency, and reliability of many DG technologies in recent years, there have been no breakthroughs that change the fundamental barriers to DG identified in the 1999 study [EPRI 1999]. The investigators do not anticipate DG market changes over the next 5 – 7 years that would significantly alter the current mix of DG and centralized electricity generation used by residential, commercial, and light-industrial end-users. While not specifically addressed under this investigation, the use of DG in combined heat and power (CHP) applications is unlikely to significantly improve DG economics enough to change the conclusions reached. This is because a) thermal energy has a much lower value than electricity, and b) thermal loads in these market segments are not always coincident with the need for electricity. Furthermore, upcoming emissions mandates for stationary generation in non-attainment areas will be difficult to meet for many DG technologies (with the exception of fuel cells).

Technology-specific observations are summarized below.

IC Engines: IC engines are by far the most common technology used in the U.S. today for DG applications of less than 1,000 kW. Its key advantages are that it's a proven technology and it achieves relatively high electric generation efficiencies (generally on par with, or higher than, those achieved by the grid). Increasingly stringent emissions mandates pose a particularly challenging hurdle for IC engine DG.

PEMFC: While there has been significant investment in PEMFC for automotive applications, these efforts do not address the relatively low generation efficiencies of natural-gas-fired PEMFC systems. In addition to efficiency, life, durability, and reliability remain significant challenges for PEMFC in DG applications.

SOFC: Significant development will be required to produce reliable, long-life, and cost-effective SOFC DG systems. As such, market impacts over the next 5 – 7 years will not be significant. However, if current development targets are met, SOFC DG systems may prove very attractive due to their inherent high electric generation efficiencies, very low emissions, and relatively modest fuel-processing requirements.

MCFC: MCFC has demonstrated many of the performance attributes needed for DG. However, key challenges remain, such as reducing costs and extending stack life.

PAFC: PAFC has been used far more in the field than any other fuel-cell technology. Like MCFC, remaining challenges include reducing costs and extending stack life. UTC Power has placed renewed emphasis on PAFC, showing their confidence in the technology.

Microturbines: With a few thousand units in the field, there is a considerable amount of experience with microturbines. The key advantage of microturbines is low emissions without after-treatment of exhaust gases. However, low generation efficiencies remain a key barrier, and are the target of DOE-supported microturbine R&D efforts.

Stirling Engines: Stirling Engines are unlikely to achieve the efficiency and life characteristics needed for most DG applications.

While IC engines will remain the most common prime mover for DG applications over the next 5 – 7 years, the investigators recommend that EPRI track future developments with particular emphasis on:

- SOFC systems (including hybrid plants), because of their high electric efficiency, very low emissions, and relatively modest fuel-processing requirements
- MCFC systems, because of their demonstrated performance attributes
- PAFC, focusing on UTC Power's commercial roll out (planned for 2009)
- Microturbines, focusing on DOE-sponsored development of advanced microturbines in the 200 – 500 kW range.

It is anticipated that electric rates may change dramatically in the future, and investigators recommend re-evaluation of the economic attractiveness of DG technologies. Also, while this report focused only on small generation technologies, continued research is needed to re-evaluate the social benefits and how utilities can make a business case for decentralized resources in general, including the portfolio of energy efficiency, load management, DG, distributed energy storage and distributed renewables.

5
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