NATURAL GAS AND ENERGY PRICE VOLATILITY

PREPARED FOR THE

Oak Ridge National Laboratory

BY THE

American Gas Foundation

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October 2003

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5. Impact Of Energy Price Volatility On Emerging Markets

5.1 Introduction

In previous chapters of this report we have examined different concepts and measurements of energy price volatility, provided detailed examples and analyses of specific incidences, and explored the impact of energy price volatility on market participants. In this chapter, we examine whether and how the existence of price volatility in the natural gas and electricity markets affects decisions regarding owning and operating emerging energy technologies -- specifically, distributed generation (DG) equipment and combined heat and power (CHP) systems. We evaluate how volatility impacts the perspectives and actions of end-use customer and energy services companies (ESCOs) as they relate to installation, ownership and operation of DG/CHP systems.

Distributed generation is the strategic placement of electric power generating units at or near customer facilities to supply on site energy needs. Combined heat and power is the generation of electric or mechanical power and thermal energy simultaneously from the same fuel source. Distributed generation projects can be designed to produce electric or mechanical power only, or to produce electric or mechanical power and thermal energy (CHP). DG benefits as compared to power from the grid for energy users may include enhanced reliability, superior power quality, independence from the grid, and lower energy costs. CHP offers individual and societal energy and environmental benefits over electric-only systems, in both central power generation and distributed generation applications. CHP systems achieve increased efficiency in fuel use, reduced emissions of air pollutants and greenhouse gases, and enhanced reliability of the electrical grid. Industrial, institutional and commercial facilities are the principal users of CHP, along with some utilities and independent power producers.

End-use customers and ESCOs making DG/CHP investment decisions may implicitly or explicitly address energy price volatility in the investment/planning context. Price volatility in this sense refers to long-term uncertainty about energy price levels that influences investment planning. This uncertainty has a number of potential implications for investors. For example, it might cause them to delay decisions to purchase appliances and equipment. Or, it might cause them to invest in different types of equipment than they might otherwise, e.g., in a dual-fuel capable system rather than a dedicated-fuel system. The ways in which potential DG/CHP investors could take price volatility into account are varied, from demanding a higher rate of return on a project, to informal considerations of impacts, to neglecting the issue entirely.

The following chapters explore and characterize, in turn:

- DG/CHP technologies, owners and operators;
- owner/operator attitudes, perceptions and actions regarding price volatility with respect to DG/CHP-related activities;
- the economics of DG/CHP systems;
- energy price volatility in DG/CHP markets, and;
- quantitative analyses of DG/CHP ownership and operation.

5.2
The Emerging DG/CHP Market: Technologies and Users

5.2.1 Introduction

There are five types of on-site generation technologies: reciprocating engines, small gas turbines, steam turbines, microturbines, and fuel cells. These technologies, known as prime movers, convert fuel to shaft power or mechanical energy. In both DG and CHP applications, the mechanical energy from the prime mover drives a generator for producing electricity. It may also drive rotating equipment, such as compressors, pumps and fans. In the case of CHP applications, a heat recovery system captures and converts the energy in the prime mover's exhaust into useful thermal energy. The thermal energy from the heat recovery system can be used either for direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

Most installed on-site generation today is CHP capacity. Table 5-1 on the following page depicts the current installed base of CHP by type of prime mover and sector. In the sections that follow, we describe the prime mover technologies and applications that are part of the emerging market for DG/CHP and profile briefly potential owners/operators of DG/CHP. Appendix G presents further detail on existing CHP capacity. Appendix H contains tables summarizing the characteristics of the DG/CHP technologies summarized below.

5.2.2 DG/CHP Technologies

5.2.2.1 Reciprocating Engines

Reciprocating internal combustion engines is a widespread and well-known technology, available for electrical power generation applications in sizes ranging from a few kilowatts to over 5 MW. There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel. Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications. However, in the

Table 5-1
Installed CHP by Sector: 58,931 MW

Prime Mover	Installed CHP Capacity By Sector (MW)			
	Industrial	Commercial	Other*	Total
Boiler/Steam Turbine	16,646	1,378	1,038	19,062
Combined Cycle	27,432	2,185	668	30,285
Combustion Turbine	5,724	1,780	2,550	9,854
Recip Engine	232	531	38	801
Other	157	38	11	206
Total	**50,191**	**5,712**	**4,305**	**60,208**

Source: Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database

United States and other industrialized nations, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. As a result, the natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (over 500 hr/yr).

Current generation natural gas engines offer low first cost, fast start-up, proven reliability when properly maintained, excellent load-following characteristics, and significant heat recovery potential. Electric efficiencies of natural gas engines range from 28% LHV for small stoichiometric engines (<100 kW) to over 40% LHV for very large lean burn engines (> 3 MW).[1] Waste heat can be recovered from the hot engine exhaust and from the engine cooling systems to produce either hot water or low pressure steam for CHP applications. Overall CHP system efficiencies (electricity and useful thermal energy) of 70 to 80% are routinely achieved with natural gas engine systems. Reciprocating engines are well suited to a variety of distributed generation applications and are widely used in the U.S. and Europe in power-only and CHP

[1] Lower Heating Value. Most quoted efficiencies are based on higher heating value (HHV), which includes the heat of condensation of the water vapor in the combustion products. In engineering and scientific literature the lower heating value (LHV – which does not include the heat of condensation of the water vapor in the combustion products) is often used. The HHV is greater than the LHV by approximately 10% with natural gas as the fuel (i.e., 50% LHV is equivalent to 45% HHV). HHV efficiencies are about 8% greater for oil (liquid petroleum products) and 5% for coal.

configurations in the industrial, commercial and institutional market sectors. Potential DG applications include standby, peak shaving, grid support, and CHP applications in which hot water, low pressure steam, or waste-heat-fired absorption chilling is provided using waste heat from the engine.

5.2.2.2 Small Gas Turbines

Gas turbines are generation systems operating on the thermodynamic cycle known as the Brayton cycle. In a Brayton cycle, atmospheric air is compressed, heated, and then expanded, with the excess of power produced by the expander (also called the turbine) over that consumed by the compressor used for power generation. Gas turbines can be used in a variety of configurations: (1) simple cycle operation which is a single gas turbine producing power only; (2) combined heat and power operation, which is a simple cycle gas turbine with a heat recovery heat exchanger to recover the heat in the turbine exhaust and convert it to useful thermal energy, usually in the form of steam or hot water; and (3) combined cycle operation, in which high pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine. Some combined cycles extract steam at an intermediate pressure for use in industrial processes and are combined cycle CHP systems.

Gas turbines are available in sizes ranging from 500 kilowatts (kW) to 250 megawatts (MW). The exhaust heat from gas turbines is very high-quality and can be used in CHP configurations to reach system efficiencies of 70 to 80%. Turbine-based CHP systems use the turbine exhaust directly for an industrial process such as drying or as input into a heat recovery steam generator that produces steam for process or space conditioning use. The efficiency, reliability and economics of small gas turbines have made them an attractive choice for industrial and large institutional users for CHP applications since the early 1980s. They are also one of the cleanest means of generating electricity. Potential DG applications for small gas turbines in power-only configuration include standby, peak shaving and on-peak systems, and grid support. CHP applications require additional equipment, but are generally a cost-effective DG option when local thermal loads can be met.

5.2.2.3 Steam Turbines

Steam turbines are one of the most versatile and oldest prime mover technologies still in general production. While the capacity of commercially available steam turbines ranges from 50 kW to several hundred MW, on-site power generation uses are in the 500 kW to 20 MW range. Unlike gas turbine and reciprocating engine CHP systems, steam turbines normally generate electricity as a byproduct of heat (steam) generation. Steam turbine systems require a boiler in which fuel is burned to provide heat for steam generation, steam that is then provided to the turbine in the form of high pressure steam that in turn powers the turbine and generator.[2] This arrangement enables steam turbines to operate with an enormous variety of fuels, varying from natural gas to solid waste. In CHP applications, steam at lower pressure is extracted from the steam turbine and used directly in a process or for district heating, or it can be converted to other forms of thermal energy including hot or chilled water.

[2] Steam can also be generated with the waste heat of a gas turbine as in the case of combined cycle power plants.

While steam turbines themselves are competitively priced compared to other prime movers, the costs of complete, “green-field” boiler/steam turbine CHP systems are relatively high on a per kW of capacity basis because of their low power to heat ratio; the costs of the boiler, fuel handling and overall steam systems; and the custom nature of most installations. Thus, steam turbines are well suited to medium- and large-scale industrial and institutional applications where inexpensive fuels, such as coal, biomass, various solid wastes and byproducts (e.g., wood chips, etc.), refinery residual oil, and refinery off gases are available. In general, steam turbine applications are driven by balancing lower cost fuel or avoided disposal costs for a waste fuel, with the high capital cost and (usually high) annual capacity factor for the steam plant and the combined energy plant-process plant application. For these reasons, steam turbines are not normally direct competitors of gas turbines and reciprocating engines in distributed generation applications.

5.2.2.4 Microturbines

Microturbines are small electricity generators that burn clean gaseous and liquid fuels to create high-speed rotation that turns an electrical generator. Microturbines entered the field testing stage around 1997 and began initial commercial service in 2000. The size range for microturbines available and in development is from 30 to 350 kW. Microturbines run at very high speeds and, like larger gas turbines, can be used in power-only generation or in CHP systems. They are able to operate on a wide variety of fuels, including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines feature emissions rates that can be up to eight times lower than diesel generators.[3] In resource recovery applications, they burn waste gases that would otherwise be flared directly into the atmosphere.

Microturbines are ideally suited for distributed generation applications due to their flexibility in connection methods, ability to be stacked in parallel to serve larger loads, ability to provide stable and extremely reliable power, and low emissions. Types of applications include peak shaving and base load power (grid parallel); combined heat and power; stand-alone, back-up and standby power; ride-through connection; primary power with grid as backup; microgrid; and resource recovery. Target customers for most of these applications are found in the financial services, data processing, telecommunications, restaurant, lodging, retail, office building and other commercial sectors. Many of the early entry microturbines currently in service are in resource recovery applications where fuel costs are negligible and unattended operation is key.

5.2.2.5 Fuel Cells

Fuel cell systems, currently in the early stages of commercialization, differ fundamentally from traditional prime mover technologies. Fuel cells are similar to batteries in that both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely as long as the fuel source, hydrogen, is supplied. Two electrodes (a cathode and anode) pass charged ions through an electrolyte to generate electricity and heat. A

[3] “Grid Power Solutions: The North American Market for Distributed Generation and Ride Through Technologies.” Venture Development Corporation, June 2001, p. 243.

catalyst enhances the process. Fuel cells have very low emissions profiles because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low energy hydrogen exhaust stream that is used to provide heat to the fuel processor. Electrical generating efficiencies range from 3% to over 50% HHV.

Fuel cells offer the potential for clean, quiet, and very efficient power generation, benefits that have driven significant investment in their development in the past two decades. As with most new technologies, fuel cell systems face a number of formidable market entry issues resulting from product immaturity, over-engineered system complexities, and unproven product durability and reliability. These translate into high capital cost, lack of support infrastructure, and technical risk for early adopters. However, the many advantages of fuel cells suggest that they could well become the prime mover of choice for certain applications and products in the future.

Today, there are only two commercially available fuel cells for distributed generation applications, a 200 kW unit[4] that has been commercially offered since the mid-1990s and a 300 kW unit[5] just entering commercial introduction. Although nearly two dozen companies are currently field testing a variety of alternative fuel cell systems for market entry, the availability of a wide array of off-the-shelf, fully warranted fuel cell systems designed for broad customer classes is still some years away.

5.2.3 DG/CHP Owners and Operators

The main participants shaping the emerging DG/CHP market through pursuit of business interests include equipment manufacturers and packagers, distributors, consulting/specifying engineers, end-use energy customers, utilities, and ESCOs. The last three groups, as potential and current owners and operators of DG/CHP systems, are the investors whose decisions may be influenced by energy price volatility. Below, we characterize each of these groups and briefly state what benefits DG/CHP technologies might offer them.

5.2.3.1 End-Use Energy Customers

End-use customers are typically classified as residential, commercial, industrial, and institutional.

The *residential* sector comprises single family dwellings, townhouses, and in some contexts, multi-family residences, such as apartment buildings and condominium developments.[6] The prices residential customers pay for natural gas and electricity are regulated by state utility commissions. Utilities pass commodity costs through to these customers according to fixed formulas and schedules, while marketers supplying energy typically offer a fixed rate. Both utilities and marketers protect residential customers from the full impacts of price volatility because they assume the burden of managing volatility through mechanisms such as storage and hedging, as discussed in the previous volume. The degree of protection depends upon the

4 Offered by UTC Fuel Cells as the PC25.
5 Offered by Fuel Cell Energy as the DFC 300
6 For the purposes of this report, multi-family dwellings are considered part of the commercial sector.

portfolio of the supplier as well as the regulatory climate and other conditions under which they operate.

However, price spike effects, seasonal energy price variation, and variations in residential bills due to weather and consumption patterns, do impact residential customers at some level. Along with this, they are subject to outages, blackouts, voltage reductions, and loss of service due to adverse weather and distribution system events, all factors that suggest DG as a potential residential application.

In the *industrial* sector, which encompasses a variety of production, manufacturing, processing and assembly facilities, many energy customers are well along the path to managing their energy use and costs through commodity purchasing from marketers and the open market, on-site generation, hedging and other price risk management techniques, and use of alternative and back-up fuels. Energy-intensive industries such as steel, where fuel costs represent a significant portion of operating costs, continue to have strong incentives to consider DG/CHP along with other mechanisms for controlling and reducing costs. In fact, industrial customers such as paper and pulp mills, plastics thermoforming, and others with energy-intensive heat treating processes plus other uses for steam were among the first to adopt CHP systems. The availability of fuels, such as black liquor and wood waste, enhance the attractiveness for customers generating such by-products.

Many *institutional* energy users, like industrial facilities, find CHP an attractive application due to existing steam distribution systems and large thermal loads. Colleges and universities, prisons, hospital systems, and others are strong candidates for CHP systems, and many have been operating CHP systems for years.

The *commercial* sector is extremely varied, made up of about a dozen major subsectors including restaurants, office buildings, hospitals, supermarkets, and others. In some contexts, including this report, it also includes multi-family housing such as apartment buildings. While many commercial energy customers purchase both electricity and natural gas from their local distribution companies, others purchase the commodity from marketers and transportation services from the LDC. For example, one major national national full-service restaurant corporation operating four different restaurant chains supplies approximately half of its stores nationwide with natural gas through marketers, and about 25% of stores with electricity purchased from marketers. However, most are less sophisticated than industrial customers regarding energy, and have fewer options available to them for managing costs and price risks. There are as many different commercial customer tariffs as there are LDCs, with varying degrees of complexity. Commodity purchases through marketers are at negotiated rates, terms and conditions. Prices may be tied to prices at market hubs or a variety of other indices.

Commercial customer interest in DG/CHP has existed and is emerging for a number of reasons. If customers are relatively more concerned about electricity price stability than natural gas or alternative fuel stability, DG/CHP may appear attractive. Businesses that depend upon data processing and other electronic transactions, such as data centers, can suffer large losses when power quality fluctuations, interruptions and outages occur, even split-second disturbances. Current and anticipated problems with electricity transmission and distribution systems feed concerns about the quality and reliability of grid power. Electricity prices in some areas are high relative to natural gas price or alternative fuel prices, so significant energy savings can result from DG/CHP installations, particularly when thermal loads allow operation of CHP systems. Shaving electric usage at peak times can also result in large electricity cost savings.

5.2.3.2 ESCOs

ESCOs are businesses that develop, install, and finance projects designed to improve the energy efficiency and maintenance costs for facilities, typically over a seven to 10 year time period.[7] ESCOs began appearing in the late 1970s and early 1980s, following the steep increases in energy prices that occurred due to the oil embargo and other events of the decade. These increases set the stage for ESCOs to implement energy efficiency projects to help control customers' energy costs by reducing and managing energy use.

Acting as project developers, ESCOs typically:

- develop, design, and finance energy efficiency projects;
- install and maintain the energy efficient equipment involved;
- measure, monitor, and verify the project's energy savings; and
- assume the risk that the project will save the amount of energy guaranteed.

ESCOs in operation today include utility subsidiaries and affiliates, divisions of equipment or controls companies, such as Honeywell, and independent companies. The difference between ESCOs and other firms offering energy efficiency services, such as consulting firms and equipment contractors, is the ESCOs' use of performance-based contracting. An ESCO's compensation, and often the project financing as well, is linked directly to the amount of energy saved through the projects implemented. The cost of the services the ESCO performs are bundled into the project's cost and repaid through the dollar savings generated. Customers usually receive a guaranteed level of savings over their previous level of expenditures, with the ESCO earning its revenues on the difference between this level and its costs to provide the services to the customer.

As might be surmised from the discussion above, ESCO interest in DG/CHP technologies lies in the ability of these technologies to reduce customers' energy costs and provide a margin to the ESCO while doing so. Under a guaranteed savings arrangement, price volatility to the ESCO reduces the probability of achieving maximum margin, thus ESCOs are in the business of managing price volatility risk as well. The customer in this case has transferred considerations of price volatility to the ESCO.

To date, ESCOs have focused primarily on larger scale, CHP applications that provide electricity and steam or hot water to industrial, institutional or large commercial customers, with sales of excess electricity back to the grid in some cases.

[7] www.naesco.org.

5.2.3.3 Utilities

Natural gas utility interest promoting customer use of natural gas-fueled DG/CHP includes both the quantity and quality of the natural gas load represented. DG typically serves as a valley filler for the gas utility, consuming the most gas to supply air conditioning loads during the summer when gas use for space heating is at its lowest. While DG technologies can run on other fuels, natural gas is the favored fuel for environmental and other reasons. Utilities may own and operate DG/CHP systems through unregulated ESCO subsidiaries/affiliates, or encourage customer installations with PUC-approved incentives and special rates.

5.3
DG/CHP Investor Perceptions of Energy Price Volatility

5.3.1 Introduction

Are end-use customers attempting to incorporate the positives or negatives of energy price volatility into their consideration of DG/CHP technologies? What has the impact of price spikes been on customers who already have DG/CHP? What are the experience and perceptions of ESCOs, utilities and manufacturers in interacting with current and potential DG customers, and how does price volatility impact investor DG-related activities?

California, during the summer and winter of 2000, provides a worst-case scenario of price volatility for users of on-site generation who were not selling electricity into the grid. As detailed in the case study in Chapter 1, both electricity and natural gas prices became extremely unstable and spiked dramatically over a period of months. However, since most customers were insulated from the electricity price fluctuation due to rates that were frozen by legislative mandate, but more exposed on the natural gas side, DG units fueled by natural gas became uneconomic to operate, and most were shut down. While prices eventually settled back to more normal levels, the price spikes caused a large variation from the return on investment expected from DG/CHP installations.

Conversely, in the Pacific Northwest, a small industrial company recently installed 10 MW of natural gas-fueled DG under a special electricity rate schedule which was arrived at through a series of negotiations. The company had been devoting over one-third of its operating budget to electricity expenditures, paying rates more than double that of its competitors. The newly established schedule allows the company to purchase electricity on the open market or from third-party suppliers, and requires the electric LDC to purchase, at market prices, any and all excess electricity generated by the customer. With the appropriate electricity hedges in place, confidence in the stable functioning of natural gas markets, and an array of natural gas price risk management strategies available, the company considers its investment in DG as part of its portfolio of tools for minimizing energy costs and protecting against energy price fluctuations.

In the following section, we summarize the perceptions and activities of current and potential DG/CHP investors with respect to price volatility, based on our discussions with end-use customers, utilities, ESCOs and manufacturers, and on results from third party surveys.

5.3.2 Investor Perceptions - General

5.3.2.1 Expectations About Future Price Volatility

In a summer 2002 survey of 600 commercial and industrial end-use customers[8] conducted by Primen, three-quarters of respondents indicated they agree with the statement that natural gas prices are likely to remain volatile and unpredictable for the foreseeable future. More than 20% felt strongly about this. Overall, on a ten-point scale, the mean level of agreement was 6.7. Our discussions with individual customers mirrored this general perception.

On the electricity price side, individual customers with whom we spoke thought future volatility was likely. Some expected an eventual decrease in the overall level of electricity prices, while others are worried that overall levels will rise. Many customers observed that the natural gas market is much farther along the path to deregulation, with open and transparent processes and transactions that act to prevent manipulation of prices and to restore equilibrium when fluctuations do occur. These customers told us they believe that the electricity price spikes were caused by gaming of the system by electricity marketers that is enabled because of the immaturity, relative opacity and uneven development of deregulated electricity markets. Further deregulation is expected to bring prices down. California customers tended to attribute volatility to the state government's role in energy issues and frequent changes in policy.

ESCOs with whom we spoke made similar observations about the natural gas and electricity markets and the cause of the California electricity price spikes. They noted that their customers feel secure and comfortable with the financial products, storage and other means available to protect themselves from volatility on the natural gas side, but are worried about what will happen on the electric side. Among their customers, concern about volatility is embedded in anxiety about general price levels, with no differentiation unless the ESCO initiates a conversation about it.

One ESCO described "real" electric price volatility as stemming from transmission and distribution (T&D) and generation constraints, and expected future volatility to occur in T&D-constrained areas, as many generation markets are overbuilt. They also foresee the possibility of volatility caused by emotional reactions if terrorists strike the energy infrastructure. This company believes that energy companies will eventually leave participation in the commodity market to the trading arms of financial companies, a move that will help avoid price volatility.

5.3.2.2 Volatility Influences on DG/CHP Investment

The Primen survey results show a weak but statistically significant correlation between agreement about continuing gas price volatility and likelihood of purchasing a base load DG system in the next two years ($r=-.11$, $p<0.5$), where strong belief in continuing volatility

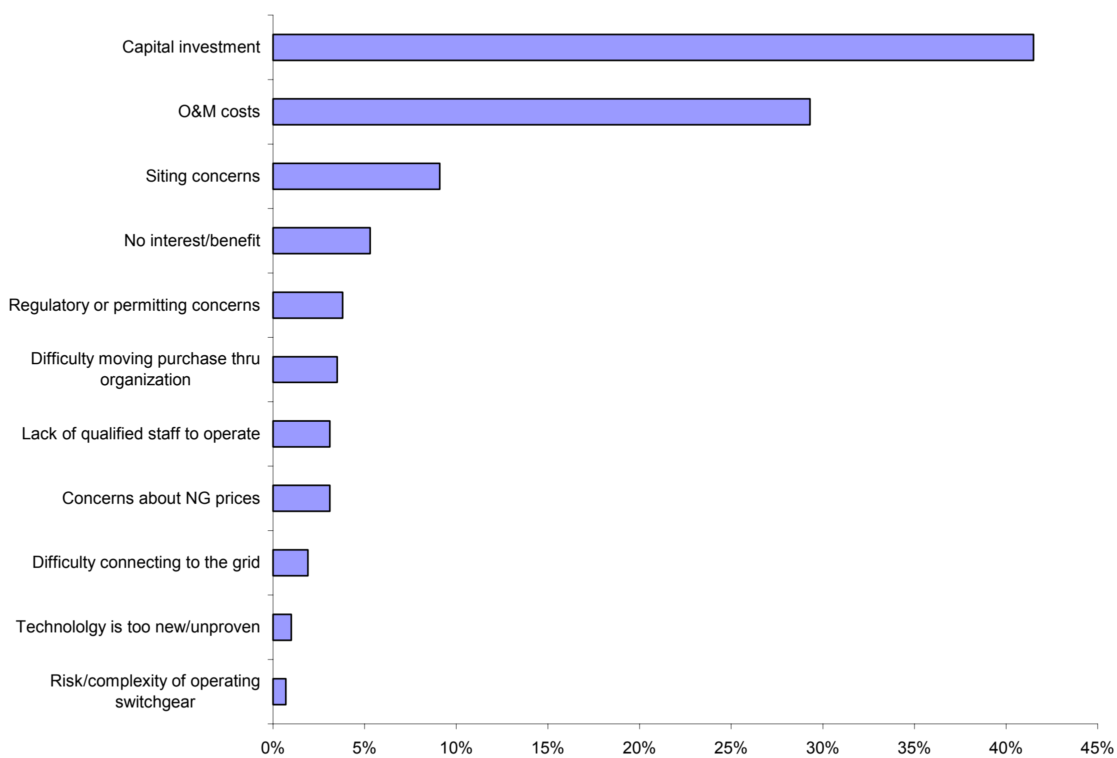
8 Respondents had average electric demand between 300 kW and 10 MW and fit into one or more of the following groups: industrial/commercial establishment with significant heat recovery potential; continuous process manufacturing; digital economy sector.

correlates with slightly lower estimates of DG purchase probability. This weak link disappears when customers estimate their probability of leasing a DG system.

When queried about potential barriers to acquiring a DG system for baseload use, only 3% of the respondents mentioned natural gas prices, as illustrated in Figure 5-1. As shown, the top three barriers cited were capital investment, operation and maintenance (O&M) costs, and siting concerns. Capital cost (including cost of up-front installation engineering) as a major barrier to customer DG investments surfaced throughout our conversations with customers, ESCOs, utilities and manufacturers.

The Primen survey respondents did not mention price volatility as a barrier to DG/CHP projects at all. However, since fuel costs are a major component of O&M costs, the barrier presented by O&M costs encompasses at least the overall level of natural gas prices. Thus, when viewing price volatility concern as uncertainty about the overall level of future prices, the survey findings do point to volatility as a barrier to customers' direct investment in baseload DG systems.

Figure 5-1
Percent of Respondents Citing Specific Barriers to Baseload DG



Primen's follow-up conversations with individual customers provided conflicting support for this conclusion. Among the 20 customers strongly considering acquiring a baseload DG system, only one mentioned natural gas price concerns, stating that these concerns had slowed the company's adoption of DG. Another customer stated that fuel price volatility had actually increased their company's interest in base load DG, as they are a firm that deals in commodity markets as part of their core business and views this as one of their strengths.

Our conversations with individual companies and ESCOs revealed more insights into these two approaches. On the one hand, customers stated that increased price volatility reduces the likelihood they will invest in capital-intensive energy equipment such as DG, or increases the performance they demand from energy projects. On the other hand are customers whose business circumstances and ability to buy energy on the open market or from marketers leads them to view DG/CHP as a tool tied to others in a portfolio of energy management strategies. Examples in the sections that follow highlight these two facets of the issue, along with others.

5.3.3 Commercial Customers

5.3.3.1 Context of Decision Making

In each commercial sector, there are drivers of profitability upon which management focuses its operational interests. Examples of such drivers are food quality and labor productivity in the restaurant industry; guest comfort in the lodging industry; and store dwell time in the retail industry. To the extent that DG/CHP can improve these drivers, there is special interest in the technologies. However, there is not a wide, deep or uniform base of knowledge or experience with DG/CHP technologies in most segments of the commercial market. Ownership, compensation structures, decision making processes and other factors all influence how profitability is achieved and maintained. These factors also influence energy equipment decisions, including DG/CHP.

In most commercial facilities, energy expenditures are not the largest budget item, or even the second, third or fourth largest, hence do not receive the same level of attention as major budget components such as labor. However, in sectors with very small operating margins such as supermarkets, energy cost changes can quickly tip the profitability scale one way or another. Additionally, many commercial establishments do not employ internal engineering or maintenance staff with understanding of onsite power generation technologies. It is within these contexts that most commercial customers make DG/CHP decisions.

There is wide variation in the level of energy sophistication among commercial customers. National account customers – those with facilities in more than a handful of states – tend to be more savvy than single-site or smaller chain companies. Many who have not felt the effects of price spikes or who have a lower energy sophistication level do not differentiate price volatility from the overall level of energy prices. Meanwhile, more sophisticated companies not only understand price volatility within each fuel market, but are purchasing energy commodity from marketers and managing their own energy portfolios, including price volatility protections.

5.3.3.2 Example: National Restaurant Company

A restaurant company operating four different quick service restaurant concepts has a total of over 1,200 stores nationwide, with $4.4 billion in food sales. While all stores are company-owned, each brand operates independently, so decisions regarding energy equipment are made separately by each brand's management. Energy expenses amount to 3 to 4.5% of the operating budget of a typical restaurant. The company had established an energy services department within the corporate engineering division in the early 1990s to seek out opportunities to achieve energy savings. The department evaluated and convinced concept managers to implement a number of quick-payback, one-time energy efficiency measures, such as switching to high-efficiency lighting and programmable thermostats. However, with the loss of the department leader, the department was transferred to purchasing and eventually disbanded.

The energy services department had investigated DG/CHP as a way to enhance energy efficiency and reduce energy expenditures, but felt it could not recommend the technology because concept management would not accept it. Reasons for this were:

- <u>Payback period too long</u>. Paybacks of less than one year for capital investments are required, a standard followed throughout the restaurant industry. The up-front cost was a particular issue, related in part to the maintenance concerns explained below.
- <u>Maintenance/capital cost concerns</u>. The company's incentive structure provides bonuses for managers based on store profitability. Expenditures on equipment maintenance directly reduce the base for bonuses, while capital expenditures for replacement equipment do not. Hence, equipment maintenance occurs infrequently and equipment is "run into the ground." In this case, the up-front cost to the corporation to replace DG equipment would be prohibitive.

The energy services department's move to purchasing reflects the choice made by this company to manage energy costs and volatility via commodity purchasing. Fully 50% of the company's restaurant locations buy natural gas from a marketer, and 25% purchase electricity from a marketer. Energy purchasing and contracting is handled centrally. The company also hedges its purchases.

Regardless of price volatility developments, DG is not likely to be re-evaluated by this company any time in the near future.

5.3.3.3 Example: National Hotel Company

Some commercial customers with larger facilities, such as resort/hotel management companies, express a high level of interest in the concept of an ESCO installing, operating and maintaining DG/CHP units for them, selling electricity to them at guaranteed prices lower than their current rates, and perhaps providing hot water or steam as well. Part of their interest lies in controlling energy costs, including exposure to price volatility. In the depressed travel scenario of the post-9/11 era, hoteliers feel they cannot raise rates to reimburse themselves for higher than planned for energy costs, and thus wish to ensure as much stability in the future as possible.

For example, a hotel company that owns and manages branded upscale hotel and resort properties worldwide has been analyzing DG/CHP for the last few years, tracking new product introductions and visiting installation sites. The average peak load of their properties is 1 MW. Most properties have a diesel generator set to provide emergency backup in case of outages. However, for noise, aesthetic and environmental reasons, their technologies of choice for baseload on-site generation are microturbines and fuel cells.

The company sees peak shaving as a potential application that will probably become more important in the future, but to be worthwhile, 300 to 400 kW would need to be shaved. A microturbine of this size has yet to be made commercially available, and while it is technically possible to operate a bank of multiple units, their analysis shows that cost per kW of capacity with such an arrangement is uneconomic. If a DG unit could operate both as emergency backup and peakshaver, it would be viewed as an emergency generator that pays for itself, and would be attractive to them. They have installed a fuel cell and a microturbine on a trial basis and are carefully monitoring results.

This customer seeks energy savings, protection from price spikes, ability to operate during power outages, and enhanced savings via use of waste heat. Like customers in other sectors, they view energy issues as tangential to their core business. Energy projects compete with much more visible capital projects, such as sleeping room refurbishment, grounds improvement, and addition of guest amenities such as spas. The company would welcome discussions with an ESCO willing to install, own and operate DG/CHP and provide a guaranteed level of savings over their current tariffs. This would free them to focus just on controlling their energy consumption through conservation and efficiency measures.

5.3.4 Industrial Customers

5.3.4.1 Context of Decision Making

As mentioned previously, energy expenses represent a significant portion of the operating expenses of many industrial firms. Energy supplies a wide variety of manufacturing, heat treating, drying, melting and other processes, some of which are very energy intensive. Many facilities' thermal loads make CHP an attractive option, as does the production on-site of by-product fuels. Because of the impact on their operations, companies in the industrial sector have long been proactive in seeking out ways to reduce energy costs, including buying energy from marketers and the open market, installing CHP systems, and seeking to bypass the distribution systems of local utilities to avoid LDC transportation charges and access cheaper gas supplied by a pipeline company, independent power producer or energy marketer.

Unlike many commercial customers, industrial facilities often employ engineering and maintenance staff, including specialists such as steam engineers, who are familiar with DG/CHP and other advanced direct-fired and thermally-driven equipment. They are also not subject to the spectrum of demands likely to face commercial concerns, such as noise, customer comfort, and aesthetics that may reduce the feasibility of some DG/CHP technologies. On the other hand, environmental regulations may restrict their choices.

The following examples describe the contexts in which several different industrial customers have operated and the role price volatility has played, and is playing, in their DG/CHP decision-making.

5.3.4.2 Example: Single Facility Small Industrial Customer

A cold storage company with processing facilities and over 1 million square feet of cold storage capacity faced electricity costs more than double those of its competitors in the early 1990s. Electricity costs comprised one-third of its operating expenses. Seeking a lower rate that would allow it to become more competitive, the company embarked on negotiations with the electric LDC that stretched over three years. With no special rate in sight, the company opened discussions with a municipal utility district (MUD) and the federal agency supplying power in a neighboring state. These discussions resulted in plans to construct a high-voltage transmission line to bypass the LDC and serve both the company's 10 MW load and the larger load of a neighboring industrial plant.

To avoid this loss of load, the LDC obtained the PUC permission needed to offer the two companies a special rate. This rate was set as the market price determined at the nearest interstate transmission border. The arrangement lasted for another three years, but eventually proved unsatisfactory to the company when the LDC altered the way the rate was computed. As the company began to revisit the bypass plans, the electricity crisis of summer 2000 hit. The company, faced with the prospect of being forced to shut down due to sky-high electricity bills, convinced the state government to intercede. Short-term arrangements to run a turbine plant extra hours were made, and the company opted to enter into a series of three one-month hedges that lowered its costs.

As cold weather settled in, the LDC began experiencing difficulties, as it is a winter-peaking utility that purchases electricity on the open market to meet winter peaks. A new special tariff available to industrial customers was quickly created. Under the tariff terms, customers can buy electricity from the open market and third-party suppliers, and then receive transportation services from the LDC at set rates. Key to this discussion, the tariff also encouraged on-site generation by requiring the LDC to buy, at market prices, all excess electricity generated by the customer.

At the same time that the company began utilizing long-term electricity price hedges, it began evaluating DG options. Some months later, it installed 10 MW of engine-driven, natural gas-fueled on-site generation. The nine engines, each slightly over 1 MW of capacity, are able to follow closely the very spiky load of the facility, and operate efficiently at part-load. The company purchases gas on a short-term basis, as it does not know in advance how much it will need on any given day, week or month. The company quickly established the algorithms that determine when and for how long the engines operate, how much internal load is met, and how much electricity is generated for sale to the LDC.

In the example, price volatility, in the sense of both overall price levels and price spike events, were the main drivers of this company's decision to install and operate DG.

5.3.4.3 Example: National Printing Plant Company

A printing company with 26 plants across the U.S., all of which operate on a 7x24 basis, budgets about $80 million per year for energy. Two-thirds of this is for electricity and one-third for natural gas. In many parts of the country, they are able to purchase energy on the open market, employing price risk management tools to minimize exposure. However, in some locations, services remain bundled and utilities "won't even negotiate." In the early 1990s, they installed a 3 MW gas turbine-based CHP system in a California plant, a decision driven primarily by energy cost savings considerations and encouraged with incentives from the gas LDC. This plant has enabled continuing (albeit partial) operation of the plant during the blackouts that have occurred in the state.

Despite the fact that the CHP system sat idle during the natural gas price fly-up of January 2001, the company is considering installation of CHP at the rest of their facilities. The increased volatility tends to cause them to demand more performance from capital-intensive energy investments. Their outlook on natural gas prices is that they will vary with the level of overall demand created by rises and fall in the GDP. They anticipate that further deregulation will improve the energy cost situation, attributing the problems in California to illegal price manipulation by power producers. In their experience, liquidity in the energy markets is improving.

Many ESCOs have approached this company over the years, but the uniqueness of their manufacturing operations tends to diminish the effectiveness of the ESCO model. The few attempts they have made to work with an ESCO have been disappointing. In particular, they have found that ESCOs are not well equipped to work successfully with environmental regulations.

For this company, with its capabilities and expertise in open market commodity purchasing and risk management techniques, price volatility has had little negative or positive impact on the on-site generation decision.

5.3.5 ESCOs

5.3.5.1 Context of Decision Making

The number of ESCOs who install, own and operate DG/CHP projects are limited, and most of these have focused on targeted institutional, industrial and large commercial customers. The following two examples illustrate how these ESCOs are addressing customer needs with DG/CHP and the role of price volatility in their activities.

5.3.5.2 Example: Institutional Customer

In the early 1990s, a county hospital in the Southwest faced electric rates that featured a high demand charge component with a series of steep ratchets. The hospital had drawn up a plan for expansion of its existing facilities and construction of a new psychiatric center, and there were several university buildings on the campus to be served. Lacking the space needed to expand the existing 25-year-old distributed boiler and chiller facilities, the hospital retained an ESCO to develop a central plant concept. The ESCO recommended installation of a CHP plant featuring three natural gas-fueled reciprocating engines, two steam-driven absorption chillers and two natural gas-fueled engine-driven single effect chillers. Exhaust and jacket heat recovered from the reciprocating engines, along with exhaust heat from the engine-driven chillers, generates steam in a heat recovery steam generator. The steam feeds into one large header that distributes the steam to individual air handling units and to heat exchangers for the production of hot or chilled water.

The hospital funded the equipment purchase and the ESCO installed and operated this system for a number of years. Several years ago, the hospital implemented the recommendation of an outside consultant to bring plant operation in-house, as part of a strategy to improve cash flow and profitability. During the gas price spikes of 2001, the plant was left operational, because if the hospital purchased electricity from the grid, the demand charge would ratchet up to a new, much higher level.

For this customer, the main drivers for installation of CHP were high electric demand charges, the need to serve a significantly expanded future load, and significant thermal loads. Due to the structure of the electric demand charges, the CHP plant has remained economic to operate even during gas price fly-ups.

5.3.5.3 Example: Retail Customer

A national ESCO recently entered into an agreement with a national big box retail customer to install, own and operate CHP systems in stores around the country, beginning with stores in the region with the highest electric rates. The customer's objective is to reduce and achieve stability in its energy expenditures. Initially, the ESCO planned to install a natural gas-fueled mini-combined cycle unit in each store that used the waste heat from the primary generator to produce additional electricity in a secondary generator. However, with the technology development schedule lagging, the ESCO has chosen instead to utilize the waste heat from the engine generator in a liquid desiccant system. The desiccant system works with the rooftop heating/cooling units that the customer already uses, drying air before it is cooled. The waste heat from the generator heats the lithium solution that has absorbed moisture from the air, separating the lithium and water molecules and thus regenerating the desiccant solution.

The ESCO, which is doing its own natural gas purchasing to supply the CHP units, feels comfortable and confident with the natural gas market and the mechanisms available for managing price risk, and this adds to their expectation of earning a profit on this contract. The customer in this case has now assured itself of a set amount of power supplied at a rate that guarantees savings over their current situation, and moved some price volatility risk onto the ESCO.

5.3.6 Residential Customers

There has been little chance to analyze the impacts of price volatility on residential customer DG decisions, as there are no products specifically designed for residential use and thus few residential DG installations to date. However, focus group work completed in 2000 sheds some light on how these customers might approach DG decisions. Primen conducted a series of six focus groups with natural gas customers in Chicago, San Diego and Washington, D.C. The participants were affluent, custom single family homeowners, with either a home business or lots of high tech features and appliances in their home. These consumers were considered most likely to be early adopters of new energy technologies. The purpose of the focus groups was to gauge the value of potential fuel cell product attributes in terms of both cost and non-cost factors, and to assess the implications for market introduction.

Participants wanted a proven product that would satisfy what they consider to be a basic need. Volatile energy prices were not a motivator for purchase. Even in San Diego, which was experiencing electricity price spikes at the time of the focus group, the protection that a fuel cell could offer was almost a non-factor for these consumers.[9] Some participants did, however, make reference to shifts in relative fuel prices, and said that if they installed a fuel cell, they would remain connected to the grid and would monitor fuel prices so they could switch back and forth to get the best deal.

Focus group participants as a whole viewed a fuel cell as an exact substitute for electricity purchased from the grid, and did not value the additional point or two of reliability they felt it represented over grid power. Consumers in areas with outage problems found the fuel cell concept attractive as a back-up power source, not a baseload power generator. However, outage costs were not viewed as significant, and power quality fluctuations described as just a nuisance.

5.3.7 Summary and Conclusions

Many of the current and potential investors in DG/CHP that are the subject of this chapter – end-use energy customers and ESCOs – have observed or experienced first-hand fluctuating natural gas and electricity prices. Our discussions with customers, ESCOs, utilities and manufacturers, along with our review and analysis of third-party customer research, suggest the following general and specific conclusions about price volatility impacts on DG/CHP investment decisions.

- <u>Smaller commercial customers: Little impact.</u>
  Smaller customers, those without access to open energy markets or to non-utility suppliers, and those less familiar with energy technologies and markets tend not to separate short-term volatility from changes in overall price levels in their thinking. Many have not yet considered DG/CHP. Price volatility, if considered at all, would be reflected in their expectations about overall price levels in the future. The up-front costs of the equipment, the need for O&M, and internal decision making processes and criteria are likely to discourage investment in DG/CHP without price volatility having ever entered

9 Electricity prices in CA had quadrupled at this point.

the picture.

- Commercial/small industrial customers: May slow down DG/CHP decision or cause them to consider an ESCO partner.
  National account customers and others with more sophistication about energy may understand volatility in the energy markets. They may be purchasing natural gas and/or electricity on the open market or from marketers for a number of locations around the country. Thus, they are managing price risks on the commodity side, through marketers or independent hedging, rather than through investment in certain types of energy equipment. Interest in DG is driven mainly by opportunity cost of outages and quality disturbances and high electricity prices (especially demand charges) relative to natural gas. Internal criteria can preclude DG ownership, especially very short required payback periods and competing, more visible uses for capital. As these customers consider DG/CHP, their desire for more stable prices may be expressed through use of an ESCO to install, own and operate DG/CHP for them. For some, however, expectations about instability are leading to postponement of DG/CHP implementation.

- Industrial customers: May encourage DG/CHP, depending on other factors.
  With significant thermal loads, dual- and alternate-fuel capabilities, and CHP an established technology among this group, CHP is often considered attractive without thought for price volatility. Many such customers have already installed CHP. With the most experience, sophistication and market/technology savvy, these larger industrial customers are much more likely than other sectors to view DG as a physical hedge against volatile electricity prices. They consider it to be one of an array of tools that can work together to minimize energy costs.

  In spite of natural gas price spike events, industrial customers expressed trust and confidence in the stability of natural gas markets, citing the maturity and openness of deregulated natural gas markets and the many tools available for price risk protection. Conversely, they saw less stability on the electric side, as the immature market is filled with loopholes that allow gaming of prices to take place. In addition, these customers are used to natural gas choices and are frustrated about the relative lack of options on the electric side for reducing costs and managing volatility. This serves as a motivator for installing DG/CHP.

- Residential Customers: No impact expected.
  While residential DG/CHP products are not yet on the market, research suggests that price volatility is neither a motivator nor a deterrent in consideration of DG, even in areas where price spike events have occurred. Consumers tend to view DG as virtually an exact substitute for grid power, i.e., as just another way to fulfill the basic need for electricity in the home. This research suggests that price volatility in the electricity and

natural gas markets will not significantly influence residential homeowner decisions about future DG product offerings either positively or negatively.

- ESCOs: May encourage DG/CHP investment.
  Like industrial energy customers, ESCOs appear comfortable with the stability of natural gas markets and the tools available to them to manage natural gas price volatility on behalf of their customers. ESCOs perceive profitable opportunities to provide price stability to industrial and commercial customers by generating electricity and thermal energy with DG/CHP and selling it to them at a price that guarantees savings over their current bills. The presence of volatility appears to be a factor that causes end-use customers to become interested in ESCO services. A few ESCOs also see opportunities for further benefiting customers through installation of thermally activated technologies – absorption cooling and desiccant dehumidification – that use waste heat to help reduce electric cooling loads.

5.4
Economics of DG/CHP Investments

5.4.1 Introduction

The economic costs and benefits of DG/CHP equipment are the primary considerations for potential investors analyzing these types of systems. This section describes the economic and financial aspects of DG and CHP. As mentioned previously, this analysis looks at two types of investors: an end-use customer owner/operator and an ESCO. To assess the attractiveness of a DG or CHP investment, prospective investors perform cash flow and life cycle cost assessments. The resulting estimates of the investment's net present value, simple payback, return on equity, and return on investment are normally used to gauge the soundness of the investment.

5.4.2 Economic Benefits of DG and CHP

5.4.2.1 Energy Cost and Other Savings

A commercial or industrial end-use energy customer who plans to own and operate the DG or CHP investment characterizes the owner/operator scenario. In this case, the economic benefit of the DG system is the savings from avoided electricity purchases and, in the case of CHP, the avoided cost of thermal energy. Peaking and standby units can achieve greater savings by avoiding peaking demand charges and high time-of-use rates, or by receiving payments from an electric system for load reduction during peak demand periods. In CHP systems, the thermal requirement is baseloaded and any extra electricity generated is sold to the grid. Thus, another potential benefit with CHP is the revenue from sales of electricity generated.

In premium power cases, a DG or CHP investment provides the power quality and reliability that an industrial or commercial owner requires. The benefits of installing a DG or CHP technology in the premium market go beyond the usual energy-related cost savings. A company in the premium power market may incur huge financial losses if a power failure occurs, through lost production time, ruined product, and disabled equipment. Thus, in this market, there is a substantial credit, albeit difficult to quantify, placed upon the power quality and power reliability provided by the investment.

Industrial and commercial firms might not want to incur the responsibility of owning and operating DG/CHP equipment when doing so is not a part of their set of core competencies. In these cases, ESCOs may be willing to install, own and operate the equipment, providing the industrial or commercial firm with its energy requirements by selling electricity or both electricity and steam to them. The benefit to the ESCO is the profit from the sale of electricity and steam to the end-use customer as they are procuring fuel at lower rates from suppliers.

5.4.2.2 Electricity Prices

The primary benefit of a DG or CHP investment is the savings from avoided electricity purchases. The amount of savings differs by customer type and by state, since electricity rates differ by customer type and state. Electric power industry restructuring has further compounded the differences. In a regulated environment, electricity prices (wholesale and retail) were based on the utility's embedded costs plus a negotiated rate of return. With the advent of electric industry restructuring, wholesale prices have changed dramatically. Wholesale transactions are now allowed to be structured using market-based rates. At the retail level, a handful of states (Pennsylvania, California, Massachusetts, Oregon and Washington) have opened the market to include alternative providers.

Large commercial and industrial end-use customers tend to enjoy lower electricity rates than other, smaller customers. Because of the size and characteristics of their loads, utilities and other power suppliers offer lower rates. These customers are also offered alternative rate designs, including interruptible service and time-of-use rates.

5.4.3 Costs of DG and CHP

There are three different types of costs that are considered when a potential investor analyzes a DG or CHP equipment investment:

- capital equipment, installation costs, and financing costs;
- fuel costs;
- non-fuel O&M costs.

For a more appropriate accounting of costs, investors apply after-tax analysis. After-tax analysis takes into consideration tax-related items such as capital depreciation and business expense deductions that impact investment cash flows. Including depreciation, for example, tends to reduce the impact of capital cost on investment cash flow, and thus has the effect of reducing the value furnished by lower project capital costs, though this remains one of the most significant technology factors affecting CHP investment economics.

There are other costs that could and do occur when investing in a DG or CHP system. Add-on pollution control equipment is required for certain equipment in certain sites and regions. Utilities typically impose substantial system exit fees, competitive transition charges, and interconnection costs, and apply special back-up and standby power rates. These charges and fees have discouraged, and will continue to discourage, many would-be DG/CHP investors.

5.4.3.1 Natural Gas Prices

Fuel costs can account for as much as 80% of the total cost of generating electricity in a DG system, depending on the technology. Thus, current and future fuel costs are a major consideration in the economic assessment of a DG or CHP investment. However, natural gas end-use prices can differ substantially by customer type, load size and shape, and state. Small commercial customers generally purchase natural gas from a local distribution company (LDC). LDC charges and rates to these customers are subject to regulatory review, and generally reflect the rolled-in average cost of natural gas to the LDC Citygate, plus the LDC distribution (transportation) charge. These customers face gas prices that do not vary with short-term (day-to-day or week-to-week) changes in energy market prices. Nevertheless, more persistent price changes, such as the winter-long increase in natural gas prices that occurred during the 2000-2001 winter, do result in substantial price increases for a period of time.

Most large commercial and industrial customers rely on the LDC only for gas transportation services. They purchase natural gas either at market prices or through a natural gas marketer who provides hedged supply. In both cases, these customers react to market prices. If the customer does not have any hedged supply, the customer will be purchasing at market prices.

5.4.4 Economic Benefits

This section illustrates the economic benefits of a DG or CHP investment. In the first example, we provide an economic analysis from the perspective of an industrial owner/operator investing in a CHP system. The second example presents an economic analysis of an ESCO investment in a CHP system.

To estimate the economic benefits of an investment, a net present value (NPV) analysis based on nominal dollars is performed. For all of the analyses done for this study, we made the following assumptions:

Nominal discount rate	6%
Income Tax – Federal	35%
Income Tax – State	8%
Inflation Rate	3%
Debt/Equity Ratio	80/20
Loan Interest Rate	7%
Term of Loan	15 years

5.4.4.1 End-Use Customer Owner/Operator

In this example, an industrial customer will operate a 5 MW CHP system as a baseload thermal unit. The customer satisfies their thermal requirements first, purchasing any additional electricity needed from the grid, or selling any excess electricity generated back to the grid. The industrial customer is assumed to be operating a gas boiler to meet current thermal energy needs and purchasing electricity from a utility.

Table 5-2 presents the technology cost and performance data for a 5 MW advanced reciprocating engine system (ARES) technology. The life cycle cost analysis uses national electricity and natural gas price projections from the U.S. Energy Information Administration (EIA). The price at which the customer can sell electricity to the grid (buy-back price) is estimated by reducing the average electricity price by 20%. An industrial customer with this type of CHP facility achieves cost savings from electricity and thermal energy produced by the CHP unit.

Table 5-2
Technology Cost and Performance Data
(5MW ARES CHP Unit)

	Capital ($/kW)	Non-Fuel O&M ($/kWh)	Power to Heat Ratio	Electrical Heat Rate (HHV Btu/kWh)
5 MW ARES Industrial Combined Heat and Power Generator	1,268	0.0107	0.91	7,817

Table 5-3 presents the results of the economic analysis of the ARES technology using the EIA energy price forecasts. The results show that the owner/operator's investment will generate a net present value of over $8 million, with a payback of less than five years.

Table 5-3
Economic Assessment Results – Industrial End-Use Customer

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)		
Base Case	6,341,860	8,205,725	5		

5.4.4.2 Energy Services Company

In this example, an ESCO will invest in a 5 MW ARES technology, sell thermal energy and electricity to an existing industrial customer at a 10 percent discount, and sell any extra electricity generated to the grid. The industrial customer is assumed to be operating a gas boiler to meet their current thermal needs, and purchasing electricity from a utility. For the life cycle cost analysis, we use EIA's national electricity and natural gas price projections. The buy-back electricity price is estimated by reducing the average electricity price by 20%. Table 5-2 presents the technology cost and performance data for a 5 MW ARES technology.

In this scenario, the industrial customer's savings will come from the discount that the ESCO's price represents over the prices they currently pay. The ESCO's revenues will come from the steam and electricity sales to the industrial customer and from the sales of the residual electricity to the grid. Table 5-4 presents the ESCO's net present value and payback of the investment. Over a 20-year period, the net present value is $3.8 million dollars. Payback is expected at six years.

Table 5-4
Economic Assessment Results - ESCO

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)		
Base Case	6,341,860	3,800,242	6		

5.4.5 Market Barriers to DG and CHP

Investors in DG and CHP systems must contend with a variety of market barriers, including environmental and siting/zoning regulations, utility resistance, power industry restructuring, and customer concerns. These are discussed below.

5.4.5.1 Electric Industry Restructuring

The restructuring of the U.S. electricity industry has provided the main impetus for interest in DG and CHP technologies. Nevertheless, it has also created some major barriers, including expensive electric utility system exit fees and competitive transition charges (CTCs) that help utilities recover stranded costs. Also, there are still numerous unresolved issues on the handling of DG and CHP systems by the independent systems operator (ISO) and regional transmission organization (RTO), including access, jurisdiction, and technical requirements. Until these are resolved, uncertainties regarding DG systems within the ISO/RTO system will remain.

5.4.5.2 Environmental Regulations

Environmental permitting can be a major barrier for any DG or CHP installation. In some states, small power producers (such as a DG/CHP user) are subject to the same requirements as large power producers (e.g., independent power producers). In this case, meeting the requirements can prove to be an expensive endeavor for the small DG/CHP user. In some cases, the efficiency of cogeneration installations used as a permitting criterion is determined based on combustion efficiency only, rather than overall efficiency, a calculation that disregards the efficiency gained from the thermal energy production and use and disadvantages the installation in the environmental arena.

5.4.5.3 Zoning and Siting Restrictions

Local zoning policies, building codes and standards, and other issues can affect the installation of DG and CHP systems. Communities may impose noise, aesthetics, and land use restrictions that complicate DG and CHP projects. Fire codes and other building code requirements (specifically, fuel storage and supply) may hinder certain DG and CHP technologies from penetrating some markets.

5.4.5.4 Utility Policies

Electric utilities can and do pose major barriers to DG and CHP investments. As mentioned above, they typically charge DG and CHP customers expensive back-up and standby power rates, high interconnection costs, large exit fees and competitive transition charges. A substantial number of DG and CHP projects have not been fully realized because of these costs. Utilities have also performed selective rate discounting to encourage customers intending to install DG or CHP technologies to cancel their projects. Finally, net metering issues may be difficult to resolve, such as valuing the customer's credit for generating its own electricity and the excess electricity sold into the grid.

Apart from high interconnection fees, utilities have imposed other barriers related to interconnection requirements. Some utilities remain reluctant to accept safety and protection devices built into a DG or CHP system, requiring more expensive but unnecessary equipment. Utilities may also require that their own staff test the DG or CHP equipment even when they do not have expertise to do so correctly or to interpret the results appropriately. Frequently, utilities also require that a DG or CHP customer perform ”pre-interconnection” studies. These expensive and time-consuming studies impose additional financial and time burdens on potential investors.

5.4.5.5 Customer Perceptions

End-use customer and ESCO awareness and attitudes about DG/CHP systems vary widely, from almost complete lack of knowledge about the technologies and their capabilities to sophisticated tracking of rates and of new DG/CHP product development. Many customers regard grid-supplied electricity as highly reliable and electricity-fueled equipment as cheaper up front, easier to maintain, and certainly much more familiar than DG/CHP technologies. Operating and maintaining advanced energy equipment does not fall within the bounds of most companies' core competencies, leaving them hesitant and unsure who to trust when it comes to considering DG/CHP systems, and unprepared to run the equipment. Finally, in most sectors, there are competing uses for capital that receive much higher priority, particularly for projects that are visible or otherwise tangible to their own customers.

5.5
Energy Price Volatility in DG and CHP Markets

5.5.1 Introduction

Over the last five years, energy price volatility has become the most significant issue facing the natural gas industry and energy companies. Natural gas, electricity, crude oil and oil product markets have all exhibited price volatility over some portion of the period. Price volatility has contributed to a climate of uncertainty for energy companies and investors and a climate of distrust among consumers, regulators and legislators.

Energy price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new technologies. Such delays may result in lost market opportunities and inefficient long-run resource allocations.

This section focuses on the impact of energy price volatility on the DG and CHP markets. It examines the way an investor might try to address the risks associated with uncertain and volatile prices. Section six will present a quantitative assessment of the impact of volatility on the investor's payback and investment return.

5.5.2 Sources of Volatility

In an "efficient" market, prices adjust to correct imbalances of supply and demand. The magnitude of the change in prices is determined by the size of the imbalance and the ability of producers and consumers to respond to relieve the imbalance. This is true in both the short-term and the long-term.

- In the short-term, weather affects to a large degree the demand for natural gas and electricity. Because weather conditions can change rapidly and unexpectedly, large and sudden shifts in "service demand" can occur that create imbalances that must be relieved.
- In the longer-term, prices signal the need to develop new resources, and provide the incentive necessary in a free market to prompt investment in new resources.

Demand price response differs depending on energy price levels relative to other energy sources. Natural gas demand is much more price elastic when gas prices are competitive with residual fuel oil and/or distillate fuel oil. When gas prices exceed the point at which available dual-fired capacity has switched from natural gas to oil, price elasticity drops, and it takes a significant increase in price to affect a small reduction in demand. When gas prices are below the point at which most dual-fired capacity has switched from oil to natural gas, a large decrease in price would be necessary to stimulate additional demand.

Recent years have also produced periods of highly volatile electricity prices. These events were usually caused by unusual weather patterns and limited generating capacity. Furthermore, electricity suppliers rely more heavily on natural gas, especially to supply marginal generators. Thus, during periods of high electricity demand, more and more units demand more natural gas, producing price spikes for both electricity and natural gas. Thus, a DG or CHP user or investor will have to contend with both electricity and natural gas price volatility.

5.5.3 Risks and Hedging Mechanisms

There are a variety of ways to hedge or reduce the risks associated with volatile prices. An investment in a dual-fuel system instead of a single-fuel system can minimize the impact of unpredictable prices. Combustion turbines and microturbines can operate on natural gas or alternate liquid fuels, such as diesel, so during periods of high natural gas prices, the turbines can operate with the alternative fuel. However, environmental and other equipment performance characteristics under alternate fuel operation can be worse, restricting the amount of time that the equipment can run this way. Boilers supplying steam turbines can be configured to operate on several alternative fuels, with a wide spectrum of fuels possible. Reciprocating engines must be dedicated to a single fuel, so do not provide the dual-fuel system switching advantage. While fuel cells can operate on reformed natural gas, methanol, landfill gas, and other sources of hydrogen, a different reformer is required to process different fuels. For larger DG or CHP investors, investments on various systems with different fuel sources can also minimize fuel price risks.

Another way to hedge risk is to engage in the various financial instruments offered by the market. These include futures contracts, price swaps, options, and forward contracts, all with attendant advantages and disadvantages. Using such instruments requires market intelligence and expertise. For a small DG or CHP investor or for an owner/operator firm whose core competencies do not encompass this type of intelligence or expertise, the need to engage with these financial instruments could easily discourage investment. An ESCO, on the other hand, if it is already in the business of commodity acquisition, would have this type of expertise as part of its core competencies, and thus is expected to engage in these financial instruments.

In the case of a small DG or CHP investor or a firm that does not have core competency in futures instruments, the investor can either secure long-term gas and electricity contracts or a contract with an ESCO to operate its energy system, as described in Chapter 4. This will insulate their operations from the volatile movements of gas and energy prices.

Finally, a DG or CHP plant may itself represent a physical hedge against volatile electricity prices, especially when operated as part of a portfolio of energy management strategies, as illustrated in Chapter 4.

5.5.4 Impacts of Energy Price Volatility

Two of the fastest growing markets for natural gas are DG and CHP. As discussed, potential investors in these markets encounter numerous barriers, including interconnection requirements, environmental permitting, zoning and siting restrictions, expensive back-up/standby power rates, high interconnection costs, exit fees and transition charges. Highly volatile energy prices further complicate the situation. As natural gas and electricity price volatility are interrelated, DG and CHP investors must contend with a variety of volatility scenarios. The volatility that the energy market has exhibited in the recent past and may be expected to show in the future could be perceived as increased project risk, rendering financing for DG and CHP projects more difficult to obtain.

Because natural gas costs account for the largest portion of the total cost of generating electricity with a DG system, natural gas price volatility can unduly affect the viability of running a DG or CHP system. While gas price volatility alone does not immediately imply critical risk, when a volatile input price (e.g., natural gas price) is combined with a stable or fixed output price (e.g., electricity price), a firm can face serious uncertainty in its financial operations. In another instance, power generators can wind up in a riskier position if they sell in a market that is competitive and dominated by generation from another fuel source. If their fuel costs increase more than the fuel costs of other types of generation, then it is likely that electricity price (in the spot market) will not completely cover their increased fuel prices, resulting in financial losses.

The primary alternative to DG is the centrally-generated electricity. Thus, the effects of gas and electricity price volatility on a DG user relative to its effects on a central utility are an important consideration when assessing the value of a DG project. In general, the central utility can generate electricity at a higher fuel efficiency rate than a power-only DG user. This means that the central utility experiences lower fuel costs per unit of electricity generated. Also, a central utility has a portfolio of generators (fueled by coal, uranium, residual fuel oil, or renewable energy), and thus may have the option of switching to other fuel generators when gas prices become too high. Thus, relatively, the central utility will be less impacted by volatile natural gas prices than a DG user.

Customers with large thermal loads that have traditionally used CHP systems, such as the paper, petroleum refining, and chemicals industries, and institutional customers such as hospitals and universities, will continue to install and operate CHP equipment, despite volatile gas prices. The savings from cogeneration are substantial enough to warrant the risk posed by volatile prices, which these customers manage by procuring long-term contracts or establishing power-marketing subsidiaries to hedge their risks. Industries that rely in part or whole on byproduct fuels such as wood waste have correspondingly less concern about natural gas prices.

Commercial and industrial firms requiring premium power (including data centers, financial institutions, computer and electronic manufacturers) will continue to consider DG or CHP systems, as financial losses could be substantial in the event of power quality events such as voltage reductions, and reliability events such as outages. These investors will hedge their risk with long-term contracts, or may be able to incorporate all or a portion of the energy price changes into their product prices.

5.6
Quantitative Analysis

5.6.1 Introduction

This section presents the results of a quantitative analysis examining the impact of energy price volatility on DG and CHP investments. Based on the cash flow analysis for an owner/operator scenario and an ESCO scenario discussed in Section 5.4, we ran several risk scenarios incorporating volatility in natural gas prices, electricity prices and in electricity and gas prices simultaneously.

5.6.2 Methodology

To assess the impact of electricity price and gas price volatility on DG and CHP investments, we incorporated a log-normal distribution on the prices into the DG and CHP 20-year life-cycle cash flow analysis underlying the tables in Section 5.4. We assigned the mean of the distribution to the EIA national level energy price projections, and used a percentage of the mean as a standard deviation. In this case, energy price varies along the mean, and the variation increases over the projected period. This approach reflects the expectation of more uncertainty and risk as the analysis ventures farther into the future.

The scenarios we ran to assess the impact of price volatility on DG/CHP project economics all assumed the installation of a 5 MW ARES on-site generation project. The investor perspectives were: 1) commercial sector owner/operator of baseload power-only DG; 2) industrial sector owner/operator of CHP supplying thermal load; and 3) ESCO with a CHP system sized to meet the thermal load of an industrial customer.

- To assess the impact of gas price volatility alone, we used a lognormal distribution on gas prices with two different standard deviations, one equal to 15 percent and another equal to 25 percent of the mean gas price. The higher percentage reflects a more volatile scenario. Figure 5-2 shows the range of commercial sector natural gas prices under the 15 percent standard deviation scenario.
- To assess the impact of electricity price volatility alone, we used a lognormal distribution on electricity prices with two different standard deviations, one equal to 15 percent and another equal to 25 percent of the mean electricity price. Figure 5-3 shows the range of commercial sector electricity prices under the 15 percent standard deviation scenario.
- To assess the impact of the combined volatility of gas and electricity prices, we used lognormal distributions on gas and electricity prices with standard deviations equal to

15 percent and 25 percent of the mean electricity and mean gas prices. We also assumed that gas and electricity prices are independent of each other.

Figure 5-2
Gas Price Volatility: S.D. = 15% of Mean Price

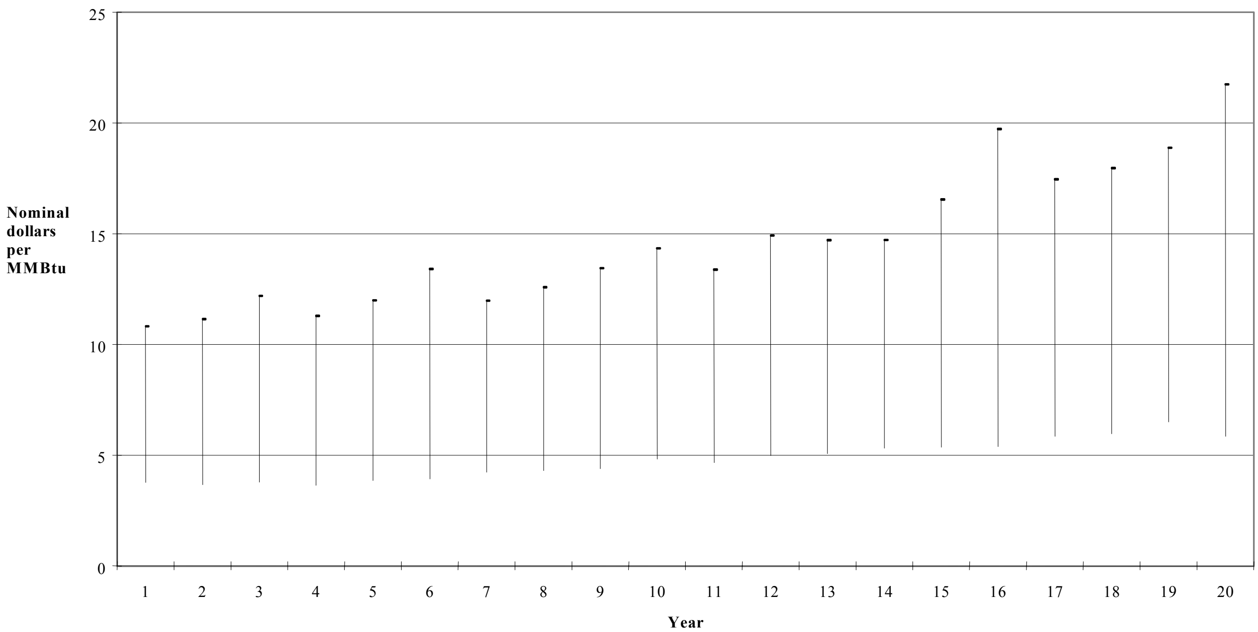
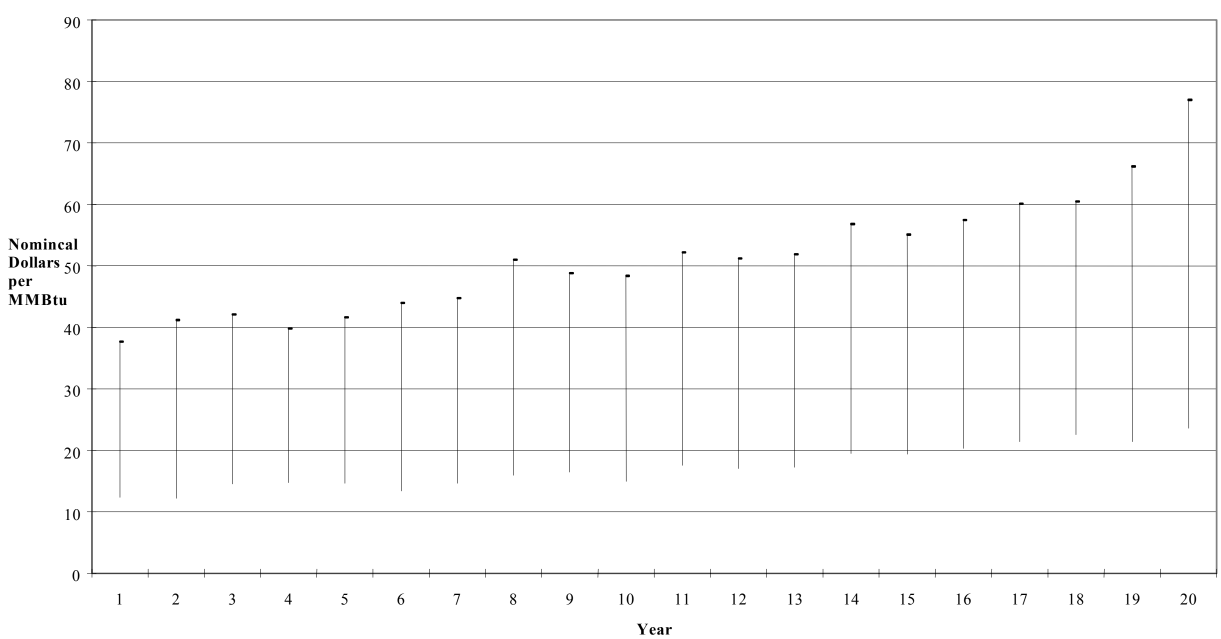


Figure 5-3
Electricity Price Volatility: S.D. = 15% of Mean Price



These analytical results do not provide any insight into the psychological impact of price volatility on investment decisions.

5.6.3 Results

The focus of our analysis was to examine the impact of volatile prices on net present value (NPV). Specifically, in each scenario, we calculated the probability of the investment resulting in a negative NPV for the investor.

5.6.3.1 Owner/Operator, Commercial Sector DG

In this scenario, a commercial firm plans to install a 5 MW ARES technology to provide all of its electricity needs. Table 5-5 below presents the economic assessment results representing a base case of non-volatile natural gas and electricity price projections. This base case offers a seven-year payback to the commercial sector energy user, with an NPV of $3.4 million.

Table 5-5
Economic Assessment Results
DG Commercial Sector, Baseload Power Only

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)
Base Case	5,400,000	3,443,082	7

Figure 5-4 shows the distribution curves of the NPV of a DG investment when gas prices are volatile throughout the projection period at the two different standard deviation scenarios. The chart shows that the probability of a negative NPV is higher with higher volatility. It is critical to note, however, that the probability of a negative NPV is still quite low (0.1 percent for the 25 percent standard deviation case), and that the probability is in fact zero for the 15 percent standard deviation case.

Figure 5-5 shows the distribution curves of the NPV of a DG investment when electricity prices are volatile throughout the projection period at the two different standard deviation scenarios. Similar to the gas price results, the probability of a negative NPV is low (0.8 percent for the 25 percent standard deviation case), and it increases as volatility increases. More interestingly, the results also show that the probability of a negative NPV is higher with electricity price volatility than with gas price volatility. This is perhaps not surprising since electricity prices are high relative to gas prices, with most of the benefits of the investment flowing from electricity savings.

Figure 5-4
Distribution of DG NPV: Gas Price Volatility Scenario

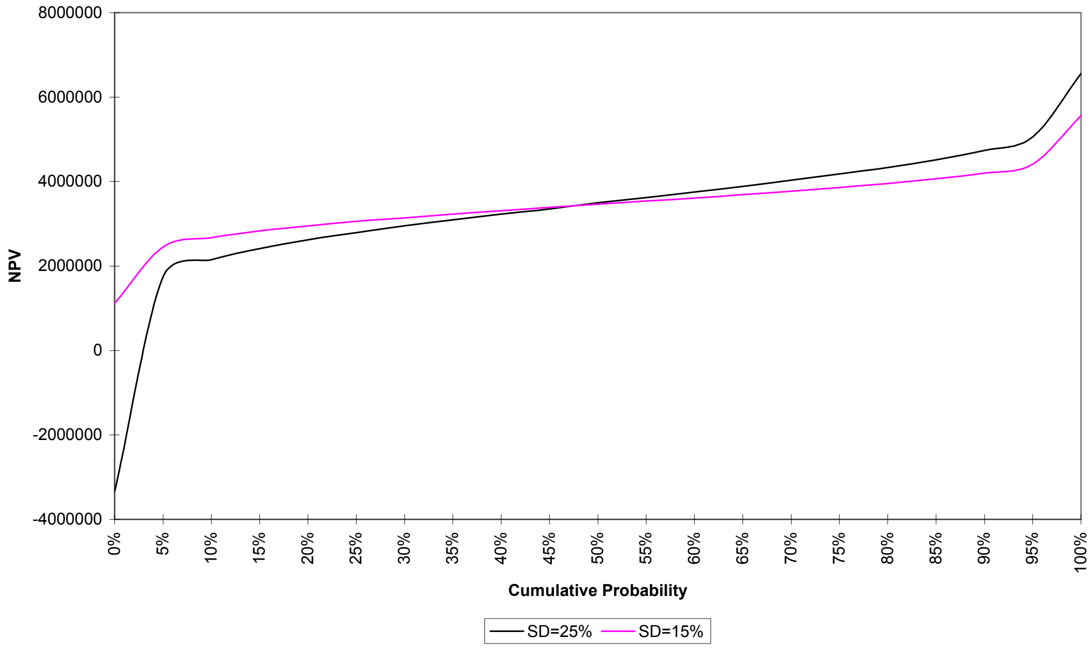


Figure 5-5
Distribution of DG NPV: Electricity Price Volatility Scenario

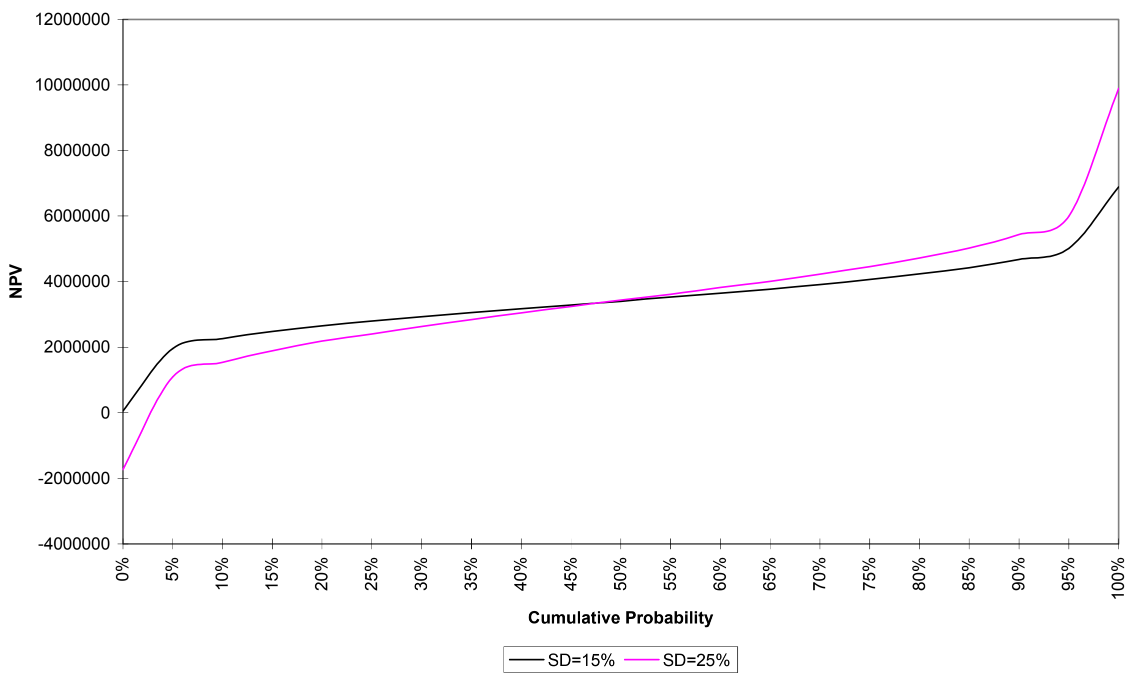
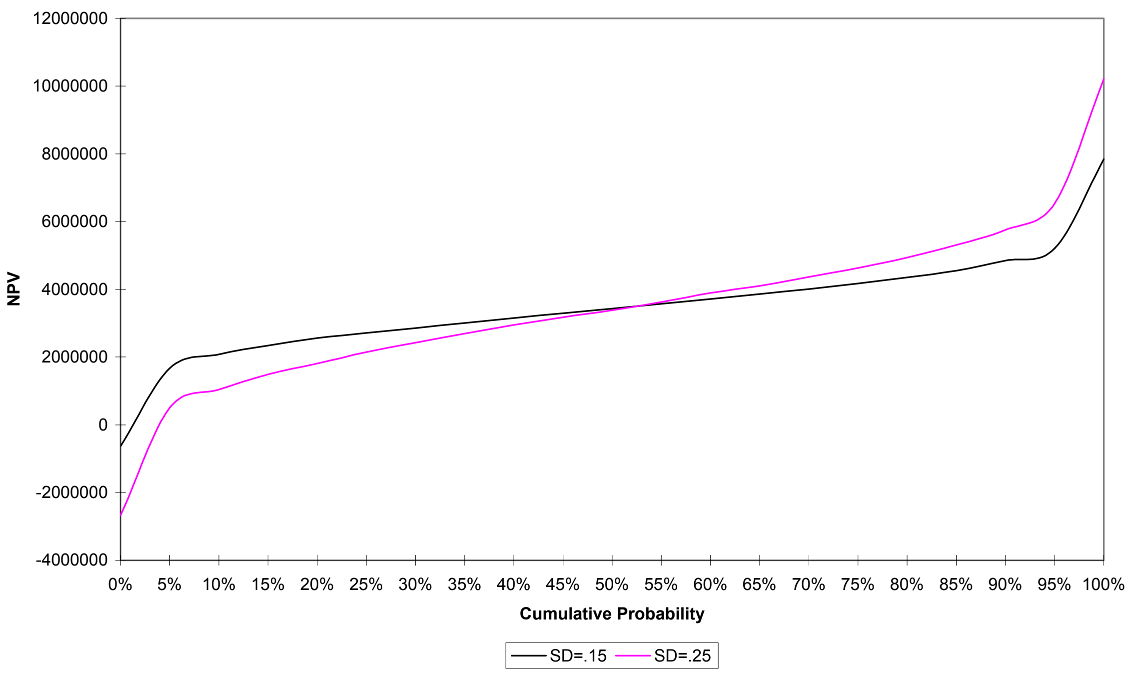


Figure 5-6 shows the distribution curves of the NPV of a DG investment when both gas and electricity prices are volatile throughout the projection period at the two different standard deviation scenarios. As expected, the results show that the probability of a negative NPV is higher as price volatility increases. The probability of a negative NPV is now higher than in the gas only and electricity only cases, with the probability reaching two percent in the 25 percent standard deviation case.

With these low probabilities of achieving a negative NPV, one would expect that a commercial sector end-use customer would not be too concerned about energy price volatility when evaluating a DG/CHP project. Furthermore, the DG owner/operator can always exercise their option of hedging the DG fuel price risk by engaging in long-term price contracts.

Figure 5-6
Distribution of DG NPV: Electricity and Gas Price Volatility Scenario



5.6.3.2 Owner/Operator, Industrial Sector CHP

In this scenario, an industrial firm plans to install a 5 MW CHP plant using an ARES technology with heat recovery to meet all of its thermal energy needs, retiring the existing gas boiler that is currently supplying the thermal loads. The firm will sell any residual electricity generated to the grid at a buy-back price of 80 percent of the end-use price. Table 5-6 presents the results of the cash flow analysis under a base case scenario of non-volatile gas and electricity price projections.

Table 5-6
Economic Assessment Results
Industrial Sector CHP

	Initial Investment ($)	Net Present Value ($)	Simple Payback (# of yrs)
Base Case	6,341,860	8,205,725	5

Similar to the power-only commercial sector DG scenario, we analyzed scenarios incorporating volatility into gas prices only, into electricity prices only, and into both gas and electricity prices.

In all the scenarios analyzed for this type of investment, the probability of the investor obtaining a negative NPV is zero. That is, none of the price volatility scenarios with standard deviations of 15 percent or 25 percent of the mean price produces a negative NPV. With these results, it is expected that CHP investors will not be overly concerned with volatile prices, although the investment returns might fluctuate with price spikes or even be lower than projected.

The analysis show that a CHP investment is less sensitive to price volatility than a power-only DG investment. This is true in this analysis for the same reason that central utility power plants are less sensitive than DG systems: higher efficiency.

5.6.3.3 ESCO with Industrial CHP Customer

In this scenario, an ESCO plans to install a 5 MW CHP plant using an ARES technology with heat recovery at an industrial customer's facility, sized to meet the customer's thermal load. The ESCO will sell the thermal energy (steam) and electricity generated to the customer at a ten percent discount off the customer's current thermal and electricity costs. The ESCO will sell any residual electricity generated to the grid at a buy-back price of 80 percent of the end-use price. Table 5-7 presents the results of the cash flow analysis under a base case non-volatile gas and electricity price projections.

Table 5-7
Economic Assessment Results
ESCO with Industrial CHP Customer, Base Case

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)
Base Case	6,341,860	3,800,242	6

Similar to the results of the industrial sector CHP owner/operator case, none of the scenarios generated a positive probability of a negative NPV. That is, none of the price volatility scenarios with standard deviations of 15 percent and 25 percent of the mean price produces a negative NPV. These results suggest that ESCOs investing in CHP to serve industrial customers are unlikely be concerned with energy price volatility. And, like many larger end-use customers, they can engage in hedging the CHP plant fuel price risk by engaging in long-term price contracts or employing other risk management tools.

5.6.4 Summary and Conclusions

The quantitative analysis performed for this study incorporated a lognormal distribution on a set of gas and electricity price forecasts underlying life-cycle cash flow analyses in a variety of DG/CHP investment scenarios. We analyzed several risk scenarios representing both owner/operator (end-use energy customer) and ESCO investors, featuring volatility in gas prices only, electricity prices only, and both gas and electricity prices simultaneously. The analysis yielded the following results:

- While higher energy price volatility leads to higher probability of a negative NPV, the probability of achieving a negative NPV is very small in all of the scenarios examined.
- Future gas price and electricity price volatility do not significantly impact the NPV of a CHP or DG investment.
- Electricity price volatility has a relatively larger impact on an investment's NPV than gas price volatility.
- A CHP installation reflects a more stable investment, as it is less affected by energy price volatility than a power-only DG investment.

5.7
Summary and Conclusions

In this volume, we have characterized DG/CHP systems, described the end-use customers and ESCOs who are the current and potential owners and operators of such systems, summarized their perceptions and experiences, addressed volatility and its general effects in DG/CHP markets, and analyzed the economics of DG and CHP projects under a variety of energy price volatility scenarios. Both the quantitative analysis and the intelligence gathered from interviews with end-use customers, ESCOs, utilities and manufacturers suggest the following conclusions about the impact of energy price volatility on the emerging DG/CHP market.

Industrial Sector DG/CHP. The economics of on-site generation, and CHP in particular, is barely impacted by volatility on either the natural gas or electricity side. The fact that the overwhelming majority of installed CHP is in the industrial sector reflects the positive economics of being able to serve large thermal loads with heat recovered from on-site generation that serves the entire facility's electrical load, often with excess to sell to the grid. Potential impacts of volatility are dampened in this sector through use of dual-fuel CHP technologies and sophisticated commodity purchasing practices with use of price risk management tools. Investors in this sector tend to view DG/CHP as one in a set of energy management strategies that work together to address energy price challenges and minimize costs. They place higher confidence in the functioning of the relatively mature natural gas marketplace than in the immature electricity marketplace, and generally anticipate that further deregulation on the electric side will decrease the opportunity for participants to game the system and upset prices.

Commercial Sector DG/CHP. With fewer opportunities for CHP, less ability to engage in commodity purchasing and price risk management, and less experience with and awareness of DG/CHP technologies, the fact that volatility does not significantly impact the NPV of commercial sector DG/CHP investments is less meaningful. Uncertainty surrounding DG/CHP investments tends to be complicated by uncertainty about future levels and relationships of natural gas and electricity prices. Competing uses for capital, typically in high-visibility projects, push energy project investments down the priority queue, and harsh financial criteria such as one-year paybacks constrict opportunities. Drivers of interest in on-site generation include the high cost of power outages and the need for high-quality, reliable power. Taking these factors together, some commercial sector customers with interest in DG/CHP are looking for ESCOs to install, own and operate on-site generation for them, selling electricity and perhaps thermal energy to them at a discount relative to the prices they currently pay. This arrangement transfers price risk to the ESCO and allows customers to focus on their core business and on achieving additional energy savings through less capital-intensive projects. For other customers, however, the need for a more stable price environment is leading to postponement of serious consideration of DG/CHP.

Residential Sector DG/CHP. With no products commercially available to residential customers yet, the impacts of price volatility on future DG/CHP investment decisions may only be surmised from research posing "what if" scenarios to potential customers. Focus group results indicate that because residential consumers view obtaining electricity as satisfying a basic household need, they tend to view DG as an equal substitute for grid electricity, even in areas affected by outages and price spikes. Outages, interruptions and power quality disturbances are perceived as merely annoying, not drivers for considering baseload DG. There appears to be some interest in DG as back-up power. With the degree of protection from volatile market prices afforded by regulated rates, especially on the electric side, it is not surprising that volatility is not a consideration in hypothetical residential DG purchase decisions.

ESCOs and DG/CHP. ESCOs active in DG/CHP plant ownership and operation possess the sophistication in commodity purchasing and risk management and knowledge of technologies that allow them to perceive opportunities for profit in developing DG/CHP projects to serve the thermal and electrical loads of commercial and industrial customers. The desire for price stability on the part of end-use customers, combined with an interest in DG/CHP, makes an ESCO arrangement potentially attractive. ESCOs, like industrial customers, tend to perceive the natural gas market as relatively mature and stable, with many more tools available to manage price risk. Thus, the lack of sensitivity of ESCO investments in DG/CHP projects reflects the current approach of ESCOs who have the skills and ability necessary to engage in DG/CHP projects to serve end-use customers.

The above conclusions above suggest that the impact of price volatility on the emergence of DG/CHP is neutral to slightly positive on the market as a whole.