Distributed Generation: Understanding the Economics

An Arthur D. Little White Paper

ARTHUR D. LITTLE

For more than a century, Arthur D. Little has been a leader in the consulting industry. Founded in 1886 by Arthur Dehon Little, it was the world's first consulting firm. Today, it still is one of the world's premier consulting firms, with over 3,500 staff members based in 51 offices and laboratories around the globe.

Arthur D. Little has been the world's leading consultant to the energy industry since the mid-1960s. It provides consulting services to the full gamut of industry players—major, independent, and national oil and gas companies; public and private utilities; independent power producers; government institutions; suppliers and contractors; and financial institutions and funding agencies. Bringing to all these assignments tailored, multidisciplinary case teams, Arthur D. Little provides a range of services in strategy development, organizational design and implementation, business-process redesign, technology and product innovation, and environmental, health, and safety consulting.

DISCLAIMER

Funding for this white paper was provided to Arthur D. Little, Inc., by the sponsoring organizations for an objective analysis and discussion of important issues related to the use of distributed generation. This white paper is intended for general information and not as an endorsement of any product, process, or point of view.

Executive Summary

This white paper is one in a series of discussion documents designed to help regulators, legislators, and other interested parties understand and evaluate distributed generation (DG).

Three independent trends—utility industry restructuring, increasing system capacity needs, and technology advancements—are concurrently laying the groundwork for the possible widespread introduction of distributed generation.

Three independent trends—utility industry restructuring, increasing system capacity needs, and technology advancements—are concurrently laying the groundwork for the possible widespread introduction of DG. DG refers to the integrated or stand-alone use of small, modular electric generation close to the point of consumption. It differs fundamentally from the traditional model of central generation and delivery in that it can be located near end-users within an industrial area, inside a building, or in a community. Locating DG downstream in the power distribution network provides benefits for customers and/or the electric distribution system itself. In addition, DG facilities can be operated remotely and used in a broad range of customer-sited and grid-sited applications where central plants would prove impractical.

Policymakers on federal, state, and local levels have been seeking to improve the economics of power delivery through a dramatic restructuring of the electric power industry. Although the ultimate outcome of restructuring is not yet clear, positive trends for DG are already apparent. The opening of retail markets has resulted in a large number of competitors offering new products and services, including DG. Utilities regulated under performance-based ratemaking can deploy DG to improve asset utilization. In addition, unbundling of services and more sophisticated market mechanisms, including real-time pricing, will send price signals that will provide economic incentives for DG.

System capacity needs are presenting regulators and policymakers nationwide with a serious challenge. Long-term demand growth is now expected to be faster than projected, with planned generating capacity not keeping pace and few bulk transmission additions anticipated. Industry restructuring has led to market-driven generation investments rather than central planning. This shift may lead to shortfalls and delays in new capacity in the near term. Under these conditions, traditional approaches that use the central plant model to increase local or regional capacity can both be extremely expensive and require many years for design, approval, and installation. DG offers an additional option to meet load growth and relieve transmission constraints.

The most timely and cost-effective sources of new power may be smaller, strategically located facilities that avoid transmission and distribution (T&D) infrastructure costs while offering benefits grid power alone cannot provide.

The most timely and cost-effective sources of new power may be smaller, strategically located facilities that avoid transmission and distribution (T&D) infrastructure costs while offering benefits grid power alone cannot provide.

DG encompasses many distinctly different power generation technologies. These technologies vary by size, application, and efficiency. Some, such as reciprocating engines and gas turbines, have been commercially successful for decades. Government and private R&D investments in small power generation technologies are beginning to pay off with new commercial products. Relative newcomers—fuel cells and microturbines—are being introduced today, with substantial improvements expected within the next few years. These technologies have adapted technical advancements in the transportation, defense, and aerospace industries to stationary power generation applications.

It is difficult to assess, even in general terms, the attractiveness of DG to regulated utilities, since the economics vary widely based on the utility's actual system configuration and the loads to be served. DG will be most economically attractive to electric utilities in scenarios where they are faced with system constraints, particularly in transmission and distribution. Without these constraints, DG will likely be more costly than a central plant option. In some situations, even with constraints, DG use could lead to lower revenues and profits. These situations include:

- *Customer-side DG that reduces metered energy and demand*
- *Cost-of-service ratemaking that encourages investment rather than cost-reduction*
- *Grid-side DG where there is no mechanism to provide revenues from DG*

For the end-use consumer, a simple analysis of electricity prices, natural gas prices, and DG installed costs confirms the economic viability of DG in many states. The economics are improved if customers value and can capture other potential DG benefits:

- *Reduced fuel costs for steam and hot water loads through combined heat and power*
- *Increased power reliability*
- *Decreased exposure to electricity price volatility*
- *Improved power quality*
- *New source of revenues from electricity sales to the grid*

DG at the customer's site can also provide benefits to the electric utility. If utility grid-side benefits, such as T&D deferral, reduced T&D losses, and voltage support, were shared with customers (assuming they could be applied, captured, and monetized), customer economics would be further enhanced. At the same time, however, customers with DG could also be levied with added costs, such as standby charges, exit fees, and additional incremental costs for interconnection, which would degrade the economic attractiveness of DG.

DG benefits and added costs depend highly on the specific application, site, customer, and utility. It is unlikely that a single DG unit would provide and be recognized for all of its theoretical benefits. However, if even a few of those benefits could apply to a particular site, DG would become more financially attractive for that customer.

DG's economic attractiveness for customers and utilities and its ability to provide for capacity in the near term is leading regulatory bodies in several states to address it. Concerns over the allocation of benefits, levying of added costs, and other competitive issues will put DG on the regulatory and legislative agendas of many more states and the federal government. An understanding of the fundamental economics of DG is essential for policymakers to address these concerns and to arrive at sound decisions regarding its future.

DG will be most economically attractive to electric utilities in scenarios where they are faced with system constraints, particularly in transmission and distribution.

Preface

This white paper is one in a series of discussion documents designed to help regulators, legislators, and other interested parties understand and evaluate distributed generation (DG). It provides an overview and economic analysis of DG as an approach to electricity generation in the United States. The overview includes a brief summary of DG technologies and outlines the forces that could lead to a broad-based increase in their use. The economic discussion defines the benefits and costs of DG from the perspectives of both utility industry companies and end-use consumers. This analysis identifies key market conditions in which DG may be an appropriate strategy for power supply, and presents the economic considerations that will play a key role in determining whether DG achieves broad-based market acceptance.

I. Introduction

For the U.S. electric power industry, the need for system improvements is unavoidable. Over the past several years, high electricity demand and insufficient capacity have resulted in brownouts, blackouts, equipment failures, and very high electricity prices at peak periods. Traditional engineering solutions to increase local or regional electricity generation and/or distribution capacity can often be costly and require prolonged schedules. In this environment, innovative solutions may offer significant business value and public benefit.

Whether DG achieves broad-based market acceptance in the future…will depend in large part on how policy issues are addressed and resolved in the regulatory and legislative arenas today.

At the same time, deregulation at the federal, state, and local levels is creating additional change in the electric power industry and the marketplace. The overall goal of deregulation is a competitive, innovative, consumer-oriented market where businesses succeed by meeting explicit customer demands such as lower electricity prices, increased energy efficiency and environmental performance, local "environmental justice," and services that address other important community needs. For energy companies, industry restructuring is making the decision-making process more transparent, more short-term focused, and more receptive to new ways of conducting their business.

Amid these major industry and market shifts, technology advancements have positioned distributed generation (DG) as a potentially major transformational force. New developments in small-scale power generation technologies, ranging from reciprocating engines to microturbines to fuel cells, provide credibility for DG's central premise of electric-power generation at or near the point of its ultimate consumption.

The DG approach to power generation and delivery could be a complement or alternative to the century-old central generation plant model. Indeed, the principle of DG raises fundamental questions about the role of utilities in restructured electricity markets and the extent to which the "wires" business should and will remain a natural monopoly. Whether DG achieves broad-based market acceptance in the future, however, will depend in large part on how policy issues are addressed and resolved in the regulatory and legislative arenas today.

II. Understanding DG

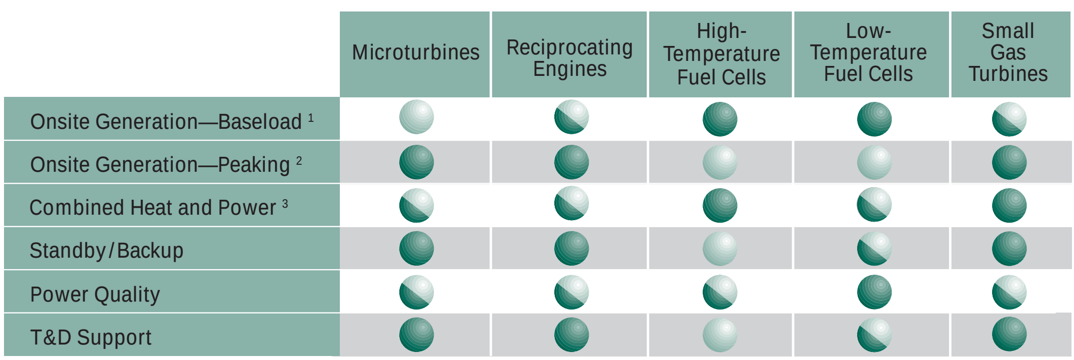
What is DG?

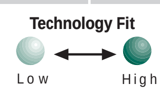
No single DG technology can accurately represent either the range of capabilities and applications or the full scope of benefits and costs associated with DG as a class.

Although it has been defined in a variety of ways, for the purposes of this paper, we define DG as the integrated or stand-alone use of small, modular electricity generation resources by utilities, utility customers, and/or third parties in applications that benefit the electric system, specific end-use customers, or both. Our definition includes cogeneration and combined heat and power (CHP)[1]. From a practical perspective, it is a facility for the generation of electricity that may be located at or near end users within an industrial area, a commercial building, or a community. DG includes a wide range of technologies for specific applications. Figure 2.1 summarizes many of the DG technologies now being adopted commercially.

DG is fundamentally distinct from the traditional central plant model for power generation and delivery. DG can deliver electrical energy directly to the power distribution network or to where it is consumed, rather than via the transmission system. Also, DG facilities are smaller than traditional central plants, can be operated remotely, and support a broad range of applications.

Figure 2.1: DG Technologies and Applications





Note: Fit represents current technology application, except for High-Temperature Fuel Cell information, which represents projected applications.

1. Fit is based on system capabilities and electricity rate structures.
2. Refers to power production only.
3. Microturbines and Low-Temperature Fuel Cells cogenerate hot water.

There are many different power generation technologies that are classified as DG. Figure 2.2 presents five of these technologies, demonstrating the significant variability in their sizes, applications, and efficiency levels. No single DG technology can accurately represent either the range of capabilities and applications or the full scope of benefits and

1. Cogeneration and CHP refer to the simultaneous production of electric energy and hot water or steam for heating or cooling purposes in industrial and commercial applications. CHP system efficiencies can approach 90 percent, a significant improvement over the 50 to 90 percent industrial boiler efficiency and 30 to 35 percent electric grid efficiency when separate production is used.

Figure 2.2: DG Technologies—Markets and Performance

	Residential	Commercial	Industrial	Grid-Distributed	Remote / Off-Grid Distributed	Typical Unit Size Range (installation size can be larger)	1999 Installed Capital Cost ($/kW)	Efficency (%)	Commercial Availability
Microturbines [1]		1	1	1	2	25–300 kW	750–900	28–33	1999
Reciprocating Engines	1	1	1	1	1	5 kW–20 MW	400–600[2]	28–37	NOW
High-Temperature Fuel Cells		1	1	1	2	100 kW–1 MW	NA[3]	45–55	2005
Low-Temperature Fuel Cells	1	1	2	1	1	2–250 kW	2,000–3,000	30–40	NOW[5]
Small Gas Turbines			1	1	2	500 kW–20 MW	650	25–40[4]	NOW

1. Recuperated microturbine
2. Large, gas-fired reciprocating engine
3. Not available
4. Forty percent efficiency achieved with advanced turbine cycle
5. PAFC only; PEM available in 2000

1 Primary Target Market

2 Secondary Target Market

costs associated with DG as a class. Some of these technologies have been used for many years, especially reciprocating engines and gas turbines. Others, such as fuel cells and microturbines, are relative newcomers. Several DG technologies are now commercially available, and some are expected to be introduced or substantially improved within the next few years.

Why is DG Emerging Today?

In the early 1900s, many businesses generated their own electricity, with vertically integrated utilities only producing 40 percent of U.S. demand. From the 1930s through the 1970s, major technology advancements, high electricity-demand growth, a regulatory system that encouraged capital investment, and the economies of scale afforded by large generating units drove the trend toward ever-larger power plants. As a result, utilities constructed large central stations to meet the demand for power; reciprocating engines and gas turbines largely were used to provide emergency backup power. Small hydro projects (with capacities on the order of 5 MW) carved a niche in some power markets, particularly in New England and the Southeast.

Although the ultimate result [of the restructuring] is not yet clear, industry changes are well under way and some positive trends for DG are already apparent.

Regulatory Changes

Major changes in regulation in the electric and natural gas industries over the past two decades have led to the development of the concept that is now known as DG. In 1978, the Public Utilities Regulatory Policies Act (PURPA) stimulated increased use of cogeneration in independent power and industrial projects. Meanwhile, natural gas deregulation lowered prices for this fuel around the country. The pace of adoption changed dramatically with the Energy Policy Act of 1992, which initiated deregulation of power generation and fundamentally changed the rules. Since the passage of this federal legislation, federal, state, and local policymakers have been seeking to improve the economics of power delivery through a dramatic restructuring of the electric power industry to promote competition, customer choice, greater cost-effectiveness, and lower energy prices.

The final outcome of restructuring is still taking shape, with many states only now beginning to enact legislation. Although the ultimate result is not yet clear, industry changes are well under way and some positive trends for DG are already apparent:

- *The opening of retail markets provides customers with choice and has resulted in a large number of competitors offering new products and services, including DG.*
- *The emergence of performance-based ratemaking provides an opportunity for utilities to deploy DG to improve asset utilization.*
- *The unbundling of services and more sophisticated market mechanisms, including real-time pricing, will send price signals that will provide an economic stimulus for DG.*

Power System Deficiencies and Price Increases

While the industry restructures, the U.S. power delivery system is being stretched to accommodate record levels of demand. In the summer of 1999, significant portions of New York City and Chicago were without power for several days due to system failures resulting from high demand. During the same season, record peak power requirements forced some major U.S. utilities to implement measures such as voltage reductions and rolling blackouts to maintain system integrity, and large industrial customers were asked to conserve power by shutting down equipment. For U.S. industry and homeowners, this translated into unacceptable losses, and they have demanded higher quality and more reliable service.

These peak-load problems reflect reduced capacity margins nationwide. The North American Electric Reliability Council (NERC) has stated that the strong economy is now expected to drive long-term demand growth faster than projected, but that planned generating capacity is not keeping pace with growth, and very few bulk transmission additions are anticipated. Industry restructuring has led to market-driven generation investments rather than central planning. This shift may lead to shorter planning horizons and delays in new capacity additions in the near term. Under these conditions, traditional approaches that use the central plant model to increase local or regional capacity can both be extremely expensive and require many years for design, approval, and installation. DG offers an additional option to meet load growth and relieve transmission constraints. The most timely and cost-effective sources of new capacity may be smaller, strategically located facilities that avoid central plant and transmission and distribution (T&D) infrastructure costs and associated protracted schedules.

DG Technology Advances

As the demonstrated need for broad-based system expansion has grown, new developments in small-scale power generation technologies have presented an opportunity for innovative solutions. Fuel cells and microturbines, in particular, have taken advantage of technical advancements in the transportation and aerospace industries and adapted them for stationary power generation applications.

These three relatively independent sources of pressure—restructuring, the need for new capacity, and DG technology advancements—are collectively laying the groundwork for the possible widespread introduction of DG. If these technologies continue to prove commercially viable and regulations and markets evolve to encourage their acceptance, these new options for supplying power may take hold. In at least some (and perhaps many) cases, the most cost-effective sources of new power will be distributed generators—smaller, strategically located facilities that avoid T&D infrastructure costs while offering the end-user higher power quality and overall reliability than grid power alone.

As the demonstrated need for broad-based system expansion has grown, new developments in small-scale power generation technologies have presented an opportunity for innovative solutions.

III. Examining DG Economics

A utility can be expected to see DG as an additional option to meet load growth and relieve transmission constraints. An end-use customer will probably view DG as a way to reduce costs and obtain other benefits such as increased reliability and power quality.

Electric utilities and their customers are the two user groups most likely to deploy DG. Other types of electric utility industry players, including energy services companies, retail companies, and other non-regulated entities, also might be motivated to integrate DG into their businesses. All of these entities have different perspectives on the economics of DG. A utility can be expected to see DG as an additional option to meet load growth and relieve transmission constraints. An end-use customer will probably view DG as a way to reduce costs and obtain other benefits such as increased reliability and power quality. Unregulated players may adopt DG to reduce costs to their customers, provide additional services, and possibly export power. These unregulated companies might even position themselves to provide DG at customer sites and aggregate this generation to compete in power markets or to respond to ISO requests. This section of this white paper examines DG economics from the utility and customer perspectives. Depending on how they deploy DG, unregulated entities may have similar economic views on DG. Supporting data for the cost and benefit calculations are presented in the *Notes* section (see page 23).

Is DG Economically Attractive for Electric Utilities?

Utilities have studied the benefits of DG and how they could integrate it into their resource strategy for the future. In addition, they have provided funding for technology development as well as sites for demonstrations. While the extent to which regulated utilities will ultimately adopt DG is unknown, an understanding of their perception of DG economics will provide insight into whether they will likely embrace or resist DG. The economics for a utility will vary based on several factors:

- *Utility structure and system characteristics*
- *Regulation and legislation*
- *Location and ownership of DG*

One approach to examining the economics of DG is to compare the costs of the options utilities have to meet new customer demand. This paper considers two of those options, the Central Plant and Distributed Generation. The Central Plant option relies on the traditional utility model of generating and transmitting power from a central location. The DG option includes small power generation installed in the distribution system on the utility side of the meter.

Utility Structure and System Characteristics

The structure of many utilities is in transition today. At one end of the spectrum are the vertically integrated utilities that own generation, transmission, and distribution assets. At the other end of this spectrum are the wires companies that act as common carriers; owning only distribution assets, they do not generate the electricity that they sell or transmit to customers.

In addition to utility structure, the characteristics of the utility's system will also drive the economics of DG use. A utility system may or may not be currently constrained in its ability to meet growing customer demand. If the utility is constrained—without enough capacity to meet demand—it must invest in its system. Constraints could be in generation, transmission, and/or distribution. Alternatively, if the system is not constrained, the utility will use the existing infrastructure to meet increasing demand. The system characteristics of most utilities will fall somewhere between the constrained and unconstrained cases. To capture the range of possibilities, we will examine four broad scenarios for the vertically integrated utility and two scenarios for the wires company.

Vertically Integrated Utility

The four scenarios considered for the vertically integrated utility are shown in Table 3.1. The cost components for the two options comprise fixed and marginal costs for generation, transmission, and distribution. The cost components of the Central Plant option are dependent on the system characteristics. Where investment is required, the costs include both fixed and marginal costs. Where no investment is required—the "no constraints" case—there are no additional fixed costs involved. The DG option is independent of the current system characteristics and primarily consists of fixed and marginal costs for the DG itself. The DG option also includes secondary distribution costs because the DG will be installed in the distribution system on the utility side of the meter.

Table 3.1: Vertically Integrated Utility Scenarios

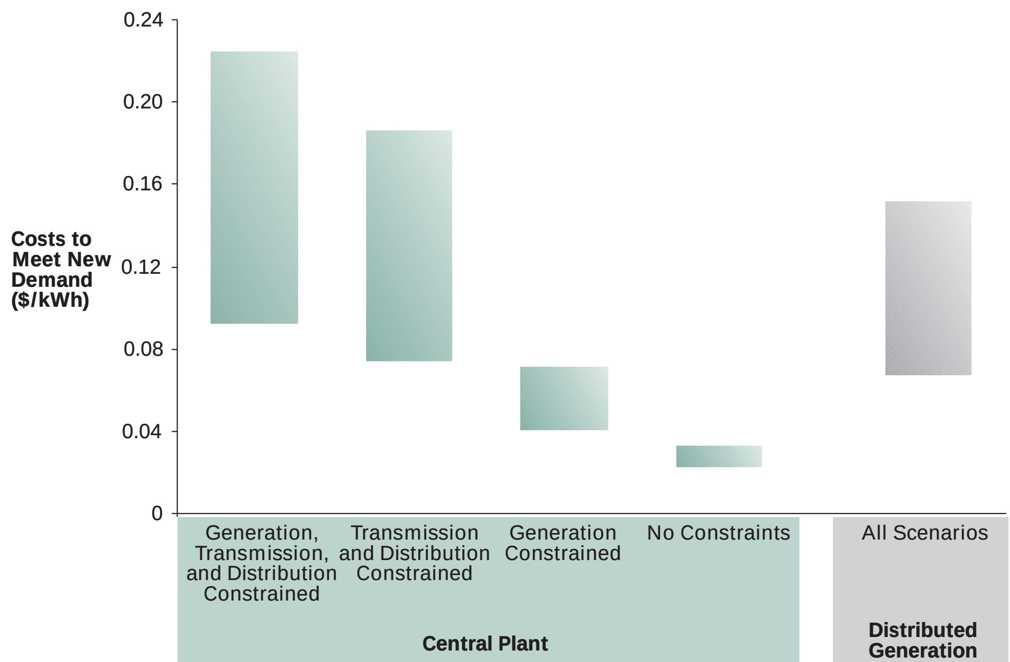
	Cost Components	
Scenario	Central Plant Option	Distributed Generation Option
Generation, Transmission, and Distribution Constrained	• Fixed costs for new generation, transmission, and distribution • Marginal costs of generation, transmission, and distribution	• Fixed costs for new generation and secondary distribution • Marginal costs of generation and secondary distribution
Transmission and Distribution Constrained	• Fixed costs for new transmission and distribution • Marginal costs of generation, transmission, and distribution	
Generation Constrained	• Fixed costs for new generation • Marginal costs of generation, transmission, and distribution	
No Constraints	• Marginal costs of generation, transmission, and distribution	

DG will be the more costly option if the system is not constrained.

Figure 3.1 presents estimated cost ranges for meeting new demand growth for the Central Plant option versus the DG option. In the No Constraints scenario, the estimated cost range for the Central Plant option is $.02–.04 per kWh. In the Generation Constrained and the Transmission and Distribution Constrained scenarios, the cost range increases to $.04–.07 per kWh and $.07–.18 per kWh, respectively, reflecting the additional costs of new generation or T&D capacity. In the Generation, Transmission, and Distribution Constrained scenario, the cost range increases to $.09–.22 per kWh, reflecting additional costs for both new generation and T&D capacity. By comparison, regardless of the scenario, the DG option cost range is $.07–.15 per kWh.

DG will be the more costly option if the system is not constrained. In many instances where there are only generation constraints, the DG option would not provide the most cost-effective solution. In systems where there are T&D constraints, the DG option may or may not be a more economic solution, but should be considered.

Figure 3.1: Range of Utility Costs to Meet New Demand—Vertically Integrated Utility



See *Notes* for details on cost assumptions

These cost estimates are derived from available industry data, and supporting assumptions are provided in the *Notes* section. Specific system characteristics and the type of load served (peaking or baseload) drive the range of costs. The true costs will vary by utility and geography, where the DG is located in the system, and the actual system addition or improvement needs. In most instances, a utility will be constrained in only certain areas rather than throughout its entire system.

Wires Company

The scenarios considered for the wires company are shown in Table 3.2. The scenarios chosen do not consider generation constraints, since a wires company does not own generation. Rather, it provides a delivery service for the energy consumer, generation company, marketer, or retail company. If a wires company does charge the customer for energy, it is only as a pass-through. Although, in some instances, a wires company may be in a region that is experiencing generation constraints, the company itself would not be constrained in generation capacity.

In cases where there are constraints, DG might prove to be more cost-effective to the wires company… However, this scenario raises some interesting questions.

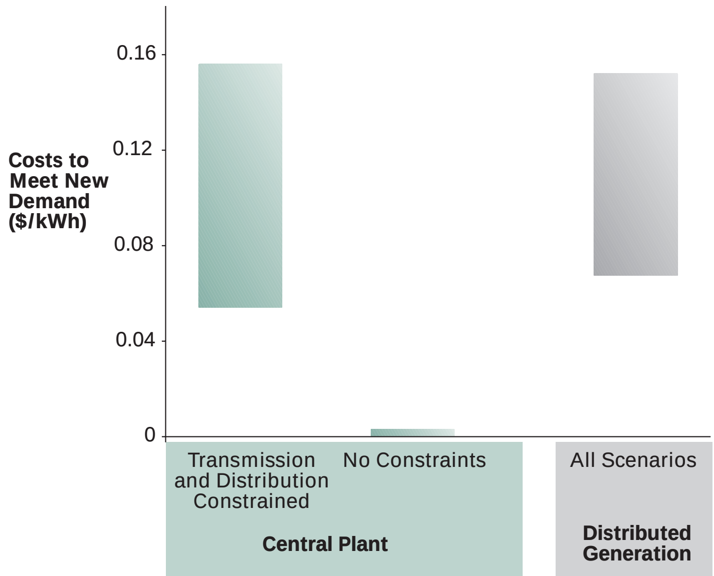
Table 3.2: Wires Company Scenarios

	Cost Components	
Scenario	Central Plant Option	Distributed Generation Option
Transmission and Distribution Constrained	• Fixed costs for new transmission and distribution • Marginal costs of transmission and distribution	• Fixed costs for new generation and secondary distribution • Marginal costs of generation and secondary distribution
No Constraints	• Marginal costs of transmission and distribution	

A cost comparison of the Central Plant option versus the DG option for the two scenarios is presented in Figure 3.2. When the wires company is not constrained, the estimated cost range for the Central Plant option is less than $.01 per kWh, reflecting only the marginal costs of T&D. In the Transmission and Distribution Constrained scenario, the cost increases to $.05–.16 per kWh as costs for new T&D are included. By comparison, the DG option's cost range regardless of scenario is $.07–.15 per kWh.

This suggests that in those situations where the system is not constrained, DG would not be a cost-effective solution. In cases where there are constraints, DG might prove to be more cost-effective to the wires company than building additional T&D capacity. However, this scenario raises some interesting questions. As mentioned above, the wires company is not engaged in the production of electricity, but rather in power-transportation services. Since most wires companies are restricted from owning generation, it may be implied that they cannot own or deploy DG. If so, then even in cases where DG is the most cost-effective option, it will not (indeed, it cannot) be chosen by the wires company. If the wires company were allowed to own or deploy DG, the kWh generated by the DG unit would have to be sold or accounted for, thereby creating a potential expansion of the company's charter to include power generation.

Figure 3.2 : Range of Utility Costs to Meet New Demand—Wires Company



See *Notes* for details on cost assumptions

Regulation and Legislation

As discussed above, DG could be a more cost-effective solution when an electric system is constrained, particularly with respect to T&D. However, how the utility is regulated will affect whether a utility views DG as a viable option. Most utilities' rate of return in the United States is still regulated under a cost-of-service (COS) approach. COS guarantees a rate of return on the utility's prudent investments. Economists have criticized COS regulation in the past for its weak incentives to reduce costs and strong incentives for utilities to overinvest in their systems despite regulators' efforts to ensure that utilities invest prudently. Although DG might be attractive as a lower-cost option, under COS a utility might be more inclined to invest in T&D since it represents the larger investment and in the long run may represent greater profits.

Some regulators in the United States and abroad have experimented with performance-based ratemaking (PBR). Typically, utilities' prices or revenues are capped under PBR systems. To increase profits, utilities have a stronger incentive to reduce costs than to invest in their systems. Under PBR, utilities may prefer the DG option in those cases where it represents the more cost-effective solution and requires lower capital investment.

Location and Ownership of DG

In most circumstances, there is little financial incentive for a regulated electric utility to encourage DG installed on the customer side of the meter, unless the generation is separately metered and its output can be billed to a customer. Despite the fact that a wires company does not sell energy, it still is responsible for determining a retail customer's power consumption using an energy meter[2], and is compensated based on metered consumption. Therefore, if DG is installed behind the customer's meter, the customer's measured energy use will reflect a deduction of any energy provided by the DG resource. Without a business model that provides them with sufficient revenues, utilities would have strong incentives to avoid or prevent DG in the distribution system on both the grid side and the customer side.

It is difficult to assess the attractiveness of DG to regulated utilities, since the economics can vary widely based on the actual system configuration and the loads to be served. DG will be most economically attractive to electric utilities when they are faced with T&D system constraints. Without these constraints, DG in most cases will be the more costly option.

Even where DG could lead to reduced costs, certain conditions would cause utilities to avoid DG because it could reduce revenues and profits. These conditions include the following:

- *Customer-side DG that reduces metered energy and demand*
- *COS ratemaking that encourages investment rather than cost-reduction*
- *Grid-side DG where there is no mechanism to provide revenue from DG*

DG is sufficiently attractive for utilities to consider it a viable option for meeting new demand. However, utilities may seek regulatory changes to address the above conditions and ensure they can maximize the economic benefits of DG.

Is DG Economically Attractive for Utility Customers?

Is DG economically viable for customers? The question is deceptively simple. At a basic level, there are three main elements that determine the economic viability of DG:

$$\text{Grid Cost of Delivered Electricity} - \left(\text{DG Capital Charges} + \text{DG Operating Cost}\right) = \text{DG Electricity Cost Savings to Customer}$$

Essentially, if the difference between the DG operating costs and avoided electricity costs is large enough relative to the investment required to meet the customer's investment-return criteria, the project will go forward.

2. Some large customers also have demand meters, which determine their capacity requirements for real and reactive power.

The economics become more complicated when added costs and benefits are considered:

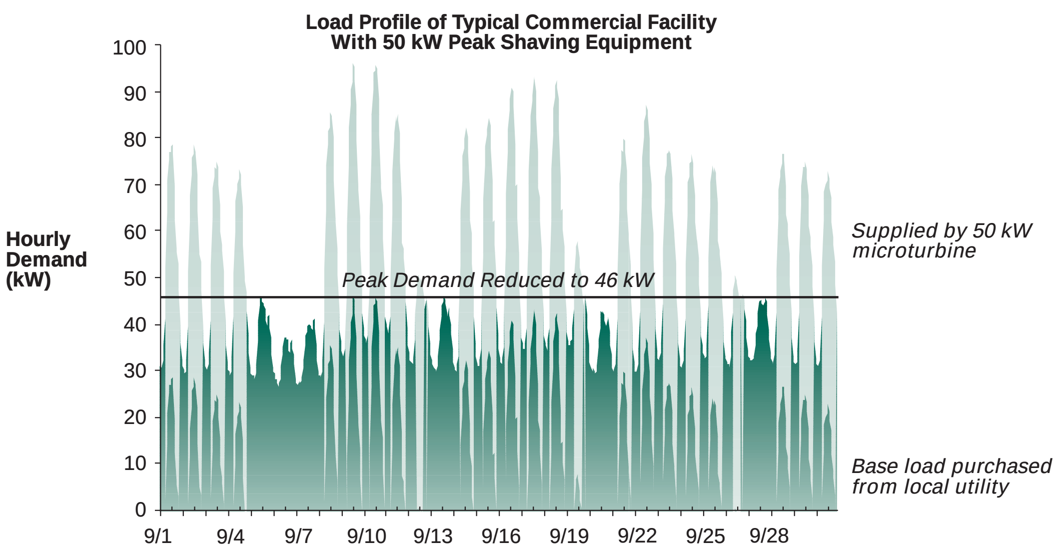
DG Electricity Cost Savings to Customer **+** Added Benefits to Customers **−** Added Costs **+** Electric Distribution Company Benefits **=** DG Economic Viability

These benefits and costs are very specific to the site, utility, and application. This portion of the economics section will first examine the simpler economics of DG for the customer on the basis of a hypothetical project. We will then address the issues of the added benefits and added costs and consider them on a national basis.

Project Economics

The first step in evaluating the economics of a DG project is to understand how the equipment would run and what the potential annual savings to the customer would be. Figure 3.3 shows the typical load profile for a commercial customer in the month of September in Boston, Massachusetts. In this example, a 50 kW microturbine is used to reduce the peak load for this customer from 96 kW to 46 kW. This reduces the customer's purchased electricity costs from $43,300 to $14,700, resulting in an annual savings of $28,600.

Figure 3.3 : DG Project Example



Annual Cost of Purchased Electricity	
Without DG Equipment	$43,300
With 50 kW Microturbine	$14,700
Annual Savings in Purchased Electricity	$28,600

See *Notes* for details of rate structure and annual cost savings

The customer will have additional operating costs to pay, namely for the fuel the DG consumes and for operation and maintenance (O&M).

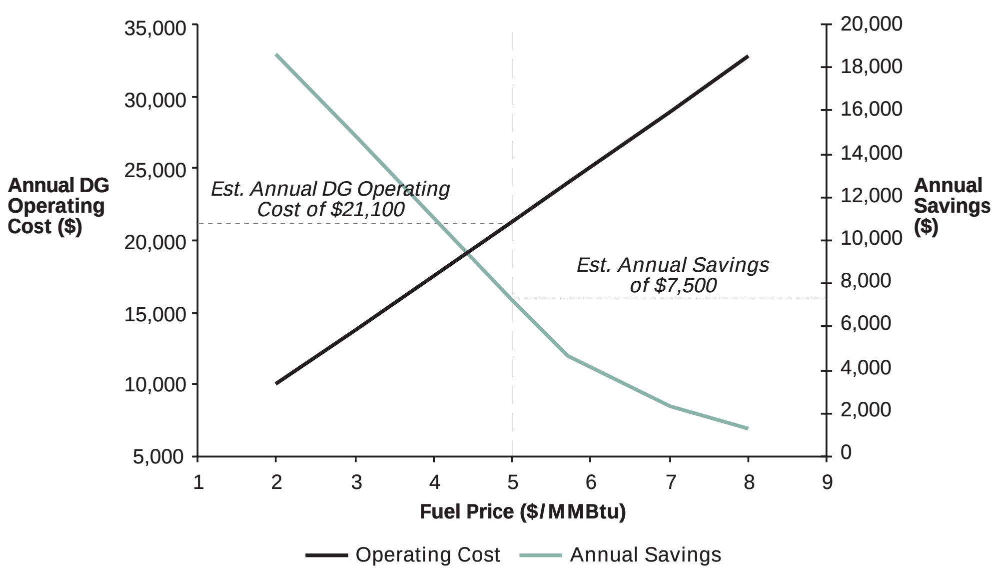
DG Operating Costs = Fuel Costs + O&M Costs

The fuel costs are a function of the efficiency of the DG and the fuel price. Figure 3.4 shows how the operating cost for a 50 kW microturbine can vary with fuel price. For example, at $5/MMBtu, the annual operating cost (fuel plus O&M) of the microturbine is $21,100. The total annual savings to the customer are found by subtracting operating costs from annual savings in purchased electricity:

Total Annual Savings = Annual Savings in Purchased Electricity − DG Annual Operating Costs

As the operating costs vary with fuel price, so will the total annual savings. In this example, at $5/MMBtu, the annual savings are $7,500.

Figure 3.4 : DG Operating Cost and Annual Savings Versus Fuel Price



Assume using a 50 kW recuperated microturbine to reduce the electric bill.
DG operating cost includes fuel cost and variable O&M expenses.

Notes: Efficiency = 31.5% (LHV); O&M Costs = 0.75¢/kWh; Capacity Factor = 72%

Projects of this type are typically evaluated on simple payback:

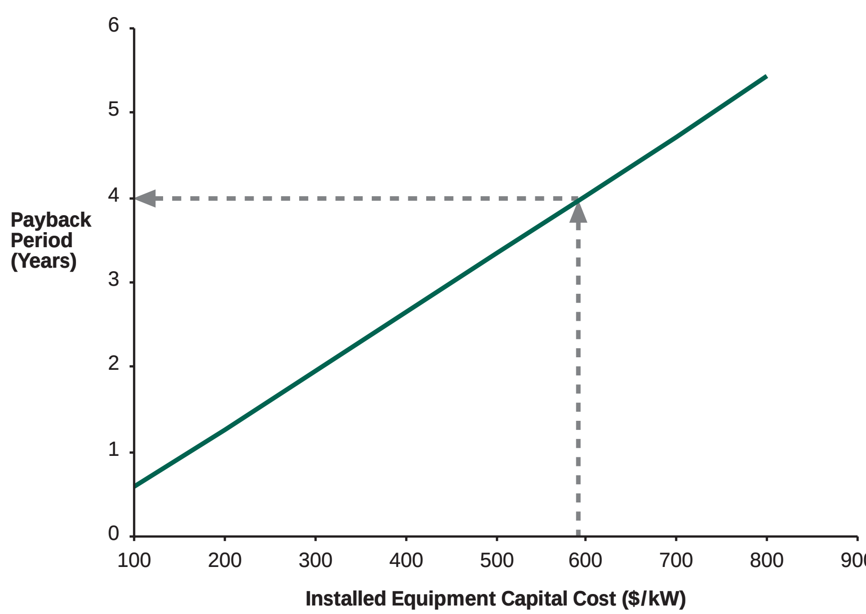
Simple Payback = Installed Costs ÷ Annual Savings

Installed costs include equipment costs as well as interconnection, construction, permitting, and engineering costs. Figure 3.5 compares installed costs and payback period for this project. For example, an installed cost of $30,000 ($600/kW) and $7,500 in total annual savings will result in a four-year payback.

The project will go forward if it can achieve the payback hurdle. Payback hurdles vary based on the ownership arrangement. For example, typically a commercial customer will require a two- to four-year payback period, while an energy service company would have a longer payback horizon of five to seven years.

If the difference between the DG operating costs and avoided electricity costs is enough to meet the customer's investment-return criteria, the project is likely to go forward. In some instances, in addition to basic economics, the customer may include other considerations, such as avoided downtime. These considerations might make an otherwise unattractive return on a project attractive to a commercial customer.

Figure 3.5: Simple Payback Versus Installed Equipment Costs

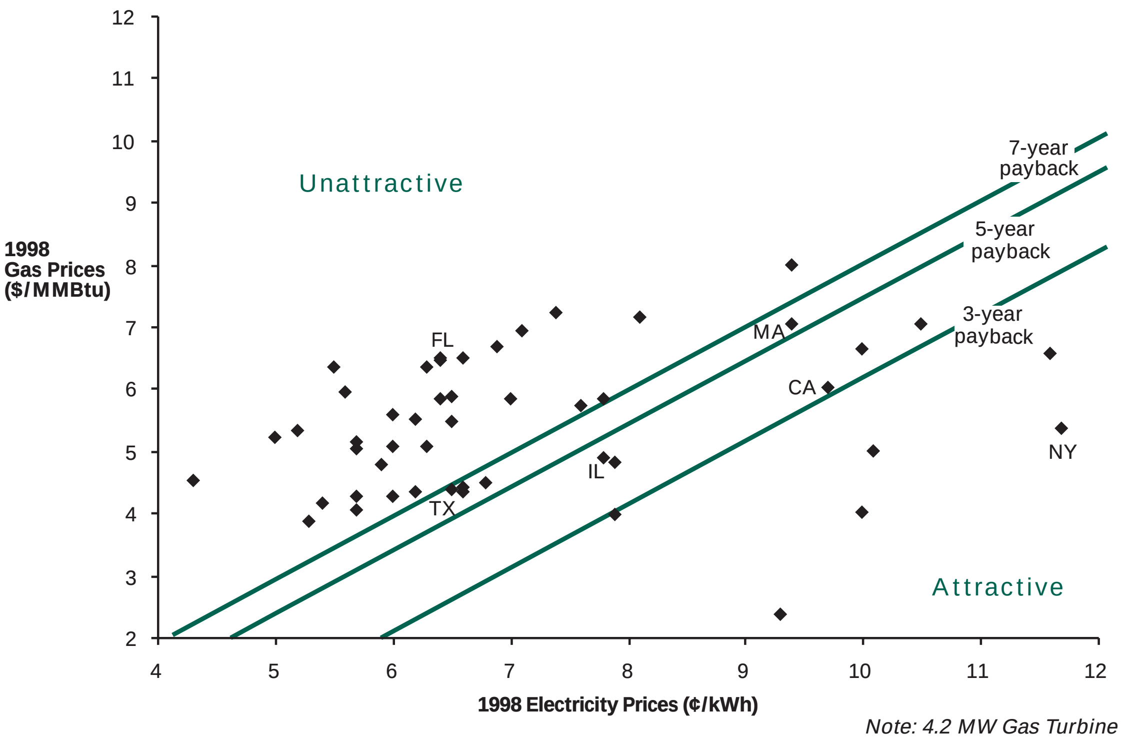


Assumptions: 50 kW recuperated microturbine; DG operating cost includes fuel cost and variable O&M expenses.

Notes: Efficiency = 31.5% (LHV); O&M Costs = 0.75¢/kWh; Capacity Factor = 72%
Assuming fuel cost of $5/MMBtu, which results in an estimated annual savings of $7,500

Using the simple payback analysis, Figure 3.6 shows the financial attractiveness of DG using a small gas turbine for commercial customers in the 50 states (highlighting California, Florida, Illinois, Massachusetts, New York, and Texas). This calculation is based solely on the three main cost elements described above: DG operating costs, avoided electricity costs, and investment-return criteria. The lines on the graph represent three-, five-, and seven-year payback periods. DG will be successful when there are high electricity prices and low gas rates (the bottom right-hand corner of the chart, to the right of the lines) in states such as California, Illinois, and New York. In other states, such as Florida, the gas prices are too high and the electricity prices too low for DG to be an economical option.

Figure 3.6: Simple Payback for DG for Commercial Customer Segment



Benefits and Added Costs

The simplified analysis presented above does not account for either the other benefits that DG can provide or additional costs beyond that of standard installation that may be incurred in the current regulatory environment. Such DG benefits and costs are highly site-specific. DG benefits can be considered from two different perspectives: that of the customer and that of the electric distribution company (EDC).

Examples often cited for how customers can benefit from DG beyond the electricity cost savings include the following:

- Reduced energy costs for thermal energy loads (steam, hot water, and cooling)—*DG, through combined heat and power (CHP) can produce steam or hot water that can be used in manufacturing processes or for space heating and cooling requirements.*
- Decreased exposure to electricity price volatility—*DG can allow customers to take more risks in energy markets or utility rates, since it acts as a hedge on volatile electricity prices.*
- Increased power reliability—*DG can avoid or reduce power outages associated with the grid that can cause operational downtime and health and safety concerns.*
- Improved power quality—*DG can provide very-high-quality power that reduces or eliminates grid voltage variation and harmonics that negatively affect a customer's sensitive loads.*
- New source of revenues—*DG may allow customers to sell excess power or ancillary services to power markets.*

This list is not exhaustive, and certain customers will have unique power-related factors that lead to other benefits. Some of the more common benefits have quantifiable values to end-use customers. Although benefit values can vary by customer, some benefits typically are similarly valued across a broad range of end-use customers. Table 3.3 shows typical values for some customer benefits. They were developed for selected benefits that a small gas turbine could provide to a commercial customer. These benefits are very site- and application-specific. In addition, some of them might not have any value to the customer. For example, if customers are satisfied with the level of reliability provided by the electric utility, they will place little or no value on the improved reliability that DG can provide.

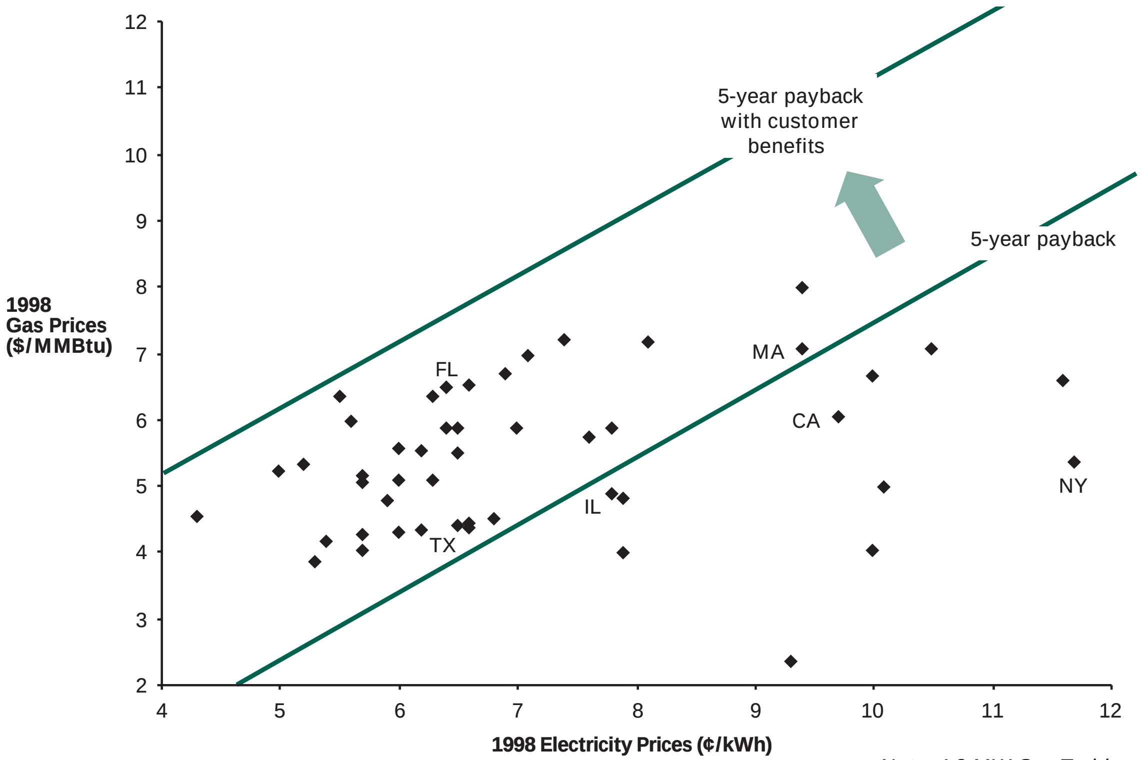
Table 3.3: Typical Customer DG Benefits

	$/kW-yr	¢/kWh (at 60% Capacity Factor)
Reduced Energy Cost for Thermal Energy Loads	110	2.1
Decreased Exposure to Electricity Price Volatility	55	1.0
Increased Power Reliability	35	0.6
Total Customer Benefits	***200***	***3.7***

Source: Arthur D. Little analysis. See *Notes* for source details

As seen in Figure 3.7, when these benefits are considered, the payback line shifts upward, making DG more attractive in many more regions of the country compared with the initial payback gradient.

Figure 3.7: Simple Payback With Customer-Side Benefits for Commercial Customer Segment



Note: 4.2 MW Gas Turbine

DG at the customer's site can also provide benefits to the electric utility. DG benefits identified by utilities include the following:

- Avoided increases in system capacity—*DG can provide an additional source of power that could preclude the need to expand the generation, transmission, and distribution system to meet increased demand.*
- Reduced T&D electric losses—*DG avoids electric losses associated with transporting power over the T&D system.*
- T&D upgrade deferrals—*Utilities can use DG to meet growing demands and defer investment in T&D capacity.*
- VAR support—*Some DG technologies can provide reactive power (VARs) that can aid utilities in maintaining system voltage.*
- Transmission congestion relief—*By generating power at or very near the point of consumption where there is congestion, DG can increase the effective T&D network capacity for other customers.*

Though these grid-side benefits can be quantified, it is not clear how they can be captured and accurately monetized and to whom the ultimate savings should go.

- Peak shaving—*DG can reduce customer demands from the grid during high-demand periods.*
- Reduced reserve margin—*By lowering overall demand levels for grid power and providing generation capacity, DG could reduce reserve margins.*
- Improved power quality—*DG can eliminate demand that negatively affects the power quality of the grid system.*
- Increased power reliability—*DG can reduce or avoid outages in certain parts of the distribution system.*
- Avoided T&D siting concerns—*By eliminating the need for new transmission and distribution lines, DG can avoid societal concerns over adding transmission lines.*

Table 3.4 shows typical values for some of these benefits. Similar to customer benefits, EDC benefits are specific to a particular site, application, and utility. Also, some benefits might not have any value to a particular utility. Though these grid-side benefits can be quantified, it is not clear how they can be captured and accurately monetized and to whom the ultimate savings should go. Figure 3.8 demonstrates that if these grid-side benefits were shared with customers, it would shift the five-year payback line upward, making DG economical for customers in virtually all states, all else being equal.

Table 3.4: Typical Grid-Side Benefits

	$/kW-yr	¢/kWh (at 60% Capacity Factor)
Avoided Increases in System Capacity	55	1.0
Reduced T&D Losses	50	0.9
T&D Upgrade Deferral	30	0.6
VAR Support	35	0.7
Total EDC Benefits	***170***	***3.2***

Source: Arthur D. Little analysis. See *Notes* for source details

In addition to the benefits DG can bring customers and utilities, there are also additional site-specific costs that must be considered:

- *Standby charges*
- *Competitive transition charges (CTCs)*
- *Exit fees*
- *Additional incremental capital costs for interconnection and permitting*

Figure 3.8: Simple Payback With Grid-Side Benefits for Commercial Customer Segment

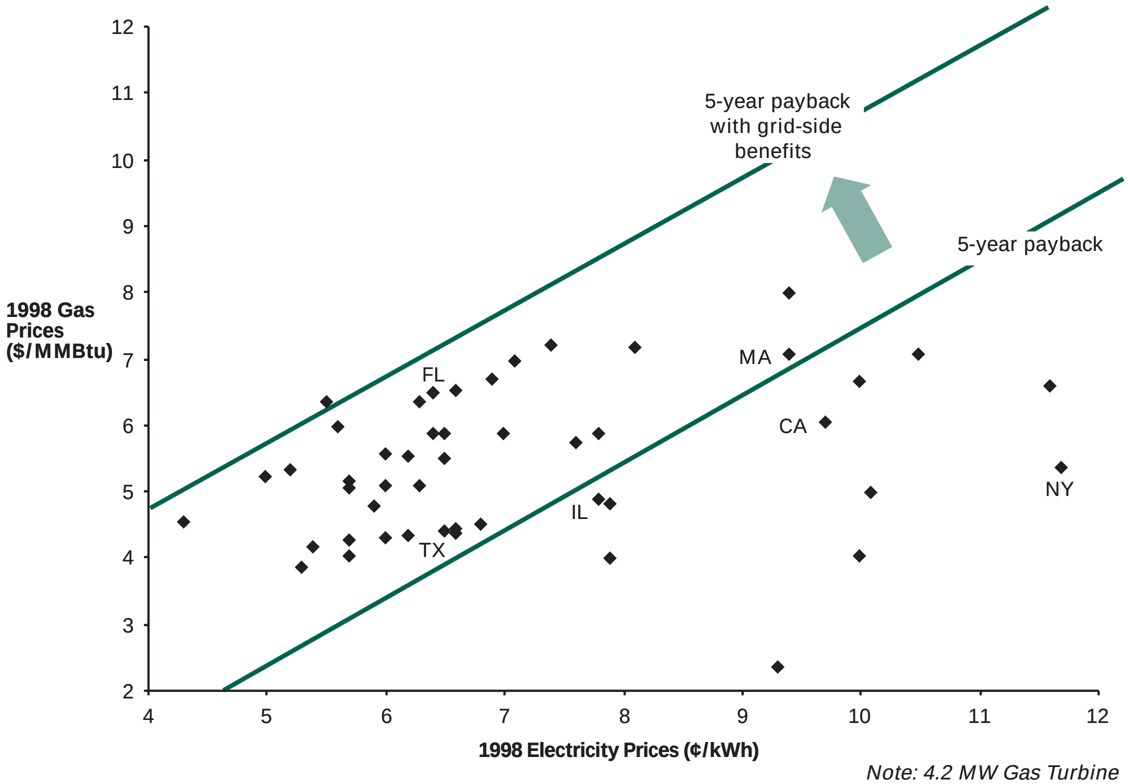


Table 3.5 provides typical values for standby charges and CTCs. This analysis was based on examining current deregulation activities and legislation as well as existing tariffs in California, Massachusetts, Illinois, Florida, and Texas.

Table 3.5: Typical Added DG Cost for Customer

	¢/kWh (at 60% Capacity Factor)
Standby Charges	0.6
CTCs	2.1
Total Added Customer Costs	***2.7***

Source: Arthur D. Little analysis. See *Notes* for source details

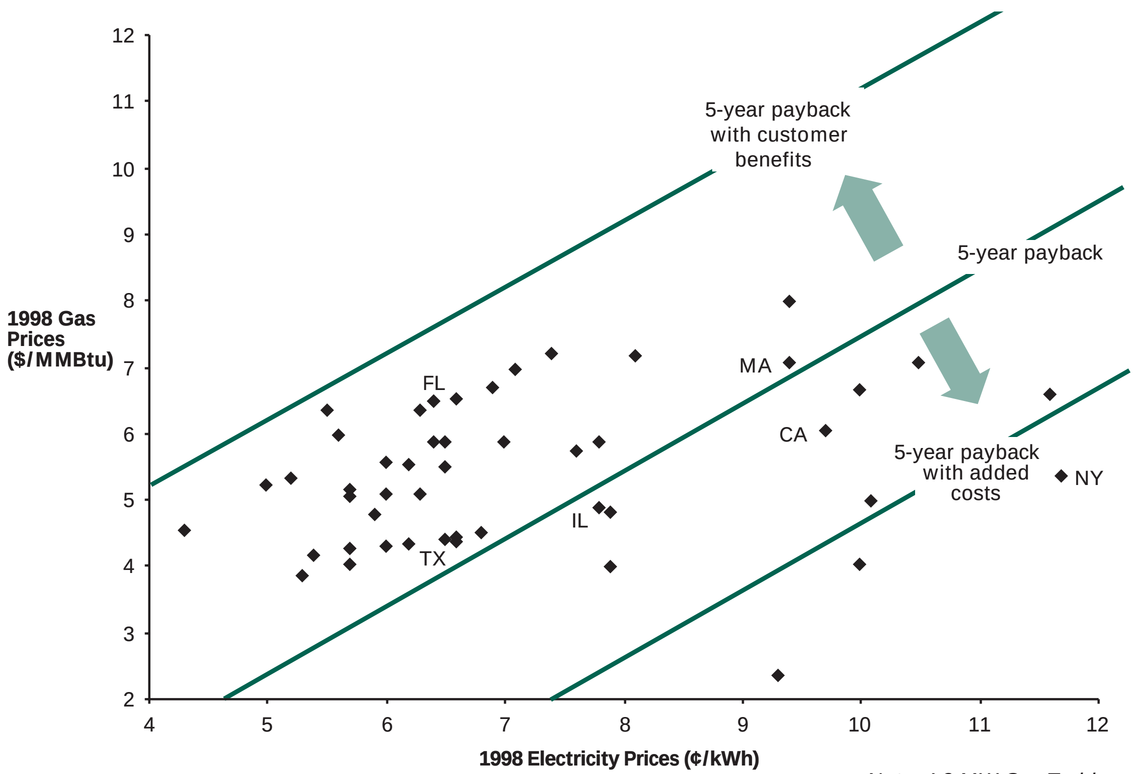
For the end-use consumer, a simple analysis…confirms the economic viability of DG in many states. The economics are improved if customers value and can capture other DG benefits.

Figure 3.9 illustrates the impact of these added costs. They lengthen the payback period for customers, making DG unattractive in all but a few states.

For the end-use consumer, a simple analysis of electricity prices, natural gas prices, and DG installed costs confirms the economic viability of DG in many states. The economics are improved if customers value and can capture other DG benefits. DG at the customer's site can also provide benefits to the electric utility. If utility grid-side benefits were shared with customers (assuming they could be applied, captured, and monetized), customer economics would be further enhanced. At the same time, however, customers with DG could also be levied with added costs, such as standby charges, exit fees, and additional incremental costs for interconnection, which would degrade the economic attractiveness of DG.

DG benefits and added costs depend highly on the specific application, site, customer, and utility. While it is unlikely that a DG unit would provide and be recognized for all of its theoretical benefits, several benefits could apply to a particular site and, if monetized, make DG more financially attractive for that customer.

Figure 3.9: Simple Payback With Added Costs for Commercial Customer Segment



Note: 4.2 MW Gas Turbine

IV. Conclusions

DG has the potential to play a major role as a complement or alternative to the electric power grid under certain conditions. DG is fundamentally distinct from the traditional central plant model for power generation and delivery in that it can deliver energy close to loads within the power distribution network. Also, DG facilities are smaller than central plants, can be operated remotely, and provide a broad range of applications for customers. The range of DG technologies and the variability in their size, performance, and suitable applications suggest that DG could provide power supply solutions in many different industrial, commercial, and residential settings across the United States. The utility and customer advantages DG may offer in site-specific situations suggest that the market may be receptive and willing to consider it as an option.

DG's economic attractiveness…[and] concerns over the allocation of benefits, levying of added costs, and other competitive issues will put DG on the regulatory and legislative agendas of many more states and the federal government.

Three relatively independent sources of pressure—restructuring, the need for new capacity, and DG technology advancements—are collectively laying the groundwork for the possible widespread introduction of DG. Given the currently evolving changes in the utility marketplace, it is unclear how the market will value the new and unique attributes of DG technologies. Many factors could be significant in the adoption of DG by different end-use customers and utilities. A key determinant will be the ability to capture and monetize the site-specific benefits and costs associated with DG in a balanced transaction involving the appropriate regulated utility company, end-use customer, and other relevant parties.

DG's economic attractiveness for customers and utilities and its ability to provide for capacity in the near term is leading regulators in several states to address it. Concerns over the allocation of benefits, levying of added costs, and other competitive issues will put DG on the regulatory and legislative agendas of many more states and the federal government. An understanding of the fundamental economics of DG is essential for policymakers to address these concerns and to arrive at sound decisions regarding the future of DG.

Notes

Assumptions for Figure 3.1

Option	Scenarios	Cost Assumptions
1. Central Plant	*A. Generation, Transmission, and Distribution Constrained*	• Generation—Includes capital and operating costs for a combined-cycle gas turbine (20–60 percent capacity factor) • Transmission—Includes capital construction costs for new construction and operating costs; Transmission construction costs based on annual capital expenditures and transmission additions for U.S. Investor-Owned Utilities (IOUs)(20–60 percent capacity factor) *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute* • Distribution—Includes capital construction costs for new distribution and operating costs; Distribution construction costs based on annual capital expenditures and transmission additions for U.S. IOUs; Operating costs based on annual operation and maintenance expenses and energy sales for IOUs; Also includes secondary distribution system costs for substation upgrades and new construction; Secondary distribution system costs based on interviews and quotes from transformer and substation equipment vendors (20–60 percent capacity factor) *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute*
	B. Transmission and Distribution Constrained	• Generation—based on marginal costs of electricity in ERCOT, California, and NEPOOL and market prices from PJM, ISO-New England, and California Power Exchange (20–60 percent capacity factor) • Transmission—Same as 1A • Distribution—Same as 1A
	C. Generation Constrained	• Generation—Same as 1A • Transmission and Distribution—Includes transmission and distribution and operating costs based on annual operation and maintenance expenses and energy sales for IOUs *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute*
	D. No Constraints	• Generation—Same as 1B • Transmission and Distribution—Same as 1C
2. Distributed Generation	*All*	• Generation—Based on the capital and operating costs for a large natural gas reciprocating engine (20–60 percent capacity factor) • Distribution—Includes capital costs for the secondary distribution system—substation upgrades and new construction; Secondary distribution system costs based on interviews and quotes from transformer and substation equipment vendors (20–60 percent capacity factor)

Assumptions for Figure 3.2

Option	Scenarios	Cost Assumptions
1. Central Plant	*A. Transmission and Distribution Constrained*	• Transmission—Includes capital construction costs for new construction and operating costs; Transmission construction costs based on annual capital expenditures and transmission additions for U.S. IOUs *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute* (20–60 percent capacity factor) • Distribution—Includes capital construction costs for new distribution and operating costs; Distribution construction costs based on annual capital expenditures and transmission additions for U.S. IOUs; Operating costs based on annual operation and maintenance expenses and energy sales for IOUs; Also includes secondary distribution system costs for substation upgrades and new construction; Secondary distribution system costs based on interviews and quotes from transformer and substation equipment vendors (20–60 percent capacity factor) *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute*
	B. No Constraints	• Transmission and Distribution—Includes transmission and distribution operating costs; Operating costs based on annual operation and maintenance expenses and energy sales for IOUs *Source: Statistical Yearbook of the Electric Utility Industry 1997, Edison Electric Institute*
2. Distributed Generation	*All*	• Generation—Based on the capital and operating costs for a large natural gas reciprocating engine (20–60 percent capacity factor) • Distribution—Includes capital costs for the secondary distribution system—substation upgrades and new construction; Secondary distribution system costs based on interviews and quotes from transformer and substation equipment vendors (20–60 percent capacity factor)

Details for Figure 3.3

Grid Cost of Delivered Energy		
Boston Edison's G-2 Rate (10–200 kW)	**Oct.–May**	**June–Sept.**
Demand Charges ($/kW) (in excess of 10 kW)	10.54	22.59
Energy Charges (¢ / kWh) (includes DSM and renewables)	4.10	4.10
Distribution Charges		
First 2,000 kWh (¢/kWh)	1.1	2.1
Next 150 kWh (¢/kWh)	.6	.8
Additional kWh (¢/kWh)	.5	.5
Transition Charges		
First 2,000 kWh (¢/kWh)	4.3	8.4
Next 150 kWh (¢/kWh)	2.2	2.9
Additional kWh (¢/kWh)	1.4	1.6

	Annual Cost of Electricity Purchased From Utility				
	Peak Demand[1] (kw)	Demand Charges ($)	Energy [2] (kWh)	Energy Charges ($)	Total Cost ($)
Without DG Equipment	75–95	13,700	439,000	29,600	43,300
With 50 kW Microturbine	25–46	5,000	125,000	9,700	14,700
Annual Savings in Purchased Electricity		8,700		19,900	28,600

1. Varies by month
2. Includes energy, DSM, renewables, distribution, and transition charges

Sources for Tables 3.3, 3.4, and 3.5

Title	Authors	Date
Mapping the Value of the Commercial PV Applications in the US; Accounting for Externalities	Richard Perez, ASRC, Univ. of Albany; Christy Herig, NREL; Howard Wenger, Astropower	1999
Fostering Sustainability in the Northern Forest Region: The Role of Renewable Energy	Steven E. Letendre, Green Mountain College	1999
Geographical Distribution of the Value of Demand-Side Commercial PV Systems in the US	Richard Perez, ASRC, Univ. of Albany; Christy Herig, NREL; Howard Wenger, Pacific Energy Group	1998
Clean Distributed Resources On Block Island, Rhode Island	Thomas Hoff, Clean Power Research; Christy Herig, NREL	1999
Proposed Methodologies for Evaluating Grid Benefits of Distributed Generation	Mark Skowronski, AlliedSignal Power Systems	1999
Application of the Distributed Utility Concept to the Boston Edison Company Creating Additional Value for the Customer	David Schoengol, MSB Energy Associates	1994
Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project	Howard Wenger and Thomas Hoff, Pacific Energy Group; Brian Farmer, PG&E	1994
Distributed Utility Valuation Project	Stephen Chapel, EPRI; Lynn Coles, NREL; Joseph Iannucci, PG&E; Roger Pupp, Quantitative Solutions	1993
Utility Planning and Operational Implications of Photovoltaic Power Systems	Greg Rueger, PG&E; Giancarlo Manzoni, ENEL	
Photovoltaics in the Utility Distribution System: The Evaluation of System and Distributed Benefits	Daniel Shugar, PG&E	
Maximizing the Benefits Derived From PV Plants: Selecting the Best Plant Design and Plant Location	Thomas Hoff, Consultant: Joseph Iannucci, PG&E	1990
Distributed Generation From an Engine Supplier Point of View	Mack Shelor	1996
Molten Carbonate Fuel Cells as Distributed Generation Resources—Case Studies for the Los Angeles Department of Water and Power—EPRI Report	M. M. El-Gasseir	1992
Strategic Market Assessment of Distributed Resources—EPRI Report	Greg Hamm, Applied Decision Analysis; Frank Graves and Alan Taylor, Brattle/IRI; Joseph Iannucci, Distributed Utility Associates: Roger Pupp, Econix	1995
Commercializing Photovoltaics: The Importance of Capturing Distributed Benefits	Steven E. Letendre, Green Mountain College; Carl Weinberg, Weinberg Associates; John Byrne and Young-Doo Wang, Center for Energy and Environmental Policy, University of Delaware	1998
Expanding PV Markets: Policies to Support a Distributed Energy System	Thomas Starrs, Kelso Starrs & Associates LLC; Howard Wenger, AstroPower	1999
The Role of Distributed Generation in Competitive Energy Markets	Distributed Generation Forum, GRI	1999
Distribution Systems Redesign Project	EPRI	1998
Statistical Yearbook of the Electric Utility Industry 1997	EEI	1998
NERC Electricity Supply and Demand Database	NERC	1998
Gas Industry Distributed Utility Market Analysis	GRI	1995

Sponsoring Organizations

AlliedSignal Power Systems, Inc.

Automatic Switch Co.

Caterpillar Inc.

Elliott Energy Systems, Inc.

Encorp, Inc.

Enercon Engineering

Fairbanks Morse Engines

Kohler Power Systems

Rolls-Royce Energy Systems

Solar Turbines Inc.

Siemens Westinghouse Power Corp.

Teledyne Continental Motors

U.S. Department of Energy

Zenith Controls, Inc.

SB30273