The Boston Consulting Group

Keeping the Lights On

Navigating Choices in European Power Generation

BCG | REPORT

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Foreword

When deregulation of the gas and power markets in continental Europe began in 1998, all key players had new ambitions. Incumbents in the power industry, whose priority had been to ensure that there were reliable supplies, shifted their focus to retaining and expanding their customer bases. Regulators and governments aspired to create more competition. And intensive energy users hoped that greater competition would allow them to obtain lower prices.

Now, five years later, markets are consolidating, several countries are moving ahead with plans to decommission nuclear plants, and price hikes in wholesale markets indicate that power supplies are growing tighter. As a result, production is back in the spotlight. Given the lead times necessary to build new generating capacity, we believe it is urgent for every player to assess how the changing market might affect it and make choices to keep the lights on in Europe.

Through its client work and proprietary research, the Energy practice of The Boston Consulting Group (BCG) has developed deep insights into these issues that are contained in this report. We would like to thank the many clients and other industry participants who shared their views with us.

We also appreciate the contributions of numerous members of BCG's staff, who offered insights on a wide range of topics, including local energy markets, power generation technologies and economics, upstream and downstream gas, intensive energy users' perspectives, CO_2 emissions, and European Union and national regulations. Colleagues who deserve special recognition are Ramón Baeza, Marc Benayoun, Janko Binnewies, Lidwien Bulckaert, François Candelon, Fabio Cantatore, Pascal Cotte, Jaap de Jong, David Dodd, Giuseppe Falco, Sergio Figuerola, Christian Hoffmann, Mathias Krahl, Riccardo Monti, David Nelson, Rick Peters, and Harald Rubner.

I would also like to thank the authors for the enormous time and expertise they invested in the project. Finally, the authors and I want to acknowledge the major analytical and editorial contributions of the project team: Steven Prokesch and Nancy Macmillan (Boston), and Elke Segers and Christophe Maquestiaux (Brussels).

We hope you will find this publication stimulating, and we welcome your questions and comments.

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Executive Summary

The European market for electricity is in flux. Deregulation, growing demand, and changes in the mix of power generation technologies will create a more dynamic market and an abundance of opportunities. But Europe must also decide how or whether to achieve conflicting goals, including more competition, greater customer choice, cheap and stable prices, reductions in emissions of greenhouse gases, capped or reduced nuclear-generated power, energy independence, and reliable supplies of power. Although these goals are interrelated, many are being addressed separately, which risks being counterproductive.

Everyone—power generators, governments, and regulators, as well as gas players, energy retailers, intensive users of energy, and power plant manufacturers—needs a holistic framework to navigate these issues, assess opportunities, and make choices. With this in mind, The Boston Consulting Group conducted a study of the European market. The study is part of the firm's continuing efforts to help companies, regulators, and governments understand tradeoffs, build scenarios, make choices, and prepare strategies. This research project integrated the factors that are shaping the evolution of the market and considered what possible scenarios would mean for prices, capacity, power generation technologies, gas supplies, and the impact of the Kyoto Protocol on global warming.

The major findings include the following:

Europe is in danger of experiencing a boom-and-bust cycle that will make it difficult to smoothly meet the region's need for at least 65 gigawatts (GW) of new capacity by 2012. Periods of underinvestment and rising prices and profitability (the boom) would be followed by periods of overinvestment and falling prices (the bust). Even though this cycle could create opportunities for some companies, it would damage customers, investors, and society at large.

Such boom-and-bust cycles are common in commodity markets. But as the brownouts and price spikes that hit California and the midwestern and the northeastern regions of the United States have demonstrated, the damage from the boom part of the cycle in electricity can be much more severe than that from booms in other markets.

A boom-and-bust cycle could be avoided, but designing and implementing solutions would be complex and time-consuming. At this point, the best bet is that Europe tries to muddle through: the region does not act in a unified fashion, and individual countries pursue initiatives on their own or, in some cases, with their neighbors. This outlook is not necessarily a bleak one for all power generators, gas players, and large energy consumers. It would present them with an array of opportunities that would surface in individual local markets at different times.

Europe will need to import significant amounts of gas to fuel new generating capacity, but this will require major investments in risky field development and transportation infrastructure. Attracting the investment will be problematic.

Combined-cycle gas turbines (CCGTs) almost certainly will account for the vast majority of the generating capacity Europe builds in the next decade. When the economics and the greenhouse-gas emissions of technologies are compared, CCGT scores best overall.

But the new CCGTs will require annual gas imports to grow from 230 billion cubic meters (BCM) today to between 465 BCM (without Kyoto) and as much as 565 BCM (with Kyoto). There is plenty of gas potentially available, but most of it costs more than existing sources and is located in technically challenging and politically risky places such as Russia, the Middle East, and North Africa.

Overall, an investment of €95 billion to €110 billion in upstream field development, pipelines, and infrastructure for regasifying liquefied natural gas (LNG) would be required by 2012. There are no current commitments to provide a substantial portion of this amount, and raising it will be challenging because of all the unknowns hanging over the energy market. They include the impact of deregulation in gas, the extent to which Kyoto will be implemented, the fate of nuclear power, and the impact that a boom-and-bust cycle would have on both the volatility of energy prices and the health of power generators.

Especially if Kyoto is implemented, the amount of generation powered by renewable energy should grow considerably, thanks to a continuous flow of subsidies. Wind power is the leading contender but has significant drawbacks.

BCG expects the amount of generating capacity powered by renewable energy to increase by 70 gigawatts (GW) if Kyoto is implemented.

The role of wind-powered electricity has grown and appears likely to become even larger for several reasons: most viable sites for hydropower have already been developed, wind power's cost position is improving, and governments are subsidizing this energy source. But the costs are still high and a power market cannot count on its being fully available: significant conventional capacity would be needed to back up wind-generated power, adding to its cost.

If Europe remains committed to implementing Kyoto, it may have to rethink its aversion to nuclear power. There are long-term considerations that argue for keeping the nuclear option open.

With strict adherence to Kyoto, Europe may eventually reach a point—around 2020—at which nuclear power becomes necessary to avoid increasing CO_2 emissions. Moreover, nuclear power may become competitive with CCGTs by then. Finally, growing dependence on imported gas may lead Europeans to reconsider nuclear power.

The minimum direct cost to Europe of implementing the Kyoto targets in the power industry alone would be about €20 billion per year, which would amount to 0.2 percent of the European Union's gross domestic product, or about €50 per person. More important, there would be significant winners and losers among stakeholders. The big question is how governments and regulators decide to allocate—or reallocate—the burden.

To comply with Kyoto, it is highly likely that governments would require power generators to be responsible for 25 to 50 percent of the reductions in CO_2 emissions that Europe would have to make. That burden would result in a direct cost of at least €20 billion per year—mainly to build power plants and supply gas that would not otherwise be needed.

Even more important, Kyoto would cause tens of billions of euros to change hands every year. If governments did not intervene, the losers would be energy consumers and owners of coal-fired and old oil- and gas-fired plants. The winners would be gas players; existing nuclear, wind, hydro, and CCGT plants; states (from carbon-tax receipts); and manufacturers of power plants. But governments might redistribute the gains to reduce the burden on some of the potential losers.

Although uncertainty hangs over the European energy market, stakeholders should take concrete steps to shape its development and be prepared to seize opportunities and minimize risks.

Uncertainty is not a reason for inaction: all stakeholders can acquire a thorough understanding of how the market may develop—at both the European and local levels. The evolution of power generation technologies and their economics, the current and potential mix of generating capacity, Kyoto policy, and competitors' behavior will drive the balance of supply and demand, as well as the choice of new investments, retirements, and prices. All stakeholders need to understand these fundamentals. This will help them avoid the overinvestment and wealth destruction that occurred in the United States and the United Kingdom. It will help them identify the optimal times and places to acquire, build, or contract for power generation. Volatility creates opportunities for those that are prepared.

In addition, there are a multitude of specific implications and choices that apply to individual categories of stakeholders. These are discussed in the section "Implications and Challenges for Stakeholders," page 27.

Introduction

Over the next decade, a sea change in the European electricity market will offer companies, governments, and regulators major opportunities. During this period, Europe will move from significant overcapacity to a significant need for new capacity. It will determine how to implement the Kyoto Protocol on global warming. Its mix of power generation technologies will change considerably. And it will revisit the competitive rules and structure of its market and take steps that could have a big impact on the size, shape, and position of players. This time of great flux will present stakeholders with important choices.

Making the most of the opportunities, however, will be anything but straightforward. It will require navigating in an uncertain environment and making high-stakes decisions with imperfect information about others' plans.

Inaction is not an option. A deadline is looming. According to The Boston Consulting Group's analysis, beyond the 15 gigawatts (GW) of new generating capacity already under construction, Europe will need at least 65 GW of new capacity by 2012—and perhaps as much as 165 GW if Kyoto is fully implemented. In addition, vast new supplies of imported gas will have to be developed, and infrastructure to bring it to market will have to be built.

To succeed will require a deep understanding of the interrelated factors that will influence how the landscape evolves. Developing such an understanding will be challenging, given that the optimal mix of technologies is changing, investments will be required at different times in different places, and implementation of the Kyoto Protocol may force more radical shifts. Furthermore, Europe's regulatory and policy environment is in flux, and individual countries and the European Union harbor many conflicting ambitions and aspirations. They include the following:

- A competitive marketplace, where many players—not just a handful of giants—battle each other in power generation, gas wholesaling, and energy retailing

- Cheap and stable prices, which both improve the competitiveness of major industries and increase the disposable income of residents

- Greater choice, improved service, and, as a result, better-satisfied customers

- Reductions in emissions of greenhouse gases

- No increase—or even reductions—in nuclear-generated power

- Energy independence, which limits Europe's exposure to politically unstable regions that supply oil and gas

- Reliable supplies

The reality is that achieving all of these goals is not possible. Decisions on tradeoffs will have to be made. For example, allowing a regulated oligopoly to dominate the market might be one way to ensure reliable supplies and stable prices, but it would obviously mean limited customer choice. Similarly, drastically reducing emissions of greenhouse gases would require major increases in clean, gas-powered generation. But such increases would require importing much greater amounts of gas and boosting Europe's dependence on Russia, the Middle East, and North Africa. Such imports would also lead to higher prices.

Goals of the Study

As part of its effort to help companies and regulators navigate the tradeoffs, shape the development of the market, and develop strategies, BCG undertook a major study of the European electricity and gas markets. The study builds on BCG's extensive work with power generators, gas players, energy retailers, intensive energy users, power plant manufacturers, and regulators in Europe and other regions.

Players can make effective choices amid all the uncertainty if they have an appropriate framework, build scenarios, and develop potential strategies for each scenario. Providing that framework and building those scenarios were the purposes of this study, which explored how various economic and competitive forces and policies would interact to shape the landscape and affect key stakeholders.

This research will reinforce BCG's efforts to

- help companies make optimal investment decisions; improve, or at least protect, their competitive positions and financial health; and argue for rational approaches to major policy issues such as the regulation of competition and how to implement Kyoto
- assist governments and regulators in making tradeoffs and establishing policies and regulations in a timely fashion

Scope of the Study

BCG has built holistic scenarios of how the power generation market will evolve and explored the following interconnected issues:

Prices. What is the likely evolution of energy prices with and without pursuit of the targets set to comply with the Kyoto agreement?

Capacity. How much new capacity will be needed by 2012? Will investors be attracted to build the right amount and mix of new capacity? Will it earn attractive returns?

Technologies. Given the advantages and disadvantages of the different generating technologies and how their economics might evolve, what will the likely mix of technologies be?

Gas Supplies. Will enough gas be available and at what price? Will enough investment be made in gas transportation infrastructure to deliver the gas to generators?

Kyoto. To what extent will the Kyoto requirements affect the power market and its different stakeholders? What will the burden on Europe be? Which stakeholders are likely to be winners and which might lose?

Long-Term Outlook. What are the challenges beyond 2012?

Implications. How can different stakeholders prepare for the future? What actions should they take now to develop the European power landscape? What positions and capabilities should they build?

To answer these questions, BCG studied the main trends for electricity and gas in Western Europe through 2012, and considered their high-level implications for the long term (through 2020).[1]

The reason for evaluating the trends at the European level is that the markets within Europe are converging. Local markets, which are defined by existing constraints in transmitting electricity from one location to another, currently have different mixes of generating technologies, different market structures, and different degrees of overcapacity—partly because of historical differences in local regulation, ownership, and government policy. By 2012, however, many of these differences will shrink as investments flow to markets with the least overcapacity and as regulations, policies, and other incentives encourage the selection of similar technologies, interconnections among markets, and the rise of pan-European energy players. The result: even though most local transmission constraints will remain in 2012, overall European trends are likely to apply to each local market, although the timing and specifics will vary for each.

In addition to BCG's knowledge of European power markets, our study incorporated the firm's experience in overseas markets such as regions of the United States and Australia. The study also took into account the following: the state of existing generating capacity; the economics of different technologies and how they might change over time; supply curves, power demand, and consequent prices; future demand for gas and the costs of supplying it; and the potential ways the targets derived from Kyoto could be achieved. (See the insert "Modeling Power Generation Markets" in the methodology section, page 36, for further details.)

1. Sixteen interconnected countries were considered: Austria, Belgium, Denmark, Finland, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.

A Boom-and-Bust Cycle Looms

Unless stakeholders adroitly address the complex set of challenges facing Europe, booms and busts in electricity are highly likely. Boom-and-bust cycles are a common feature of commodity industries with stable technologies. They are characterized by periods of underinvestment and rising prices and profitability (the boom), followed by overinvestment and falling prices (the bust). Customers, investors, and society at large can be affected significantly by these cycles.

The Pattern in Commodity Industries

Boom-and-bust cycles typically play out in the following fashion:

There are several competitors, all with similar technology and high fixed costs. New plants are generally large and expensive and take several years to build. The consumer is usually indifferent to who its supplier is.

During industry downturns (an initial bust, usually due to a slump in demand), profitability falls as all competitors cut prices to retain market share and cover as much of their fixed costs as possible. Investors are wary of adding capacity; as a result, when demand does pick up, there is a capacity shortage. Before new investment can come online, the shortage results in price spikes (a boom).

The higher prices encourage further investment. But several competitors overinvest, for a number of reasons. They want to avoid losing market share (and the associated benefits of scale). Because of the lack of a liquid futures market or long-term contracts, long-term price signals are inadequate to warn investors of impending overcapacity. Or investors are simply overoptimistic.

When the dust settles, a bust occurs. There is significant overcapacity and prices therefore fall. Because all competitors have invested in new, low-cost technology, prices tend to fall further than in the previous bust.

The bust damages several stakeholders. The prolonged periods of low prices and low profitability result in underused assets—in other words, wasted investment. Smaller players and others that have overextended themselves suffer financial distress. Especially in industries with a mature technology, overall profitability falls as the marginal high-cost players that had been supporting the price are forced out of the market.

Booms and Busts in Electricity

As in other industries, a bust in the electricity business has serious consequences for several stakeholders. But because of the special characteristics of electricity, a boom in power generation can create problems in addition to price spikes. The inability to store and import significant amounts of power means that shortages can occur more easily, requiring reductions in power demand or even brownouts (temporary reductions or cutbacks in voltage) or blackouts (the loss of power in a market). Because there is no effective substitute for electricity in the short term, customers have to close down operations or acquire expensive backup power units. Consequently, power shortages are a disaster for some customers, the economy, regulators, and governments. Even power generators may not come out ahead: governments and regulators may not allow them to keep the profits they make during the boom.

An example of a market in which a boom wreaked havoc is California, where a shortage of generating capacity led not only to brownouts but also to sharp increases in wholesale electricity prices. The structure of power contracts did not allow all utilities to pass all of these increases on to their customers. Making matters worse, many end customers had no incentive to reduce demand because of contractual protection from price increases. Several utilities went bankrupt. The government had to intervene and pay a large part of the bill. There were also significant longer-term effects. The entire regulatory and competitive framework was discredited, undermining the movement to open up the industry to competition in many portions of the United States. As a result of this effect and the collapse of large energy traders, investors have become very skittish about investing in power companies in competitive markets, causing a credit crunch for these companies and less liquidity in the power market. And the generators that made huge profits from the upheaval in California have ended up having to fight accusations that they manipulated prices.

Busts can also be devastating. An example of a bust in electric power generation occurred recently in the United Kingdom. Overbuilding of combined-cycle gas turbines (CCGTs) resulted in falling prices and bankruptcies for the major nuclear-power generator and many smaller generators. Several of the new CCGT plants remain mothballed. The main beneficiaries have been the vertically integrated companies, which were able to retain larger margins by passing on to their customers only a portion of the reductions in wholesale prices.

Of course, even boom-and-bust cycles offer opportunities for those who recognize or understand them. Buying assets in the bust and selling assets in the boom can produce attractive returns. In addition, the volatility in prices can offer numerous opportunities for arbitrage and risk-management services.

Europe Is on a Risky Path

If Europe proceeds on its current course—if it continues to seek free markets and more competition without carefully structuring these markets—a severe boom-and-bust cycle is likely.

Europe today has significant generating overcapacity, but it will disappear before the end of the decade. (The exact timing varies by region). In addition to the 15 GW of new capacity that is under construction, BCG foresees that at least 65 GW more will be needed by 2012.[2] (See Exhibit 1).

If Europe adheres to its commitment to achieve the targets for reducing CO_2 emissions established in the Kyoto accord, a further 60 GW to 100 GW of new capacity will be needed to replace relatively "dirty" generation assets. (See the insert "How Kyoto Could Reshape Power Generation," page 14.)

Two scenarios are possible. One is that generators invest in new capacity, leading to a crash in prices and profitability. (See Exhibit 2, pages 12 and 13.) Why would this happen? First, as demand rose, so would wholesale electricity prices. Eventually, they would reach €30 to €35 per megawatt hour (MWh), the range at which new base-load capacity would be economic, encouraging investors to build such plants.[3]

But as the U.K. experience has shown, adding new, low-cost capacity would drive down prices and profits. This would occur because the new capacity would "flatten" the supply curve: Plants with higher short-run marginal costs that had operated frequently and had been setting relatively high prices would be pushed out by the new capacity and would become excess or reserve capacity. (For explanations of the technical terms, see the insert "Modeling Power Generation Markets" in the methodology section, page 36.) As a result, prices, on average, would fall.

These lower prices, however, would not cover the long-run marginal costs of the new CCGTs. Thus, a bust would quickly follow the initial boom.

Such a boom and bust can occur even if there is no overinvestment in capacity. The reason is that the new base-load capacity flattens the supply curve and brings down prices even if supply and demand remain appropriately balanced and there is normal reserve capacity.[4] If overinvestment were to occur, as it did in the United Kingdom, the impact on prices and profits would be even greater.

2. This assumes growth in power demand on the order of 1.7 percent per year. Alternative scenarios with slower demand growth result in a similar boom-and-bust cycle, although it may occur up to three years later.

3. This price refers to the average price a plant realizes, which depends on its position on the supply curve. As plants move to the right, they operate fewer hours annually, but the average price they realize rises because they enjoy an increasingly richer mix of prices. (Typically, a base-load plant realizes a mix of off-peak, intermediate, and peak prices and operates all the time. A peak plant realizes a higher average price because it supplies only peak demand, but it operates fewer hours annually than a base-load plant and therefore receives less annual revenue per megawatt of capacity.)

4. If a mix of peaking and base-load plants were built, prices would not collapse and the total investment would be lower. But in a competitive generation market, only new base-load plants would be built. (During the recent building surge in the United Kingdom, for example, almost all the new plants were base-load CCGTs.) The primary reason is that peaking plants, by definition, operate only occasionally during the year and therefore need very high prices to recover their fixed costs. Even if the lowest-cost peaking plant ran as much as 2,000 hours per year, which is rare, prices would have to be at least €60 per megawatt hour for it to recover its fixed costs—and attract investors. Such high prices occur only when there are significant, prolonged shortages of power or unusual circumstances.

In the second scenario, companies see the danger of a bust and do not invest in a timely fashion. The result is shortages, brownouts, and price spikes similar to those that occurred in markets in the United States such as California, the Midwest, and the Northeast. Eventually, governments might have to step in to secure new investments. But by the time they did, much damage would already have been done.

In summary, BCG's analysis suggests that the likelihood of a boom-and-bust cycle is extremely high because of a complex combination of economic forces, investor behavior, regulatory and government action (or inaction), and the particular characteristics of the electricity generation business. Moreover, the likelihood is high whether or not Europe implements the Kyoto treaty. The major difference if Kyoto is implemented is that the damage resulting from the boom and bust could be more severe because larger investments in new capacity would be at risk. Finally, although the trends described in this report will affect all of Europe, the nature and timing of their impact will vary by local market. (See the insert "The Impact of the Trends Will Differ by Market," page 16.)

How the Cycle Could Be Avoided

Addressing the problem of boom-and-bust cycles requires achieving a delicate balance between promoting competition in some portions of the market and carefully regulating other areas. However, there are no existing successes that can serve as models. Forging solutions will require translating possible theories about what could work into pragmatic plans, executing those plans carefully, and fine-tuning them along the way.

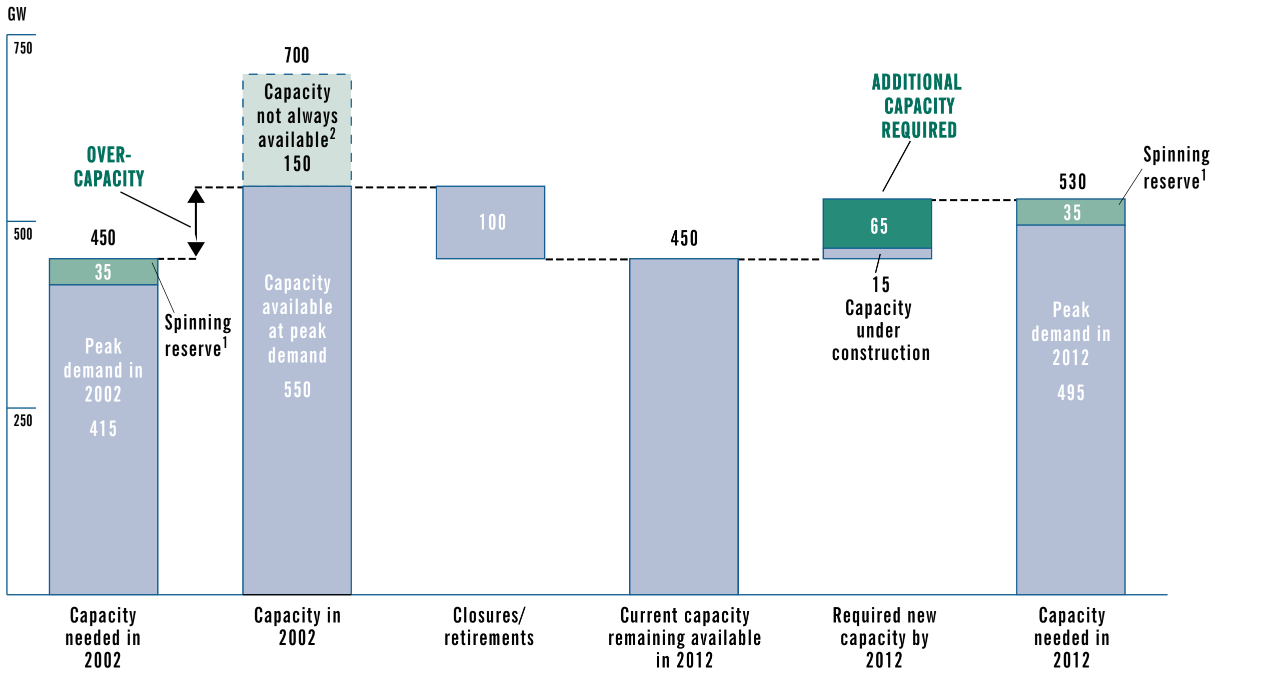
Permitting Industry Concentration

As in any commodity industry, power generators' natural tendency is to merge to form oligopolies that provide price stability and dependable sup-

EXHIBIT 1

ABOUT 65 GW OF NEW CAPACITY WILL BE NEEDED BY 2012

Western European Electricity Supply-Demand Outlook for 2012



Sources: *Union for the Co-ordination of Transmission of Electricity Statistical Yearbook*; Credit Suisse First Boston; BNP Paribas equity research; *EURPROG 2000 Report*; *EU Energy Outlook to 2020* (European Commission); Platts; press; BCG analysis.

[1] *Spinning reserve* is backup capacity required for responding to small fluctuations in demand.

[2] Part of the total capacity has to be discounted because selected plants cannot be counted on to be fully available at peak demand (hydroelectric and wind-powered plants in particular).

plies. Such oligopolies do not necessarily need to be European in scope; they can be at the local market level. (A local market is one with limited connections to other markets.)

Oligopolies might avoid boom-and-bust cycles for two reasons. First, members of an oligopoly have a significant interest in maintaining a stable market in general and stable prices in particular because the latter are both attractive to investors and acceptable to customers. Second, because the oligopoly controls prices, the primary incentive for each player is to minimize costs. The optimal way to minimize costs is to invest in the "correct" mix of base, intermediate, and peaking capacity—one that avoids a flattening of the supply curve and volatility in prices.

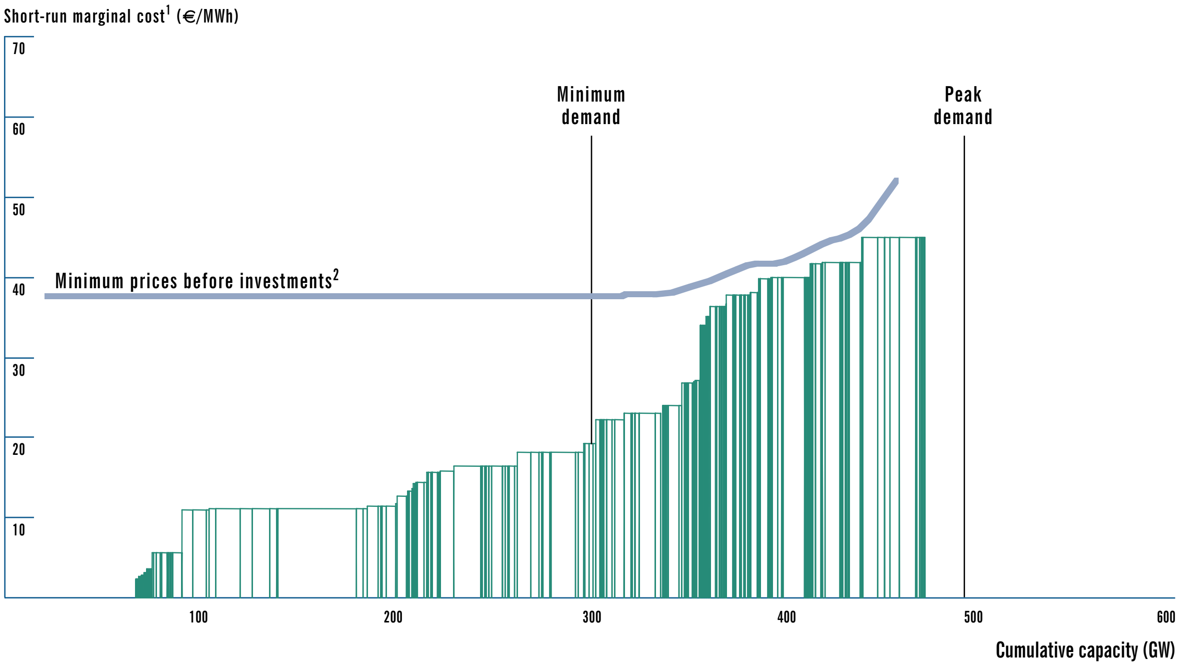
Of course, allowing such oligopolies would conflict with the policy goals of increased competition and customer choice. An example is the early stages of U.K. deregulation of power generation. Two competitors controlled the market. Prices were relatively stable and there was no boom or bust. But prices were relatively high, which caused resentment among major users and retailers, leading to a decision to break up the oligopoly. Ironically, that decision contributed to the recent bust. Price caps have also been used—for example, in the United States, where the Federal Energy Regulatory Commission has imposed them to protect consumers. However, simultaneously protecting consumers and providing adequate incentives to investors to maintain enough capacity is a delicate balancing act. Clearly, this kind of solution is not without its challenges.

Europe is now close to having an oligopolistic market structure. Most local markets are concentrated.

EXHIBIT 2A

WITHOUT NEW CAPACITY, EUROPE FACES A SHORTFALL . . .

Western European Supply Curve in 2012, Without Investments



NOTE: This exhibit shows two supply curves for Europe. The first (Exhibit 2A) is without new capacity. The second (Exhibit 2B) is after enough investments to meet anticipated demand in 2012 and provide adequate capacity reserves to balance peak demand and supply, with an appropriate reserve margin. The height of the bars represents the short-run marginal cost of each type of plant, and the width of the bars is the capacity. Also shown are *minimum prices before investment*. As can be seen on the second supply curve, these prices are above the long-run marginal cost (or full cost) of a new CCGT plant, which suggests that prices will be high enough to encourage investment. The second supply curve also shows *minimum prices after investments*, which indicates that prices could fall below the long-run marginal cost of the new CCGTs, resulting in losses for these new plants. This example assumes that CCGTs are built. However, the outcome would be the same whether the new plants were CCGTs, coal fired, or a mixture of these and other base-load technologies.

Were oligopolies allowed to develop further, markets could perhaps be controlled or regulated by using price controls and cost benchmarks to ensure that other policy objectives such as low prices were met.

Creating Incentives to Invest in Peaking Plants

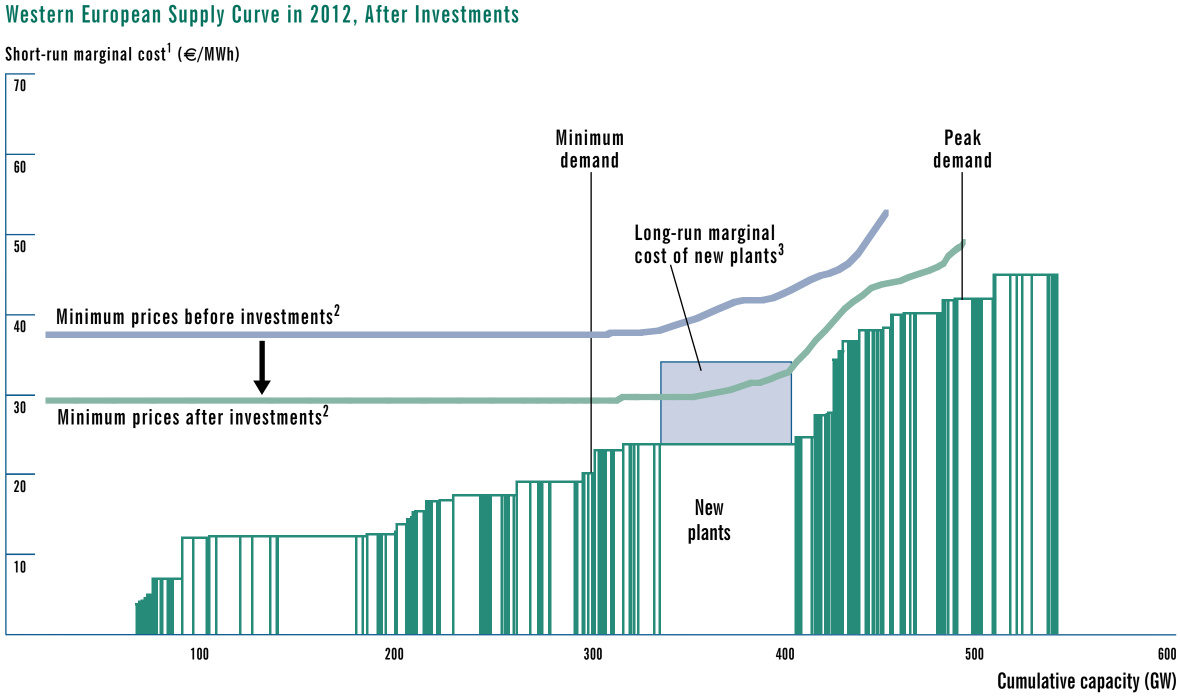
Regulators could design the power markets to ensure that enough peaking capacity gets built to reduce the risk of a boom-and-bust cycle and avoid flattening the supply curve. There are many ways to do this, but two primary options are to create capacity markets or to impose regulations ensuring that sufficient peaking capacity is provided.

- Capacity markets require someone to pay a fee to subsidize peaking and intermediate plants. Typically the provider of the subsidy is the customer or retailer, who is required to contract for excess capacity equal to some fraction of peak demand (a "capacity charge"). But the providers could also be governments or even base-load plants, which have the advantage of running all the time. Several regions, including the northeastern United States and the United Kingdom, have tried this approach, but none of the attempts have been perfect and some schemes have been stopped. Nevertheless, one could learn from these attempts and design a system that would significantly reduce the chance of a boom and bust by increasing incentives to invest in peak capacity.

- Under the approach of regulating peaking capacity, the regulator or some other third party determines how much peaking capacity is required and acquires it. Adding more peaking capacity than would otherwise be built would make prices less

EXHIBIT 2B

. . . BUT ADDING CAPACITY COULD CAUSE A PRICE BUST



Source: BCG analysis.

[1]The short-run marginal cost is the variable cost incurred directly when producing electricity: fuel, nuclear waste processing, variable operations and maintenance (O&M) costs. This scenario is without a carbon tax (without Kyoto).

[2]The minimum price that a given power plant is likely to realize in a competitive wholesale market, depending on its position on the supply curve.

[3]The long-run marginal cost is the full cost of a power plant, including the short-run marginal cost, the other cash costs (such as fixed O&M costs), and the costs of the investment (capital and financing costs). This supply curve assumes new investments in CCGTs, but the long-run marginal cost of coal plants is at the same level.

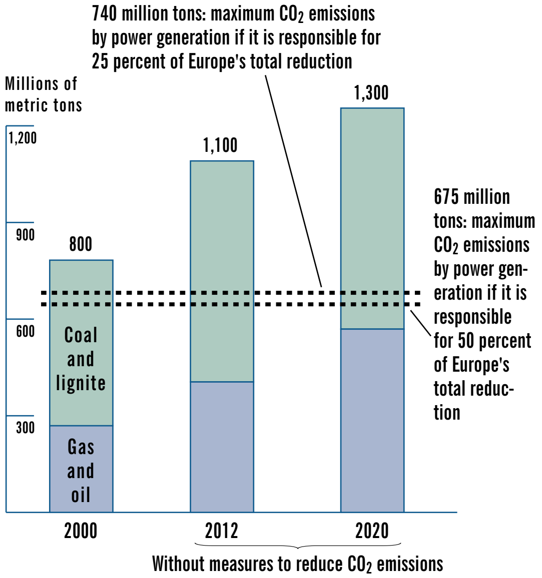
HOW KYOTO COULD RESHAPE POWER GENERATION

To achieve the targets for reducing greenhouse gases in the Kyoto Protocol would require European countries to impose significantly higher costs on power stations for producing CO_2. Such measures to encourage the industry to replace dirtier power-generating plants with cleaner ones would also drive up electricity prices.

As can be seen in the exhibit below, without action, CO_2 produced by power generation in the 16 countries could actually rise from about 800 million tons in 2000 to 1.1 billion tons by 2012. If Kyoto were implemented, all of this increase would have to be eliminated. In addition to finding ways to avert these emissions, the power industry must contribute to the reduction of 250 million tons that Europe has committed itself to make by 2012. In this study, BCG assumed that power generation's share of this amount would be 25 to 50 percent, or approximately 60 million to 125 million tons.

EUROPE WOULD HAVE TO LIMIT POWER GENERATION'S CO_2 EMISSIONS TO ABOUT 700 MILLION TONS TO REACH KYOTO'S TARGETS

Annual CO_2 Emissions from Power Generation



Source: BCG analysis.

Note: A conservative view of the increase in CO_2 emissions, assuming that new capacity investments made to meet the increase in demand are mainly CCGTs and, to a lesser extent, generating plants powered by renewable energy. The market considered includes 14 European Union members (excludes Greece), Norway, and Switzerland.

Power generation currently is responsible for about 30 percent of the CO_2 produced, which would suggest that its share of the burden should be about 30 percent. However, it is easier to achieve reductions from changes in power generation than in sectors such as agriculture, residential, and transportation. (Indeed, most of the decline of 50 million tons achieved to date has come from cuts in coal-fired power generation in Germany.) Consequently, governments and economists are likely to argue that power generation's share of the burden should be more than 30 percent. For their part, power generators may well contend that their share of the remaining burden should be less than 30 percent because they have been the main contributor to reductions to date.

Therefore, BCG assumed that power generators would have to limit their total output of CO_2 by 2012 to between 675 million tons and 740 million tons. In other words, they would have to reduce CO_2 emissions by 360 million to 425 million tons: the 300 million tons they have to avert plus the additional 60 million to 125 million tons.

Coal- and lignite-fired plants are the biggest emitters of CO_2. Quite conceivably, governments could enact measures to increase the short-run marginal costs of such plants to make them more expensive than lower-emission combined-cycle gas turbines, while continuing to subsidize investments in low-emission plants such as renewable energy or even CCGTs. This would induce companies to replace 40 GW to 50 GW of existing coal- and lignite-fired plants with cleaner power-generation technologies and make remaining coal- and lignite-fired plants operate less often than today.

From a purely economic standpoint, these 40 GW to 50 GW of coal- and lignite-fired capacity should be replaced by CCGTs. However, since it is highly likely that investments in renewable energy will continue to be subsidized—even though it is more expensive—BCG's model assumes that 70 GW of such capacity will be added.[5] Because most plants powered by renewable energy are not available all the time, these 70 GW will be not nearly enough to replace the prematurely retired coal-fired plants. Therefore, we assume also that an additional 30 GW to 40 GW of gas-fired capacity (mainly CCGTs) will be built. This gas-fired capacity is in addition to the 65 GW of capacity BCG estimates would be required without Kyoto.

Possible Scenarios

To reach such a reduction in emissions, a minimum levy of €25 per ton of CO_2 would be required. This implies that cleaner technologies (renewables and CCGTs) would continue to be subsidized. Without subsidies, the minimum levy would be higher. The levy could be imposed as a carbon tax, by issuing a limited number of tradable carbon-emission permits, or as a combination of both.[6]

To illustrate the impact of a reasonable range of scenarios, BCG's modeling for achieving Kyoto's targets considered two cases. One has the power industry shouldering 25 percent of the total targeted CO_2 reduction, and uses a levy of €25 per ton of CO_2 emissions plus subsidies for cleaner capacity to implement the policy. In the second, power generators are responsible for 50 percent of the total CO_2 reduction, and a levy of €35 per ton is applied.

If Europe were to choose not to implement its emission reduction targets fully, these costs would be lower.[7] (BCG's estimates are not forecasts of what will happen, but of what would be required for Europe to achieve the Kyoto targets.)

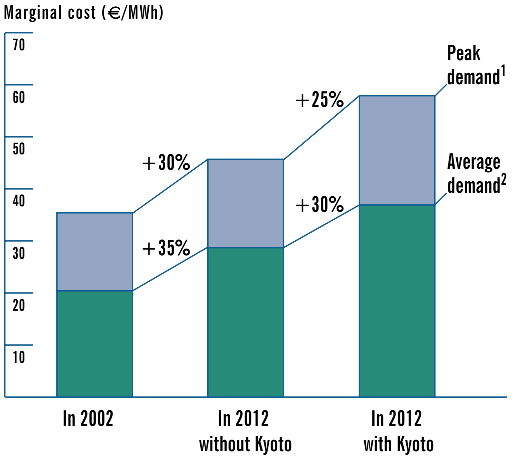
Higher Power Prices with Kyoto

A levy of €25 to €35 per ton of CO_2 would push wholesale electricity prices to levels €8 to €13 per MWh higher—or up to 30 percent higher for average prices and up to 25 percent for peak prices—than without Kyoto. (See the exhibit below.)

But the marginal costs of the new plants would rise by nearly the same amount. As a result, the likelihood of a boom-and-bust cycle's occurring is virtually the same with or without the implementation of the Kyoto targets. However, if Kyoto were implemented, the damage from a boom and bust could be much more severe because the larger investments in new capacity required to achieve the Kyoto targets would be at risk.

KYOTO WOULD RESULT IN HIGHER PRICES

Marginal Costs of Producing Power in 2002 and 2012 with and without a €25-per-Ton Carbon Tax



Source: BCG analysis.

Note: The 2012 scenario without Kyoto assumes CCGTs account for the largest share of new capacity.

[1]The minimum price that a peak plant is likely to realize in a competitive wholesale market, with about 1,500 hours of operation per year.

[2]The minimum price that a base-load power plant is likely to realize in a competitive wholesale market—that is, a mix of base-load, intermediate, and peak prices.

5. BCG assumes this capacity will consist of 55 GW of wind-based power and 15 GW of hydropower.

6. A carbon tax of a given euro amount and carbon credits issued in a small enough quantity to be traded at the same amount of euros would increase the short-run marginal costs of power plants producing CO_2 by an equivalent amount. Therefore, both would have the same impact on power prices. However, tradable carbon credits would impose a significantly lower penalty on owners of coal-fired plants than a carbon tax would, since the former would provide these plants with a form of compensation: the money they could earn by selling the credits.

7. For example, Europe could decide not to implement Kyoto fully or could support a system that subsidized other countries to accept a share of its emission-reduction burden. The numbers in this section illustrate the consequences of Europe's (as defined in this report) meeting its emission targets through reductions in its own CO_2 output.

likely to fall as far in a bust because the higher-cost peaking plants would continue to set relatively high peak prices. There are a number of ways to implement this approach. One option is for the regulators to issue power purchase agreements (PPAs) to generators. Such contracts could be put out for bid to provide an element of competition. Another option is for the regulated grid company to acquire the necessary peaking capacity. Such an approach would encourage the appropriate level of investment in peaking capacity, provided the regulator has the ability to anticipate needs accurately.

Both solutions mix regulation and free-market approaches and thus are controversial, complex, and difficult to implement. They (and similar approaches) would also require compromises in policy goals, such as introducing more competition and lowering prices.

Muddling Through: Be Prepared

Everyone should be trying to avoid a boom and bust. In a utopian world, European stakeholders would sit down together and negotiate a common policy framework and timetable that provided explicit and agreed-upon tradeoffs among the different objectives. At this point, however, the prospect of Europe's acting in a unified fashion appears slim.

What is more likely is that each country will create its own shifting mix of policies and sporadically try to coordinate or cooperate with other countries. It is possible that regulators and policymakers might

THE IMPACT OF THE TRENDS WILL DIFFER BY MARKET
Germany and Italy: An Illustrative Comparison

Regional power-generation markets in Europe differ significantly. Nevertheless, BCG believes that the trends described in this report will affect all markets—albeit the timing, magnitude, and details will vary. For example, consider Germany and Italy, two markets whose differences include the composition of their generating capacities and the shape of their supply curves. (See the exhibit "Supply Curves for German and Italian Power Generation.")

Germany depends predominantly on coal-fired plants that have low short-run marginal costs, and has a number of old gas- and oil-fired plants that serve as peaking generators. As a result, Germany has a flat supply curve that then rises steeply, reflecting the high costs of the oil- and gas-fired plants. Italy has a wide mix of technologies, burning oil, orimulsion (heavy fuel oil), and gas. Most are relatively costly, so Italy's supply curve rises steadily from left (base-load plants) to right (peaking plants).

Another difference between the two markets is in the supply-demand balance. As can be seen in the exhibit, there is more overcapacity in Germany than in Italy. This means that competitive prices in Germany are very low much of the time, with the exception of occasional spikes at peak times. In contrast, prices in Italy are much higher in general.

Will the effects described in this report vary by market? Yes and no. The main trends are similar. Each country will require new capacity. Gas-fired capacity will be the most economic. The demand for new capacity will be higher with Kyoto. Wholesale gas and electricity prices are likely to rise. And each country could experience a boom-and-bust cycle.

But there will be differences, too. For example, both countries face the risk of a boom-and-bust cycle, but the nature of the cycles could be dissimilar. In Germany, the low prices could discourage investment, which increases the likelihood of shortages, price spikes, and the problems associated with a boom. In Italy, the higher prices make investment more likely, but there is also the risk of a consequent bust—particularly if there is overinvestment—as the new capacity causes the supply curve to flatten.

The impact of fully implementing Kyoto's targets would be more severe in Germany, which would have to retire much of its coal- and lignite-fired base-load capacity. But adhering to the treaty would tend to push up prices in both countries. This would be able to take local initiatives that could minimize the size of boom-and-bust cycles—for example, by expanding transmission capacity between markets to increase the flexibility of supply, by imposing price caps, and by issuing PPAs to ensure adequate reserve margins.

Whether the initiatives are taken at the European or local level or both, anticipation is of the essence. In this industry it takes a long time to decide on new regulations, build investor confidence in their stability, and design and construct the new plants. Other, related issues could also take time to resolve. These include obtaining access to the gas required to supply the new gas-fired plants.

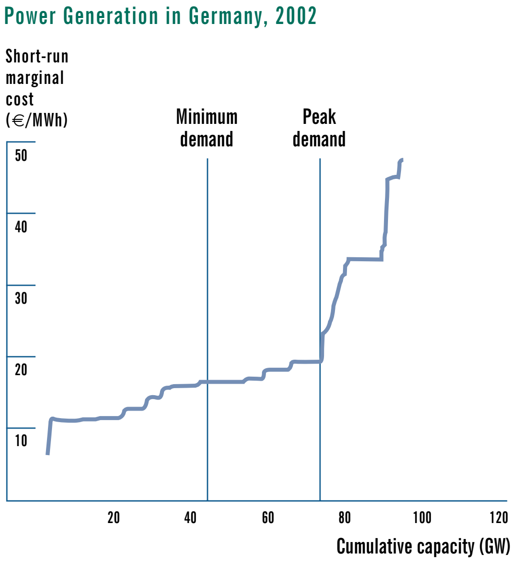
Given the uncertainty about what will happen and the substantial risk that a boom and bust could occur in all or large portions of Europe, companies should prepare for the possibility. Although this cycle would inflict pain on many stakeholders, the volatility and uncertainty would also present opportunities to reap significant rewards.

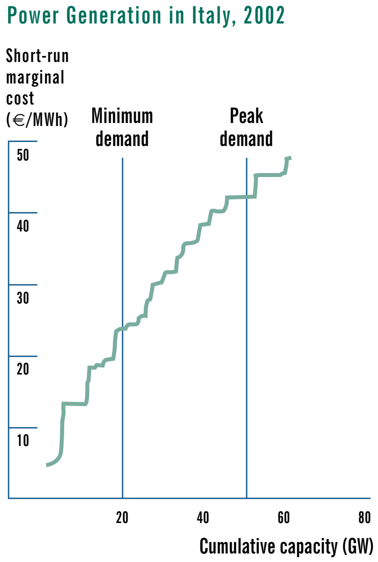
For example, the U.K. experience suggests that large, vertically integrated energy companies could be in the strongest position. Such companies can better shape regulatory policy, hedge risk, and gain access to capital at the right time in the investment cycle. This could provide an important competitive advantage and thus superior returns. Small players could make money in the boom if they were nimble enough to avoid the bust by selling out early. Large consumers of electricity might enjoy lower prices, at least for some periods, particularly if they hedged prices at the right time in the cycle.

create winners and losers. German coal-fired plants could suffer significantly if the carbon levy were imposed in the form of carbon taxes, but German nuclear plants would benefit. In Italy, oil-fired plants could be hit hard, whereas hydropower plants and existing CCGTs would benefit.

In summary, the trends will generally be the same across Europe, but exactly how and when they will develop will vary by market. For stakeholders, understanding how the trends could play out in local markets is the starting point for deciding what actions they need to take.

SUPPLY CURVES FOR GERMAN AND ITALIAN POWER GENERATION





Source: BCG analysis.

Power generators and other stakeholders (such as energy retailers and large users of energy) must choose the timing, the size, the nature, the risk exposure, and the location of their investments very carefully. Some markets could prove too risky. Others may offer attractive returns if a particular investor commits capital at the right time in the boom-and-bust cycle and uses long-term contracts with customers to manage the price risks. Being able to assess the ability of a country's government and regulators to muddle through effectively will be critical.

The Gas Import Challenge

Developing and Transporting Supplies

Combined-cycle gas turbines are the technology of choice, because both their CO_2 emissions and their long-run marginal costs (or full costs) are relatively low. The long-run marginal cost of a CCGT is on a par with that of a new coal- or lignite-powered plant. However, investors are likely to favor such gas-fired plants because a new coal- or lignite-powered plant produces significantly more CO_2 for each megawatt hour of electricity produced. Although it remains to be seen whether and how Europe actually implements the Kyoto accord, its continuing commitment to doing so makes investments in coal- and lignite-burning plants very risky. For similar reasons, gas-fired turbines are the technology of choice for peaking capacity.

A Substantial Increase in Imports Will Be Needed

Because of a substantial expansion in CCGTs, BCG estimates that annual gas imports will increase by 2012 from 230 BCM today to between 465 BCM (without Kyoto) and as much as 565 BCM (with full commitment to achieving Kyoto's targets). (See Exhibit 3.)

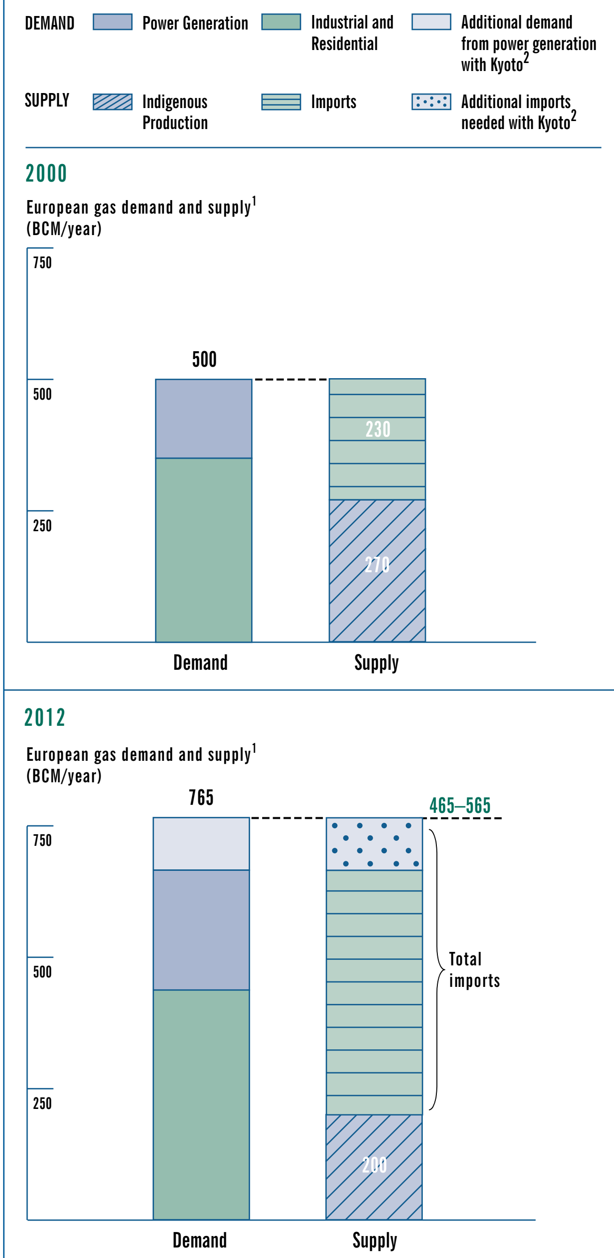
There is plenty of gas potentially available. (See Exhibit 4, page 20.) But most of it is more expensive than existing sources and located in technically challenging and politically risky environments.

New, piped gas will have to come from increasingly risky projects in remote places such as Siberia. Such huge projects (those capable of producing in excess of 80 BCM per year) require large sums of capital to develop fields and transportation infrastructure. For the capital to be raised, prices of this gas will have to be relatively high in order to provide investors with sufficiently attractive returns.

Liquefied natural gas (LNG) imported from North Africa, Trinidad, Nigeria, and eventually Qatar and Iran is another likely source of supply. Such gas, however, is also costly in comparison with today's supplies. (Its costs would be comparable to those of gas piped from large new fields in Siberia.) Large amounts of this gas are available, but they would

EXHIBIT 3

SIGNIFICANT INCREASES IN GAS IMPORTS WILL BE NEEDED, WITH OR WITHOUT KYOTO



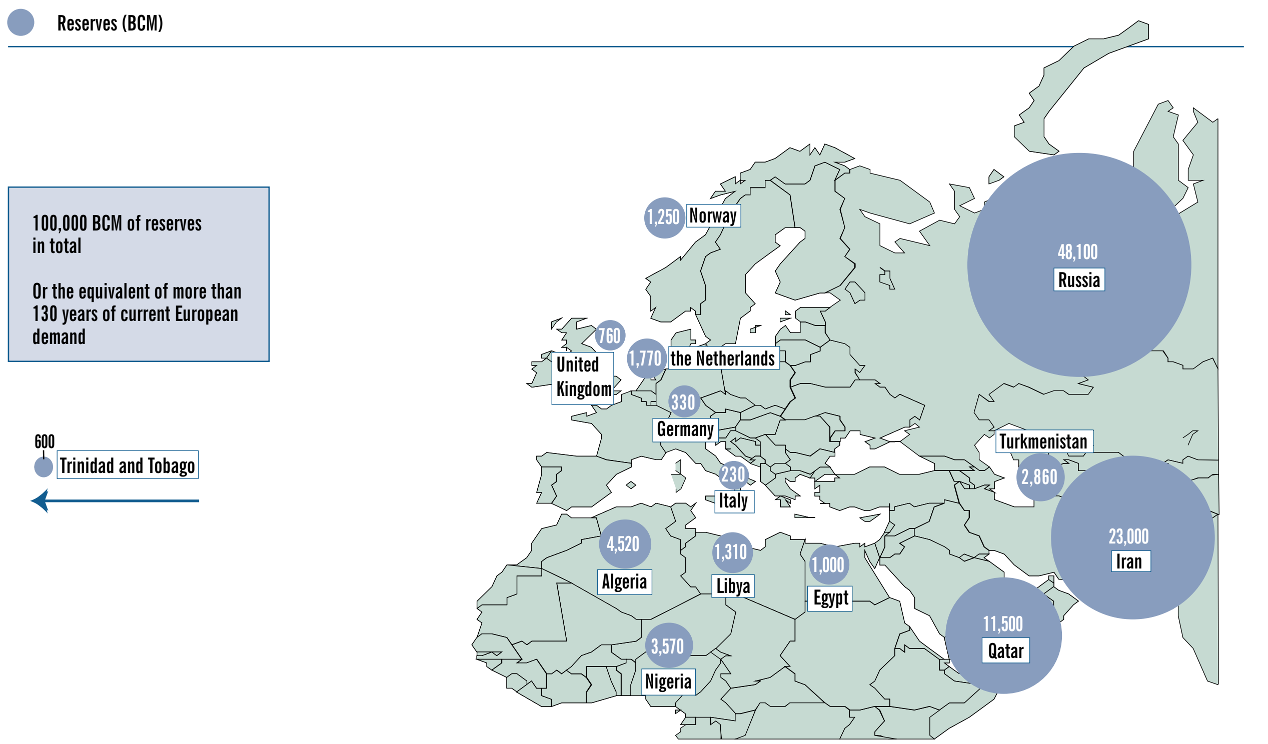
Source: BCG analysis.

[1]European demand considered in BCG's gas analyses includes all the European countries, including Turkey and excluding only Russia, Ukraine, and Belarus. This market has to be considered at a European level because all these countries compete for the same gas reserves. The indigenous production takes into account only the 15 EU members (mainly the Netherlands, the United Kingdom, Germany, and Italy), while Norwegian production is considered as imports.

[2]This is the upper limit of gas demand, with power generation responsible for helping Europe achieve 50 percent of its overall target for reducing CO_2 emissions.

EXHIBIT 4

PLENTIFUL, DIVERSE RESERVES EXIST TO SUPPLY EUROPE'S GAS NEEDS



Sources: International Energy Agency; Global energy statistics; BP Amoco, 2001; Cedigas.

also require substantial investments: major liquefaction facilities at the source of the gas, lots of tankers, and many new gasification terminals in Europe. Building large numbers of these terminals, which convert LNG back into gas and feed it into the pipeline system, has its own challenges: environmental and safety concerns have resulted in strong local opposition to such plants. Nevertheless, additional LNG is a complementary source of gas for power generation if insufficient piped gas is available.

Raising the Capital Could Be Difficult

Overall, an investment of €95 billion to €110 billion in upstream field development, pipelines, and LNG-regasification infrastructure would be required by 2012. (The range depends on whether Kyoto's targets are implemented.) There are currently no commitments to provide a substantial portion of this amount, and raising such a sum could be challenging.

In principle, gas players would be keenly interested in providing supplies to the power industry because that would represent a major growth opportunity. But gas players, banks, and other potential investors are unlikely to commit the remaining capital required without secure long-term contracts with reliable purchasers.

Because the costs of the incremental gas from new Russian fields and LNG are high, contract terms would need to be very tight to make investing attractive—especially since many of the investors have other options. For example, oil companies, which are major potential investors, may see oil as a better bet because of the long history of high returns for upstream oil investments in relation to costs. Also, investment in oil production is somewhat less risky than investment in gas pipeline projects. Oil is a global commodity that can be moved easily around the world, whereas the fortunes of piped gas are typically tied to the fortunes of one market or even, as in Europe, one customer segment: power generation.

In addition, it will be difficult to raise the needed capital until several unknowns are dispelled. One is the electricity market's rules and structure. Until they are established, power generators are unlikely to agree to the tight terms that gas infrastructure players need in order to sign the contracts. For example, they will find it difficult to agree to fixed volumes and minimum prices if they face volatile prices for their own output. Other unknowns include how rigorously the Kyoto accord is going to be implemented and the fate of nuclear power. Without resolution of these issues, it will be hard to provide the kind of solid estimate of likely demand for gas and gas-related infrastructure that investors will want.

Investors in gas infrastructure also have concerns because the European Union wants the gas industry to become more competitive, which would increase risks and uncertainty, thereby potentially making it harder to sign long-term contracts. For example, it is standard practice today for retailers and wholesalers to pass on price increases to their customers. But if customers were allowed to switch suppliers, wholesalers and retailers would be unable to commit to buying gas at fixed prices or volumes. As a consequence, it would be difficult for suppliers, wholesalers, and retailers to sign long-term contracts with each other unless liquid, cost-effective markets developed that made it possible to hedge long-term risks. Given the current concentration of Europe's industry, creating such markets would be challenging. (Notably, even in the United Kingdom, which has the most competitive gas market in Europe, long-term markets have not developed.)

The overall uncertainty and risks make investments in the largest gas projects, such as Shtokmanovskoye and Yamal 2 in Siberia, unlikely in the short term. Instead, European power generators are likely to have to rely on a more complex composite of smaller-scale projects and LNG.

Much Larger Imports Would Mean Much Higher Prices

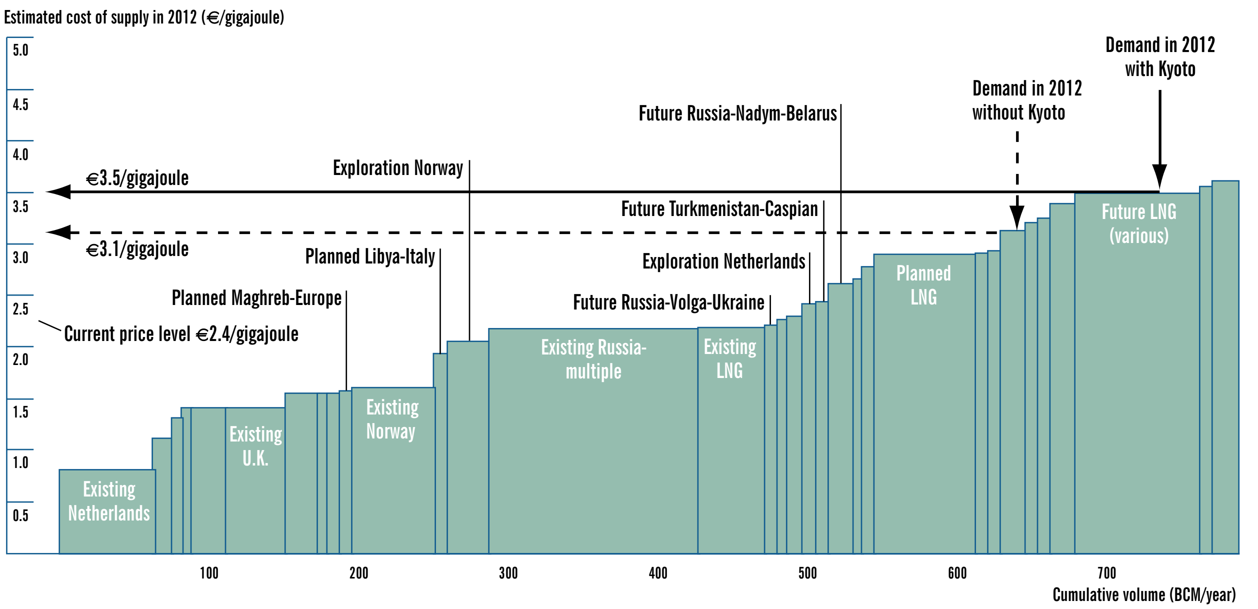
If, in the end, investments in field development and transportation infrastructure are made, Europe still faces the prospect of having to pay significantly higher wholesale gas prices.

The new sources of gas have higher delivered costs than the old sources. Therefore, to make these new sources of gas profitable, prices are likely to rise—

EXHIBIT 5

THE COST OF GAS WILL RISE AND WILL BE EVEN HIGHER IF KYOTO IS IMPLEMENTED

European Gas Supply Curve, 2012



Sources: Energy Information Administration; International Energy Agency; Cedigas; Global Insight Inc. (formerly WEFA); BCG analysis (simulation output).

Note: The supply curve shown here is based on the full costs of supplying the gas to Europe, which include initial and continuing capital expenditures, operational expenses for production, the cost of transportation to European entry points, and storage costs. The supply scenario includes gas sources that are certain or very likely to be in operation and connected to the market in 2012 as well as sources that are still uncertain.

particularly if the balance of supply and demand is tight. The most expensive sources of gas today cost about €2.4 per gigajoule (GJ) but will rise to €3.1 per GJ by 2012 without Kyoto or €3.5 per GJ with Kyoto (because of the need for more gas and thus more expensive sources of gas). (See Exhibit 5.) This increase in gas costs of €0.7 to €1.1 per GJ would affect prices for all supplies of gas and all customers, and therefore would affect Europe broadly, including investments in new power generation.[8]

Since major Siberian projects are unlikely to move forward in the short term, dependence on LNG should grow. Gas prices could be more volatile, especially if the increased demand for LNG eventually brings about competition between Europe and North America for LNG supplies.

8. Our estimate that gas prices are likely to rise has been taken into account in our analysis of the economics of the different power-generation technologies.

The Limits of Renewable Energy

We assume that the amount of generating capacity using renewable energy will increase significantly from the current 195 GW. Our model assumes that if Kyoto's targets are adhered to, the total amount of such capacity will grow by 70 GW. (See Exhibit 6.)

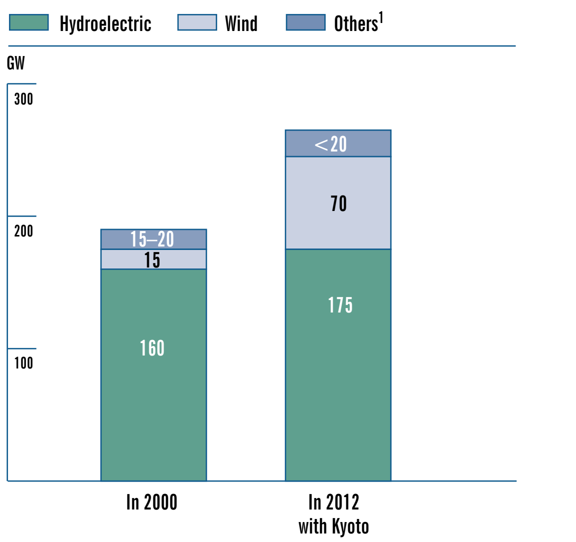
Wind power's role has grown and appears likely to become even larger as a result of an improving cost position and subsidies from governments, particularly Germany's. Traditionally, Europe's main source of renewable energy has been hydropower. But the opportunities to expand hydropower are limited, because the most viable sites have already been developed.

Other existing technologies such as biomass (including mixing biomass with coal in existing coal plants) and geothermal power might contribute a bit more. But it is difficult to see these technologies being used to produce large amounts of electricity anytime soon, because the costs of both are relatively high and there are few geothermal sites.

EXHIBIT 6

WINDMILLS WILL ACCOUNT FOR MOST OF THE INCREASE IN CAPACITY USING RENEWABLE ENERGY

Renewable generation capacity in Europe



Source: BCG analysis.

[1]Mainly biomass.

Further out, technologies such as tidal and wave power, solar power, and hydrogen-powered fuel cells and technologies for storing electricity and reducing peak loads could have an impact. But since their viability depends on technological breakthroughs, it is unrealistic to expect them to become important factors in the next decade.

Although the full cost position of windmills has been improving, their costs are still high: from €40 per MWh (for the relatively small number of windy onshore sites, where windmills can operate at 40 percent of their capacity) up to €70 per MWh (for less windy onshore sites, where windmills can operate at only 25 percent of their capacity, and for offshore sites). This is well above the cost of €30 to €35 per MWh of coal- or gas-fired plants.

Moreover, these figures do not reflect the full cost of wind. Because wind is unreliable, windmills cannot be counted on for times of peak demand. This is especially an issue in Europe, where the high-pressure systems that produce low temperatures often do not generate much wind—so wind power is not available when it is most needed. Therefore, significant conventional capacity would be needed to back up wind-generated electricity, adding to its cost.

In addition, many of the best sites for windmills are in remote regions such as thinly populated areas of Scotland. This means that major investments in the transmission grid would probably have to be made to transmit the power to the centers of population. (In the United Kingdom, some in the industry claim that investments of €1.4 billion to €3 billion could be required.)

Besides the economic challenges, large wind farms are not generally considered to be aesthetically pleasing. That fact, combined with the fact that their purpose is not to serve local power needs, almost guarantees strong local opposition to their construction.

The Case for Retaining the Nuclear Option

New nuclear power is currently more expensive than CCGTs. That expense, combined with long lead times to build it and the public's negative attitudes, make any development highly unlikely before 2010. Europe is actually planning to retire nuclear plants.

But if society can find acceptable solutions to the environmental issues that have made nuclear power controversial, there is an argument for retaining existing nuclear plants and the capability to build new plants. If nuclear plants are retired after 40 years of operation, as is proposed in many countries, 25 GW of prime base-load capacity will be closed from 2012 to 2020. This loss will put further pressure on the power generation industry, increasing the demand for gas, European dependence on gas imports, CO_2 emissions, and the risk of boom-and-bust cycles.

If Europe adheres strictly to Kyoto, it may eventually reach a point where nuclear power becomes necessary to avoid increasing CO_2 emissions. At some point around 2020, after all coal-fired plants have been retired and replaced by gas-fired generation, any growth in electricity demand will have to be satisfied by zero-emission technology. Without some breakthroughs in other technologies, nuclear may be the only viable way of achieving this goal.

Moreover, nuclear power may become competitive with CCGTs, at least if built on existing sites. Exhibit 7 compares the economics of electricity produced by nuclear and gas-fired power plants and how their relative cost position varies according to the cost of gas, the cost of building nuclear capacity, and the level of carbon taxes.

Given the current state of nuclear technology, a construction cost of €1,600 per KW appears to be achievable within the next 20 years. At that level, new nuclear plants would not be competitive with new CCGTs. However, since gas prices of €3.1 to €3.5 per GJ are likely (see the section "The Gas Import Challenge," page 19), nuclear could become competitive if other developments were to occur: if a significant carbon levy were imposed to implement Kyoto and if the cost of building nuclear plants could be reduced to €1,200 per KW, which would be achievable only with a technological breakthrough.

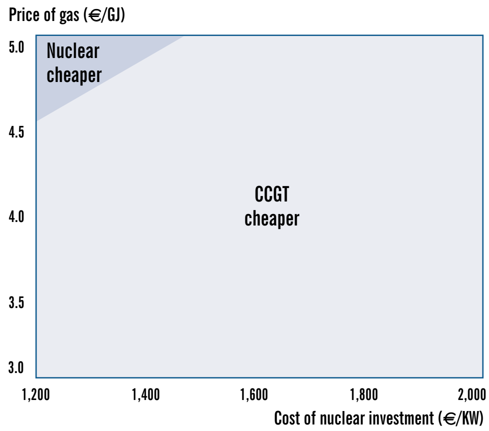
Regional security considerations might also lead Europeans to reconsider nuclear power. They could decide that it is unwise to allow Europe to become too dependent on gas imports from a handful of sources and that nuclear power could be a more attractive option.

EXHIBIT 7

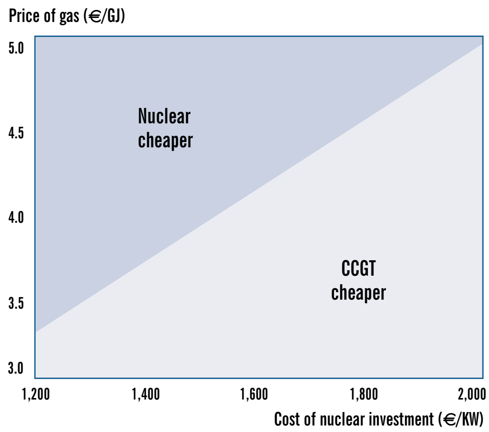
NUCLEAR POWER MIGHT BECOME ATTRACTIVE

With a Combination of Lower Investment Costs, Higher Gas Prices, and a Carbon Tax

Without a carbon tax



With a €25-per-ton carbon tax



Source: BCG analysis.

Note: Competitiveness is based on projected full costs and improvement in thermal efficiency.

Paying the Cost of Kyoto

Overall, Kyoto would impose significant costs on the economy. The minimum direct cost to Western Europe of implementing Kyoto targets in the power industry alone would be about €20 billion per year, which would amount to 0.2 percent of the European Union's gross domestic product (GDP), or about €50 per person. (See Exhibit 8.) This represents about 25 percent of the total revenues from power generation.

These estimates exclude indirect effects, such as the loss of jobs in the coal-mining industry and the impact on the competitiveness of Europe's energy-intensive industries such as metals and chemicals.

An important part of the cost would come from the investment in new plants (CCGTs and capacity powered by renewable energy) that would be needed to replace plants that would have to be prematurely shut down (mainly coal-fired and, to a lesser extent, oil-fired and old gas-fired plants). This investment would average €8 billion per year.

Of the total cost of Kyoto, gas would account for the largest proportion. The added costs due to the greater amounts of gas that would be needed and the higher average prices that would have to be paid for imported gas would be €10 billion and €7 billion per year, respectively. These costs would be offset, to a certain extent, by the €5 billion annual savings from reductions in fuel and labor that would result from retiring coal-fired plants and old oil- and gas-fired plants or using them less.

EXHIBIT 8

KYOTO MEASURES FOR POWER GENERATION COULD COST EUROPE AT LEAST €20 BILLION PER YEAR

Scenario with €25-per-Ton Carbon Tax

	Economic costs for Europe (€billions/year)
New power-plant construction	8
Increased gas consumption	10
Increased profits for non-European producers from higher gas prices	7
Cost savings from closing/reducing operation of coal-fired plants (fuel, labor)	–4
Cost savings from closing old oil- and gas-fired plants (fuel, labor)	–1
Total	**20**

SOURCE: BCG analysis.

NOTE: This is a scenario with power generation required to be responsible for 25 percent of Europe's total reduction in CO_2 emissions to meet the Kyoto goal. The evaluations are for 2012 power generation. Operations and maintenance costs of new plants are excluded.

A case can be made that the power industry should play a major role in reducing CO_2 emissions, both because of the industry's share of emissions and because it is one of the most cost-effective options. But it still leaves unresolved how the annual net cost to Europe of at least €20 billion should be shared. That promises to be a daunting and politically charged issue. (See Exhibit 9, page 26.)

For example, consider a scenario in which the Kyoto targets are achieved through a mix of subsidies to investors in CCGTs and generation powered by renewable energy and a €25-per-ton carbon tax:

- Large industrial users of electricity (such as the metals, chemicals, pulp and paper, and glass industries) would have to bear the burden of significantly higher prices for electricity and gas: increases of up to 30 percent and 10 percent, respectively. These hikes would mean more than €14 billion in higher annual costs and would probably produce large changes in behavior.

- Commercial and residential consumers would have to pay more than €27 billion per year. This would translate into a more moderate price increase of 8 to 12 percent for electricity and 2 to 3 percent for gas because the wholesale cost of energy in some markets accounts for less than 20 percent of the total retail cost. Furthermore, these increases in wholesale costs might be offset by reductions in the distribution and retail costs that make up the majority of residential consumers' bill.

- Coal-fired generating plants would also bear a major burden. Meeting the Kyoto targets would require the premature closure of 40 GW of coalfueled capacity. (This is on top of the 40 GW of capacity that would be closed over the next decade even if Kyoto were not implemented.) In addition, output from remaining plants would be reduced by 285 terawatt hours (TWh) because they would cost more than gas plants and therefore would be used less. Including the carbon tax, the result would be a €15 billion drop in net revenues for the sector (a drop in revenue of €11 billion plus the €4 billion carbon tax), which would be partly offset by a €7 billion reduction in fuel and labor expenses.

- Gas suppliers would enjoy higher prices on all of their output (worth €10 billion in pure profits) and higher product volumes (worth €10 billion in revenues).

- Nuclear plants and existing plants powered by renewable energy would benefit from increased prices for their output. Overall, these technologies would enjoy €15 billion in higher revenues, all of which would be profit.

- Existing CCGTs would enjoy higher power prices and would also gain from increased operation. However, this would be offset by carbon taxes and higher gas prices. Therefore, the net increase in profit would be somewhat under €1 billion.

- Governments would reap €17 billion from the new carbon tax. After the €2 billion in subsidies for plants powered by renewable energy and CCGTs, governments would have €15 billion. They presumably could use most, if not all, of this amount to reduce the cost burden on some stakeholders.

In alternative scenarios—for example, with carbon credits instead of carbon taxes, or with charges of up to €35 per ton on CO_2 emissions—the net cost to Europe would not change much. But who won and who lost would vary significantly. In all of these scenarios, however, some stakeholders would stand to suffer much more than others. As a result, it is highly likely that governments would redistribute part of the burden.

EXHIBIT 9

KYOTO MEASURES FOR POWER GENERATION COULD CAUSE SIGNIFICANT WEALTH REDISTRIBUTION

Scenario with €25-per-Ton Carbon Tax

Primary Beneficiaries	Source of Benefit	Change in Value Added (€billions/year)
Power plant manufacturers	Revenues from construction of new power plants	8
Gas players	Revenues from increased gas consumption	10
	Increased profits of non-European producers from gas price increases	7
	Increased profits of European producers from gas price increases	3
Selected generators	Additional profits for nuclear power plants	9
	Additional profits for existing hydroelectric and wind-powered plants	6
	Additional profits for existing CCGTs	1
States	Carbon tax receipts, less subsidies to renewables	15
	TOTAL BENEFICIARIES	**59**

Primary Losers	Source of Loss	
Consumers	Increase in energy prices for large industrial users	–14
	Increase in energy prices for commercial and residential customers	–27
Selected generators	Cost savings from closing coal-fired plants or operating them less (fuel, labor)	–4
	Write-offs and lost profits from closing coal-fired plants or operating them less	–11
	Cost savings from closing old oil- and gas-fired plants (fuel, labor)	–1
	Write-offs and lost profits from closing old oil- and gas-fired plants	–2
	TOTAL LOSERS	**–59**

Source: BCG analysis.

Note: Scenario with power generation required to be responsible for 25 percent of Europe's total reduction in CO_2 emissions to meet Kyoto goal. Evaluations for 2012.

Implications and Challenges for Stakeholders

Inability to project the future should not be an excuse for inaction. Although it is impossible to determine precisely how the European electricity market will evolve, it is possible to understand the factors that will drive the market development, to shape them, and to prepare to seize opportunities.

Many implications are specific to individual groups of stakeholders. All stakeholders, however, will need to understand how the market might develop—at both the European and the local level. They will need to do what they can to shape policy and regulation, and to deal with issues such as preventing or mitigating a potential boom-and-bust cycle; implementing Kyoto; securing access to gas; shaping policies for nuclear power and renewable energy; and setting competition policy in the gas and electric sectors. They will also need to prepare for a more volatile energy market.

Power Generators

This section first explores common challenges and implications of the market changes. It then looks at the issues facing generators with particular types of plants.

All Generators

Optimize the value of existing assets. Many of the assets that generators now own could become more attractive as a result of rising prices, but the increase in value also might need to be defended. For example, the challenge for owners of nuclear plants would be to avoid their forced closure. Consequently, companies will benefit from taking the following steps:

- Evaluating the implications for their assets of possible developments (such as boom-and-bust cycles, the implementation of Kyoto, and regulatory actions such as special windfall taxes aimed at redistributing any increases in profits)
- Identifying steps they might take to maximize the value of those assets in each possible scenario

Create a framework for investing in different competitive environments. It will be critical to understand how different sets of conditions will affect the attractiveness of investments in generating plants. For example, consider the following circumstances:

- Concentrated markets are likely to be the most attractive over the longer term, so insulated markets where oligopolies naturally reside could be attractive. But the allure of such pockets might fade if changes in the grid and access rules cause interconnections among markets to strengthen.
- Alternatively, regulated markets that guarantee respectable returns—for example, capacity markets for peak supplies—will probably be much healthier than deregulated, highly competitive markets.
- Highly competitive wholesale markets coupled with the significant possibility of a boom-and-bust cycle are likely to make investments in capacity attractive primarily to those investors who feel confident of their ability to invest and divest opportunistically (buy capacity at distressed prices during the low point in the cycle and sell it at the peak). Such investment would be highly risky, however, and therefore unattractive to other investors.

Secure access to gas. It seems highly likely that there will be a major increase in gas-fired generation, which will lead to much tighter gas supplies and higher gas prices. In such an environment, generators that secure long-term access to competitively priced gas supplies could have an advantage.

Accelerate the consolidation of the power and gas business. Under most scenarios, becoming a vertically integrated giant, if that is permitted, will be highly desirable. Such companies will be in a much stronger position than others to influence prices, secure stable customer bases, obtain access to imported gas, and forge strong relationships with governments and regulators. Such a position may be viable in one region, but it may well extend across regions to limit regulatory and market risk. Clearly, these players will need to prove to regulators and governments that they are benefiting the consumer, not just themselves.

Prepare for the opportunities that will result from increasing volatility. Volatility in wholesale markets will change. For example, modest price volatility may occur during busts because of the flattening of the supply curve, while tight supplies or shortages may trigger high volatility during booms. To build the flexibility that will be required to profit in such an environment, generators (and other stakeholders such as retailers and even major users) will need the following characteristics:

- An ability to understand continuously how developments could affect the value of specific assets and market positions.
- Financial muscle to weather the bust. For example, this could allow a company to invest in attractive positions and assets even during the down portion of the cycle.
- Vertical integration—so the negative impact of volatility in one part of the value chain is offset by its positive impact on another part.
- A diverse portfolio of assets and contracts, particularly "swing" assets that can be used to alter exposure to the power and gas markets as prices fluctuate (for example, gas storage and generating capacity for serving peak demand).
- A risk-management capability that can both measure the value at risk and hedge against the risks.
- An asset-trading mentality and skills attuned to a cyclical environment, where an ability to time investments and hedge properly will be crucial.

Nuclear Generators

In all likelihood, existing nuclear plants will be highly valuable. The challenges will be capitalizing on their stronger position (retaining windfall profits) and prolonging their lives.

Maintaining and strengthening links to governments will be critical: the support and involvement of governments is going to be vital in the medium and long term to retain profits, limit cost overruns and price volatility, secure cost-effective financing, and extend the life of reactors beyond 40 years. Private investors, however, will view the risks of new plants—volatility in electricity prices, cost overruns, the cost of financing construction, the time needed to build plants, and uncertainty about regulations in the long term—as significant barriers to committing capital.

Coal Generators

To protect the value of coal-powered plants, companies should have a plan for managing the endgame if Kyoto is implemented. Operational considerations include the feasibility of using some biomass fuels and improving the ability of plants to cycle on- and offline so that they can supply intermediate, not just base-load, demand. In addition, companies should be exploring creative options for minimizing regulatory and business risks—for example, spinning off or selling coal-fired capacity. They will need to seek compensation for the costs of closure due to Kyoto, including but not restricted to ownership of the trading rights for the CO_2 these plants emit today. They may also be able to stay in coal-fired generation if they can get subsidies for clean-coal technologies—although it does not look likely that such technologies will prove economic in the next decade.

Gas Generators

Although this segment of the industry faces great growth prospects, reaping solid returns may be challenging. It could depend heavily on gaining access to gas supplies under favorable terms. Larger generators with strong balance sheets or the ability to hedge price, volume, and credit risks may enjoy significant advantages over smaller players. Suppliers are likely to view smaller players as higher risks and be reluctant to offer them favorable contracts. So size will matter. Companies that cannot build critical mass on their own might consider a partnership, acquisitions, or a merger with a major gas player.

Exhibit 10 compares the positions of Europe's top ten generators along several dimensions that will be important in the next decade.

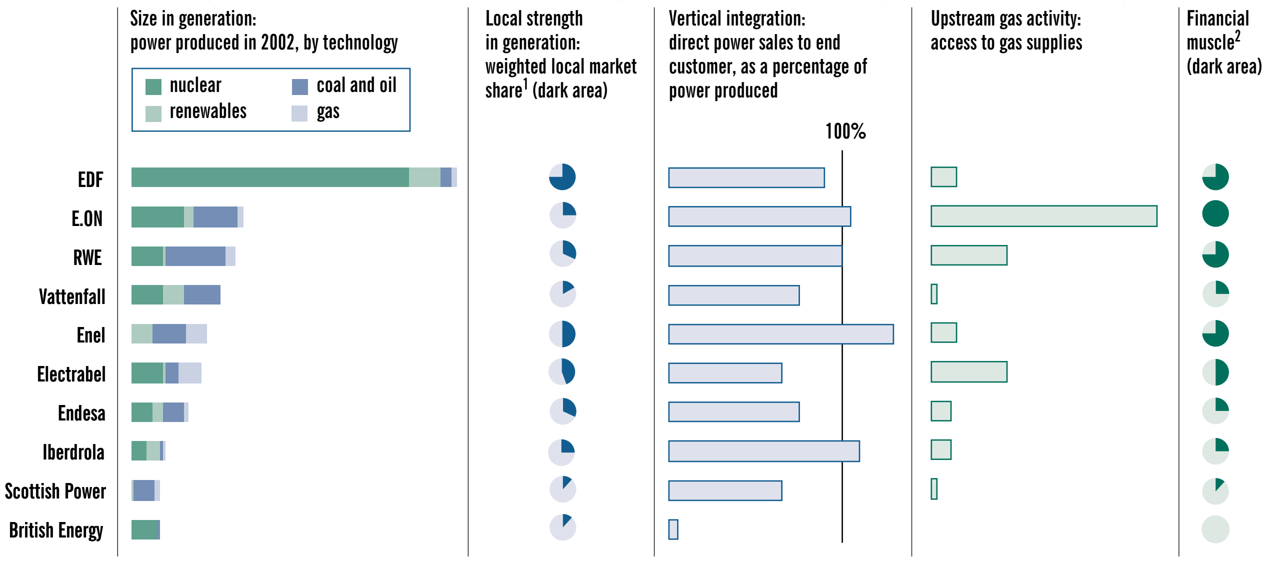
Gas Players

Everyone should prepare for a tight, growing, and generation-driven gas market. Companies with access to relatively low-cost, long-term supplies will be in an enviable position when prices rise.

The market may swing between periods of excess gas supplies and shortages (its own boom-and-bust

EXHIBIT 10

RELATIVE POSITIONS OF EUROPE'S TOP TEN POWER GENERATORS



Source: BCG analysis and estimates.

Notes: Estimates are for 2002 for Europe only, rounded. The European market includes the 16 countries considered for power-generation supply curves as well as selected Eastern European countries (the Czech Republic, Hungary, Poland, and Slovakia). Estimates include consolidation moves or alliances announced but not yet closed.

[1]Financial muscle is represented by average market share in electricity generation for each local market weighted by the importance of the local market in the company's power-generation portfolio.

[2]This assessment is based on market value and financing capacity (additional debt to reach EBIT/gross interest=2.5, plus noncore assets that could be sold, plus cash and cash equivalents).

cycle). Consequently, many of the recommendations for power generators also apply to gas players. Because the development of competition in the European gas market is uncertain and may differ by country, there is a range of possible business models. To succeed over the long term, players will benefit from being nimble, developing a variety of skills and positions, and creating different options for the potential scenarios.

Upstream Companies

These players face the happy prospect of rising margins on existing production. In addition, they will have plenty of investment opportunities. But profit margins on new fields promise to be thinner because these fields will cost more to develop than existing fields did. Moreover, these new opportunities will be unlocked only when the future electricity landscape becomes clearer—in other words, when major issues such as implementation of Kyoto, the competitive structure of the electricity market, and the fate of nuclear power are resolved.

Gas Importers and Wholesalers

Their challenge will be finding new, flexible ways to serve the rising demand. In the future, power generators will potentially be exposed to prolonged swings in prices and perhaps in the amounts of gas they need. As a result, strong risk-management skills will be required.

Swing gas fields that gas importers have been relying on to respond to demand shifts will be declining even as demand is rising. This will put a premium on new sources of flexibility such as storage, interruptible or flexible contracts, LNG, and swing generating assets such as gas-fired power plants.

To remain in the game, importers and wholesalers should consider forming partnerships with power generators that otherwise might bypass them and build their own gas businesses, eventually marginalizing them. (An alternative would be investing directly in the power business, but such moves may not offer attractive returns if there are boom-and-bust cycles.)

Intensive Energy Users

Many large users of electricity are not yet facing the facts. They are still expecting deregulation to give them the power to negotiate significantly lower prices. They should not, however, expect prices to be driven down over the long term.

Despite some potential gains in the short term, wholesale energy prices are likely to rise and become more volatile over the longer term. The reasons are an increase in the marginal cost of delivered power (up to 35 percent without Kyoto and up to 65 percent with Kyoto) and an increase in the marginal cost of delivered gas (up to 25 percent without Kyoto and up to 40 percent with Kyoto). Clever buyers could find themselves with a significant cost advantage if they sort out the risks they face and how to manage them, and time their investments and contracts well.

Savvier large electricity or gas users will strive to build a sustainable and competitive long-term supply of energy—whether through long-term contracts or direct investments. Goals or actions they should consider include the following:

- Aim to buy electricity and gas over the long term below their future long-run marginal costs (although this will depend on the future structure of the local energy markets).

- Review supply contracts to assess their value in a future in which prices are more volatile. For example: What are the scenarios for prices in the local electricity market? What would happen to a company's own energy costs given its particular electricity and gas contracts? What would happen to its overall competitive cost position? Are there attractive caps on prices that could be valuable and might be extended? How creditworthy is the company's current supplier?

- Hedge risks. For example, a big energy user might be able to benefit from a boom-and-bust cycle by making tactical investments in assets and contracts. By understanding the position in the cycle, it might be able to sign attractive deals just as prices bottom out. Another option for some heavy users is to invest in assets that provide flexibility to manage and benefit from volatility—combined heat and power plants (CHP) that can produce power or heat, for example.

- Because higher prices mean that efforts to improve efficiency will have a higher payoff, intensify the push to achieve greater energy efficiency in their processes.

- Review investment plans and consider moving energy-intensive operations to places with more plentiful, cheap supplies of energy. For example, Alcoa recently agreed to build a smelter with 322,000 metric tons of annual capacity in Iceland, where cheap (and environmentally friendly) hydropower is available.

Energy Retailers

Much of the advice for industrial users also applies to retailers of electricity or gas. Like major energy users, retailers need to understand how cyclicality and long-term rising prices will affect their costs and demand from their customers, how to benefit from these trends, and how to hedge their risks.

In particular, if such retailers are not already part of a vertically integrated company, they will need to consider how to hedge their risk by acquiring long-term contracts or assets. Doing so at the right time in the cycle, however, will be critical. For example, Centrica recently acquired gas-fired power-generating assets at about one-third their original cost. One further implication for energy retailers: don't overcommit in deals with customers, and be particularly careful to avoid long-term price caps.

Power Plant Manufacturers

These companies should assume that gas-fired generation and generating technologies powered by renewable energy will remain their most attractive business opportunities. But like their customers, manufacturers should be preparing for a boom-and-bust cycle in the demand for new generating plants. They will need to make engineering and manufacturing as flexible as possible, so they can ramp capacity up and down faster. Because many of their smaller customers in the electricity industry may fail in the years ahead, manufacturers should also pick their long-term relationships carefully.

In addition, their cost and performance targets should be based on a solid understanding of local markets as well as global trends. For example, targets for the costs of "clean" coal plants need to be very aggressive. Companies need to be able to build greenfield, clean-coal plants at a cost of €700 per kilowatt or less, depending on local gas prices. This amount is lower than the current targets of some manufacturers.

Regulators and Governments

Regulatory agencies and governments will have to recognize that not all policy goals are achievable; tradeoffs will have to be made. The major issues or priorities these bodies will have to address include the following:

Cheap and stable prices and reliable supplies. Given the consequences of a boom and bust, assuring reliable supply (keeping the lights on) and stable prices (minimizing volatility) should be treated as vital and challenging goals. In particular, regulators need to think through how they encourage and support the investments needed to ensure supply. While keeping prices low should always be a goal, regulators will have to resign themselves to the fact that wholesale prices in most markets are almost certain to rise, particularly if Kyoto is implemented. It might be advantageous to spread the cost of Kyoto unevenly across different customer segments; regulators will have to decide which customers most need cheaper prices. In the longer term, rising prices for selected customers might even decrease the overall burden of Kyoto by promoting energy conservation.[9]

Customer choice and competition. Are these goals or means? Policymakers need to think hard about this, because they are challenging and even risky goals. If they are means to cheaper prices, their effectiveness needs to be compared with that of alternative pathways. It may be that the increased risk to suppliers of not being able to lock in customers will result in higher costs that will eventually be passed on to customers, as well as higher risks of a boom and bust.

Greenhouse gases and reliable electricity. Deciding exactly how to eliminate or dramatically reduce emissions of greenhouse gases obviously involves making a host of tradeoff decisions that will affect everyone in Europe. In tackling that enormous challenge, governments should realize that the ultimate decision about how to allocate the burden is not the only issue that matters. To prevent the uncertainty about Kyoto from delaying critical investments in the energy industry, it is equally important that governments make decisions in a timely fashion and plan carefully for effective implementation. Before they commit further capital, investors in power generation will want to understand how Kyoto will affect costs and prices down the road.

Nuclear power. A hard-line goal of phasing out nuclear power is probably a risky choice, since nuclear may have significant value in the future. This means considering how to keep the option open by doing the following:

- Reviewing the planned timetable for phasing out nuclear plants.
- Preserving technical capabilities so that if and when a new plant is required (perhaps ten years from now), it can be built. As a major user of power, Europe probably needs to play a part in preserving or even developing such capabilities.
- Continuing to develop a government track record in supporting nuclear plants to overcome private investors' reluctance to back nuclear projects (for example, in helping hedge risks of cost overruns by providing guarantees to lower costs for financing when a new plant might be required).

Energy independence. This is a serious economic and security issue, but it is a goal that will be extremely difficult to achieve given the likely need to import significant quantities of gas from Russia, the Middle East, and Africa. Diversifying risk by supporting the growth of LNG, developing more confidence in sources of piped gas, and supporting nuclear and renewable power might alleviate these concerns.

Set appropriate incentives for key stakeholders. This requires understanding in detail the economics that matter to different stakeholders and the incentives that shape their behaviors. For example, merchant generating plants (ones that do not have long-term supply agreements) typically make 90

9. Slower growth in energy demand is unlikely to reduce significantly the risks of a boom-and-bust cycle, the likely increase in prices, or the cost of Kyoto by 2012. But it could do so in the following decade.

percent of their profits in 10 percent of their operating hours. Excessive price capping will undermine their business model and make them highly unattractive to investors. There is an argument, however, that some sort of price control is needed because short-term demand for electricity is relatively inelastic. (This is because power is a small part of many users' total costs, and there is currently no effective way to reduce demand from households at short notice.) So if regulators decide that price caps are necessary but they also want merchant plants to play a role in the market, they will have to carefully craft and implement price caps in a way that assures investors that they are seriously committed to nurturing the sector.

A stable regulatory environment. Creating a long-term framework and setting the rules for electricity and gas markets are critical to attracting long-term investment in the optimal mix of generating capacity, transmission capacity, gas supplies, gas infrastructure, and nuclear power. Before they move, investors will insist on a clear set of long-term policy goals (and explicit tradeoffs), and a track record in adhering to them.

A common European policy. The ideal would be for governments to act collectively in addressing at least some issues that transcend national boundaries. These include implementing Kyoto, taking a coherent approach to prices for heavy users of energy, and ensuring adequate gas supplies. If acting at the European level proves to be impossible, however, governments should strive to act nationally or regionally whenever possible.

* * *

The technology, capital, investors, and expertise exist for Europe to make the right tradeoffs and decisions. But achieving this future requires concerted actions by an array of stakeholders on a variety of fronts and in different countries. A degree of muddling through is likely, and need not be disastrous. But companies, investors, energy consumers, and policymakers that address in a timely fashion the issues this study has raised stand to realize a significant payback.

Methodology

BCG created a model of the 2002 market for European power generation and then projected changes in supply and demand.[10]

Large Overcapacity Exists

Although peak demand was only 415 GW in 2002, there were 700 GW of power generation capacity. Of these 700 GW, Europe could count on only 550 GW to be available at peak demand. The remainder, mainly from hydroelectric and wind-powered plants, could not be depended on. This still left an excess of 33 percent, which is well above reserve levels required to ensure that generators can meet peak demand.

This overcapacity existed—and still largely exists—because of the way regulated regimes operated in each individual country. Regulators tended to err on the side of caution in preventing shortages of electricity. And companies were willing to oblige and build more capacity than necessary because their position protected them from the resulting risks; they could simply pass on the higher costs to customers.

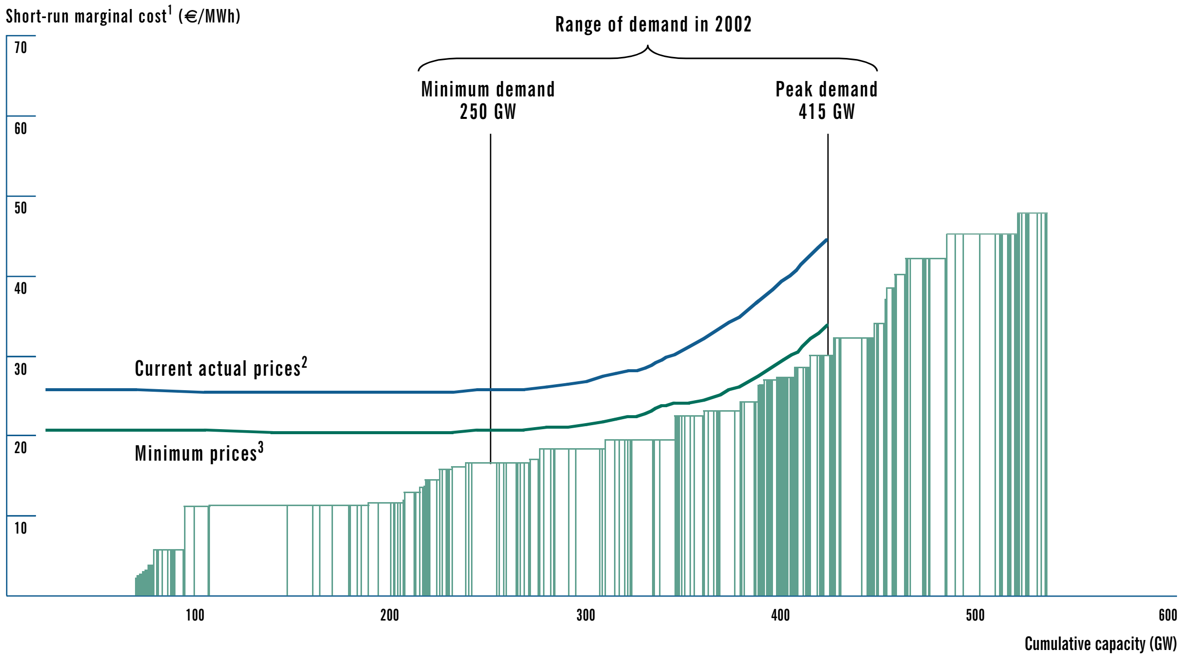
The overall situation can be summarized in the European supply curve shown in Exhibit 11. European power plants are sorted from left to right on the basis of their short-run marginal costs (shown on the vertical axis). The horizontal axis represents the capacity of each plant, adjusted to reflect its

10. The markets taken into account in this supply curve include 16 interconnected European countries: Austria, Belgium, Denmark, Finland, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.

EXHIBIT 11

OVERCAPACITY AND MODERATE PRICES IN EUROPE

European Supply Curve in 2002



Source: BCG analysis.

[1]The short-run marginal cost is the variable cost incurred directly when producing electricity: the costs of fuel, nuclear waste processing, and variable operations and maintenance (O&M).

[2]These prices are derived from a weighted average of quotations in the different markets considered. Selected transactions are likely to be slightly lower, as these quotations often represent an index that large purchasers try to better.

[3]The minimum price that a given power plant is likely to realize in a competitive wholesale market, depending on its position on the supply curve.

average availability. Also shown is the demand, which ranges from 250 GW to 415 GW at its peak.

The exhibit also shows estimates of the average prices each plant would be able to realize in a perfectly competitive market *(minimum competitive prices)*.[11]

Actual prices are higher than minimum competitive prices, for a number of reasons. (See the insert "Modeling Power Generation Markets," page 36.) As Exhibit 11 shows, actual prices realized by base-load plants are an average of €5 per MWh higher than those in a perfectly competitive market.[12] Peak prices trade at an even higher premium.[13]

Capacity Will Be Retired or Mothballed

A number of plants will be forced to close in the coming years because of a combination of obsolescence, environmental issues, and low prices, which will leave higher-cost plants unable to recover their fixed operating costs. Exhibit 12 shows a simplified version of the supply curve, including the full cash cost per MWh that each plant has to cover to break even. Also shown is the price per MWh in 2002.

Many plants are not even covering their full cash costs and are likely to be mothballed or closed. This is particularly true of old oil- and gas-fired plants.[14] In addition, some of the older coal-fired plants can expect only low or negative returns, or are reaching the end of their technical lives. Some of these will be retired, depending on the balance of supply and demand in the local market, prices, and the capital costs required to make the plants competitive. As a result, Europe is likely to continue experiencing a net loss of generating capacity.[15]

A Large Amount of New Capacity Will Be Needed

Excluding factors that could change the projected supply and demand (such as the implementation of Kyoto), Europe will require 80 GW of new capacity before 2012 (65 GW in addition to the 15 GW already under construction). Although the exact number depends on many assumptions, it appears likely that most markets will require significant new capacity by that time, and for many (such as Scandinavia, Spain, and Italy) the need is more pressing.

The estimate of required new capacity is based on the following assumptions:

- There are currently about 135 GW of excess capacity (550 GW of capacity available to supply peak demand of about 415 GW).
- Add to the 135 GW the approximate 15 GW of new capacity already being built.
- Subtract from that total about 40 GW of coal-fired plants that will be retired by 2012 and up to 60 GW of old, mainly uneconomical oil- and gas-fired plants that will be mothballed or closed by that time.
- Subtract an additional 80 GW for the capacity that will be needed to supply the increase in peak demand resulting from the expected 1.7 percent annual growth in the market, which will cause peak demand to grow from about 415 GW today to about 495 GW by 2012.
- Subtract a spinning reserve of about 35 GW that will be required to respond quickly to small fluctuations in demand.

11. This price refers to the average price a plant realizes, which depends on its position on the supply curve. As plants move to the right, they operate fewer hours annually, but the average price they realize rises because they enjoy an increasingly richer mix of prices. (Typically, a base-load plant realizes a mix of off-peak, intermediate, and peak prices and operates all the time. A peak plant realizes a higher average price because it supplies only peak demand, but it operates fewer hours annually than a base-load plant and therefore receives less annual revenue per megawatt of capacity.)

12. The prices shown are, however, based on publicly quoted prices in power pools. The largest power purchasers seek discounts from this level when negotiating power contracts directly. As a result, actual wholesale prices are likely to be slightly lower than shown here, and thus closer to minimum competitive prices.

13. Typically, peak prices are more influenced than base-load prices by local transmission constraints. For example, they are more affected by the withdrawal of capacity within a local market. Therefore, observed, or actual, peak prices tend to be higher above the minimum competitive price than base-load prices.

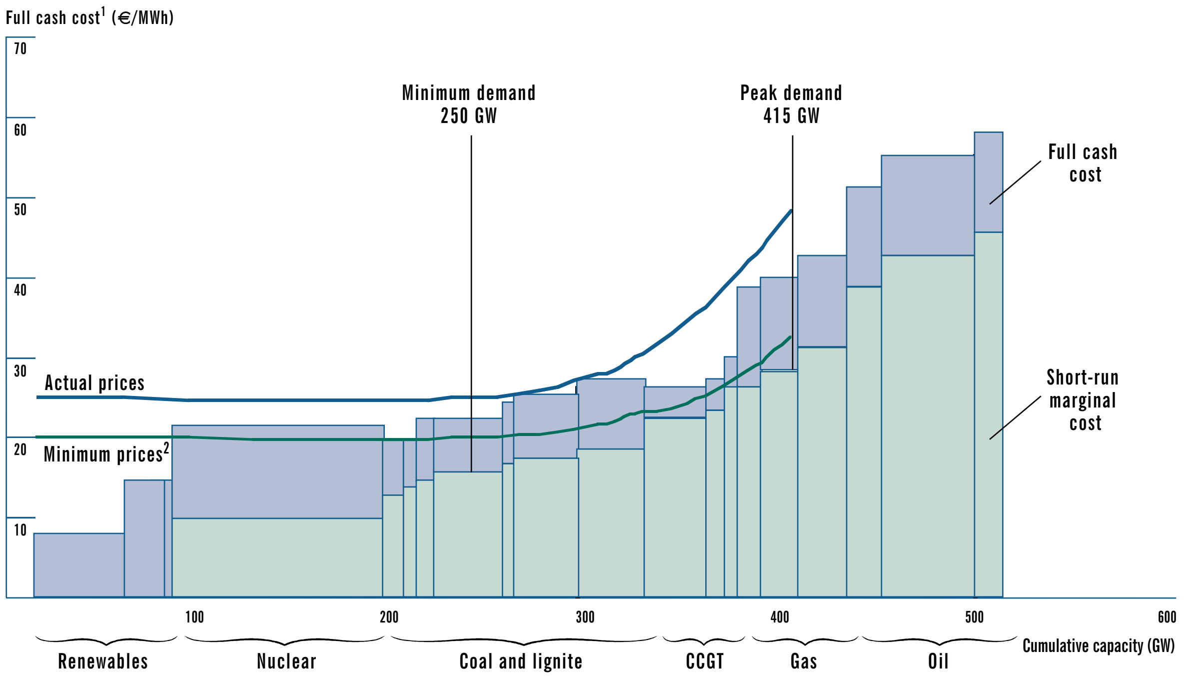
14. These plants are usually uneconomical and are typically justified only to the extent that they are required to maintain system security.

15. Of course, the amount and timing will vary by local market because different markets have different balances of supply and demand and different growth rates.

EXHIBIT 12

MANY PLANTS ARE BARELY COVERING THEIR CASH COSTS

Simplified European Supply Curve in 2002



SOURCE: BCG analysis.

[1]The full cash cost is the total cash that has to be expensed over the year to maintain the plant, divided by its actual power production. It consists of the short-run marginal cost plus the costs of staff and of fixed operations and maintenance (O&M).

[2]The minimum price that a given power plant is likely to realize in a competitive wholesale market, depending on its position on the supply curve.

In the more conservative scenarios that BCG constructed—for example, those with slower growth in demand, or with fewer plants being retired and all plants being run more hours per year on average—the need for significant investments in capacity would be delayed, but only by three years at the most. The conclusions of this report remain valid under these scenarios: there would still be a boom and bust; energy prices would increase by the same amount, albeit over a longer period of time; and the cost of implementing Kyoto would be on the same order.[16]

16. Measures to curb growth in demand, however, are likely to have a more important impact in the longer term, in particular between 2012 and 2020 if nuclear reactors are phased out as planned.

MODELING POWER GENERATION MARKETS

The **short-run marginal cost** of a power plant is its direct cost of producing one MWh of energy. This typically consists of the cost of fuel, variable operations and maintenance (O&M) costs, and the cost of waste produced by nuclear plants. A plant would typically run only if the price were above its short-run marginal cost.

A **supply curve** models a power generation market by ranking the plants in terms of their short-run marginal costs. In a perfectly competitive market, prices of power for any level of demand will settle at the marginal cost of the marginal producer. Plants to the right of the particular demand will not be used to supply it.

Like demand, power prices fluctuate. Base-load prices are lower than peak prices, which are set by more expensive plants. A steep supply curve indicates that there will usually be both higher prices and more variability in prices as demand fluctuates.

In practice, **actual prices** tend to be above the theoretical, minimum competitive price in each local market (isolated from other markets by transmission constraints). There are a number of reasons, including the following:

- Oligopolistic pricing behavior.
- Differences in local technology mix: for example, the Netherlands has more gas plants and thus higher marginal costs than France, which has many nuclear plants.
- Operational constraints within the local market that limit the ability to operate the lowest-cost plants, particularly at times of peak demand. For example, there may be local transmission constraints or some plants may not be available quickly enough to be put into operation, or they may have higher variable costs if they have to be brought online quickly for short periods. Typically, transmission constraints have a greater impact on peak prices than on base-load prices, which explains why European base-load prices are on average €5 higher per megawatt than minimum competitive prices, while peak prices are on average €10 to €15 higher per megawatt than minimum competitive prices.
- Gas arbitrage opportunities that induce generators to sell their gas rather than to burn it in their plants.

The **full cash cost** per MWh of a plant consists of its short-run marginal cost plus its fixed O&M and staff costs, divided by its actual production. The full cash cost will typically depend on the number of hours the plant can run over the year, which in turn depends on its position on the supply curve. Plants to the right of the supply curve are operated less often and therefore have high full cash costs per MWh. Plants whose full cash cost is above actual prices will not be able to cover their fixed costs and are thus candidates for closure or mothballing.

The **full cost**, or **long-run marginal cost**, of a plant includes its capital costs and financing costs on top of its full cash cost. An investment in a new plant would be made only if projected prices were above the long-run marginal cost.

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