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The Next Wave of Generation Investment

EEI Edison Electric Institute

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I. Executive Summary

The next wave of investment in U.S. generation is about to hit. While conservation and renewables can play a role, the bulk of our need for new sources of electricity will be met by some mix of natural gas, coal, or potentially nuclear-fuelled capacity. The choice involves billions of dollars for assets that will live for 30 years or more—and getting it "right" has never appeared more daunting. History teaches that choosing the wrong technology can wipe out billions of dollars of investment, and the economics are driven by some highly unpredictable factors. Will gas prices continue on their historic ascent? Will some form of carbon regulation result in the value of investments in coal generation being erased? Will low-carbon technologies—such as IGCC coal and next-generation nuclear—end up costing much more than anticipated?

While many view this approaching wave as an opportunity for growth and profit, some are more reticent. They recall the industry's previous track record in picking the right technology has been mixed; take the last decade's enthusiasm for natural gas combined cycle technology. And the role of the regulator in helping to underwrite these risks is more uncertain than ever. Yet the failure to invest could be even more damaging, with higher power prices, reduced reliability, and growing political pressure to "do something." So if the industry must take the plunge, what should policymakers do to help reduce the risks? Even more importantly, what should industry players be doing to protect their shareholders and ratepayers from another financial wipeout?

The industry confronts great uncertainty over what the "right" choices are when it comes to building new baseload[1] capacity. And electric companies risk "getting it wrong," with serious consequences for the industry and the nation. In response to these concerns, Edison Electric Institute (EEI) and Booz Allen Hamilton embarked on a study to define the magnitude and sources of risk around meeting the nation's need for electricity generation and to identify alternative ways to address such risk.

Recent history highlights the stakes. During both the nuclear-building boom of the 1970s and the gas-fired boom of the late 1990s, the industry's collective decisions to place big bets on the latest technologies cost many shareholders and customers dearly. Nuclear plant construction costs more than doubled after the Three Mile Island and Brown Ferry incidents, while low-cost natural gas in the 1990s and the growth of independent generation led to a gas-fired capacity glut—driving key investors into Chapter 11 and reducing the trading values of natural gas combined cycle (NGCC) facilities to some 60 percent of original capital investments.[2] Many generation-sector executives and investors are understandably hesitant when it comes to making choices about the next wave of generation investment.

[1] Throughout this report, the term "baseload" generation refers to types of units designed to operate for approximately 6,000 hours or more throughout the year. Over the years, hydro, nuclear, gas, and above all coal-based generation technologies have been applied to meet this need.

[2] Sources: See Exhibit 2.

Many factors affect the economics of investing in new generation, but three dominate:

1. The future price of natural gas;
2. The future regulation—and potential price—of greenhouse gas (GHG) emissions; and
3. The true cost of emerging baseload technologies (most notably, IGCC and next-generation nuclear).

Given current price relationships and technologies, and with the range of possible regulatory actions, the choice of the "right" technology balances on a razor's edge. The industry must make investment decisions involving billions of dollars for assets that will live for 30 years or more, and whose value can move up or down significantly, based on changes in three complex and highly uncertain variables. The consequences of underinvestment would principally be higher electricity prices, at least in the near term, although there could be emerging reliability risks in parts of the country.

Recent public policy has begun to address some of the risks regarding natural gas prices and emerging technologies. Moreover, the industry would benefit from taking a united and proactive stance on GHG regulation. Yet while public policy can go some way toward mitigating the three risks, there is no political or regulatory solution for the uncertainty they engender.

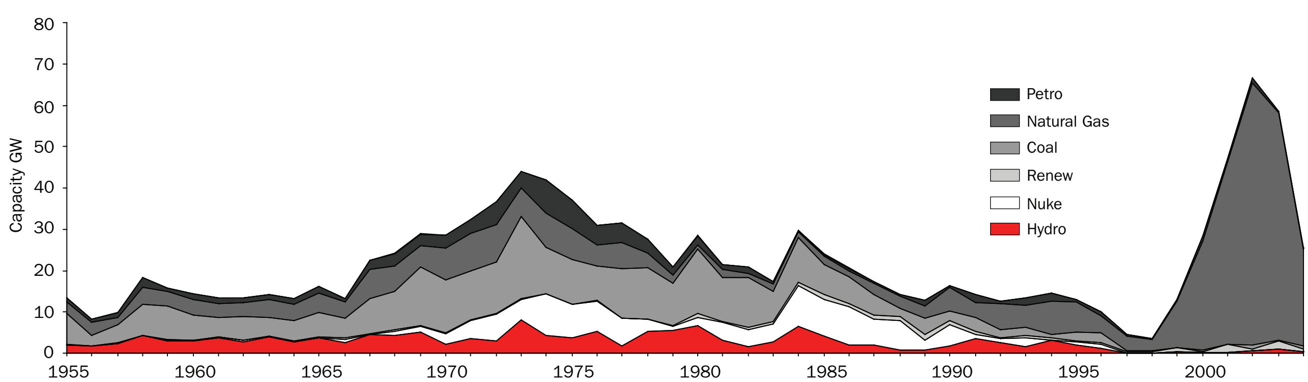
In this study, we identify some avenues the industry's leaders could pursue to better mitigate and manage these risks. We believe that the industry is unlikely to address the risks associated with investment and operation in generation assets through the further refinement of complex spot markets alone. A more practical means is to rely on simple bilateral contracts combined with predictable and balanced regulation.

More fundamentally, though, adopting the financial structure and business processes common to other capital-intensive industries managing risks will be critical for U.S. generators to thrive. Many have already modified their balance sheets and their dividend payout policies to reflect the realities of the industry. Players may also capture value by investing contra-cyclically and targeting under-performing assets, as do private equity firms. Applying rigorous, industrial-style business processes to operating power plants is also serving to unlock substantial value and mitigate risk in the sector. We also expect to see players attempting to capture the benefits of portfolio diversification, financial heft, and deep expertise needed to compete. Acquiring that ability, even more than the pursuit of creating scale alone, is likely to fuel much of the industry consolidation in the future.

II. Introduction

Today, electric companies must define how they will address the need for baseload generation capacity additions, which are imminent over the next five to 10 years. The industry is certainly not of one mind on the best response. Many companies embrace the impending requirement for new baseload investment

Exhibit 1
Historical Gross Capacity Additions



Note: Summer capacity.
Sources: North American Electric Reliability Council (NERC); Electricity Supply & Demand (ES&D); Energy Information Administration (EIA) 860; Energy Velocity; Booz Allen Hamilton analysis.

as a source of earnings growth, either through expanding their rate base or investing in non-regulated coal, nuclear (potentially), or renewable generation capacity in today's environment of high gas (and thus electricity) prices. Others, especially smaller players, are concerned about their ability to fund such investments in light of other demands on cash flow (such as transmission and distribution upgrades, environmental retrofits, and aging information technology). Many independent power producers (IPPs) worry that unpredictable wholesale prices and mercurial regulation will make investing in merchant generation uneconomic. Finally, regulators struggle to create the right set of incentives to attract investment without burdening consumers with excessive costs.

Still, there is consensus on two basic facts: First, the industry confronts a staggering degree of uncertainty over what the "right" choices are when it comes to building the next generation of baseload. Second, companies run a risk of getting it wrong, with serious consequences for the industry and the nation.

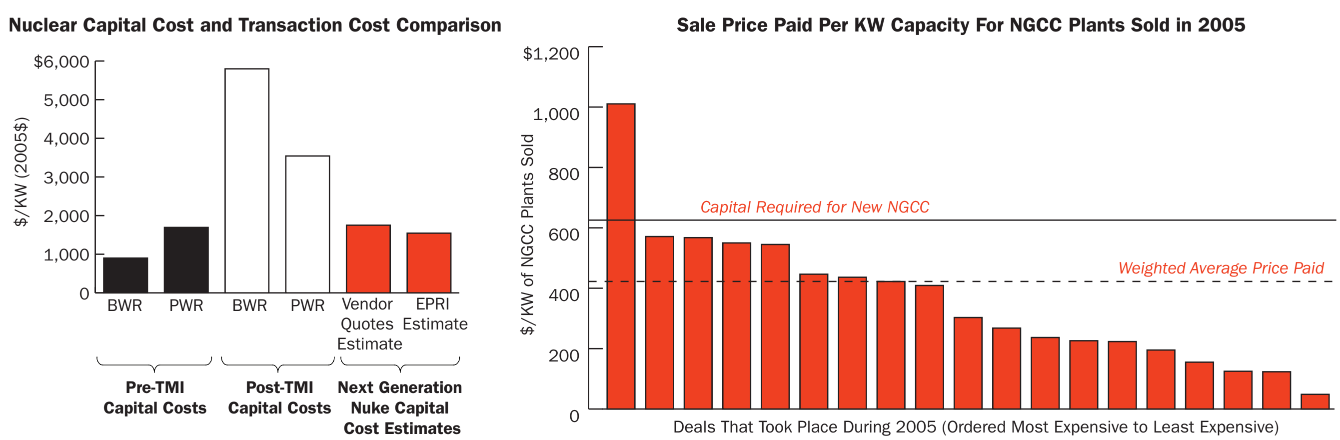
III. Experience So Far

Over the past four decades, the U.S. electricity industry has gone through two major building cycles (see Exhibit 1, page 2). In the 1960s and 1970s, the industry invested in coal and nuclear generation capacity to meet anticipated growth in electricity demand. As the 1970s progressed, however, not only was demand growth slowed by an energy crisis, economic recession, and increased energy efficiency, but inflation and construction delays made "too cheap to meter" nuclear technology much more expensive to build than anticipated. The possibility of rate hikes for the consumer, plus concerns about safety and environmental impact, brought on intensive regulatory and political scrutiny of nuclear projects, particularly after Three Mile Island. All of those factors combined to cause significant cost overruns (see Exhibit 2).[3]

In the 1990s, a period of sustained low natural gas prices, the passage of the Clean Air Act Amendments, and the emergence of highly efficient NGCCs led to another boom in generation investment. Seeing an opportunity to capitalize on the seemingly inevitable onset of power industry deregulation and the anticipated retirement of coal-based and nuclear plants, investors built smaller, cleaner, less expensive, and more easily constructed NGCCs. That led to a large capacity glut. The volatility of natural gas prices, the tightening of the gas market, and the use of highly levered, complex financing structures by many of the players further compounded the problem.

In both cases, the industry's collective decisions to make investments in single technologies had significant adverse effects. In the nuclear case, consumers bore much of the cost, whereas deregulation shifted much of the risk (and cost) from the consumer to the owners of the generation assets in the case of gas. In fact, NGCCs have traded at a significant discount to

Exhibit 2
Recent Transactions



Notes: 1) Estimate based on EIA forecast and vendor quotes; 2) Average of 2002-2005, excluding "unknown" transactions.
Sources: EIA; University of Pittsburgh; Energy Velocity; Dow Jones; Booz Allen Hamilton analysis.

[3] Source: University of Pittsburgh (L. Cohen).

their original investment, trading at an average of 60 percent of their asset value in 2005, with many individual facilities trading well below this level.

Electric utilities have spent the last five years or so repairing their balance sheets and reducing their risk profiles. Indeed, on Wall Street, the industry has outperformed most sectors over the past two years. Now, many generators are in the process of planning for new baseload generation, five to ten years from today. Industry executives and investors are understandably hesitant when it comes to choices about the next surge in investment.

The degree of risk isn't uniform across the industry. Business models, geography, and customer base play a large part in determining the amount of exposure different companies face. Due to their business model, for example, merchant generators face some of the greatest risks. Vertically integrated utilities, on the other hand, can rely on both their customers, who can ensure a source of demand for generation investments, and regulators, who can (at least in theory) assure that investors receive an adequate return on their investment.

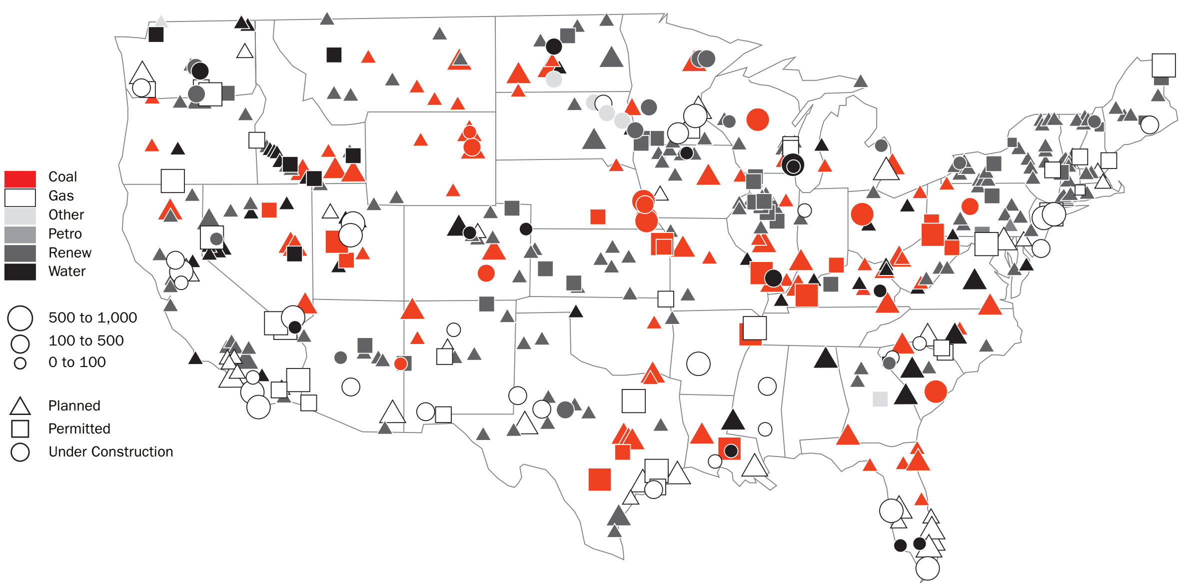
From a geographic perspective, our analysis suggests that there are two distinct regional challenges. About 30 percent of the United States largely depends on NGCC capacity and is exposed to volatile gas prices. Those regions, which include New England, Texas, and California, tend to be deregulated and require the most significant investments in new capacity over the next ten years. Right now, generators in these regions are investing little in capital-intensive new capacity.[4]

The rest of the nation's electricity demand is in regions where new capacity is unlikely to be necessary in the near future or where electric utilities receive traditional rate-of-return regulatory treatment for their investments. Yet a disproportionate amount of planned new capacity will go up in those regions; and vertically integrated companies are building the plants (see Exhibit 3).

IV. A Wealth of Worries

Not all regions fall neatly into those categories. Even companies in regions with generation-investment requirements farther in the future and with the benefits of a regulator still face many of the same fundamental risks to generation investments as their merchant counterparts. Indeed, the sheer number and complexity of risks to a new capacity investment is one of the most troubling aspects of the environment facing generation companies.

Exhibit 3
Planned Generation Capacity Additions, December 2005



Source: Energy Velocity Intelligent Map, as of February, 2005.

[4] Sources: Energy Velocity; Booz Allen Hamilton analysis.

Drawing on more than 150 hours of interviews with industry experts and executives, we identified several critical issues that impede investment in generation:

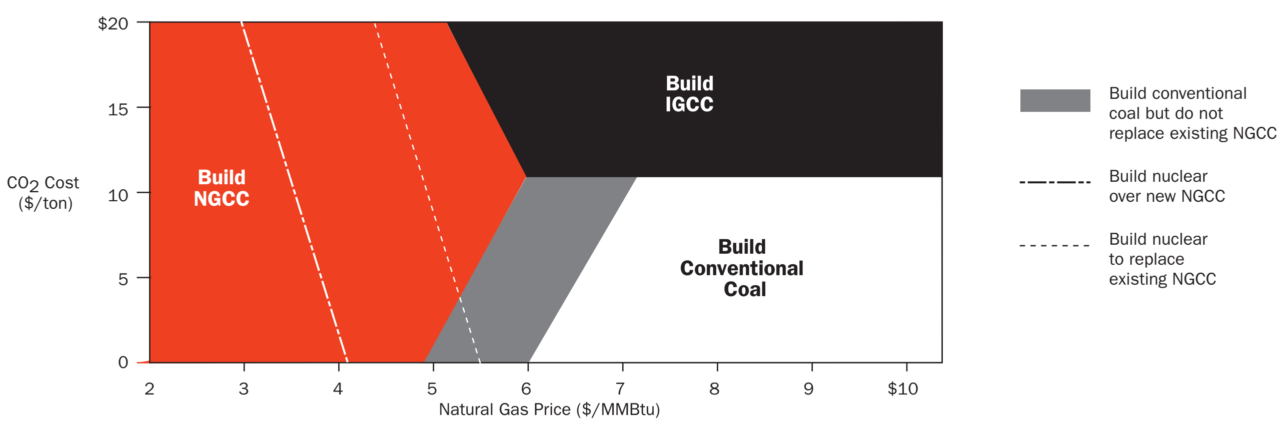
- Flaws in wholesale generation markets (for energy, capacity, ancillary services, and transmission);
- Inadequate transmission capacity;
- Mandates for renewable portfolio standards;
- Inadequate capital (given multiple demands on firm's cash flow and limited ability to reduce risk of the investments);
- Tendency of PUCs to disallow investments after the fact;
- Not-in-my-backyard (NIMBY) concerns;
- Local and state siting processes;
- Dysfunctional local and regional planning processes;
- Mercury and nitrogen oxide emissions regulations;
- Inadequate engineering/procurement/construction and skilled labor capacity; and
- "Unfair" treatment of purchased power agreements serving to disadvantage qualified IPPs from participating in the market.

We explored each of these issues to assess their likely impact on companies' investment behavior. In each case, we found that while the concern may have been decisive in specific instances, it tended to have only limited or secondary importance to the industry at a broader level.

Applying a "bottom up" model of U.S. electricity generators' finances,[5] we combined our forecasts of the expenditures required to build generation capacity over the next 20 years—across multiple scenarios—to determine whether the industry as a whole could make the anticipated investments without putting credit ratings or dividends at risk. Financing was a real concern for several companies, which were typically smaller or more financially stressed than others. For the industry as a whole, however, it was not a driving force. We confirmed this result several times in interviews with leaders in the financial community. "Finding capital is not a big worry at the moment," said one financial institution executive. "In the current environment, there seems to be plenty of capital available." Another said that "when you see capital markets not funding a project, it is because it is a bad deal, not because it is this industry."

Instead, we found that the fundamental sources of uncertainty facing utilities center on the question of which technology to choose for the next generation of baseload. We believe that issues about regulatory treatment and the financing of future investments boil down to the question of whether regulators and investors view them as economically sound. Three factors dominate the economics of baseload generation:

Exhibit 4
Technology Choice Trade-Off



Sources: EIA, Booz Allen Hamilton analysis.

[5] Note: We modeled the generation-capacity forecast on the National Energy Modeling System (NEMS), the same econometric tool used by the U.S. Department of Energy to develop forecasts for the Annual Energy Outlook and to analyze various proposed legislation and regulations. The model was modified to enable analysis of multiple fuel-price, environmental, technological, and transmission-infrastructure-development scenarios. The model of the generation sector's financial capacity was based on a "bottom up" analysis of each individual company's financial statements, plus company-specific forecasts for future transmission and distribution upgrades, environmental retrofits, ongoing capital expenditures, and future capital structure and dividend policy.

1. *The future price of natural gas.* Fuel is the dominant variable cost for generation. Coal prices are stable in the United States compared to natural gas and, based on our understanding of the coal market, are likely to remain that way over the coming decade. Gas prices, on the other hand, are extremely volatile and notoriously difficult to forecast.
2. *The future regulation and potential price of GHG emissions.* In the next decade, there is a plausible scenario whereby the United States will regulate GHG emissions. Depending on the details of the regulatory regime, carbon dioxide (CO_2) prices could be significant: $20, $30, or higher, as they currently are in Europe.[6] Such costs could radically change the economics of various baseload generation technologies.
3. *The true cost of emerging baseload technologies.* Both IGCC (critically, with carbon sequestration) and nuclear power promise relatively low and stable electricity prices, as well as low GHG emissions. The risk is that the capital and operating costs of those technologies could turn out to be much higher than anticipated.

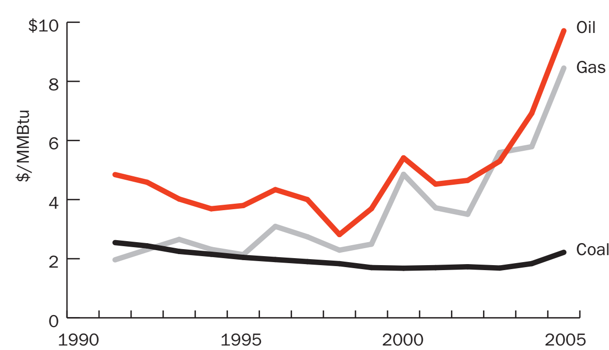
For example, forecasts including a moderate to low gas price suggest that new supply needs are relatively low: Companies will use recently built NGCC units as baseload capacity. But forecasts with sustained high gas prices suggest a need to double investments in new supply, as resources with relatively lower marginal costs (such as coal and nuclear) displace existing NGCC capacity. Exhibit 4 (see page 5) highlights the sensitivities of the economically preferred baseload technology to natural gas and CO_2 prices. (For simplicity, this is drawn with constant coal prices—the gas-coal trade-off is clearly a function of the price differential per MMBtu.) At "low" gas prices (for example, $5 per million Btus and below), NGCC is the lowest-cost option. As gas prices rise above $6 to $7 per MMBtu, however, not only is conventional coal the preferred technology, but the resulting gross margin (the "dark spread") is high enough to justify replacing existing NGCC with new coal plants. At $8 to $9 per MMBtu, a conventional coal plant becomes very attractive. Now, add in CO_2 charges, and IGCC with carbon sequestration capabilities becomes the best choice. And if current political resistance to new nuclear power plants softens and if the capital costs of the next generation nuclear plants are as low as predicted by some, then nuclear becomes the optimal choice when gas prices are above the $4 to $5 range.

The key take-away? Simply that the industry faces significant economic risks. It must make investment decisions involving billions of dollars, for assets that will live for 30 years or more, whose value can move up or down significantly on the basis of changes in three complex, practically unpredictable variables—gas prices, GHG regulation, and future generation technology. We will analyze each of these briefly, before turning to examine some possible approaches to mitigating and managing these risks.

V. Natural Gas Prices

Over the last 10 years, natural gas prices have increased dramatically. From the mid-1980s until 1999, North American gas prices were well below the heat equivalent of oil and nearly equivalent to coal (see Exhibit 5). Given all of the other advantages natural gas offered when compared to coal, natural gas was a "no-brainer" investment. But gas prices were low because for 15 years North America had more gas capacity than demand, so gas-on-gas competition drove prices down. The so-called "gas bubble" burst in 1998-1999, when supply fell short of demand—just as the construction of NGCC boomed. In fact, prices rose so much that a subset of industrial users, which represent 5 to 10 percent of the natural gas market, either left the market altogether or switched to petro-

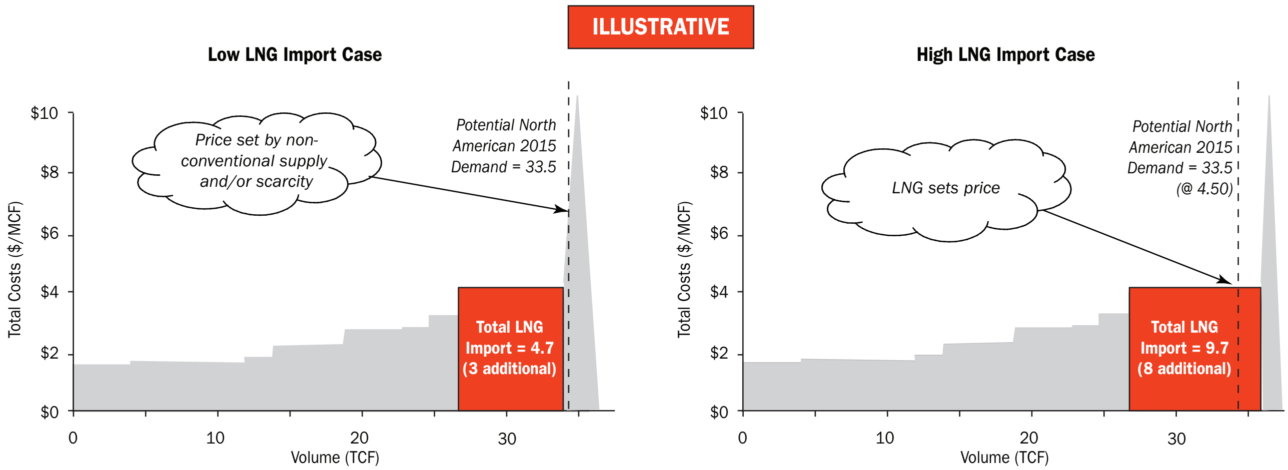
Exhibit 5
Fuel Prices Annual Average



Source: Bloomberg.

6 Source: Point Carbon, 2005, European carbon trade as of March 1, 2006.

Exhibit 6
Natural Gas Supply/Demand Scenarios
2015 Low LNG Import and High LNG Import Cases



Note: Capital costs include 15 percent return for investments.
Sources: EIA; National Petroleum Council (NPC); LNG Shipping Solutions; literature searches; Booz Allen Hamilton analysis.

leum products.[7] Since oil-based sources can meet the current marginal demand for natural gas in select industrial segments, the gas price is linked to the price of oil. Thus the run-up in oil prices in the last few years pulled natural gas along with it.

Today, natural gas trades around $7 per MMBtu; oil is at around $10. Futures markets prices are $7 to $8 for natural gas and $10 to $11 for oil through 2010.[8] These high long-term gas prices are due in part to an increase in demand, especially from the generation sector. Also, easily accessible (i.e., inexpensive) domestic sources of natural gas are inadequate to fully satisfy demand.

Due to the tight relationship between natural gas and world oil prices, high prices for gas should remain until 2010 or beyond, assuming no dramatic decrease in demand or new source of supply. Our analysis suggests that the nation would need an additional 5 to 7 trillion cubic feet (TCF) of gas supply to unlock natural gas from oil prices.

The import of significant amounts of liquefied natural gas (LNG) into the United States may lead to structural changes in the natural gas market. Depending on the landed price and amount of LNG, some believe it will become the marginal source of natural gas and therefore set the price. Others believe that though LNG will have an impact on the market, domestic gas will provide the marginal supply, setting a higher price, though still significantly lower than would be the case without increased LNG imports.

We believe there is a reasonable chance that sufficient amounts of LNG import capacity will help unlock the natural gas price from the price of oil (see Exhibit 6). Large oil and gas companies now participate in the country's nascent LNG business. To date, 18 North American LNG terminals have been approved, representing 9.9 TCF of new LNG capacity. More than 5.5 TCF of this capacity is under construction; major oil companies own 3.3 TCF.[9] Other forecasts range from 3 to 6 TCF total capacity to come online by 2010.[10]

The Energy Policy Act of 2005 also lessened the uncertainty about increased LNG use by granting the Federal Energy Regulatory Commission (FERC) authority over the siting of LNG import terminals. If LNG helped decouple natural gas prices from oil prices—and if LNG or lower-cost domestic resources set the price for natural gas supplies—gas prices could decrease to $5 to $6 per MMBtu, roughly half of what we saw in late 2005.

While most recognize LNG's potential to relieve the current pressure on gas prices, many remain unconvinced. Indeed, most utility executives we interviewed

[7] Sources: EIA; Bloomberg; Cambridge Energy Research Associate; Booz Allen Hamilton analysis.
[8] Source: Nymex futures, February 28, 2006.
[9] Source: Federal Energy Regulatory Commission (FERC).
[10] Sources: FERC 2005; National Petroleum Council (NPC), "Balancing Natural Gas Policy," 2003; EIA, "Annual Energy Outlook 2006."

are skeptical and anticipate natural gas prices will remain in the range of $7 to $9 per MMBtu for the foreseeable future. They point to local opposition to LNG re-gasification siting, despite FERC's new authority. LNG critics contend that an over-reliance on imported LNG introduces a geopolitical dimension to gas prices, reminiscent of OPEC's oil cartel. In addition, they warn that growing demand for LNG imports in such booming economies as China and India could also place upward pressure on worldwide natural gas prices. Yet there is agreement that a key indicator of the future price of natural gas is the pace and scope of the expansion of LNG import capacity.

VI. Carbon Constraints

The regulation of GHGs is another major uncertainty facing electric utilities as they consider investments in new capacity. Right now, there are no regulations at the federal level placing a specific cap on GHGs. The United States did not sign the Kyoto Treaty. Among other things, that allows U.S. electric utilities greater leeway in choosing new power sources. Federal government regulations (the Clean Air Act, Clean Air Interstate Rule, and so on) do not regulate CO_2 or other GHG emissions, such as methane.

Yet there is growing consensus that carbon-constraining regulations will come into play soon. State governments, for example, are moving forward. Last year, the Regional Greenhouse Gas Initiative of New England states—a region of the country soon to be in need of new supply—issued a Memorandum of Understanding to regulate CO_2. California, too, has passed legislation regarding the transportation sector's CO_2 emissions.[11] This year, Governor Schwarzenegger has announced new GHG emission-reduction programs that could have an impact on power supply there.[12] California is already constrained by laws and regulations precluding coal and nuclear technologies; and the state is highly dependent on NGCC.

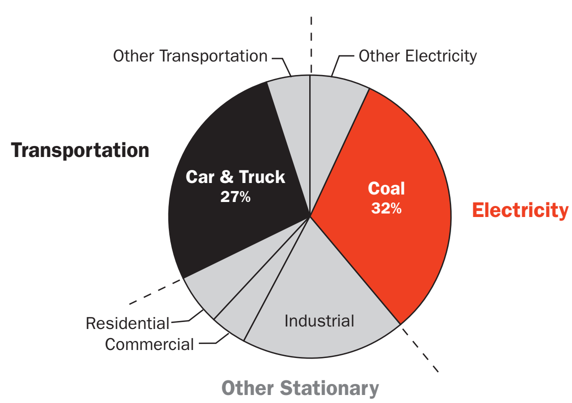
Pressure for the U.S. government to take action is accumulating from other areas, as well. Last December, for example, Goldman Sachs agreed to publicly report on its efforts to reduce emissions at power plants it owns and to look at carbon risks when judging future investment activity.[13]

"There will be a groundswell to do something," said one interviewee. "A pinch point is coming—society will suddenly demand action," added another. But just when this pinch point will occur is open for debate. Some interviewees feel the government will defer carbon constraints for at least five years; others foresee some form of regulation during the current administration. Still others feel that today's high energy costs could lessen and delay the onset of controls. That said, a sea change in the political climate in Washington, D.C., could result in more stringent regulation. Regardless of domestic politics, pressure from the international community continues to mount.

Moreover, there is no consensus on the structure of new CO_2 restrictions. Policy experts and legislators differ on whether constraints should come under cap-and-trade programs (generally preferred by industry) or a carbon tax. Furthermore, the value of carbon reductions also remains unclear. The current price in Europe for carbon reductions is around €26 per ton, but that price could go as high as €70 per ton due to the volatility of this young market.[14]

The U.S. economy could experience significant impacts from a carbon charge, and both industry and consumers would feel the costs. The two industries with the biggest stake in the future of carbon regulation are the automotive and electric utility sectors (see Exhibit 7).

Exhibit 7
U.S. CO_2 Emissions (2004)



Sources: EIA, Booz Allen Hamilton analysis.

11 Note: California Clean Car Program, passed by the Environmental Protection Agency on January 4, 2006.
12 Source: Brian Hansen, "California Sets Greenhouse Emission Goal," *Inside Energy*, June 6, 2005.
13 Source: Goldman Sachs Environmental Policy, December, 2005.
14 Sources: Point Carbon; Power in Europe.

Exhibit 8

Coal Capacity "Forced Out" vs. Prevailing Gas Prices and CO_2 Tax

CO_2 Tax, $/Ton	$3.00	$4.00	$5.00	$6.00	$7.00	$8.00	$9.00	$10.00
$100	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	95.7%
90	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	97.7%	80.8%
80	100.0%	100.0%	100.0%	100.0%	100.0%	97.9%	81.4%	65.5%
70	100.0%	100.0%	100.0%	100.0%	99.6%	83.8%	65.5%	48.6%
60	100.0%	100.0%	100.0%	100.0%	87.2%	65.5%	45.4%	27.9%
50	100.0%	100.0%	100.0%	92.2%	64.5%	42.6%	22.7%	7.5%
40	100.0%	100.0%	96.9%	64.5%	39.4%	15.3%	5.2%	2.3%
30	100.0%	98.1%	64.3%	34.2%	7.9%	2.7%	1.9%	1.0%
20	100.0%	64.1%	24.0%	4.1%	2.0%	0.9%	0.7%	0.5%
10	64.0%	10.8%	2.1%	0.9%	0.5%	0.3%	0.3%	0.1%
0	2.5%	0.7%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%

Natural Gas Price, $/mmBtu

0-5% 6-25% 26-50% 51-75% 76-100%

Sources: EIA; Booz Allen Hamilton analysis.

The incentives they face and the resources they can bring to bear to influence the outcome differ significantly. We believe the power sector has a strong interest in taking a more proactive stance in defining the appropriate regulatory framework for GHGs.

First, let's consider the other party: the politically powerful automotive industry. For this sector, delaying GHG regulations is important for protecting themselves from further market-share losses to overseas vehicle manufacturers. Better fuel mileage is the main path to lower CO_2 in the auto industry, but manufacturers can achieve it only by downsizing vehicles to boost efficiency or by using non-traditional powertrains (such as hybrids) that reduce GHG emissions. However, U.S.-based auto makers such as Ford, General Motors, and Chrysler lag behind their Japanese competitors in commercializing these technologies. Today's leaders in efficiency and hybrids are foreign manufacturers such as Toyota and Honda. This creates a strong incentive for U.S. auto makers to fight to defer decisions on carbon constraints and to shift as much of the costs as possible to other sectors.

Electric utilities hold a different hand because GHG regulation threatens them less significantly than it does the automotive industry. Electric utilities have relatively more ways to reduce emissions, including investing in different fuel types or reducing emissions by using one fuel over another (for example, NGCC versus IGCC). Nor do they face the threats from advantaged overseas competitors. Such investment decisions will vary depending on the timing and exact mechanisms of federal regulation. But the promulgation of sensible regulations sooner rather than later can create clarity, and the industry can thereby avoid stranded investments. Increased delays, on the other hand, raise the risk of the political process producing draconian rules or rules that shift more costs to generators. So the electric utility industry may gain more from resolving the uncertainty on carbon constraints—if it makes investments without certainty, the industry faces a much narrower, and riskier, range of options.

To get a sense of the possible cost of getting the design of a GHG regulatory regime "wrong," see Exhibit 8. Regulations that involve simply charging all existing generation a fee—directly, via a tax, or indirectly, via a credit-trading approach—could render a large percentage of the U.S. coal generation fleet uneconomical. The results for generators would likely be financial distress, at least partially shared by customers and taxpayers. In this scenario, the current movement to new coal plant investments could end in a round of stranded investments. On the other hand, if a generator were certain of the regulatory treatment, it could plan accordingly. Furthermore, a regime in which only new units need meet the standards would result in relatively modest costs and even less disruption and risk to generators and customers alike.[15]

VII. Alternative Technologies

While renewable technology's economics do continue to improve and their role to expand, over the next decade or two we believe IGCC and next-generation nuclear reactors are the two baseload technologies with the greatest potential to radically change the game (see Exhibit 9, page 10).

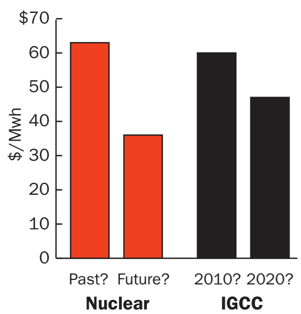
Three IGCC power plants, representing 620 MW of capacity, operate in the United States (though none of these facilities uses carbon sequestration).[16] IGCC plants gasify coal and separate out carbon monoxide and hydrogen as a syngas fuel. Using a combined cycle configuration leads to greater efficiency in converting coal to electricity, reducing fuel costs. The process can also isolate CO_2 in concentrated form, making seques-

15 Sources: EIA; Booz Allen Hamilton analysis.

16 Sources: Energy Velocity; company Web site; company press releases; Booz Allen Hamilton analysis.

Exhibit 9
Technology Uncertainties

Cost of Electricity Generation ($2005)



Quotes from Executive Interviews

Nuclear
- *"Costs are expected to be much lower—largely due to standardization."*
- *"Capital cost estimates are very notional, operating costs more so."*
- *"Politically charged issues around the fuel cycle will delay commercialization."*
- *"I doubt if they'll come back ... Very long lead times and changeable regulations."*

IGCC
- *"I would not do it now… it's just too hard. Even some of the vendors don't know how to support it."*
- *"This is still a developing technology ... far from mass commercialization."*

Sources: EIA; EPRI; University of Pittsburgh (L. Cohen); company Web sites; company financials; Booz Allen Hamilton interviews; Booz Allen Hamilton analysis.

tration less expensive compared to conventional coal technologies. However, IGCC technology with carbon sequestration remains largely unproven, and most utility representatives we interviewed weren't able to commit to this complex option.

There is also much uncertainty surrounding the next generation of nuclear reactors. Original equipment manufacturers (OEMs) and select experts claim that standardizing nuclear technology—as was done in France and other countries with successful nuclear power programs—is the key to lowering costs and reducing management challenges. Even so, none of these next-generation nuclear reactors have been built yet, and cost estimates for them remain controversial. Yet to be resolved are other issues concerning nuclear waste disposal. "Politically charged issues around the fuel cycle will delay commercialization," predicted one interviewee. Still, three consortia of generators and OEMs are in various phases of exploring new nuclear construction.

VIII. Learning From Other Capital-Intensive Industries

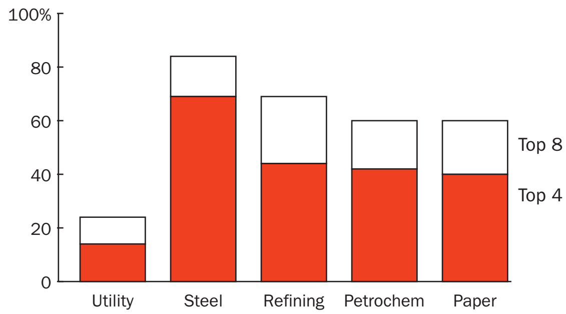
How do other capital-intensive industries respond to the investment risks they face? Their approaches could provide helpful clues as to how the electric utility industry as a whole, as well as individual utilities, can move forward on future investment strategies. Today's generating company has much more in common with other capital intensive companies than it used to—and it should face risks in similar ways.

Among the industries that face similar investment risks as electric utilities are the petroleum refining, petrochemical, paper, and steel industries. Each requires significant capital investment to increase capacity, and each must also contend with highly volatile feedstock prices, variable demand volume, and unstable output prices. The outputs of these industries are also traded without long-term (life-of-plant) contracts. Paper, for example, is typically sold in single-year contracts. Two-thirds of the nation's steel volume is moved in contracts of one to four years in length. Refiners and the petrochemical industry seldom use long-term contracts to sell finished products. In each case, short-term supply contracts are indexed to either spot market or other moving target benchmarks. Despite these familiar challenges—often cited by utility executives as reasons they cannot invest in new supply capacity—other industries regularly invest in new capacity and earn their cost of capital.

Of course, the generation sector faces unique risks, the primary one being that it is highly susceptible to adverse political intervention. This can take the form of price caps or other price-mitigation tools, mandated limits on capacity payments, and other prohibitions and requirements found in the design of electricity markets. The complexity and relative newness of competitive electricity markets make them especially vulnerable to changes by regulators, placing revenues for market participants at risk. More dramatically, even in "deregulated" markets, there is the threat of political intervention when electricity prices rise significantly. Recall the Western energy crisis of 2000-2001, when FERC eventually stepped in with price caps. "Political pressure is forcing [regulators] to keep electricity prices down with price caps," said one utility executive whose company operates in a deregulated environment. Another executive from a deregulated utility echoed these feelings: "When the price is high, we can't realize the upside, but we receive no guarantees when there is overcapacity. "Many other capital intensive-industries make the bulk of their profits during "peak price" times—for electric utilities, these are the moments when regulators step in and clamp down on profits.

Another distinguishing feature of the electric utility industry, and another legacy of its regulatory history, is its fragmentation, particularly compared to other

Exhibit 10
Top 4 and Top 8 Player U.S. Market Share (2004)



Sources: Energy Velocity; Bloomberg; Oil & Gas Journal; Nexant; Paperloop; Booz Allen Hamilton analysis.

capital-intensive industries (see Exhibit 10). As a result, many generators are unable to achieve the benefits of portfolio diversification or to realize economies derived from scale or depth of technical and management expertise. Smaller companies face a higher likelihood of bankruptcy should a major investment prove in retrospect to have been a mistake.

IX. Living with Uncertainty

Investment risks will never completely go away, even with improved forecasting. The key is to learn to live with the inherent uncertainties of the business, without the familiar benefit of a regulatory safety net—as other capital-intensive industries do. Despite the differences between power markets and those industries, there is much the former can learn from the latter when it comes to thriving in a highly uncertain environment.

The role of markets. Unlike wholesale markets in most other capital-intensive industries, administrators in many U.S. electricity markets play a pivotal role in resource allocation. While they surely allow for increased efficiency in dispatch, it is unclear whether these types of institutions are either necessary or sufficient for enabling investment in major baseload capacity. Rather than spot markets, it may be that bilateral contracts—as used in most other capital-intensive industries, in power markets such as the Energy Reliability Council of Texas, in provider-of-last-resort auctions in states like New Jersey, and in the New Electricity Trading Arrangement regime in the United Kingdom—are a more practical option. It is also possible that vertical integration into retailing may prove an efficient solution to securing the revenues needed to support baseload investments, setting aside the complexities of retail electricity (de)regulation for the moment. That has been an outcome in the U.K. power market.

Finance and business processes. The financial structure and business processes of many generators still bear the signs of the industry's regulated legacy. At the simplest level, the capital structure and dividend policy of electric companies is often better suited to a much less volatile business. While it is true that utilities just went through a period of improving their leverage ratios, their debt is still high compared to other capital-intensive industries, which also typically offer lower dividend payout ratios. In addition, many utilities are entering into creatively structured joint ventures in order to access the financing and technical skills needed to make major investments in new baseload.

Other industries use a myriad of techniques to minimize and share risk, some of which are also employed by power generators. Those practices include a broad range of contractual arrangements through equity participation; project finance structures; long-term contacts or guarantees (with providers and customers); sharing risks and costs with public entities (for example, underwriting debt, preferential tax treatment, and public R&D), and both natural and financial hedging. The list also includes stringent capital budgeting and the relentless cost-cutting that characterize the capital-intensive commodity businesses.

Another lesson from capital-intensive, bust-and-boom industries is the importance of timing in making investments, whether to build or to buy. Buying contra-cyclically—that is, buying assets at the trough of the cycle, or buying poorly performing assets susceptible to improvement—can make all the difference in investment profitability. That has been the traditional domain of private equity firms, which capitalize on the tendency for corporations and individual investors to extrapolate recent performance—that is, over-optimism on recent successes and pessimism on recent failures.[17]

[17] Source: Harry Quarls, Thomas Pernsteiner, and Kasturi Rangan, "Love Your Dogs," *Strategy + Business 42,* Spring 2006.

Industry structure—diversification, expertise, and size. Other capital-intensive industries are composed of firms that are bigger than most electric utilities; the company with the largest market capitalization in the electric industry has just over a tenth of the market cap of Exxon Mobil.[18] Furthermore, those other industries are highly concentrated, with a handful of very large companies. Because of those factors, companies in these industries can withstand negative outcomes to the "big bets" they place—losses that might sink a smaller electric company. Size also enables investment diversification to reduce risk, while still enabling companies to develop depth of expertise in different domains. Operators of large nuclear and coal generation portfolios, for example, have such size and depth. Finally, increased concentration of ownership can also serve to discourage market players from overbuilding, thereby increasing profit margins and the probability of full capital cost recovery.

Electric companies need to capture the benefits of portfolio diversification, financial heft, and deep expertise needed to compete. Acquiring that ability and then deploying it aggressively—much more than the pursuit of creating scale alone—is likely to fuel much of the industry restructuring in the future. A particularly relevant analogue can be found in the refining industry over the past several years: the imposition of highly standardized and frugal operating practices on a large fleet of assets that were previously autonomous businesses. The impact on costs and availability has been striking. In the electric company sector, a few innovators are trying to apply such industrial-style business processes and management rigor. This evolution is inescapable, but will still be a slow and painful process for all but a few of the major players.

X. Conclusions—Embracing Risk

If the U.S. generation sector is troubled over the prospect of choosing how and when to invest in the next wave of baseload generation, that unease is well founded. In some ways, this is a testament to the positive impact of deregulation on the industry. In many cases, companies are responding rationally to the uncertainty by deferring investment, keeping their options open, and awaiting resolution of some of the risks they face. And, in cooperation with its regulators and policymakers, electric companies can mitigate other risks, notably through taking a proactive approach to GHG regulation.

Yet there are limits to what the sector can gain from public policymakers. At the end of the day, the U.S. generation sector is not very different than any other capital-intensive, cyclical industry. Some risks are unavoidable. Rather than pretending to forecast the future, successful companies will need to learn from those more mature industries: investing wisely, learning to build asset portfolios consonant with their owners' appetite for risk, and relentlessly seeking opportunities to improve efficiency.

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[18] Note: March 1, 2006, market capitalization. Source: Bloomberg.

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