NATIONAL ENERGY TECHNOLOGY LABORATORY

Investment Decisions for Baseload Power Plants

January 29, 2010

ICF INTERNATIONAL

402/012910

Disclaimer

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402/012910

FINAL REPORT

January 29, 2010

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Volume VI Case Studies on Recent Baseload Coal Investments

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DOE Contract #DE-AC26-04NT41817

Acknowledgments

This work was completed by **ICF International** under a **Research and Development Solutions, LLC (RDS)** site support contract with the United States Department of Energy's National Energy Technology Laboratory. This work was completed under DOE NETL Contract Number DE-AC26-04NT41817. This work was performed under RDS Subtask 41817-402.01.05. ICF International logo used by permission.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Anthony M. Zammerilli, NETL Technical Monitor

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List of Acronyms and Abbreviations

AACE	Association for the Advancement of Cost Engineering
Acfm	Actual cubic feet per minute
AEO	Annual Energy Outlook
AEP	American Electric Power Company
AGR	Acid gas removal
ANSI	American National Standards Institute
ASU	Air separation unit
BACT	Best available control technology
BFW	Boiler feed water
Btu	British thermal unit
Btu/hr	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
Btu/scf	British thermal unit per standard cubic foot
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CCF	Capital charge factor
CDR	Carbon dioxide recovery
CF	Capacity factor
CFBC	Circulating fluidized bed combustor/combustion
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
cm	Centimeter
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
COR	Contracting officer's representative
CT	Combustion turbine
CTG	Combustion turbine-generator
CWA	Clean Water Act
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DLN	Dry low NO_x
DOE	U.S. Department of Energy
DSM	Demand-side management
EAF	Equivalent availability factor
EIA	Energy Information Administration
EOR	Enhanced oil recovery

EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPC	Engineer/procure/construct
EPRI	Electric Power Research Institute
EPCM	Engineering/procurement/construction management
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOAK	First of a kind
FPL	Florida Power and Light Company
FRCC	Florida Reliability Coordinating Council
FRP	Fiberglass-reinforced plastic
ft	Foot, feet
ft, w.g.	Feet of water gauge
gal	Gallon
gal/MWh	Gallon per megawatt hour
GDP	Gross domestic product
GJ	Gigajoule
GJ/hr	Gigajoule per hour
gpm	Gallons per minute
GT	Gas turbine
h, hr	Hour
H_2	Hydrogen
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
Hg	Mercury
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICF	ICF International
ICR	Information collection request
ID	Induced draft
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGVs	Inlet guide vanes
In. H_2O	Inches water
In. Hg.	Inches mercury (absolute pressure)
In. W.C.	Inches water column
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated planning model

IPP	Independent power producer
ISO	International Organization for Standardization
ISO	Independent system operator
ISO-NE	Independent system operator Northeast
kg/GJ	Kilogram per gigajoule
kg/hr	Kilogram per hour
kJ	Kilojoules
kJ/hr	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
LAER	Lowest achievable emission rate
lb	Pound
lb/hr	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/TBtu	Pounds per trillion British thermal units
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LHV	Lower heating value
LMP	Locational marginal pricing
LNB	Low NO_x burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m/min	Meters per minute
m^3/min	Cubic meter per minute
md	Millidarcy (a measure of permeability)
MAF	Moisture and ash free
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine
MHz	Megahertz
MISO	Midwest Independent System Operator
MJ/Nm^3	Megajoule per normal cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/hr	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ	Million kilojoules (also shown as 10^6 kJ)
MMkJ/hr	Million kilojoules (also shown as 10^6 kJ) per hour
MMscf	Million standard cubic feet
MNQC	Multi nozzle quiet combustor

MPa	Megapascals
MVA	Mega volt-amps
MW,MWe	Megawatts electric
MWh	Megawatt-hour
MWt	Megawatts thermal
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NEMA	National Electrical Manufacturers Association
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
Nm^3	Normal cubic meter
NOAK	Nth of a kind
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NWPPE	Northwest Public Power
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OC_{Vnq}	Category n variable operating cost for the initial year of operation
OD	Outside diameter
OP/VWO	Over pressure/valve wide open
OSHA	Occupational Safety and Health Administration
PA	Primary air
PC	Pulverized coal
PF	Power factor
PJM	Regional Transmission Organization, PA, NJ, MD, OH, WV
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm or less
$PM_{2.5}$	Particulate matter measuring 2.5 µm or less
POTW	Publicly owned treatment works
PPA	Power purchase agreement
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PRB	Powder River Basin coal region
PSA	Pressure swing adsorption
PSD	Prevention of significant deterioration
psia	Pounds per square inch absolute
psid	Pounds per square inch differential
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
PURPA	Public Utility Regulatory Policies Act
PURPA QF	Public Utility Regulatory Policies Act Qualifying Facility
Qty	Quantity

RDS	Research and Development Solutions, LLC
RH	Reheater
RPS	Renewable portfolio standard
RR	Revenue requirements
RTO	Regional Transmission Organization
SC	Supercritical
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction process or equipment
SDA	Spray dryer absorber
SERC	Southeast Reliability Corporation
SG	Specific gravity
SGC	Synthesis gas cooler
SGS	Sour gas shift
SO_2	Sulfur dioxide
SO_x	Oxides of sulfur
SNCR	Selective non-catalytic reduction process or equipment
SRU	Sulfur recovery unit
SS	Stainless steel
STG	Steam turbine generator
TCR	Total capital requirement
TEWAC	Totally enclosed water-to-air cooled
TGTU	Tail gas treating unit
Tonne	Metric ton (1,000 kg)
TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
U.S.	United States
USC	Ultra-supercritical
V-L	Vapor liquid portion of stream (excluding solids)
vol%	Volume percent
WACC	Weighted average cost of capital
WB	Wet bulb
wg	Water gauge
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule

Executive Summary

This six-volume report is designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

Volume I of this report identifies the key factors that power companies should consider in managing the risks associated with investment decisions in new baseload electric generation capacity. Investment uncertainty is problematic because the power industry is one of the most capital-intensive industries in the U.S., and accounts for a large portion of the non-governmental, non-financial debt raised in the U.S. Uncertainty complicates this financing process.

The five major risk factors surrounding the decision to build baseload generation are summarized below. They affect both the utility and independent power producer (IPP) sectors:

- **Natural Gas and Oil Prices** – The low and stable natural gas prices in the 1990s were a key predicate for the overwhelming interest in gas-fired power plants in recent years. Similarly, the rise of gas prices and their volatility have been a key factor driving the search for alternative new generation options.

- **Carbon Dioxide** – At the very time U.S. utilities were turning away from gas to coal, concerns about carbon dioxide (CO_2) and climate change came to the fore. The increasing likelihood of CO_2 regulation, especially the potential for Federal regulation, is making coal less attractive compared to other alternatives, and increasing interest in technologies that decrease the carbon footprint of coal.

- **Capital Costs** – Over the last two years, there has been a record level of growth in power plant construction costs. The average cost of building a plant in the U.S. increased over 50 percent from 2006 to 2008. This rapid rise in power plant costs makes investment in baseload plants in particular more risky because they tend to be more capital intensive. The run-up in capital costs was a factor in many utilities' decision to revise cost estimates and, in some cases, delay or cancel projects.

- **Renewables** – A large number of states have renewable portfolio standards (RPS), and a federal RPS could be enacted by Congress in 2010. Among the legislative proposals being discussed is an RPS of 20 percent of generation by 2020. Renewables combine two features that have increased popular support: energy security and lower CO_2 emissions. However, they can be expensive, are often located far from load centers, and contribute little to grid reliability. Implementing a Federal RPS could delay decisions to build new baseload capacity.

- **Demand and Demand-Side Management** – Recently, the focus on demand-side management has greatly increased with state actions, as well as with the American Recovery and Reinvestment Act of 2009 (the "stimulus bill"). Furthermore, the recent sharp decline in electric demand and related drop in capital expenditures increases the risks that investors in baseload electric generation capacity face concerning future demand growth.

Volume II focuses primarily on why power plant developers are investing in certain types of baseload technology. This volume looks closely at coal-fired technology, namely supercritical pulverized coal and integrated gasification combined cycle (IGCC), but also discusses nuclear and combined cycle technology. A discussion of investment viability of baseload technologies is facilitated through an economic gap analysis using ICF's capacity expansion modeling platform, the Integrated Planning Model (IPM®).

In Volume III, the focus is on the impacts of the current financial climate on the financing of power plant investments by IPPs and regulated electric utilities. This section outlines the impacts of the current credit crisis on the weighted average cost of capital (WACC) in the short term. The increasing WACC has adversely affected the power industry through postponements and cancellations of projects. These impacts can be more readily seen in the IPP sector. ICF believes these effects are valid for the short term only, and as the economy recovers, credit will become more readily available and the WACC will revert towards long-term averages. However, forthcoming legislative developments will continue to put pressure on new coal investments.

The proposed Waxman-Markey climate change legislation (HR 2454, The American Clean Energy and Security Act of 2009), which requires U.S. CO_2 emissions to be 17 percent below 2005 levels by 2020, and potential new federal RPS requirements will most likely channel new investments in generation capacity to those with low carbon emissions, such as renewable energy resources, natural gas-fired plants, and potentially new generation clean coal generation investments.

On the regulated side of the industry, new baseload power projects that will best weather the current financial climate are those made by utilities with strong financial fundamentals, demonstrated robust performance in varying market conditions, and authorized pass-through of carbon emission costs. In addition to the cost-recovery mechanisms, projects developed by electric utilities can improve their access to the capital markets with application to the U.S. Department of Energy's (DOE) loan guarantee programs.

On the merchant side, the increasing cost of capital will result in only the most essential power projects being completed. Projects with well-structured power purchase agreements (PPAs) will help lower project risks and be less susceptible to varying market conditions. As with the utilities, DOE's loan guarantee programs and direct financing for clean coal projects can play a pivotal role in making a baseload investment economically viable.

Volume IV of this report shows that the decision to invest in different types of capacity across different regions varies considerably. This is because there are many factors that affect whether a region will provide sufficient returns to stimulate additional generation investment. Regions such as ECAR-MECS or PJM-WC are projected to not attract coal investments for a long time, primarily due to the low margins generated in the region. Another coal region, SPP-North, has so much baseload capacity that it will not have high enough margins to drive new coal investments through at least 2030. However, it still has capacity needs and the margins are sufficient for gas turbines or combined cycles. ERCOT will build gas turbines and combined cycles as well, though this is due more to the large and growing presence of wind, which suppresses energy margins, than to a preponderance of baseload capacity. The decision to invest should also have a timing component as some regions are in an extreme surplus condition. Entergy suffers from developers building a significant capacity surplus; it will not need any new capacity for at least 20 years.

Volume V identifies the major market developments that have changed the investment decision process of investors in power generation. Electric markets have changed significantly since the first "pure" merchant generator came online following the passage of the Public Utility Regulatory Policies Act (PURPA). A second distinct market type has developed over the past ten years: the competitive deregulated market. While regulated markets still resemble the power system of the early-1980s, having stayed undergone few changes since then, deregulated markets have evolved and grown significantly over the past ten years. Deregulated markets now represent a significant portion of U.S. power generation and demand.

The four major market developments over the past two decades are summarized below:

- **Divestiture** – Approximately 11 states have forced utilities to divest themselves of their generation and transmission assets through legislation; many more states have encouraged divestment. In this legislative climate, utilities soon realized that they would be better off divesting their power plants and purchase power from the market, because merchant power was priced lower than their average costs. In newly competitive markets, many utilities could no longer afford to run their older, inefficient power plants. As a result, and in conjunction with IPPs entering the marketplace, many utilities have completely left the power generation business and shifted to simply serving load. In essence, deregulated competitive wholesale markets have allowed many new investors into the marketplace.

- **Federal Energy Regulatory Commission Order 888 & Creation of Regional Transmission Organizations** – Passed in 1996, Federal Energy Regulatory Commission (FERC) Order 888 forced utilities to provide non-discriminatory market access to merchant generators. As a result, IPPs were able to sell power into different markets for the first time. In conjunction with FERC Order 2000, Order 888 also established the framework for Independent System Operators (ISOs)/Regional Transmission Organizations, which have grown across the U.S., opening up investment access to many new investors.

- **Locational Marginal Pricing** – About ten years ago, ISOs introduced locational marginal pricing (LMP, also known as nodal pricing), which allows more certain pricing data to be known across many different points in a marketplace, as opposed to a single zonal price. These better price signals help developers site new generation in locations that are most in need and offer the highest returns.

- **Capacity Markets** – Although the first one was only introduced in 2006, capacity markets are now fully functioning in New York, ISO-NE, and PJM, with planned markets in MISO and CAISO. Capacity markets provide an incentive for new plant investment by providing a revenue stream with more certain returns, allowing many more risk-averse investors to become active in the marketplace.

Looking ahead, the next significant event most likely to influence investment decisions for baseload generation investors will be the passage of national CO_2 legislation. However, there is great uncertainty as to what form such legislation would take. The current front-runner, a bill introduced by Senators Waxman and Markey, has already passed the Senate. It would impose stiff regulations to achieve its goal of reducing CO_2 emissions to 82 percent below 2005 levels by 2050. Even though some allowances would be allocated to merchant coal generation at first, this would add a significant cost to power generation from fossil-fired plants and will grow larger over time.

In the last volume of this report, Volume VI, two case studies of recent baseload power projects are presented to provide real-world examples of the investment drivers for new baseload electric generation, as discussed in the previous five volumes. The projects examined in this volume are Duke Energy's IGCC in Edwardsport, Indiana, and LS Power's Plum Point Energy Station in Arkansas. Both case studies are designed to be coal-fired baseload power plants. The Plum Point power plant is being developed by an IPP and uses a proven generation technology. The Edwardsport plant is being developed by a utility and uses a new generation technology. These two case studies provide good examples of the range of approaches that developers are using to successfully build and finance new coal-fired generation plants.

Volume I: Investment Risk Factors for Baseload Generation

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Chapter 1
Introduction

This is the first volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

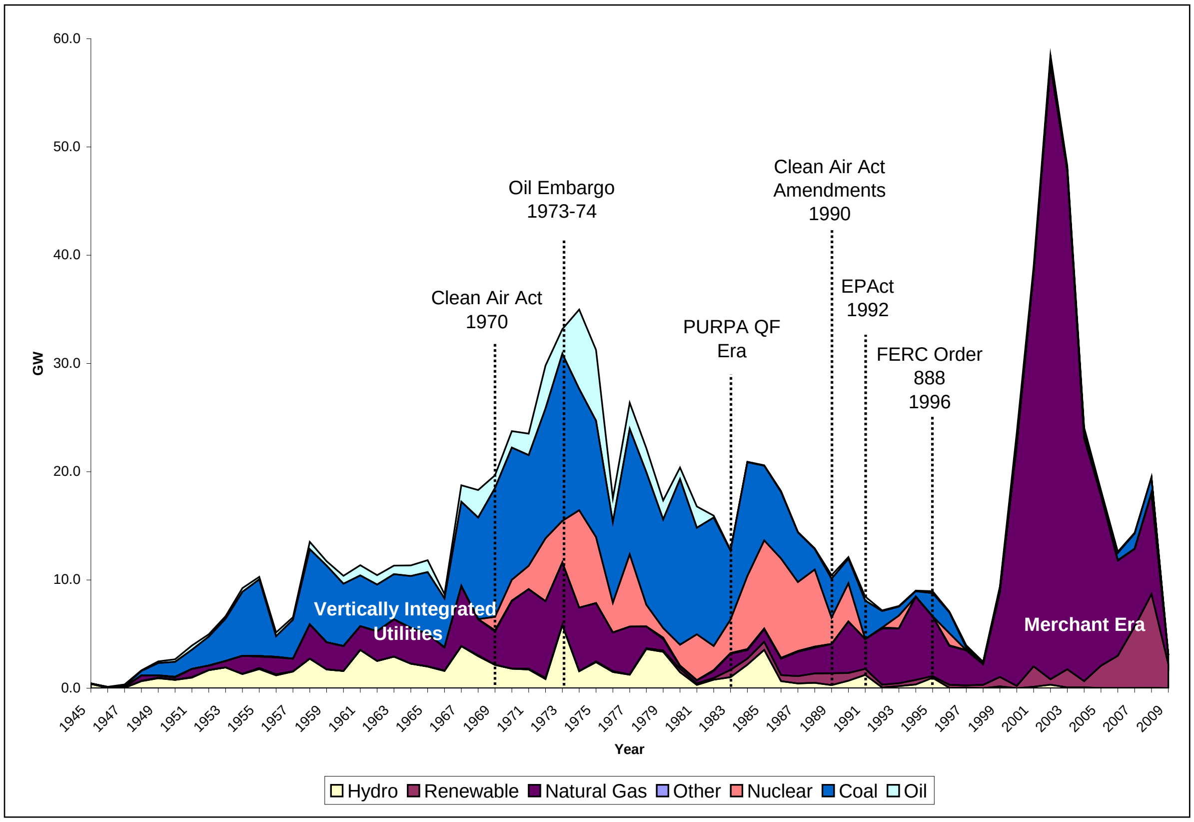
The purpose of this volume is to identify the key factors that power companies consider in making investment decisions about new baseload electric generation capacity. After a brief introduction, the first section provides a discussion of the methods used by each of the power players to evaluate a new electric generation baseload investment. The next section discusses investment risk factors from a regulated utility perspective. This is followed by an assessment of how independent power producers evaluate risks when making investments in baseload generation capacity. The final section provides a summary of the analysis and a discussion of next steps.

Electric utilities continue to need new generation capacity resulting from continuing electric demand growth and the retirement of existing power plants. The decision regarding which technologies to pursue has become extremely complicated, and the direction is unclear. This uncertainty is problematic because the power industry is one of the most capital-intensive industries in the U.S., and accounts for a large portion of the non-governmental, non-financial debt raised in the U.S. Uncertainty complicates this financing process. This is also problematic because of the importance of the power industry to economic performance and environmental impacts.

This complexity is evidenced in five respects:

First, as illustrated in Exhibit 1-1, technology choices have varied widely even within the last ten years. At first, natural gas power plant construction, mostly combined cycle, grew quickly. This was followed by renewed interest in coal, though the amount of coal additions has been much less than expected. Currently, renewables — especially wind — dominate U.S. construction patterns.

Exhibit 1-1
Historical Capacity Additions from 1945 to Present



Source: Energy Velocity Database, Ventyx 2009

Second, another aspect of this complexity includes the variety of choices among types of plants. For example, circulating fluidized bed, sub critical, super critical, ultra super critical, and IGCC plants all use coal for fuel.

Third, the range of issues and factors that need to be considered in making new generation build decisions continues to broaden. While this has been a component of decision making for at least several decades, never has the uncertainty and complexity of the decision-making process been greater.

Risk factors should be considered in any power plant investment. Most of these drivers will be covered in more detail in Chapters 3 and 4.

- **Natural Gas and Oil Prices** – The low and stable natural gas prices in the 1990s were a key predicate for the overwhelming interest in gas-fired power plants in recent years. Similarly, the rise of gas prices and their volatility have been key factors driving the search for alternative new generation options.

- **Carbon Dioxide (CO_2)** – Concerns about CO_2 and climate change greatly influenced U.S. utilities to turn away from gas to coal. The increasing likelihood of CO_2 regulation, especially the potential for federal regulation, is making coal less attractive compared to other alternatives and is increasing interest in technologies that decrease the carbon footprint of coal.

- **Capital Costs** – Over the last two years, power plant construction costs have exhibited record growth. The average cost of building a plant in the U.S. increased over 30 percent from 2006 to 2007 and rose another 20 percent in 2008. This rapid rise in costs makes investment in baseload plants in particular more risky because they tend to be more capital intensive.

- **Renewables** – A large number of states have renewable portfolio standards (RPSs), and a federal standard could soon be enacted by Congress. Among the legislative proposals being discussed is a renewables standard of 20 percent of generation by 2020. Renewables combine two features that have increased popular support: energy security and lower CO_2 emissions. However, they can be expensive, are often located far from load centers, and contribute little to grid reliability. Implementing a federal RPS could delay decisions to build new baseload capacity. Interestingly, only one state has a portfolio standard that includes options such as coal with carbon capture and storage (CCS) and nuclear, both of which enhance energy security and reduce CO_2 emissions.[1]

- **Demand and Demand Side Management** – Prudent planning to meet demand growth gained increased focus from state public utility commissions in the 1970s, when demand growth slowed dramatically as a result of a sharp increase in oil prices. The surprise glut in electric generation capacity led to the adoption of a more comprehensive integrated resource planning (IRP) process, which required that power companies include energy efficiency and other demand side management (DSM) measures in their consideration of the least cost means for meeting energy demand. The focus on DSM has greatly increased with state actions, as well as with the recent stimulus bill.

- **Externalities/Other Environmental Issues** – Debates about whether regulations are sufficiently stringent to limit the undesirable environmental and health effects of the byproducts of electricity production are ongoing. These effects, which include SO_2, NO_X, and mercury emissions, frequently appear as issues in the IRP processes. Water consumption and coal ash disposal are other pressing issues.

- **Reemergence of the Nuclear Power Plant Option** – Major efforts are underway to revive the option of nuclear power, including loan guarantees.

- **Imminence of Need/Lead Time** – In many cases, utilities are asked for ways to delay via DSM and less expensive options.

- **Transmission** – While generation investment has increased over the years, transmission investment has lagged behind due to the difficulty of siting new lines. In some cases, the lack of transmission investment led to stranded new generation investments. However, the extent to which new transmission lines can be built will determine whether new generation investment options can be opened.

[1] A bill to encourage development of a lower-emissions coal plant became Illinois law Jan. 12. The Clean Coal Portfolio Standard Act sets a goal of having 25% of electricity used in the state by 2025 produced from clean coal sources.

- **Technology** – The risk of building new generation technology or incorporating new control technology is a large issue in most cases, with utilities and decision makers needing to weigh the risks in terms of performance and costs. In these situations, technology is frequently being reviewed to assess the extent to which it offers new solutions.

- **Regional Variation** – Availability of fossil fuel resources, emission regulations, political issues, transmission constraints, physical space requirements, and the supply/demand balance at the peak all drive what type of power plant is built in a given region.

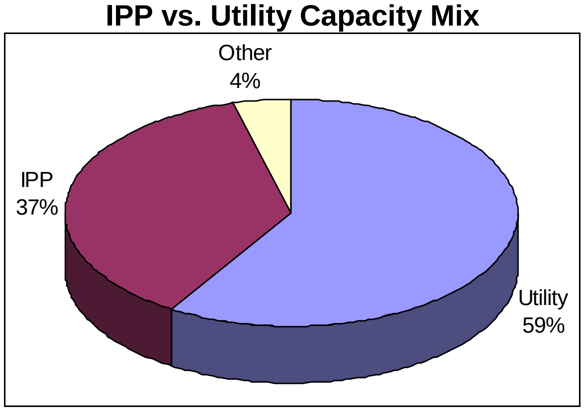
- **Energy Security** – As occurred with the oil embargos of the 1970s, the recent run-up in oil prices to nearly $150 per barrel has brought energy security concerns to the forefront once again. Fuel diversity, insulation from price spikes, and availability of fuel are all key concepts that will, in turn, influence future baseload build decisions.

- **Purchasing from the Market** – Utilities now have greater options to buy power from the marketplace, such as from industry spot markets or independent power producers (IPPs). In some regions, default supply is from the marketplace. This policy has led to a range of issues affecting build decisions, including how to balance market power and scarcity pricing concerns and how to protect consumers from volatility.

Fourth, in addition to the range and complexity of issues now typically enjoined, the investment decision goals are often competing. A common example is low cost, low annual variation in bills, and minimum environmental footprint. This has often led to a portfolio of options being pursued as a compromise among these varied interests.

Fifth, in addition to electric utilities, partial restructuring of the power sector has created new decision makers, the IPPs. As shown in Exhibit 1-2, IPPs or deregulated affiliates of utilities own 37 percent of U.S. generation capacity and approximately 25 percent of U.S. coal capacity. Deregulated affiliates of utilities own most of this coal capacity.

Exhibit 1-2
IPP vs. Utility Capacity Mix



Source: Energy Velocity Database, Ventyx 2009.

Overall, the IPP decision-making process is simpler because the overriding goal is profit maximization with little outside input, except as it is manifest in the markets and financial sector access to capital. However, many of the same concerns — such as gas prices, CO_2 allowance prices, renewable portfolio requirements, and environmental limits — exist for this sector as well. The build decisions for utilities and IPPs involve significant risk.

Chapter 2
Investment Valuation Methodologies

2.0 Introduction

Investing in new baseload electric generation capacity involves exchanging an up-front capital outlay in return for an uncertain income stream in the future. Companies will make this exchange if the expected project returns are high enough to cover the initial lump sum as well as compensate them for taking on the project risks. Project risks arise from many sources including policy/regulatory, market, and financial.

These risk factors affect the economic viability of different baseload generation technologies in different ways, and may alter the relative attractiveness of the various investment options from which a generation company may choose. For this reason, the investment decision-making process must incorporate risk into the analysis.

For example, technical risks vary considerably between technology types and will be important elements of investment decision making, since, all else being equal, companies would prefer to invest in lower-risk technologies.

This section provides an overview of the differing methodologies that are used by regulated utilities and IPPs to make investment decisions in new baseload generation capacity. The methodologies differ substantially between the two different types of power companies, reflecting the rules that govern their ability to earn a return on their investment and the impact these rules have on the risks to which they are exposed.

2.1 Investment Concepts and Methodology for Utilities

2.1.1 PVRR Minimization

A key concept and goal in integrated resource planning is cost minimization. One metric used to measure least cost is the present value of revenue requirements (PVRR). PVRR is the current worth of the expected stream of future revenue requirements associated with a proposed utility project or set of projects for meeting electric demand. Often the PVRR is considered for the entire utility generation fleet, plus a variety of potential new projects. The current value is obtained by applying a discount rate to the expected stream of future payment requirements. These revenue requirements are determined by the amount of money that must be received to cover fixed costs, operating expenses, taxes, interest paid on debt, and if applicable, a reasonable rate of return. Least-cost planning attempts to minimize PVRR, which is an important decision criterion in the IRP process.

2.1.2 PVRR at Risk

As discussed in Chapter 1, the uncertainties facing power company decision makers have been increasing. To better understand future revenue requirements (RR) and the impact of uncertainty, utility decision makers usually assess revenue requirements by using scenario analysis or a PVRR at-risk analysis. The results of their analysis may be that utilities may not prefer the least-cost option, but rather prefer to accept a higher PVRR solution that has a lower risk of a negative outcome.

Power companies use scenario analysis to understand how sensitive a particular set of investment decisions is to the range of possible outcomes for key factors with high levels of uncertainty, such as stringent CO_2 regulations or high gas prices. In Exhibit 2-1, we show an illustrative example of this process. For this purpose, ICF used one of its models to estimate the total costs to ratepayers under three different capacity expansion plans. In this analysis, total costs are calculated as the PVRR over the period 2010–2030.

In this example, the PVRR estimates for the three alternative generation portfolios are calculated for a base case and for various fuel price sensitivities to determine which portfolio represents the optimal capacity expansion plan.

As shown in Exhibit 2-1, the base case results indicate that the primarily coal portfolio has the lowest PVRR. However, the mixed (or most diversified) portfolio has a PVRR similar to the primarily coal portfolio. In addition, as shown in Exhibit 2-2, the mixed portfolio has lower risk, as indicated by its consistent ranking as the median outcome of the three portfolios.

Exhibit 2-1
Illustrative PVRR at Risk Example

Case	PVRR of Total Cost (2006$) ('000s)		
	Mix	All Gas	Primarily Coal
Base Case (4P)	17,668,000	17,854,000	17,480,000
Non-carbon case (3P)	13,593,000	14,138,000	13,196,000
High capital cost case	18,275,000	18,155,000	18,313,000
High gas price case	18,763,000	19,536,000	18,181,000
Low gas price case	16,779,000	16,574,000	16,941,000
High coal price case	18,765,000	18,728,000	18,768,000
Low coal price case	17,437,000	17,750,000	17,127,000
Bid-based analysis	17,496,000	17,605,000	17,306,000

Exhibit 2-2 shows the relative ranking, with "1" representing the lowest cost portfolio.

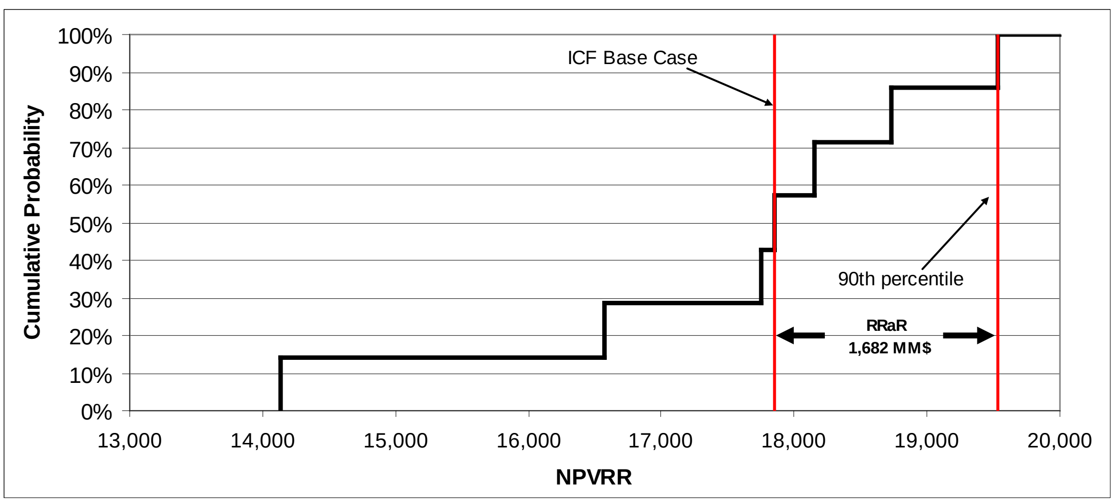
Exhibit 2-2
Portfolio Ranking[1]

Case	Ranking by PVRR of Total Cost		
	Mix	All Gas	Primarily Coal
Base Case (4p)	2	3	1
Non-carbon case (3P)	2	3	1
High Capital Cost	2	1	3
High Gas Price	2	3	1
Low Gas Price	2	1	3
High Coal Price	2	1	3
Low Coal Price	2	3	1
Bid-based analysis	2	3	1

[1] 1 represents the lowest cost portfolio.

Scenario analysis as depicted above is limited in value because it implicitly assigns equal likelihood to all possible outcomes. One way to improve the utility of scenario analysis is to assign probabilities to each of the analyzed cases. This allows for an assessment of the magnitude of the risks to each portfolio, such as 90 percent confidence interval for revenue requirements. As an example, Exhibit 2-3 shows the cumulative probability distribution of the net present value of a portfolio's RR. The gas portfolio is shown in this example. Also shown in the exhibit is the revenue requirement at risk (RRaR). The RRaR is typically defined as the difference between the RR at the 90th percentile and the median RR value.

Exhibit 2-3
All-Gas Portfolio – Cumulative Probability Distribution



Note: RRaR = Revenue Requirement at Risk; NPVRR = Net Present Value Revenue Requirement
Source: ICF International

As shown in Exhibit 2-4, examining the probability distribution of RR indicates that the primarily coal portfolio could be an attractive alternative, depending on one's attitude to risk. The all-gas portfolio appears less attractive under many outcomes, including the base case and no-carbon control cases, as well as the high gas price and low coal price sensitivity cases. Of the portfolios, the all-gas (low diversity option) had the greatest risk of high revenue requirements.

Exhibit 2-4
Summary Comparison of Revenue Requirements at Risk

Parameter	RRaR (MM$)
Mix	1,097
All Gas	1,682
Primarily Coal	1,288

Source: ICF International

2.1.3 Fuel Volatility – Coal Prices and Fuel Adjustment Clause

Another consideration for utility decision makers is yearly fluctuations in pricing. For example, natural gas prices have historically been much more volatile than delivered coal prices. This lower price volatility can favor coal-based options. As described above, part of the revenue requirement includes recovery of operating expense, which includes both fuel and non-fuel variable costs. If fuel costs increase more than originally planned, a fuel adjustment clause in the tariff rate typically allows for quick recovery of the unexpected price increase.

The fuel price volatility — as shown through the standard deviation for natural gas and coal — is illustrated in Exhibit 2-5. Prices for natural gas delivered to utilities has been much higher than delivered coal over the period 1995–2005.

Exhibit 2-5
Delivered Fuel Price Volatility for Utilities – U.S. Average

Year	Nominal$/MMBtu		
	Coal – U.S. Average Delivered Utility Cost[1]	Gas – U.S. Average Delivered Utility Cost[1]	Henry Hub Spot Gas Price[2]
1995	1.32	1.98	1.72
1996	1.29	2.64	2.81
1997	1.27	2.76	2.48
1998	1.25	2.38	2.08
1999	1.22	2.57	2.29
2000	1.20	4.30	4.70
2001	1.23	4.49	3.70
2002	1.26	3.56	3.02
2003	1.28	5.39	5.46
2004	1.36	5.96	5.90
2005	1.54	8.21	8.50
2006	1.69	6.94	6.45

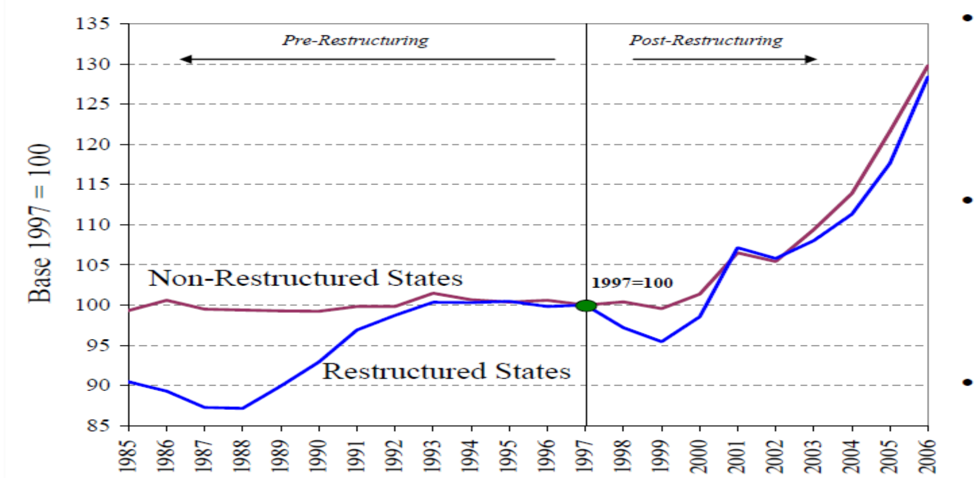
Average	1.33	4.27	4.09
Standard Deviation	0.15	2.00	2.11
Correlation Coefficient with Henry Hub	69%	99%	

[1] EIA Electric Power Annual 2006 Exhibit 4.5, p. 37.
[2] *Platts' Gas Daily*. Prices from 1995 onwards are volume-weighted averages.

Even with the fuel adjustment clause typically built into their tariffs, regulated utilities may not be protected from some of the risk associated with higher fuel price volatility because regulators may not allow all the increase to be passed through to the ratepayers. Thus, all else being equal, a need for stable fuel prices would favor the coal option.

Exhibit 2-6 shows the run-up in retail rates since 2000 in states that restructured and those that did not. The main driver to this has been the increase in fuel prices. Regardless of whether the utility was in a restructured state, rates were fairly stable before 1998 and increased significantly thereafter. Fuel price instability continues today.

Exhibit 2-6
U.S. Retail Rates Normalized



Sources and Notes:
EIA Data: SEDS, Form 861, Monthly Energy Review, and Form 826.
2006 reflects January 2006 - July 2006 monthly data.

Public utility commissions respond to rate run-ups, in some cases with retail price freezes or at least with less of an increase. Thus, utilities may not fully recover fuel price escalations due to regulator discretion. This is especially true in a recessionary environment like the one we face today. One result is that, as utilities seek new investment opportunities in baseload electric generation capacity, they often put fuel cost containment high on their priority list, which, in turn, would favor the least volatile fuel option.

2.1.4 Integrated Resource Planning/Demand Side Management

Since the late 1970s, integrated resource planning (IRP) has been the basic decision-making process for new investment for most utilities. IRP was originally designed to serve as a regulatory means of ensuring that a utility's expansion plan was transparent and included a broad array of alternatives. As discussed above, the main concept behind IRP is least cost planning or minimizing the revenue requirement of the utility to meet the demand for energy services. This process entails a review of all supply alternatives to meet forecasted demand at the lowest cost possible. Demand-side management (DSM) has introduced energy efficiency as another resource available to meet the demand for energy services.

Although the regulatory requirements and the level of detail vary, a typical IRP process is focused on determining how to best meet future energy needs given available resources. The objective function of the IRP is no longer mere cost minimization, although costs are an important variable. The most beneficial portfolio of resources is now considered to be one that meets the demand for energy services at minimum cost while also providing a measure of supply security, risk minimization, resource diversity, and other considerations depending on the state commission. The metric that guides this decision process is the “PVRR at Risk” metric, as described above. Other criteria typically include environmental factors (e.g., greenhouse gas emissions), resource adequacy, service reliability, and, increasingly, the inclusion of mandated renewables.

This is a complex set of parameters to consider and balance given the many conflicting IRP objectives. Following an aggressive strategy to add renewable generation, for example, may lower emissions but could also increase costs to ratepayers. Heavy reliance on coal may be the cheapest short-term option, but it could expose ratepayers to higher costs should there be a significant increase in the price of coal or a future requirement to reduce CO_2 emissions. Similarly, having an extra cushion of capacity adds to supply reliability, but also increases expenses. Investing in extra transmission capacity increases opportunities to import lower-cost generation from distant generators, but making that investment is costly. Additionally, a heavy emphasis on energy conservation and peak-load reduction reduces the need for supply-side resources, but at a cost.

2.2 The Integrated Resource Planning Process

The IRP process typically consists of the following steps:

- Data validation,
- Demand forecasting,
- Resource characterization,
- Risk and scenario analysis,
- Strategy evaluation, and
- Implementation.

As in any business-planning exercise, it is critical to have correct and current input data and to incorporate the best available input assumptions. Use of inaccurate, out-of-date, or biased data will lead to suspect results and an unsuccessful study. The next critical step is to forecast the load to be served. Generally, IRP uses either econometrics or end-use process engineering models to project future energy demand.

The next step in the IRP exercise is to define a comprehensive list of supply and demand-side resources and their physical and cost characteristics. This critical step defines the basic assumptions and the inputs that go into the remaining steps. Environmental considerations, renewable energy mandates, reserve margin requirements, cost or penalties for resource diversity, risks, and other variables are usually defined in this stage.

The next step is risk characterization through scenario analysis. Sensitivity case analyses, or a stochastic approach, may be used as part of the scenario analysis. RRaR concepts are usually employed in this stage of the analysis.

The strategy-building phase of the IRP process typically begins with compiling a list of the risk-responsive resources selected as the lowest cost solution in each scenario and sensitivity case. Other scenarios may then be examined. For example, a renewable portfolio standard scenario may be analyzed to examine the relative costs and benefits of each alternative renewable resource. Part of the strategy building phase is also to test how reasonable an alternative resource may be that was not found to be optimal. Reviewing environmental considerations is also appropriate at this phase of the IRP process. Special interest groups such as consumer advocacy groups or environmentalists may contest specific assumptions or demand scenarios that support their specific views at this phase.

The final step in a typical IRP exercise is to make sense of the many model runs, various strategies examined, and various scenarios considered. If done properly and transparently with meaningful participation and input by competent stakeholders, the IRP process can lead to strategies that have broad public support and backing. In the best of worlds, utility management will have approval of a particular technology or fuel type that has broad support from all stakeholders.

2.3 Rate Case Process

Upon receiving approval from the public utility commission to build baseload generation capacity identified in the IRP process, the utility will submit the necessary permit applications and obtain the best financing possible for the plant. The equity will mostly come from the utility's balance sheet, and debt will mostly come from the capital markets in the form of a new bond issuance.

To recover their capital investment, utilities will then attempt to add the investment to their rate base by filing a new cost-of-service rate increase. In simple terms, a utility's cost-of-service, or revenue, requirement is composed of three primary elements: (1) operating costs, such as fuel costs, purchased power costs, operations and maintenance costs; (2) a return *of* capital cost, otherwise known as depreciation expense; and (3) a return *on* capital cost.

Costs deemed prudent by the commission are eligible for recovery. After a rate case is made on new revenue requirements, rates remain fixed until the next rate hearing. Most utilities, however, have adjustment clauses that allow them to increase or decrease rates to reflect the volatility in their operating costs, such as fuel and purchased power in any given year.

Traditionally, new investments were not allowed to be recovered in the rate base until the new asset was in service generating power. A full rate case that reviews all of a utility's cost of service is needed for allowance of new generation investment into the rate base. Once the new facility has come online, a full rate case can be filed. New electric tariff rates are set that allow for return of and on investment. Adding a large new investment into the rate base can produce a strong increase in tariffs. To avoid large tariff rate increases, regulators have gone to alternative approaches, such as including a Construction Work in Progress (CWIP). In this alternative tariff adjustment method, commissions allow the financing of related construction expenses to be built into the rate base as incurred, which smoothes out the rate impact in the short term.

2.4 An Auxiliary Tool – Levelized Cost Approach

2.4.1 Role of Levelized Costs

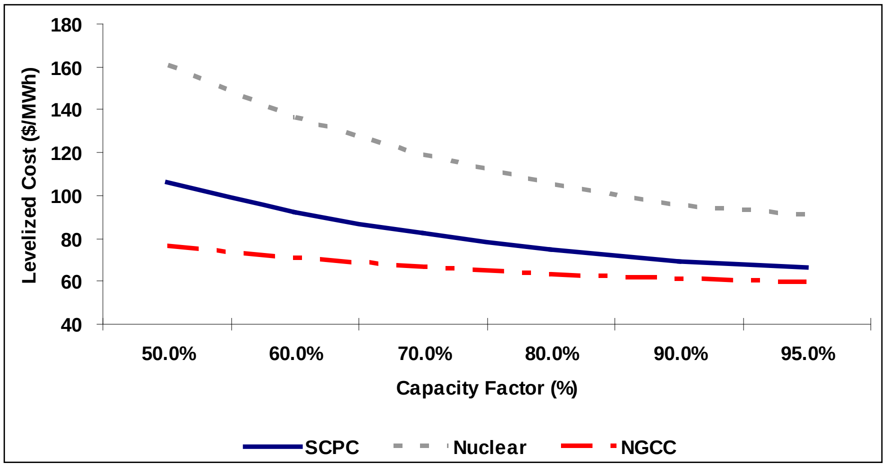
Levelized cost analyses attempt to capture the full lifetime costs of a power generation station and allocate those costs over its lifetime. These costs are then discounted to their present values. Estimates of levelized cost of electricity generation originated under conditions where electricity networks were operated as monopolies, as closely regulated private utility companies, or as local municipalities. They are used by utilities and regulators to provide a first indication of a plant's relative costs. These costs are one of the main submissions to the regulatory commissions in the IRP process. However they do not override the PVRR analysis.

2.4.2 Levelized Cost Calculations

The typical methodology for calculating levelized costs is similar to calculating an annuity for a mortgage. The power station's capital investment and operation costs are taken as a lump sum, and an annuity factor is applied to levelize the amount in equal yearly payments, typically on a $/MWh basis. The annuity factor takes into consideration the following: plant construction costs, variable and fixed operation costs, fuel costs, environmental costs, utilization rate, and an annuity factor. The annuity factor is driven by the weighted average cost of capital (WACC) of the project, property taxes, and insurance.

An example of levelized costs is given in Exhibit 2-7. In this example, the levelized cost of a new combined cycle plant is well below the cost of a new coal or nuclear plant across the full range of potential capacity factors. In reality, the levelized cost of alternative generation technologies depends on a number of factors, including capital costs, financing costs, fuel costs, variable and fixed operation and maintenance costs, and environmental costs. These and other cost drivers are discussed in Chapter 3.

Exhibit 2-7
Illustrative Levelized Costs for
Alternative Baseload Electric Generation Capacity



Source: ICF International Assumptions. See appendix (p. I-62) for details.

2.4.3 Method Limitations and Other Approaches

Levelized cost calculations and the more thorough IRP approach have been very useful in guiding regulator decisions on the optimal mix of resources needed to meet the projected demand for energy services. However, levelized costs analyses and the IRP process have limitations for the independent power developer.

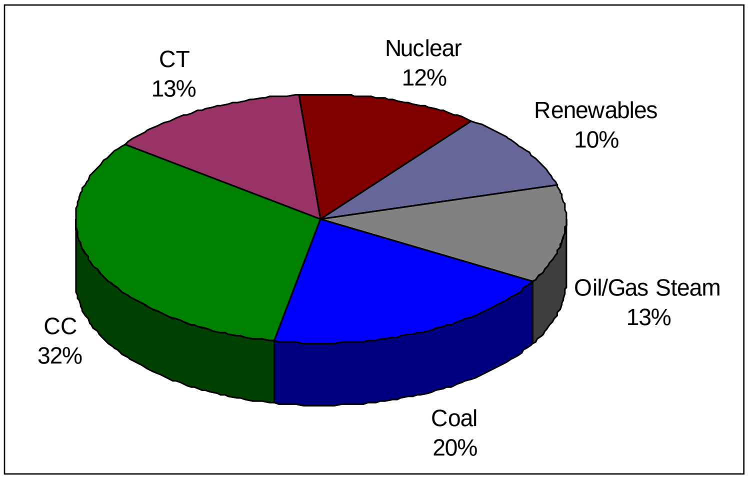
One of the more limiting factors of the levelized costs approach is that it cannot capture the relationship between electricity price variation/uncertainty and investment risk. Independent power investment is concerned not with levelized costs, but with the investment's internal rate of return (IRR) and its associated level of risk. These factors are not only affected by cost and cost risk, but also by revenues, prices, and price risks.

2.5 Investment Methodologies for Merchant Investors

2.5.1 Risk-Adjusted Expected Returns

The passage of the Energy Policy Act (EPAct) of 1992 and FERC Order 888, which was adopted in 1995, began the electric market restructuring process and led to the creation of independent power producers that are active players in the market today. As of March 2009, non-regulated entities own approximately 370 GW of capacity, of which 32 percent are combined cycle facilities. Almost all the gas-fired facilities in operation today, both combined cycle and simple cycle, were built since the late 1980s. In contrast, most of the coal and all of the nuclear capacity in restructured states are held by non-regulated affiliates of utilities and were purchased when the utility divested.

Exhibit 2-8
U.S. Capacity Mix



Source: Energy Velocity Database, Ventyx 2009.

An IPP invests in new baseload generation when the expected revenue stream from a new power plant is greater than the investment cost associated with the plant. Many of the same considerations that drive the IRP process also affect the IPP decision because they have a direct impact on the expected revenue or cost of the new facility, including the following factors:

- Coal versus natural gas prices,
- CO_2 regulations,
- Capital costs,
- Demand growth,
- Renewable requirements, and
- Technology risk.

Once a project starts moving forward, permits must be applied for and financing must be raised. Equity is usually from the company itself or through private investment partnerships. Debt is usually non-recourse debt referred to as "project financing." For this debt, the cash flows and assets of a specific investment are used as collateral against the debt and held at that specific project. This type of financing is subject to many different types of requirements. Because of the non-recourse nature of the debt, cash flows and the quality of the cash flows of the individual project become very important to the successful financing of the project. The quality of the cash flows and how the investment banking community views the potential project debt are discussed in detail in the Chapter 4.

2.5.2 Preferred Method for Investors in Unregulated Assets

Simplistically speaking, unregulated investors use a discounted cash flow (DCF) approach to determine the value of an investment. DCF analysis is based on the premise that the value of an investment is equal to the net present value of the future benefits of the investment.

Because the value of a dollar varies by year, returns or profits from each year cannot be simply added. Each payment must be weighted according to when it was received. The DCF analysis provides a framework for this. To calculate the present value of this cash flow, it is discounted by the weighted cost of capital. Sophisticated mathematical models have been developed based on economic/engineering principles to estimate future revenues and costs for a particular power plant investment. All else being the same, the investment that yields the highest internal rate of return and is greater than the investor's hurdle rate will be the likely choice.

Proforma is the financial analysis used to track revenues, costs, tax implications, depreciation, and IRR. For illustrative purposes, a simplified one is included at the end of the Chapter. Developers and investment bankers will typically use a more sophisticated proforma, but this simple format captures all the important factors.

2.5.3 Deterministic Analysis

The discounted cash flow approach is generally conducted as a deterministic analysis, thus assuming all the inputs and outputs are constants that do not vary. For instance, a deterministic power model would produce one power price for a given hour. This is a useful and valid approach that is able to accurately project long-term, marginal, cost-based trends incorporating many different inputs, such as fuel prices, energy demand, and emissions prices. Many IPPs and investment players use this method to forecast the earnings of the power plant of interest.

2.5.4 Probabilistic Analysis

However, in the short term, price volatility is possible. In any given hour, the power price could be higher or lower, depending upon numerous factors. For instance, super-peak prices can occur during periods in which prices jump dramatically due to plant or transmission outages. A probabilistic model will take power prices as an input and, using probability theory, incorporate volatility into the operating profits of a plant. This form of analysis is usually derived from a financial market's options theory, known as Black-Scholes. The two methods of analysis tend to work hand-in-hand. Deterministic analysis will capture long-term trends and provide a reasonable valuation, assuming volatility will even out in the long term. Probabilistic analysis can provide short-term valuations, accounting for price volatility.

Regardless of which approach is used, investments are made in light of the risks and prospective returns on investment. Returns depend on revenues as well as cost, so the price of electricity becomes an important risk factor in the investment decision. Price and other risk factors depend on the market structure and the investment being considered, and can affect the way an investment is financed — and, therefore, the cost of capital. Thus, risk is an important component of investment decision making. In the following sections, we will discuss the various investment risk drivers that the independent power producers (IPPs) may face.

2.6 Conclusions

Utilities' and IPPs' approach to investment are similar. In the energy market, energy price is influenced by many factors, such as supply versus demand, the level of competition in the marketplace for power, or the availability of power transmitted from other areas. The cost of energy production for an IPP is composed of the fixed costs associated with the existence of the plant, and the variable costs associated with the production of electricity. To maximize profit, an IPP will want to maximize the price at which they can sell energy, and maximize the amount of energy that can be sold at that price without going beyond the point where marginal cost exceeds marginal revenue. In other words, since an IPP has minimal influence over the market price for energy, it will try to sell more energy (thereby increasing profits) by lowering its costs, sometimes referred to as "cost minimization." In other words, to maximize profit, an IPP will have to lower its costs as much as possible.

2.7 Appendix – Illustrative Proforma

Below is a sample proforma that shows the first five years of free cash flows. Because power plant investments are long-lived, the typical proforma will capture at least 30 years.

Year		2009	2010	2011	2012	2013
Inflator Normalized To	$2,006	1.08	1.11	1.13	1.16	1.19
Year		1	2	3	4	5
Net Operating Revenues						
Gross Margin	($000)	53,709	58,198	62,625	65,678	71,226
Operation & Maintenance Expenses						
Insurance Costs	($000)	859	859	859	859	859
Property Taxes	($000)	2,664	2,664	2,664	2,664	2,664
State Franchise Tax	($000)					
Additional Fees	($000)					
O&M Cost	($000)	18,012	15,969	16,660	24,578	15,790
Total Operating Costs	($000)	21,535	19,492	20,183	28,101	19,313
Net Operating Income						
Net Operating Income	($000)	32,174	38,706	42,442	37,577	51,912
Tax Deductions						
Interest Payment	($000)	13,218	12,899	12,558	12,192	11,800
Depreciation	($000)	10,741	20,676	19,124	17,692	16,363
Taxable Income	($000)	8,216	5,131	10,761	7,694	23,750
Usage of Net Operating Losses (NOL)						
Cummulative NOL available for CarryFor	($000)	-	-	-	-	-
Test For Positive Operating Income	($000)	8,216	5,131	10,761	7,694	23,750
Net Income						
Income Taxes	($000)	3,276	2,046	4,291	3,068	9,470
Net Income	($000)	4,940	3,085	6,470	4,626	14,279
Cash Available for Debt Payment						
Net Operating Income	($000)	32,174	38,706	42,442	37,577	51,912
Income Taxes	($000)	3,276	2,046	4,291	3,068	9,470
Cash Available for Debt Payment	($000)	28,898	36,660	38,151	34,509	42,442
Use of Funds for Debt						
Beginning Balance	($000)	186,169	181,678	176,867	171,714	166,196
Ending Balance	($000)	181,678	176,867	171,714	166,196	160,286
Principal	($000)	4,492	4,811	5,152	5,518	5,910
Interest	($000)	13,218	12,899	12,558	12,192	11,800
Total Debt Payment	($000)	17,710	17,710	17,710	17,710	17,710
Implied Shareholder Return on Equity						
Capitalized Payment for Equity	($000)	(100,245)	-	-	-	-
Capitalized Major Maintenance Expenditu	($000)	4,500	400	1,400	500	500
Capitalized Payment for Retrofits	($000)	35,000	15,000	-	-	-
Cash Net of Debt Payment	($000)	11,188	18,950	20,442	16,800	24,732
Cash Available for Equity Distribution	($000)	(28,312)	3,550	19,042	16,300	24,232
Nominal Return on Equity	14%					
NPV of Equity Distribution	(1,973)					
Debt Service Coverage Ratios	%	1.8	2.2	2.4	2.1	2.9

Project Financial Assumptions	
After Tax Nominal Equity Rate:	14.00%
Equity Ratio:	35.0%
Pre-Tax Nominal Debt Rate:	7.1%
Debt Ratio:	65.0%
Weighted average cost of capital (WACC a	8.0%
Income Tax Rate:	39.9%
Property Taxes	0.93%
Insurance	0.30%
Inflation	
Debt Life	20

	2009	2010	2011	2012	2013
MACRS 20 Years Depreciation Schedule	7.22%	6.68%	6.18%	5.71%	5.29%

Chapter 3
Identification of Investment Risk Factors Considered by Utilities

3.0 Introduction

This Chapter discusses factors affecting the risk of utility power company investment decisions in baseload electric generation. Many of these risk factors will have applicability to independent power producers as well. Exhibit 3-1 provides the list of factors that will be discussed.

Exhibit 3-1
Risks Affecting Investments in
Baseload Generation Investment Decisions

Major Risks	Minor Risks
Fuel Price Volatility	Federal RPS
CO2 Regulation	Demand Growth and DSM
Capital Outlay and Commodity Prices	NOx, SOx, Hg Controls and Regulatory Policies
Lead Time	Market Design
Energy Security and Portfolio Diversification	Transmission, Infrastructure and Transportation
Financial Incentives	Water Usage and Regulation
Waste Storage	Air Permitting
Technical Performance/Reliability	Regional Variation in New Capacity Needs

As illustrated in Exhibit 3-2, the impact of the major risk factors varies across the baseload generation alternatives. For example, fuel price volatility is a high risk factor for natural gas-fired combined cycle plants, is a much more moderate risk factor for coal-fired plants, and is a low risk factor for nuclear plants.

Exhibit 3-2
Relative Ranking of Risk Factors by Alternative Baseload Generation Options

	Fuel Price Volatility	CO_2 Regulation	Capital Outlay and Commodity Prices	Lead Time	Financial Incentives	Waste Storage	Technical Performance/Reliability
CC	Fuel price very volatile	Less exposed to CO_2	Low cost	4 years	Easy for both IPP and Utility	No waste storage issues	Mature technology, reliable
SCPC	Fuel prices relatively stable, domestic	Very exposed to CO_2	Medium cost	5-6 years	Difficult for both IPP and Utility	Potential coal ash regulations, potential CO_2 sequestration issues	Mature technology, reliable
IGCC	Fuel prices relatively stable, domestic	Very exposed to CO_2, could take CCS more readily	High cost	6-8 years	Difficult for both IPP and Utility	Potential CO_2 sequestration issues	Mature components, integration is not
Nuclear	Fuel prices low and stable	Not exposed to CO_2 policies	Very high cost	10+ years	Extremely difficult for IPP, very difficult for utility	Only medium-term storage available for radioactive and hazardous waste, subject to gov't monitoring	Recent experience is only from overseas

3.1 Fuel Price Volatility Risk

As illustrated in Exhibit 3-3, spot natural gas prices have recently been as high as $13/MMbtu and as low as $4/MMBtu. These price movements have been highly correlated with oil prices, which also reached record highs in 2008. This greatly complicates investment decisions, since hedging gas prices can be very difficult and requires large amounts of collateral.

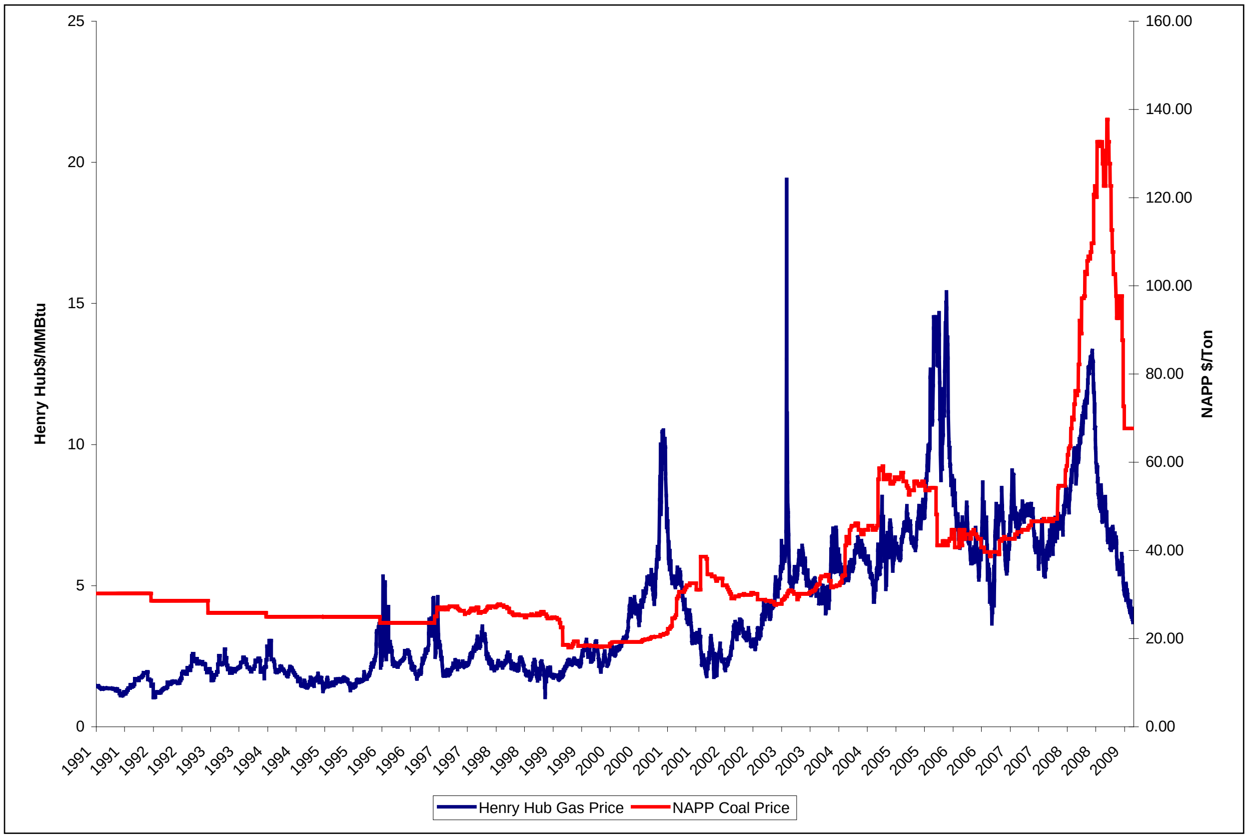
Over this same time period, some U.S. coal markets have been volatile, especially those marginal markets with greatest participation potential in international markets. Northern Appalachian low sulfur spot coal prices have risen to nearly $140/ton, before dramatically falling to below $70 per ton. While prices of both natural gas and coal have been highly volatile in the past year, in general, natural gas prices are typically higher and more volatile than coal prices. The much greater volatility of natural gas is emphasized by the much smaller movements in Powder River Basin (PRB) coal prices. PRB coal is the largest source of coal in the U.S. and is much less susceptible to developments in international markets, as well as competition with natural gas. Other U.S. coal markets also show less volatility compared to Central Appalachia.

As mentioned in Chapter 2, while a fuel adjustment clause is typically built into the utility tariffs, utilities may not be protected from some of the risk associated with higher fuel price volatility because regulators may not allow all the increases to be passed through to the ratepayers. Thus, all else being equal, a need for stable fuel prices would favor the coal option for a baseload investment decision.

It should also be noted that this gas price volatility is occurring in the absence of CO_2 regulations, which are expected to increase gas prices, and which would add another volatile commodity — CO_2 allowances — to the mix.

Given that fuel costs comprise the major variable cost of fossil-fired generation plants, fuel price volatility is a major risk factor for power plant developers evaluating baseload generation alternatives. This is especially the case when one considers that consumers also prefer stable prices for power on a year-by-year basis.

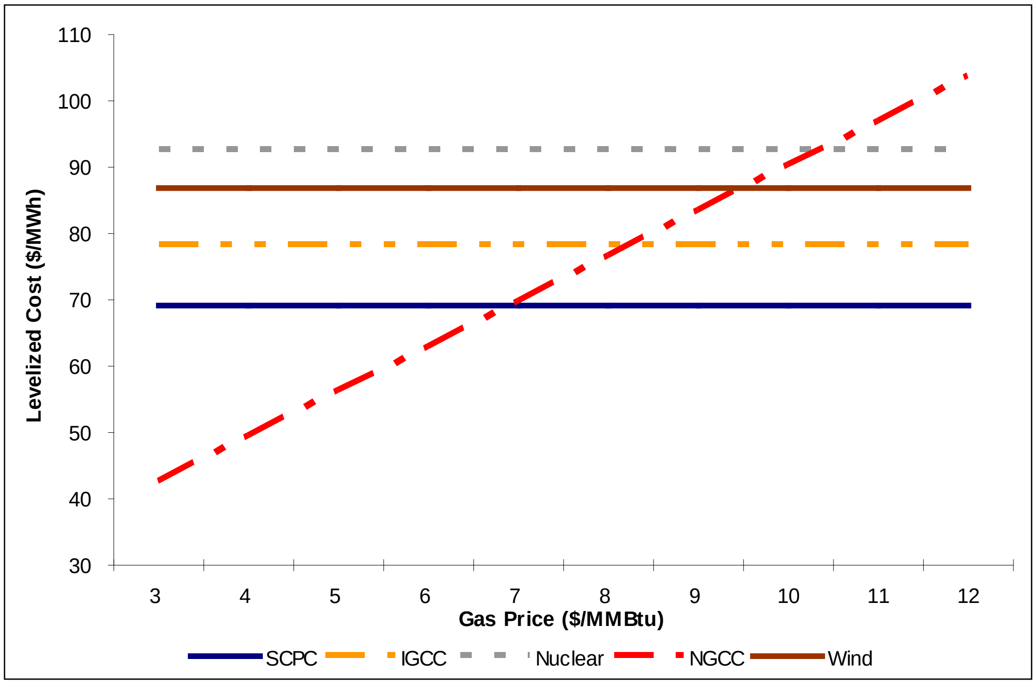
Exhibit 3-3
Historical Henry Hub Natural Gas Prices and NAPP Coal Price



Source: Bloomberg. Historical Henry Hub Natural Gas Spot Prices and Northern Appalachia Coal Prices.

Fuel price volatility impacts baseload power plant decision making in several ways. First, as illustrated in Exhibit 3-4, the absolute level of natural gas prices has a large impact on the levelized cost of a combined cycle plant relative to other baseload options. In this illustrative example, with natural gas prices below $6.50 per MMBtu, combined cycle plants have lower levelized generation costs than the other baseload generation options. However, as natural gas prices rise above $6.50 per MMBtu, the levelized cost of combined cycle plants rises above the cost of super critical pulverized coal units. Also, as natural gas prices rise further, the levelized cost of combined cycles begins to exceed the cost of the other generation options. Indeed, as seen in Exhibit 3-4, should natural gas prices rise above $11–12 per MMBtu, the cost of a combined cycle unit would increase above all other baseload options.

Exhibit 3-4
Illustrative Example of Levelized Cost Sensitivity to Gas Price



Source: ICF Assumptions. See appendix (p. I-62) for assumption details.

Since natural gas power plants are on the margin and setting power prices in many hours in some regions, natural gas price volatility also has indirect impacts on baseload power plant decisions.

While fuel price volatility is a source of risk for investors in new baseload generation, these risks are typically reduced for regulated utilities because the rates at which they sell electricity, as established by the state public utility commission, typically include fuel cost adjustment clauses that allow them to pass on increases in fuel costs to their ratepayers.

3.2 CO_2 Regulatory Risk

Some form of CO_2 regulation in the U.S. is becoming more likely. Numerous legislative proposals have been introduced in Congress in recent years. In addition, the Supreme Court has ruled that the U.S. Environmental Protection Agency (EPA) has the authority to determine whether CO_2 emissions should be regulated under existing legislative authority. Because nuclear plants emit no CO_2, and new pulverized coal plants emit approximately twice the CO_2 per MWh as new combined cycle natural gas plants, the ultimate stringency and design of CO_2 regulation will have a significant impact on what new baseload generation capacity is built. To a large extent, the lack of new coal-fired capacity additions in the U.S. in recent years is due to the growing likelihood of CO_2 emission regulation, as well as increases in construction costs. In addition, the role of technology and the potential for CCS and other mechanisms for lower CO_2 emissions can be important determinants of the impact of CO_2 controls.

The following section provides a brief overview of the possible legislative and regulatory pathways that could result in CO_2 emission controls.

3.2.1 Legislative Path

Ten or more Congressional climate bills introduced during the past two years came close to passage, though none have served to define the range of policy issues and alternative approaches that will be addressed by any new federal cap-and-trade legislation. All include a cap-and–trade component, so a CO_2 tax with a known rate and, hence, less uncertainty, appears unlikely. The incoming 111th Congress is picking up the debate where the 110th Congress left off, but with a changed political composition and new administration. In addition, President Obama has endorsed CO_2 controls starting as early as 2012.

Two influential proposed bills for economy-wide cap-and-trade programs — S.3036 from Senators Lieberman, Warner, and Boxer, and a draft bill from Representatives Dingell and Boucher — are likely to serve as starting points for a negotiated compromise. As identified in Exhibit 3-5, these bills address the following key CO_2 policy issues:

- Greenhouse gas and sector coverage
- Point of regulation
- Start year
- Reduction targets
- Method of allowance distribution: allocation or auction
- Use of offsets
- Allowance price limits
- Early action credits
- Treatment of state programs

Exhibit 3-5
Summary of the Dingell-Boucher and Lieberman-Warner Bills

	Dingell-Boucher (draft)	Lieberman-Warner-Boxer (S.3036)
Introduced/Circulated	October 2008	May 2008
Gas & Sector Coverage; Point of Regulation	5 GHGs + NF3; HFCs covered separately. Electricity generators and large industrial facilities; producers and importers of fossil fuels and other bulk non-HFC GHGs; natural gas distribution companies; geologic sequestration sites. Coverage threshold: 25ktCO2e/yr.	5 GHGs; HFCs covered separately. Entities using >5,000t/yr of coal (i.e. electricity generators and large industrial facilities); producers and importers of fossil fuels and other non-HFC GHGs. Coverage threshold: 10ktCO2e/yr.
Start Year	2012 for electricity and transportation; 2014 for industry; 2017 for commercial and residential	2012
Targets (Covered)	Allowance budgets given in absolute terms. Authors claim these target: 6% below 2005 levels by 2020; 44% by 2030; 80% by 2050.	Allowance budgets given in absolute terms. Authors claim these targets: 19% below 2005 levels by 2020 and 71% below 2005 levels by 2050.
Allocation	Four allocation options ranging from 49% allowances to no free allowances allocated to electric sector. Full auction begins in 2016.	29% auctioned in 2012 with 64% auctioned by 2031. 18% freely allocated to generators including rural electric cooperatives, 11% to manufacturers, 2% to refiners but not fuel importers, 0.75% to natural gas processors and importers, all decreasing to 0% by 2031; 9.5% to 10% to electricity LDCs; 3.25% to 3.5% to natural gas LDCs.
Offsets	Increasing share of compliance obligation can be met with offsets. 2013-2017: 5% domestic or international ; 2018-2020: 15%domestic or international; 2021-2024: 15% domestic and 15% international; 2025+: 20% domestic and 15% international. Unlimited use of international allowances.	30% of compliance obligation can be met with offsets: 15% domestic, 5% international project offsets, 10% international forestry (or up to 25% if domestic offsets in short supply); unlimited import of international allowances.
Price Controls	Offsets; unlimited banking, borrowing at complier level (interest rate applies); strategic reserve auctions (based in part on program-level borrowing).	Unlimited banking, borrowing at complier level (interest rate applies), borrowing at program level triggered by price (emergency offramp) or Carbon Market Efficiency Board; cost containment auctions.
Early Action Credit	Sets aside 2095Mt to be allocated through 2025, and recognises action from 2002-enactment.	Sets aside 4,043Mt to be allocated through 2026 and recognises action from 1994-enactment.
Treatment of state programs	Holders of RGGI and California allowances to be compensated for cost of obtaining and holding allowances, but state programs pre-empted by federal one.	Holders of RGGI and California allowances to be compensated for cost of obtaining and holding allowances. Program allowances set aside for states that join federal program and already had more aggressive targets in place.

The two proposed bills are similar in many respects. In particular, they both:

- Establish GHG emission markets starting in 2012 and eventually covering some 80 percent of U.S. emissions;
- Allocate a decreasing proportion of allowances to compliers for free overtime; and
- Permit the use of domestic and international offsets as well as banking and borrowing to control prices and volatility.

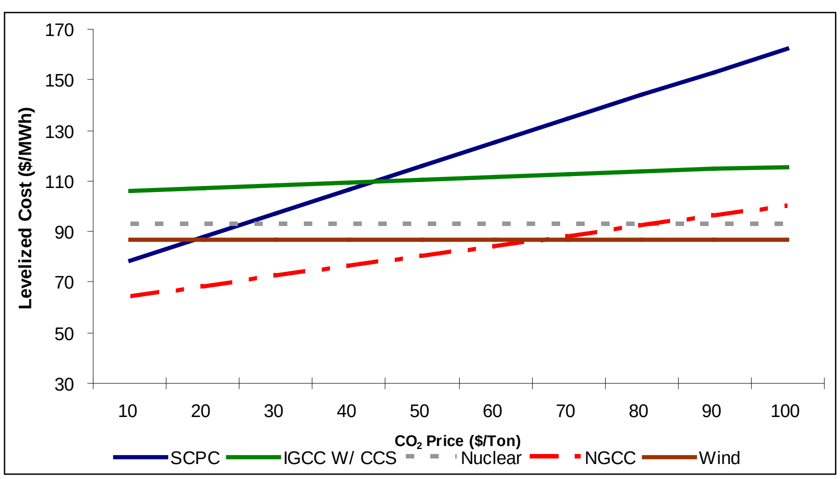
However, the two bills differ markedly in what they prescribe with respect to the following:

- Emission reductions: The Dingell-Boucher bill's cuts are less aggressive than the Lieberman-Warner bill through 2020 (though may require similar levels of abatement within covered sectors);
- Allocation: Utilities and industry could get more free allowances initially under Dingell-Boucher (true under two of four proposed allocation options);
- Cost containment: Dingell-Boucher allows fewer offsets in initial years, but more later (note again that it requires fewer overall emission cuts initially); and
- Treatment of state programs: unlike Lieberman-Warner, the Dingell-Boucher bill pre-empts state programs.

While these and other CO_2 bills have been debated over the past several years, uncertainty about the scope, timing, and stringency of any final federal CO_2 legislation is still an issue. The ultimate level of CO_2 allowance prices that could result from these or similar proposals is also still uncertain. In Europe, CO_2 emission allowance prices have been very volatile and prices have been highly correlated to natural gas and oil prices. This volatility is compounded by the fact that government policy is such a large and difficult-to-predict driver of the price.

As illustrated in Exhibit 3–6, CO_2 prices will also have a significant impact on the levelized cost of baseload generation capacity alternatives. In this illustrative example, combined cycle plants have lower levelized costs than coal options at all CO_2 prices. However, at higher gas prices, this could change, as seen in Exhibit 3-4.

Exhibit 3-6
Illustrative Example of Impact of CO_2 Allowance Prices on Relative Levelized Costs of Baseload Generation Alternatives



Source: ICF Assumptions. See appendix (p. I-62) for assumption details.

Given its large potential impact on power plant economics, it is not surprising that many commercial banks and credit rating agencies cite the likelihood of CO_2 regulation as one of their main financing concerns for utilities.

CO_2 legislation will also lead to related regulatory risks. In particular, CO_2 regulation will lead to an increase in variable costs reflecting the cost of CO_2 allowances. Regulated utilities will try to pass these higher variable costs on to ratepayers. While pass-through mechanisms are in place for variable cost increases in many states, the degree to which cost increases associated with CO_2 allowance costs can be passed through to ratepayers is uncertain. In addition, with large rate increases expected as a result of CO_2 regulations, demand growth for electric power may decline, causing delays in need for new baseload capacity. Not surprisingly, the growing likelihood of CO_2 regulation is putting added pressure on power companies to move away from new investment in baseload coal generation capacity whose CO_2 emissions are not controlled.

3.2.2 Administrative Path

While Congress moves forward in debating federal legislation to reduce CO_2 emissions, EPA is evaluating the need for CO_2 emission regulation under its existing authority provided by the Clean Air Act (Clean Air Act). In April 2007, the Supreme Court ruled that the EPA has the authority to regulate tailpipe GHG emissions as air pollutants under the CAA. The EPA has the obligation to do so if it finds that GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare.

In July 2008, the EPA issued an advanced notice of proposed rulemaking to gather further scientific evidence pertaining to the endangerment of public health or welfare, and to inform possible future law-making. On March 20, 2009, the EPA sent to the Office of Management and Budget a proposed finding that CO_2 and five other greenhouse gases endanger human health and the environment and, therefore, must be regulated as pollutants under the CAA.

One way that coal generation could be regulated under existing legislation is through a revision of the new source performance standard (NSPS).

3.2.3 Regulatory – NSPS Revisions

The EPA issues NSPSs for the different pollutants that it oversees. An NSPS reflects the degree of emission limitation achievable through the application of the “best system of emission reduction” that the EPA determines has been adequately demonstrated. EPA may consider certain costs and non-air-quality health and environmental impacts and energy requirements when establishing NSPS.

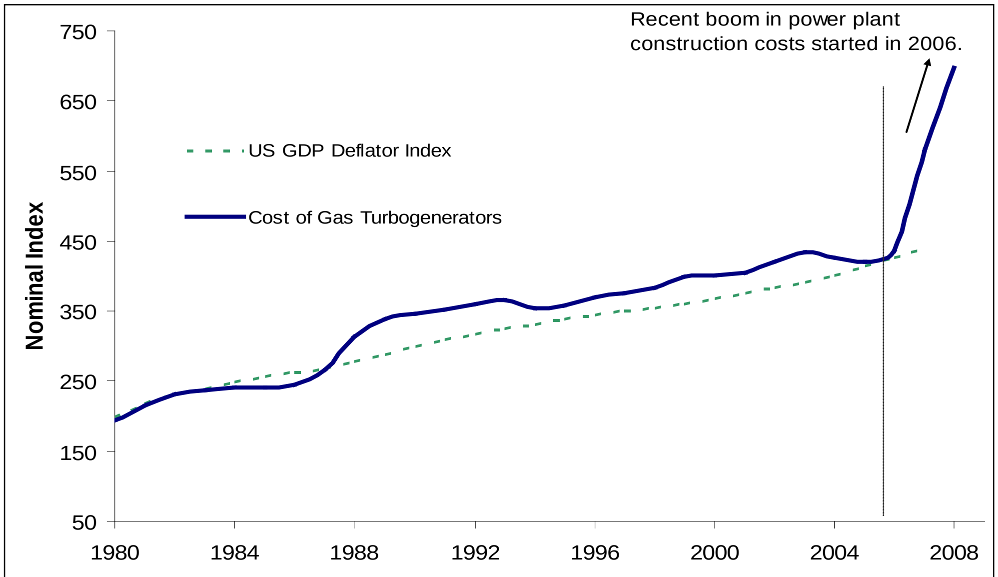
If the NSPS is revised to add CO_2 as a regulated pollutant, it may affect coal plants as well as other stationary sources. For example, the Sierra Club supports the adoption of an emissions standard for CO_2 set equal to the emission rate of a natural gas combined cycle plant (i.e., 800 lb/MWh). The current coal fleet emits roughly double the amount of CO_2 per unit as a combined cycle. This regulatory risk could significantly curtail new coal generation, as only a coal facility with carbon capture could meet that CO_2 emission rate target.

3.3 Capital Outlay and Commodity Price Risks

Power plant investment is expensive. Even though utilities have a rate recovery mechanism, full recovery is not guaranteed. Costly and imprudent power plant investments in the 1970s and 1980s have brought about a financial crisis and sometimes bankruptcy for power companies including the Public Service Company of New Hampshire, El Paso Electric, Long Island Lighting Company, and Gulf States Utilities.[2]

Over the last several years, capital costs for new power plants have escalated at a record pace, peaking, at least for the near term, in the summer of 2008 (see Exhibit 3-7 below). This escalation was due to rising material costs and high international demand for power plants and their associated equipment and labor services. Notable examples include China and India, whose surge in demand for large amounts of new coal capacity strained materials, equipment, and labor supplies globally. The surge in foreign demand was also related to a weaker U.S. dollar.

Exhibit 3-7
Historical Construction Cost Trends of
New Gas-Turbine-Based Power Plants



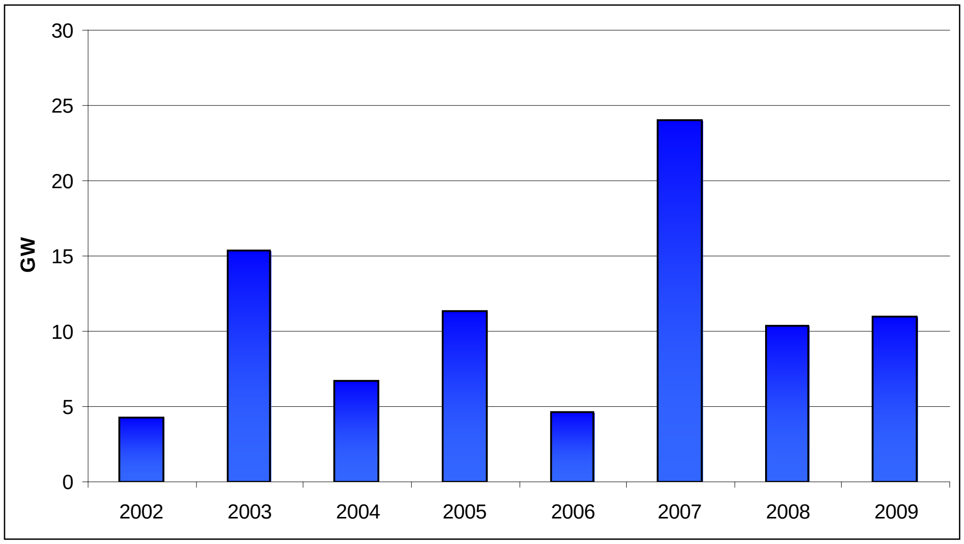
Source:
Capital Cost: Handy Whitman; ICF
GDP Deflator: Bureau of Economic Activity

Key commodity indices such as steel and copper, which approximately doubled or even quadrupled over the same time period, were also drivers to the capital cost run-up. Concrete costs also increased, though at a lower rate than the other commodities. Labor costs, especially for specialists in plant construction, also escalated. Although the graphic above is for gas-turbine-based equipment, the run-up in construction cost has affected all types of power plants, ranging from coal to gas to renewables.

As seen above, natural gas prices had a significant run-up in price during the mid-2000s and influenced many utilities to start construction in coal-based projects. However, as the global demand for coal-fired plants increased, construction costs increased as well. As seen in Exhibit 3-8, the run-up in capital costs influenced many utilities to revise estimates and, in some cases, delay or cancel projects.

[2] Lapson, Ellen and Richard Hunter. "The Future of Fuel Diversity: Crisis or Euphoria?" *Public Utilities Fortnightly*, Oct 2004, p. 62.

Exhibit 3-8
Coal Capacity Cancelled



Source: Energy Velocity Database, Ventyx 2009.

Following are two examples of utility project escalation and cancellations:

- Duke Energy Carolinas originally estimated the cost for its two-unit coal-fired Cliffside project at approximately $2 billion. In the fall of 2006, Duke announced the project cost had increased by approximately 47 percent ($1 billion). The project was downsized after the North Carolina Utilities Commission refused to grant a permit for two units. Shortly thereafter, Duke announced that the remaining unit would cost approximately $1.53 billion, an estimate that then increased another 20 percent by May 2007. The Cliffside facility is currently under construction.

- TXU originally planned to build eleven coal plants in Texas in order to meet reliability needs. However, as part of TXU's proposed buyout by private equity, the utility said it would no longer build eight of those plants, or roughly 9,000 MW of coal-fired generation. The buyers needed to shore up support, and as a result, the expensive units were canceled.

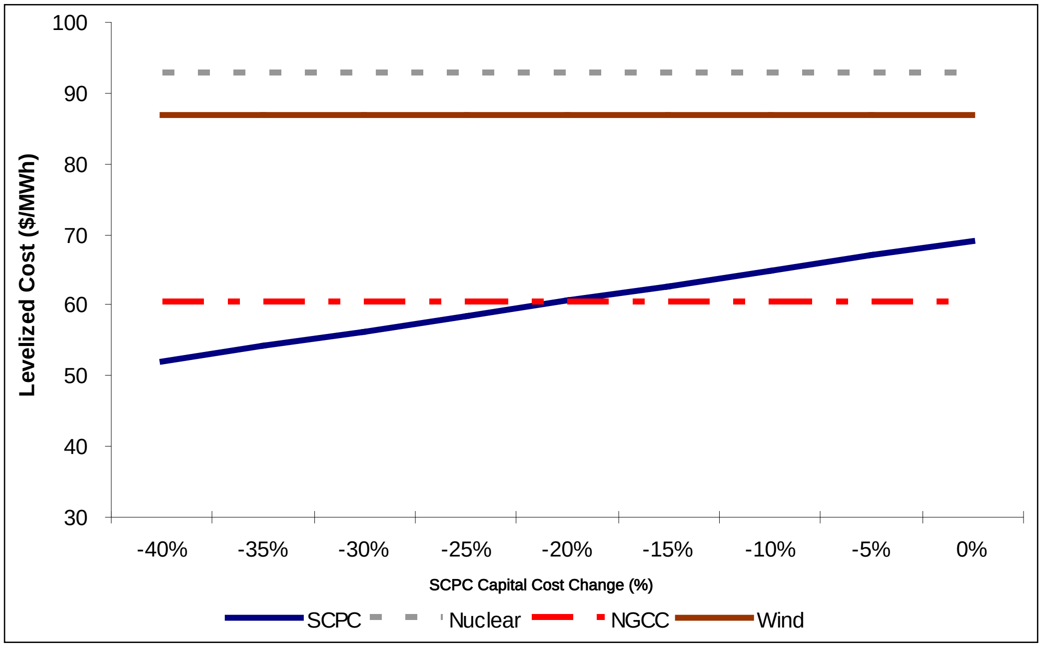
IPP projects were also hit with escalating capital costs. The projected costs for LS Power's nominal 1,600-megawatt coal-fired White Pine Energy Station in Nevada has more than tripled during the planning stages. In 2004, the company estimated that capital investment in the facility would range from $600 million to over $1 billion, depending on the project's final size. By April 2006, however, projected capital investment had climbed from a range of $1 billion to over $2 billion. That range increased even further by August 2007 to between $1 billion and $3 billion. In early March 2009, LS Power cancelled the White Pine project, citing the bad economy, regulatory uncertainty, and high construction costs.[3]

Exhibit 3-9 shows how falling construction costs for a supercritical coal plant would impact its levelized cost relative to other baseload generation options, with all other factors being held

[3] Barber, Wayne. "LS Power halts Nevada coal plant; Navajo Nation approves right of way for Sithe plant line." *SNL Financial,* Mar 06, 2009.

constant. Construction costs for the coal plant have to fall significantly for it to be on parity with a natural-gas-fired combined cycle plant.

Exhibit 3-9
Illustrative Example of Levelized Cost Sensitivity to Changes in Coal Capital Cost

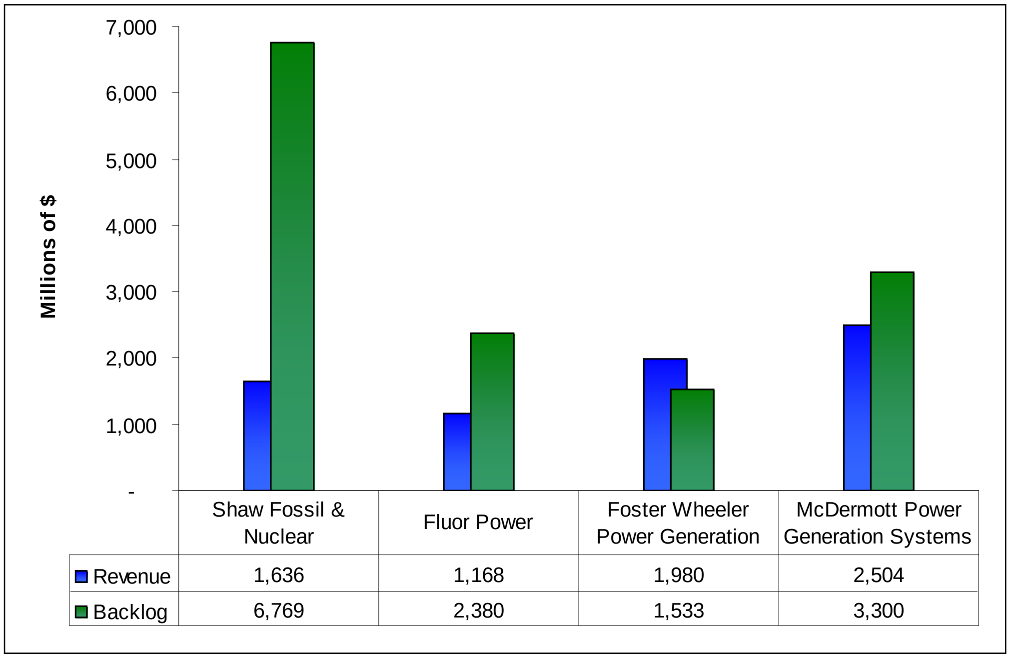


Source: ICF assumptions. See appendix (p. I-62) for assumption details.

3.3.1 EPC Contracts

The significant backlog of project contracts at large engineering, procurement, and construction (EPC) firms also contributed to the run-up in construction costs. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue. This effect may lessen as the recession continues to stall out new capital projects. As shown in Exhibit 3-10, many major EPC contractors have significant backlogs compared to their 2007 gross revenues. The backlog pressure is expected to remain for at least the next one to two years.

Exhibit 3-10
2007 Revenues vs. Backlog Comparison for EPCs



Source: Annual reports of each company.

3.3.2 EPC Design and Construction

Risks once borne by EPC contractors are being shifted to plant developers. In the past, major EPC contractors were willing to enter fixed-price contracts for new power plants. (EPC costs are well over 60 percent of the all-in construction cost.) As a result, contractors bore the risk that materials, equipment, and component prices would be higher than estimated. However, recent experience at numerous coal plant construction projects shows that major EPC contractors are no longer willing to enter fixed-price contracts.

This change is the result of the volatile costs for materials (alloy pipe, steel, copper, and concrete) as well as the tight construction labor market. Recently, several EPC contractors commented that they are willing to fix the price for specific projects, but the amount of money to be added to cover potential risks of a cost overrun would render the project uneconomical. As a result, recent construction project contracts shift the risks of higher commodities, equipment, and/or labor costs to plant owners and investors.[4]

Some good news from the EPC sector, however, is standardization. New combined cycle plants that originally took 36 months to complete back in the late 1990s now take less than 24 months. In TXU's announcement three years ago that it would build out 11 new coal projects, the underlying cost-controlling measure was standardization. Such ideas have had an impact on the nuclear industry as well.

Much has changed in the nuclear sector since the mid-1970s to improve the chances that utilities will move forward with plans to develop new nuclear capacity. In the 1970s and 1980s,

[4] "The Risks of Investing in Coal Facilities." *Synapse Energy Economics*. 2008, p. 41.

no design standardization meant that plants were designed as construction went along. Inconsistent construction practices led to mixed results, with some projects that worked out well and others that did not (i.e., Shoreham, Midlands). Today, the industry has evolved and developed standardized plant designs that are NRC-certified before construction begins. Furthermore, lessons learned from nuclear projects overseas have now been incorporated into these approved designs.

3.4 Federal Renewable Portfolio Standard Risks

A Federal renewable portfolio standard (RPS) could be passed by Congress this year. Growing popular support for an RPS reflects growing concerns about energy security and increasing support for reducing CO_2 emissions. The new Obama administration is aggressively pursuing some form of an RPS program.

Two of the most likely federal RPS scenarios currently being considered are:

- **20 percent by 2020** – Senator Bingaman has introduced legislation that aims to have 20 percent of total end-use energy supplied by renewable resources by 2020. It is not clear what the definition of "renewables" will be, however. Furthermore, 5 percent of the requirement could potentially be met with energy efficiency.

- **25 percent by 2025** – Congressman Markey has proposed a bill with a slightly more aggressive target in that it continues the 1-percent-per-year growth of renewable penetration out to 2025.

As wind is currently the most economical renewable resource, a significant increase in wind generation capacity is likely to result from a federal RPS. A 25 percent by 2025 policy could result in over 200 GW of wind by 2025. For comparison, if continued out to 2025 with no further changes, current state RPS standards (33 states and the District of Columbia in total) would result in about 80 GW of wind and represent an effective 8 percent RPS.

Substantial obstacles are still standing in the way of a federal RPS, such as:

- Strenuous opposition from utilities in the Southeast and some in the Ohio Valley, where no strong wind resources exist. This obviously limits opportunities to participate in the program and attract new investment.

- Uncertainty as to the role of biomass.

- Most wind resources are located far from load centers and will need significant transmission investment to move forward. As will be discussed later, siting new transmission lines is a significant hurdle unto itself.

- The investment does not usually contribute to grid reliability and, in fact, may diminish grid reliability due to the intermittent nature of the resource.

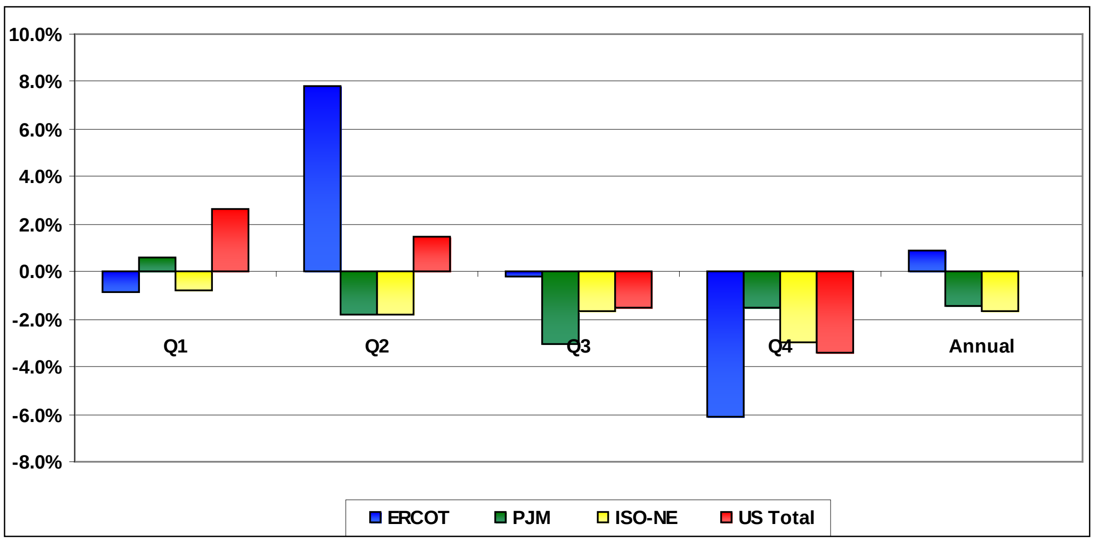
- Costs can be high.

Nevertheless, if an RPS is passed, significant implications both in terms of "brown" power pricing as well as potential delays in new fossil baseload generation requirements could result. This report estimates that wholesale U.S. power prices will, on average, go down approximately 10 percent. However, adding large amounts of intermittent renewable resources will likely also require adding substantial new fossil-based peaking capacity to ensure continued reliability of the electricity grid.

3.5 Demand Growth and Demand Side Management Risks

The U.S. market entered a recessionary phase in September 2008, as problems in the credit market slowed the flow of funds needed to bring new capital projects to market. As seen in Exhibit 3-11, the U.S. peak demand for electricity decreased approximately 4 percent in Q4 of 2008 and declined from 2007 to 2008.

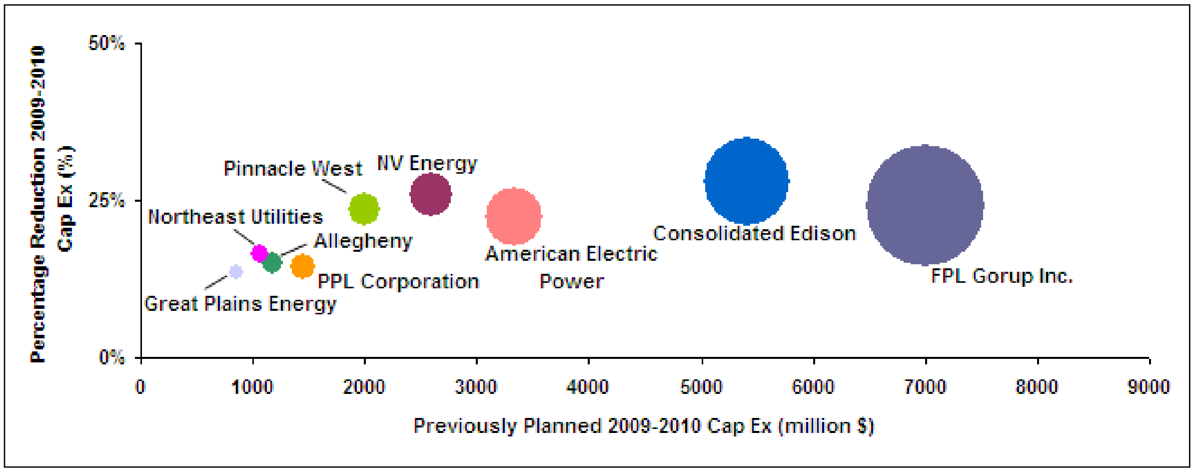
Exhibit 3-11
U.S. Peak Demand for Electricity



Source: EIA data.

Although other factors, particularly weather, influence demand from year to year, the recession that started in September 2008 is clearly exerting downward pressure on growth. In general, there has been an appreciable drop in energy demand since the second quarter of 2008, which has brought about a slowdown in utility capital expenditure projections (see Exhibit 3-12).

Exhibit 3-12a
Capital Expenditure Reductions in 2009-10



Source: SNL Financial.

As seen in Exhibit 3-12b, negative growth was also observed during past recessionary periods, namely 1981–1982, 1991–1992, and 2001–2004. During these recessions, the average annual energy growth rate was 0.2 percent. Immediately following these periods were periods of recovery. During these recovery periods (1983–86, 1993–95, and 2005–06) the average annual growth rate was 4.3 percent. The average annual growth rate over all the recession and recovery-from-recession years was 2.3 percent. This is the same as the 2000–2007 ten-year rolling average annual growth rate.

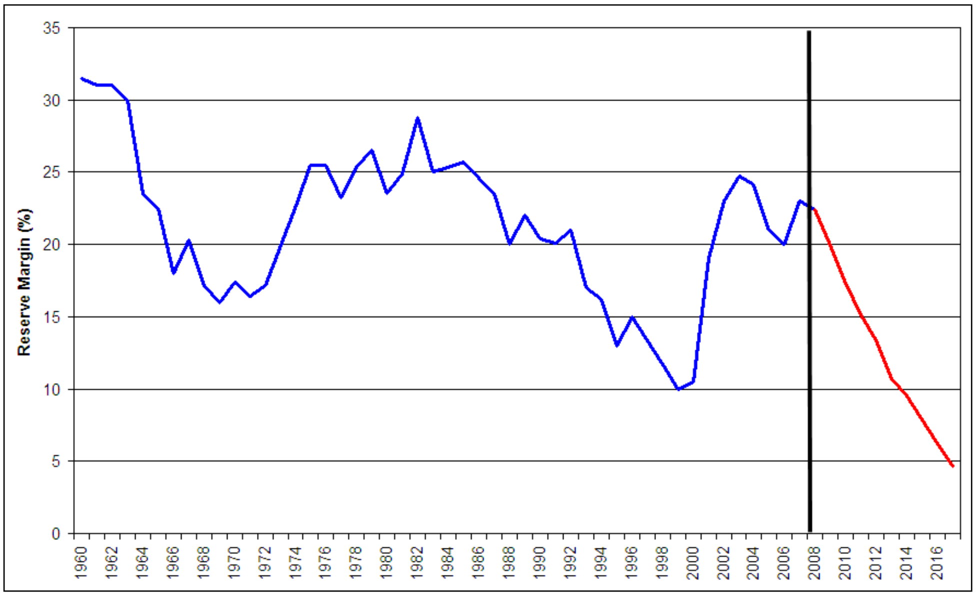
Exhibit 3-12b
U.S. Peak Demand Growth during Recessions

Iranian Revolution – Worst Post-WWII Recession			Gulf War			9/11		
Year	Peak (GW)	Growth (%)	Year	Peak (GW)	Growth (%)	Year	Peak (GW)	Growth (%)
1980	427	N/A	1990	546	N/A	2000	678	N/A
1981	**428**	**+0.2**	**1991**	**551**	**+0.9**	**2001**	**688**	**+1.4**
1982	**414**	**-3.3**	**1992**	**549**	**-0.4**	**2002**	**715**	**+3.9**
1983	448	+8.2	1993	575	+4.7	**2003**	**709**	**-0.8**
1984	451	+0.7	1994	585	+1.7	**2004**	**704**	**-0.7**
1985	460	+2.0	1995	620	+6.0	2005	759	+7.7
1986	476	+3.5	1996	617	-0.5	2006	789	+4.0
Average	N/A	+1.8	Average	N/A	+2.1	Average	N/A	+2.6

Source: NERC ES&D.

Major utilities such as Florida Power & Light (FPL) and American Electric Power Co. (AEP) have forecast a reduction in capital expenditures of approximately 25 percent. Not all of these expenditures are earmarked for new investments, but clearly new investment is being constrained. In the near term, the decline in capital expenditures will mostly cause reserve margins to fall because significant lead times are required in capital projects and peak demand recovers very quickly after recessions. This is illustrated on a national level in Exhibit 3-13.

Exhibit 3-13
Falling Reserve Margin Shortages Due to Limited Capital Expenditures



Source: 1960-1999 EEI, Statistical Yearbook of Electric Utility Industry and NERC ES&D; NERC ES&D 2000–2013 reserve margin.

The recent sharp decline in electric demand and related drop in capital expenditures increases the risks that investors in baseload electric generation capacity face concerning future demand growth. In particular, these investors must manage the risks associated with the uncertainty about when demand growth will recover, the strength of the recovery, and the timing of the market's response to this increase in demand growth in terms of investing in new generation capacity.

3.5.1 Demand Side Management

Roughly $20–26 billion is earmarked for energy efficiency, demand side management (DSM) programs, smart grid, weatherization, and green buildings in last year's stimulus bill. It is anticipated that these monies will be spent over the next two to three years. The impact of this large investment in energy efficiency will be to delay electric demand growth and, in turn, to delay new investment in generation projects.

Currently, U.S. utilities spend approximately $2–3 billion on DSM and have achieved approximately 0.2 percent incremental annual savings in terms of reduced demand. Applying this metric to the stimulus bill monies would roughly imply a loss of demand growth of 1–1.5 percent per year for the next three years. Thus, a moderate slowdown in growth recovery might occur. A surge in federal spending on DSM programs may lead to an erosion of demand and may cause a delay in power plant construction.

As alluded to above, this is already happening to a lesser extent under existing utility programs. For example, Duke Energy expects to spend at least $200 million less on capital expenditures in 2009 due to DSM programs delaying the construction of a gas-fired combined cycle. [5]

This large jump in energy efficiency investment adds to the risks that investors in baseload generation capacity must manage in terms of the optimal timing for and location of new investment.

3.6 Carbon Capture and Sequestration

3.6.1 CCS Risks

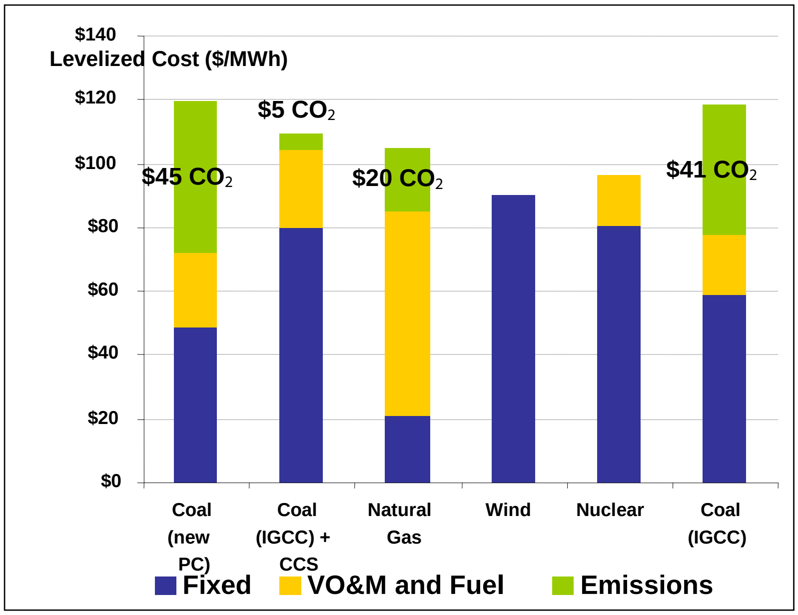
Tremendous uncertainty exists around the eventual costs of new baseload technologies in the future. This is especially true for new nuclear and coal with CCS technologies that have not yet been commercialized. If Federal CO_2 legislation is passed, the coal and electric industries will mostly need to rely on capturing and sequestering CO_2 as the primary way to reduce costs associated with CO_2 emissions. Although CO_2 capture in the pre-combustion CCS technologies to be used at IGCC facilities is promising, no commercially viable CCS technology for utility scale pulverized coal plants is currently available.

Pulverized coal may need CCS to be part of the future baseload. Currently, if stringent CO_2 regulations are promulgated, new pulverized coal plants without CCS may not be an economic choice. In combination with the high capital expenditures associated with building a new coal plant, a CO_2 allowance price will diminish coal's relative fuel price advantage compared to natural gas, potentially making new coal assets economically less attractive than natural gas ones. In addition to coal being more carbon intensive than natural gas, coal-fired generation is less energy efficient than new natural gas-fired generation. As a result, coal assets face higher CO_2 compliance costs for a given quantity of electricity produced and CO_2 allowance price.

Exhibit 3-14 provides an illustrative example of how, at a carbon price of $48/ton, a new pulverized coal unit faces $45/MWh in additional cost from CO_2, compared to $20/MWh for a new combined cycle unit, which makes a coal unit costlier than a gas-fired unit.

[5] Burr, Michael T. "Desperately Seeking Liquidity," *Public Utilities Fortnightly*, Feb 2009, p. 27.

Exhibit 3-14
Illustrative Example of the Levelized Cost of New Capacity Investment at $48/Ton CO_2



Source: ICF International.

However, several pilot coal-fired power plants with CCS are already in operation, and demonstration projects are under construction or planned around the world. CCS, though, is not yet an economical option for most commercial power generation facilities for three reasons:

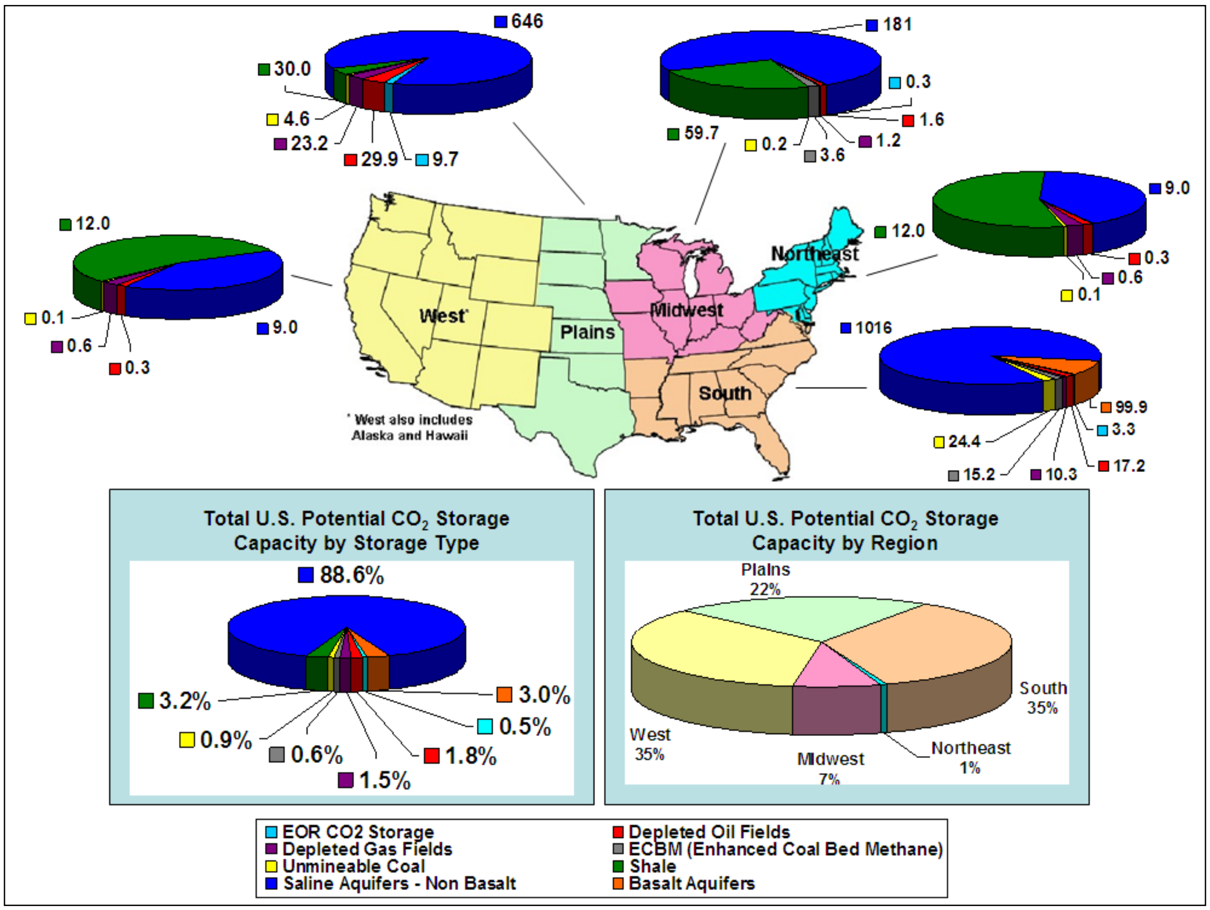
- CCS needs further development to address technical issues, identify and refine the best technologies, to reduce costs (especially of capture), and demonstrate storage under diverse geological conditions.
- The legal-regulatory framework for CCS is not yet in place, particularly as it relates to CO_2 injection and undefined long-term liability for CO_2 storage.
- The near-term economic value placed on reducing CO_2 emissions (e.g., under a CO_2 emissions-trading program) is currently too low for plant developers to earn an adequate return without a higher-value market for the CO_2, such as enhanced oil recovery (EOR) or industrial reuse.

The addition of CCS technology may have several adverse impacts on pulverized coal facilities. Apart from the investment required to add the expensive technology, the operation of the technology is likely to result in performance penalties due to reduced plant efficiency and the addition of the incremental on-site auxiliary loads needed to operate the new CCS equipment, which will lower the plant's net output. Together, these impacts will greatly increase the cost of generating electricity.

Given the preliminary state of the testing of post-combustion carbon capturing technologies, it is not surprising that the costs of actually capturing and sequestering CO_2 from pulverized coal facilities are uncertain. Apart from the cost incurred in capturing the CO_2, the transportation and sequestration of the captured CO_2 would also increase this cost. Also, it may be more expensive to retrofit carbon capture technology onto existing coal-fired power plants, compared to the cost of installing CO_2 controls on new plants that would be designed and built to include carbon capture technology at the outset.

Exhibit 3-15 provides an overview of U.S. geologic sequestration potential by region and reservoir category. These categories include EOR, depleted gas fields (Gas), depleted oil fields without EOR (Oil), gas shale's (Shale), basalt aquifers (Basalt), enhanced coaled methane (Coaled), and saline aquifers – non-basalt (Saline). Among the storage types, saline aquifers have the largest potential.

Exhibit 3-15
Metric Gig tons of Potential CO_2 Storage
Capacity by Region and Storage Type



Sources: NATCARB and ICF International analysis.

3.6.2 CCS Financial Incentives

A variety of federal financial incentives, such as the Energy Policy Act of 2005, support the development of clean coal technologies. In particular, the first few projects will benefit greatly because these incentives are intended to 'jump-start' such technologies, bringing the cost of new projects close to the cost of a supercritical pulverized coal project with best available control technologies included.

The Energy Policy Act has enabled the U.S. Department of Energy (DOE) to provide $200 million annually between 2006 and 2014 to gasification and other clean coal projects in the U.S. in the form of loan guarantees, loans, and direct grants, for a total of $1.8 billion. Of this amount, at least 70 percent must be used for gasification projects. The act encourages active use of sub-bituminous coal in gasification projects. Assuming that project grants are made directly available to sub-bituminous projects, IGCC technology could make advancements in demonstrating capabilities on lower heat-content coals than would otherwise be possible.

The loan guarantees provide an opportunity for developers to obtain a credit rating that they otherwise would not be able to achieve. This will be particularly attractive to IPP entities that use project finance. Federal loan guarantees allow potential project sponsors to participate in multiple major projects concurrently while avoiding the risk of possible failure due to factors such as construction cost overruns and low power prices that could endanger a company's financial viability. A process will need to be established for determining qualifications for the amount of a project's loan guarantee.

Under the new program, the loan guarantees will cover, at most, 80 percent of the debt for any project, which in turn, reduces the cost of the insured portion of the debt over the project lifetime from 1–2 percent. However, the DOE may issue guarantees of up to 100 percent of the amount of debt if the loan is issued and funded by the U.S. Treasury Department's Federal Financing Bank.

Loan guarantees are only valid for projects employing advanced generating technologies that avoid, reduce, or sequester air pollutants or greenhouse gas emissions. Neither conventional coal nor combined-cycle natural gas plants qualify for the loan guarantee program.

The DOE will issue loan guarantees only if borrowers and project sponsors, rather than taxpayers, pay the "credit subsidy cost" for the loan guarantees they receive. Additionally, the Secretary of Energy must determine that repayment is a "reasonable prospect" of the guaranteed debt before a loan guarantee may be issued.

In a loan default situation, the DOE will have a superior legal claim on all project assets pledged as collateral for the loan guarantee; however, in the event of a default, it is possible that lenders and holders of non-guaranteed debt could claim a portion of the proceeds from the sale of project assets pledged as collateral.

The Energy Policy Act also establishes tax credits of up to $800 million for IGCC projects and up to $500 million for other advanced coal-based projects. The annual tax credit for gasification projects is 20 percent of the qualified investment, while the annual tax credit for other advanced coal-based projects is 15 percent.

The American Recovery and Reinvestment Act of 2009 provides additional incentives. Despite the recent loss of White House support for the FutureGen clean coal project, the stimulus package provides $3.4 billion for clean coal and CCS research and development. Additionally, it provides for a $10/ton credit for permanent CO_2 sequestration.

Although they will not totally offset the market uncertainties associated with carbon regulation, federal financial incentives can still advance clean coal development by helping to break down current investment barriers.

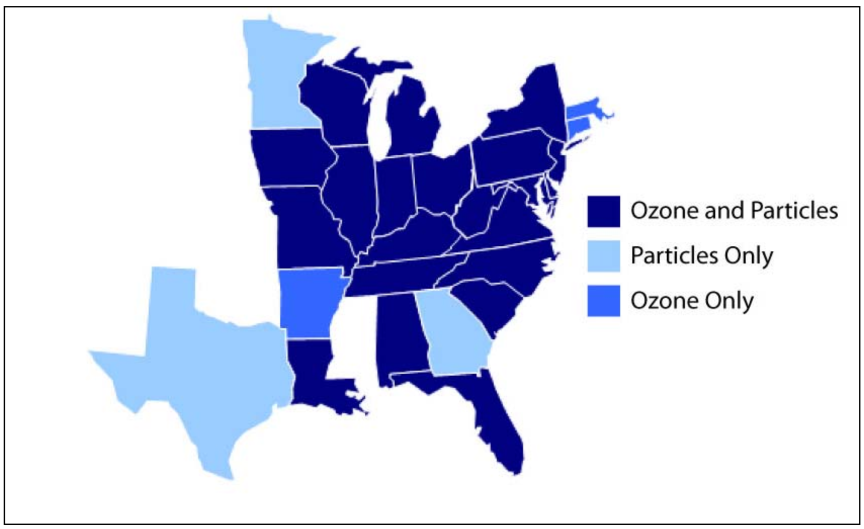
3.7 Other Environmental Issues and Externalities

3.7.1 NO_x and SO_2

The power sector currently faces several layers of air regulations at the federal, regional, and state levels, ranging from Title IV SO_2, to the NO_x SIP Call, to state and regional multi-pollutant policies in the Northeast and elsewhere. Going into 2008, generators were well along the path to preparing for the implementation of the Clean Air Interstate Rule (CAIR) (NO_x in 2009 and SO_2 in 2010) and the Clean Air Mercury Rule (CAMR). However, by the end of 2008, CAIR and CAMR had both been vacated by the U.S. Court of Appeals for the District of Columbia Circuit.

At the end of 2008, the court temporarily reinstated elements of CAIR and remanded CAIR back to the EPA for revision. CAIR covers 25 states and the District of Columbia. As shown in Exhibit 3-16, CAIR covers most of the Eastern U.S. but leaves out most of the Western U.S. Note that the dark blue shading represents ozone and particles, light blue is particles only, and royal blue is ozone only.

Exhibit 3-16
Clean Air Interstate Rule (CAIR) Program Coverage



Source: ICF Consulting.

Many aspects of CAIR were contested, but two of the most critical challenges that the U.S. Court of Appeals decided were that

- Emission trading does not provide adequate certainty of reductions from upwind sources. Therefore, trading is not an appropriate tool to control upwind emissions for attainment of the National Ambient Air Quality Standards (NAAQS); and

- EPA does not have authority to change SO_2 allowance allocation or retirement ratios. Therefore, EPA cannot integrate further SO_2 reductions into the Title IV program.

The EPA is required under the CAA to move ahead with the reinvention of CAIR, consistent with the court's 2008 decision. Given the findings of that decision, it is difficult to see how EPA will be able to offer a cap-and-trade solution for SO_2 and NO_x without a legislative fix.

Furthermore, CAIR's SO_2, annual NO_x, and ozone-season NO_x programs were intended to assist non-attainment areas under EPA's current particulate matter (2.5 microns or less, $PM_{2.5}$) and 8-hour ozone standards in achieving attainment.

- $PM_{2.5}$ and 8-hour ozone non-attainment designations were finalized in 2004, with modifications made to $PM_{2.5}$ designations in early 2005.

- These non-attainment designations are based on the 1997 standards from EPA's last review of $PM_{2.5}$ and 8-hour ozone.

The court's decision opens the door for EPA to revise CAIR. New legislation may also call for tighter limits than originally developed for CAIR. Given the continuing review required by the CAA and the remand of CAIR for revision, more stringent standards may result in further tightening of SO_2, annual NO_x, or ozone-season NO_x caps.

3.7.2 Mercury

In December 2000, EPA announced that it would regulate emissions of Mercury (Hg) and other air toxics from coal- and oil-fired electric utilities under Section 112 ("Hazardous Air Pollutants") of the CAA.

- Under Section 112(d) of the CAA, emissions standards must require the maximum degree of reduction in emissions in order to meet a maximum achievable control technology (MACT) standard.

- As required, on December 15, 2003, EPA released its proposed Hg reductions rule. This rule proposed a MACT standard as required under Section 112(d). Additionally, EPA also proposed a Hg cap and trade program as an alternative under Section 111 of the CAA.

On December 15, 2005, EPA released its final Hg rule, the Clean Air Mercury Rule (CAMR), containing a cap-and-trade program. Twenty states sued EPA over the delisting of coal plants from Section 112 of the CAA. On February 2, 2008, the U.S. Court of Appeals for the District of Columbia Circuit agreed with those states and ruled that EPA violated the CAA when it delisted coal units from Section 112.

In the absence of new legislation to define a mercury emission reduction requirement, EPA must now go back and propose a new rule under Section 112. This most likely will be the MACT standard. While it is fairly inexpensive to control for Hg as opposed to SO_x and NO_x, it still may lead to some earlier than expected retirements of coal facilities.

Thus, investors in new baseload electric generation capacity must manage the considerable risk and uncertainty associated with the ultimate scope, timing, and stringency of SO_2, NO_x, and mercury regulations. More fundamentally, these recent court rulings highlight the overall risks associated with environmental regulations.

3.8 Nuclear Option

Recently, interest in nuclear technology as the baseload technology of the future has increased. Over the past few years, more than 48 nuclear operator renewal applications have been approved. Twelve applications are in the review process, and an additional 22 parties have expressed their intent to file for renewal.

As seen in Exhibit 3-17 below, the interest is led by the utility sector. The merchant sector has not yet ventured into this space because the cost of investing in a single unit is estimated to be more than $5 billion**.**

Exhibit 3-17
Recent Activity in the Nuclear Development Space

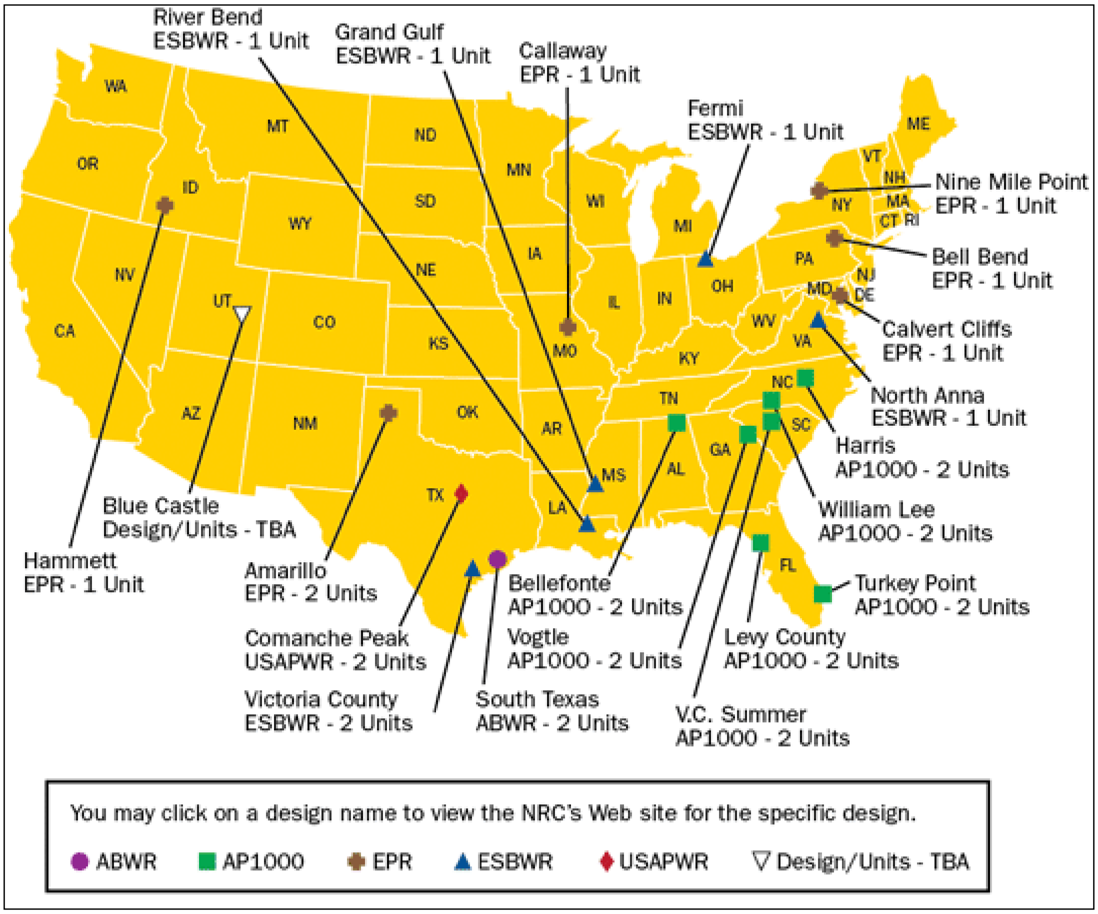
Company	Location	Capacity (MW)	Earliest Combined License Filing
TVA	AL	2,200	October 2007
Duke	SC	2,200	Fall 2007
SC E&G	SC	2,200	Fall 2007
NRG	TX	2,600	Fall 2007
Dominion	VA	1,500	2007
Progress Energy	FL	2,200/2,200	Jan 2008/July 2008
Entergy	MS/LA	3,000	Feb 2008/May 2008
Southern Company	GA	2,200	March 2008
Constellation	MD	1,600	2008
Ameren	MO	1,600	2008
Unitary	NY	3,200	2008
Amarillo	TX	1,600	2008
TXU	TX	3,400	2008
FPL	FL	3,000	Late 2009
TOTAL	–	34,700	–

Source: Nuclear Energy Institute and Nuclear Regulatory Commission.

Much uncertainty still surrounds the next generation of nuclear reactors. Original equipment manufacturers (OEMs) such as GE and Toshiba claim that standardizing nuclear technology, which has been done in France and other countries with successful nuclear power programs, is the key to lowering costs and reducing management challenges. Even so, no next-generation nuclear reactors have been built yet in the U.S., and cost estimates remain controversial.

Exhibit 3-18 shows the location of projected new nuclear power reactors. The largest amount of new capacity is expected in Southeast Florida (FL) and the Southeast Reliability Council (SERC), which represents a relatively large and growing share of total U.S. electricity sales and, thus, requires more capacity than other regions. The growth in demand for electricity in the Southeast is well above the national average.

Exhibit 3-18
Location of Projected New Nuclear Power Reactors

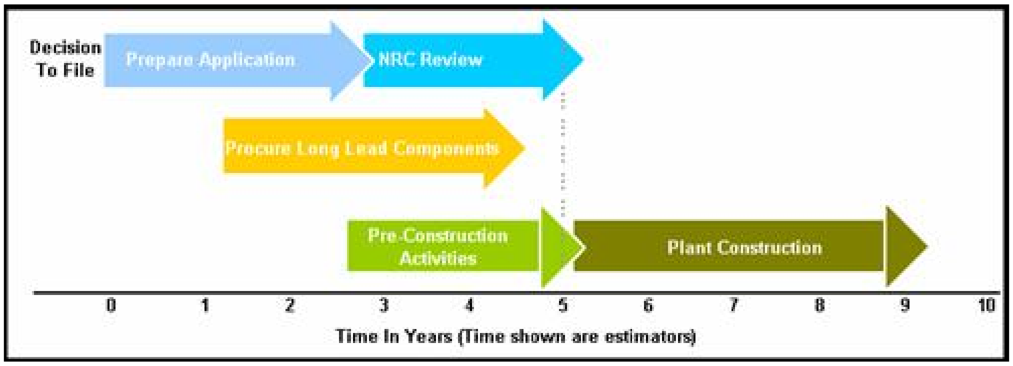


Source: Nuclear Regulatory Commission.

3.8.1 Nuclear Lead Times and Licensing

Lead times have improved significantly for nuclear power development. In the mid 1970s the total time needed for application, development, and construction of a new facility was 15 years. Now the Nuclear Regulatory Commission (NRC) estimates the process will only take 9–10 years. Before the actual construction begins, approximately five years are required for the preparation of the application, review by NRC, and procurement of components (Exhibit 3-19). Reducing the build cycle time reduces exposure to interveners, construction cost risks, and other market risks.

Exhibit 3-19
Nuclear Construction Process

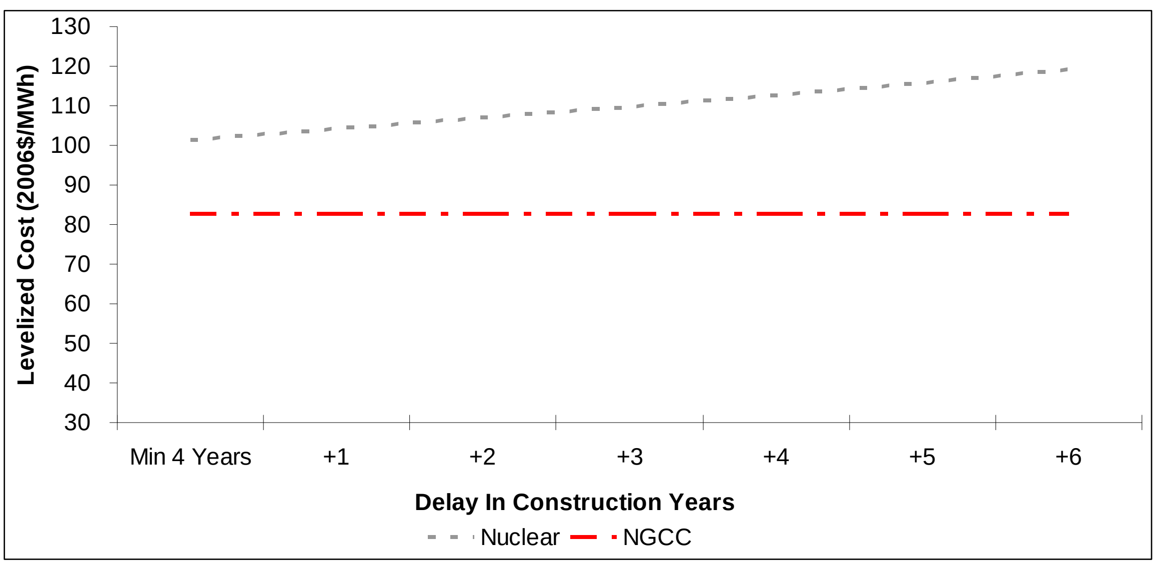


Source: NEI.

Based on what has been routinely achieved overseas, a 48-month construction period is now expected.

Exhibit 3-20 illustrates that nuclear plant construction time does matter. As the plant experiences delays, interest costs during construction escalate, thereby increasing the levelized cost for the plant. In the past, construction delays primarily stemmed from licensing and approval delays, partly caused by public protests, rather than from engineering and actual construction problems. In this exhibit, natural gas combined cycle (NGCC) construction is not delayed.

Exhibit 3-20
Nuclear Costs Are Very Sensitive to Construction Time



Source: ICF Assumptions. See appendix (p. I-62) for details.

3.8.2 Nuclear Plant Approval Procedures

Another improvement that will help smooth the investment in new nuclear capacity is the ongoing standardization of regulatory procedures and requirements. The nuclear development process was restructured in recent years so that now the NRC must approve both the site and the plant design before issuing a single license to build and operate, *and* before capital is placed at risk. Furthermore, the process by which interveners can express opposition has been limited. These limits are at well-defined points in the regulatory process and must be based on objective evidence that design requirements have not been and will not be met.

3.8.3 Nuclear Waste Storage

Most, if not all, nuclear facilities in the U.S. use dry storage for waste, which is only a short- to medium-term solution. Currently, 52 reactors have run out of storage room in their pools, and another 25 reactors will run out of space by 2010. Yucca Mountain has been selected as a national repository for spent fuel, although it will not be available until 2017 at the earliest, if at all. Construction delays, along with the recent loss of the Obama administration's support, challenges the likelihood that Yucca Mountain will serve as the nation's needed permanent storage facility. As the issue of spent fuel storage is heavily litigated, this issue could prove a potential fatal flaw in some project development and likely will need to be addressed before new construction will begin.

3.8.4 Nuclear Production Tax Credit and Loan Guarantees

The next generation of U.S. nuclear plants will be modeled after existing plants while incorporating features designed to make them safer and less costly to operate. Because of "first-of-a-kind" design and engineering costs, approximately $500 million per reactor design, the first new nuclear plants will cost more than later, follow-on plants.[6]

Recognizing this, the Energy Policy Act of 2005 provides investment stimulus in the form of production tax credits (PTC) and federal loan guarantees to offset the higher costs of nuclear plants. A PTC of $.018/KWh for the first 8 years of operation is applicable to the first 6,000 MW of new nuclear generation. This PTC incentive is equal to that given to renewables. The act additionally makes available loan guarantees of up to 80 percent of total project costs. PTC and loan guarantee subsidies may enable the first new nuclear plants to be competitive and economically viable. Once the first few new nuclear plants are built and "first-of-a-kind" design and engineering costs have been recovered, follow-on plants can be built without federal financial support.

The 2005 energy legislation also provides an innovative form of investment protection for the first six reactors. This risk insurance is similar to the sovereign risk insurance available, through institutions like the Overseas Private Investment Corp., to American companies doing business abroad. The federal government will cover debt service and other costs for the first few plants if commercial operation is delayed for reasons beyond the company's control, such as litigation or a failure by the NRC to meet schedules. The industry believes the NRC's new licensing process will work as intended, but no one can be completely certain until it has been tested. The regulatory process is the one risk that the industry cannot hedge. Federal protection against unforeseen delays will allow boards of directors to authorize multi-billion-dollar investments in new nuclear plants with confidence.

[6] International Energy Agency. *Tackling Investment Challenges in Power Generation*. IEA, 2007, p. 52.

Many risks are associated with investments in new nuclear baseload generation capacity. These risks impact not only those considering investing in new nuclear capacity, but also those considering investing in other baseload technologies.

3.9 Financial and Regulatory Risks

3.9.1 Unfriendly Regulators

Despite alternatives to traditional cost-of-service regulation, the determination of allowed returns on utility investments still remains among the contentious tasks faced by many regulators. Driving this tension is the opposing estimates of utilities' required rates of return and the views of commissions and interveners. As a result of rising inputs (i.e., fuel prices, power purchase agreements) to the production of generation, tariff rates have dramatically increased over the last ten years. Commissioners with the ratepayers in mind have a tendency to favor lower rates of return and lower depreciation rates.

A number of companies have learned from this experience and are requesting pre-approval determinations that plant expenditures are prudent. However, even though they may be issued certificates to build new coal-fired power plants, regulatory commissions are reserving the right to disallow imprudently incurred construction and/or operating costs. Regulation does not guarantee full cost recovery; instead, it simply gives a utility an unbiased opportunity to recover prudently incurred costs. Before utilities can pass the capital investment and operating costs of the regulated plants onto electric customers through rates, public utility commissions (PUCs) review the costs being added in periodic prudence reviews. A PUC can disallow the recovery of costs deemed extravagant or imprudent.

In some regulated states, utilities may recover the carrying costs of capital investments in rates during construction. This type of rate arrangement is often referred to as Construction Work in Progress (CWIP) and generally reduces the utility's plant financing costs and improves its cash flows. Florida and Georgia, for example, both allow CWIP for utilities investing in new nuclear power. The CWIP cost-recovery mechanism allows utilities to expedite cost recovery through their rate base. Some utilities can also recover the costs incurred to construct the facility even if it is cancelled, as long as the PSC finds that the utility's decision to cancel the project is prudent.

Although the CWIP cost-recovery mechanism generally protects utilities from cost increases by deferring the expense to ratepayers, utilities still face some risks. For example, lawmakers may be slow to enact the cost-recovery mechanism, or they may not enact one at all. Even with a CWIP cost recovery mechanism in place, the recovery process could be drawn out and contested if ratepayers react to excessive budget overruns and schedule delays.

Receiving appropriate depreciation rates and rates of return to allow for the recovery *of* investment and recovery *on* investment have important implications for a utility's ability to finance needed new generation. For example, if a utility files for a 3.4 percent depreciation allowance and regulators decide on 2.2 percent depreciation allowance, it will take the utility an additional 16 years to recover its investment costs. A utility's ability to recover these two investment-related cost-of-service items is critical to its credit rating, which, in turn, affects the utility's access to low-cost capital.

As Standard & Poor's (S&P) stresses, "insufficient regulated authorized returns" are one of the most significant factors contributing to the downward pressure on credit quality. Over the past few years, S&P has downgraded utilities specifically because of regulatory actions that lowered allowed return on investment and plant depreciation allowances.

3.9.2 Credit Crunch and Liquidity

The credit crunch has created two groups of utilities: those with and without access to credit. Those that have access to capital are moving forward, but at a much more cautious rate than before. Those that do not have access to credit are at risk, both in terms of not meeting current loan covenants and the possibility of takeover.[7]

The credit crunch of 2008 has strained the balance sheets of some utilities. Constellation is one such company that made the news in mid-2008. A weak utility with nuclear assets combined with a weak dollar brought Electricity *de France* (EDF) into the U.S. nuclear market. EDF's bid on Constellation's nuclear fleet was accepted in late December 2008, turning back Constellation's previous suitor, Warren Buffet's MidAmerican Energy. The impact of this shift in ownership is significant. Under Buffet's control, it's clear that no new nuclear projects would have likely gone forward. However, with EDF's capital resources and technical expertise in nuclear technology and operation, the picture of new nuclear development in the U.S. has completely changed.

Not only has the credit crunch caused liquidity issues with some utilities, but it has also made it difficult for utilities to collect payments from customers experiencing financial difficulties. Most utilities believe that this will have minimal impact in delaying future investments.

3.9.3 New Cooling Water Requirements

In December 2008, lawyers from government, industry, and an environmental group presented arguments before the U.S. Supreme Court on the role that cost should play in deciding the best technology available for reducing the number of fish killed at power plant cooling water intake structures. At issue is EPA's promulgated rules for Section 316(b) of the Clean Water Act (CWA), centering on whether a large number of existing nuclear and fossil fuel plants could be forced to install expensive closed-cycle systems that would use far less water and kill a fraction of fish compared to the more common once-through systems.

The 4th U.S. Circuit Court of Appeals invalidated these regulations on procedural grounds in 1977. Since then, the EPA has implemented Section 316(b) case by case. But in 2001, the agency issued new rules in response to a consent decree. The CWA's Phase I rules applied to new plants and generally required implementation of closed-cycle cooling systems. The 2nd Circuit in 2004 mostly upheld these rules.

Phase II regulations were issued in 2004 and applied to existing plants that took in at least 50 million gallons of water daily. Phase II rejected closed-cycle cooling as the best technology available (BTA), and it provided several compliance alternatives. In 2006, Entergy, Public Service Enterprise Group, the Utility Water Action Group, and several Northeastern states challenged Phase II rules. The 2nd Circuit Appeals court remanded the issue back to the EPA which proceeded to suspend Phase II in July 2007. In early 2008, the Supreme Court agreed to review the case. The first hearing took place in December 2008, and the decision from the Supreme Court was to reverse the judgment of the court of appeals for further proceedings.

[7] Burr, Michael T. "Desperately Seeking Liquidity," *Public Utilities Fortnightly*, Feb 2009, p. 27.

3.9.4 Air Permitting Challenges

Even if the utility's expansion project makes it through the IRP process, interveners have been successfully stopping projects by challenging air permits. In late 2007, the denial of an air permit was used to stop progress on Sunflower Electric Power's Holcomb (Kansas) expansion. The proposed expansion would add a 700-MW supercritical coal unit next to an existing 400-MW unit. However, the Kansas Department of Health and Environment denied issuing a permit on the grounds that it emitted too much CO_2. Sunflower contested the permit denial and has pushed for the passage of legislation that would overturn the decision. Efforts to overturn the permit denial had been vetoed by the state's governor until last year. In February 2009, the legislature again passed a bill allowing Holcomb to begin construction, and the new governor signed it in May 2009. Language in the bill forbids air permit conditions more strict than federal standards.

3.10 Transmission, Infrastructure, and Transportation Risks

Modern coal-power-plant technologies allow coal to be used with dramatically lower emissions than possible when the last round of coal plants was built. However, it is still very hard to site coal generation near major population centers; the further coal generation is placed from load centers, the more likely it is to need additional transmission infrastructure. Because most utility development of coal is performed through expansion on existing sites with existing infrastructure, siting new coal generation is more of an issue for merchant investors. If the siting barrier is too difficult to overcome, a developer may opt to build smaller combined cycle gas-fired facilities near cities.

Another issue revolving around transmission capability is the potential for coal to be locked out of a market due to load serving entities (LSE) complying with renewable resource requirements. For example, a large portion of California imports has historically come from coal. However, as the major LSEs in California comply with the state's standards, new renewable resources will have to come from outside the state and may force some coal out.

Since many coal plants rely upon low-cost, low-sulfur western coal, rail infrastructure could become an issue as more and more coal ships from west to east. Railroads account for over 70 percent of coal transportation. Rail delays (caused by maintenance or bad weather, for example) have caused an estimated $228 million in costs to the electric power industry since 2005. As more generation is fired by western coal, transportation costs could grow prohibitively, especially if rail companies continue to avoid building buffer capacity to handle unexpected surges in demand. Constrained coal supply leads to coal price volatility, which, in turn, adds risks to investment in new baseload coal fired generation sited further from supply basins.[8]

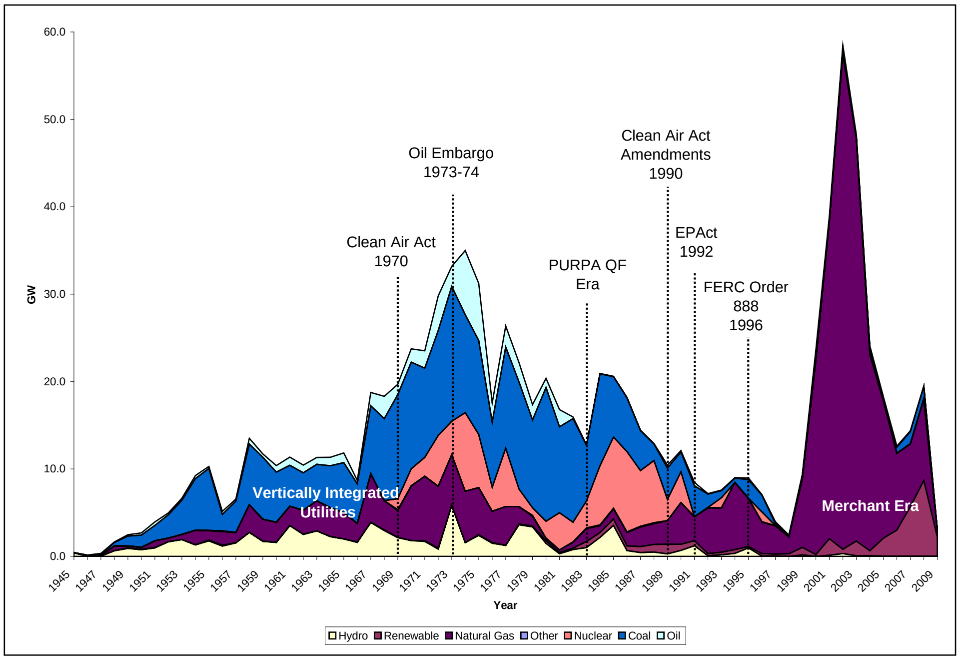
3.11 Lead Time/Imminence of Need Risks

Long lead times for power plants can be problematic, given the uncertainty in demand and other factors being discussed here. In the late 1990s, uncertainty about the impacts of deregulation led utilities to adopt a "wait and see" investment strategy. As shown in Exhibit 3-21 (note: same graphic as Exhibit 1-1), after FERC 888 opened up transmission access, utility investment in new construction declined; instead, the merchant boom was born. The "wait and see" strategy proved beneficial to utilities like Entergy and Southern who, in turn, were able to successfully purchase IPP-owned combined cycles in their service territories at distressed prices.

[8] Kaplan, Stan Mark. *CRS Report for Congress – Rail Transportation of Coal to Power Plants: Reliability Issues.* September 26, 2007.

With a new administration and the ongoing recession, much of the sector is in a "wait-and-see" mode, increasing emphasis on shorter-term lead-time options. Conversely, greater clarity about future conditions will support longer lead time investment options.

Exhibit 3-21
Historical Capacity Additions from 1945 to Present



Source: Energy Velocity Database, Ventyx 2009.

The recession-related decline in electric demand, the large boost in energy efficiency investments included in the stimulus bill, turbulence in commodity markets, and the growing likelihood of CO_2 regulations make this a very challenging time for investors in new baseload electric generation to manage the risk associated with timing their investments.

3.12 Water Usage Risks

Another major concern is the availability of water for cooling existing plants and whether the available supply can support new plant development. Currently, makeup water and cooling water are major concerns in the power industry. For example, in 2007, the Nuclear Energy Institute (NEI) noted that because rainfall in some areas of the country was 15–20 inches below normal, utilities had to take steps (e.g., reduce production) to reduce water consumption.

According to a 2004 U.S. Geological Survey (USGS) report,[9] steam-based power generation, as a whole, accounts for approximately 40 percent of freshwater withdrawal, but only about three percent of actual consumption. Going forward, utilities and other power developers will have to approach the development of new generation alternatives with an understanding of water supply needs and availability.

[9] Wolfe, Dr. John E. Water Management Section, Special Report. *Power Magazine*, Jan 2008, P. 46 Vol. 152 No. 1.

Nuclear plants currently use the most water per megawatt hour of any form of electric generation. As such, this technology will be most at risk of all new baseload technologies. Most of the new proposed nuclear plants are designed to be built at sites where other plants already exist.

The cost of acquiring water depends on its location, scarcity, water rights, and use rules. Where water is abundant and local regulations permit, the cost of acquiring water for a new plant may be limited to investing in wells or surface water intakes. Preventing fish entrainment and limiting impingement may be costly when only surface water is used. Due to its scarcity, water rights laws govern allocation in the West, making water costly and sometimes unavailable during droughts. The cost of acquiring water varies widely, from as low as 50 cents/1,000 gallons where water is abundant and regulations permit, to as much as $3/1,000 gallons where water is very scarce and rights must be acquired from existing owners.

As water issues have become a high-risk factor for expansion of the baseload fleet, the Electric Power Research Institute (EPRI) has been conducting research on developing, testing, and deploying efficient advanced water cooling technologies. EPRI is considering four possible options:

- Implementing a hybrid system that uses a combination of dry (air) cooling and wet cooling;
- Increasing the thermal conversion efficiency of the thermoelectric plant;
- Replacing a freshwater source with a non-traditional water source; and
- Recycling water within the plant.

Although dry cooling systems are more expensive and less efficient than wet cooling condensers, dry cooling is a possibility for baseload plants (e.g., the Wyden coal plant has dry cooling as do numerous combined cycle facilities). Another alternative to wet cooling that also carries a higher cost is a hybrid system that involves air-cooled condensers operating in parallel with wet-cooling towers.

Better cooling options can even make it easier to site a plant near its market and fuel supplies, potentially boosting profits. Water availability and cost should not be second-tier considerations during the planning of a power project. They should be as important as electricity demand and fuel availability. Investors and developers have taken notice of this. For example, the Mystic combined cycle facilities are sited in downtown Boston and operate with dry cooling.

Changing environmental laws (see New Cooling Water Requirements, 3.9.3) and public pressure are forcing some existing power generating facilities to discontinue their use of once-through river or ocean cooling water options and retrofit them with closed-cycle cooling water systems. The pragmatic developer may also select dry cooling early in a project because doing so increases plant siting options and takes water use issues off the table, which, in turn, can significantly accelerate the approval of construction permits. Shortening a project schedule by even six months can completely change the economics of a project and easily offset the increased capital cost of dry cooling options.[10]

Finally, water availability will add additional risk to investors considering building new baseload coal-fired generation in a carbon constrained world. The National Energy Technology

[10] Wurtz, William and Dr. Robert Peltier. SPX Cooling Technologies Inc., Plant Cooling Section. *Power Magazine.* Sep 2008, p. 56, Vol. 152, No. 9.

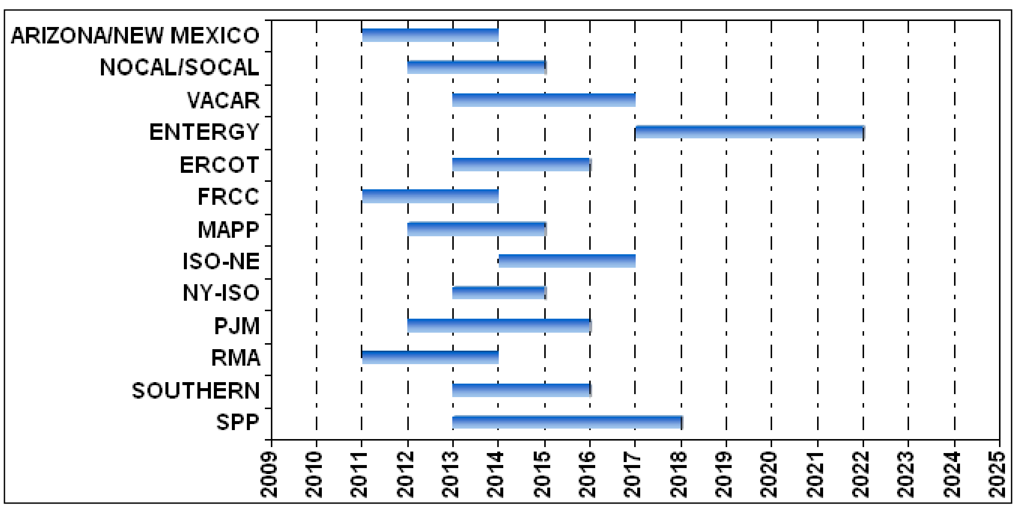
Laboratory has estimated that the use of water at coal-fired power plants with CCS will be 2.16 times that of plants without CCS (21.6 versus 10.0 gallons per minute per MW).[11] This increase in water usage is due to the cooling water requirements of the CO_2 capture process. The availability of this additional water is another uncertainty associated with new coal-fired power plants, especially for those plants located in arid areas and/or during peak summer conditions or prolonged drought conditions.[12]

3.13 Regional Variation Risks

The regional supply/demand balance at the load peak is one of the key risks for investors in generation capacity to consider. Understanding this supply/demand balance requires information on the local supply resources as well as the demand for power. Furthermore, power can be transported from region to region. Therefore, the ability to transmit power at the peak also influences the balance. Typically, sophisticated economic/engineering models are used to analyze this data-intensive exercise. Exhibit 3-22 shows ICF's projection of when different electric power regions are expected to need new capacity. Exhibit 3-23 acts as a legend for Exhibit 3-22.

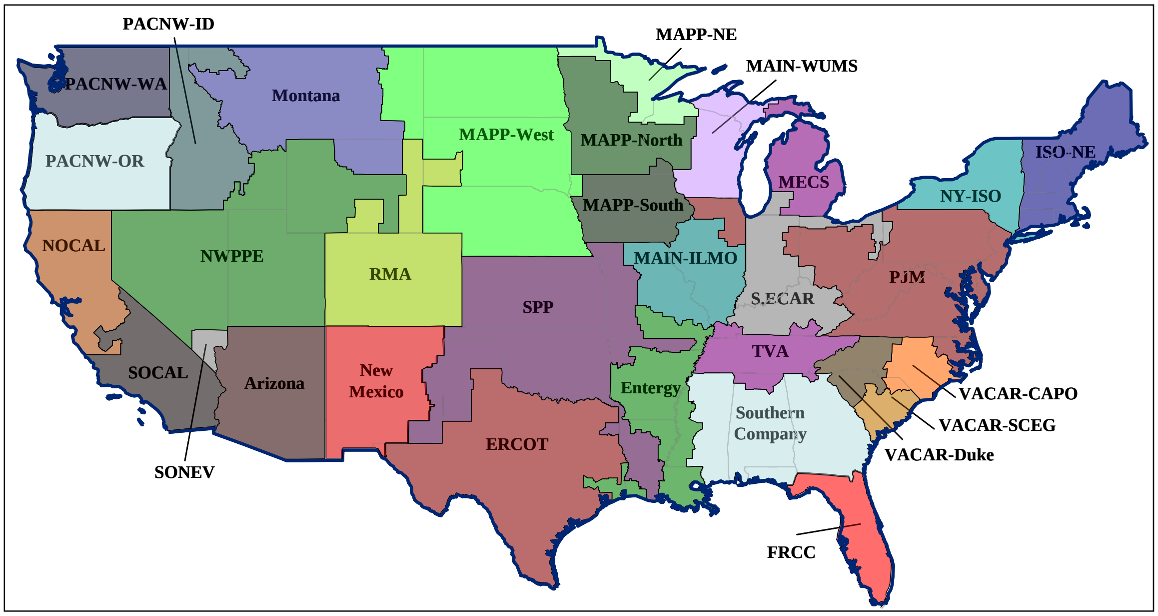
For example, resources in the desert southwest are generally established through transmission (typically the cheapest option). If transmission is not available, new resources need to be built as soon as 2011–2014. Given that power plants have significant lead times, new capacity needs to be built fairly quickly to meet the desert southwest's generation needs, or shortages can be expected. Entergy is in the opposite situation as the region had an extreme build out of new capacity in the early 2000s. The current surplus situation is expected to take many years to work out. Surplus tends to lead to lower power prices, all else being equal. Many IPP developers failed to realize this and ended up with cash-flow problems, which, in turn, ultimately led to their sale to the local utility.

Exhibit 3-22
Projected Timing of the Need for New Generation Capacity by Region



[11] Synapse Energy Economics. "The Risks of Investing in Coal Facilities," 2008, p. 32.
[12] Synapse Energy Economics. "The Risks of Investing in Coal Facilities," 2008, p. 41.

Exhibit 3-23
ICF Power Market Regions



3.14 Energy Security and Portfolio Diversification Risks

Energy security involves the concepts of supply resource diversification, fuel availability, and price stability. For example, natural gas generators in the Northeast receive much of their gas from the Gulf Coast, leaving them with the possibility of supply disruption if there is a failure in the natural gas pipeline infrastructure. When extreme weather, such as a hurricane, hits the Gulf, gas supply to the Northeast can be compromised. Coal generators have similar issues in dealing with long supply chains and are subject to rail supply disruptions.

Utilities have, therefore, diversified their fuel dependencies over time, with a portfolio mix of supply technologies, transmission investments, and demand-side management programs. Power suppliers have also bolstered energy security by pursuing domestically available fuels and resources, thereby minimizing exposure to often volatile foreign supplies. U.S. power generation from oil (or its derivatives) has largely been supplanted by coal and natural gas. In a carbon constrained world, nuclear and renewable energy are now being looked at as possible new capacity solutions.

3.15 Coal Ash Storage

A handful of coal slurry spills during the last decade — culminating with the Tennessee Valley Authority (TVA) spill in Kingston, TN, on December 22, 2008 — has led to increased environmental concerns. The TVA spill occurred when a large pond used to hold fly ash failed, flooding more than 300 acres of land below the pond and destroying 12 homes. Environmentalists have placed much of the blame for the spill on the federal government, arguing that EPA and other agencies have dragged their feet on developing national standards for the regulation of coal ash impoundments. TVA is estimating cleanup costs from $525 million to $825 million, depending on the method of ash disposal assumed. This range excludes costs for items such as regulatory actions, litigation, or long-term environmental remediation.[13]

[13] Munawar, Adnan. "TVA posts fiscal Q1'09 net loss of $305 million on Kingston cleanup costs." *SNL Financial.* Feb 13, 2009.

This is a large problem because many existing coal sites have ash ponds. A survey by the American Coal Ash Association estimated that more than 131 million tons of "coal combustion products" were generated from power plants in 2007. An estimated 56 million tons of the ash, roughly 43 percent, were then used in road building, construction, and other beneficial uses. Roughly speaking, one-half of most coal ash ends up in landfills lined with compacted clay soil, a plastic sheet, or both. As rain and melted snow filter through the waste pit, toxic metals are pushed downward by gravity toward the lining and the soil below. An EPA study found that all liners eventually degrade, crack, or tear.[14]

Since the Kingston spill, Congressional leaders have been pushing EPA to take action on the coal ash disposal issue. Democratic leaders have also called on the agency to propose possible rules to regulate coal combustion waste under the Resource Conservation and Recovery Act. EPA plans to move quickly to develop new coal ash disposal regulations and anticipates having a proposed rule ready for public comment in early 2010. If enacted, coal ash storage regulation will place potentially significant additional costs on coal generation waste disposal.[15]

[14] Barber, Wayne, "Trade group: More than 40% of coal ash reused." *SNL Financial.* January 13, 2009.
[15] Niven, Michael. "EPA unveils coal ash plan, orders utilities to provide impoundment data." *SNL Financial.* March 10, 2009.

Chapter 4
IPP Investment Risk Factors

4.0 Introduction

IPPs generate revenue by dispatching their power plants when power prices exceed variable production costs. Although all generation technologies within a given market are subject to the same time-of-day pricing, the level of exposure to this price risk varies considerably across the different generating technologies. As a result, electricity price risk is an important risk factor affecting technology choice in investment decisions. If electricity prices were fixed or extremely stable, it would be possible to capture many of the issues using levelized costs, and the simulation models referred to in Chapter 2 would not be needed. For utilities, many of the cost risks can be passed through to consumers.

While many of the risk factors discussed in Chapter 3 apply to IPPs as well, this Chapter will discuss the additional factors of electricity price risk and financial risk. Exhibit 4-1 summarizes these factors.

Exhibit 4-1
Investment Factors Affecting Baseload
Generation Investment Decisions by IPPs

Electricity Price Risk Factors	Financial Risk Factors
Short Run Marginal Cost Risk Factors	Cash Flow Predictability
Long-Run Price Risk Factors	Contract and Project Market Competitiveness Risks
Spark Spread Risks	Technical and Operating Risks

4.1 Electricity Price Risk Factors

For IPPs making investment decisions in new baseload generation capacity, uncertainties about future prices for electricity arise for a range of reasons, from weather changes to volatility in fuel prices to forced outages of power stations. To understand the implications of price uncertainty and the resultant potential fluctuation of revenues for investors, it is first necessary to understand how wholesale electricity prices are formed, and what sets them.

The two basic markets where electricity prices are formed are as follows:

- **Bilateral Markets** – These are markets with no formal clearing price mechanism. Two parties negotiate at arm's length to develop both short-term and long-term contracts for electricity.

- **Power Exchanges or Independent System Operator (ISO)** – These are more developed and more open markets with transparent pricing. They usually have a formal clearing price mechanism for all participants. Markets vary, with both day-ahead and real-time clearing prices. Markets clear when bids and offers for electricity are balanced on the transmission system. The system operator may also contract for various forms of ancillary services to cope with unexpected demand variations due to weather and forced plant outages. Due to the increased transparency in electricity pricing, IPPs are usually active in these markets.

Electricity prices include a time-of-day component, since generation must be increased and decreased as demands fluctuate. Open markets use a uniform clearing price auction in which electricity generators place bids representing their variable cost for a particular time period. The generators are then dispatched from lowest to highest price until all power demand is met. Each generator whose bid is accepted is then paid the same price as was paid to the last unit of electricity accepted. This is how the spot price is determined. In these cases, the market determines the "dispatch" of plants according to their cost characteristics relative to the spot price of electricity at any given time of day, which is set by the short-run marginal cost of the last generator to be dispatched on the system. Thus the system-marginal plants acting as price makers set the price of electricity for that particular time of day. All other plants on the system are price takers. Generally speaking, for most power markets, gas is on the margin in on-peak time-of-day hours. Therefore, natural gas price levels and volatility are key uncertainties affecting, in turn, electric price uncertainty.

4.1.1 Short- Run Marginal Cost Risk Factors

Short run marginal costs include all variable costs borne by the electricity producer, like fuel costs, variable operating and maintenance costs, and environmental costs. They exclude fixed costs such as capital depreciation and fixed operating and maintenance costs. The lowest short-run marginal cost plants are used first, and operate most of the time. Such plants, including most coal and nuclear plants (often referred to as "baseload" generators), are usually high in capital cost but low in fuel cost. Fuel prices and plant efficiencies for the system marginal plant(s) determine the short run price of wholesale electricity. This also implies that fuel price volatility is reflected in wholesale electricity prices, and fuel price increases are eventually passed through to wholesale consumers. To a certain extent, fossil fuel generators have a degree of natural hedge against fuel price fluctuations because changes in fuel prices are reflected in changes to electricity prices.

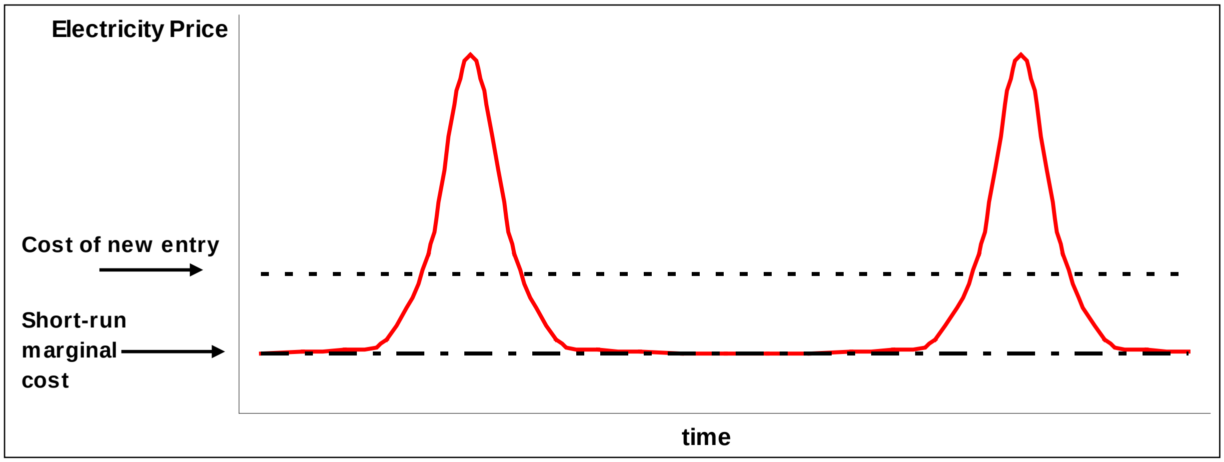
Not all electricity is traded at the spot price. Companies will often use a variety of trading activities and contract structures to help manage price risks, including forward contracts and more complex financial derivative contracts. Today, many developers are seeking long-term price contracts to mitigate significant long-run fuel price uncertainty.

4.1.2 Long Run Price Risk Factors

Another important source of electricity price risk results from the long-run investment dynamics that arise in competitive electricity markets. These may tend towards boom-and-bust cycles that play out over a number of years. Thus, price risks also come into play over longer time scales. In competitive markets, producers receive a signal to invest through the product price. When electricity supply is becoming tight relative to demand, prices should rise, creating the incentive to invest in new capacity.

Because it takes several years to bring a new power plant online, this process requires some judgment in advance of likely impending shortfalls in the market. Therefore, the timing of investment in new baseload-generating capacity is critical. In a surplus capacity situation, price follows closely the short-run costs of the marginal generating units. In this case, these prices are too low to encourage new entry. As plants retire due to physical age or economics, or as demand increases, the market gradually becomes tighter until average prices spike up above the threshold for new entry. These cycles are illustrated in Exhibit 4-2. At this point, there may be a race to bring a new plant online to make the most of the higher prices, which once again returns the market to a period of low prices and low investment until the next price spike.

Exhibit 4-2
Capacity Premiums or Scarcity Rents in the Electricity Price Cycle



Source: ICF International.

The “price spike” is sometimes referred to as the capacity premium or scarcity rent. In Exhibit 4-2, a price spike would be anything above short-run marginal cost. In any competitive, price-based system, the capacity premium is necessary to encourage power plant supply expansion. Without the premium, the marginal power plant (i.e., the short-run price setter) would operate only to meet demand in peak periods. As a result, these “peakers” would not be economic because the power price they receive would never exceed their variable costs and they would not be able to cover their fixed costs.

4.1.3 Spark Spread Risks

For IPPs, revenues are generated by selling their power at the market price, which is determined by the variable cost of the marginal unit. Spark spread is an industry term that indicates to the developer the potential profit margin that can be earned in any given hour. The spark spread is defined as the difference between the wholesale price of electricity and the cost of the fuel used to generate it. The spark spread is typically calculated for gas projects. The price of fuel is an important factor in this spark spread calculation because it is the main variable cost of electricity generation. The traditional spark spread calculation is as follows:

$$\text{Traditional Spark Spread} = (\$/\text{MWh}_{\text{market}} - \$/\text{MWh}_{\text{plant}})$$

Some market analysts prefer the formulation of spark spread shown below, because it shows the potential for profits and gas price impact on spark spread margins more readily.

$$\text{Alternative Spark Spread} = (\text{Btu/kWh}_{\text{market}} - \text{Btu/kWh}_{\text{plant}}) * \$/\text{MMBtu}_{\text{gas}}$$

For coal-generating units, a similar dark spread is calculated as follows:

$$\text{Dark Spread} = (\$/\text{MWh}_{\text{market}} - (\text{Btu/kWh}_{\text{plant}} * \$/\text{MMBtu}_{\text{coal}}))$$

Thus, the dark spread captures the potential additional profit that can be realized by coal generating units when coal prices are below natural gas prices.

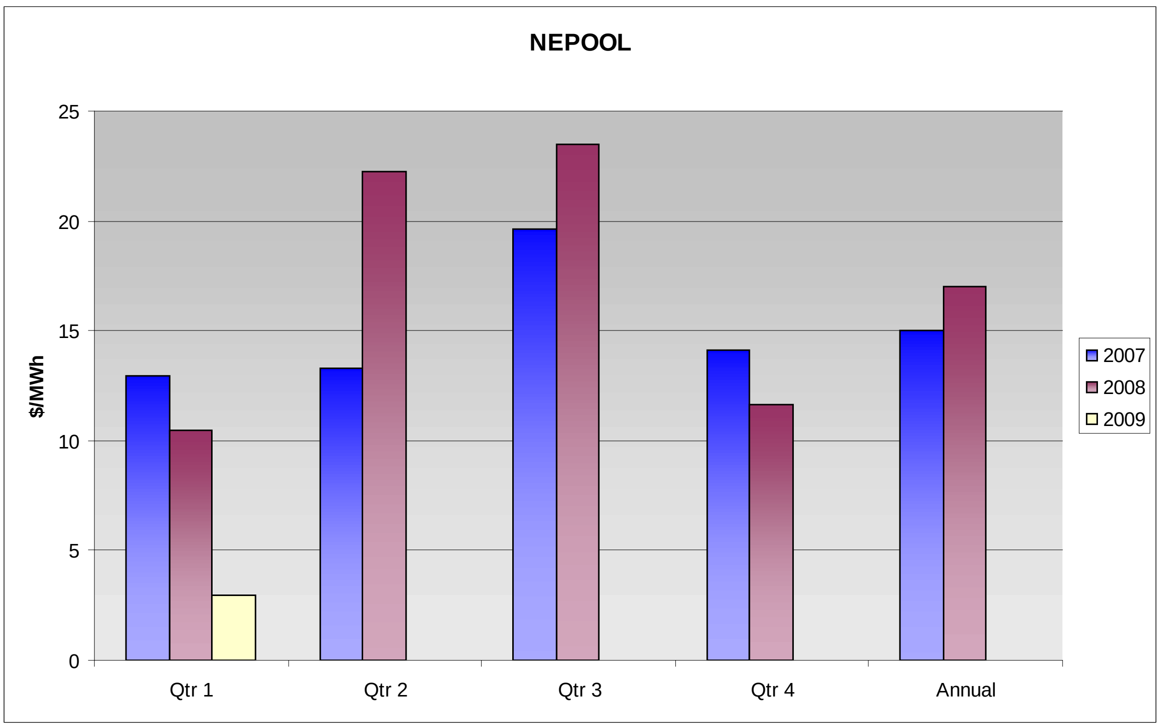
Spark spread will vary among plants using different fuels and may vary even among plants using the same fuels. It should be positive for any plant that is actually in current operation (otherwise contribution would be negative, and presumably, the plant would not operate). In the long term the spark spread should be large enough to provide developers with an adequate return on investment.

Gross margins for a project can easily be projected if one understands the amount of electricity that can be sold over a given time frame.

$$\text{Gross Margin} = (\text{Btu/kWh}_{\text{market}} - \text{Btu/kWh}_{\text{plant}}) * \$/\text{MMBtu} * \text{MWh}$$
$$= \text{Spark Spread} * \text{Dispatch}$$

Exhibit 4-3 presents the historical quarterly spark spreads in ISO-NE (NEPOOL). On average, 2008 spark spreads were higher than in 2007 due to higher gas prices. First quarter 2009 reflects low spreads due to falling gas prices. Depending on the market, a new combined cycle should be in the range of $20/MWh to $25/MWh of spark spread to be economic.

Exhibit 4-3
NEPOOL Market Spark Spreads 2007/2008/2009



Source: MegaWatt Daily Historical Power Prices for Mass Hub and Bloomberg Gas Prices for Algonquin CityGates + $0.15 LDC.
Methodology: Spark Spreads at 7,000Btu, (((Power Prices/(Gas Price + LDC)*1,000) 7,000)/1,000*Gas Price.

4.2 Financial Risk Factors

IPP projects are those projects whose developers are primarily in business to generate and sell electrical power. Independent power generation projects, or merchant projects, generally have substantially greater levels of business risk than regulated utility projects because they do not have captive ratepayers. The business or financial risk these projects carry can vary depending upon whether a project has well-structured power purchase contracts with high-quality counterparties governing its electricity sale. Projects that sell exclusively into the wholesale market as pure merchant generators are typically viewed as higher risk than those with firm power purchase agreements.

IPP projects are financed with private equity and debt issuance. Over the last several years, debt has cost approximately 8 percent while the cost of equity has typically been around 13–15 percent, reflecting the greater risk taken on by equity investors. As debt is cheaper, most developers would like their capital structure to have as much debt has possible. Many independent baseload projects have an 80 percent debt and 20 percent equity split. Natural gas-fired combined cycle projects, which have less predictable cash flows than baseload projects, generally have a capital structure ratio of 45 percent debt and 55 percent equity. In other words, their cost of capital is higher than that of a baseload project because of the greater risk associated with the greater cash flow uncertainty. Both the amount of debt and cost of debt are important. If the cost of capital becomes too high, many promising projects become economically infeasible. Thus, it is important to understand how creditors look at a project and how they rate its creditworthiness.

Credit rating agencies, such as Fitch, Standard and Poor's, and Moody's, rate the creditworthiness of power projects. The highest rating is investment grade, and the lowest is junk grade. If the project is rated as investment grade, it will be able to secure more debt and at a lower cost than if it was rated as junk. Each rating agency has its own methods, but essentially they all look at three key factors:

- Cash flow predictability,
- Contract and project market competitiveness, and
- Technical and operational risks.

4.2.1 Cash Flow Predictability

One of the most important credit factors is the certainty of the cash flow stream supporting a project's debt load. This cash flow uncertainty can be a significant risk to the lender because the wholesale power market is driven by marginal cost pricing. Given that in many markets natural gas-fired power plants are on the margin in many hours, cash flow risks are often directly related to natural gas price volatility.

The common metric used to measure the ability to pay back or support the debt load is called the Debt Service Coverage Ratio (DSCR). This is calculated as the operating cash flows less major maintenance expenses divided by scheduled interest and principal payments. The higher the coverage ratios, the better or less credit risk the project. Having a ratio of around 1.5 may be considered investment grade.[16]

Because electricity prices, and therefore cash flows, are volatile, it is important to evaluate a project's revenue stream by assessing its degree of contractual support and the diversity of its revenue sources. As stated earlier, a project's power sales arrangements can range from those that are fully contracted through the life of the financing to those that have no contracts or hedges in place. Although fully contracted projects are generally perceived to be safer, they still carry risks if counterparties are not credit-worthy or if significant conditions are attached to the receipt of payment. Reliable counterparties are those that have an investment grade rating, and thus give high predictability to the contracted cash flows. Typical contracts are tolling

[16] Moody's, "Global Infrastructure – Industry Outlook: U.S. Investor-Owned Electric Utilities". January 2009.

arrangements or power purchase agreements (PPAs), where the pass-through of fuel costs, O&M costs, and possibly environmental costs have structural conditions. With possible CO_2 legislation on the horizon, the ability to pass through environmental costs is an important factor, especially for coal-fired projects.

However, many projects have gone forward with less than a fully contracted position. Unhedged cash flow positions are expected to exhibit volatility. If none of the expected cash flows are based upon contracted or hedged positions, the credit rating will reflect the more risky cash flow with a much lower rating.

Another aspect of cash flow volatility is the severity of the conditions for the receipt of payment under the off-take arrangements. Typically a PPA or tolling agreement has performance criteria such as minimum availability or capacity thresholds and maximum heat rate requirements. If the project cannot meet the criteria, certain penalties would be incurred. The severity of the performance criteria drives the level of risk associated with the contract terms.

Degrees of risk exposure are even associated with projects that are fully exposed to wholesale markets. For example, formal capacity markets are in New York, and more recently in PJM and ISO-NE. In other words, these markets have a structure in place that puts a value on plant capacity. Capacity prices in these markets are generally determined by an auction process that seeks to have sufficient capacity available to ensure electric supply reliability. The auction process should offer some capacity price visibility, generally over a three-year time horizon, which provides projects operating within these markets a degree of cash flow stability related to the sale of their capacity. Thus, in some sense, capacity revenue can be viewed as a form of short-term contractual revenue. As stated above, projects with predictable revenue are viewed as less risky and receive a better credit rating than projects that are fully exposed.

4.2.2 Contract and Project Market Competitiveness Risks

The overall competitiveness of the project relative to the market is also an important determinant of perceived project risk. Project competitiveness can be viewed either in terms of the contract provisions relative to the market or in terms of how competitive the project is on a cost-of-generation basis relative to other plants in the same market should the contract be terminated. In terms of contract competitiveness, contracts are viewed as more favorable if the contract provisions will always be very competitive relative to prevailing market prices. This Market-to-Model approach is so called because the tolling agreement or PPA contract, which is typically long term, is compared to forward prices developed from modeling exercises.

Lenders and rating agencies also consider contract termination risks for IPP projects by assessing the value of the plant should the power sales contract be terminated, with the result that the plant output must be sold into the merchant power markets. A contract would be on the investment grade end of the spectrum if it were above or at market prices, and if it were terminated, no significant impact would be seen on cash flows due to the competitiveness of the project on its own variable cost merits. In contrast, a contract would be considered to be on the risky end of the spectrum if it would significantly lose cash flows if the power sales agreement were terminated because the plant was not competitive in the power market on a variable cost basis. Similarly, a lower rating is given if replacement power is difficult to obtain.

A project's market competitiveness is judged based on its production costs compared to other generation options in the relevant market. A highly competitive project will always be the one with the lowest cost assets that also has little or no exposure to future environmental challenges. However, being the low cost asset in a market is no guarantee for a good rating. A project could be operating in a market with weak supply/demand fundamentals (i.e., low margins) or in a market where regulations favor the local utilities' generation fleets. Market transparency and liquidity are also important.

4.2.3 Technical and Operating Risks

Another important consideration in determining a power project's creditworthiness is the project's expected technical performance and how well it will be operated and maintained. Commercially proven technologies should easily meet availability and performance requirements set forth in its off-take agreements. Time is needed for a technology to be commercially proven. In the gas-fired combined cycle space, GE-7FA technology would be a commercially proven technology, having been on the market since the mid-1990s and having well over 100 GW of installed capacity. The GE-7FA is in its fourth generation cycle. The more recent Siemens 501G technology, first introduced in the early 2000s, offers a 2 percent better heat rate than the GE-7FA. However, long start-up times and availability issues have kept it from being fully accepted. Thus, projects using the Siemens technology may receive a lower credit rating. Sub-critical and super-critical coal plant technologies have proven designs in the coal-fired space. Commercially proven technologies should also have well understood capital expenditure (CAPEX) and maintenance programs. Commercially unproven technologies would be on the other side of the credit spectrum. Some unproven technologies may have years of operating experience but still perform well below established industry standards. Strong warranties and well-structured long-term service agreements help mitigate technology/operating risk.

Chapter 5
Summary

This volume has identified the key factors that power companies should consider in managing the risks associated with investment decisions in new baseload electric generation capacity. Investment uncertainty is problematic because the power industry is one of the most capital intensive industries in the U.S., and accounts for a large portion of the non-governmental, non-financial debt raised in the U.S. Uncertainty complicates this financing process.

The five major risk factors surrounding the decision to build baseload generation and affecting both the utility and IPP sectors are summarized below:

- **Natural Gas and Oil Prices** – The low and stable natural gas prices in the 1990s were a key predicate for the overwhelming interest in gas-fired power plants in recent years. Similarly, the rise of gas prices and their volatility have been a key factor driving the search for alternative new generation options. While fuel price volatility is a source of risk for investors in new baseload generation, these risks are typically reduced for regulated utilities because the rates at which they sell electricity typically include clauses that allow them to pass on increases in fuel costs to their ratepayers.

- **CO_2** – At the very time U.S. utilities were turning away from gas to coal, concerns about CO_2 and climate change came to the forefront of national discussions. The increasing likelihood of CO_2 regulation, especially the potential for federal regulation, is making coal less attractive compared to other alternatives and spurring interest in technologies that decrease the carbon footprint of coal. Regulated utilities will try to pass these higher variable costs on to ratepayers. While pass-through mechanisms are in place for variable cost increases in many states, the degree to which cost increases associated with CO_2 allowance costs can be passed through to ratepayers is a great uncertainty.

- **Capital Costs** – Over the last two years, power plant construction costs have grown immensely. The average cost of building a plant in the U.S. increased over 50 percent between 2006 and 2008. This rapid rise in costs makes investment in baseload plants in particular more risky because they tend to be more capital intensive. The run-up in capital costs was a contributory factor for many utilities' decisions to revise cost estimates and, in some cases, delay or cancel projects.

- **Renewables** – A large number of states have RPSs, and a federal RPS could be enacted by Congress this year. Among the legislative proposals being discussed is a renewable standard of 20 percent of generation by 2020. Renewables combine two features that have increased popular support: energy security and lower CO_2 emissions. However, they can be expensive, are often located far from load centers, and contribute little to grid reliability. Implementing a federal RPS could delay decisions to build new baseload capacity.

- **Demand and Demand Side Management** – Recently, the focus on DSM has greatly increased with state actions, as well as with the stimulus bill. Furthermore, the recent sharp decline in electric demand and related drop in capital expenditures increases the risks that investors in baseload electric generation capacity face concerning future demand growth. In particular, these investors must manage the risks associated with the uncertainty about when demand growth will recover, the strength of the recovery, and the timing of the market's response to this increase in demand growth in terms of investing in new generation capacity.

In addition to these major risk factors, two more risk factors will impact the decision-making in the IPP space:

- **Electricity Price Risk Factors** – Unlike utilities, IPPs do not have captured ratepayers and do not have fuel adjustment clauses. For IPPs, making investment decisions in new baseload generation capacity is complicated by uncertainties about future prices for electricity. Tools to mitigate these risks are limited and include such things as fuel hedges and power purchase agreements.

- **Financial Risk Factors** – IPP projects generally have substantially greater levels of business risk than regulated utility projects because they do not have captive ratepayers. IPP financing is usually done through non-recourse debt. As debt is cheaper than equity, developers would like their capital structure to have as much debt as possible. Thus, it is important for developers to understand how creditors look at a project and how they rate its creditworthiness.

Appendix A
Levelized Cost Assumptions

A.1 Introduction

In order to calculate the levelized costs of electricity (LCOE) presented in Exhibits 2-7, 3-4, 3-6, and 3-9, ICF International generated a set of assumptions. A summary of these assumptions is presented in Exhibit A-1. The capital cost, fixed O&M and variable operation and maintenance (O&M) costs reflect plants with a 2020 online year. The fuel price is a levelized cost reflecting 20 years starting in 2020.

Exhibit A-1
Levelized Cost Assumptions (2006$)

	PC	IGCC	IGCC w/ CCS	Nuclear	NGCC	Wind
Capital Cost ($/kW)	2,900	3,500	4,800	4,600	1,200	2,400
Fixed O&M ($/kW-yr)	27	32	41	110	10	30
Variable O&M ($/MWh)	3.3	2.2	4.0	1.2	2.8	0.0
Heat Rate (Btu/kWh)	9,100	8,300	10,100	10,400	6,800	0
Capacity Factor	90%	85%	85%	93%	92%	37%
Levelized Fuel Price ($/MMBtu)	2.00	2.00	2.00	1.20	5.60	0.00
CO2 Price ($/ton)	0	0	0	0	0	0

Source: ICF Assumptions.

A.2 The Levelized Cost Equation

The equation to calculate levelized cost is as follows:

> LCOE = Capital Cost * Capital Charge Rate + Fixed O&M + Variable O&M + Fuel Cost + Emissions Cost

The LCOE utilizes the capital charge rate to convert the capital cost from a $/kW number into a $/MWh number.

The capital charge rate is used to convert capital cost into a stream of levelized annual payments that ensures capital recovery of an investment. The capital charge rate is a function of many parameters, such as debt/equity ratio, debt rate, debt life, return on equity, depreciation, book life, taxes, and insurance. Technologies with high debt-to-equity ratios have lower capital charge rates, as debt is cheaper than equity.

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Volume II: Technology Overview and Economic Viability Assessment of Baseload Generation

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Chapter 1
Introduction

1.0 Introduction

This is the second volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

This volume examines why power plant developers are investing in certain types of baseload technology. The discussion focuses on coal-fired technology, namely supercritical coal and integrated gasification combined cycle (IGCC), but also includes nuclear and combined cycle technology. In addition, the discussion of investment viability of baseload technologies is facilitated through an economic gap analysis using ICF's capacity expansion modeling platform, the Integrated Planning Model (IPM®).

The first four chapters of this volume detail the current and advanced states of baseload technologies, focusing on pulverized coal (PC), integrated gasification combined cycle (IGCC), nuclear, and natural gas combined cycle (NGCC). The chapters on PC and IGCC pay special attention to possible methods of capturing carbon to allow these baseload units to remain economically viable in a carbon-constrained world.

The last section discusses whether these technologies are economically viable within the context of an electric power market model simulation. A long-term view of the U.S. power market under climate change regulations is developed using ICF International's (ICF) capacity expansion planning model, IPM®. The goal is to understand whether baseload investments are financially prudent in a carbon-constrained world, and if not, what it would take for them to become economically viable.

To help answer this question, the following baseload generation types were modeled and analyzed:

- Supercritical pulverized coal (SCPC),
- SCPC with carbon capture and sequestration (CCS),
- IGCC,
- IGCC with CCS,
- Nuclear, and
- NGCC.

Each analysis starts with a "Reference Case," which serves as a baseline or reference point. Then a return on equity (ROE), based on cash flows projected from the model simulation, is calculated for each technology. Baseload capacity investments are deemed economically viable if investor hurdle rates are met. For baseload technologies that are not found to be economically viable, a gap analysis is used to quantify what would make them viable. The gap analysis is performed through sensitivity cases.

After discussions with NETL personnel, it was determined that the five key parameters below should serve as the basis for the sensitivities. In each of the sensitivity cases, only one of the parameters was changed to gauge its impact on the ROE for a particular technology:

- **Carbon Dioxide (CO_2) Price** – There is considerable uncertainty over the shape and degree of future controls on carbon emissions. Our analysis gauges the effect of carbon emission constraints on the six study plants above by varying the CO_2 allowance price from $0–$80 per ton.

- **Natural Gas Price** – Because natural-gas-fired units set the wholesale price during many hours in many power markets, natural gas price variations have a large effect on the profit margins of baseload generation. As natural gas prices increase, profit margins improve. Natural gas prices have been particularly volatile over the past few years, reaching record highs as well as near-record lows. A gap analysis gauges the effect of increasing gas prices on the ROE of the six baseload technologies.

- **Federal Renewable Standards** – There may soon be a federally-enforced renewable portfolio standard (RPS) that could force upwards of 20 percent of U.S. generation to be from renewable sources (such as wind or solar) by 2020. This scenario is examined herein, as are two others, one more extreme and one more mild.

- **Capital Costs** – Many of the technologies studied, notably IGCC and CCS, are new technologies or new designs that have not yet reached commercialization. As the designs improve and more facilities are built, significant construction cost reductions may be realized that improve their economics. On the other hand, there is also the risk that current cost estimates are too low, as most nuclear developers discovered when they estimated low, "competitive" costs for their projects in the past. This analysis examines eight different cases, ranging from 40 percent lower to 40 percent more expensive than the Reference Case assumptions.

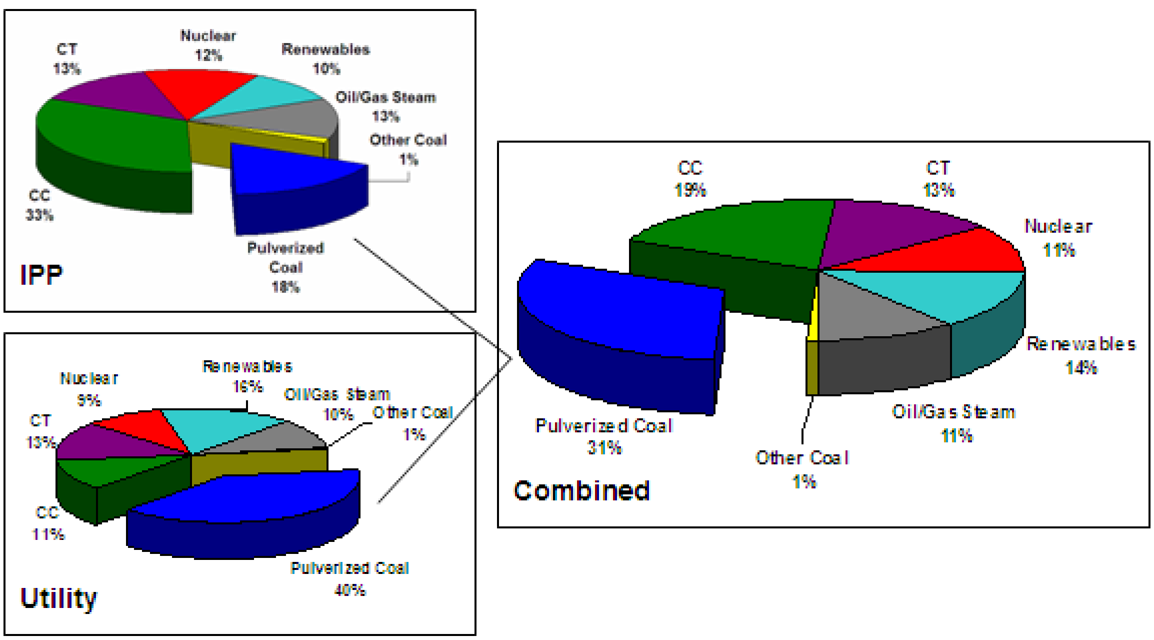
- **Availability** – There is considerable range in the amount of time different plant types are available. Modern NGCC plants generally have very good availability factors, typically achieving factors of 92 percent. On the other hand, operating IGCC plants have yet to achieve this level due to component integration problems. This analysis examines how increased availability at the six study plants potentially impacts their ROE.

It is important to note that the results presented here are based on ICF assumptions and are susceptible to change due to variations in market assumptions, and plant technology cost and performance characteristics. The primary purpose of these gap analyses is to explore how variations in an individual factor impact the economic viability of various baseload technologies. In some cases this gap may appear large and unachievable. However, in reality, small changes in multiple factors may collectively improve the economic viability of a generation technology.

Chapter 2
Pulverized Coal

Pulverized coal (PC) plants play a significant role in U.S. power generation, with 294 gigawatts (GW) of independent power producer (IPP) and utility-owned pulverized coal capacity providing nearly 30 percent of the country's operating generation capacity. Exhibit 2-1 provides a breakdown of IPP and utility-owned operating pulverized coal capacity. Worldwide research and development efforts over the last several decades have yielded major technological advances that have reduced emissions, improved reliability, increased efficiency, and decreased capital costs. Due to the maturity of subcritical and supercritical pulverized coal technology, these forms of PC generation have historically been very economically attractive relative to alternative baseload generation options. However, over the last several years, volatile commodity prices coupled with uncertainty regarding the implementation of federal CO_2 regulation have diminished pulverized coal's edge over natural-gas-fired capacity. To remain competitive in the new "carbon-constrained" market environment, additional technological advancements must be achieved to reduce capital costs and future CO_2 compliance costs. This chapter provides an overview of pulverized coal technology by examining its historical development, state-of-the-art parameters, and ongoing research and development projects.

Exhibit 2-1
U.S. IPP and Utility Operating Capacity



Source: Ventyx 2009.

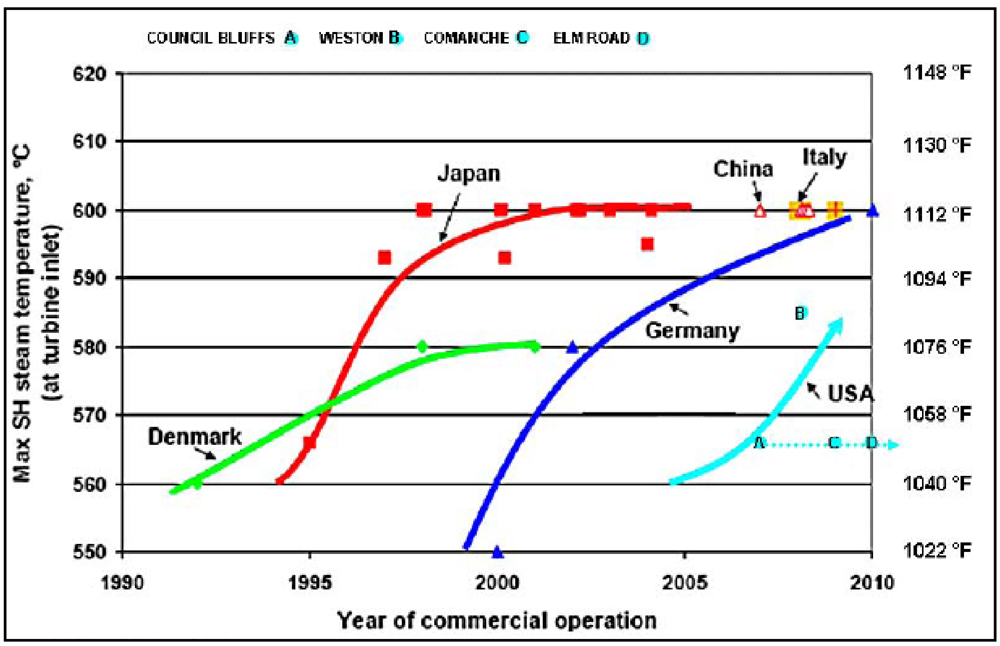
2.1 Technology Overview

2.1.1 Supercritical and Ultrasupercritical Pulverized Coal International Development

In total, there are around 600 SCPC and ultrasupercritical pulverized coal (USCPC) generating units operating worldwide, with the vast majority classified as supercritical. The aggregate capacity of these units is more than 300 GW.[1]

Early SCPC plants in the U.S. in the 1960s and 1970s experienced reliability issues, and SCPC development largely moved overseas. In the 1990s, Danish manufacturers developed advanced plants with temperature exceeding 1,050 degrees Fahrenheit (ºF). Soon thereafter, the Japanese started developing a large number of units that would be classified as ultrasupercritical by the Electric Power Research Institute's (EPRI) definition (with temperatures reaching 1,110 ºF). Exhibit 2-2 illustrates the advancement of commercial SCPC and USCPC plants in a global context.

Exhibit 2-2
Recent Improvements in Pulverized Coal



Source: EPRI 2007.

China has been investing heavily in USCPC projects over the last several years. By 2007, 10 USCPC units, each rated at 600 megawatts (MW), and 18 USCPC units, each rated at 1,000 MW, were under construction or ordered in China.[2] China's Lanshan plant, commissioned in 2009, is one of the world's most advanced USCPC plants, with steam conditions of 4,420 pounds per square inch (psi) and 1,112 ºF while using smaller unit sizes (4 x 660 MW net). Lanshan is a significant achievement in China's energy development, placing China as a leading nation in the deployment of USCPC technology and likely allowing it to surpass Japan,

[1] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants.* 2007.
[2] Thermal Power Research Institute. Commercial Clean Coal Technologies, 2007.

Italy, and Germany before the end of the decade.[3] Overall, projects being developed in Germany, Italy, and China will substantially increase the world's installed base of generating units with ultrasupercritical steam conditions.[4]

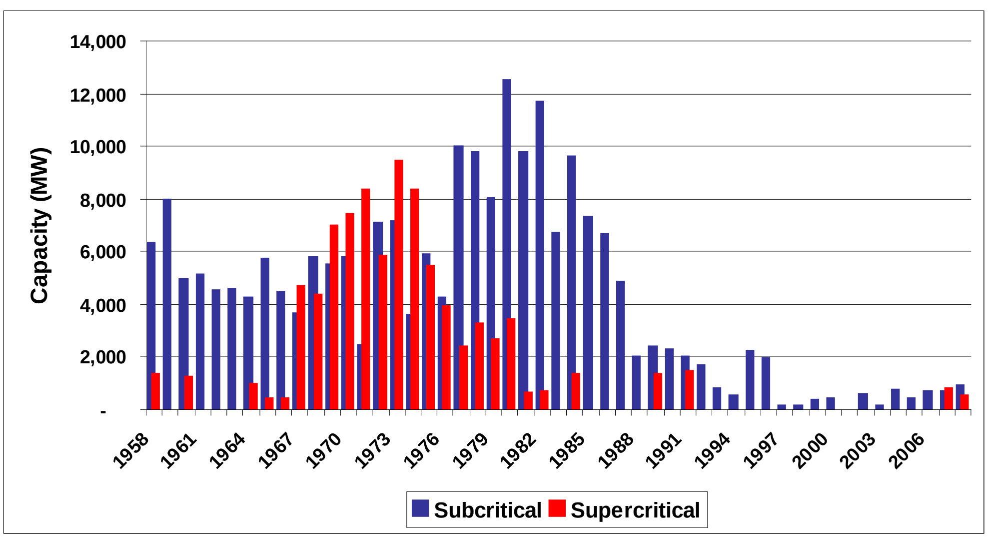
2.1.2 Pulverized Coal Development in the U.S.

The U.S. has nearly 250 GW of installed subcritical PC capacity, representing more than 25 percent of total operational U.S. capacity. There are more than 160 supercritical pulverized coal (SCPC) units in the U.S. with an aggregate capacity of nearly 87 GW, representing nearly 9 percent of total operational U.S. capacity. Most of the SCPC units have capacities ranging from 300 MW to 1,100 MW, with a few units being as large as 1,300 MW.[5]

Subcritical PC capacity additions peaked in the early 1980s due to cheap coal and the national effort to increase fuel diversity following the 1973–1974 Arab oil embargo. However, subcritical PC additions have been in a steady decline since that peak due to the growing supplies and falling prices of natural gas.

As illustrated in Exhibit 2-3, installations of SCPC plants in the U.S. over the last half-century peaked in the mid-1970s and proceeded to fall precipitously because coal remained inexpensive and the SCPC technology was costly and not yet as reliable as that of subcritical PC. These cost and reliability issues have since been resolved with the advancements made overseas.

Exhibit 2-3
Coal Capacity Installations by Plant Type



Source: Ventyx 2009.

Investments in new subcritical PC units will most likely decline further with the introduction of federal carbon legislation, the passage of which could render some existing subcritical PC units uneconomical and may lead others to be retrofitted with CCS technology.

[3] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants.* 2007.
[4] Ibid.
[5] Ventyx 2009.

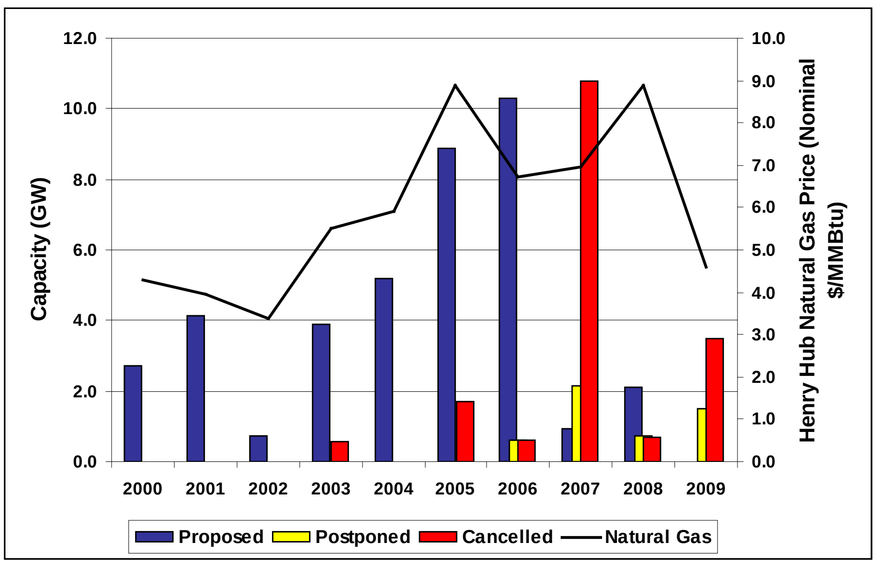
Proposed in 2001, MidAmerican's 790 MW Council Bluffs Unit 4, also known as the Walter Scott Jr. Energy Center, was the first supercritical unit commissioned in the U.S. in almost 20 years, and it began operations in the summer of 2007. The second SCPC unit to be commissioned in the post-2000 period was Wisconsin Public Service Corp.'s 500-MW Weston Unit 4, which began operations in the summer of 2008.

American Electric Power (AEP) is currently preparing a site for its 600-MW USCPC John Turk Jr. facility located in Arkansas. The plant will produce steam temperatures of 1,115 ºF and pressures of 3,800 psi, and will have an 11 percent efficiency advantage over a similar supercritical plant.[6]

Over the last decade, 43 projects amounting to nearly 39 GW of SCPC and USCPC capacity builds have been announced in the U.S.[7] EPRI has classified roughly 26 GW of the 39 GW announced capacity as USCPC.[8]

As natural gas prices soared between 2002 and 2008, SCPC and USCPC annual capacity announcements grew, peaking in 2006 with more than 10 GW of announcements. However, growing public opposition and uncertainty regarding the implementation of carbon legislation prompted several project postponements and many project cancellations starting in 2007, a trend that can be seen in Exhibit 2-4. Additional catalysts behind the postponements and cancellations include the precipitous decline of natural gas prices in 2008–2009 and the tightening of credit markets.

Exhibit 2-4
SCPC and USCPC under Development in the U.S.



Source: Ventyx 2009; Bloomberg. Historical Henry Hub Natural Gas Spot Prices (Nominal $).

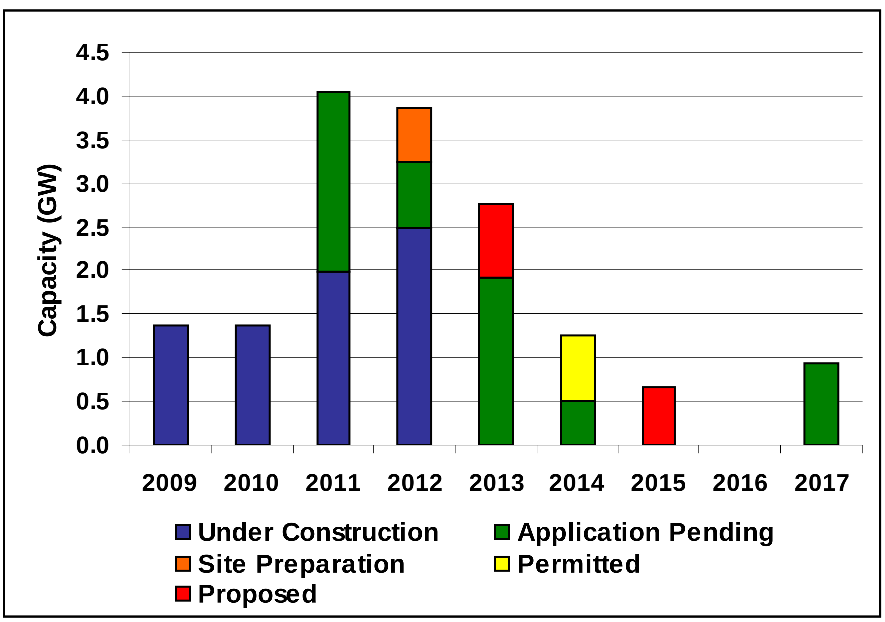
[6] Sigmon, William L. *Energy Biz Magazine*. 2008.
[7] EPRI defines USCPC units as those with temperatures reaching 1,110°F.
[8] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants,* 2007.

Of the nearly 39 GW of SCPC and USCPC capacity builds proposed over the last ten years, only 1.3 GW have become operational, with 5 GW being postponed, and nearly 18 GW cancelled.

Much of the nearly 11 GW of the capacity cancellations in 2007 (all of which EPRI classified as USCPC)[9] was due to TXU Corp.'s cancellation of eight of its proposed Texas coal projects, which had a combined capacity of 5.6 GW. In 2007, TXU was purchased for $45 billion, and as part of the buyout, TXU was required to cancel those plants to settle a series of lawsuits with the Environmental Defense Fund and the Natural Resources Defense Council.[10] Over 5 GW of other 2007 cancellations include Glades Power Park (Florida), Taylor Energy Center (Florida), Red Rock (Oklahoma), and Holcomb (Kansas).[11] The overarching trend behind these cancellations was the denial of permits due to unprecedented state opposition. Many states have begun to shy away from business-as-usual practices in preparation for impending federal carbon regulation.

Of the 16.2 GW of announced SCPC and USCPC capacity that are not postponed, cancelled, or already operational, 7.2 GW are under construction, 0.6 GW are undergoing site preparation, 0.8 GW have been permitted, 6.1 GW have pending applications, and 1.5 GW remain in the proposal stage.[12] Exhibit 2-5 provides an overview of the planned commercial online dates (COD) of capacity not cancelled, postponed, or operational.

Exhibit 2-5
Planned COD of Active, Announced SCPC and USCPC Capacity by Current Status



Source: Ventyx 2009.

[9] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants.* 2007.
[10] Sourcewatch.org.
[11] A compromise was reached in May 2009 that permits the construction of a single 895 MW unit at Holcomb rather than the two 700 MW units originally planned.
[12] Ventyx 2009.

The eight projects currently under construction took an average of five years to move from the proposal phase to the construction phase, and the developers of these projects anticipate that construction will take an average of four years to complete. However, these projects varied significantly in the amount of time they took to move from the proposal phase to the construction phase, ranging from two to six-and-a-half years. The anticipated construction time, on the other hand, is fairly consistent, ranging from three-and-a-half years to four-and-a-half years. With this in mind, it is important to highlight that of the 9.2 GW anticipated to come online between 2011 and 2012, 3.6 GW have not begun site preparation or construction and thus their COD will likely be pushed to beyond 2013. EPRI classifies the vast majority of the projects currently under construction as USCPC.[13]

2.2 Cost and Performance Characteristics

2.2.1 Construction Cost

PC-fired plants cost more and take longer to build than natural gas-fired combined cycle plants, but less than nuclear plants. Exhibit 2-6 provides cost and performance parameters of state-of-the-art PC units most recently released by NETL and EPRI. Both NETL and EPRI data represent a single-furnace SCPC unit incorporating selective catalytic reduction (SCR) and wet flue gas desulfurization (FGD) for emission control. However, while the plants modeled by EPRI include activated carbon injection (ACI) for mercury (Hg) control, those modeled by NETL do not, because co-benefit capture alone exceeds the Hg control requirements of new source performance standards (NSPS) and recent permit averages. Costs for units modeled by both NETL and EPRI reflect normal sparing of equipment. The SCPC unit modeled by NETL is 50 MW smaller than the SCPC unit modeled by EPRI.[14]

When comparing capital cost estimates from different sources, differences in definitions of what is contained in "capital costs" might cause some confusion. Two of the main definitions used to describe capital costs are total capital requirement (TCR) and total plant cost (TPC). TPC is just the overnight capital cost, and does not include owner's costs.[15] TCR is the sum of the TPC, owner's cost, and allowance for funds used during construction (AFUDC). While NETL does not provide TCR, EPRI states that typical owner's costs could add anywhere from 5 to 22 percent to TPC (depending on the owner and site-specific requirements) and AFUDC adds another 11–12 percent to TPC. EPRI's estimates reflect the lower end of these ranges, as their TCR is only 16 percent higher than their TPC for all PC cases.

Exhibit 2-6 shows the reported levelized cost of electricity (LCOE). As mentioned in Volume 1, *Investment Risk Factors for Baseload Generation*, LCOE is an effective screening metric when comparing economic performance of generation technologies. LCOE takes into account capital costs, operation and maintenance (O&M), and fuel costs levelized over the book-life of a power plant. Another driver in differences between the two estimates is assumptions on book life. NETL calculates a 20-year LCOE whereas EPRI calculates a 30-year LCOE. The assumed book-life is a key determinant of the capital carrying charge factor, which, in turn, drives levelized capital costs lower if spread over more years. NETL's SCPC LCOE estimate is nearly $9/megawatt-hour (MWh) higher than EPRI's SCPC LCOE estimate. This difference can mostly

[13] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants.* 2007.
[14] NETL. *Cost and Performance Baseline for Fossil Energy Plants*. 2007; EPRI. *Updated Cost and Performance Estimates for Clean Coal Technologies Including CO_2 Capture*. 2006.
[15] Owners costs include, but are not limited to, land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, legal fees, owner's engineering, preproduction costs, furnishings, owner's contingency, etc. NETL. *Cost and Performance Baseline for Fossil Energy Plants*. 2007.

be explained by NETL's higher $/MWh capital cost, which is driven in large part by NETL's assumption of a 20-year plant book-life rather than the 30 years assumed by EPRI.

Another reason for NETL's higher LCOE estimates is that while NETL's SCPC heat rate assumptions are lower than that of EPRI, NETL's fuel prices are higher, which, in turn, leads NETL's SCPC unit to have a higher $/MWh fuel expense.

Exhibit 2-6
Parameters of State-of-the-Art Pulverized Coal Units Without CCS (Mid-2006$)[1]

	NETL		EPRI	
	20 Yr Levelized Cost		30 Yr Levelized Cost	
Technology	**Subcritical**	**SCPC**	**SCPC**	**USC**
Net MW	550	550	600	600
Total Plant Cost (TPC $/kW)	1528	1554	1800	1825
Total Capital Requirement (TCR $/kW)	-	-	2088	2117
Fixed O&M ($/kW-yr)	24.34	24.84	50.4	51.1
Variable O&M ($/MWh)	4.94	4.80	1.6	1.6
Heat Rate(Btu/kWh HHV)	9,276	8,721	9,137	8,995
Net Plant HHV Efficiency (%)	36.8%	39.1%	37.3%	37.9%
Capacity Factor	85%	85%	80%	80%
Fuel Price ($/MMBtu)	1.78	1.78	1.50	1.50
Capital Charge Factor	0.164	0.164	0.117	0.117
Capital ($/MWh)	33.7	34.2	30.1	30.5
O&M ($/MWh)	8.2	8.1	8.8	8.9
Fuel ($/MWh)	16.5	15.5	13.7	13.5
Total LCOE ($/MWh)	63.1	62.5	52.5	52.9
CO2 (Emitted lbs/MWh)	1886	1773	1937	1907
NOX (lbs/MWh)	0.613	0.579	-	-
SOX (lbs/MWh)	0.743	0.701	-	-
Hg (lbs/MWh)	1.00E-05	9.40E-06	-	-

Source: NETL 2007 and EPRI 2006.
[1] Dashes signify that data are not available.

NETL's 2007 estimates reflect the SCPC technology advancements that now permit an LCOE in line with that of subcritical PC plants. Although the TPC of a SCPC unit is 1.7 percent higher than the TPC of a subcritical PC unit, the SCPC unit has a 6.4 percent heat rate advantage over the subcritical PC.

Likewise, EPRI's 2006 estimates reflect the USCPC advancements that allow for the technology to have an LCOE close to that of SCPC plants. At a coal price of $1.50 / million British thermal units (MMBtu), the USCPC heat rate advantage does not outweigh the additional cost to build the more advanced technology. However in a higher fuel price environment USCPC could prove more economically attractive. USCPC economics further improve if carbon compliance savings are included.

2.2.2 Efficiency

Improved efficiencies reduce overall fuel use and lower emission compliance costs. SCPC units currently have only a marginal thermal efficiency advantage over typical subcritical units. NETL assumes that a state-of-the-art subcritical plant achieves an efficiency of nearly 37 percent and that a state-of-the-art supercritical plant achieves an efficiency of a little more than 39 percent. EPRI's efficiency estimates of 37–38 percent for SCPC and USCPC, respectively, highlight the near homogeneity of efficiencies across the current spectrum of pulverized coal technology.[16] However, with additional advancements in the field, the performance of these technologies will increasingly diverge, especially if future SCPC plants achieve anticipated higher heating value (HHV) efficiencies in the range of 43–45 percent, and if future ultrasupercritical plants achieve anticipated HHV efficiencies of up to 50 percent, which implies a heat rate reduction in the range of 20–25 percent.[17]

2.2.3 Availability

Outage time is the main factor used to compare the maintenance cost of subcritical and supercritical plants, and it has two components: outage frequency and duration. System sparing can play a key role in achieving greater availability, which could improve the economics of advanced pulverized coal plants.[18] Component redundancy is costly to implement but may become a greater priority as more plants rely on power purchase agreements (PPAs) for financing and face even costlier replacement power penalties in the event they are not able to supply power unexpectedly, which would be a breach of a PPA, triggering the liquidated damage provision.

2.2.4 Cyclic Duty

Although typically not needed for new baseload duty, PC units can achieve fast startup times, providing them with load following capability. SCPC once-through boilers do not have a steam drum or other thick walled components like subcritical units, allowing them to cold start in 15–20 percent less time. Additionally, advanced SCPC boilers with full/partial flow separators and new control systems can achieve load changes at a rate of up to 5 percent per minute.[19] Some SCPC units can even accommodate daily start-stop cycling.

2.2.5 Environmental Factors

Greater efficiency of supercritical technology also allows for reductions (per unit of electricity generated) in the following:

- Emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), CO_2, particulates, and Hg;
- Environmental impacts of coal mining, transportation, and handling;
- Ash production and disposal; and
- Water consumption for condenser cooling.

[16] Note that efficiency is a function of plant location, cooling methods, etc. A plant in the northern U.S. would be more efficient than in the southern U.S.
[17] Achieving these efficiencies is dependent on metallurgical advances; Public Utilities Commission of Nevada. 2007.
[18] EPRI. *CoalFleet Guideline for Advanced Pulverized Coal Power Plants.* 2007.
[19] Viswanathan, et al. *Power Magazine*. 2004.

An EPRI analysis found that increasing the efficiency of an USC plant from 37 percent to 48 percent would reduce its CO_2 emissions by more than 23 percent, from 0.85 to 0.65 metric tons/MWh. Such an improvement would make USCPC more economically attractive under carbon regulation.[20]

2.2.6 R&D Efforts on Improvement – Materials and Design Upgrades

The main enabling advancements of SCPC and USCPC plants have been stronger building materials and modifications to the boiler design. Boiler design upgrades and modifications have addressed problems experienced with boiler pressure parts, such as fatigue failures in the economizer and lower furnace tubes, structural damage to such areas as windbox supports, and stress failures due to large transient temperature differences between the boiler parts. In addition, design modifications to boiler parts addressed issues including temperature cycling limits and slow response.[21]

In 2001, the U.S. Department of Energy (DOE) launched a high-temperature materials program with the support of EPRI, Ohio Coal Development Office, Oak Ridge National Laboratory, and U.S. boiler manufacturers. The objective of this ongoing program is to evaluate materials capable of performing at up to 1,400 ºF at 5,000 psi that will allow USC designs with dramatically reduced heat rates.[22] Since the start of the program, significant progress[23] has been made on issues such as coatings for steam oxidation and SPE protection, welded configuration for HP/IP rotors and non-welded integral rotor development. Advances in materials have permitted steam turbine and boiler parts to withstand higher steam temperatures and pressures with the necessary fabricability, resistance to creep, oxidation, corrosion, and fatigue.[24] This program is anticipated to yield technology that will improve USCPC unit efficiency by 8–10 percent and reduce greenhouse gas emissions by nearly 30 percent.[25] Although worldwide research has yielded numerous high-strength alloys, additional investigation is needed to further improve the economics of advanced materials technologies.

2.3 Carbon Capture and Sequestration

With federal carbon regulation on the horizon, existing pulverized coal units and those under development must prepare to purchase emission allowances or pursue CCS options to drastically reduce their carbon footprint. In early 2008, many major financial institutions concluded that the U.S. government will cap greenhouse gas emissions and announced that they will follow a new set of guidelines known as the “Carbon Principles,” which impose new environmental standards that make it harder for companies to get financing for coal projects. The banks, which include Bank of America, Citi, Credit Suisse, JP Morgan, Morgan Stanley, and Wells Fargo, plan to encourage energy efficiency and renewable energy projects before backing new coal plants.[26]

2.3.1 Capital Cost

Adding CCS technology to a PC plant introduces additional costs relating to the need to install and power the new equipment, build a transportation system, and store CO_2. At present, the

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[20] Ibid.
[21] Upgrades and Enhancements for Competitive Coal-fired Boiler Systems. 1996.
[22] Viswanathan, et al. *Power Magazine*. 2004.
[23] http://www.netl.doe.gov/publications/factsheets/project/Proj463.pdf
[22] DOE. *Steam Turbine Materials for Ultrasupercritical Coal Power Plants*. 2007.
[25] NETL Advanced Materials for Ultrasupercritical Boiler Systems, Project Facts 08/2007.
[26] Ball, Jeffrey. *The Wall Street Journal.* 2008.

additional capital investment and operational costs that come with enabling CCS renders the technology uneconomical (see detailed discussion in Chapter 5).

Exhibit 2-7 provides the cost and performance characteristics of state-of-the-art PC units with the addition of CCS. Both NETL and EPRI modeled the capture of CO_2 from a clean flue gas using Fluor's Econamine FG Plus (EFG+) amine absorber process. Although the net power of the PC units is nearly the same as it was before the addition of CCS, each unit actually incurs a capacity penalty due to the large parasitic load of the carbon capture equipment. Both NETL and EPRI oversized the gross power of their modeled PC units to offset their respective 14 percent and nearly 16 percent estimated gross capacity penalties due to CCS.

Exhibit 2-7
Parameters of State-of-the-Art Pulverized Coal Units with CCS (Mid-2006$)[1]

	NETL		EPRI	
	20 Yr Levelized Cost		30 Yr Levelized Cost	
Technology	**Subcritical**	**SCPC**	**SCPC**	**USC**
Net MW	550	546	550	550
Total Plant Cost (TPC $/kW)	2,856	2,832	3,004	3,044
Total Capital Requirement (TCR $/kW)	-	-	3485	3531
Fixed O&M ($/kW-yr)	36.9	36.9	84.1	85.2
Variable O&M ($/MWh)	9.2	9.2	1.6	1.6
Heat Rate(Btu/kWh HHV)	13,724	12,534	12,714	12,428
Net Plant HHV Efficiency (%)	25%	27%	27%	27%
Capacity Factor	85%	85%	80%	80%
Fuel Price ($/MMBtu)	1.78	1.78	1.50	1.50
Capital Charge Factor	0.175	0.175	0.124	0.124
Capital ($/MWh)	67.1	66.6	61.6	62.5
O&M ($/MWh)	14.2	14.2	13.6	13.8
Fuel ($/MWh)	24.4	22.3	19.1	18.6
Total LCOE ($/MWh)	117.2	114.6	93.8	93.9
CO2 (Emitted lbs/MWh)	225	209	273	267
COE Adder for CO2 Capture ($/MWh)	-	-	30.28	30.37
CO2 Captured (lb/MWh)	1661	1564	2422	2368
COE Adder for Transportation & Storage[2]	-	-	10.99	10.74
Cost of CO2 Avoided (incl. T&S) ($/short ton)	67.1	67.1	49.6	50.1

Sources: NETL 2007 and EPRI 2007.
[1] Dashes signify that data is not available.
[2] NETL's estimated cost of CO_2 transportation, storage and monitoring is included in their LCOE estimation, of which it comprises less than 4 percent.

With the addition of CCS, NETL's modeled capital costs for SCPC increase by more than 80 percent and EPRI's modeled costs increase approximately 70 percent. These increases can be mostly attributed to equipment needed to meet additional cooling water needs and for both the CO_2 capture and compression processes.[27]

The LCOE component costs significantly changed for the SCPC units with the addition of CCS. Capital costs, a major component of LCOE, for the NETL and EPRI SCPC units grew significantly, by 94 percent and 105 percent, respectively, as did fuel costs, which increased by

[27] NETL. *Cost and Performance Baseline for Fossil Energy Plants. 2007.*

44 percent and 39 percent, respectively. O&M grew by 74 percent for NETL's SCPC unit and by 55 percent for EPRI's SCPC unit.

Both NETL's and EPRI's CCS options reduce CO_2 emissions by more than 85 percent. However, NETL's $67/ton estimated cost of CO_2 removal is roughly 34 percent higher than EPRI's $50/ton estimated cost of CO_2 removal. The implied $/ton CO_2 removal cost is calculated by taking the difference of a unit's LCOE ($/MWh) with and without CCS and dividing that difference by the amount of CO_2 removed (tons/MWh) with CCS. The significant difference between NETL and EPRI's cost of CO_2 removal is explained almost entirely by NETL's more conservative levelization assumptions, particularly its use of a 20-year book-life rather than a 30-year book-life as assumed by EPRI. These CO_2 removal cost estimations represent a large step in the supply curve of CO_2 allowance prices. Indeed, in a very mild CO_2 case, CO_2 removal costs may even be a good indication of an upper bound.

As shown in Exhibit 2-8, the addition of CCS technology creates a significant increase in parasitic load, thereby resulting in a significant increase in plant heat rate.

Exhibit 2-8
Parameter Penalties with Addition of CCS

	NETL Subcritical	NETL SCPC	EPRI SCPC	EPRI USC
Heat Rate (Btu/kWh HHV)[1]	48.0%	43.7%	39.1%	38.2%
Net Plant HHV Efficiency[2]	-11.9%	-11.9%	-10.5%	-10.5%
Capacity[1]	-16.6%	-14.3%	-15.7%	-13.3%

Sources: NETL 2007 and EPRI 2007.
[1] Percent change.
[2] Absolute change.

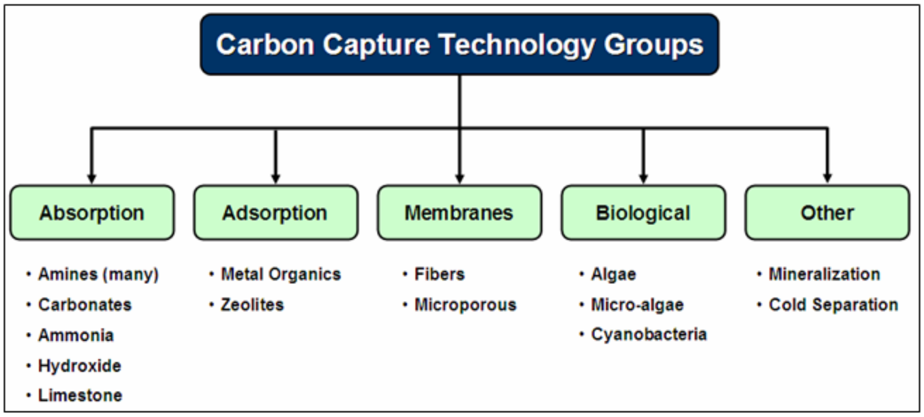
For both NETL PC cases, the addition of CO_2 capture causes nearly a 12 percent decrease in efficiency. The loss in efficiency is due to the large auxiliary loads of the Econamine process, CO_2 compression, and, to a minor extent, the increase in cooling water needs.[28]

2.3.2 Post-Combustion Carbon Capture

CO_2 can be removed from PC units through a post-combustion capture process. As of April 2009, EPRI has determined that there are over 50 post-combustion CO_2 capture concepts and 6 physical and chemical process types under development, which can be categorized as depicted in Exhibit 2-9.[29]

[28] NETL. *Cost and Performance Baseline for Fossil Energy Plants. 2007.*
[29] EPRI. *CO_2 Capture Status*. 2009.

Exhibit 2-9
Post-Combustion CO_2 Capture Technology Groups



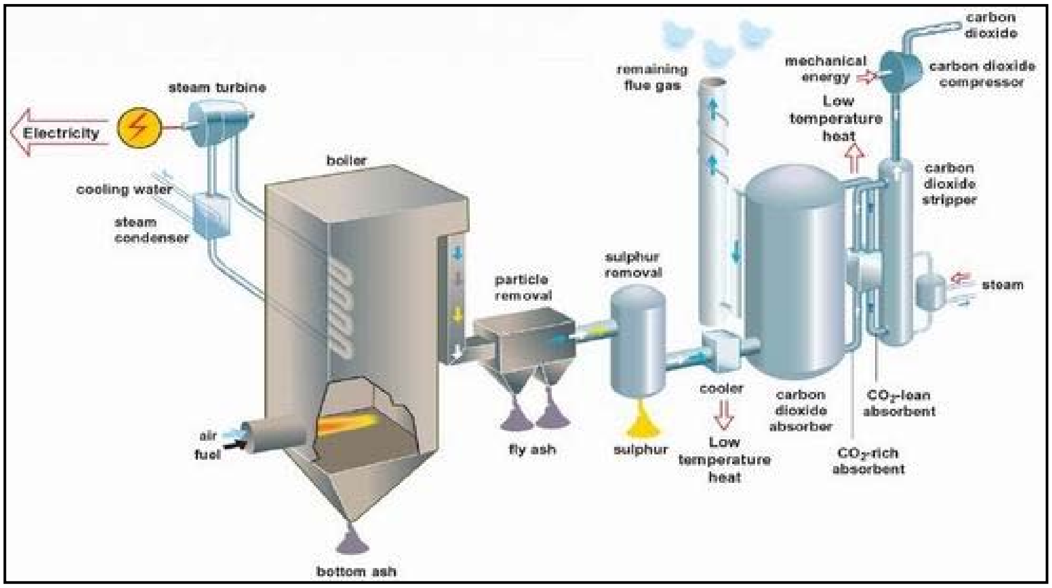
Source: EPRI 2009.

The post-combustion capture process can be seen in Exhibit 2-10. Low concentrations of CO_2 are first captured from the low partial pressure exhaust gas stream in an absorption tower, where flue gas is brought in contact with an absorbent solvent (e.g., amine or chilled ammonia). The CO_2 binds with the solvent at temperatures of 104–140 ºF. The flue gas, now separated from most of its CO_2, receives a water wash after which it heads to the stack. Meanwhile, a heat exchanger pumps the CO_2 'rich' solvent to the regeneration vessel (or stripper), which has slightly more than atmospheric pressure and temperatures ranging from 212–284 ºF. Under these conditions, the solvent begins the regeneration process and CO_2 is stripped. The heat supplied to the regeneration vessel to strip CO_2 from the solvent carries a significant energy cost.[30] The CO_2 is then cooled, dried, and compressed to a supercritical fluid, at which point it can be sequestered or used commercially.[31] After the removal of CO_2, the "lean" solvent is cooled and pumped back to the absorption tower by a heat exchanger to be used to capture again.[32]

The two post-combustion, carbon capture, absorbent solvents most under consideration at this time are organic amines and chilled ammonia. Carbon capture using organic amines, such as mono-ethanol amine (MEA), is state-of-the-art, commercially proven technology. Amine solvents can remove substantial amounts of CO_2 at low pressure and are relatively inexpensive. However, they are corrosive, have high degradation in the presence of oxygen, have high solvent losses due to fast evaporation, and require a significant amount of energy for regeneration.[33] NETL estimates suggest the low pressure steam requirements may reduce a unit's power output by 20–40 percent.[34]

[30] Center for Energy and Economic Development. *Carbon Capture*. 2007.
[31] National Coal Council. *Advanced Coal Technologies: Greater Efficiency and Lower CO_2 Emissions.* 2008.
[32] Center for Energy and Economic Development. *Carbon Capture*. 2007.
[33] Justin, Zachary, Ph.D., and Sara Titus. "CO_2 Capture and Sequestration Options – Impact on Turbomachinery Design." 2008.
[34] NETL, *Existing Coal Power Plants and Climate Change: CO_2 Retrofit Possibilities and Implications. 2008.*

Exhibit 2-10
Post-Combustion Carbon Capture Process (Absorption)



Source: Vattenfall.

Chilled ammonia carbon capture is another promising absorption technology still under development. Its carbon capture process is very similar to that of amine carbon capture, but it is oxygen- and sulfur-tolerant, and does not require flue gas to be as clean of contaminants nor does it have nearly as much parasitic load. The greater efficiency of the chilled ammonia carbon capture process can be attributed to its reduced heat of reaction energy needs (60 percent lower than MEA), its ability to regenerate without stripping steam, and its greater CO_2 absorptive capacity.[35]

One downside of chilled ammonia carbon capture is that its need for several absorber vessels increases its capital costs. Additionally, ammonia can be unstable and its rate of CO_2 absorption is slower than that of MEA. Lastly, chilled ammonia has more technological uncertainties associated with it when compared with MEA, given the lack of commercial-scale process experience at this time.[36]

E.ON and Siemens are expected to commence a joint amine pilot project in Germany in summer 2010, and Southern Company has expressed interest in an amine pilot in Mississippi. Alstom Power is the primary developer of chilled ammonia technology and currently has several pilot projects underway in North America and Europe. Exhibit 2-13 summarizes these and other pilot carbon capture projects.

2.3.3 Oxy-Combustion Carbon Capture

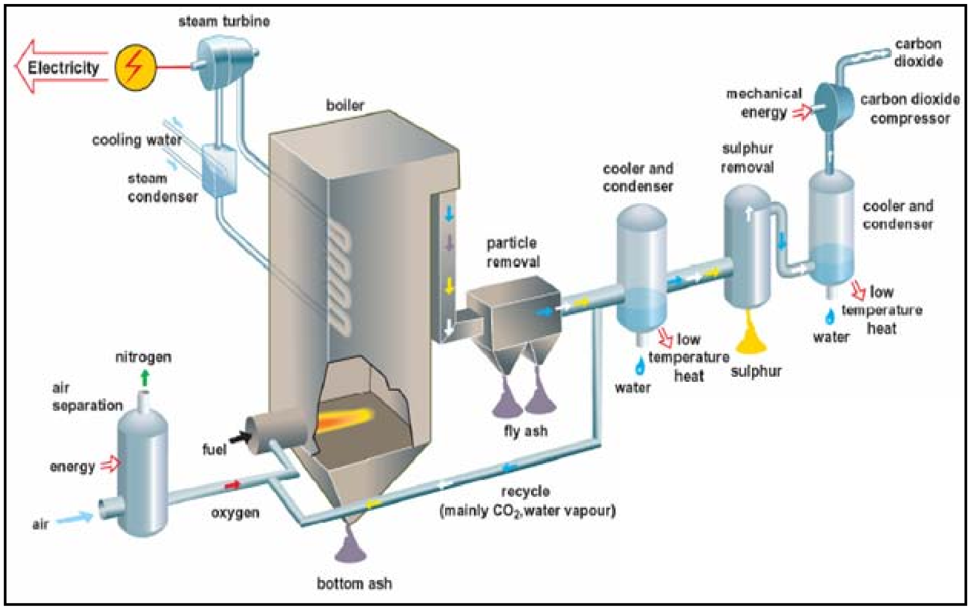
Another promising carbon capture approach is to use high-purity oxygen for combustion, to produce an extremely concentrated stream of CO_2 that is easily compressed and delivered by pipeline for sequestration. The oxy-combustion process, illustrated in Exhibit 2-11, begins with fuel being combusted in pure oxygen and recycled flue gas consisting of water vapor and CO_2.

[35] Ibid.
[36] Justin, Zachary, Ph.D., and Sara Titus. "CO_2 Capture and Sequestration Options – Impact on Turbomachinery Design." 2008.

The exhaust flue gas is then cleaned, after which it consists of mainly CO_2 and water vapor. Next, the flue gas is cooled and condensed, leaving nearly pure CO_2.[37]

By using the oxy-combustion process, the need for post-combustion CO_2 capture is avoided, thus lowering the cost of carbon compliance. Additionally, Hg emissions are reduced and NO_x emissions are estimated to be cut in half.[38]

Exhibit 2-11
Oxy-Combustion Carbon Capture Process



Source: Vattenfall.

One concern for this approach to carbon capture is that air may penetrate the system to the detriment of the process, creating the need for additional distillation after combustion to sufficiently purify the CO_2 in flue gas.[39] For an oxy-combustion-based power plant to be cost-effective, a low-cost supply of pure oxygen is needed. Although commercially available cryogenic air separation technology is both capital- and energy-intensive, several technologies are being developed that could greatly reduce costs. While many organizations are working to advance this technology, most of the completed and ongoing oxy-combustion pilot projects have been developed by Alstom.[40]

[37] Alstom, *Oxyfuel combustion capture*.
[38] Justin, Zachary, Ph.D., and Sara Titus. "CO_2 Capture and Sequestration Options – Impact on Turbomachinery Design." 2008.
[39] Ibid.
[40] NETL. *Innovations for Existing Plants: Oxy-Combustion CO_2 Control.*

2.3.4 Transport

The third cost of implementing CCS is transporting CO_2 to a storage location. Although CO_2 can be transported as a supercritical fluid in ships, trucks, and rail tankers, the most common method for transporting large volumes of CO_2 is via pipeline. Overall, the cost of transporting CO_2 is a small percentage of the total cost of CCS, thus the impact of transport cost uncertainty is relatively limited. For example, a 100 percent transport cost increase may in fact represent only a 10 percent increase in the total CCS cost. Distance is the main driver behind the total cost of transporting CO_2 because the cost of materials and construction are directly proportional to the transportation distance.[41] The longer the distance from the source to a CO_2 sink, the greater likelihood other sources could be networked into the pipeline and share transportation costs. ICF analysis indicates that if several power plants feed into a common pipe, costs could be as low as \$4.60/metric tonne of CO_2, or about \$0.03/mile per metric tonne of CO_2. Transportation technology is similar to natural gas pipelines and is mature. Significant changes are not expected in the near future.

2.3.5 Storage

Storage is the fourth and final additional cost component for CCS. The overall cost of storage, while not a major component of the CCS value chain, has the highest variability relative to other components, due to the range of possible characteristics of storage locations.[42] Capital expenditures make up the vast majority of storage costs (operating expenses are very small). An important driver of storage cost is the actual size of the storage site. Storage costs for a large field that services two plants simultaneously could be roughly one third lower than storage costs for a storage field that can only service a single plant.[43] Storage is possible in various types of geological formations.

There is an estimated 3,400 metric gigatonnes of CO_2 storage potential in the U.S. The geological formations with the greatest CO_2 storage potential in the U.S.[44] are non-basalt saline aquifers, which represent nearly 90 percent of total U.S. storage capacity. The remaining potential storage is distributed among the following (in order of most to least potential capacity): shale, basalt aquifers, depleted oil fields, depleted gas fields, unmineable coal, enhanced coal bed methane, and enhanced oil recovery. The South, West, and Plains areas of the country each have a significant amount of potential storage capacity, collectively representing 92 percent of the total U.S. storage capacity. Relative to these areas, the Midwest and Northeast are fairly limited in storage capacity.[45]

The only operating large-scale geologic storage project in North America is the Weyburn Enhanced Oil Recovery project in Canada, which stores CO_2 captured from the lignite-fired Dakota Gasification Company synfuels plant site in North Dakota. It annually captures and stores 1–2 million metric tonnes of CO_2.

2.3.6 Water Usage

Raw water usage for pulverized coal plants is dominated by cooling tower makeup requirements, which account for about 89 percent of raw water in NETL's non-capture cases

[41] McKinsey & Company. *Carbon Capture and Storage: Assessing the Economics.* 2008.
[42] Ibid.
[43] Ibid.
[44] http://www.swhydro.arizona.edu/archive/V8_N5/feature2.pdf
[45] NATCARB and ICF International Analysis. 2009.

and 92 percent of raw water in its CO_2 capture cases. The raw water used in the CO_2 capture cases is greatly increased by the cooling water requirements of the amine process. The additional cooling water required by the capture process is needed to

- Reduce the flue gas temperature from the FGD exit temperature to the amine absorber operating temperature;
- Remove the heat input by the stripping steam to cool the solvent;
- Remove the heat input from the auxiliary electric loads; and
- Remove heat in the CO_2 compressor intercoolers.[46]

NETL estimates that significantly more water in absolute terms is needed by PC units with carbon capture than PC units without carbon capture. With the addition of carbon capture, NETL estimates that total water demand will increase from 10 to 21.6 gallons per minute per megawatt-hour (GPM/MW) for its modeled SCPC unit.[47]

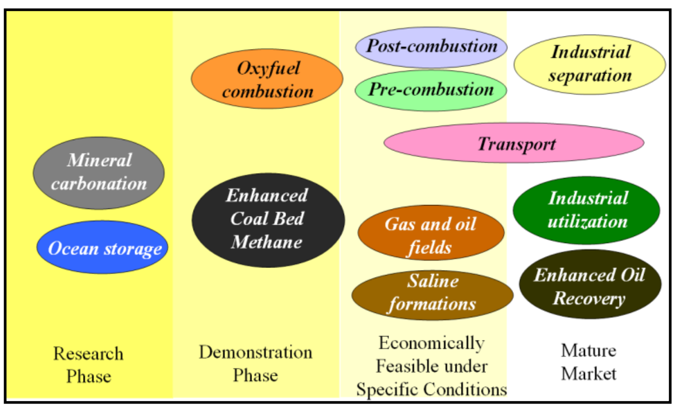
2.3.7 Retrofitting

In general, retrofitting an existing power plant would lead to a higher carbon capture capital cost. The costs are highly dependent on the specific site characteristics, including plant specifications, remaining economic life, and overall site layout. Retrofitting CCS is unlikely for plants older than twelve years since the total carbon capture costs of such plants would be at least 30 percent higher than those of new power plants. However, if the plant was built as capture-ready, and the retrofit planned to minimize downtime, the additional costs could be 10 percent or even lower.[48]

2.3.8 Status of CCS Component Technologies

Commercial scale carbon capture and storage technologies are still several years away from achieving economic viability. Exhibit 2-12 gives an overview of the relative status of these technologies.

Exhibit 2-12
Status of CCS Component Technologies RD&D



Source: ICF International.

[46] NETL. *Cost and Performance Baseline for Fossil Energy Plants*. 2007.
[47] Ibid.
[48] McKinsey & Company. *Carbon Capture and Storage: Assessing the Economics.* 2008.

Many experts[49] believe these technologies could potentially be commercially available by 2020 and could approach a mature stage around 2030. The most noticeable changes expected to accompany the maturation of these technologies include greater storage flexibility, capacity factor enhancement, economic life extension, and a decrease in LCOE.[50]

2.3.9 CCS Pilot Projects around the World

In terms of post-combustion capture in the U.S., the most important plant is the Wisconsin Energy 1.7 MW CCS pilot project at its Pleasant Prairie subcritical coal plant, which began in 2008. The pilot implements Alstom's chilled ammonia-based absorption system to remove CO_2. Early on, the power-intensive test only captured 1 percent of the plant's carbon emissions; however, Alstom recently reported the project is now capturing 88–90 percent of its carbon emissions.[51] Exhibit 2-13 provides an overview of several post-combustion CCS pilot facilities that have recently been announced, begun construction, or commenced operations. AEP's 20-MW chilled-ammonia pilot at its Mountaineer facility is currently under construction. It is expected to commence operations in September 2009 and will build upon the results of the Pleasant Prairie pilot.

Exhibit 2-13
Anticipated Post-Combustion CCS Pilot Projects

Developer	Project	Location	Size (MW)	Technology	Proposed Online Date
EON & Siemens	Staudinger	Germany	1	Siemens Amino Acid Salt	2009
AEP	Mountaineer	West Virginia	20	Alstom Chilled Ammonia	2009
Vattenfall & GDF Suez	Schwarze Pumpe	Germany	30	Alstom SA Oxyboiler	2009
CS Energy	Callide 'A'	Australia	30	Oxyfuel	2009
RWE Power	Niederaußem	Germany	TBD	BASF Amine	2010
Clean Energy Systems	Kimberlina	California	50	Oxyfuel	2010
AEP	Northeastern	Oklahoma	200	Alstom Chilled Ammonia	2011
Sargas	Sargas Husnes	Norway	400	TBD	2011
NRG/Powerspan	WA Parish	Texas	125	Powerspan Non-Chilled Ammonia	2012
TransAlta	Pioneer	Canada	125	Alstom Chilled Ammonia	2012
Scottish & Southern Energy	Ferrybridge	UK	500	Unspecified Post-Combustion	2012
Basin Electric	Antelope Valley	North Dakota	120	Powerspan Ammonia	2012
RWE Npower	Tilbury	UK	1600	Unspecified Post-Combustion	2012
Tenaska	Tenaska	Texas	600	Unspecified Post-Combustion	2014

Sources: IndustrialInfo.com, EPRI, and MIT CCS Technologies Program.

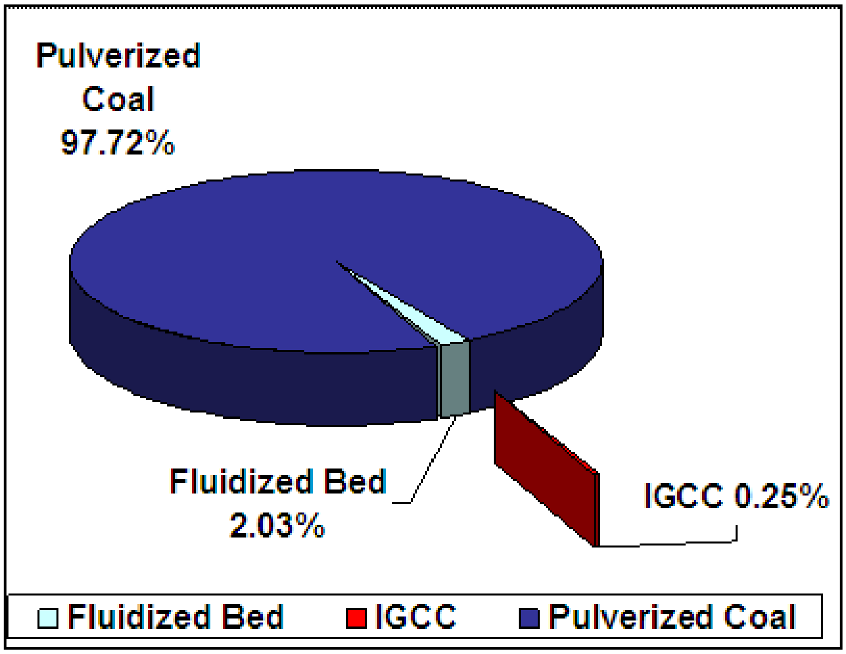
Many demonstration facilities, which serve as the link between a pilot- and a commercial-scale plant, are expected to commence operations around 2015.

[49] http://www2.goldmansachs.com/ideas/environment-and-energy/partnerships/capturing-king-coal-doc.pdf
[50] McKinsey & Company. *Carbon Capture and Storage: Assessing the Economics.* 2008.
[51] Ball, Jeffrey. "Coal Hard Facts: Cleaning It Won't Be Dirt Cheap." 2009, and Continued Power Engineering Magazine. "Carbon Capture Project Posts 'Encouraging' Results." 2009.

Chapter 3
Integrated Gasification Combined Cycle

IGCC systems are one of the clean coal technologies being pursued by power plant developers in the U.S. Although the share of IGCC in the current U.S. coal capacity is less than 1 percent, as shown in Exhibit 3-1, efforts are ongoing to deploy the coal gasification technology extensively through both re-powering of old pulverized coal plants and developing new greenfield IGCC units.

Exhibit 3-1
U.S. Installed Coal Capacity by Plant Type



Source: Ventyx 2009.

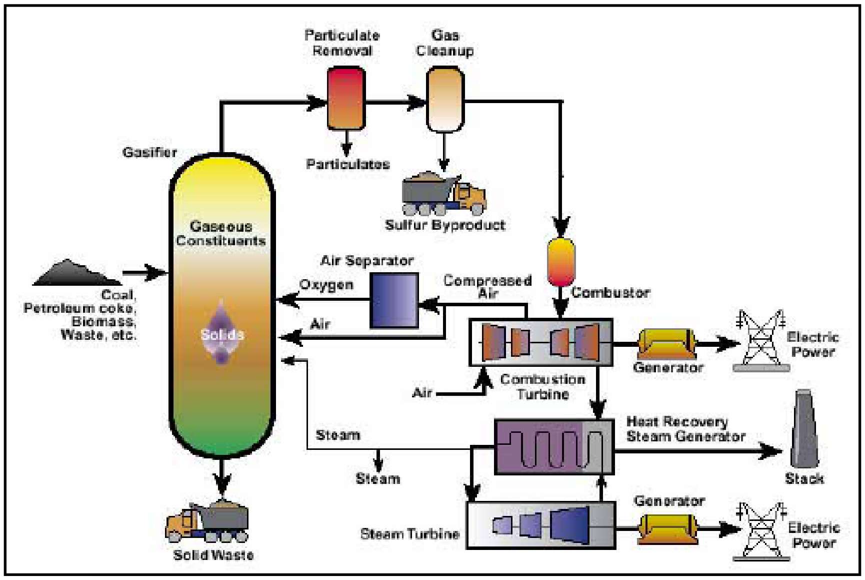
3.1 Technology Overview

IGCC is a power generation process that integrates a gasification system with a combustion turbine combined cycle power block. The gasification system converts coal (or other solid or liquid feed-stocks such as petroleum coke or heavy oils) into a synthetic gas (syngas), which is primarily composed of hydrogen (H_2) and carbon monoxide (CO). This combustible syngas is used to fuel a combined cycle power block to produce electricity. Exhibit 3-2 provides a simple diagram of the major components of an IGCC power plant.

Many of the components of IGCC are associated with processes that are already in wide commercial use in the power, refining, or chemicals industries. For example, the CC power block of an IGCC employs the same turbine and heat recovery technology used extensively around the world to generate electricity with natural gas. Only minor adjustments are needed to account for the lower energy content of syngas. Modern gasifiers have been used in the chemical industry since the 1950s and have consistently shown a high availability factor.

One of the potential advantages of IGCC technology is that capturing CO_2 from these plants could be easier than capturing it from conventional coal plants. This is because the chemical processes to separate CO_2 from other gases requires less energy when operating on the more concentrated CO_2 streams found in IGCC's syngas.

Exhibit 3-2
IGCC Technology



Source: NETL.

3.2 Types of Gasifiers

Gasifiers convert carbon-based feedstocks (such as coal, petroleum coke, or heavy oils) into gaseous products at high temperatures (2,000–3,000 °F) and elevated pressures (400–1,000 psi). Gasification occurs in the presence of oxygen or air and steam in a reducing environment where only enough oxygen is supplied for an incomplete combustion of the fuel feedstock. In this reducing environment, partial oxidation of the feedstock produces syngas and generates heat.

IGCC systems can incorporate a number of gasifier designs, but all are based on one of three generic configurations:

- ***Entrained-Flow Reactors*** – In entrained-flow systems, PC particles are reacted with steam and oxygen at high temperatures. These systems can gasify all coals regardless of rank, but may use different coal feed (dry or water slurry) and heat recovery systems.[52] All IGCCs currently operating in the U.S. use this reactor design. Lead developers of this technology include GE, ConocoPhillips, and Shell.

- ***Moving-Bed Reactors*** – In moving-bed reactors, large particles of coal move slowly down through the gasifier while reacting with gases moving up through the feedstock. Several different "reaction zones" accomplish the gasification process.

[52] Rosenberg, G. William, et al., *Deploying IGCC in this Decade with Three Party Covenant, Volume 1*, Harvard University, 2004.

The Lurgi dry-ash and British Gas/Lurgi gasifier designs employ this technology and are currently operating at several facilities in Europe.

- ***Fluidized-Bed Reactors*** – Fluidized-bed reactors efficiently mix feed coal particles with coal particles already undergoing gasification in the reactor vessel. Coal is supplied through the side of the reactor, and oxidants and steam are supplied near the bottom of the reactor. Some major fluidized bed gasifiers used include the High Temperature Winkler and Kellogg-Rust-Westinghouse designs. Few of these systems are currently in operation. Fluidized bed reactors are a combination of two common continuous flow reactors. Because of their excellent heat and mass transfer characteristics, fluidized bed reactors are ideal for highly exothermic reactions as they eliminate local hot-spots.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers, as they produce no hydrocarbon liquids, and the only solid waste is an inert slag. The relatively high H_2/CO ratio and high CO_2 content of syngas produced by entrained-flow gasifiers helps achieve low NO_x and CO emissions even in the higher-temperature advanced combustion turbines.[53]

3.3 Operating IGCC Facilities

Currently, there are only three "commercial-scale" IGCC facilities operating in U.S. The major characteristics of these facilities are described below in Exhibit 3-3.[54]

Exhibit 3-3
Characteristics of U.S. Operating IGCC Facilities

Plant Name	Wabash Power Station	Polk Power Station	Delaware City
Owner	**Wabash Valley Power Association**	**Tampa Electric**	**Valero**
Location	Indiana, US	Florida, US	Delaware City
Capacity (MW net)	262	250	240
Gasifier	ConocoPhillips	GE Energy	GE Energy
Gas Turbine	GE-7FA	GE-7FA	GE-6FA
Efficiency (% HHV)	39.7	37.5	
Heat rate (Btu/KWh HHV)	8,600	9,100	8,000
Fuel Feedstock	Bit. coal/ pet coke	Bit. coal/ pet coke	Pet Coke
Particulate control	Candle filter	Water scrubber	Water Scrubber
Acid gas clean-up	MDEA scrubber	MDEA scrubber	
Sulfur recovery	Claus plant	H2SO4 plant	
Sulfur by-product	Sulfur	Sulfuric acid	
Sulfur Recovery (%)	99% design	98% design	
NOx control	Steam dilution	Nitrogen & steam dilution	

Source: Deploying IGCC in this decade with 3 party covenants financing, July 2004, Harvard.

[53] NETL, DOE, *Cost and Performance Baseline for Fossil Energy Plants*, 2007.
[54] Currently the view of commercial size is a 2x1 configuration with a capability of approximately 500 MW.

3.3.1 Wabash Power Station

Commencing operations in 1996, the Wabash Power Station in Indiana is the oldest IGCC plant in the country. The project was initiated in 1991 as a DOE Clean Coal Technology program demonstration project. Construction began in 1993 and was completed in two years. The project re-powered an existing coal power plant by adding a gasification island and combustion turbine (CT).

The 260-MW facility utilizes the ConocoPhillips gasification process, which is based on an entrained-flow, oxygen blown, two-stage gasifier that uses natural gas for start-up. The facility was designed to use bituminous coal, which it did for its first three years of operation; however, it has since switched to petroleum coke, which has been much cheaper than coal in recent years. The total plant investment was $538 million[55] ($2,052/kW in mid-2008 dollars).

Between 2000 and 2008, it had an average capacity factor of 22 percent[56] with its highest level of generation in 2002, when it reached a 54 percent capacity factor. The plant has been running at very low capacity factors since 2004, when it switched from coal to natural gas.

3.3.2 Polk Power Station

The Polk Power Station is a 250-MW IGCC plant built by Tampa Electric Company based on the entrained-flow, oxygen-blown GE Energy gasification technology. Construction on the greenfield Polk Station began in October 1994 and finished in approximately two years.

Polk Power Station utilizes a variety of bituminous coals as well as petroleum coke/coal mixtures. The total direct cost of the project in 2008 dollars was $534 million ($2,135/kW).[57] Tampa Electric estimates that by incorporating the lessons it has learned, it could build the facility for 8 percent less than it originally cost.[58]

The plant's availability improved steadily from just over 60 percent in 1998 to 80 percent in 2000. In 2001, two unplanned outages decreased its availability to 70 percent, but it increased back to 74 percent in 2002. If distillate oil is used as a backup, the facility can achieve an availability of about 90 percent. The overall average capacity factor between 2002 and 2008 of the Polk Power station was 67 percent.[59]

3.3.3 Delaware City

The latest IGCC plant built in the U.S. is at the Premcor Refinery located in Delaware City, Delaware. Similar to the Wabash facility, this project was also designed as a re-powering project that used the existing steam turbines at the site and reconfigured them into an IGCC plant. The plant was designed to use only petroleum coke that was produced during the refining process to generate 240 MW of electric power and process steam.[60] The project uses two GE

[55] DOE, *The Wabash River Coal Gasification Repowering Project, an Update*, Clean coal technology topical report number 20, 2000.
[56] SNL.
[57] NETL, DOE, *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report*, 2002.
[58] Ibid.
[59] SNL.
[60] Hawley F. Roger, *Delaware City Refinery repowering project overview and project status*, 2000 Gasification Technologies Conference, California, 2000

oxygen-blown gasifiers and an acid-gas-removal process to produce clean syngas for two GE-6FA combustion turbines and heat recovery steam generators. The power block was commissioned in March 2000 and it uses low-sulfur diesel as back-up fuel. Historically, the plant has run at an approximate 19 percent capacity factor over the 2003–2008 period.[61] Due to chronic maintenance problems and the current recession, this IGCC has been temporarily shut down.

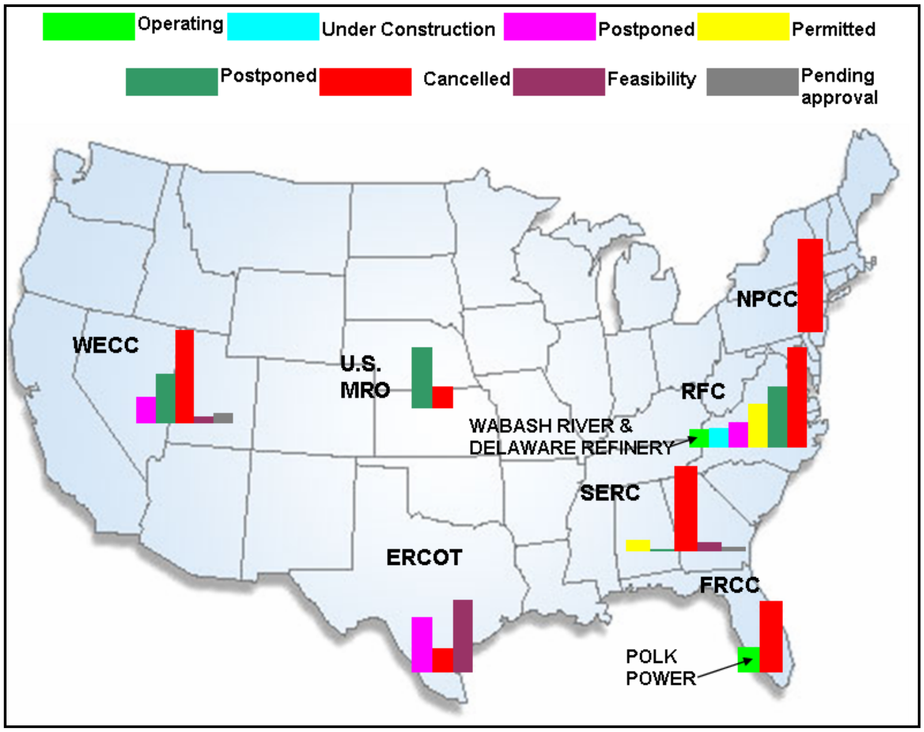
3.4 The Next Tranche of IGCC

There is only about 4,100 MW of gasification-based, electric generating capacity in the world, of which 900 MW[62] are in the U.S. A few years ago, there was a surge in interest in IGCC, but the interest of developers has been recently waning due to their concerns over financing and climate change regulations. Although major growth is still expected over the next few decades, the extent of IGCC deployment is mostly dependent upon the advancement of CCS technology. CCS technology development has also slowed down considerably in light of DOE's 2008 cancellation of the FutureGen demonstration project. The enthusiasm for IGCC projects has been further tempered as the EPA and other government entities are still grappling with drafting federal policies for underground injection of CO_2. The developers consider it an open-ended risk to pursue IGCC at present, with underground carbon storage issues unresolved. With climate change legislation not yet a certainty, coal gasification plants are also facing a tough time winning regulatory approval, and many have been either tabled or canceled in the U.S.

Exhibit 3-4 shows the status of IGCC facilities in the U.S., by North American Electric Reliability Corporation (NERC) sub-region. Overall, 900 MW of IGCC capacity[63] is currently operating in the U.S., with an additional 630 MW under construction. About 33,567 MW of new IGCC plants have been proposed so far, out of which 2,000 MW have been permitted, 6,500 MW have been postponed, and 3,500 MW are under pending feasibility approval status. Due to the large uncertainty associated with IGCC, both in terms of technology and costs, 17,900 MW of capacity have been cancelled.[64]

[61] Ventyx Solutions Database, 2009
[62] Ibid
[63] Net Dependable Capacity
[64] Ventyx Solutions database 2009

Exhibit 3-4
Current Status of IGCCs in the U.S.



Source: Ventyx Solutions, 2009.

A few companies are still planning commercial-scale IGCC facilities despite current uncertainties, which is important since it usually takes several years to get a project permitted and financed. The work on three proposed facilities in Midwestern states is progressing. These three IGCCs are all within about 150 miles of one another, and all could be operating within a decade. These three proposed facilities are discussed in more detail below.

3.4.1 Duke Energy – Edwardsport

Duke Energy's 630-MW Edwardsport project will be one of the cleanest and most efficient coal-fired power plants in the world[65]. Duke expects the facility to be operational by the summer of 2012; as of March 2009, 20 percent of the project had been completed.[66] (Bechtel Power is the engineering procurement and construction (EPC) contractor). The project will use GE's gasification technology. In January 2009, the Indiana Utility Regulatory Commission (IURC) approved a revised cost estimate of $2.35 billion or $3,730/kW for the project[67]. Duke also recently filed a petition with the IURC to study carbon sequestration at the site. Duke has already received approval to study the feasibility of 18 percent carbon capture at the site.

[65] http://cleantech.com/news/4818/duke-energy-china%E2%80%99s-top-utility-ink; http://sustainabilityreport.duke-energy.com/environmental/diversification.asp
[66] Barber, Wayne, *Amid coal plant cancellations, Midwest IGCCs remain viable*, SNL, 2009.
[67] Ibid.

3.4.2 Tenaska – Taylorville Energy Center

Tenaska has hired two leading firms to do the front-end engineering design (FEED) study and facility cost report for its 525-MW Taylorville Energy Center. Under new state legislation known as the Illinois Clean Coal Portfolio Standards Act, the FEED study and facility cost report will be submitted to the Illinois Commerce Commission and Illinois General Assembly for possible funding support. Total capital cost is currently estimated at $3.5 billion or approximately $6,667/kW.[68] Tenaska aims to start construction in 2010.

3.4.3 FutureGen

The FutureGen project is a near-zero emissions facility designed to burn coal and capture 90 percent of its greenhouse gas emissions, while producing hydrogen for power generation. It is based on a 275-MW coal gasification power plant combined with CCS. The DOE and FutureGen Industrial Alliance, Inc. planned to fund the project jointly.

The project, which was a centerpiece of the Bush administration's carbon research program, was cancelled in early 2008 by the DOE after the project cost was estimated to have nearly doubled from $950 million to $1.8 billion. However, it was later discovered that the project costs were greatly overestimated due to inflation and commodity cost adjustment errors[69].

Several Illinois congressmen have worked to keep the FutureGen IGCC project alive, and Energy Secretary Steven Chu appears to be taking a fresh look at it. The new leadership at the DOE could support FutureGen with some modifications to fit into the government's research portfolio.

3.4.4 Excelsior – Mesaba

Excelsior's Mesaba Energy Project is to be built in two phases, both of which are currently postponed. This proposed $2 billion[70] project, based on ConocoPhillips' E-Gas gasifier technology, would have added an additional 1,482 MW to the power supply.[71] The Mesaba plant would initially capture 30 percent of its CO_2 emissions and transport it via a yet-to-be-developed pipeline to the Williston Basin in North Dakota for enhanced oil recovery. Excelsior hopes to see the final federal environmental impact statement for Mesaba issued in the last quarter of 2009.[72] Also, there is a PPA to be negotiated for Phase I between Excelsior and Xcel Energy. In fact, this lack of agreement on the PPA is the primary reason the project is currently on hold.

Because Xcel Energy has not yet agreed to sign a PPA with Mesaba, Excelsior's ability to receive additional federal financial support and attract private investors has been called into

[68] Ibid.

[69] FutureGen was the subject of reports released March 10, 2009, by the House Science and Technology Committee and the U.S. Government Accountability Office, which concluded there had been no valid basis for the decision to stop the project. According to the GAO report, the DOE made its 2008 decision largely on the conclusion that costs for the original FutureGen had doubled and would escalate substantially. However, in its decision, DOE compared two cost estimates for the original FutureGen that were not comparable because DOE's $950 million estimate was in constant 2004 dollars and the $1.8 billion estimate of DOE's industry partners was inflated through 2017.

[70] Bily, Beth, *Excelsior Energy targets municipal PUCs in search for a buyer as key May 1 deadline looms, 2009*, http://www.businessnorth.com/exclusives.asp?RID=2934.

[71] Ventyx Solutions Database, 2009.

[72] Barber, Wayne, *Duke Energy, Excelsior Energy proceed with IGCC Project*, SNL, 2008.

question. Since failing to negotiate a PPA with Xcel, Excelsior Energy has also turned to city/local governments in the hope of financial rescue for Unit I of the Mesaba Project.[73]

3.4.5 NRG – Somerset

There is also an ongoing effort in the Northeast by NRG to convert an old 109-MW pulverized coal plant, Somerset Unit 6, to an IGCC using plasma gasification.[74,75] NRG Energy has agreed to either shut down or re-power Unit 6 by January 2010. Re-powering Somerset will cut SO_2 and Hg emissions by 95 percent and NO_x emissions by over 60 percent. Opponents of the re-powering lost an initial appeal in 2007 before the Massachusetts Department of Environmental Protection, which granted NRG permission to retrofit the plant with experimental coal gasification technology without requiring the plant to undergo an environmental review. Currently the Conservation Law Foundation has announced that it will sue in federal court to try and stop the repowering effort.[76]

3.5 Suppliers and Manufacturers

As described earlier, nearly all commercial IGCC systems in operation or under construction are based on entrained-flow gasifiers. Commercial entrained-flow gasifier systems are available from GE Energy Gasification Technologies (GE Energy), ConocoPhillips, Shell, PRENFLO™, and Noell. The different design features of the major manufacturers are listed in Exhibit 3-5, and a brief discussion of their main features follows the table.

Exhibit 3-5
Major Design Features of Main Suppliers

Technology Name/Design Feature	GE Energy (Formerly Texaco)	E-Gas (ConocoPhillips)	Shell
Feed System	Coal in Water Slurry	Coal in Water Slurry	Dry Coal, Lock Hopper & Pneumatic Conveying
Gasifier Configuration	Single Stage Down flow	Two Stage Up flow	Single Stage Up flow
Plant Efficiency (%)	38.2	39.3	41.1
CO2 emissions	197	199	200
Raw Water Usage (GPM)	4003	3757	3792
Gasifier Wall	Refractory	Refractory	Membrane Walll
Pressure (psig)	500-1000	Up to 600	Up to 600

Source: *Cost and Performance Baseline for Fossil Energy Plants*, NETL, DOE, August 2007.

3.5.1 GE Energy

The GE Energy gasification process has the most extensive track record in IGCC applications. Originally developed by Texaco in the 1950s, the technology was purchased by GE from Chevron-Texaco in 2004. The process uses an entrained-flow, refractory-lined gasifier that can operate at pressures in excess of 900 psi. The coal is fed to the gasifier as coal-water slurry and injected into the top of the gasifier vessel. Syngas and slag flow out the bottom of the gasifier.

The GE Energy gasifier uses a unique radiant syngas cooler system through which the hot syngas is initially passed and cooled. This syngas is then further cooled through a water

[73] *CAMP cautions municipal utilities about Mesaba project*, April 17, 2009. < www.camp-site.info\news.html>

[74] Plasma gasification is the gasification of matter in an oxygen-starved environment to decompose waste material into its basic molecular structure. Plasma gasification does not combust the waste as incinerators do. It converts the organic waste into a fuel gas that still contains all the chemical and heat energy from the waste.

[75] SNL.

[76] Dion, Munroe Marc, Herald News, April 22, 2009.

quench process prior to entering the syngas scrubber. The use of radiant syngas cooler results in increased output and higher efficiency.

Since the 1950s, more than 100 commercial applications of the GE Energy gasification process have been licensed, which is a key advantage of GE Energy's gasification technology. The process has been used in several coal and petroleum coke-to-chemicals applications. Another advantage is that the gasifier operates at an extremely high pressure, which facilitates economic CO_2 separation from a relatively small volume of syngas. This makes the technology more efficient for CCS and reduces equipment costs.

High operating temperatures, the need for relatively high oxygen requirements, limited refractory life and the high waste heat recovery duty cycle are the main disadvantages of this gasification technology. The GE Energy process also has limited ability to handle low-rank coals economically relative to moving-bed and fluidized-bed gasifiers, as well as to entrained-flow gasifiers with dry feed.[77]

3.5.2 Shell

Shell began developing its dry-feed entrained-flow gasification process in the 1950s, and in the mid-1970s it formed a joint project venture with Krupp Koppers. However, by the early 1980s, both companies agreed to go their separate ways in the development of coal gasification. Krupp Koppers has since developed a competing dry-feed, membrane-wall gasifier with the trade name PRENFLO™.[78]

One of the major achievements of the Shell gasifier is its successful gasification of a wide variety of coals, ranging from anthracite to brown coal. The feed flexibility is achieved by the usage of a more expensive dry-feed system (as opposed to slurry-fed). This feed flexibility eliminates the impact of moisture on the gasifier performance and also extends the range of the gasifier to low rank coals. The dry-pulverized-feed system developed by Shell uses all coal types with essentially no operating or design modifications.

This ability to feed dry solids minimizes the oxygen requirement and makes the Shell gasifier somewhat more efficient than entrained-flow gasifiers employing slurry-feed systems. The penalty paid for this increase in efficiency is a coal-feed system based on lock-hoppers that is more costly and operationally more complex. The biggest disadvantage of the Shell process has been its higher capital cost, which is inherent in the gasifier design (boiler tubes are more expensive than refractory brick) and dry-feed system. Another disadvantage of the Shell technology is the high waste heat recovery (synthesis gas cooler) duty cycle.[79]

3.5.3 ConocoPhillips E-Gas

ConocoPhillips owns the E-Gas gasification technology originally developed by Dow Chemicals in the mid-1970s. The E-Gas process features a unique two-stage gasifier design. E-Gas can use a fire tube boiler because the two-stage design reduces the gas temperature and drops the syngas temperature into a range where a radiant cooler is not needed. The gasifier is refractory-lined and uses a coal-water-slurry feed.

[77] NETL, DOE, *Cost and Performance Baseline for Fossil Energy Plants*, 2007.
[78] Phillips, Jeffrey, Different Types of Gasifiers, EPRI.
[79] NETL, DOE, *Cost and Performance Baseline for Fossil Energy Plants*, 2007.

Efficiency improvements and reduced oxygen requirements are a few of the key advantages that this ConocoPhillips technology offers. This is primarily due to the two-stage gasifier design, which enables better operation on slurry feeds as compared to single stage (i.e., GE Energy design). Furthermore, like all entrained flow designs, this technology produces only inert slag as a solid waste and no hydrocarbon liquids. Finally, the fire-tube boiler design used by E-Gas has a lower capital cost requirement than a water tube design. There has been operational experience as both the Wabash and now-retired Plaquemine plants used the E-Gas technology.[80]

Due to its high operating temperature in the first stage, the E-Gas gasification technology has a short refractory life and also high waste-heat recovery duty. The quenched syngas, produced by the two-stage gasifier, also has higher methane content, which passes through the sour gas water shift reactors without any change. This limits the amount of carbon that can be captured and, hence, becomes a disadvantage when carbon capture is considered.[81]

3.6 Current Status of Commercialization of Technology

Historically, IGCC has remained commercially unattractive as it is a more risky and expensive alternative to conventional coal combustion. However, over the last few years, as climate change regulations have begun to appear inevitable in the U.S., IGCC has gained considerable attention from both industry and government in the U.S.

Major gas turbine vendors also see the carbon-constrained market environment as an opportunity to leverage their combined cycle gas turbine (CCGT) technology to capture market share of coal plants, especially at a time when natural gas price volatility threatens long-term competitiveness of their traditional CCGT business.

Major gas turbine players, particularly GE Energy, Mitsubishi, and Siemens, have all entered the IGCC market, investing substantial resources to develop commercial solutions to overcome the cost and technological hurdles facing IGCC. The goal is to incorporate the technological lessons learned from the previous generation of projects, while standardizing plant designs and partnering with EPC firms for turnkey plant delivery to companies. This is aimed at driving down costs by transferring risk from the customer to the supplier. Gas turbine machines currently supplied for syngas are up to F-class or equivalent. Gas turbine suppliers are preparing to make available advanced turbines for firing with hydrogen-rich syngas. Such turbines will be needed for CO_2 capture in IGCC.

To this end, these three manufacturers are developing reference plants using their gasification technology to achieve cost reductions. Mitsubishi is using a two-stage, entrained, air-blown gasifier in its design to reduce parasitic losses associated with the air separation requirements. Siemens acquired the Sustec gasification technology in the past few years. Siemens' designs have yet to penetrate the U.S. market but are being licensed in China. The reference plants from the three turbine original equipment manufacturers (OEMs) are typically using a 2x1 power island with either the F or G turbine technology. Plant capacity will be in the 500–600 MW range.[82]

[80] Ibid.
[81] Ibid.
[82] Gas Turbine World, January 2007.

The need for a complete plant package is also not lost on the OEMs. A few years ago, NRG was very active in IGCC development in New York, Delaware, and Texas. NRG initially selected Shell as its gasification partner. However, NRG switched to Mitsubishi, as it was able to offer overall plant performance warranties and long-term maintenance contracts — key elements needed to obtain financing.[83]

3.7 Cost and Performance Characteristics

High capital costs are probably the largest inhibitor to market penetration of IGCC. Capital costs are high for IGCC relative to other combustion technologies, and increasing IGCC's reliability and fuel flexibility is likely to increase its capital cost further. IGCC plant designs are very sensitive to fuel characteristics such as heating value and sulfur, ash, and moisture content. This sensitivity often makes it difficult to maximize efficiency while also increasing plant fuel flexibility.

Exhibit 3-6 illustrates cost and performance parameters for state-of-the-art IGCC plants, based on NETL and EPRI estimates. These estimates have been tabulated for three gasifier technology types: Shell, GE Energy, and ConocoPhillips.

Exhibit 3-6
Cost and Performance Parameters for IGCC without CCS (Mid-2006$)

	NETL			EPRI		
	20 Year Levelized			30 Year Levelized		
Technology	**Shell**	**GEE**	**Conco**	**Shell**	**GEE**	**Conco**
Net MW	636	640	623	620	600	612
Total Plant Cost (TPC $/kW)	1,951	1,789	1,710	2,234	1,894	1,938
Total Capital Requirement (TCR $/kW)	-	-	-	2,658	2,254	2,306
Fixed O&M ($/kW-yr)	34.7	34.8	34.8	78.2	72.0	73.6
Variable O&M ($/MWh)	6.2	6.4	6.3	1.0	1.0	1.0
Heat Rate(Btu/kWh HHV)	8,306	8,922	8,681	8,466	9,600	8,870
Net Plant HHV Efficiency (%)	41.1	38.2	39.3			
Capacity Factor(%)	80	80	80	80	80	80
Fuel Price ($/MMBtu)	1.8	1.8	1.8	1.5	1.5	1.5
Capital Recovery Factor	0.19	0.19	0.20	0.12	0.12	0.12
Capital ($/MWh)	53.5	49.7	47.6	38.3	32.4	33.2
O&M ($/MWh)	11.2	11.4	11.2	1.1	1.1	1.1
Fuel ($/MWh)	14.8	15.9	15.5	12.7	14.4	13.3
Total LCOE ($/MWh)	79.4	77.0	74.3	52.1	47.9	47.6
CO2 (Emitted lbs/MWh)	1409	1459	1452	1714	1944	1796
NOX (lbs/MWh)	0.41	0.41	0.43			
SOX (lbs/MWh)	0.07	0.09	0.09			
Hg (lbs/MWh)	4.03E-06	4.24E-06	4.16E-06			

Sources: NETL 2007 and EPRI 2006.

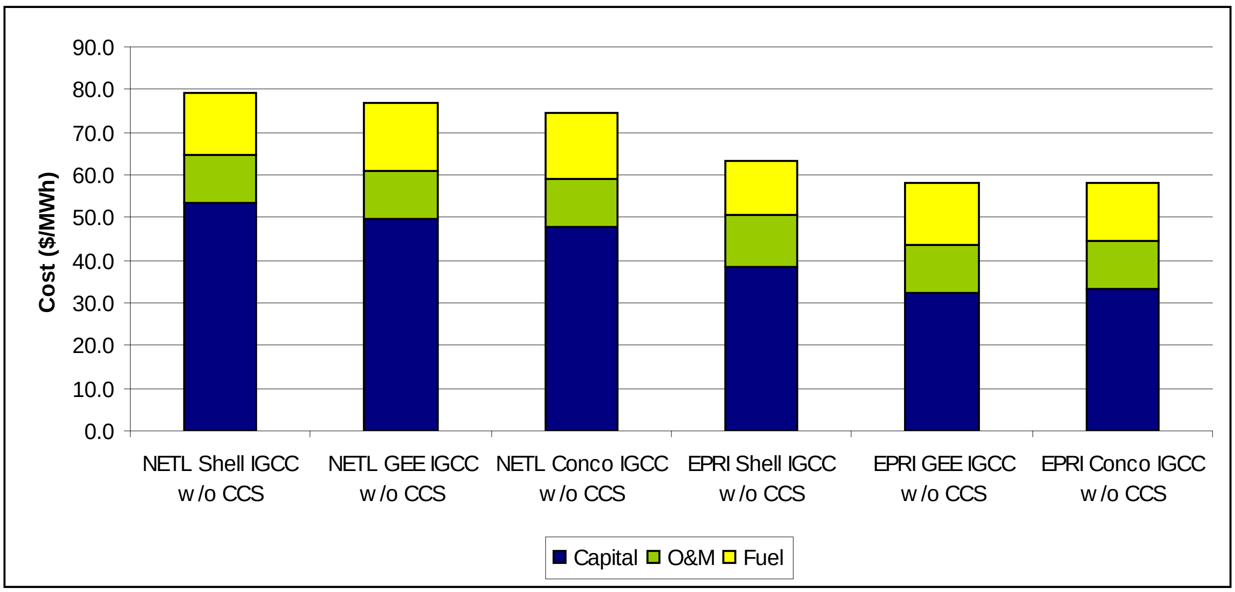
Among the IGCC technologies, both NETL and EPRI estimates show that the LCOE is highest for Shell technology. This is primarily because of higher capital costs for the Shell gasifier. NETL estimates the cost of an IGCC plant using the Shell gasifier to be approximately 10 percent higher than that of a plant using the GE Energy gasifier. As described earlier, this is primarily due to the higher cost of the dry coal injection system used in the Shell gasifier, as

[83] Ibid.

compared to slurry prep and feed system used in GE Energy's gasifier. The benefit of the higher capital cost gasifier is a more efficient process (Shell's heat rate is 8,300 Btu/kWh while the lower cost GE is 8,900 Btu/kWh). At $1.78 / MMBtu for feedstock cost, this reduces the fuel cost incurred but does not outweigh the higher capital cost, which eventually makes the LCOE for Shell technology the highest. Clearly, at higher feedstock prices, the Shell process would be less expensive than the GE Energy process. The O&M cost, according to NETL estimates, is almost the same across the technologies.

Exhibit 3-7 provides a visual breakdown of the LCOE.

Exhibit 3-7
Levelized Cost of Electricity LCOE ($/MWh)



The ConocoPhillips IGCC unit has an approximately 4 percent lower LCOE than that of the GE Energy unit, due to both the lower capital cost and lower fuel cost for ConocoPhillips (ConocoPhillips's heat rate is 8,700 Btu/kWh, while GE's is 8,900 Btu/kWh). The lower capital cost of a ConocoPhillips unit is primarily due to the lower costs of the gasifier and accessories. One of several features that contribute to its lower cost is its fire tube syngas cooler, which is much smaller and less expensive than the radiant cooler design used in the GE gasifier. Furthermore, the two-stage operation of the ConocoPhillips gasifier improves efficiency, reduces oxygen requirements, and enables more effective operation on slurry feeds relative to a single-stage gasifier.[84]

As mentioned in Chapter 2, it is important to note that EPRI provides a 30-year levelized LCOE, while NETL provides a 20-year levelized LCOE. This is a major reason why EPRI's estimates are lower than those of NETL.

[84] NETL, DOE, *Cost and Performance Baseline for Fossil Energy Plants*, 2007.

3.7.1 Capital Cost

The major components of coal-fueled IGCC power plants include coal handling equipment, gasifier, air separation unit (ASU), gas cooling and cleanup processes, and combined cycle power block. Exhibit 3-8 shows a breakdown of these costs. The largest cost is for the combined cycle power block, which accounts for 33 percent of total cost. Other major cost components include the gasifier (cost varies by technology), air separation unit, and syngas cooling system, which collectively account for another 30 percent of the cost. ASU cost, on average, represent about 15 percent[85] of total IGCC cost.

Exhibit 3-8
A Breakdown of Capital Cost for an IGCC without CCS

Process Description	Function	Share of Construction Cost
Coal Handling Equipment	Receive, prepare and feed coal feedstock into gasifier	12%
Gasifier, ASU and Syngas Cooling	Gasify coal into syngas; produce pure oxygen stream for gasification process, and cool raw syngas	30%
Gas Clean-up and Piping	Remove particulates, and acid gases from syngas	7%
Combined-Cycle Power Block	Generate electricity with syngas using a CT and steam turbine cycle	33%
Remaining Components and Control Systems	Cooling systems, spent ash and sorbent handling, controls and structures	18%

Source: Deploying IGCC in this decade with 3 party covenant financing, July 2004, Harvard.

The capital cost of a new IGCC facility is typically around 20–30 percent higher than the cost of a new conventional PC-fired plant. Although IGCC has a heat rate advantage over PC, this does not outweigh PC's capital cost advantage at current coal prices.

3.7.2 Availability

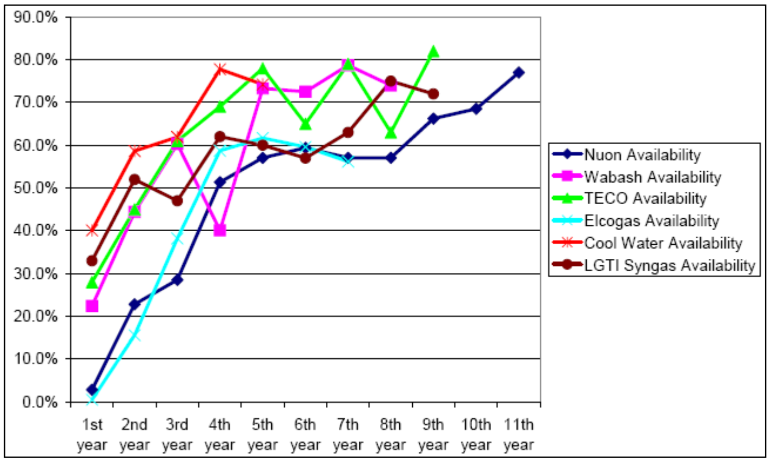
One of the major challenges facing IGCC facilities is the concern over their limited availability in early stages of operation. If early availability is low, the net present value of the project investment decreases significantly. Low revenues early in the project life make the ability to service debt very difficult, and raise major concerns within the financing community. The low availability rates in the early years of operation at Polk and Wabash River are typical examples of this issue.

Exhibit 3-9 illustrates the availability of Polk and Wabash River Station IGCC plants, as well as a few European projects. Low availability at Polk and Wabash were primarily attributable to their unique design challenges, equipment and inter-component design problems, operating

[85] NETL, DOE, *Current and Future IGCC Technologies*, 2008.

problems, and general inexperience with IGCC technology. Furthermore, different components, such as the air separation unit, gasifier, co-production facilities, gas turbines, and sulfuric acid production units, must generally be acquired from multiple manufacturers, thereby complicating the integration of all process operations. As discussed earlier, turbine OEMs are trying to address this specific issue by teaming with EPC contractors.

Exhibit 3-9
IGCC Availability History
(Excludes Operation on Back-Up Fuel)



Source: Electric Power Research

After an initial "burn-in" period, both Polk and Wabash river plants have performed well, achieving availability rates of approximately 80 percent and 75 percent, respectively, in recent years.[86] Indeed, the challenge is to reduce this initial "burn-in" period.

3.7.3 Environmental Benefits

Commercial IGCC plants have significant environmental benefits that should help deployment of the technology as national interest in environmental issues continues to grow. The major environmental benefits delivered by IGCC technology are briefly described below, with CO_2 benefits discussed separately in this chapter.

Mercury: Compared to other technologies, IGCC plants have a major advantage when it comes to Hg control because they remove Hg from the syngas upstream of the gas turbine, where there is less volume. This facilitates Hg removal at low cost, as the size of the equipment is reduced. Activated carbon beds filter syngas and remove 90–95 percent of the Hg. The incremental cost of removing 90 percent of Hg emissions in an IGCC unit is about one-tenth the cost of comparable Hg removal in a flue gas-based system used at a conventional coal-fueled plant.[87]

Solid Wastes: In terms of volumes of waste material produced, as well as the potential for leaching of toxic substances into soil and groundwater, IGCC has a reduced environmental impact compared with similarly sized coal combustion-based power plants. The largest solid

[86] O'Brien, N. John, *An analysis to institutional challenges to commercialization and deployment of IGCC technology in the U.S. electric industry*, Global Change Associates, 2004.
[87] NETL, DOE, *The cost of mercury removal in an IGCC plant*, 2002.

waste stream produced in an IGCC facility is slag (or bottom ash in some designs).[88] Slag is a black, glassy, sand-like, marketable byproduct.

Water Usage: Water use is also an important environmental consideration for coal power generation. IGCC facilities use water from the plant's steam cycle as boiler feed water and cooling water, and for other processes such as emissions control. However, because the steam cycle of IGCC plants typically produces less than 50 percent of the total power output, IGCCs have an inherent advantage over PC boilers in the amount of water required. On an output basis, IGCC generally requires 30–60 percent less water than competing combustion technologies. Most processed water in an IGCC facility is recycled, which minimizes consumption and discharge.[89]

3.7.4 Construction Timeframe

Due to the lack of construction experience, there is a great deal of uncertainty about the construction time for an IGCC. All types of power generation projects share a desire to standardize design and streamline permitting processes. IGCC designs are expected to profit from the extensive construction experience on combined cycles. The typical NGCC now takes between 18–24 months, while the latest PC units take approximately 60 months. Many expect IGCC construction to fall somewhere between those timeframes.

In terms of actual "on the ground" experience, both the Wabash River re-powering project and the Polk Power Station greenfield project were completed within two years of physical construction time. A 48-month timeframe seems ambitious for an IGCC, even if a couple of years were assumed for time needed to design, obtain permits, and finance the project.

3.8 Carbon Capture

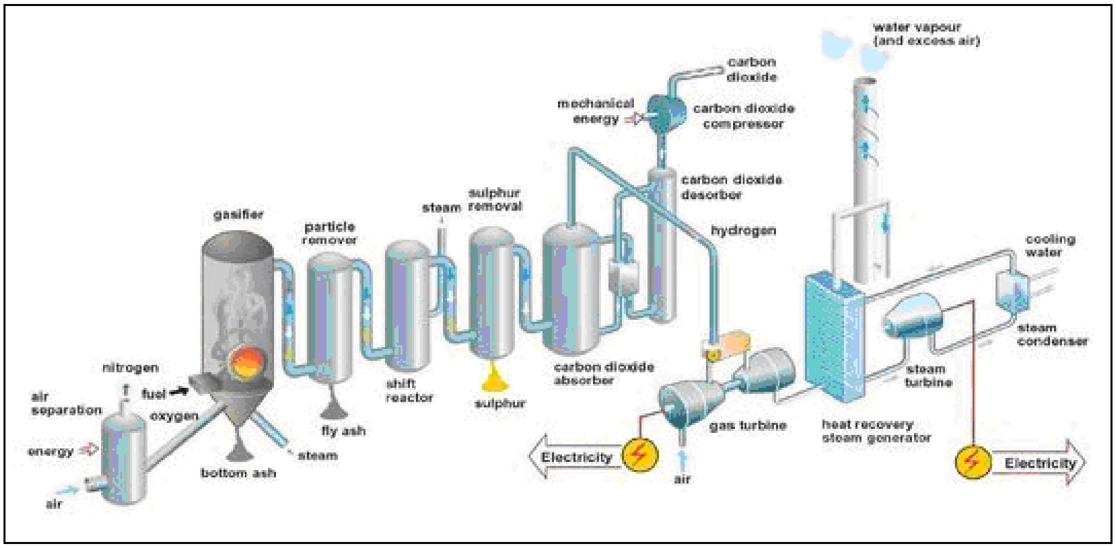
Carbon capture prior to combustion ("pre-combustion") involves the removal of the carbon content of a fuel before burning it. The syngas formed through gasification is mostly CO and H_2, with some small amount of CO_2. To remove the carbon, the CO is shifted using steam to produce CO_2 and more H_2. This is done prior to acid gas removal, and is therefore termed as "sour water" gas shift. Acid gases are removed from the shifted syngas in a two-stage Selexol™ process, with CO_2 removed in the second Selexol™ stage. The cleaned H_2-rich fuel gas powers the turbines. In the IGCC/CCS configuration, the turbine firing temperature is reduced to protect the turbine blade service life due to the high moisture content in the turbine exhaust. Exhibit 3-10 shows the entire process involved in pre-combustion carbon capture.

This pre-combustion technique yields a high concentration of CO_2 at high pressures, resulting in a low volume of gas being treated and thereby reducing equipment capital cost requirements. The higher concentration of CO_2 in the shifted syngas also means that less powerful solvents are needed, which, in turn, require less energy to be regenerated. This makes the capture of CO_2 more energy efficient and potentially cheaper than the post-combustion process already discussed. Moreover, this pre-combustion approach uses techniques that are already widely used in the chemical industry.

[88] NETL, DOE, *Major Environmental Aspects of gasification-based power generation technologies*, 2002.
[89] Ibid.

One disadvantage of the pre-combustion method is that it cannot be retrofitted to the PC power plants that make up much of the world's installed base of fossil fuel power. Another disadvantage is that the gas turbines running on H_2-rich fuel may need to be modified. As H_2 has over twice the heating value as natural gas, without any modifications flame temperatures are hotter, flame propagation is faster, and pre-ignition becomes an issue. This requires further cooling in the combustor. Current techniques used to address these issues include diffusion combustion where nitrogen or steam is introduced with the H_2. Also, the higher moisture content in H_2 tends to increase heat transfer to hot gas path parts of the turbine, reducing component life.[90]

Exhibit 3-10
Pre-Combustion Carbon Capture Process



Source: Vattenfall.

Exhibit 3-11 displays both the NETL and EPRI cost and performance parameters for IGCC with CCS. In this exhibit, there are two key parameters to compare across the technology types: LCOE and cost of CO_2 avoided.

[90] Zachary, Justin, *CO_2 capture and sequestration options - Impacts of turbine machinery design,* 2008.

Exhibit 3-11
Cost and Performance Parameters for IGCC with CCS (Mid-2006$)

	NETL			EPRI		
	20 Year Levelized			30 Year Levelized		
Technology	**Shell**	**GEE**	**Conco**	**Shell**	**GEE**	**Conco**
Net MW	517	556	518	500	523	515
Total Plant Cost (TPC $/kW)	2,633	2,359	2,399	3,267	2,410	2,670
Total Capital Requirement (TCR $/kW)	-	-	-	3,888	2,868	3,177
Fixed O&M ($/kW-yr)	43.2	43.2	45.7	114.3	91.6	101.5
Variable O&M ($/MWh)	7.9	8.0	8.4	1.0	1.0	1.0
Heat Rate(Btu/kWh HHV)	10,674	10,505	10,757	11,156	11,300	10,895
Net Plant HHV Efficiency (%)	32.0	32.5	31.7			
Capacity Factor	80	80	80	80	80	80
Fuel Price ($/MMBtu)	1.8	1.8	1.8	1.5	1.5	1.5
Capital Recovery Factor	0.20	0.20	0.21	0.12	0.12	0.12
Capital ($/MWh)	75.9	68.7	70.2	55.9	41.3	45.7
O&M ($/MWh)	14.1	14.1	14.9	17.3	14.1	15.5
Fuel ($/MWh)	19.0	18.7	19.2	16.7	17.0	16.3
Total LCOE ($/MWh)	108.9	101.5	104.3	90.0	72.3	77.6
CO2 (Emitted lbs/MWh)	147	152	187	159	138	255
COE Adder for CO2 Capture ($/MWh)	29.5	24.6	30.0	37.92	24.35	29.95
CO2 Captured (lb/MWh)	1262	1307	1265	1555	1806	1541
COE Adder for Transportation & Storage[1]	0	0	0	9.58	9.81	8.9
Cost of CO2 Avoided (incl. T&S) ($/short ton)	46.8	37.6	47.4	61.1	37.8	50.4

Sources: NETL 2007 and EPRI 2006.

[1] The CO_2 transport storage and monitoring LCOE comprises less than 4 percent of the total LCOE in all the capture cases.

As discussed earlier, the major component of LCOE is the initial capital cost. The capital cost for an IGCC with CCS is still the highest for the Shell gasifier due to the dry coal feed system. The GE Energy gasifier has the lowest cost among the three technologies when considered with CCS technology.

According to NETL estimates, when CCS is considered in these three technologies, GE Energy has the lowest heat rate, 10,505 Btu/kWh, and ConocoPhillips has the highest, 10,757 Btu/kWh. With CCS technology incorporated, the dry fed Shell gasifier experiences the largest energy penalty, primarily because of the steam required for the water gas shift reaction is provided as quench water to reduce the syngas temperature, thereby reducing the amount of heat recovered in the syngas cooler.[91] The energy penalty for the GE Energy gasifier is smallest because a large amount of water is already in the syngas from the quench step prior to the sour gas shift. While the quench limits the efficiency when the CO_2 capture is not included, it is the primary reason that the net efficiency of the system using the GE gasifier is slightly greater than ConocoPhillips and Shell when CO_2 capture is included.[92]

With CCS, the Shell technology has the highest LCOE, $108.9/MWh. due to its high capital cost and lower efficiency. The GE Energy technology has the lowest LCOE of all three technologies, $101.5/MWh, primarily due to its lower capital cost and lower heat rate.

[91] NETL, DOE, *Cost and Performance Baseline for Fossil Energy Plants*, 2007.
[92] Ibid.

Although all three technologies emit almost 90 percent less CO_2 when CCS is incorporated, the LCOE also increases because the CO_2 capture requires an additional Selexol process and a separate CO_2 removal and compression system. According to NETL estimates, the cost of CO_2 removal is highest for ConocoPhillips at $47.4/ton, with Shell at $46.8/ton and GE Energy at $37.6/ton. Based on these estimates, if the CO_2 allowance price is greater than $37.6/ton on average, it will make economic sense to install IGCC facilities with CCS.

If the economics are favorable to install an IGCC with CCS, the GE Energy technology appears to be most viable, as it operates at high pressures, allowing for a smaller volume of CO_2 to be treated and reducing the cost of the equipment required.

3.9 Challenges to Large-Scale Commercial Development of Technology

There are a number of major barriers to large-scale commercial development of IGCC. One of the major problems with IGCC financing is that the developers are unwilling to assume the risks associated with this technology, despite its potential advantages over conventional coal. Other barriers include:

- **Uncertainties around High Capital Cost:** A significant challenge for developers is their exposure to considerable uncertainty regarding IGCC capital cost requirements. This makes it very difficult for developers to finance a project without direct government subsidies. Major cost reductions may not come from the power island or the gasifier, as they are mature technologies. Reductions will most likely come from the components that integrate the power island and gasifier. Thus, the ASU and the syngas cleanup systems are the potential targets for reducing capital costs. This is discussed in more detail later in this chapter.

- **Equipment and Technology Procurement:** Currently, IGCC developers must undertake an extensive procurement program for obtaining the equipment and services needed to build and operate an IGCC power plant. Unlike conventional coal or CCs, there is no single procurement source for the wide range of technology and equipment required to permit and construct an IGCC. However, as mentioned earlier, gas turbine OEMs are taking significant steps to address this.

- **Siting and Permitting Process:** An IGCC facility has to undergo many markedly different permitting processes in comparison to a conventional coal unit. Furthermore, the permitting process has been based on the standards applicable to other gas turbine technologies, which are more stringent than for conventional coal plants. The different permitting methodology for IGCC projects is most evident with respect to NO_x emission requirements. IGCC is required to emit less NO_x compared with those required for other coal-fueled plants.

- **Lack of Comprehensive Legal and Regulatory Framework for CCS:** CCS raises new legal and regulatory risks associated with siting and permitting projects, such as CO_2 transportation, injection, and sequestration. These risks are not yet fully understood, nor are uniform standards or government regimes in place to address and mitigate them. Development of a consistent regulatory framework requires regulators to address a few key questions to be addressed, like property rights, title to CO_2 during transportation, injection and storage, and government-mandated caps on long-term CO_2 liability.

3.10 Incentives for Technology Development

Over the last few years, the government has introduced legislation that will help advance clean coal technology. As mentioned in Volume I of this report, the 2005 Energy Policy Act (EPAct 2005) provides a 20 percent investment tax credit for "eligible properties" for gasification. The EPAct 2005 also establishes tax credits of up to $800 million for IGCC projects and up to $500 million for other advanced coal-based projects. The EPAct 2005 authorized DOE to provide $200 million annually between 2006 and 2014, in the form of loan guarantees, loans, and direct grants, to gasification and other clean coal projects in the U.S., for a total of $1.8 billion.

The Economic Stimulus Act of 2008 will provide an additional $1.25 billion for clean coal and $250 million for gasification projects. It also increases the tax credit to 30 percent on investment for gasification and clean coal projects. These projects must demonstrate the ability to capture 65 percent of their CO_2 emissions.

The American Recovery and Reinvestment Act of 2009 provides additional incentives. The stimulus package provides $3.4 billion for clean coal and CCS research and development, out of which $800 million is for additional amounts for the CCPI Round III funding opportunity announcement. Additionally, it provides for a $10/ton credit for permanent CO_2 sequestration. The 2010 fiscal year budget has $600 million for coal power projects, out of which $404 million is for coal research, including the development of more efficient gasification, turbine, and fuel cell technologies; innovations for existing coal plants; and large-scale CCS injection tests.

3.11 Engineering Development and Performance Improvement

Unlike mature conventional coal technology, IGCC technology is in the development phase, with little extensive commercial operation experience. There is a great deal of opportunity for major performance improvements and capital cost reductions. As both gasification and power island technologies are mature, most efforts are focused on the development of integration components such as air separation, syngas cleanup, and advanced turbines for hydrogen-rich gas. Factors driving gasifier developments center on increasing availability and reliability and reducing the investment cost.

Exhibit 3-12 shows the areas with potential improvement possibilities and their potential effect on the capital cost. The improvement focus areas are discussed briefly below.

Exhibit 3-12
Areas of Potential Technology Improvement and Their Impacts

Technology	Major Technology Impact	Efficiency Impact (% point increase)	TPC Impact ($/kW reduction)	TPC Impact (% reduction)
Syngas cleanup	Warm gas clean up eliminates cold gas cleanup thermal penalties and reduces capital cost	2	319	17.6%
Air Seperation through Ion Transport Mechanism and advanced syngas turbine	Eliminates ASU thermal penalty and auxiliary load and reduces capital cost	0	118	6.5%
Air Seperation through Ion Transport Mechanism and advanced syngas turbine (II)	Combination of increased power output and efficient, cheaper ASU	2.1	89	4.9%
Advanced syngas turbine	Increases power output	0.9	73	4.0%
Dry coal feed pump	Increases cold gas efficiency	1	19	1.1%
Advanced IGCC Technology Total Impact		**5.9**	**618**	**34%**

Source: *Current and Future Technologies*, NETL, DOE, October 2008. The base cost is $1,800 / kW over which reductions are computed.

3.11.1 Syngas Cleanup

One of the significant areas of potential improvement in IGCC technology is the process of syngas cleanup. To avoid damaging the turbine, particulate materials must be removed or cleaned up before the syngas produced by the gasifier is injected into the gas turbine.

Conventional syngas cleanup is generally accomplished by cooling the syngas to a low temperature of approximately 100 °F or less. This, however, requires that the syngas be re-heated after particulate removal and before sending it into the turbine. To avoid heat rate and capacity penalties associated with this conventional cleanup process, work on less complex syngas cleanup systems with moderately cooled syngas requirements (“warm gas cleanup”) are being developed.

The warm gas cleanup process uses solid sorbents for the removal of particulate materials at high temperatures of around 900 °F. The solid sorbents are regenerated by oxidization, which produces high-quality heat to improve the steam cycle. CO_2 is captured through a H_2-permeable membrane, eliminating the needed for the Selexol™ process. All these factors contribute to increased steam power generation and lower auxiliary power requirements.[93]

In addition, there is a significant capital cost reduction from replacing cold gas cleanup with warm gas cleanup and an H_2 membrane. Warm gas cleanup is projected to cost about 25 percent less than cold gas cleanup. When capital costs are measured on a $/kW basis, they are further reduced as both the steam power cycle is increased and auxiliary power requirements are lowered.[94]

3.11.2 Air Separation

Air separation provides pure oxygen for the gasifier. Currently, this is achieved by using a cryogenic process in which air is cooled to a liquid state and then distilled. However, the cryogenic process requires a large amount of power and can add as much as 15 percent to the

[93] NETL, DOE, *Current and Future IGCC Technologies*, 2008.
[94] Ibid.

unit's capital cost. Hence, lowering the cost of air separation will significantly improve the economics and efficiency of IGCC power plants.

One of the main technologies under development that aims to improve air separation is the ion transport membrane (ITM). This alternative to cryogenic technology operates at between 1,471 and 1,651 ºF, producing pure oxygen at low pressure and nitrogen at high pressure for fuel stream dilution and expansion through the gas turbine. Because ITM produces nitrogen at elevated pressure, auxiliary power for compressing the dilution nitrogen is decreased. The most efficient configuration is obtained when ITM is partially integrated with the syngas turbine compressor, eliminating the large auxiliary load and cost of a stand-alone compressor for the ASU.[95]

The total cost of an IGCC plant is reduced by 7 percent, as the cost of an ITM is projected to be one-third less than a cryogenic unit.[96]

3.11.3 Advanced Syngas Turbine

Testing shows that diluting pure $H_2$with nitrogen could be fired in current-vintage F-Class turbines. However, achieving significantly higher efficiencies, reducing emissions, and lowering costs will require advances in combustor technology, materials, and aerodynamics. Research and development (R&D) is focused on increasing efficiency by 2 to 5 percent compared to the conventional combustor F-frame turbines.[97] One way to achieve this target is to increase the current inlet temperature of syngas to between 2,500 and 2,650 ºF from the current operating temperature of 2,250 ºF. Another option for improving syngas turbine performance is to increase mass throughput, and therefore power output, through improved expansion efficiency.[98]

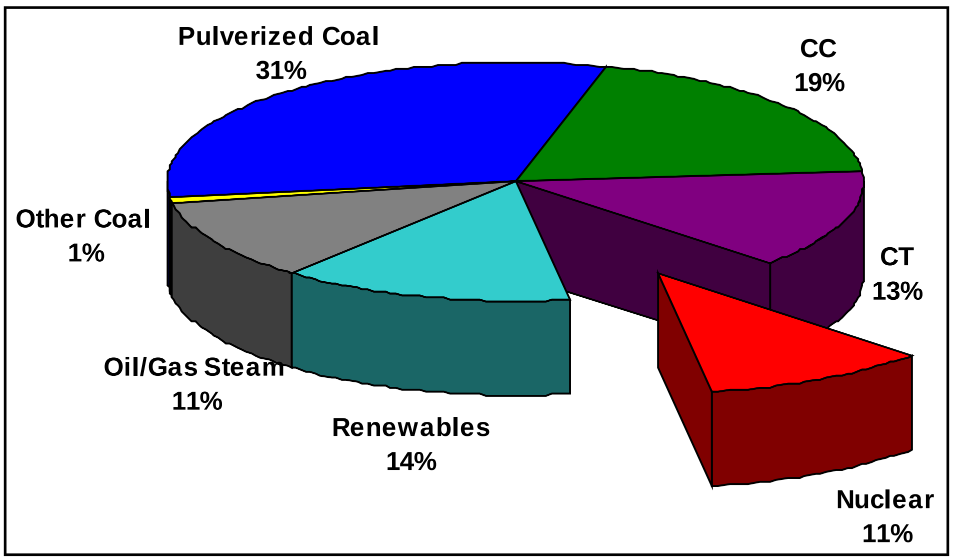
A turbine designed for H_2 or H_2-rich fuel can also operate at a higher pressure ratio and, thus, a slightly higher throughput, such that it can generate 250 MW of power (compared to 232 MW for current vintage F-Class machines).

[95] NETL, DOE, Current and Future IGCC Technologies, 2008.
[96] Ibid.
[97] Ibid.
[98] Ibid.

Chapter 4
Nuclear Power Reactors

Since commercial U.S. nuclear power generation began in the 1950s, several generations of reactor technology have been developed. Generation I reactors, developed in the 1950s and 1960s, were characterized by their use of natural uranium and graphite-moderation. Generation II technology, developed in the 1960s and 1970s, powers the current U.S. fleet of nuclear reactors and relies on enriched uranium, water cooling, and water moderation.[99] Today, 104 Generation II light-water reactors provide nearly 100 GW of IPP and utility-owned capacity, amounting to approximately 11 percent of total U.S. operating capacity.[100] Exhibit 4-1 illustrates the IPP/utility ownership breakdown of nuclear capacity. Of the 104 plants, 69 are pressurized water reactors (PWRs) and 35 are boiling water reactors (BWRs), both of which have proven very reliable over decades of operation.[101]

Exhibit 4-1
IPP and Utility Capacity Breakdown in the U.S.



Source: Ventyx 2009.

To operate, a nuclear plant must have a twenty-year operating license issued by the Nuclear Regulatory Commission (NRC). As a plant approaches the expiration of its license, its owner(s) may apply to renew the license, which would allow the plant to operate for an additional twenty years. The oldest nuclear reactors still operating were licensed in 1969.[102] There has been significant interest among utilities and electric power generators in license renewal and the NRC has approved more than 48 nuclear operator renewal applications in recent years. As of November 2009, there were 12 applications in the review process, and an additional 22 parties have expressed their intent to file for renewal.[103]

[99] The Encyclopedia of Earth – eoearth.org; *nuclear power reactors*.
[100] Ventyx 2009.
[101] Cheng, Bo. *A Review of Nuclear Energy in the U.S.* EPRI. 2009.
[102] DOE Web site. Nuclear Power.
[103] NRC.

Interest in constructing new nuclear capacity waned in the 1970s, which is when the last order for a reactor was placed. Although nuclear capacity in the U.S. has remained nearly constant since 1996, the year in which the last nuclear plant under construction was completed, nuclear power generation has steadily increased over the last several decades. This improved performance resulted from the divestiture of utility-owned nuclear assets in the 1990s that came with deregulation. Merchants purchasing these assets heavily invested in them to improve operations and reliability, which, in turn, yielded significant performance improvements. Between 1999 and 2009, nuclear generators have achieved an average capacity factor of about 90 percent.[104]

Increasingly stringent environmental regulations and fuel price volatility in recent years have renewed interest in nuclear power. Decades of extensive R&D and lessons-learned from around the world have given rise to Generation III nuclear reactor designs and construction plans that many proposed projects will implement if there is a decision to move forward within the next decade.

4.1 Generation III Nuclear Power Technologies

4.1.1 Overview of Third Generation Reactors

U.S. power producers have submitted combined operating license (COL) applications to the NRC for approximately 45 GW of new Generation III nuclear capacity with tentative online dates between 2015 and 2022.[105] A COL authorizes the construction and operation of a nuclear unit at a specific site.

General characteristics shared by Generation III reactors include:

- A standardized design that trims the licensing process, construction time, and capital costs;
- A simplified, more durable design that improves operational flexibility, reliability, and longevity (typically 60 years);
- Greater protection against core meltdowns and aircraft impact; and
- Improved fuel efficiency and reaction control.[106]

The passive safety features incorporated in many Generation III technology designs offer significant improvement over Generation II technology safety features. In the event of a problem, many Generation III passive systems can avert disaster without intervention or the use of active controls, as they rely on gravity, natural convection, or resistance to high temperatures.[107]

Early Generation III reactors have been operating since the mid-1990s in Japan, and late Generation III designs are now being built. The NRC has certified several Generation III technology designs, although a few remain in the early stages of the certification process, which will likely take several more years to complete. Designs that are not yet approved by the NRC

[104] Ventyx 2009.
[105] Cheng, Bo. *A Review of Nuclear Energy in the U.S.* EPRI. 2009.
[106] World Nuclear Association (WNA).
[107] WNA.

are expected to provide notable cost savings and reliability and safety improvements over current early Generation III technology designs.[108]

Exhibit 4-2 provides an overview of the reactor designs submitted as part of COL applications, which represent those most likely to be constructed in the near future. The NRC has not received COL applications for Generation III technology reactor designs like System 80+, Super Safe, Small, and Simple (4S), Advanced Candu Reactor (ACR), Advanced Passive 600 (AP600), International Reactor Innovative & Secure (IRIS), Pebble Bed Modular Reactor (PBMR), or Gas Turbine - Modular Helium Reactor (GT-MHR).

Exhibit 4-2
Projected New Nuclear Reactors[1]

	Manufacturer	Standard Design Certification Application Submitted	Most Recent Estimated Capital Cost ($/kW)[2]	Approximate Capacity per Reactor (MW)	Number of Projects	Number of Reactors
AP1000	Westinghouse	Certified December 2005	5500 to 8100	1150	7	14
US EPR	Areva	December 2007	3750 to 6250	1600	6	7
ESBWR	GE-Hitachi	August 2005	5400 to 8000	1550	5	6
ABWR	GE-Hitachi, Toshiba	Certified May 1997	2946	1370	1	2
US APWR	Mitsubishi	December 2007	4412	1700	1	2
				Total	**20**	**31**

Source: Nuclear Regulatory Commission (NRC).
[1]Received Combined License (COL) Applications as of October 2008.
[2]Sources: Public Service Commission Filings, Press Releases, and Ventyx 2009.

The generic O&M cost for a Generation III reactor is estimated to be $9.5/MWh, and the generic fuel cost is estimated to be $7.5/MWh.[109] Estimates for total capital costs of Generation III plants in the COL application phase range from approximately $2,950 to $8,100/kW. The differences in capital cost estimations can be attributed to several factors, such as regional labor and material cost differences, incomplete designs, and the state of the construction market at the time the estimate was developed. The volatile, wide-ranging capital cost of a new nuclear plant serves as a formidable challenge for future development. Cost uncertainty carries significant credit rating risk, essentially necessitating that a developer secure a revenue stream and/or funding either through PPA(s) (if an IPP) or through ratepayers (if a utility). In April 2009, S&P's Ratings Services downgraded the corporate credit ratings of SCANA Corp., South Carolina Electric & Gas Co., and Public Service Co. of North Carolina Inc. from A- to BBB+, citing the numerous construction and financing risks the partnership is assuming in its pursuit of building two new nuclear plants.[110]

This is not a surprise, as initial projections of nuclear capital costs have historically underestimated final actual costs, as illustrated in Exhibit 4-3. DOE estimates that most plants constructed between 1966 and 1977 exceeded initial cost estimates on average by over 200 percent.[111]

[108] Ibid.
[109] Nuclear Energy Institute (NEI), *The Cost of New Generating Capacity In Perspective*. 2009.
[110] Lum, Rosy. "S&P downgrades SCANA, utilities on nuclear construction risks." *SNL Financial.* 2009.
[111] Congressional Budget Office. *Nuclear Power's Role in Generating Electricity*. 2008.

Exhibit 4-3
Projected and Actual Construction Costs for U.S. Nuclear Power Plants

Construction Starts	Average Overnight Costs (2006$)			
Year Initiated	Number of Units	Utilities' Projections ($/kW)	Actual ($/kW)	Overrun (%)
1966 to 1967	11	612	1279	109
1968 to 1969	26	741	2180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1220	3882	218
1974 to 1975	14	1263	4817	281
1976 to 1977	5	1630	4377	169
	Weighted Average	**938**	**2959**	**207**

Source: Congressional Budget Office. 2008.

Exhibit 4-4 provides an overview the COL applications that have been submitted or are soon expected to be submitted. Less than one-third of the total reactors proposed will be merchant-operated. The primary reason merchants have expressed less interest in nuclear development than utilities is the difficulty of financing the multi-billion-dollar investment and the inability to pass upfront costs on to ratepayers (as many utilities can do through a construction work in progress (CWIP) mechanism).

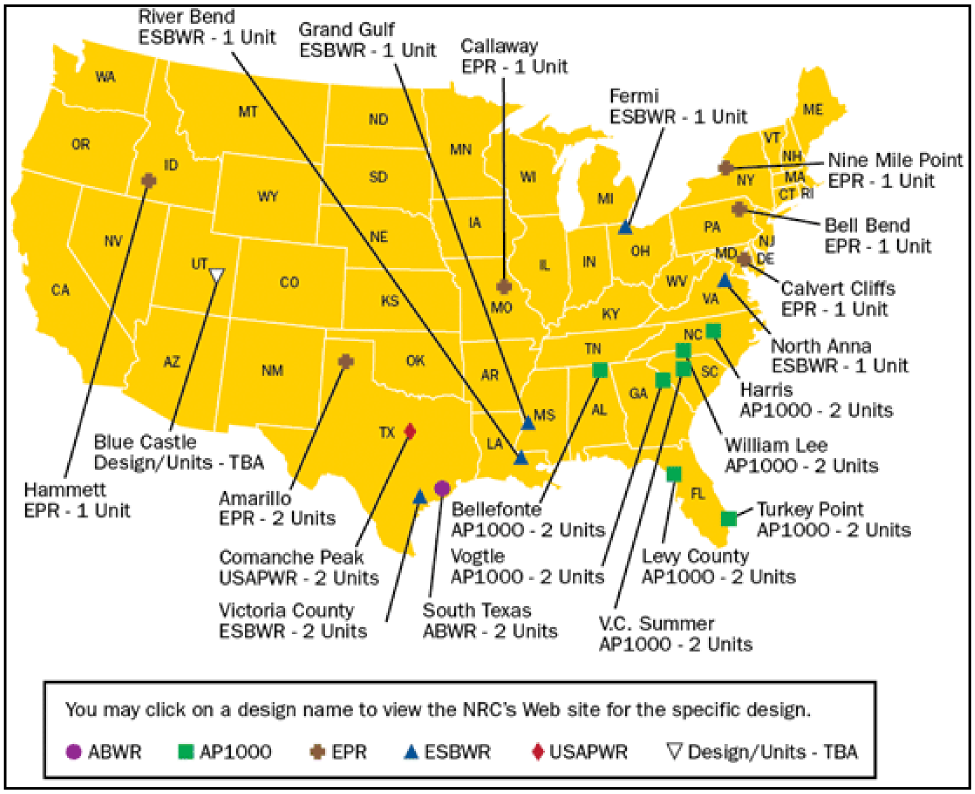
Exhibit 4-4
Combined License (COL) Applications

Owner	Plant	Reactor Design	State	Date Submitted	Number of Reactors
TVA	Bellefonte, Units 3 & 4	AP1000	AL	Oct-07	2
Duke	William Lee, Units 1 & 2	AP1000	SC	Dec-07	2
SCE&G	Virgil C. Summer, Units 2 & 3	AP1000	SC	Mar-08	2
SNC	Vogtle, Units 3 & 4	AP1000	GA	Mar-08	2
PEC	Harris	AP1000	NC	May-08	2
PEF	Levy, Units 1 & 2	AP1000	FL	Jun-08	2
FPL	Turkey Point	AP1000	FL	Jun-09	2
UniStar	*Calvert Cliffs, Unit 3	EPR	MD	Jul-07	1
AmerenUE[1]	Callaway, Unit 2	EPR	MO	Jul-08	1
UniStar	*Nine Mile Point, Unit 3	EPR	NY	Sep-08	1
PPL	*Bell Bend	EPR	PA	Oct-08	1
Amarillo Power and UniStar	*Amarillo	EPR	TX	2009 TBA	2
Alternate Energy Holdings	Hammett	EPR	ID	2009 TBA	1
Dominion	North Anna, Unit 3	ESBWR	VA	Nov-07	1
Entergy	Grand Gulf, Unit 3	ESBWR	MS	Feb-08	1
Detroit Edison Company	Fermi, Unit 3	ESBWR	MI	Sep-08	1
Exelon	*Victoria County, Units 1 & 2	ESBWR	TX	Sep-08	2
Entergy	River Bend, Unit 3	ESBWR	LA	Sep-08	1
Luminant	*Comanche Peak Units 3 & 4	US APWR	TX	Sep-08	2
NRG Energy	*South Texas, Units 3 & 4	ABWR	TX	Sep-07	2

Source: NRC and World Nuclear Association.
[1]Ameren suspended all nuclear expansion efforts on April 23, 2009 due to financial and regulatory uncertainty.
*Merchant plant.

Exhibit 4-5 shows the location of projected new nuclear power reactors for which utilities have submitted COL applications. As shown in the exhibit, the largest amount of new capacity is expected in the Southeast (FRCC and SERC), which represents a relatively large and growing share of total U.S. electricity sales, and thus requires more capacity than other regions.[112] The Southeast, dominated by regulated utilities such as Southern, has a high concentration of AP1000™ proposals. This highlights the trend of regulated utilities leaning towards the more advanced but more expensive AP1000™ design, in contrast with many merchants, like those in New England, who are leaning towards the less-expensive US-EPR design. The AP1000's™ passive safety system is a major driver of its higher price whereas the US-EPR's active safety system allows the possibility of lower construction costs.

Exhibit 4-5
Location of Projected New Nuclear Reactors



Source: NRC.

4.1.2 Light Water Reactors

4.1.2.1 Advanced Passive 1000 (AP1000™)

When approved by the NRC in 2005, the Westinghouse AP1000™, with a capacity of nearly 1,150 MW, was the first late-Generation-III nuclear reactor design to be certified. Apart from the fact that it nearly doubles the output of its early Generation III predecessor, the AP600™, the AP1000™ has a longer life span (60 years) and takes advantage of economies of scale that allow it to provide very competitive generating costs. The AP1000™ requires five times less steel and concrete than most Generation II designs and, as a result, it is about 25 percent the size of most Generation II designs. One-third of its structural and mechanical components can

[112] International Energy Outlook - DOE/EIA-0484 (2007).

be built in modules offsite, which helps reduce construction costs and reduces construction time to just 36 months.[113] Florida Power and Light (FPL) recently projected the total capital costs for two AP1000™ units at its Turkey Point facility could range from nearly $5,500/kW to nearly $8,100/kW.[114]

4.1.2.2 U.S. Evolutionary Pressurized Water Reactor (US-EPR)

The Areva US-EPR design is similar to that of the European pressurized water reactor. Its predecessors are the French N4 and German Konovi reactor designs. It is expected to provide power 10 percent cheaper than the N4 and have the highest thermal efficiency of any light water reactor. While it does not have a passive safety system, it does have four separate active redundant safety systems. The European design was approved by the French in 2004, and the U.S. version (renamed "Evolutionary") is expected to be certified by the NRC in 2012.[115] While the capital cost estimate for Ameren's recently cancelled Callaway unit in Missouri was only $3750/kW, the capital costs of the still-planned Calvert Cliffs Unit 3 and Bell Bend projects are much higher at $6000/kW and $6250/kW, respectively.[116]

4.1.2.3 Economic Simplified Boiling Water Reactor (ESBWR)

GE Hitachi Nuclear Energy's 1,520-MW ESBWR is a late-Generation-III design that builds upon the strengths of the older and proven ABWR technology. The ESBWR relies on a passive safety system and boasts lower building and operating costs than the ABWR. Its design eliminates the need for 25 percent of the pumps, valves, and motors needed in older nuclear designs. It is expected to complete NRC certification in 2011.[117] A recent estimate reported by FPL projected total capital costs for two ESBWR units could range from $5,500/kW to $8,000/kW.[118]

4.1.2.4 U.S. Advanced Pressurized Water Reactor (US-APWR)

Mitsubishi's 1,700-MW US-APWR has the largest unit capacity size of the Generation III designs. The advanced PWR combines active and passive safety systems, achieves 39 percent efficiency, and has a 2-year refueling cycle cooling system.[119] A U.S. design certification application was submitted in January 2008; approval is expected in 2011 and certification expected in mid-2012. The first units may be built for TXU at Comanche Peak near Dallas, Texas. Luminant's Comanche Units 3 and 4 have been estimated to cost more than $4,400/kW.[120]

4.1.2.5 Advanced Boiling Water Reactor (ABWR)

The 1,370-MW ABWR is one of the oldest reactor designs, but it has a proven track record in Japan, where four units have been operating (one since 1996), three additional units are under construction, and nine more are planned.[121] GE, Hitachi, and Toshiba partnered and developed

[113] WNA and EIA.
[114] Nuclear Energy Institute (NEI). *The Cost of New Generating Capacity In Perspective*. 2009.
[115] WNA.
[116] Ventyx 2009.
[117] WNA.
[118] Nuclear Energy Institute (NEI), *The Cost of New Generating Capacity In Perspective*. 2009.
[119] WNA.
[120] SNL Financial.
[121] General Electric.

the design together, but Toshiba split off after its 2006 acquisition of Westinghouse Electric, which makes the AP1000. Both GE-Hitachi and Toshiba have rights to sell the design. The only planned project in the country incorporating an ABWR reactor is STP Nuclear Operating Company's (STP) South Texas Project. STP contracted with Toshiba to supply two ABWR units rather than contracting with GE-Hitachi, which tried to sell STP their own ESBWR design.[122] The South Texas reactors are estimated to cost $3,000/kW.[123]

4.2 Development Process for Generation III Nuclear Reactors

Before applying for a COL, a company must assess project resources and select both the site and technology design. This first phase takes approximately 24 months and may cost slightly less than 1 percent of the total plant costs. In the second phase, a company must submit a COL application and obtain a COL. At this time, a company will also need to secure state and local permits. This phase will take three to five years and may cost $50–100 million, or 1 percent of the total plant costs. Approximately 12 months before the COL is issued, a company starts its long-lead procurement of major components and commodities, which makes up 5 percent of total plant costs. In the construction phase, a company secures transmission interconnection and fuel load and begins its testing. This final phase takes around three to four years. Overall, the development of a nuclear plant is about an eight-year process.

4.3 Generation IV Nuclear Power Technologies[124]

Generation IV reactors are still in the design phase and are likely more than a decade away from being constructed. These reactor designs promise notable capital cost reductions and improvements in efficiency, passive safety systems, waste management, and reliability. Generation IV reactors still require significant fuel, material, and thermal-hydraulic research and development.

4.3.1 Generation IV Thermal Reactors

The 205-MW Very-High-Temperature Reactor (VHTR) is a graphite-moderated, helium-cooled thermal reactor with an open, once-through fuel cycle. It can produce hydrogen and process heat due to its significant core outlet temperature of 1,832 ºF.

The 1,000-MW epithermal Molten Salt Reactor (MSR) system produces fission power in a liquid mixture of sodium, zirconium, and uranium fluorides. With its highly efficient heat transfer and low vapor pressure, this mixture of molten salts reduces vessel and piping stress. This reactor also produces H_2.

The 1,500-MW Supercritical-Water-Cooled Reactor (SCWR) may be a thermal reactor with an open fuel cycle or a fast reactor with a closed fuel cycle. It operates above the thermodynamic critical point of water and is one-third more efficient than current light water reactors. Its passive safety system is based on designs used in simplified boiling water reactors.

[122] Power Magazine, April 2009.
[123] SNL Financial.
[124] Generation IV International Forum; NEI, *Overview of Generation IV Technology Roadmap.*

4.3.2 Generation IV Fast Reactors

The Gas-Cooled Fast Reactor (GFR) system uses a direct-cycle helium turbine to generate electricity. The design seeks to reduce radioactive waste and efficiently use fissile and fertile materials (including depleted uranium) two times more efficiently than thermal spectrum systems. In addition to electricity generation and waste management, the reactor can be used for hydrogen production as well. A major design barrier is the need to develop fuels and materials capable of operating at temperatures of 1,562 ºF.

Primarily designed for small grids, Lead-Cooled Fast Reactor (LFR) systems vary greatly in projected size, with units ranging from 50 to 1,200 MW. This high efficiency reactor design produces hydrogen and has a 15–20 year refueling cycle, which helps manage and greatly reduce nuclear waste.

The Sodium-Cooled Fast Reactor (SFR) also varies greatly in size, with units ranging from 300 to 1,500 MW. With its highly efficient uranium conversion process, this reactor features advanced nuclear waste recycling options.

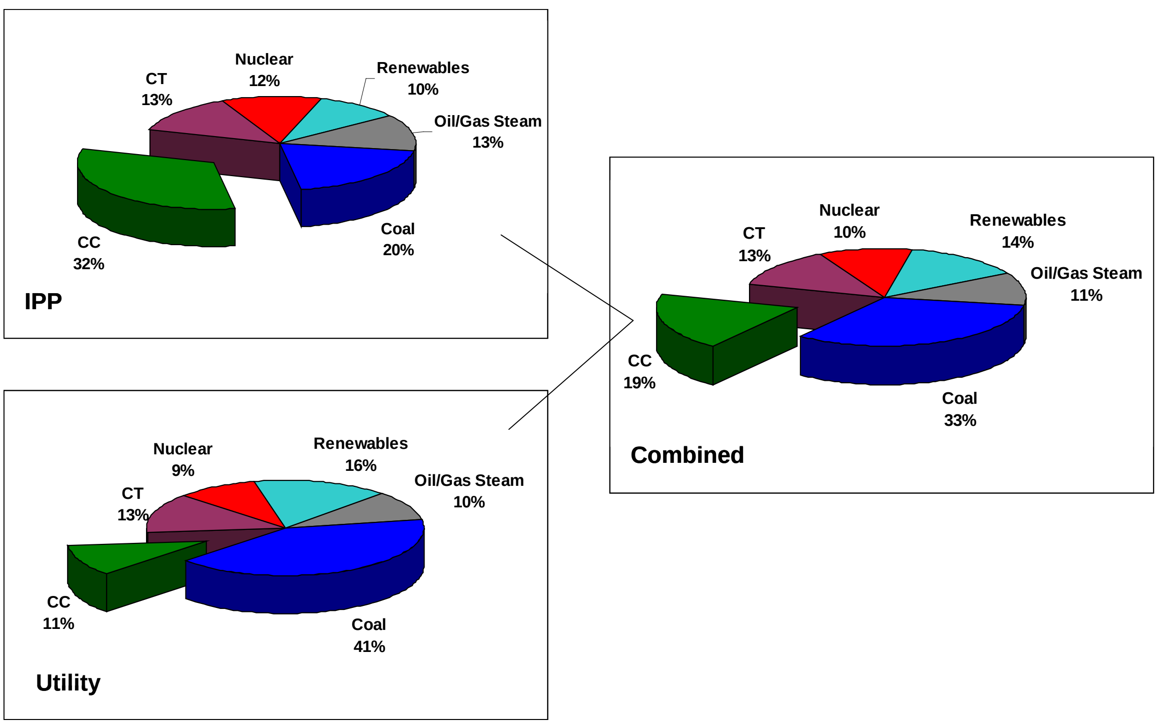
4.4 Challenges to Nuclear Power Development

Despite renewed interest in nuclear power, there remain numerous development hurdles, including credit risks, high capital costs, waste storage uncertainty, not-in-my-backyard (NIMBY) issues, and water usage risks. These hurdles are addressed in detail in Volume 1.

Chapter 5
Natural Gas Combined Cycles

NGCC plants play a significant role in U.S. power generation. Since the mid-1990s, combined cycles have been expanding to make up nearly 20 percent of the U.S. capacity mix (see Exhibit 5-1). Prior to 2002, natural gas was a relatively cheap fuel and, as a result, NGCC power plants were a very attractive option because they were cheap to build and run. Developer interest in NGCC was so significant that over 75 GW of capacity was built in 2002 and 2003 alone.[125] However, the increased demand for natural gas accompanying this capacity growth drove up natural gas prices significantly. As a result of the fuel price increase, modern NGCCs are often relegated to intermediate duty, only dispatching after lower cost providers such as coal and nuclear. NGCCs only truly serve as baseload power in regions where more conventional baseload options, such as coal and nuclear, are scarce (e.g., New England or New York City).

Exhibit 5-1
U.S. IPP and Utility Operating Capacity



Source: Ventyx 2009.

Since the rise of merchant generation in the late-1990s, IPPs have chosen to build NGCCs because of their low capital costs and ease of financing. Utilities did build some NGCCs, but to a much smaller extent than IPPs.

[125] Ventyx 2009.

5.1 Technology Overview

A generic NGCC power plant is composed of a combustion turbine, heat recovery steam generator, and a steam turbine. Both the steam turbine and the combustion turbine are targets for efficiency improvements.

5.1.1 Efficiency

Combustion turbine efficiency has improved greatly over the last 30 years. The earliest combined cycles had efficiencies of around 30 percent, but by the 1980s, they had reached 40 percent. The current standard technology, F technology, has achieved 56 percent efficiency. The next generation, so-called G technology, achieves 58–59 percent efficiency. GE is currently developing H technology, which promises 60 percent efficiency.[126] Efforts to improve steam turbines in combined cycles mirror efforts to improve steam turbines used in coal plants. As this is a mature technology, further improvements are limited and most gains will occur at the gas turbine.

5.2 Carbon Capture and Sequestration

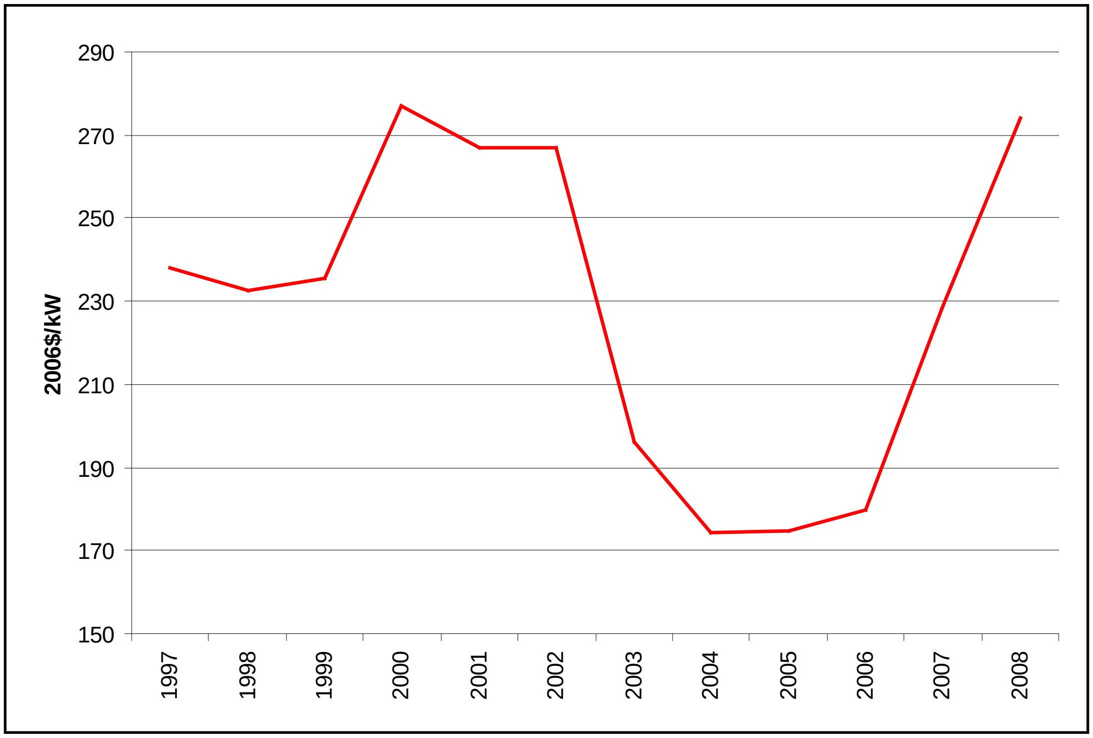
NGCCs run on natural gas, which is largely composed of methane and is not as amenable to pre-combustion CO_2 as the syngas created by coal gasifiers. As a result, the CO_2 must be removed post-combustion, similar to CO_2 removal in PC plants. Despite their comparable carbon capture process, NGCCs emit much less CO_2 than PC, which will give them a competitive advantage over non-capture PC in a carbon-constrained world. Generally speaking, a modern NGCC releases only about 800 lbs of CO_2 per MWh, about 60 percent less than a supercritical SCPC plant. Nevertheless, the cost increase of adding CCS to an NGCC plant will be significant, since CO_2 cannot be removed pre-combustion. For a discussion of post-combustion capture of CO_2, please refer to Chapter 2.

5.3 Capital Cost Overview

The single largest cost component of NGCCs is the cost of the combustion turbine. The current technology, F-tech, has been available since the mid-1990s. Its cost has fluctuated largely with demand. As seen in Exhibit 5-2, its price was largely stable from 1997 to 1999, but then started to surge due to the rise of merchant generation and the greatly increased demand for combustion turbines. As OEM production capability cannot be quickly ramped up, demand quickly outstripped supply. After 2002, when gas prices started to rise, demand tailed off, and gas turbine prices decreased significantly. In 2003, the price of a new 7FA gas turbine decreased by over 25 percent. However, just a few years later, as worldwide demand for power grew, especially in the BRIC (Brazil Russia, India, and China) countries,[127] prices for gas turbines surged.

[126] GE has already built an H-tech demonstration project in Wales and its first commercial plant, Inland Empire Energy Center, is expected to enter full service in late 2009.
[127] BRIC countries include Brazil, Russia, India, and China.

Exhibit 5-2
Capital Cost of GE 7FA Combustion Turbine



Source: Gas Turbine World, ICF experience.

5.3.1 Capital Cost with Carbon Capture

Exhibit 5-3 provides NETL's most recently released levelized cost and performance parameters of state-of-the-art NGCC units. The unit modeled by NETL is a 2x1 F technology combined cycle, which means the unit has two combustion turbines and one steam turbine. As discussed in Chapters 2 and 3, NETL's cost estimations are only TPC, which accounts solely for overnight capital cost and does not include owner's costs or allowance for funds used during construction (AFUDC).[128]

[128] NETL. *Cost and Performance Baseline for Fossil Energy Plants*. Volume 1.

Exhibit 5-3
Parameters of F-Technology Combined Cycle with and without CCS (2006$)

	20 Yr Levelized Cost	
Parameter	**W/O CCS**	**W/ CCS**
Net MW	560	482
Total Plant Cost (TPC $/kW)	554	1172
Fixed O&M ($/kW-yr)	9.82	16.64
Variable O&M ($/MWh)	1.32	2.56
Heat Rate(Btu/kWh HHV)	6,719	7,813
Net Plant HHV Efficiency (%)	50.8%	43.7%
Capacity Factor	85%	85%
Fuel Price ($/MMBtu)	6.75	6.75
Capital Charge Factor	0.175	0.175
Capital ($/MWh)	13.0	27.5
O&M ($/MWh)	2.6	4.8
Fuel ($/MWh)	45.4	52.7
Total LCOE ($/MWh)	68.4	97.4
CO2 (Emitted lbs/MWh)	783	93
CO2 Captured (lb/MWh)	-	690
Cost of CO2 Avoided (incl. T&S) ($/short ton)	-	82
NOX (lbs/MWh)	0.06	0.06
SOX (lbs/MWh)	Negligible	Negligible
Hg (lbs/MWh)	Negligible	Negligible

Source: NETL 2007.[129]

It is interesting to note that the cost of adding CCS is roughly the same as the cost of the plant itself. CCS also increases the parasitic load of the plant by approximately 80 MW and raises the heat rate by over 1,000 Btu/kWh. The type of CCS employed by the plant is an amine-based CO_2 capture system, which was discussed in detail in Chapter 2. The NGCC-CCS unit is estimated to have a CO_2 avoided cost of $82/ton, significantly higher than the SCPC-CCS cost of $67/ton. This is because NGCC units emit much less CO_2 than does a pulverized coal plant, while requiring roughly the same amount of equipment.

[129] The CO_2 transportation, storage, and monitoring component of LCOE is only 3% of the total in the CCS case.

Chapter 6
Baseload Investment Decisions

This chapter discusses why power plant developers are investing in certain types of baseload technology. The discussion focuses on coal-fired technologies, namely SCPC and IGCC, but also includes nuclear and NGCC technologies. The investment viability of baseload technologies is also examined through an economic gap analysis using ICF's capacity expansion modeling platform, IPM®, to create a long-term view of the U.S. power market under climate change regulations.

In addition, this chapter looks at the impacts of five key investment factors (previously discussed in Volume I) on the decision to build or not build different types of baseload facilities, using the concepts of an investor's hurdle rate and discounted cash flows (DCFs). Cash flows are derived using ICF's IPM®. A "Reference Case" is developed to serve as a baseline or reference point; it reflects ICF's expected view of market parameters. For the gap analysis, sensitivity cases are used to analyze impacts on ROE from changes in baseline assumptions. In each of the sensitivity cases, only one of the parameters is changed to gauge its impact against the Reference Case. Details on the mechanics of IPM® and other underlying key assumptions are provided in Appendix B.

Simplistically speaking, unregulated investors use a DCF approach to evaluate long-lived investments. The DCF approach is a well-known and commonly accepted valuation technique used to determine the value of an investment that produces a revenue stream of payments over time. DCF analysis is based on the premise that the value of an investment is equal to the net present value (NPV) of the future benefits of the investment. All things being equal, the investment that yields the highest internal rate of return and is greater than the investor's hurdle rate will be the likely choice.

The DCF approach is generally conducted as a deterministic analysis. Deterministic analysis assumes all inputs and outputs are known in advance with certainty, while in fact all inputs are uncertain and typically vary. A deterministic power model would project one power price for a given hour. This is a useful and valid approach that projects long-term, marginal power price trends and incorporates many different inputs, such as fuel prices, energy demand, and emissions prices. For long-term analysis, many IPPs and investment players use this method to forecast the earnings and derive a value for the power plant of interest. For analysts with a short-term view, a stochastic approach is sometimes employed to capture near-term volatility that deterministic analysis may not be able to capture.

6.1 Methodology and Approach

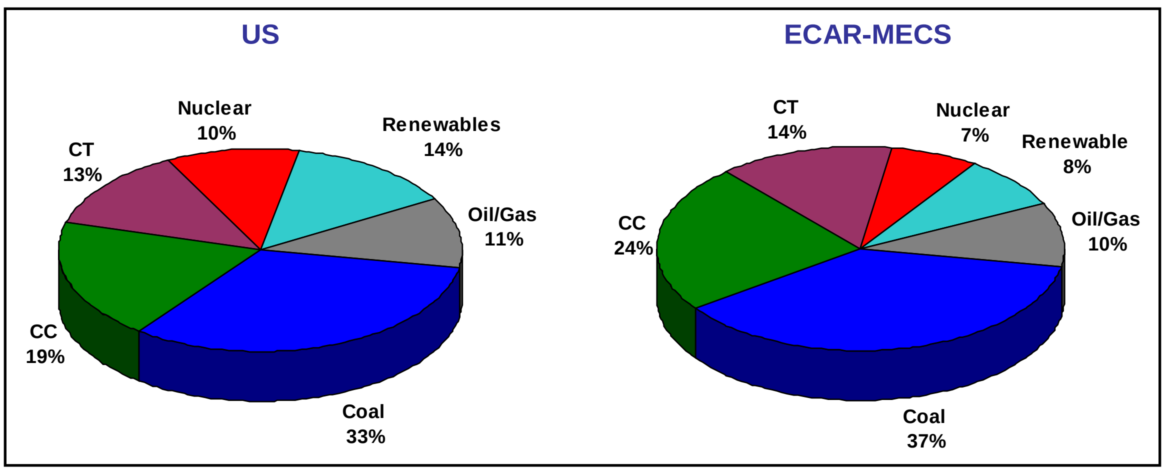
The following ICF analysis examines the economic viability of six potential baseload investment options for a single wholesale power market, ECAR-MECS, within the North America wholesale power market. The analysis is performed using ICF's generic assumptions. These assumptions are ICF's expected view of the underlying modeling data as of early 2009. These potential investment options are further analyzed under a range of sensitivity cases.

These analyses use ICF's capacity expansion planning model, IPM®, and cover a 40-year forecast horizon commencing in 2020. For each investment option, revenues and operating costs are obtained as output of the IPM model. Revenues are derived from both energy and capacity sales.[130] The level of dispatch for each option for which energy sales are calculated is an output of the model. Costs that are accounted for include capital, fixed and variable operating expenses, fuel expenses, and emission compliance costs. Annual operating profits are simply revenues minus costs. An investment option's internal rate of return (IRR) is developed for each case and examined through a financial *pro forma* analysis. Annual operating profits are obtained from model results and fed into the *pro forma*, along with tax implications, depreciation, and debt treatment.

To deem an investment economically viable, the hurdle rate was set at 12.75 percent for all options. Those options with an IRR lower than 12.75 percent are not economically viable. A more detailed explanation of the IPM® model and the financial assumptions behind the hurdle rate can be found in Appendix B.

The power market region ECAR-MECS has been selected as the sample region due to its large existing power generation capacity and diverse baseload mix, which is similar to that of the U.S. capacity mix (see Exhibit 6-1). Another motive for the selection is that ECAR-MECS does not have any current state legislation for CO_2. The location of ECAR-MECS is generally the Michigan peninsula, but is more accurately depicted in the map in Appendix B.

Exhibit 6-1
U.S. and ECAR-MECS Operating Capacity Mix



A summary of the six potential investment options analyzed in the ECAR-MECS market is given below:

- **Supercritical Pulverized Coal (SCPC):** The SCPC unit will burn bituminous coal and has the following emission control technology: activated carbon injection to reduce Hg emissions by 90 percent, and flue gas desulfurization (FGD) technology to reduce SO_2 emissions by 95 percent and Hg emissions further by 40 percent. Selective catalytic reduction (SCR) and Low NO_x burners (LNB) will reduce NO_x

[130] Electricity markets in the U.S. typically have either a single electricity price product or in more sophisticated markets (as seen in the markets of the Northeast) have separated electricity price into an energy price and a capacity price. In markets with two price components the energy price reflects short-run marginal pricing and the capacity price reflects long run marginal pricing. Thus capacity pricing reflects the value of maintaining reliability of the overall system. Capacity value in a market with a single bundled electric power product is often reflected through price spikes or volatility in the power price. The algorithm in the IPM® model breaks electricity price into its energy and capacity components similar to the more sophisticated power markets. Our reference to capacity sales reflects capacity sold at a capacity price developed internally by the model.

emissions by 95 percent. The standard SCPC power plant modeled has an average capacity of 700 MW.

- **Supercritical Pulverized Coal with Carbon Capture and Sequestration (SCPC-CCS):** This unit will have the same configuration as the SCPC unit, but with CCS technology reducing CO_2 emissions by 90 percent and incurring a heat rate penalty of approximately 40 percent. Costs are based on a post-combustion amine absorption process. For sequestration, the model utilizes a comprehensive database of potential storage sites, listed by type of reservoir (e.g., saline aquifers or basalt) and region. The sites and storage potential are summarized in Appendix A. The model includes a transportation-cost adder matrix to map the potential baseload unit to various storage sites.

- **Integrated Gasification Combined Cycle (IGCC):** The modeled IGCC will burn bituminous coal. The IGCC unit has similar emission reduction factors as the SCPC unit. Capital cost and performance characteristics are based on a standard 2X1 GE-7FA, configured, 500–MW, CC power island using a GE gasifier.

- **Integrated Gasification Combined Cycle with Carbon Capture and Sequestration (IGCC-CCS):** This unit will have the same configuration as the IGCC unit, but with CCS technology reducing the CO_2 emissions by 90 percent and incurring a heat rate penalty of 21 percent. Cost and performance characteristics of the CCS are based on the Selexol process.

- **Natural Gas Combined Cycle (NGCC):** Based on 2x1, configured, power island using 501G combined cycle technology with SCR and LNB for NO_x emission control. The standard NGCC power plant has a nominal capacity of 600 MW.

- **Nuclear:** This unit will be a US-EPR Generation III nuclear reactor design with an average capacity of 1,600 MW. The US-EPR was selected as the option in ECAR-MECS as merchant developers will most likely choose the design that is least expensive.

While the discussion focuses on the ECAR-MECS market, the other power markets in the lower-48 states and Canadian provinces will be modeled as well. The above investment options are also available in those regions, but may have slightly different cost and performance characteristics. For example, an SCPC unit in the Rockies would be given Powder River Basin (PRB) coal instead of bituminous coal; so although it would be able to use a cheaper coal, it would have higher capital costs due to the larger furnace and a corresponding heat rate penalty for firing PRB coal.

Exhibit 6-2 shows the basic plant characteristics of the baseload capacity options analyzed. As mentioned above, these specific assumptions are for investment options in ECAR-MECS and will vary by power market region.

Exhibit 6-2
Summary of Plants Reviewed (2006$)

Plant Type	Capital Cost ($/kW)	Heat Rate (Btu/kWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
NGCC	1,200	6,800	10	2.8
SCPC	2,900	9,100	27	3.3
SCPC-CCS	5,300	13,100	40	7.4
IGCC	3,500	8,300	32	2.2
IGCC-CCS	4,800	10,100	41	4.0
Nuclear	4,600	10,400	110	1.2

ICF has not reconciled cost and performance assumptions with those of NETL and EPRI, but a quick review indicates that ICF's estimates for SCPC and IGCC capital costs are notably higher than those projected by NETL and EPRI. There are a number of potential reasons for this. For example, whereas ICF's and EPRI's view of costs includes AFUDC and owner's costs, NETL's do not. Also, ICF's view on costs represents a more current 2009 look, while EPRI and NETL views date back to 2006 and 2007, respectively, thus possibly missing some of the significant run-up in construction costs experienced in the market in 2008.

The power plants examined in this chapter are assumed to be fully merchant plants with no PPA in place. It is likely, however, that many power plant investment decisions in the marketplace today will need the support of a PPA for financing purposes to mitigate market risk. This analysis did not address PPA hedges, as they would introduce large unknowns regarding the price, quantity, and tenure of the PPA. For each baseload capacity investment option, the ROE is calculated with the assumption that it will begin operating in 2020 and generate revenues over a 40-year period. IPM® optimizes energy prices and potential investment builds in such a way that the ROE of any economic power plant investment decision cannot exceed 12.75 percent, the pre-defined hurdle rate. If the ROE were higher for a particular investment, the IPM® capacity expansion algorithm would add more capacity to that investment unit until power prices fall to the point that the ROE drops back to the 12.75 percent target.

In any modeling exercise, there are a number of compromises. First, the only investment decisions reported are for the online year of 2020 and for ECAR-MECS, because reporting all years and all regions would be extremely data intensive. Furthermore, the online year of 2020 was selected because there will be a need for additional baseload capacity in most of the U.S. regions by 2020; climate change and other federal emission policies will most likely be in place by this point as well. It should be noted that investment decisions may vary if a different online year is reviewed. For example, if an earlier online year, such as 2015, were analyzed, perhaps only gas turbines would be needed because the underlying prices are too low to support baseload capacity. Another compromise is the number of years that the model projects forward cash flows. Due to modeling size constraints, the revenue and cost streams of the investment units were only modeled through 2039. Between 2039 and 2059, the revenue streams of these baseload plants are extrapolated and assumed to remain flat in real dollar terms.

As mentioned earlier, power prices and, therefore, investment decisions, are sensitive to their underlying assumptions. This analysis uses a Reference Case to serve as a baseline or reference point against which all other sensitivity cases will be measured. The Reference Case reflects ICF's expected view of market parameters and assumptions on plant technologies as of early 2009. After discussions with NETL personnel, it has been determined that five key parameters should serve as the basis for the sensitivities. In each of the sensitivity cases, one of the parameters is changed to gauge its impact against the Reference Case. The five key parameters examined are shown in Exhibit 6-3:

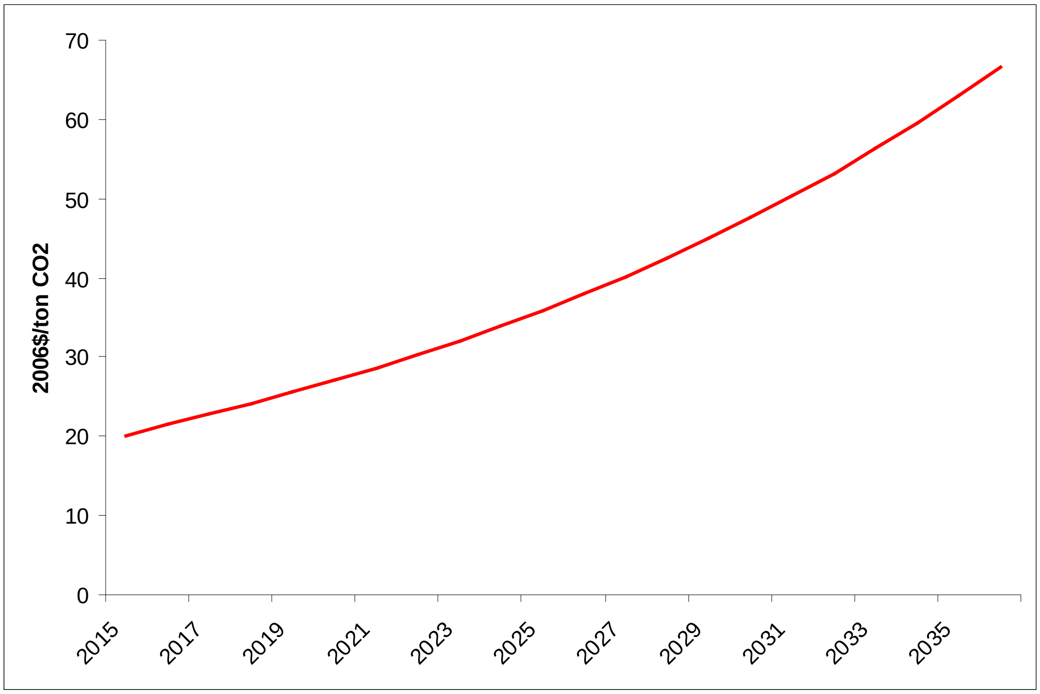
Exhibit 6-3
Summary of Parameters Reviewed

Technology	Market
Capital Cost	Natural Gas Price
Availability	CO_2 Price
	Federal RPS

The Reference Case includes assumptions on federal regulations for four pollutants (SO_2, NO_x, Hg, and CO_2), along with current state RPS standards. In the near term, the Reference Case includes legislative action to carry on NO_x and SO_2 cap-and-trade programs consistent with Clean Air Interstate Rule (CAIR) Phase I and tighter caps for Phase II, which are more consistent with Senator Caper's bill than with CAIR's original Phase II caps in the long term. The modeled Hg program is a hybrid that combines a federal maximum achievable control technology (MACT) starting in 2014 and regulations already imposed at the state level.

The climate change program in the Reference Case derives an expected CO_2 price based on a probability-weighted outcome of several CO_2 price trajectories, and is expected to be non-zero starting in 2015. Exhibit 6-4 shows the CO_2 price stream for the Reference Case. It is assumed that power plants that come online in the near term (in or before 2010) will receive some amount of CO_2 emission allowances. However, the baseload unit investment options considered in these sensitivities that come online after 2010 will not receive any allowances. In other words, the economic decision on the investment must cover 100 percent of the carbon allowance cost.

Exhibit 6-4
Reference Case CO_2 Price Stream (2006$ per Ton)



While IPM® is designed to generate projections based on economic fundamentals; ICF acknowledges that factors other than economics may drive decisions in the market. Technology improvements over time are especially difficult to project for new nuclear designs and CCS, as nothing has been commercialized. Limits are therefore imposed as to where and when these technologies would be available. For example, only allow nuclear development at existing brownfield sites are allowed, and CCS is restricted based on estimates of storage capacity, which is limited in certain areas of the country.

6.2 Discussion of Results (Reference Case – Year 2020)

Under the Reference Case, which includes a CO_2 policy, new baseload investment decisions for the region ECAR-MECS in the year 2020 include both NGCC and limited nuclear expansion at brownfield sites. Both types of units achieved ROEs of 12.75 percent, thereby meeting the hurdle rate. The SCPC unit had a ROE of 10.6 percent. Burdened with additional cost, the SCPC-CCS option had an ROE of only 7 percent. The IGCC had an ROE of 8.1 percent, while the IGCC option with the CCS addition increased the ROE to 10.6 percent. Exhibit 6-5 summarizes the ROE of each technology type. The Reference Case results indicate that in 2020, neither SCPC nor IGCC (with or without CCS) are economical to build at ICF's expected carbon allowance levels.

Exhibit 6-5
Reference Case

Baseload Capacity Investment Options	
Unit Type	**ROE (%)**
SCPC	10.6
SCPC-CCS	7.0
IGCC	8.1
IGCC-CCS	10.6
NGCC	12.8
Nuclear	12.8

The SCPC unit has a lower ROE than the hurdle rate of 12.75 percent, due to the addition of carbon emission costs. The SCPC-CCS also has an ROE less than the hurdle rate even though it has around 86 percent less CO_2 emissions than the SCPC unit. Its failure to meet the hurdle rate is primarily due to the high incremental capital cost of amine-based CCS versus the cost of compliance. The SCPC-CCS performance might be improved by instead using the chilled ammonia process, which has greater CO_2 absorptive capacity, is able to regenerate without stripping steam, and has 60 percent lower heat of reaction energy needs.

Both IGCC and IGCC-CCS units have an ROE less than the hurdle rate of 12.75 percent. The IGCC-CCS investment decision does, however, become economically viable in 2025, when CO_2 prices, which continue moving upward, drive the power prices high enough to outweigh the high incremental capital cost of CCS.

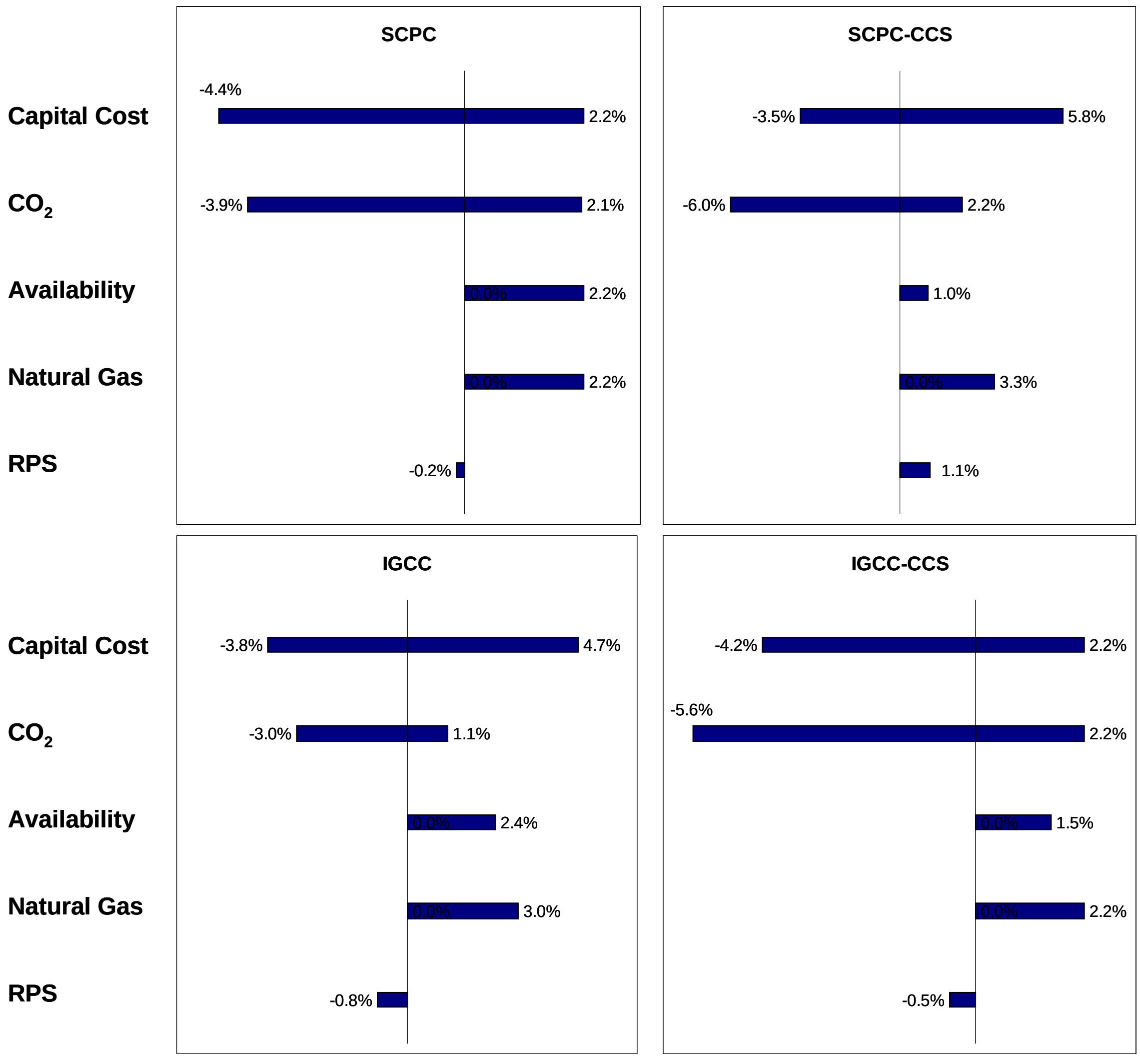
ICF expects a significant amount of NGCC capacity to be built by 2020, primarily due to its low initial capital cost and relatively low carbon emissions compared to both conventional and IGCC coal. Nuclear units also have an ROE equal to the hurdle rate, in spite of a high capital cost, as these units do not incur any carbon emission cost.

Under the assumptions of the Reference Case, these investment decisions for ECAR-MECS show that coal-based technologies are not economically viable. For any coal-based project to go forward, the existing economic gap must be closed. In the following sections, ICF examines the results of five parametric analyses to consider how the economic gap for coal could be bridged.

6.2.1 Market Parameters

Three key market parameters are examined using sensitivity cases, including CO_2 allowance prices, natural gas prices, and a federal RPS policy**.** A summary of the ROE impacts that each scenario has on the four coal options is shown in Exhibit 6-6. Impacts are shown as ROE deltas to the Reference Case. To provide a comprehensive view of the results, the technology scenarios are captured in Exhibit 6-6 as well.

Exhibit 6-6
Summary of ROE Impacts by Scenario



The two scenarios that had the largest impact by far on the coal technology ROE were capital cost and CO_2. The availability and natural gas scenarios showed moderate upside for coal, while the federal RPS case had the smallest effect of all, affecting ROE by only about one percent even for its most stringent case.

6.2.1.1 CO_2 Sensitivity

In addition to the Reference Case and ICF's 3-Pollutant case, which has no carbon policy, ICF reviewed six different CO_2 sensitivity cases, shown in Exhibit 6-7. For a detailed discussion of ICF's carbon policy assumptions, see Appendix B. The Reference Case projects an average CO_2 allowance price of $48 per ton from 2020 to 2039. The six cases change in 25 percent increments above and below the Reference Case. Overall, the average CO_2 allowance price reviewed ranges from $0 to $84 per ton.

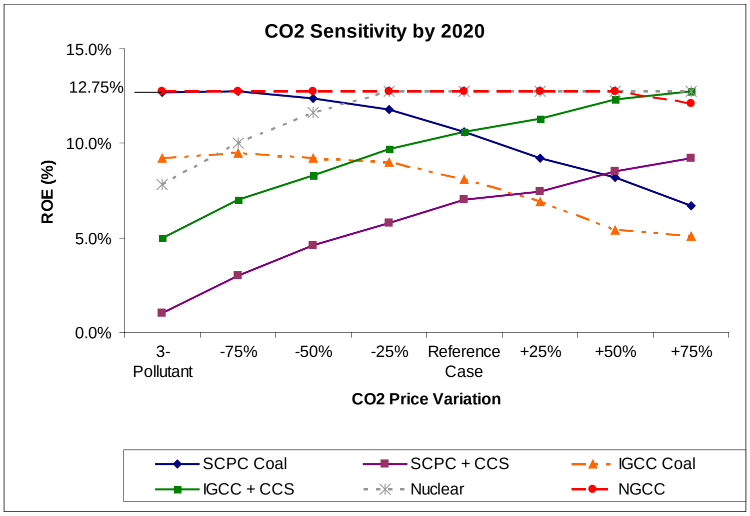
Exhibit 6-7
Summary of CO_2 Price Sensitivities

CO_2 Allowance Price (2006$ per Ton)	
Case	**2020–2039 Annual Average**
3-Pollutant Case	0.0
-75% CO_2 Price	12.1
-50% CO_2 Price	24.1
-25% CO_2 Price	36.2
Reference Case	48.2
+25% CO_2 Price	60.3
+50% CO_2 Price	72.3
+75% CO_2 Price	84.4

Exhibit 6-8 shows the impacts of varying CO_2 prices on the ROE of potential baseload investments. As CO_2 allowance prices increase, the ROEs for the coal options with CCS increase. This occurs because energy margins improve as power prices increase due to increasing CO_2 costs. Although the ROEs increase, the improved energy margins do not justify the high-capital-cost investment of CCS under these assumptions, except in the most extreme case. The options without CCS have declining ROEs, as the cost of CO_2 compliance outweighs the revenue increase due to higher energy prices.

SCPC is an economic investment in regimes of no carbon policy or, at best, a mild carbon policy scenario. In this particular analysis, the SCPC would still be a viable investment under a carbon policy, with an average price of $12 per ton. IGCC-CCS becomes economically viable when the average CO_2 allowance price reaches approximately $84 per ton. IGCC and SCPC-CCS never become economically viable in any of the CO_2 sensitivity cases.

Exhibit 6-8
Summary of CO_2 Price Sensitivities



The combined cycle investment option is economically viable in all cases except the one with 75 percent higher CO_2. In this extreme carbon case, IGCC-CCS replaces new NGCC capacity in the region. Nuclear power becomes economically viable as CO_2 allowance prices pass $36/ton.

While IGCC-CCS is not economically viable in ECAR-MECS, except in the case with 75 percent higher CO_2, it is viable in the U.S. as a whole, starting in the case with 50 percent higher CO_2.

6.2.1.2 Natural Gas Sensitivity

ICF's Reference Case has an average natural gas price of $9.2/MMBtu over the 2020–2039 period. From this baseline, three additional sensitivity cases were developed that reflect a 20, 40, and 60 percent increase over average prices from 2020 to 2039. These additional cases are summarized in Exhibit 6-9. The 60 percent case represents an extremely high gas price and has an average gas price of $14.7/MMBtu. The ICF analysis did not examine lower gas cases, since these cases do not improve the investment decisions for coal-based options. CO_2 prices were allowed to move with the changes in natural gas prices.

Exhibit 6-9
Summary of Natural Gas Sensitivities

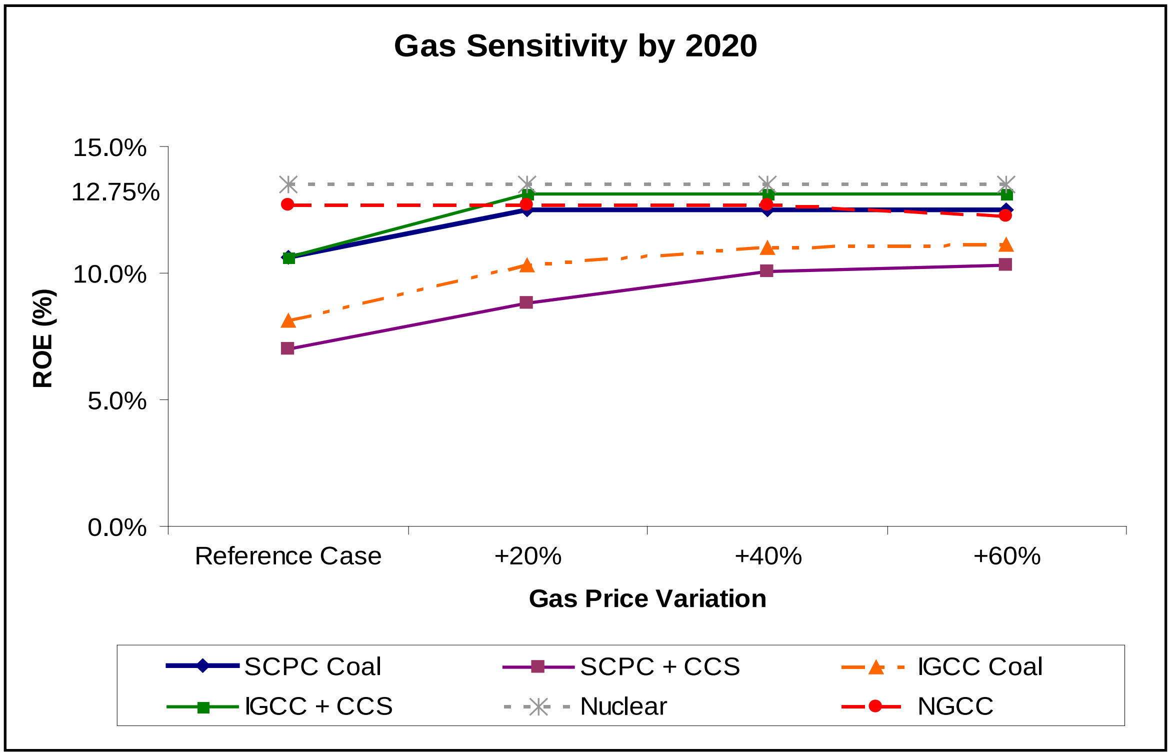
Henry Hub Gas Price (2006$ per MMBtu)	
Case	**2020–2039 Annual Average**
Reference Case (4P)	9.2
+20% Natural Gas Price	11.0
+40% Natural Gas Price	12.9
+60% Natural Gas Price	14.7

As mentioned above, the SCPC option is not an economically viable investment in the Reference Case, due to the addition of carbon compliance costs. However, SCPC does become economically viable when gas prices increase by 20 percent over the Reference Case.

The SCPC-CCS ROE never meets the hurdle rate of 12.75 percent as other baseload investments (i.e., IGCC CCS and SCPC) become economically viable and keep energy prices from rising higher. Results are summarized in Exhibit 6-10.

IGCC is also never economic in any of the sensitivity cases for many of the same reasons as SCPC-CCS. The IGCC-CCS investment option, however, becomes economically viable when gas prices increase by 20 percent. With gas prices at that level, these units recover the initial investment through higher power prices, which are being set by gas-fired units during marginal hours.

Exhibit 6-10
Summary of Natural Gas Sensitivities



Note: While the NGCC ROE appears below the 12.75 percent hurdle rate in the above graph, its ROE is at 12.75 percent. It has been moved slightly for clarity purposes. SCPC and IGCC+CCS lines have also been moved (starting with the +20% case) for the same purposes.

The combined cycle investment option remains economically viable unless natural gas exceeds \$14/MMBtu on average. At higher gas prices, other baseload investment options, such as SCPC and IGCC-CCS, become economically viable and suppress any further rise in power price, limiting an NGCC's energy margins below its needed level. The nuclear investment option remains economically viable in all natural gas sensitivity cases. Investment decisions in the lower-48 states generally follow these same trends.

6.2.1.3 Federal RPS Sensitivity

As discussed with NETL personnel, it was thought best to use a different reference case for a parametric analysis of a federal RPS program. For this analysis, a reference case is developed without a federal carbon policy, which allows for better isolation of the RPS program and its effects (compared to its being performed under a carbon policy regime). Under a carbon policy, renewable investment options have more financially favorable, thereby obscuring the impacts of a federal RPS program.

The new reference case is referred to as a 3-Pollutant case, which has SO_x, NO_x, and Hg programs in place and enforces state RPS programs. Similar to the natural gas price analysis, from this baseline (the 3-Pollutant case) we developed 3 additional sensitivity cases that reflect a 10, 20, and 30percent federal RPS program. The most extreme RPS sensitivity case requires 30 percent of total power generation nationwide to be met by renewable power sources by 2020. Likewise, the 10 and 20 percent federal RPS cases require that renewable sources meet 10 and 20 percent of all U.S. generation, respectively, by 2020. The incremental generation that should be met by additional renewable capacity is shown in Exhibit 6-11. Any increase in renewable generation forced in through an RPS standard will tend to suppress wholesale power prices, as renewables tend to have zero variable production costs and would appear at the bottom of a dispatch stack. Thus, a strong RPS program would incentivize renewable builds, which may, in turn, delay baseload needs.

Exhibit 6-11
Summary of Federal RPS Sensitivities

Incremental Renewable Generation Needed by 2020	
Case	**GWh**
3-Pollutant Case	–
+10% Federal RPS	233,000
+20% Federal RPS	633,000
+30% Federal RPS	1,032,000

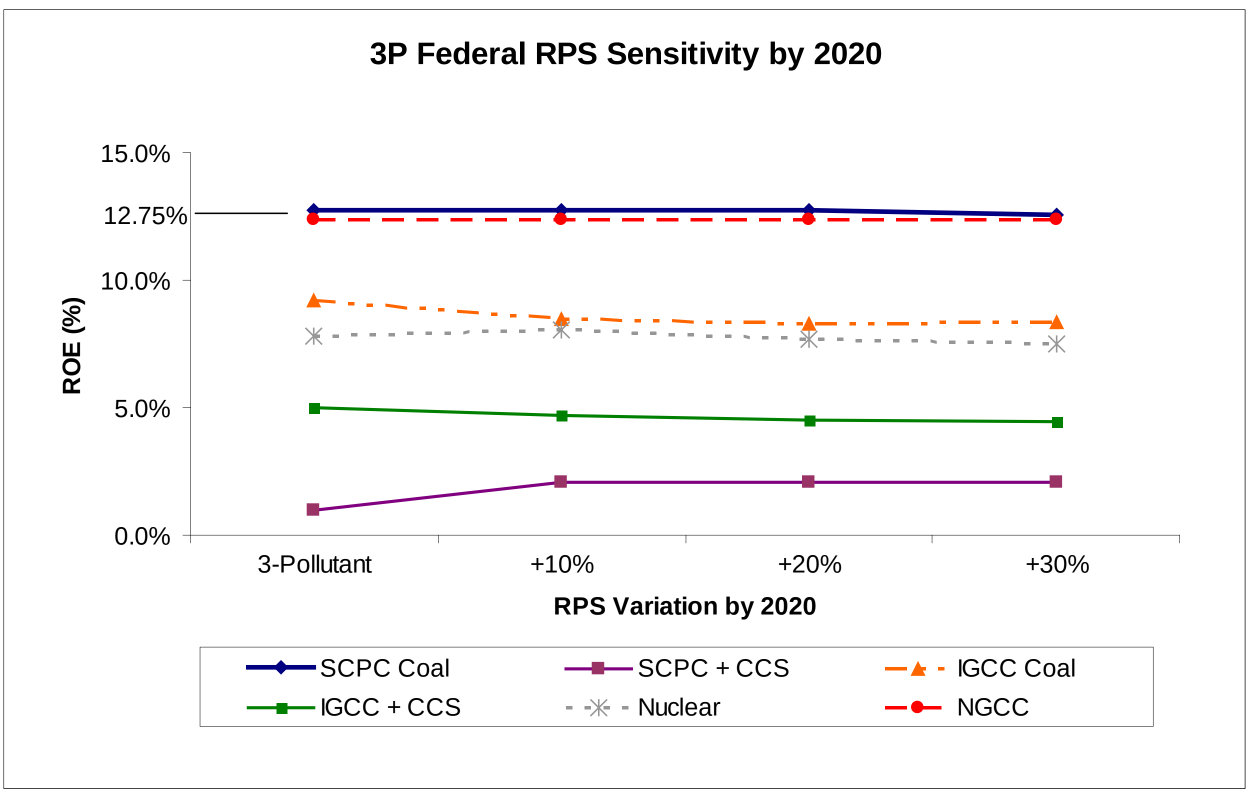
Exhibit 6-12 shows the total amount of renewable builds that are required to meet the RPS targets by 2020. Among the federal RPS sensitivities, the 10 percent federal RPS case is the only non-binding case, as the requirements are essentially already met by state RPS requirements. At the extreme, however, state RPS programs only meet 44 percent of the requirements of a 30 percent federal RPS program. Thus, the 30 percent federal RPS case requires an estimated 112 GW of additional renewable capacity nationwide.

Exhibit 6-12
Summary of Federal RPS Sensitivities

US Renewable Builds by 2020 (MW)	
Case	**2009-2020**
3-Pollutant Case	87,700
+10% Federal RPS	87,700
+20% Federal RPS	134,400
+30% Federal RPS	199,200

As shown in Exhibit 6-13, both the SCPC and NGCC investment options are economically viable in the 3-Pollutant case. Both options also stay economically viable in the 10 and 20 percent federal RPS cases. However, the SCPC's ROE falls slightly under the ROE hurdle rate in the 30 percent federal RPS case, as the additional renewable capacity suppresses wholesale power prices. The SCPC-CCS, IGCC, and IGCC-CCS investment options are not economically viable in all federal RPS sensitivity cases. The NGCC investment option is economically viable regardless of the federal RPS policy. However, the nuclear investment option is not economically viable in all federal RPS sensitivity cases.

Exhibit 6-13
Summary of Federal RPS Sensitivities



Note: While the NGCC ROE appears below the 12.75 percent hurdle rate in the above graph, its ROE is at 12.75 percent. It has been moved slightly for clarity purposes.

When looking at the U.S. as a whole, these federal RPS requirements have similar impacts on investment build decisions, with the biggest impact being on SCPC, NGCC, and renewable investments. While SCPC and NGCC capacity investments are lowered significantly, wind and other renewable investments increase dramatically.

6.2.2 Plant Technology Parameters

ICF also examined the effect of variations on cost and performance characteristics of baseload options. Specifically we reviewed variations in capital cost and plant availability. All sensitivity cases in this section are based on the Reference Case.

6.2.2.1 Capital Cost Sensitivity

ICF analyzed eight different capital-cost scenarios. Capital costs were increased and decreased at intervals of 10 percent. Thus, the maximum change in the capital cost from the Reference Case is 40 percent. Exhibit 6-14 illustrates the range of capital costs examined in these sensitivity cases. Capital costs represent an all-in cost (i.e., Total Capital Requirement), and reflect the cost of the technology with an online year of 2020.

These sensitivity cases were developed without assessing the physical or economic possibility of such cost reductions or increases. Rather, the 40 percent case was used as a bound, as it loosely represents the recent incremental increase in capital costs experienced over the 2006–2008 period.[131] Significant cost reductions are more probable with the IGCC, as it is still between the demonstration and commercialization phase. Significant cost reductions for SCPC will most likely be achieved only through "standardization" of design, as this is a mature technology.[132]

Capital costs were varied one prime mover at a time. For example, the cost of an SCPC was increased or decreased while holding all other prime mover capital costs constant.

Exhibit 6-14
Summary of Capital Cost Sensitivities
Capital Cost (2006$/KW)

Case	SCPC	SCPC-CCS	IGCC	IGCC-CCS	NGCC	Nuclear
-40% Capital Cost	1,740	3,180	2,100	2,880	720	2,760
-30% Capital Cost	2,030	3,710	2,450	3,360	840	3,220
-20% Capital Cost	2,320	4,240	2,800	3,840	960	3,680
-10% Capital Cost	2,610	4,770	3,150	4,320	1,080	4,140
Reference Case (4P)	2,900	5,300	3,500	4,800	1,200	4,600
+10% Capital Cost	3,190	5,830	3,850	5,280	1,320	5,060

[131] ICF experience in the marketplace between 2006 and 2007 saw construction costs on power projects rise approximately 20%. From 2007 to the summer of 2008 costs again rose an additional 20%.

[132] In April of 2006 TXU announced the building of approximately 8,00MW of coal capacity in Texas at a cost of approximately $10 billion or $1,100/kW. Through the use of a standard plant design TXU believes it can capture approximately $350/kW in construction cost savings. This translates to approximately 25% of the total cost. Cost reductions are to be achieved through a single plant design, procurement of major equipment in scale, reductions in overhead and lean construction labor.

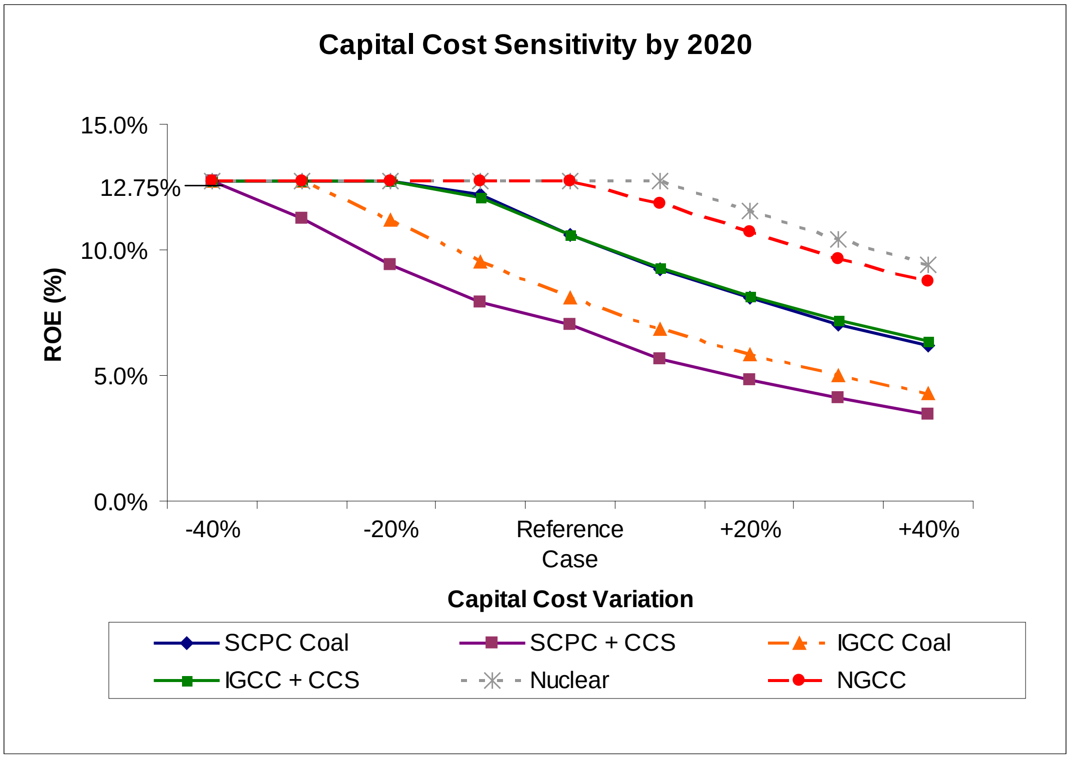
Case	SCPC	SCPC-CCS	IGCC	IGCC-CCS	NGCC	Nuclear
+20% Capital Cost	3,480	6,360	4,200	5,760	1,440	5,520
+30% Capital Cost	3,770	6,890	4,550	6,240	1,560	5,980
+40% Capital Cost	4,060	7,420	4,900	6,720	1,680	6,440

SCPC and SCPC-CCS have ROEs less than the hurdle rate and are, therefore, not economically viable investments in the Reference Case and any cases where capital costs are increased. However, as illustrated in Exhibit 6-15, when capital costs are reduced between 10 and 20 percent, the SCPC unit becomes economically viable. SCPC's ROE improves as decreasing capital cost reduces the debt liability, while revenues remain unchanged. SCPC-CCS becomes economically viable only when its capital cost is lowered by 40 percent, which seems to be a significant barrier to CCS deployment on SCPC. Since SCPC technology is already mature, most cost reductions must come from advancements in CCS components.

IGCC and IGCC-CCS become an economically viable investment only when their capital costs are lowered by 30 percent and 20 percent, respectively. Based on ICF's research, this potential target of cost reduction appears to be a possibility for both IGCC options. Exhibit 3-12 in Chapter 3 shows the areas of potential technology improvement and the effect on capital cost in terms of percentage reduction. If both improvements to the air separation unit and syngas cleanup are actualized, this target can be achieved.

Investment in new NGCC becomes not economically viable when its capital cost rises by 10 percent from its current level. This underscores the marginal unit role the NGCC plays in ECAR-MECs in 2020. New nuclear investment has an ROE lower than the hurdle rate of 12.75 percent when its capital cost increases by 20 percent. Such increases may occur in the future from a variety of reasons. As shown in Exhibit 3-20 of Volume I, one example may be the delay during construction and its escalation of finance charges.

Exhibit 6-15
Summary of Capital Cost Sensitivities



6.2.2.2 Availability Sensitivity

Availability is defined here as the time in a year a power plant is available to dispatch, accounting for scheduled, planned, and forced outages. The availability levels analyzed in these cases are conservative and achievable for the SCPC. Availability at the 83 percent level is certainly possible for the IGCC (see Exhibit 3-9). The challenge for the IGCC will be moving beyond the 83 percent level at a reasonable cost addition. Adequate redundancy, such as full-sized spare gasifiers or natural gas backup, can be incorporated into the design, but the trade-off will be a higher, as of yet uncertain, cost. Additional costs were not added to simulate these higher availabilities.

Exhibit 6-16
Summary of Availability Sensitivities

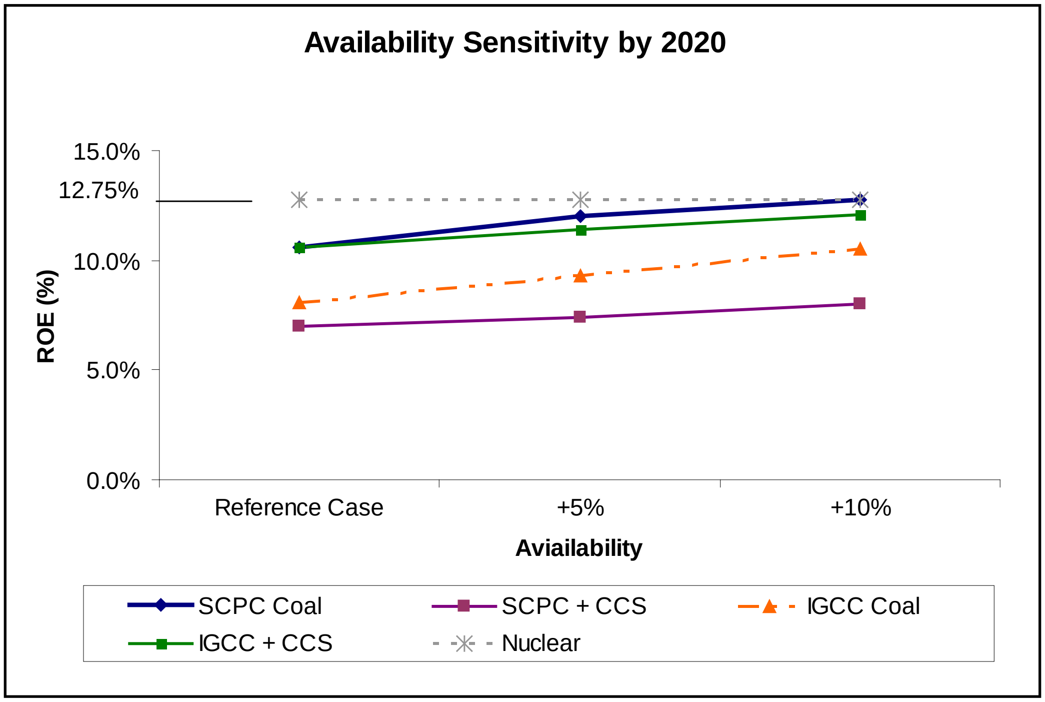
Availability (%)					
Case	**SCPC**	**SCPC-CCS**	**IGCC**	**IGCC-CCS**	**Nuclear**
Reference Case (4P)	82.9	82.9	82.9	82.9	90.0
+5% Availability	87.9	87.9	87.9	87.9	95.0
+10% Availability	92.9	92.9	92.9	92.9	100.0

SCPC becomes an economically viable investment option when its availability is as high as 92.9 percent. As seen in Exhibit 6-17, the ROE for the SCPC is very sensitive to availability. This makes sense, as the facility's revenues increase due to an increase in sales volume at relatively little incremental cost. Many world-class facilities in this country are currently following a "best-practices" approach program to maintenance that allows them to achieve high availability rates.

The ROE of an IGCC-CCS investment almost reaches the hurdle rate of 12.75 percent at 92.9 percent availability. While encouraging, this may be difficult to achieve, as reaching these availability targets would require additional costs.

On the other hand, while their ROEs improve, both SCPC-CCS and IGCC remain not economically viable even when availability is increased significantly.

Exhibit 6-17
Summary of Availability Sensitivities



6.2.3 Conclusion

It is important to note that these results are based on ICF assumptions and are susceptible to change due to variations in market assumptions, plant technology cost, and plant performance parameters.

The major goal of these sensitivities was to see how much each parameter on its own had to change to make the different plant types economically viable investments. Exhibit 6-18 summarizes the results by identifying the sensitivity cases in which each coal unit becomes economically viable. In reality, many of these factors may combine and push a plant past the hurdle rate to become economically viable. For example, as shown in Exhibit 6-18, SCPC becomes economically viable if gas prices are 20 percent higher, its capital costs are reduced by 20 percent, or its availability is increased by 10 percent. It is possible that these variables improve in minor ways, but combine in such a way that SCPC becomes economically viable, even in a carbon-constrained world.

A number of market or technology developments could make SCPCs economically viable. SCPC investment is economically viable in the 3-Pollutant and mild CO_2 cases. SCPC investment is also economically viable when gas prices are 20 percent higher than in the Reference Case. In addition, SCPC remains economically viable in 3-Pollutant sensitivity cases when federal RPS requirements are no more than 20 percent. In terms of technology sensitivities, SCPC becomes economically viable when its capital cost drops by 20 percent and when its availability improves by 10 percent.

Based on ICF assumptions, it appears that SCPC-CCS is unlikely to become an economically viable investment unless its capital cost falls 40 percent, at which point it would cost about as much as SCPC without CCS. Similarly, IGCC (without CCS) only becomes economically viable when its capital cost is reduced by 30 percent. However, IGCC becomes economically viable in more cases when it is coupled with CCS.

Exhibit 6-18
Summary of Sensitivities Meeting or Exceeding Investment Hurdle Rate

Sensitivity Cases	SCPC	SCPC-CCS	IGCC	IGCC-CCS
CO_2 Sensitivities	75% Lower CO_2	None	None	75% Higher CO_2
Gas Sensitivities	20% Higher Gas	None	None	20% Higher Gas
Federal RPS Sensitivities	RPS lower than 20%	None	None	None
Capital Cost Sensitivities	Lower by 20%	Lower by 40%	Lower by 30%	Lower by 20%
Availability Sensitivities	Higher by 10%	None	None	None

IGCC-CCS investment is not economically viable under ICF's Reference Case assumptions. However, this outcome critically depends on the assumed CO_2 allowance prices, natural gas prices, and capital cost. IGCC-CCS becomes an economically viable investment when the average annual CO_2 price is 75 percent higher than the Reference Case or when the average annual natural gas price is 20 percent higher. Finally, a capital cost reduction in the proximity of 20 percent will favor the IGCC-CCS investment option. This could be achieved either by lowering the IGCC costs or those of the CCS process.

The NGCC investment option is economically viable in a carbon-constrained environment, unless annual average CO_2 allowance cost is increased by 75 percent or annual average gas price is increased by 60 percent as other baseload options become more economically viable.

Nuclear investment is an economically viable decision in a carbon-constrained environment as well. However, when annual average carbon allowance costs are reduced by 50 percent, nuclear loses profitability and is no longer economically viable. In a similar fashion, any capital cost increase in the proximity of 20 percent will also make this investment unattractive.

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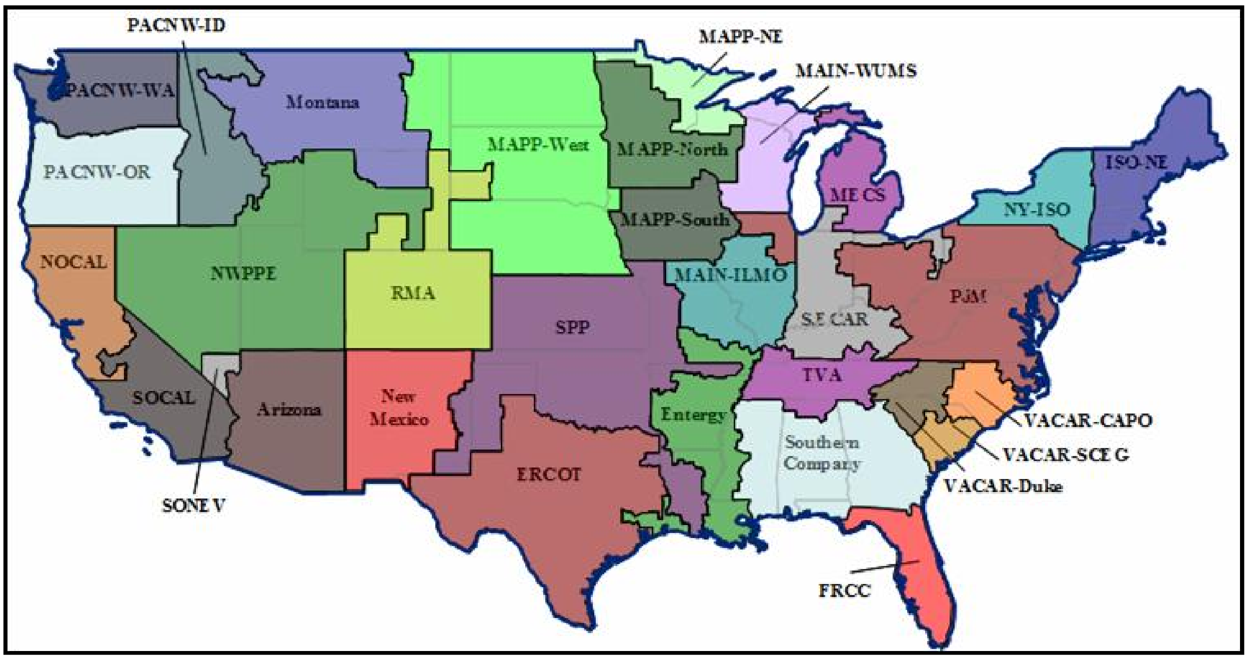
Appendix A
Key Market Assumptions

This section provides a summary of the key market assumptions that influence future power prices in U.S. power markets, with a focus on the Michigan Electric Coordinated Systems (MECS) sub-region.

A.1 Modeling Treatment

ICF's economic and engineering modeling tool, IPM®, simulates the entire energy market of both the United States and Canada. The energy market area is broken into over 100 regions and sub-regions to capture commercially significant transmission congestion. Exhibit A-1 illustrates a high-level breakup of the U.S. power grid. Our focus region, MECS, is one the sub-regions simulated in the Midwest.

Exhibit A-1
High Level View of IPM® Modeling Regions



A.2 Summary of Key Market Assumptions

A.2.1 Demand Levels and Demand Growth

ICF uses weather-normalized forecasts obtained from the NERC's *2008 Long-Term Reliability Assessment* to determine peak demand in 2009 as the starting point for MECS. Sources and methodology for energy requirements mirror those of peak requirements. Exhibit A-2 below provides an overview of MECS demand assumptions.

Exhibit A-2
Demand Assumptions Overview for MECS

Parameter	Treatment
	ECAR-MECS
2009 Net Internal Peak Demand (MW)	21,668
Annual Peak Growth (%)	
2009-2013	2.0
2014-2020	1.3
2021-2027	0.8
2028-2033	1.0
2034-2039	1.6
2009 Net Energy Load (GWh)	114,148
Annual Peak Growth (%)	
2009-2013	1.9
2014-2020	1.2
2021-2027	0.8
2028-2033	1.0
2034-2039	1.5

Source: 2008 Long-Term Reliability Assessment.

Projected demand growth rates are derived from a combination of historical data and projected growth rates from NERC or the respective ISO. In the short-term, ICF projections are closer to historical levels; in the long-term, our demand assumptions give greater weight to industry forecasts such as those issued by NERC. ICF applies this methodology to all regions and sub-regions in the U.S. The annual nationwide demand growth rate is estimated to be 1.2 percent on average for all years, as projected in ICF's Reference Case.

A.2.2 Reserve Margin Targets

In combination with peak load growth, planning reserve margins (which are distinct from operating reserves) determine the total power demand in a market. Planning reserve margin targets account for uncertainties in both operations and weather/demand. Either the market or the industry can set total planning reserve margins even though only the industry can set operating reserves.

For example, with a 16 percent reserve margin goal and an expected peak of 30 GW, 4.8 GW of planning reserves are needed. It is extremely rare for new power plant construction to be fully economically viable (i.e., earn full returns), except when the reserve margin requirement is binding (taking imports and exports into consideration). ICF models a 15 percent planning reserve margin for ECAR-MECS, consistent with the current reserve margin of the territory in which it is located, Midwest ISO (MISO).

A.2.3 Changes in Supply Dynamics

New-builds over the forecast horizon include both firm and non-firm builds as necessary to meet net peak demand and reserve requirements. Firm builds are new additions included in the model, irrespective of economic viability. ICF considers capacity additions to be “firm” if they are operational or under construction. In a few rare instances, ICF includes capacity expansion as firm that has not yet begun construction if a project has secured permits, financing, and PPA. Exhibit A-3 summarizes ICF’s assumptions regarding firm builds.

Exhibit A-3
Firmly Planned Additions across the U.S.

Region	2009	2010	2011	2012	Total
California	1,160	549	–	–	1,709
ECAR	956	750	967	–	2,673
Entergy	–	665	–	–	665
ERCOT	2,476	1,602	–	900	4,978
FRCC	1,250	1,550	–	–	2,800
ISO-NE	–	–	–	–	0
MAIN	815	915	1,500	–	3,230
MAPP	663	99	220	–	982
Arizona/New Mexico	400	–	–	–	400
NWPP	26	–	485	–	511
NYISO	934	250	–	–	1,184
PJM	–	–	–	–	0
RMPA	750	–	–	–	750
Southern Company	–	–	–	–	0
SPP	600	850	–	–	1,450
VACAR	600	-	–	800	1,400
Total	**10,630**	**7,230**	**3,172**	**1,700**	**22,732**

The capacity mix of non-firm builds (unplanned) is endogenously determined by the IPM model based on economic viability.

A.2.4 New Build Costs

The ICF long-term outlook requires new capacity to be built to meet net internal peak demand and reserve margin requirements, while accounting for inter-regional trading of pure capacity, mothballing, and retirements. Characteristics of new units drive decisions on the mix of capacity added and, consequently, affect both energy and capacity prices.

Combustion turbines (CT) have the lowest capital- and fixed-O&M costs among all of the new generation options. However, this advantage is offset by its higher variable operating costs associated with higher heat rate and variable O&M costs. NGCC has higher capital costs, but lower variable operating costs. Coal plants and nuclear plants have the highest capital costs, but fairly low variable operating costs (primarily due to lower fuel costs for coal and uranium as compared to natural gas). ICF develops its construction cost estimates by reviewing sources such as the Gas Turbine World Handbook, client and EPC discussions, IRP filings, year-to-date commodity prices, and EPC backlogs.

For MECS, we assume new combined cycle plants are available in 2013 at approximately $1,300/kW (2006$). Additionally, we model a new combustion turbine as having an all-in capital cost of $700/kW (2006$) for 2011.

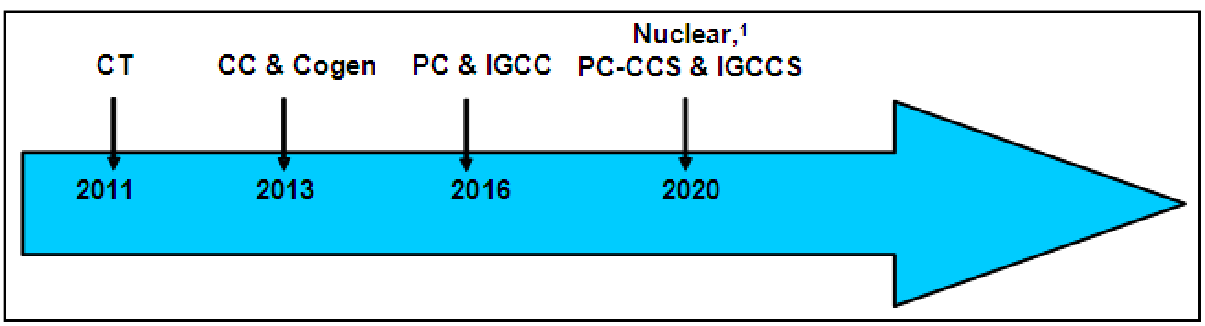
Because capital costs are key drivers of capacity pricing, ICF estimates capital costs on a summer capacity basis. Exhibit A-4 summarizes estimated new build costs for the MECS region.

Exhibit A-4
Key New Power Plant Cost Assumptions for MECS (2006$/kW)

Year	PC	PC-CCS	IGCC	IGCC-CCS	NGCC	Nuclear
2009	NA	NA	NA	NA	NA	NA
2011	NA	NA	NA	NA	NA	NA
2013	NA	NA	NA	NA	1300	NA
2016	3100	NA	3700	NA	1300	NA
2020	2900	5600	3700	5100	1200	4600
2025	2800	5400	3600	4800	1200	4400
2030	2800	5400	3600	4800	1200	4400
2036	2800	5400	3600	4800	1200	4400

Over the entire analysis period, we allow the model to optimize the selection of new units based on economics. If energy margins are tight, combustion turbines may be favored; however, in times of strong margins, a combined cycle or coal plant may be favored.

Exhibit A-5
Unplanned Build Timeline for ECAR MECS



[1]Nuclear builds may only be built after 2020 at existing sites only. Thus, in some sense, only brownfield projects are allowed.

ICF imposes restrictions on the start dates of unplanned capacity additions to account for the necessary construction and permitting lag times and the commercial acceptance of new technology. These restrictions can be seen in Exhibit A-5. Specifically for combined cycles, the 4-year lag represents 1–2 years for permitting and financing, 1-year delay in securing turbines, and 2 years of construction. Lead times for baseload generation options are shown below.

A.2.5 Financing Costs

A source of uncertainty for new builds is their financing structure. Due to a growth in perceived market risk and overall financing difficulty over the last few years, projects are increasingly "hedged" in nature. This contrasts with projects developed earlier this decade, which were primarily merchant in nature. However, there are still many purely merchant projects under development. We recognize that the split between merchant and utility will vary over time and regionally, and we believe that a 50:50 mix is a reasonable assumption; hence, financing costs reflect such a blend of utility and IPP financing costs. ICF captures the varying levels of risks through the financing mix (debt/equity ratio), such that when the equity risk is unlevered to strip out the financial risk, the baseload asset has the lowest market risk.

As shown in Exhibit A-6, the real levelized capital charge rate for a new CC in MECS is 11.8 percent. A new CT has a 12.5 percent capital charge rate, and both coal and nuclear plants have lower capital charge rates of 10.8 percent.

ICF considers the capital charge rate to be the levelized rate of return on an investment. As mentioned earlier, the components of this rate are based on a combination of utility and merchant financing. Projects differ in capital charge rates and discount rates due to variations in book life and debt-equity ratios. For baseload units in all cases, ICF incorporates a required nominal after-tax ROE of 12.75 percent and an interest rate on debt of 7.13 percent. Exhibit A-6 shows the financial assumptions to rely on this ROE barrier and interest rate on debt.

Exhibit A-6
New Plant Financing Cost Assumptions for ECAR-MECS Region

Debt/Equity Ratio (%)[1]	
CC & Cogen	50/50
CT & LM6000	42/58
Coal & IGCC	58/42
Nominal Debt Rate CC/CT/Coal (%)[1]	7.1/7.6/7.1
Nominal After Tax Return on Equity (%)[1]	12.75
Income Taxes (%)	41.2
Other Taxes (%)[2]	1.2
General Inflation Rate (%)	2.5
Levelized Real Capital Charge Rate (%)	
CC/Cogen	11.8
CT/LM6000	12.5
Coal/IGCC	10.8

[1] Assuming 2.5 percent inflation, this equates to a 4.5 percent real debt rate for CC/Cogen/Coal/IGCC/Nuclear and 5.0 percent real debt rate for CT; 10.3 percent real after-tax return on equity rate for all capacity types.

[2] Includes property taxes, as well as insurance costs of 0.3 percent for all the subregions.

A.2.6 Natural Gas Prices

Exhibit A-7 presents ICF's natural gas price forecast in real dollar terms. Our approach to natural gas price forecasting for the short term reflects a reliance on liquidly traded futures. Specifically, our 2009 Henry Hub prices reflect NYMEX futures traded during the September–

October 2008 period. Beginning with 2011 and thereafter, ICF uses its own fundamentals-based forecast using our in-house gas markets model. We use a blend of 2009 futures and 2011 fundamentals pricing for the 2010 gas prices. Similarly, basis differentials reflect forward trading for the near term and fundamentals-based assessments for the long term.

Exhibit A-7
Natural Gas Price Forecast (2006$/MMBtu)

Year	Henry Hub	Delivered Prices[1]
		ECAR-MECS
2009	7.16	7.30
2011	7.30	7.54
2013	7.07	7.27
2016	7.34	7.50
2020	8.39	8.59
2025	8.71	8.96
2030	9.11	9.33
2036	9.98	10.09

[1] Includes respective LDCs and taxes.

As mentioned above, gas prices from 2011 onward are from ICF's Gas Market Model (GMM). GMM is a full supply-demand equilibrium model of the North American gas market. The model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's 114 nodes, or market hubs, which cover the U.S. lower-48, Canada, Alaska, and Mexico border points. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. LNG import volumes are solved at each of the existing import terminals, as well as terminals that are projected to come online in the forecast period. On the demand side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices, determined by the shape of the supply and demand curves. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of pipeline load factor.

ICF projects that natural gas prices are going to decrease from 2011 to 2013 relative to current levels, due to increased production in the Mid-Continent Shales and the Northern Rockies and corresponding pipeline expansions out of these two areas. LNG imports are also projected to increase, but high gas prices in Europe and Asia limit the amount of LNG delivered to North American terminals, particularly in the winter months. From 2013 to 2020, prices are projected to increase modestly, as the combined growth in domestic production and imported LNG roughly matches the growth in gas demand. After 2020, lower-48 gas production is projected to hold steady, with increases in the Northern Rockies, the Shales, and deepwater Gulf of Mexico production, offsetting declines in more mature production areas. New supply from the Alaska Gas Pipeline and continued increases in LNG imports allow for growth in gas demand. New LNG terminals will be built primarily along the Gulf Coast, taking advantage of the existing pipeline infrastructure.

Delivered prices differ regionally due to varying basis differentials, fuel taxes, and local distribution and/or swing charges. Additionally, commodity and transportation prices vary with demand on a seasonal basis in accordance with our forecasts and historical trends (e.g., higher prices in the winter than in the summer). Near-term seasonality is driven by futures prices, as with the Henry Hub and basis differentials. We employ GMM outputs and market and historical data to derive our long-term seasonality trends.

A.2.7 Coal Prices

In the short term, coal prices are expected to drop significantly from the record-setting highs of 2008, as U.S. and international demand for coal decreases. Prices, especially for coal from the Appalachian regions, are expected to drop to the cost of production as a delayed production response to the export market surge at the end of 2008 intersects with rapidly evaporating global demand. This supply-demand dynamic has nudged producers in both the eastern and western basins to announce short-term production cuts and forced high-cost operations offline.

In the long term, prices from most basins are expected to gradually decline as older coal units retire and fewer new coal plants are built due to expected climate change legislation, limiting long-term domestic coal demand. Prices in the eastern basins, however, are likely to experience upward pressure due to their exposure to the export market, and rising international need for coal. The overall price stability for PRB coal is primarily due to the large reserves and underutilized productive capacity in that region, which permits ramped-up production when needed.

Exhibit A-8
Coal Price Assumptions (2006$/Ton)

Year	Central Appalachian	Northern Appalachian	PRB 8800 Btu/lb
Heat Content (Btu/lb)	12,500	13,000	8,800
Sulfur Content (lb/MMBtu)	1.5	3.0	0.8
2009	85.5	87.1	36.8
2011	72.2	74.8	14.6
2013	62.5	62.4	13.7
2016	57.4	55.0	12.9
2020	57.4	52.5	13.6
2025	58.5	51.6	13.6
2030	61.6	50.8	13.8
2036	64.6	50.9	14.2

Source: ICF Forecasts.

A.2.8 New Unit Characteristics

The G-technology-based new combined cycles and combustion turbine units are assumed to have HHVs of 6,800 and 10,900 Btu/kWh, respectively, in 2020. These modeled heat rates are long-term averages with unrecoverable degradation included. Combustion turbine-based options improve modestly over time when compared to CCs, due to the quicker commercial acceptance of next generation gas turbines such as the FB-, G- and H-technologies.

New supercritical coal units are assumed to have a heat rate of approximately 9,100 Btu/kWh and IGCC heat rates are assumed to be around 8,300 Btu/kWh (assuming a 7FA-Technology power island).

Exhibit A-9
New Power Plant Characteristics in 2020

Plant Type		
IGCC	**PRB**	**BIT**
Fixed O&M (2006$/kW/yr)	32	32
Non-Fuel Variable O&M (2006$/MWh)	2.2	2.2
Average Full-Load Heat Rate (Btu/kWh)	9,100	8,300
Availability (%)	83	83
PC[1]	**PRB**	**BIT**
Fixed O&M (2006$/kW/yr)	26	27
Non-Fuel Variable O&M (2006$/MWh)	4.2	3.3
Average Full-Load Heat Rate (Btu/kWh)	9,700	9,100
Availability (%)	83	83
IGCC-CCS	**PRB**	**BIT**
Fixed O&M (2006$/kW/yr)	41	41
Non-Fuel Variable O&M (2006$/MWh)	4.0	4.0
Average Full-Load Heat Rate (Btu/kWh)	11,200	10,200
Availability (%)	83	83
PC-CCS[1]	**PRB**	**BIT**
Fixed O&M (2006$/kW/yr)	39	40
Non-Fuel Variable O&M (2006$/MWh)	7.4	7.4
Average Full-Load Heat Rate (Btu/kWh)	13,900	13,100
Availability (%)	83	83
Combined Cycle and Cogen Units		
Fixed O&M (2006$/kW/yr)	10-20[2]	
Non-Fuel Variable O&M (2006$/MWh)	0.7-2.8[3]	
Average Full-Load Heat Rate (Btu/kWh)	6,800	
Availability (%)	92	
Nuclear Units		
Fixed O&M (2006$/kW/yr)	110	
Non-Fuel Variable O&M (2006$/MWh)	0.5	
Average Full-Load Heat Rate (Btu/kWh)	10,400	
Availability (%)	90	

[1] These represent a SCPC with SCR, FGD, and ACI for Hg control.

[2] Fixed and variable cost modeling structure varies for combined cycle units depending on cycling activity. Actual costs are determined endogenously in the model for each unit based on its operation. FOM includes labor, G&A and capital expenditures. It excludes property taxes and insurance.

[3] Variable costs are representative; assuming a 5 percent capacity factor for simple cycle turbine units, and 80 percent for combined cycle and coal units. Actual values are results of the analysis.

The variable operation and maintenance costs (VOM) for new unplanned build options shown in Exhibit A-9 typically cover items that are a function of generation, such as water, limestone, ammonia, chemicals, waste disposal, start-up fuel, and cost per start (major maintenance/LTSA fees). For the two coal options, however, we treat cost-per-start as a fixed component due to their intended baseload design. Thus, while both the CC and IGCC have essentially the same power island, the VOM is slightly lower for the IGCC because its cost-per-start is treated as fixed.

A.2.9 Environmental Regulations

There is uncertainty regarding the exact form and timing of future environmental regulations. However, ICF has incorporated regulations currently "on the books," as shown in Exhibit A-10, covering regulations for the three pollutants SO_2, NO_x, and Hg. ICF has also included CO_2, which will most likely be regulated in the near future. As discussed, the assumption of CO_2 regulations has important implications for natural gas prices and for the costs of fossil-fuel generation.

Exhibit A-10
Federal Environmental Assumptions Overview

<table>
<tr><th>Parameter</th><th>Treatment</th></tr>
<tr><td>SO_2 Regulations</td><td>Phase II Acid Rain; CAIR; allowance prices assume tightened CAIR regulations</td></tr>
<tr><td>NO_x Regulations</td><td>SIP Call; CAIR; allowance prices assume tightened CAIR regulations</td></tr>
<tr><td>CO_2 Regulations</td><td>ICF's expected CO_2 case based on a probabilistic assessment of potential legislation.</td></tr>
<tr><td>Hg Regulations</td><td>State level MACT regulations for those units that opted out of CAMR, remaining states subject to 90 percent MACT from input starting in 2014</td></tr>
<tr><td>Allowance Prices (2006$/ton)</td><td>$SO_2$: Starts at $1320/ton in 2009 rising steadily to over $3,240/ton by 2025 and then falls back to $1,790/ton by the end of the forecast.
NO_x: Annual NO_x under CAIR increases from $1,115/ton in 2009 to $2,070/ton by 2020 then diminishes for the rest of the planning period.
National and RGGI CO_2:
<table>
<tr><th>Year</th><th>RGGI CO_2 Price (2006$/ton)</th><th>National CO_2 Price (2006$/ton)</th></tr>
<tr><td>2008</td><td>0</td><td>0</td></tr>
<tr><td>2009</td><td>2.19</td><td>0</td></tr>
<tr><td>2011</td><td>2.30</td><td>0</td></tr>
<tr><td>2013</td><td>5.0</td><td>0</td></tr>
<tr><td>2016</td><td>5.0</td><td>21.6</td></tr>
<tr><td>2020</td><td>5.0</td><td>27.1</td></tr>
<tr><td>2025</td><td>5.0</td><td>35.9</td></tr>
<tr><td>2030</td><td>5.0</td><td>47.6</td></tr>
<tr><td>2036</td><td>5.0</td><td>66.5</td></tr>
</table></td></tr>
</table>

The air regulatory structure for ICF's Reference Case is representative of the timing, scope, and stringency likely to be realized under current and future regulation/legislation. While it remains unclear as to how NO_X, SO_2, and Hg will actually be constrained over the next decade, the reductions included here are within the range of those currently proposed by both EPA and legislators.

ICF's Reference Case includes legislative action to carry on NO_x and SO_2 cap-and-trade programs consistent with CAIR as planned in 2009 and 2010, respectively, through Phase I, ending by 2015. In 2015, ICF's Reference Case assumes the legislation moves from a regional to a national program for annual NO_x and SO_2, with tighter caps than included for Phase II of CAIR. The Phase II caps are instead consistent with the proposal of Senator Carper in his Clean Air Planning Act of 2007 (CAPA, S.1177). The Hg program is a hybrid that combines a Federal MACT and regulations already imposed at the state level.

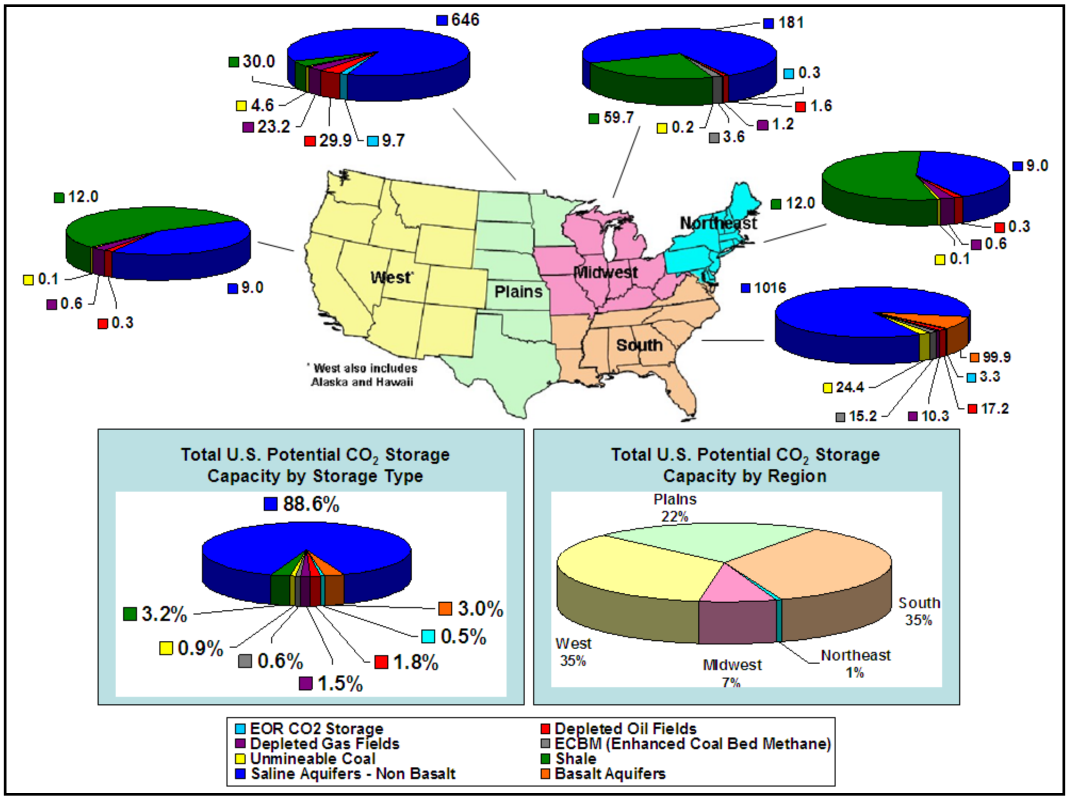
California has already passed CO_2 legislation and many states from the Mid-Atlantic and Northeast are developing a regional CO_2 cap under the Regional Greenhouse Gas Initiative (RGGI). Furthermore, legislators such as Sens. McCain, Lieberman, and Carper have also proposed carbon-reduction programs. We have modeled each of the bills separately in the past, which has given rise to our expected view on CO_2 allowance prices. After 2015, ICF expects that national CO_2 regulations will replace (and be more stringent than) the state and local level CO_2 regulations.

ICF's Reference Case derives an expected CO_2 price based on a probability-weighted outcome of several CO_2 reduction trajectories, with the probability of a more stringent policy increasing over time. CO_2 prices are zero prior to 2015, with the expectation that power plants coming online in the near future will receive CO_2 emission allowances. The baseload unit investment options considered in the sensitivity cases will not receive any allowances, since they will come online in 2020. In other words, the economic decision includes 100 percent of the carbon allowance cost.

A.2.10 Carbon Transportation and Sequestration

IPM® utilizes a comprehensive database of potential storage sites, listed by type of reservoir and region. The sites and storage facilities are summarized in Exhibit 3-15 of Volume 1, *Investment Risk Factors for Baseload Generation*, which is repeated here as Exhibit A-11. The different type of storage options included are enhanced oil recovery (EOR), depleted gas fields (Gas), depleted oil fields without EOR (Oil), gas shales (Shale), basalt aquifers (Basalt), enhanced coalbed methane (Coalbed), and saline aquifers – non-basalt (Saline).

Exhibit A-11
Metric Gigatons of Potential CO_2 Storage Capacity by Region and Storage Type



Sources: NATCARB and ICF International analysis.

IPM utilizes a storage cost curve that factors in the cost of transportation, storage, and demand to create a nationwide view of CO_2 sequestration costs and capabilities. As demand for a particular storage type in a region goes up, the cost goes up accordingly until a cap is met or a lower cost alternative is available. CO_2 storage sites that offer EOR would have negative storage costs, as there would be a net benefit of adding CO_2 to these sites. However, these are extremely limited in both sites and capability. The CO_2 transportation potential is considered to be unlimited, as the storage capability will be the major limiting factor. As a result, the storage potential in the Northeast is lower than in the South, and consequently would have higher storage costs.

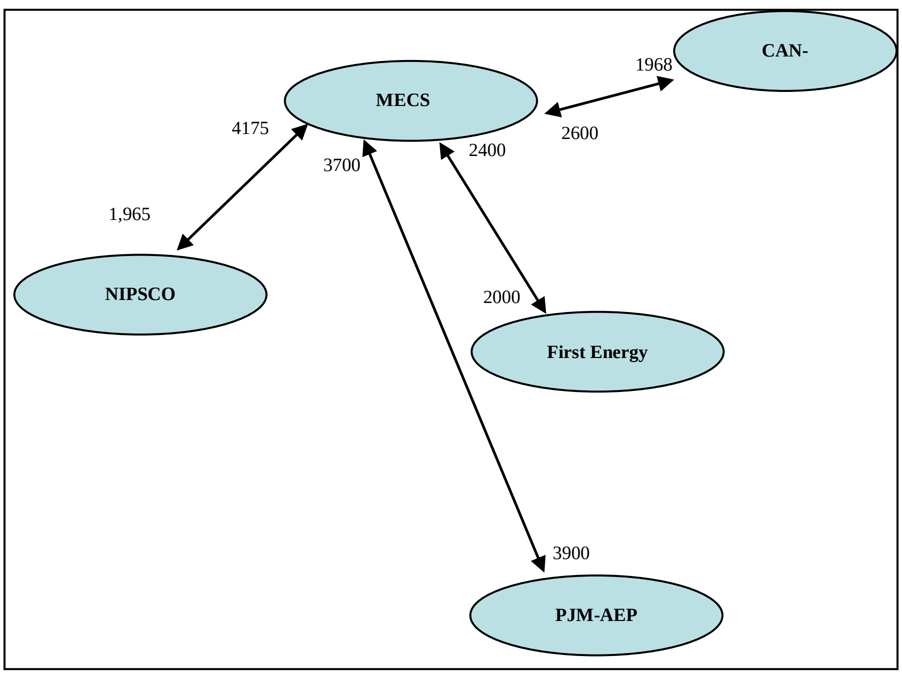
A.2.11 Transmission

Power will flow on an economic basis subject to transmission limits, as specified by the total transfer capability and subject to transmission costs and losses. We treat transmission capability in two ways: firm vs. non-firm and simultaneous vs. non-simultaneous. Transmission capacity for commercial energy transactions is categorized as either firm or non-firm. Firm transmission capacity reflects capacity net of margins reserved for reliability. Total available firm transmission capacity is determined after all possible credible contingencies have been taken into consideration; thus, firm transmission capacity can be regarded as dependable transmission. A generator in one region may be counted as contributing to another region's reserve margin if, and only if, firm transmission capacity is available to that generator. Similarly, ICF's market analysis uses firm transmission capacity only for reserve margin capacity trades between regions.

Non-firm transmission is additional capacity over and above the firm transmission capacity level. It is offered in markets usually for economic energy flows, with the stipulation that in the event of a contingency, transactions using non-firm transmission will be curtailed. Thus, energy transactions scheduled under firm transmission reservations are only curtailed under extreme contingency conditions and after all non-firm transactions have been curtailed. As a result, non-firm transmission capacity is less expensive than firm transmission.

Transmission capability is also classified as simultaneous or non-simultaneous, depending on whether power transfers involved are to or from a single interconnected neighbor (non-simultaneous) or simultaneously to/from all neighbors (simultaneous). Exhibit A-12 is an illustrative example of the MECS non-simultaneous transmission capability.

Exhibit A-12
Illustrative Example of MECS Non-simultaneous Transmission Capability (MW) with Its Neighbors



Simultaneous (joint) import or export transfers are usually lower than the sum of non-simultaneous transfers. Simultaneous transfer limitations are captured in our modeling by using joint interface capacities for all interconnecting paths to a region.

Appendix B
ICF Modeling Approach

This chapter presents ICF's modeling approach, which assumes a perfectly competitive market. Actual markets may tend to have some deviation from perfect competition, which typically results in higher market pricing. Since these deviations are not considered, our analysis is somewhat conservative.

Methodology

Energy and Capacity (Price Spike Revenue) Pricing Approach

The value of a power plant is assessed by examining the applicable forecast of revenues and costs associated with plant operations. Power plant revenues are primarily based on sales of two unbundled products: electrical energy and "pure" capacity. Electrical energy prices are associated with the variable costs of operation for the highest variable cost unit dispatched to meet energy demand (i.e., the marginal unit). Pure capacity pricing reflects the value of maintaining reliability of the overall system. Capacity value in a market with a single bundled electric power product is often reflected through price spikes or volatility in the power price. The sum of the spot price of unbundled electric energy and the spot price of unbundled capacity is the spot market price of firm electricity. Exhibit B-1 shows several examples of the bundled or firm power price, which may vary depending on actual conditions experienced in individual marketplaces. These two products are individually analyzed in this analysis; a more detailed description of these products is included below.

Exhibit B-1
Three Examples of Firm Pricing ($/MWh) – Illustrative

	Low	Medium	High
Electrical Energy (Interruptible)	15	20	25
Pure Capacity/Price Spikes	5	10	20
Total Firm	20	30	45

Note that although power generation facilities may be able to sell ancillary services, in most situations, when making these sales, the plant must forgo sales of energy and capacity.

Valuation Approach

Valuation in its most mechanical form is a two-step process. First, in equilibrium, capacity revenues are based on the capacity of the plant and the annual "pure" capacity price.

Capacity Revenues = Capacity (kW) x "Pure" Capacity Price ($/kW/yr)

Second, energy revenues are based on three factors: the capacity of the plant, the level of dispatch for the plant, and the energy price during hours the plant operates. The level of dispatch, in turn, depends on the bid. In a competitive market, the bid price reflects the variable costs of the plant, namely the variable component of fuel price, variable O&M costs of the plant, any environmental allowance costs, and any uplift bid in by the participant.

Energy Revenues = Capacity (MW) x Hours of Operation (Hours) x Realized Energy Price ($/MWh)

While all available power plants receive similar revenues for capacity (on a per kW basis), net energy revenues will vary across plants.

Note that we use this approach even for markets where no separate capacity market exists. This ultimately derives from the empirical finding by ICF that no market in the U.S. in equilibrium will be reliable without a premium above electrical energy prices. Thus, unless the price is made sufficient in some manner in the long run, the grid cannot be operated reliably.

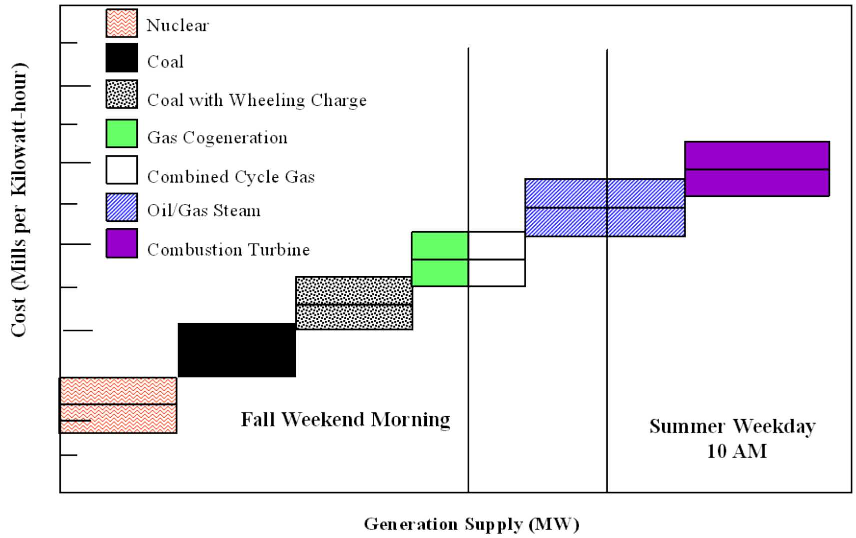
In a competitive market, the hourly dispatch of a plant will be based on economics. That is, if the plant's variable costs are lower than the hourly market price, the plant will be dispatched. The margin it will earn will be the difference between the price in that hour and the variable cost.

Energy Pricing — System Lambdas, Interruptible Electrical Supply, Economy Energy

Competitive wholesale or spot electric energy prices are determined on an hourly basis by the intersection of supply (the available generating resources) and demand (Exhibit B-2). In each hour, the prevailing spot price of electric energy will be approximated by the short-run marginal cost of production of the most expensive unit operating in that hour.[133] Thus, the spot electric energy price in the bulk power market in a given hour is equal to the marginal energy cost in that hour. Note that prices are determined hourly because power cannot be readily stored. These competitive electrical energy prices are also known in the industry as system lambdas, economy energy, and interruptible power.

[133] The variable cost may incorporate compensation for lost profits during turndown hours of operation. When the price exceeds this level, it is defined as the hourly pure capacity price. See "pure" capacity pricing discussion.

Exhibit B-2
Illustrative Supply Curve for Electrical Energy



Note: Cogeneration units can have a wide range of heat rates. The most efficient gas cogeneration units are more competitive than gas-fired combined cycles. During certain seasons, gas-fired cogeneration and combined cycle units can be more competitive than select coal-fired units.

Additional detailed dimensions of this problem include:

- Treatment of power imports and exports – Power analysis is complicated by hourly product markets and prices, but also by geographically diverse product markets and prices. A representative supply step labeled "coal with wheeling charge" is included in Exhibit B-2 to highlight this point.

- Operational constraints, including minimum run times, start times, and start-up costs.

- The opportunity cost of using environmental allowances.

- The effects of uncertainty on prices – Power price analysis is also complicated by the uncertainty in fuel, demand, plant operations, etc. that can affect a plant's value. Put another way, since a plant acts somewhat like a call option, a complete analysis would consider a full range of outcomes affecting electrical energy price. For example, rather than using a single deterministic scenario, a Monte Carlo analysis approach could be used to capture the variability in parameters affecting pricing. The approach used here compensates for this by determining the add-on to prices available to new entrants necessary to ensure they earn their full return on equity. This is achieved, as discussed below, via price spikes above electrical energy prices, which reflect the effects of random plant outages and demand uncertainty. Over the long run, this ensures that, on average, the investment returns made are those specified as required. Existing plants with characteristics similar to the chosen new entrant are likewise guaranteed to earn a similar return (e.g., ability to dispatch and contribute to reliability at system peak). Our approach further accounts for variability by distinguishing the option value of existing units from new units based on differentiating characteristics, such as the ability of many existing units to utilize both gas and residual oil, or the range of choices in pollution control equipment at existing plants.

"Pure" Capacity (Price Spike Revenue) Pricing

Exhibit B-3 illustrates supply-and-demand equilibrium for megawatts, the point at which existing power plant supply is equal to the level of peak demand plus reserve requirements. Our derivation of pure capacity prices (described in this section) reflects these equilibrium conditions. In other words, ICF's IPM® power model will build units to meet reserve margin if the market is short of capacity, and may retire or mothball units if the region is long on capacity.

Exhibit B-3
Equilibrium in the Capacity Market

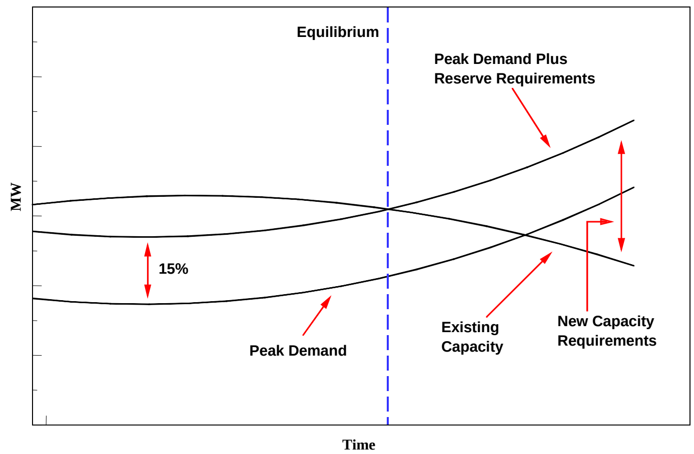
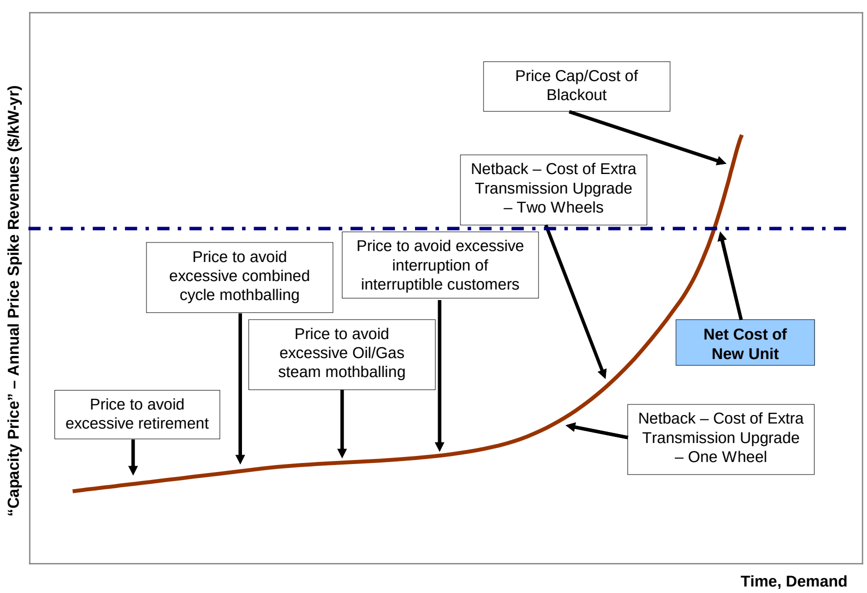


Exhibit B-4
Capacity Pricing Mechanism in Competitive Markets



Equilibrium is usually defined as a condition in which there is sufficient capacity to meet a planning reserve margin over expected system peak. However, some regions rely more on operating reserve requirements than on planning reserve requirements. Either way, significant reserves are needed. That is, planning reserve requirements are set to ensure that there is enough reserve capacity available to operate at peak. Thus, the fact that the model is estimating a separate capacity price is appropriate even for markets without enforceable planning reserve requirements.

Capacity increases the reliability of electrical energy supply. Consequently, the power price structure must be high enough to ensure that sufficient "pure" capacity exists (i.e., units that almost never operate are available and are purely for reserve). To the extent that prices are above system lambda (i.e., above the competitive electrical energy price or the marginal variable cost of the last unit dispatched), this premium is the "pure" capacity price. The "pure" capacity market is not entirely separate from the energy market, but is linked.

ICF uses a sophisticated linear-programming-based computer modeling approach to forecast capacity prices in which all model output is simultaneously determined. However, it is useful to describe this approach using seven steps.

Step 1. Evaluate Near-term Capacity Balance: The potential for excess builds in the near term is evaluated. Excess builds have the potential to create a near-term over-supply that could lower the market price of capacity.

Step 2. Ensure Ongoing Cost Recovery: The annualized costs (capital related and annual fixed non-fuel O&M) of the least costly type of additional megawatts are estimated. In the model, these costs are calculated for numerous new plant options (e.g., simple cycles and combined cycles, and coal plants).

Step 3. Estimate Dispatch Profitability: The energy sales profit of new power plants (i.e., the fact that new plants may not provide strictly "pure" capacity is accounted for). For example, if a new power plant can make profit on electrical energy sales, this diminishes the price premium (i.e., the pure capacity price) required to build the necessary megawatts for reliability. For example, if a new combustion turbine can make $10/kW/yr in energy profit and it costs $57/kW/yr to build, the pure capacity price is $47/kW/yr.

The formula for the Step 3 adjustment is more complicated than Step 1 because all new potential entrants (e.g., both combined cycles and simple cycles) can profit from energy sales and both are marginal sources of megawatts. The "pure" capacity price is driven by the lower capacity price required of the two plants (or lower of other plants as well, such as coal, LM6000s), as shown in the following, simplified formula:

If $(C_x - X) \leq (C_y - Y)$, then $P = C_x - X$
If $(C_x - X) \geq (C_y - Y)$, then $P = C_y - Y$

Where:

X = Energy sales profits of a new combustion turbine
Y = Energy sales profits of a new combined cycle
C_x = Annual fixed costs of a new combustion turbine

C_y = Annual fixed costs of a new combined cycle
P = “Pure” Capacity Price

Step 4. Evaluate Firm Transmission: The model makes decisions to import or export firm megawatts. Thus, the equilibrium in the capacity market is determined by simultaneously answering three questions: (1) how much reserves are required in a regional marketplace (with reference to planning reserve requirements and accounting for demand growth)? (2) how much can be traded? and (3) what, if any, retirements or mothballing occur (see Step 5)? We highlight trading of firm capacity rights for megawatts in the capacity pricing discussion because exporters are at a disadvantage to local generation, since transmission charges are required on firm capacity purchases.

Step 5. Account for Unit Shut Down: We analyze whether the very last existing units in the dispatch order should be mothballed or retired if the pure capacity price is not sufficient to allow them to cover their net fixed, non-fuel, cash-going-forward costs after energy sales. In addition, the competitive market price for pure capacity will be less than the required capacity payment for new entrants in cases of excess capacity, unless sufficient retirements occur to bring the market into equilibrium. In this case, the net cost of new plants must be greater than or equal to the cost of the most expensive units on a discounted multi-year basis. Our model is distinguished by its ability to make decisions including retirement decisions. It does this by incorporating expectations about the future through solving all years simultaneously.

Step 6. Ensure Investment Cost Recovery: Addresses the multi-year nature of new power plant investment. The decision on whether to add new capacity to the system and the type of capacity to be added depend on the long-term potential for recovery of costs associated with the investment. If the capital costs associated with new power plants are anticipated to be lower in the future such that the price of “pure” capacity in those years will also be lower, an additional premium in the early years would be warranted and necessary to compensate for lower profits in the out years. Otherwise, the price will be sufficient for the later entrants to recover costs and earn a return, but not the earlier entrants. This issue exists with some saliency due to several factors, including the possibility that the real costs of new gas power plants and their heat rates will continue to decrease.

Step 7. Evaluate Curtailment Potential: Addresses the response to interruptible load. The interruptible load represents a significant force in maintaining price floors. Customers who may not be willing to pay full price for firm power, but are willing to pay some value above zero, tend to opt for interruptible service. Therefore, they help set a floor on capacity prices. Interruptible contracts also assist in maintaining stable peak prices by allowing interruptions in service levels in emergency situations. This element is captured in our modeling.

The history of interruptible contracts is complicated by the fact that they have been used to subsidize customers who, in fact, may best be considered as firm. In periods of fully available supply, regulators allow so-called interruptible consumers to pay below market price. In periods of limited supply availability, the interruptible consumers are then allowed to switch to firm rates freely. Because of this, consumers are somewhat allowed to misrepresent whether they are firm or interruptible customers. This contributes to explaining the large growth in interruptible load. This notwithstanding, we use historical estimates of interruptible load to be conservative.

Note that market power (the ability to manipulate the market pricing through capacity withholding or bidding differently than cost of service) and forward contracts also contribute to capacity price determination. These factors are not explicitly captured in our modeling. Market power can be especially strong at the peak, when all megawatts are needed. In this situation, withholding capacity could result in artificially high prices. Forward contracts hedge against volatility, including low capacity prices. Additionally, RMR units that would not dispatch on a cost basis but may be dispatched out-of-merit by the ISO can affect the market price and value of capacity. Units that are qualified RMR capacity operate under a regulated cost structure, which prevents the exercise of market power.

A final step not considered in this analysis would be to evaluate the hourly loss of load probability to calculate the expected unserved energy on an hourly basis and hence, determine the timing and level of price spikes. This is especially relevant in the very near term, when no capacity additions are possible.

Modeling Approach

We will use ICF's proprietary model IPM® to examine the MISO power markets and value for the Covert power plant.

ICF's IPM® is a production cost simulation model that focuses on analyzing wholesale power markets and assessing competitive market prices of electrical energy, based on an analysis of supply-and-demand fundamentals. The model also projects plant generation levels, new power plant construction, fuel consumption, and inter-regional power flows. The model determines generation and, therefore, production costs and prices, using a linear programming optimization routine with dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over specified years). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, and operating constraints. Based on looking at the supply/demand balance in the context of the various factors discussed above, IPM® projects hourly spot prices of electric energy within a larger wholesale power market. IPM® also projects the annual "pure" capacity price.

IPM® addresses a wide range of issues, including:

- Projection of competitive market prices;
- Estimation of the dispatchability of specific units;
- Assessment of the revenues and costs of merchant power plants;
- Explanation of the reasons for long-term dispatch patterns within power markets;
- Assessment of the impact of different variables on prices and dispatch patterns; and
- Projection of capacity expansion levels and mix.

Transmission constraints can have significant effects on the IPM® forecasts. Non-firm transmission limits can restrict the flows of electrical energy. In regions with high variable cost units, tight transmission limits raise market-clearing prices relative to scenarios with larger or looser transmission limits. This can also raise dispatch of local units, since dispatch is primarily driven by the number of hours in which prices exceed a unit's short-run variable costs. Put another way, the competitive supply external to the market goes down. Note that the transmission limits are set as model inputs, but the power flows are not inputs; the model forecasts power flows and the solution is developed simultaneously with nearly all other industry parameters, including unit dispatch and capacity expansion. The solution reflects supply and demand fundamentals in that period. Conversely, a region with low variable cost power plants will have lower market-clearing prices and less dispatch if the transmission constraints are relieved. This can be thought of heuristically as reducing demand.

Firm transmission limits affect the transmission of pure capacity, which can be thought of as super-peak megawatts of supply. In the modeling, there are separate requirements for super-peak supply versus hourly energy supply to capture the separate products of energy and capacity needed for reliability. Regions with excess capacity relative to the system peak have lower capacity prices in the event the firm export transmission limits are lower, all else being equal. Conversely, regions with capacity shortages have higher prices for pure capacity if the firm import transmission limits are low.

Volume III: Impact of the Current Financial Climate on Baseload Investment Decisions

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List of Exhibits

Chapter 1
Introduction

This is the third volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

This volume focuses on the impacts of the current financial climate on the financing of power plant investments by independent power producers (IPPs) and regulated electric utilities. After a brief introduction on the chronology of the financial crisis, Chapter 1 provides a qualitative discussion of how the crisis changed the financing components of new power plants. Chapter 2 quantifies these components and illustrates their impact on the cost of capital in the short term. The final chapter provides a long-term view of power plant financial components in order to contextualize the near-term changes in capital markets.

One of the most capital-intensive industries in the U.S., the electric utility industry needs $150 billion of capital expenditures (CapEx) over the next two years.[1] This level of CapEx spending is needed for major transmission and distribution system upgrades, environmental and energy efficiency improvements, and new capacity demands. The CapEx needs in the U.S are spread across both regulated and unregulated territories requiring both utilities and IPPs to go to the capital markets for financing. In this current climate, some of these projects may be delayed or canceled. Coal projects are vulnerable to cancellation and delay because they are more capital intensive than most other generation sources. In the future, coal plants that incorporate carbon capture and sequestration (CCS) technology will be especially vulnerable due to their higher capital costs. CCS is estimated to add as much as 80 percent to the total capital cost of a supercritical pulverized coal plant.[2]

The two methods used by IPPs and utilities to finance generation investments are described below.

> **Project Finance** – This finance method is most used by the IPPs. It allows developers to seek financing using only the project as recourse for the loan. For instance, a project developer may wish to develop a new baseload unit but will seek to finance the project in such a way that if it defaults on the loan, debtors have recourse limited to the project itself and not against the larger holdings of the project developer. Project finance is used when project is a self-sustaining, revenue-earning entity.
>
> **Corporate Finance** – A developer will raise capital on the strength of the company's balance sheet and not the fundamentals of individual potential projects. In this type of financing, the debtors have recourse to an entire company's assets.
>
> a) Power developers relying on corporate finance are typically regulated electric utilities whose project debt is recourse to the entire utility. For this reason, they have easier access to capital and may enjoy a lower cost of capital as well.

[1] EEI. *2008 Financial Review—Plus 2009 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*. May 2009.

[2] See Task 2 of ICF's series. With the addition of CCS, NETL supercritical pulverized coal (SCPC) capital costs increase by more than 80 percent and EPRI's SCPC capital costs increase approximately 70%. These capital cost increases can be mostly attributed to equipment needed to meet additional cooling water needs and for both the CO_2 capture and compression processes.

b) Merchant plants that are covered by long-term power purchase agreements (PPAs) with a utility or a creditworthy counterparty still use project financing, but may have a cost of capital similar to that of regulated electric utilities.

The impact of the current financial climate on both project and corporate financing will be discussed in the following sections.

Chapter 2
Impact of the Financial Crisis on the Financial Market for New Power Plants

Liquidity shortages in capital markets began in the second half of 2007 as subprime mortgage losses began to accumulate. As a result of these losses, Standard and Poor's (S&P's) and Moody's downgraded several hundred subprime bonds and securities, prompting additional investigation of weakness in the pillars of financial markets. On January 24, 2008, President Bush and Congress agreed on a $150 billion economic stimulus plan to prevent the U.S. economy from slipping into a recession. However, the crisis deepened, as stock markets worldwide crashed and entered a period of high volatility. A considerable number of banks, mortgage lenders, and insurance companies failed in the following weeks. On March 16, 2008, Bear Stearns was acquired for $2 a share by JPMorgan Chase in a fire sale to avoid bankruptcy. The deal was backed by the Federal Reserve, providing up to $30 billion to cover possible Bear Stearns losses. On September 7, 2008, the mortgage giants Fannie May and Freddie Mac were both taken over by the federal government. Just a week later, Lehman Brothers filed for bankruptcy. In an effort to slow down the crisis, a revised bailout plan was signed on October 3, 2008, that gave the Treasury Department the power to purchase $700 billion in bank-held toxic debt. Finally, on February 17, 2009, the Obama Administration signed a $787 billion economic stimulus package designed to stabilize financial markets and provide a foundation for economic recovery.

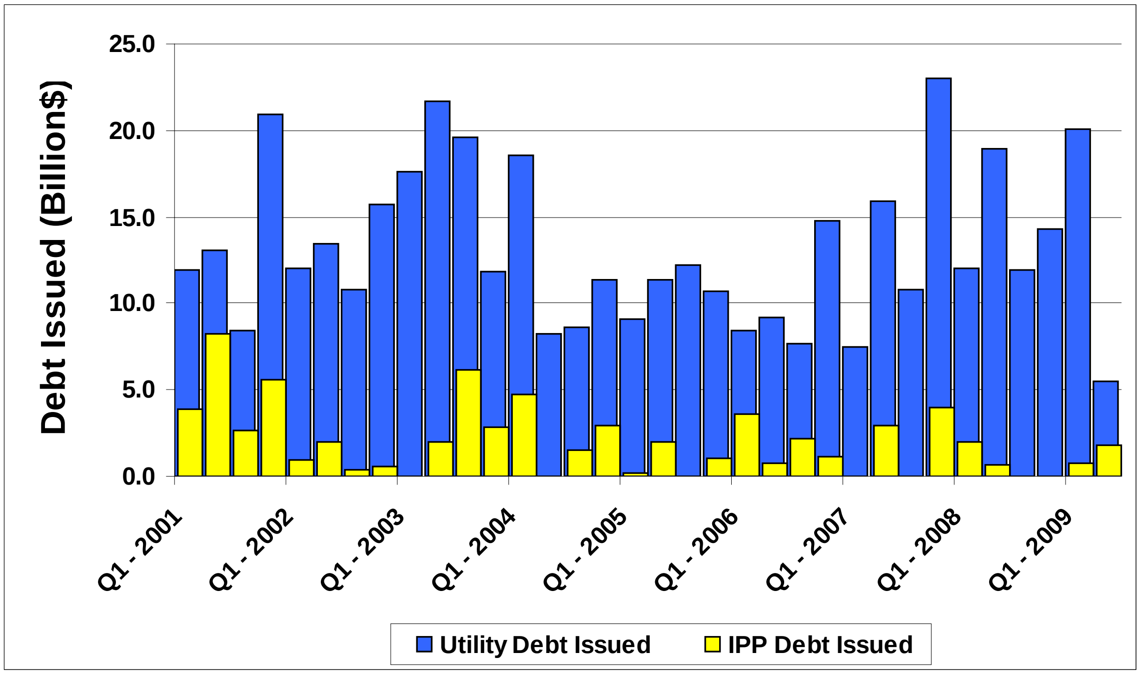
The current credit crisis facing the power industry has many implications for near-term projects. Symptoms of the credit crisis include liquidity issues limiting access to capital, risks associated with the legislative and regulatory uncertainty threatening credit ratings, and energy-demand decreases curbing the potential returns of new capacity investments. These factors have collectively reduced access to and raised the cost of debt and equity, in turn increasing the cost of new baseload investments. The credit crisis has affected IPPs with junk-bond-grade debt the most. In addition to the recent increase in their cost of capital, they suffer from lack of access to capital markets, impeding their baseload development plans.

2.1 Low Liquidity Levels

Having a high degree of liquidity in capital markets allows for large, capital-intensive deals to transact with little price movement in the terms of credit. For utilities and IPPs, having access to a high level of capital these days is crucial to maintaining their financial credibility. One of the factors leading to a reduction in available capital is bank closures. Additionally, most banks lack a good sense of the extent of their toxic holdings and, thus, to limit their exposure to future losses they are reluctant to make new loans. Furthermore, most banks are unsure of how stable other financial players are, further contributing to their reluctance to lend. Collectively, these factors have limited access to the capital markets.

Tight capital markets have slowed many capital-intensive projects in the power industry, especially in the independent power space. Exhibit 2-1 provides an overview of the quarterly debt issued by banks to IPPs and utilities since 2001. The exhibit highlights the slowdown of IPP debt issuance, which came to a standstill in the third and fourth quarters of 2008 but has since slightly picked up. Meanwhile, utilities have had somewhat easier access to capital as investors have continued to express interest in relatively low-risk utility debt throughout the current economic crisis. This flight to safety is indicative of a market shift away from investing in risky and toward safer debt. Much of this shift reflects the realignment of lending banks as risk-averse commercial banks, which have taken over the space left by the collapse of several high-risk, high-profile investment banks such as Lehman Brothers and Merrill Lynch. Generally speaking, debt issued to utilities is viewed as safer than that issued to merchant players because utilities essentially have a captured market, often with “guaranteed” returns. Therefore, utilities are still able to access capital and retain their liquidity levels. This helps explain the decrease in IPP debt issued in the current market downturn as it has become increasingly difficult for IPPs to access capital.

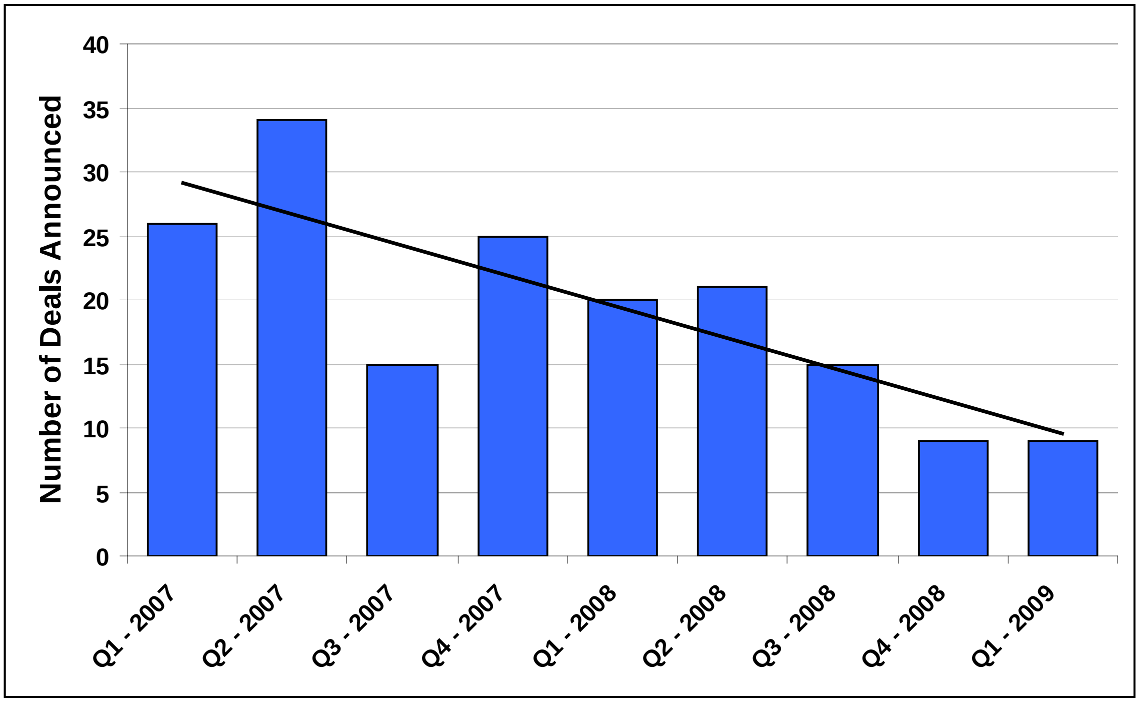
Exhibit 2-1
Debt Offerings for Utilities and IPPs



Source: SNL Financial.

Although the power industry has seen an increase in mergers and acquisitions in recent years, deals slumped in the fourth quarter of 2008 and the first quarter of 2009. As shown in Exhibit 2-2, only nine deals for power plants were struck in these quarters, ranking them as the two slowest quarters in the past two years.

Exhibit 2-2
Power Industry Deal Summary by Quarter



Source: SNL Financial.

This decline can be explained by the decrease in credit supply and increase in the cost of capital in the power industry.

2.2 Declines in Credit Quality

The credit rating of a corporation — or one of its bonds — is an indicator of debt quality and the company's ability to pay back its debt. Generally speaking, electric utilities with better credit ratings enjoy easier access to capital and at lower rates. Utilities with lower credit ratings (and most of the IPPs) are more limited in their access to capital markets and low-cost financing. Factors driving the credit quality of a bond issuance include default risk, availability of free cash flows, and extent of company liabilities and leverage.

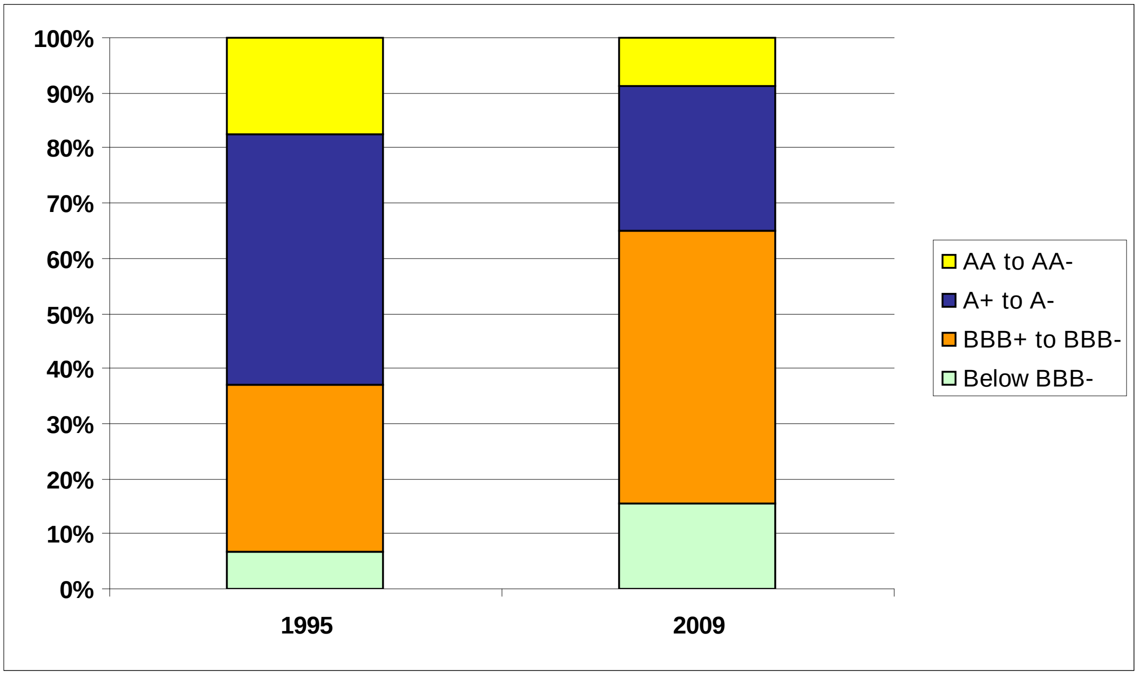
Technology risk is another factor that can dampen credit quality. Recently, S&P's Ratings Services lowered the corporate credit ratings on Scana Corporation, South Carolina Electric & Gas Company, a regulated public service company, to BBB+ from A- due to risks associated with the construction of new nuclear units.[3]

When determining debt ratings, credit rating agencies also take into account the regulatory environment in which companies operate. Uncertainty surrounding a utility's ability to pass construction costs and future carbon compliance costs through to its ratepayers can increase its market risks and reduce its credit quality. At current high-risk levels, financial markets require greater regulatory support to ensure that utilities are financially strong and can maintain their

[3] Lum, Rosy. "S&P downgrades SCANA, utilities on nuclear construction risks." SNL Financial. April 2009.

debt ratings. Under the current, more rigid credit standards, merchant power developers will likely need to sign PPAs covering a significant portion of project capacity to secure affordable financing.

Exhibit 2-3
Electric Utilities' S&P Credit Ratings Distribution[1]



Source: Bloomberg and EIA.

[1] S&P's rating system extends above AA to AA+ then AAA; however, no power company achieved either of these credit ratings in 1995 or 2009.

Exhibit 2-3 illustrates the change in distribution of electric utilities' credit ratings over time. The decrease in utilities with ratings higher than A+ and the increase in non-investment-grade ratings (below BBB-) indicates a decrease in the credit quality of electric utilities over the last 15 years. This shift in credit rating distribution is mostly due to utilities taking on new significant construction initiatives over the past decade, which raised their financial leverage and degraded their credit. Other factors contributing to the rise in utility credit downgrades include reduced market liquidity, rigid credit standards, and legislative and regulatory uncertainty in the power industry.[4] In many instances, declining credit quality has reduced project developer access to cheap debt and rendered the cost of capital prohibitive for new baseload investment.

2.3 Legislative and Regulatory Uncertainty

State and federal energy and environmental legislation and regulation play a major role in determining the economic viability of generation investments. At the forefront of challenges facing generation developers today is impending federal climate change legislation. Uncertainty surrounding this legislation has clouded the investment horizon and brought much new generation investment to a standstill due to the potentially significant burden of carbon

[4] An additional factor is the inclusion of a number of IPPs in 2009 figures, which is not the case for 1995 figures.

compliance costs. Given the higher carbon content of coal relative to natural gas, climate change legislation uncertainty is particularly challenging for new conventional coal-fired plants. Indeed, carbon legislation may redefine the investment landscape by redirecting billions of investment dollars to generation options with low carbon emissions, such as natural gas-fired plants or renewable energy resources.

In June 2009, the House passed the American Clean Energy and Security Act (Waxman-Markey). It includes an allowance allocation scheme within a cap-and-trade framework. The final bill calls for a reduction in U.S. carbon dioxide (CO_2) emissions of 17 percent below 2005 levels by 2020, rather than the 20 percent cut in emissions required in the initial draft. The bill also requires electric utilities to obtain 15 percent of their electricity from renewable energy sources by 2020 and to demonstrate annual electricity savings of 5 percent from energy efficiency measures. If a state determines that its utilities cannot meet the 15 percent federal Renewable Portfolio Standard (RPS) requirement, it may reduce the RPS requirement to 12 percent and increase the efficiency requirement to 8 percent. The initial draft of the bill had set an RPS requirement of 25 percent by 2025.

Any renewable energy standards (RES) legislation enacted in the future will place additional pressure on nonrenewable baseload investments, though the degree of pressure will vary by state. States with a large renewable resource, such as Texas or a mid-western state, may be disproportionately affected since large numbers of renewable builds will lower wholesale pricing and delay new capacity requirements.

Regulatory approval of financing costs is also of great importance in the current market environment. State regulatory support can enable a regulated utility to earn a greater return on its investments, increase its liquidity, and strengthen its cash flows. Public utility commission decisions regarding how much of a return a utility may earn on its investments and how quickly it can pass costs on to ratepayers may greatly impact the viability of a generation project. Overall, legislative and regulatory uncertainties attach a high degree of risk to generation investments, which, in turn, increases the cost of financing those investments.

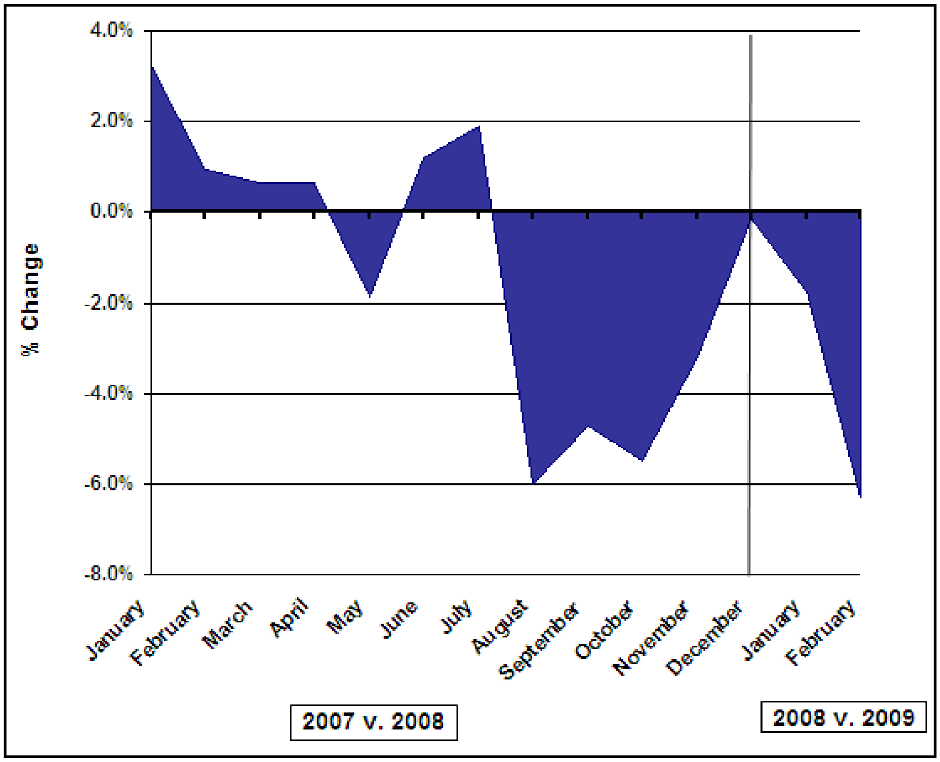
2.4 Decrease in Energy Demand

The current economic recession has also negatively impacted electric demand, as end users have cut back on usage to reduce costs. In terms of financing new power plants, the most significant impact of lower energy demand is the reduction in the need for additional generation capacity. As energy demand decreases, the need for additional capacity diminishes and subsequently planned and proposed capacity additions might be postponed or cancelled, depending on how strongly the reduction in demand affects the urgency of that investment.

A decline in electricity demand can also affect future power-project margins by leading to a decrease in dispatch and power price projections. While the dispatch of a baseload unit is generally resistant to energy demand changes, lower power prices can still reduce a project's cash flow and challenge its economic viability.

Exhibit 2-4 shows the change in electricity sales for 14 months of national data, capturing the slowdown in demand during this recessionary period. The first 12 months reflect the percent of change in monthly sales relative to the previous year (between 2008 and 2007) and the last two months reflect the relative change between 2009 and 2008.

Exhibit 2-4
Change in Total Electricity Sales (MWh)



Source: Energy Information Administration, Form EIA 826.

In April 2009, the Energy Information Administration (EIA) forecasted that the national energy demand would decrease 1.8 percent in 2009, a decline from which the U.S. is not expected to recover until 2010.[5] EIA forecasts that a decrease in the total electricity demand will continue in the near future.

Decreased economic activity across North America is also primarily responsible for a significant drop in peak-demand forecasts for the 2009 summer season. Compared to the demand forecast for 2008, the North America Electric Reliability Corporation (NERC) projected a national demand reduction of nearly 15 gigawatts (1.8 percent) in 2009.[6] Given that the average historic U.S. peak-demand growth rate is approximately 2.3 percent, a standard year would require 21 gigawatts of additional capacity to cover just the incremental growth. However, the recent decline in peak demand has made most capacity additions unnecessary and will likely delay any additional capacity needs.

If the current decline in the energy demand continues, projected cash returns of potential baseload investments will fall. A decline in a potential project's cash flow increases the risk associated with that project, which, in turn, drives up the cost of financing for that project and may lead to postponement or cancellation.

[5] Lum, Rosy. "Moody's: US power projects face 2009, 2010 headwinds." SNL Financial. March 2009.
[6] NERC. 2009 Summer Reliability Assessment.

2.5 Higher Cost of Debt

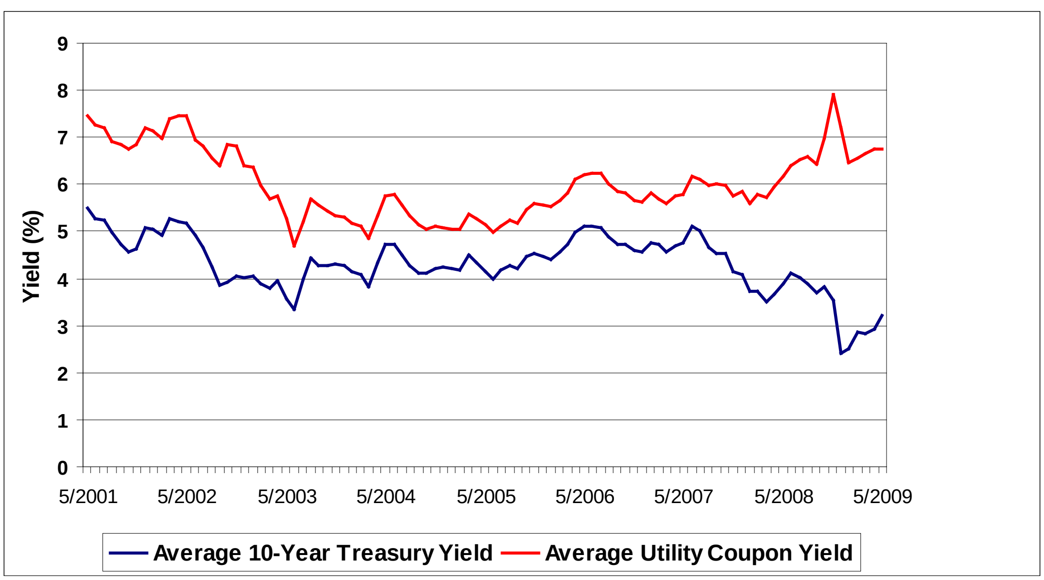
All IPPs and electric utilities rely on debt to finance new capacity investments. The cost of debt essentially has four main risk components:

- Liquidity risk
- Volatility risk
- Default risk
- Risk-free rate

Liquidity risk has gone up due to the low liquidity in the capital markets, jeopardizing the viability of many potential generation investments. Lower credit ratings for the power industry indicate a higher default risk, while regulatory and legislative uncertainties have increased volatility risk. In addition, the cost of debt has increased because investors now require greater returns to offset the recent growth in risk associated with many utility and IPP bonds.

In the debt markets in recent months, yield spreads relative to Treasury bonds, which are normally 1–2 percent, have increased to 3.4–6.8 percent, depending on the credit quality.[7] Yield spreads are used as a metric to evaluate the perceived market risk of the debt. Exhibit 2-5 illustrates the change of this spread between 2001 and 2009. The spread is the difference between the average utility coupon yield and the average 10-year Treasury yield (which represents the risk-free rate). As shown, this spread increased starting at the end of 2007, a movement which can be attributed to the rising liquidity, volatility, and default risk components of the cost of debt.

Exhibit 2-5
Utilities' Cost of Debt

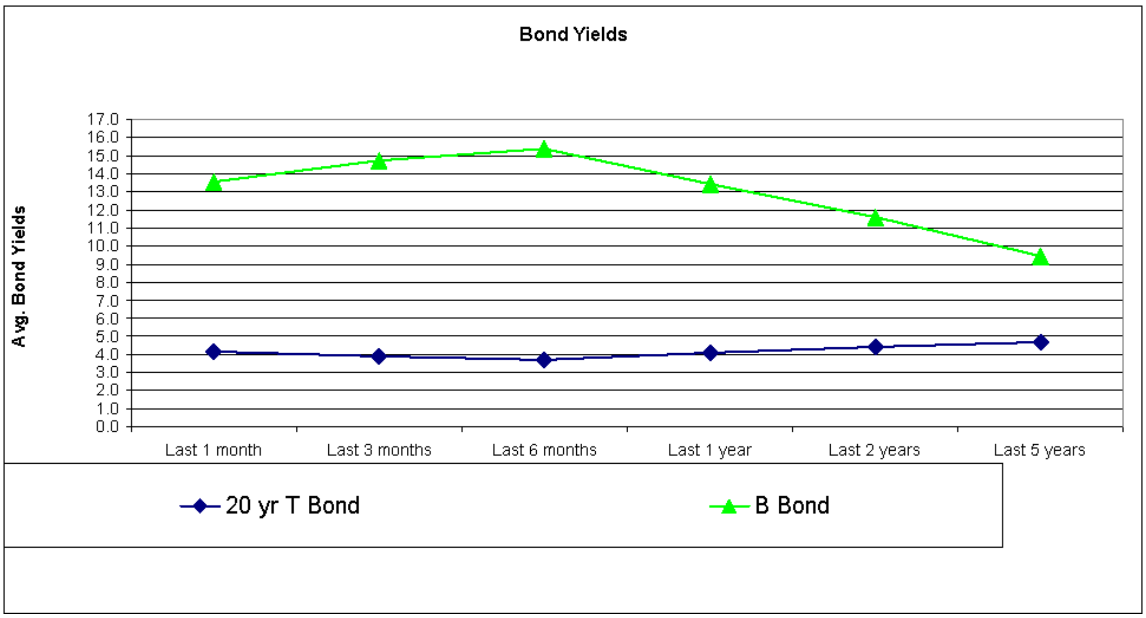


Source: SNL Financial and Bloomberg.

[7] J.M. Cannell Inc. *The Financial Crisis and Its Impact on the Electric Utility Industry*. Edison Electric Institute. February 2009.

As seen above, the average utility debt rate is on the rise. Using the average coupon rate for electric utilities' 10-year bond offerings as a proxy for debt, debt rose to 8.2 percent in the fourth quarter of 2008, which is its highest level since 2001. However, in the first five months of 2009, it dropped to its previous levels and fluctuated in the range of 6.5–7 percent.[8] Recently, the average cost of debt for utilities has fluctuated in a relatively narrow range and has not increased more than 1–2 percent. The major reason for this minor movement in debt rates is the decreasing risk-free rate (i.e., the government bond yield) in the same time frame. The U.S. government has subsidized markets to keep rates low. However, these subsidies may not continue because a government policy designed to decrease inflation will increase the risk-free rate. Coupled with higher spreads, this policy shift would tend to drive up the cost of debt.

Exhibit 2-6
Independent Power Producers' Cost of Debt



Source: Bloomberg.

The average bond yields of B-investment grade[9] IPPs for different time spans are shown in Exhibit 2-6. For instance, the average of the IPP bond yields during "last 1 month" (May 2009) is between 13 and 14 percent, as shown on the far left side of the figure. The average bond yields for the IPPs were as high as 15 percent when viewed from a time frame of in the "last 6 months." This drastic increase in the cost of debt on the merchant side, however, does not reflect their cost of debt from a project-financing perspective but rather indicates a short-term supply-and-demand balance of the market for non-investment-grade bonds. The spread between the Treasury bond yield and the average B-grade IPP bond yield is shown to be on the rise as well. Although still higher than it has been in recent years, the spread has narrowed recently as the sudden impact of the credit crisis has started to subside.

[8] EEI. *2008 Financial Review—Plus 2009 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*. May 2009.
[9] B-investment grade bonds are considered non-investment grade and of high risk.

2.6 Higher Market Cost of Equity

In financial terms, the market cost of equity has three main building blocks:

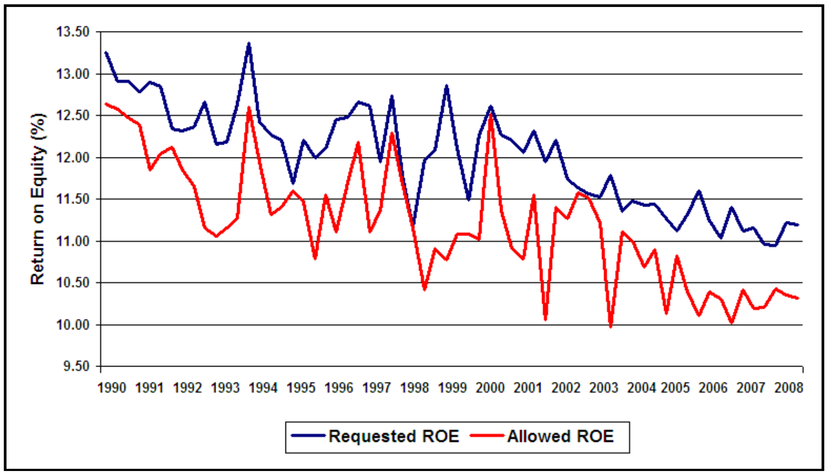
- Equity market risk premium
- Industry composite equity beta
- Risk-free rate of return

During the current recessionary period, both the risk-free rate of return — represented by the yield of U.S. Treasury Bills — and the equity market risk premium have declined, while equity beta has increased, resulting in a net increase in the market cost of equity.

The equity market risk premium is the expected return of an individual stock or an industry over the risk-free rate. The power industry risk premium has decreased in the last quarter of 2009 due to drastic decreases in energy stock prices. Even though the risk-free rate has gone down, energy stock returns have dropped faster in the same period, narrowing the margin. The industry composite equity beta of the power industry measures the volatility or systematic risk of the industry relative to the market as a whole. The average equity beta in the power industry has increased due to higher volatility of the energy stocks with respect to the market.[10] The high volatility in energy stocks during the last half of 2009 can be attributed to volatile gas prices and decreasing project developer credit quality.

Utilities may not always earn sufficient returns to meet the market cost of equity, making it difficult for them to finance new investments. Regulated utilities typically seek to earn an allowed (authorized) return on equity (ROE), and they file a rate case with a public utility commission in which they request an ROE that will allow them to both meet shareholder expectations and maintain credit lines. A significant risk facing regulated utilities is that the public utility commission may not allow them to earn a high enough return to cover their projected expenses.

Exhibit 2-7
Electric Utilities' Historical Average Allowed ROE



Source: 2008 EEI Financial Review.

[10] Analysts typically use the S&P 500 to serve as proxy for the overall stock market.

As illustrated in the Exhibit 2-7, the average allowed ROE for regulated electric utilities has steadily decreased over the last decade, falling from a peak of 12.5 percent in the first quarter of 2001 to an average of about 10.3 percent in 2008. This decline is due to falling interest rates and the Public Utilities Commission's (PUC) efforts to mitigate rising electricity rates.

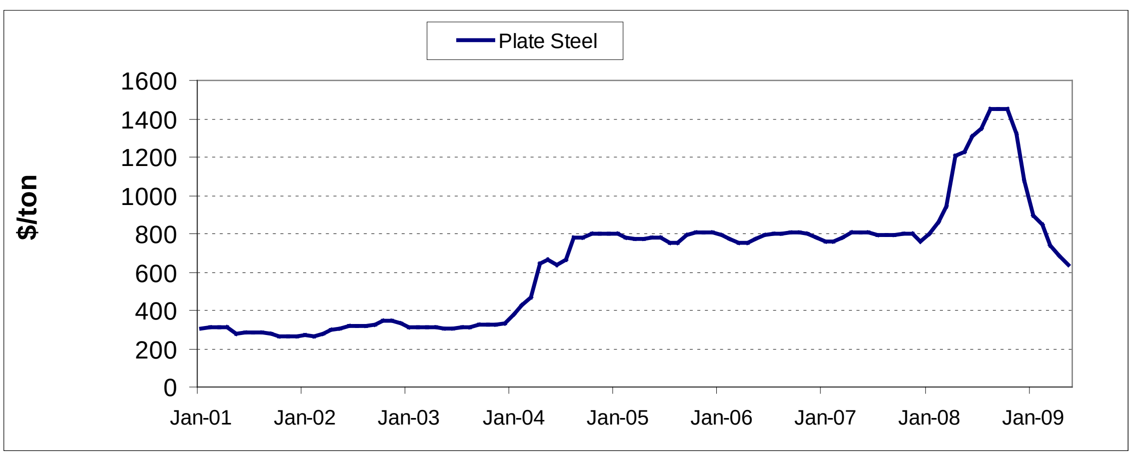
Average authorized ROE for the regulated utility sector are currently in the 10.25–10.5 percent range, with some jurisdictions approaching as low as 9 percent.[11] Although the average allowed ROE for utilities increased from approximately 10.4 percent in 2007 to 10.5 percent in 2008, this slight increase has not allowed utilities to keep up with the even greater increase in the market cost of equity.

Fitch Ratings recently argued that unless there is a meaningful increase in authorized ROE, electric utilities may have difficulty attracting adequate capital to fund new reliability, infrastructure, and generation investments.[12]

2.7 Decline in Cost of Construction

From the baseload generation developers' perspective, one positive outcome of the recession is the release of pressure on construction costs due to falling commodity prices and decreased demand for new plants. Worldwide commodity demand has plummeted due to the current economic recession. Exhibit 2-8 shows the drastic decline over the last ten months in the plate steel price, which peaked in August 2008.

Exhibit 2-8
Historic Plate Steel Price



Source: Bloomberg.

The slack in worldwide equipment demand has also resulted in a turbine price decline. ICF International expects the net result of lower commodity and turbine prices to reduce construction costs between 8–12 percent from the August 2008 high.

[11] Fitch Ratings. *U.S. Utilities, Power and Gas 2009 Outlook*. December 2008.
[12] Fitch Ratings. *U.S. Utilities, Power and Gas 2009 Outlook*. December 2008.

2.8 Federal Financial Incentives

Federal investment incentives, including loan guarantees, have come to play an increasingly important role in the generation investment decision-making process. Federal efforts to stimulate new technology can help a project obtain needed debt and equity financing. For example, the U.S. Department of Energy (DOE) has set aside $8 billion in loan guarantees for advanced coal gasification projects. While such programs do not channel funding directly to project development, they do improve the likelihood that utilities — and especially merchants — can secure financing. For example, Secure Energy, an IPP, recently applied for $647 million in government backing for its planned $800 million gasification project. The project is designed to convert 1.4 million tons of Illinois coal annually into 21 billion cubic feet of synthetic natural gas.[13] Secure Energy initially sought funding in capital markets, but tightening credit markets left them in need of federal loan guarantees to attract investors.

Another example of federal support that will play a key role in generation development is DOE's loan guarantee program for new nuclear generation, which will guarantee up to $18.5 billion of debt for a handful of projects. This program could guarantee all of an approved project's debt, reducing that project's risk and allowing it to not only secure financing more easily but also to greatly reduce the cost of that financing. Developers of 14 nuclear projects spent millions of dollars vying for a piece of the program, but DOE has narrowed down the eligible list to just four projects and one alternative.

An additional example of a federal financial incentive that will provide developers with greater access to cheaper financing is the future allocation of carbon emission allowances to certain generation technologies. The Waxman Markey bill allocates bonus allowances for CCS equal to 2 percent of the emission cap for 2012–2016 and 5 percent for 2017–2050. The first 6 gigawatts of CCS capacity will receive allowances equivalent to $90 per ton of CO_2 sequestered for units capturing more than 85 percent of their carbon emissions. The payment received by units capturing less than 85 percent but more than 50 percent of their carbon emissions will be scaled down to $50 per ton. These subsidies will help capital-intensive, early generation, carbon capture technology gain financial access to capital.

[13] *Gas Turbine World*. "US Decatur gas plant gets gasifiers, but awaits Federal loan backing." March-April 2009.

Chapter 3
Impact of the Recession on the Cost of Capital

The main purpose of this section is to quantify the impact of the current economic and financial realities on the financing of power-project investments. In that sense, the cost of capital[14] for an investment provides a perspective on how much the required return on the project should be and what returns project stakeholders should expect to receive from their investments. Briefly, the cost of capital of a project sets the cost-versus-benefit expectations of power producers and investors.

A widely accepted principle in corporate finance is that the cost of capital of an investment is the rate of return required by the investors in the project. If suppliers of capital (i.e., investment banks and equity partners) do not receive a fair rate of return to compensate them for the risk they are taking, they will move their capital in search of better returns. At a minimum, the cost of capital should equal the investors' opportunity cost. As described in Volumes I and II of this report, the cost of capital is sometimes called the investor's hurdle rate.

Another widely accepted idea is that a reasonable approach to estimating the cost of capital is to use the Weighted Average Cost of Capital (WACC) methodology. A company's WACC is equal to the weighted cost of equity and debt finance, with the weightings determined by the relative levels of debt and equity (D/E ratio) in the company's asset base, sometimes referred to as the company's financial leverage. A company's or utility's WACC is given in the formula below:

WACC =

(Share of Equity * Cost of Equity) + (Share of Preferred Stock * Cost of Preferred Stock) + (Share of Debt *After Tax Cost of Debt)

The WACC has the following three main components:

- Capitalization structure,
- Cost of debt, and
- Cost of equity.

This section of the paper discusses the impact of the current financial climate on each of these components. This will be followed by a discussion of ICF's long-term view on the cost of capital. To add additional insight, present the views of the Energy Information Agency (EIA) and the Edison Electric Institute (EEI) are also presented.[15] The most recent WACC component assumptions of ICF, EIA, and EEI are summarized in Exhibit 3-1 below.

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[14] Cost of Capital (Discount Rate) = Pre Tax Debt Rate * (1-Tax) * W_d + Post Tax Equity Rate * W_e.

[15] EIA publishes generic numbers for all technology types in its National Energy Modeling System (NEMS) assumption documentation. Edison Electric Institute (EEI) publishes cost of capital parameters for electric utilities each year in its year-end "Financial Review" document.

Exhibit 3-1
Views on the Cost of Capital Parameters

Component of WACC	Independent Power Producers			Regulated Electric Utilities		
	Long-term Impact		Short-term Impact	Long-term Impact		Short-term Impact
	ICF	EIA	ICF	ICF	EEI	ICF
WACC	CTs 12.1% CCs 10.8% Coal 9% Nuke 9% Renew 9%	10.30%	CTs 12.9% CCs 11.2% Coal 9.6% Nuke 9.6% Renew 10.1%	6.70%	6.70%	6.90%
Capital Structure	CTs 30/70 CCs 45/55 Coal 60/40 Nuke 60/40 Renew 55/45	45/55	CTs 30/70 CCs 45/55 Coal 60/40 Nuke 60/40 Renew 55/45	55/45	57/53[1]	59/41
Cost of Debt	CTs 9% CCs 8% Coal 8% Nuke 8% Renew 8%	8%-9%	CTs 10% CCs 9% Coal 9% Nuke 9% Renew 9%	6.25%	6%-7%	7.00%
Required Return on Equity (ROE)	15.20%	14%-15%	15.90%	10.30%	10.30%	10.90%

Sources: ICF, EIA, EEI.
[1] Average of 2006, 2007, and 2008 EEI Utilities' Average Capital Structure Data.

Exhibit 3-1 presents ICF's views on the relative differences of cost of capital, not only between IPPs and utilities but also among prime movers. For IPPs planning to build a coal plant, ICF estimates that the cost of capital has increased from 9 to 9.6 percent and for utilities from 6.7 to 6.9 percent, reflecting the recent turmoil in capital markets.

ICF has different capitalization structures and cost of debt for different technology investment projects. ICF's long-term view is mostly in agreement with the views of EIA and EEI.

3.1 Short-Term Market Impact on the Cost of Capital

For both utility and IPP players, the financial crisis has made capital more expensive in the short-term. High WACC levels typical of the current marketplace pose a challenge to financing new capacity investment. Ben Garey, vice president of the investment banking division at Morgan Stanley, recently commented on the rising cost of capital, stating that "the bar's much higher to raise capital."[16] To illustrate this view, the following section focuses on the three components of WACC: capitalization structure, cost of debt, and required ROE (or cost of equity).

3.1.1 Capitalization Structure

Debt capital is cheaper than equity capital because it has a more senior claim on assets (i.e., it's less risky) and because the interest expense associated with it is tax deductible. As debt is added to a company's capital structure, the company's cost of capital, or the WACC, will decline. However, as more debt is added to the capital structure (i.e., the financial leverage), the risk of bankruptcy and, subsequently, the cost of debt also increase. Indeed, the increased use of debt to lower one's cost of capital will continue until the benefit of the interest tax shield from debt is outweighed by bankruptcy risk.

[16] Rivera, Corina. "Power purchase agreements called key to financing new generation." SNL Financial. April 2009.

ICF's short-term assumptions for an IPP capitalization structure do not vary from ICF's long-term assumptions. Even though there is a tendency in the industry to rely on more debt financing than equity financing to reduce the cost of capital, in the current market environment IPPs cannot afford higher financial leverage with their correspondingly higher default risks. On the other hand, the additional cost of adding more expensive equity (which lowers financial leverage) outweighs the benefits of the decrease in the cost of debt due to lower default risk. However, lowering financial leverage increases the WACC. ICF's long-term capital structure view is balanced for merchant financing and can be used in the short term as well.

On the utility side of the industry, ICF adopted the average capitalization structure of utilities in 2008 as its view of a typical short-term capitalization structure. Thus, as per EEI's latest estimate, 59 percent of the capital used for utility investments will be financed by debt, compared to 55 percent in ICF's long-term view. The current increase in utility financial leverage is an effort to reduce their WACC by relying on more debt.

3.1.2 Cost of Debt

Debt is generally more expensive for IPPs than for utilities because of their greater exposure to market volatility and weaker balance sheets. In the short term, ICF projects a 1 percent increase in the cost of debt across all technology types. Accordingly, the cost of debt of a baseload merchant project is estimated to be 9 percent in the short term. This view was developed by a review of recent merchant bond yields during 2008 from the pure merchant players such as NRG, Mirant, Reliant, and Dynergy. These numbers provide a more conservative look at the cost of debt for merchant financings, since the cost of debt reflects the average of year 2008 with low bond yields before and after the financial crisis.

The cost of debt calculations used in the WACC calculations here are based on expected returns. The yields for bonds are reasonable proxies for the cost of debt unless the companies are highly leveraged, in which case the yields also include a default premium. In ICF's opinion, current yields are a reflection of the credit crisis, and the ensuing loss of market capitalization of merchant companies has caused them to become over-leveraged. As such, the existing yields may also reflect a default premium that should be disregarded while determining the required returns for longer-term investment decisions.

ICF also reviewed recent merchant bond yields published by a leading industry magazine, *Project Finance*. The credit ratings of merchant energy bonds are generally below investment grade (BBB-) and are thus deemed non-investment grade. Even though the bond yield for a merchant project varies by project type and credit rating of the merchant, the current level of rates are in the range of 5–9 percent over the 3-month LIBOR (London Interbank Offered Rate) average.[17]

Reviewing the average bond coupon rates of electric utilities in recent years (as shown in Exhibit 2-5) shows that the average cost of debt for utilities ranges from 6.5 to 7 percent in the second half of 2008 and most of 2009. ICF adopts the upper bound of this recent historic range, taking into account the high financial leverage of electric utilities. In other words, ICF assumes a 7 percent cost of debt for electric utilities in the short term (a 75-basis-point increase from the long-term assumptions).

[17] *Project Finance Magazine*. "Small Mercies." November 2008.

3.1.3 Required Return on Equity (Cost of Equity)

ICF uses the Capital Asset Pricing Model (CAPM) to estimate a short-term view of the cost of equity. The CAPM approach is explained in detail in Section 3.2.3.

ICF's short-term estimation for a merchant ROE is 15.9 percent, which is 0.7 percent higher than our long-term view. The higher required short-term ROE for IPPs can be attributed to the rapid increase in IPP equity betas in the last half of 2009 due to market forces explained in Section 2.6.

ICF estimates a 10.9 percent required ROE for electric utilities in its short-term projections. The increase in ICF's short-term view can be attributed to the recent high financial leverage practices of electric utilities and their higher average equity beta. Using the CAPM approach to develop ICF assumptions, the higher the equity beta of electric utilities, the higher becomes ICF's required-ROE estimation.

3.2 Long-Term ICF View of the Cost of Capital

In this section, we present ICF's long-term view on financing parameters to give some context to the short-term run-up experienced in the first half of 2009. We also present alternative views, including EIA data for the merchant or IPP sector and EEI data for the utility sector.

3.2.1 Capital Structure

Energy project investments can be financed either through debt or equity. The ratio of debt to equity (D/E) is known as the capitalization structure, and it determines the leverage of the project or utility. Capitalization structures vary depending on the technology type and its risk profile.

The new generation investment selection process is largely driven by the risk profile of potential investments. An investment in a combustion turbine is likely to be much riskier than an investment in a baseload technology, because a combustion turbine operates as a peaking unit that is only able to generate revenues in times of high demand. On the other hand, a baseload unit generates revenues over many more hours in a year. Projects that are risky cannot support a large amount of debt; thus, baseload technology investments can afford higher debt levels. In this sense, coal and nuclear technologies share a similar degree of risk since both have high availabilities and capacity factors.

Exhibit 3-2 shows ICF's long-term view on capital structures of investments in various generation technologies. All baseload technology investments have the same financial leverage, with a utility D/E ratio of 55/45 and a merchant D/E ratio of 60/40. IPP non-baseload technology investment D/E ratios vary depending on market risk levels.

Exhibit 3-2
ICF's Long-Term Capital Structure View

Technology	Utility	IPP
SCPC & IGCC*	55/45	60/40
Nuclear	55/45	60/40
Combined Cycle	55/45	45/55
Combustion Turbine	55/45	30/70
Wind and Other Renewables	55/45	45/55

Source: ICF International. *IGCC stands for integrated gasification combined cycle.

ICF's long-term view on capitalization structure for utilities is determined using U.S. utility capitalization ratios derived from Bloomberg data. ICF assumes a 55/45 capitalization structure for all regulated utility generation investments regardless of technology because utilities typically finance projects off their balance sheets, which removes the return risk associated with individual projects.

Merchant baseload investment capitalization structures have been estimated by conducting empirical analyses of pure merchant company capitalization structures, including those of Dynergy, Mirant, Calpine, Reliant, and NRG.

Each year, EIA publishes the "Electricity Market Module Documentation," which presents its financial assumptions and the methodology used to support projections for its NEMS. EIA assumes a D/E ratio of 45/55 for IPPs regardless of technology type. These estimates lower leverage and therefore yield a higher discount rate (WACC) that corresponds to ICF's long-term view of merchant financing of baseload units.

According to EEI's "2008 Financial Review," the sharp rise in regulated utility CapEx spending and debt financing of some large-scale buyouts in recent years are the primary drivers of the increasing leverage ratios. As shown in Exhibit 3-3, debt as a percentage of total capitalization has increased since the end of 2006.

Exhibit 3-3
Utility Capitalization Structures Over Time ($ Millions)

Source of Funds	Dec. 31, 2008	Dec. 31, 2007	Dec. 31, 2006
Common Equity	267,391	270,082	257,073
Preferred Equity	659	566	596
Long-term Debt	384,434	350,219	323,106
Total	**652,483**	**620,867**	**580,774**
Common Equity %	41.0	43.5	44.3
Preferred Equity %	0.1	0.1	0.1
Long-term Debt %	58.9	56.4	55.6
Total %	**100**	**100**	**100**

Source: EEI 2008 Financial Review.

However, due to the higher cost of debt, many companies are making downward revisions to their 2009 CapEx projections.[18]

3.2.2 Cost of Debt

ICF's long-term debt rate assumptions are shown in Exhibit 3-4. IPP debt is more expensive than utility debt, reflecting the greater market risk associated with IPPs — which, unlike utilities, lack captive ratepayers. Thus, for the cost of merchant baseload projects, the debt is 1.75 percent higher than that of utility baseload projects.

Exhibit 3-4
ICF's Long-Term Debt Rates View

Technology	Utility %	Merchant (IPPs) %
Coal & IGCC	6.25	8.0
Nuclear	6.25	8.0
Combined Cycle	6.25	8.0
Combustion Turbine	6.25	9.0
Wind and Other Renewables	6.25	8.0

Source: ICF International.

The cost of debt for the merchant sector is computed assuming an average 3-month LIBOR of 5 percent[19] and an average spread of 3 percent, which reflects the low to low-medium grade of merchant bonds. These values are also corroborated against yields corresponding to high-yield bond indices typical of the merchant power sector. An additional 1 percent spread is assumed for combustion turbine units, due to the price volatility of combustion turbine units. Simple cycle combustion turbines are also riskier because they typically have low capacity factors, so most of their revenues are achieved over a very short period of time.

ICF estimates the long-term cost of debt for utilities to be 6.25 percent. ICF's estimation methodology starts with categorizing the utility bonds into various credit rating steps based on information obtained from EEI. Historic yields are analyzed for the various steps based on data obtained from Bloomberg. A weighted average cost of debt is then determined based on the historic yields and percentages of utility credit rating classes. The estimated value is also corroborated against the yield to maturity of Moody's average utility bond index.

In its long-term projections, EIA estimates the cost of debt for merchant financings to be in the range of roughly 8–9 percent. EIA assumes that the average project debt rating is Baa. EIA's debt premium is determined by an average historic spread between the corporate 10-year Aa bond rate and Baa rate.[20]

[18] EEI. *2008 Financial Review—Plus 2009 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*. May 2009.
[19] The average of the 3-month LIBOR rate over the past five years.
[20] EIA Office of Integrated Analysis and Forecasting. *The Electricity Market Module of the National Energy Modeling System—Model Documentation Report*. U.S. Department of Energy. September 2008.

3.2.3 Required Return on Equity (Cost of Equity)

ICF uses the CAPM to determine its long-term ROE view for both utilities and IPPs. The general idea behind CAPM is that investors must be compensated for the time value of money and the relative risk of the investment.

CAPM Formula: $R_e = R_f + \beta (R_m - R_f)$

In the CAPM formula, the risk-free (R_f) rate represents the time value of the money, whereas the beta factor (β) multiplied by the market premium represents the level of risk that investors take by investing in company stock. The CAPM parameters used to estimate ROE are also presented in the Appendix.

ICF estimates the ROE for a merchant project to be 15.2 percent regardless of the technology. This is based on empirical analysis of stock price data of the pure play comparable merchant companies, Reliant, NRG, Dynergy, Mirant, and Calpine.

ICF's view of a regulated utility's ROE is calculated as 10.3 percent. This value is based on empirical analysis of correlation of the returns on the S&P Utility Index versus the broader S&P 500 Market Index for the last five years to determine the levered beta. Similar CAPM parameters are used to estimate the ROE of the utility sector.

ICF's long-term view of IPP ROE is roughly comparable to EIA's published estimates of 14 percent in 2008 and 15 percent in 2010. ICF's long-term view of electric utilities' ROEs is in accordance with EEI's view. EEI estimates that the average awarded ROE between 2006 and 2008 is approximately 10.3 percent.[21]

[21] EEI. *2008 Financial Review—Plus 2009 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*. May 2009.

Chapter 4
Conclusion

This paper has outlined the impacts of the current credit crisis on the cost of capital (WACC) in the short term. The increasing WACC has adversely affected the power industry through postponement and cancellation of projects. These impacts can be more readily seen in the IPP sector. ICF believes these effects are valid for the short term only. As the economy recovers, credit will become more readily available, and the WACC will revert toward more long-term averages. However, forthcoming legislative developments will continue to put pressure on new coal investments.

The amended Waxman-Markey climate change legislation (which requires U.S. CO_2 emissions to be 17 percent below 2005 levels by 2020) and the expected new federal RES requirements will most likely channel new investments in generation capacity to those with low carbon emissions, such as renewable energy resources, natural gas-fired plants, and potentially to new-generation clean-coal generation investments.

On the regulated side of the industry, new baseload power projects that will best weather the current financial climate are those made by utilities with strong financial fundamentals, demonstrated robust performance in varying market conditions, and authorized pass-through of carbon-emission costs. In addition to the cost recovery mechanisms, projects developed by electric utilities can improve their access to the capital markets with application to DOE's loan guarantee programs.

On the merchant side, the increasing cost of capital will result in only the most essential power projects being completed. Projects with well structured PPAs will help lower project risks and be less susceptible to varying market conditions. As with the utilities, DOE's loan guarantee programs and direct financing for clean coal projects can play a pivotal role in making a baseload investment economically viable.

Appendix A
Capital Asset Pricing Model Assumptions

The table below presents parameters used in the CAPM modeling framework to estimate ICF's short and long view on required return on equity for both merchant investors and regulated utilities.

Exhibit A-1
ICF's CAPM Assumptions

CAPM Parameters	ICF's Long-term View		ICF Short-term Impact View	
	Utilities	IPPs	Utilities	IPPs
Required ROE	10.3%	15.2%	10.9%	15.9%
Average Equity Beta (β)[1]	0.67	1.36	0.84	1.62
Market Premium[2]	7.1%	7.1%	6.5%	6.5%
Risk Free Rate[3]	4.9%	4.9%	4.6%	4.6%
Size Premium[4]	0.65%	0.65%	0.81%	0.81%

[1] *CAPM Formula:* $R_e = R_f + \beta\,(R_m - R_f) + SP$ *where;*

R_e : *Required ROE*
β : *Levered Equity Beta*
$(R_m - R_f)$: *Market Risk Premium*
R_f : *Risk-free Rate*
SP : *Size Premium*

[1]*Source: Bloomberg and ICF.*
The equity beta measures the volatility or systematic risk of electric utilities or IPPs relative to the market as a whole. The values are based on empirical analysis of correlation of returns on the S&P utility index and the selected merchant companies against the broader S&P 500 market index for the last five years to determine the average levered equity beta.
[2] *Source:* Morningstar/Ibbotson's Associates. *Stocks, Bonds, Bills, and Inflation, 2009 Yearbook Valuation Edition.*
[3] Source: Federal Reserve Statistical Release (H15 Data), March 2009.
ICF's computed risk-free rate reflects the average return of the last 20 years' 10-year Treasury bonds.
[4] *Source:* Morningstar/Ibbotson's Associates. *Stocks, Bonds, Bills, and Inflation, 2009 Yearbook Valuation Edition.*

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Volume IV: Factors Affecting Regional Differences in Power Plant Investment

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List of Exhibits

Chapter 1
Introduction

This is the fourth volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

This volume explores factors that drive regional variations in power plant investment decisions, including why a coal plant that may be profitable to operate in one part of the country may not be profitable in another. It also considers why some regions disregard economics completely and effectively block certain generation investments. In many areas of the country, it is becoming increasingly difficult to develop new baseload generation and increasingly important for stakeholders in baseload generation investment to understand why. There are many barriers to new investment — including legislation, public opposition, or just plain economics—and this paper demonstrates how these factors encourage or discourage baseload generation investment.

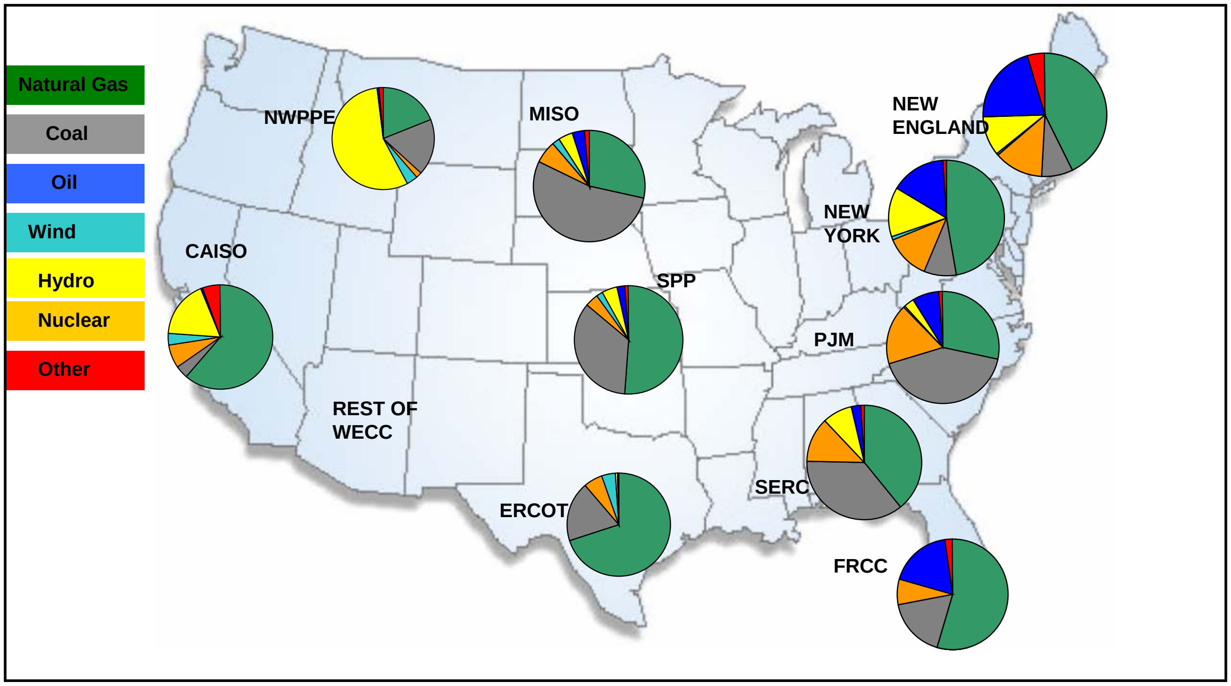
This volume is divided into two parts. The first part of this paper examines several reasons that could cause a difference in return on investment (ROI) for power plants in different parts of the U.S. Broadly speaking, they can be divided into four major categories:

- Power price drivers,
- Market structure differences,
- Legislative/regulatory differences, and
- Siting issues.

The second part utilizes ICF's Integrated Planning Model (IPM®) to simulate these regional differences to provide a quantitative analysis of their effects.

One of the most important factors that could impact potential baseload generation is capacity mix. The capacity mix of a particular region can have a significant impact on investment in that region. Exhibit 1-1 shows the stark difference in capacity mix across the country. Regions with easy access to coal will have lower fuel costs, resulting in lower operating costs for coal generation, driving down power prices. Regions with a lot of gas generation will have higher power prices, driving up energy margins for new baseload builds. Finally, a region with a large renewable presence, such as Northwest Public Power (NWPPE), will have reduced energy margins.

Exhibit 1-1
United States Capacity Mix



Source: SNL Financial.

Chapter 2
Regional Difference Drivers

This section discusses the four major drivers of regional differences. Each of these drivers has different sub-factors that affect them.

2.1 Power Price Drivers

Power price can be thought of as having two main components: energy price and capacity price. As described in Volume II, energy price is the short-term marginal price paid for electricity. Capacity price is the payment given to plants providing firm capacity towards meeting a load serving entity's reserve margin and, thus, maintaining system reliability. Some markets do not separate power price into two products; nevertheless, there are drivers for each of the two components.

2.2 Energy Price Drivers

2.2.1 Capacity Mix

Capacity mix is a major driver of energy price in any region. Throughout the U.S., electricity is typically priced through a marginal dispatch method, which means the power plant that generates the last unit of electricity determines the energy price in a given hour. As a result, regions with gas generation on the margin most of the time, such as New England, will generally have higher energy prices compared to regions that have mostly low-cost sources of supply. Regions such as New York, New England, FRCC, and CAISO have a very large proportion of natural gas capacity as compared to other types of fuels. Because natural gas is generally more expensive than coal, gas plants on the margin will lead to high energy prices, providing an opportunity for investment in new baseload plants that could reap the benefits of expensive electricity. However, some regions have coal-siting issues, like California, which does not allow new coal generation.[1]

Regions with a significant amount of coal-generating capacity will tend to have lower energy prices because coal will be on the margin for most of the hours in a day. This in turn tends to suppress energy margins that could spur new baseload development. Typically, regions with large coal reserves have tended to build mostly coal-fired capacity because it is the cheapest resource. Over time as these regions have shown a demonstrated willingness to build coal, there tends to be fewer siting and permitting risks involved in these areas. As shown in Exhibit 1-1, MISO, SPP, PJM, and SERC all have large amounts of existing coal capacity.

Finally, NWPPE, which includes the states of Oregon and Washington, is a region with a large proportion of hydro-generating capacity. Because hydro plants have virtually zero variable cost, this region has very low energy prices. Indeed, renewable generation, because its fuel cost is in most cases almost zero, tends to have the lowest operating costs of all plant types. The massive presence of low-variable-cost hydro in NWPPE severely hurts the competitiveness of new, higher-variable-cost baseload generation. While no new large hydro projects will likely be built in the U.S., renewable generation has received considerable attention over the last two

[1] On September 29, 2006, California Senate Bill 1368 was passed, prohibiting generation from power plants that exceed greenhouse gas emissions of 1,100 pounds of CO_2 per MWh. The standard of 1,100 lbs CO_2/MWh is equivalent to a power plant unit with an effective heat rate of a new combined-cycle. Without stringent CCS control, coal-fired power plants could not achieve these standards, effectively shutting them out of the California market.

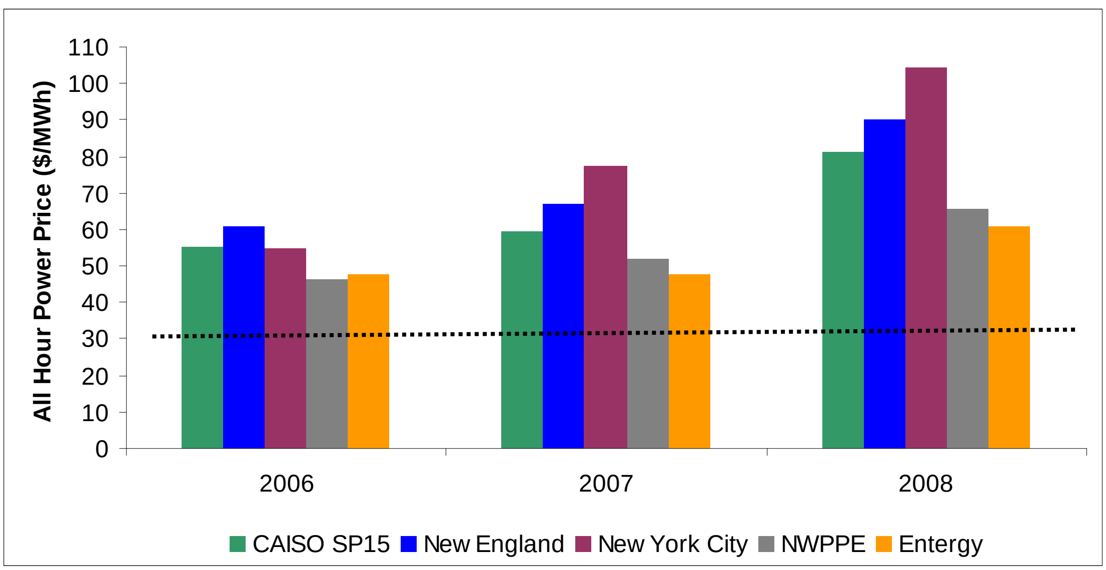
years. In time, as either federal RPS requirements or carbon legislation improve the economics, other regions with large renewable resources will have this same effect on new fossil baseload generation.

2.2.2 Energy Price, Spark Spread, and Dark Spread

As discussed above, energy prices are set by the marginal generating unit, which is the last unit dispatched in a given hour. The marginal unit is typically either a coal or natural gas plant, depending upon the region and hour of the day. A region with a large amount of natural gas generation will have a higher energy price in comparison to a region with a large amount of coal generation.

Exhibit 2-1 below shows historical power prices in different regions across the U.S. The black line shows the production cost of a standard pulverized coal plant, which is lower than the energy prices in these regions. Note that this coal plant production cost estimate does not take into account construction costs. It shows that regions with a significant amount of natural-gas-based generation capacity have higher annual average power prices. Obviously, gas dominant regions, such as New York City and New England, have higher annual average power prices when compared with NWPPE (hydro dominant). However, less obvious is that New York City and New England are also higher than Entergy, which is also gas dominant. Because Entergy is located in the area of the major natural gas resource for the continental U.S., its delivered natural gas costs tend to be among the cheapest as well.

Exhibit 2-1
Regional Energy Prices, 2006–2008[2]



Source: Megawatt Daily and Bloomberg.

The horizontal line in Exhibit 2-1 shows the production cost incurred by a PC plant. Though production costs, which significantly impact ROI, are recovered in most regions, a coal plant in a region with a higher power price will have a higher ROI relative to one in a region with lower

[2] The black line shows the generation cost of $37/MWh for a coal plant at a heat rate of 9,100 Btu/kWh for Northern Appalachian coal at $3.4/MMBtu. This includes VOM and FOM [what do these terms mean?] cost as well.

prices. This happens because the region with higher energy prices offers better energy margins and, all things being equal, favors new baseload development.

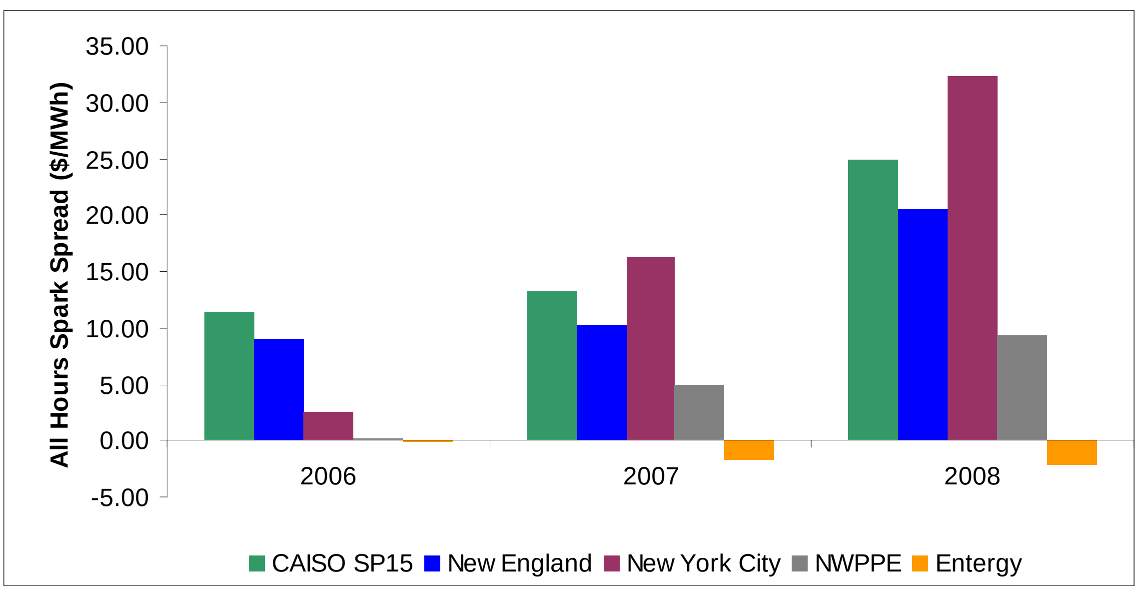
As explained in Volume I, spark spread is an industry term that indicates the potential profit margin that can be earned in any given hour. Spark spreads are typically used by gas-fired power plant developers as a key metric in evaluating power plant profitability. The spark spread is defined as the difference between the wholesale price of electricity and the cost of the fuel used to generate it. The simple spark spread calculation is as follows:

$$\text{Spark Spread} = (\$/\text{MWh}_{\text{market}} - (\text{Btu/kWh}_{\text{plant}} * \$/\text{MMBtu}_{\text{natural gas}}))$$

Power prices in a gas-dominated region are often set by a low efficiency natural gas power plant, such as a combustion turbine. Given that spark spreads are typically calculated for highly efficient combined-cycle units as the point of reference, spark spreads are greater when gas prices are higher. Thus, spark spreads in 2008 were very high relative to the past few years, since natural gas prices were also very high. Thus, developers of combined cycles would seek out gas markets with combustion turbines setting the margin in as many hours as possible.

Exhibit 2-2 shows the implied spark spread of the same regions discussed above. Entergy has negative spark spreads because, between 2006 and 2008, the power prices in this region did not increase at the same rate as gas prices, reflecting the fact that combined cycles were setting the price in many hours, and coal and nuclear were setting prices in the remaining hours.

Exhibit 2-2
Regional Spark Spreads, 2006–2008



Source: Megawatt Daily and Bloomberg.

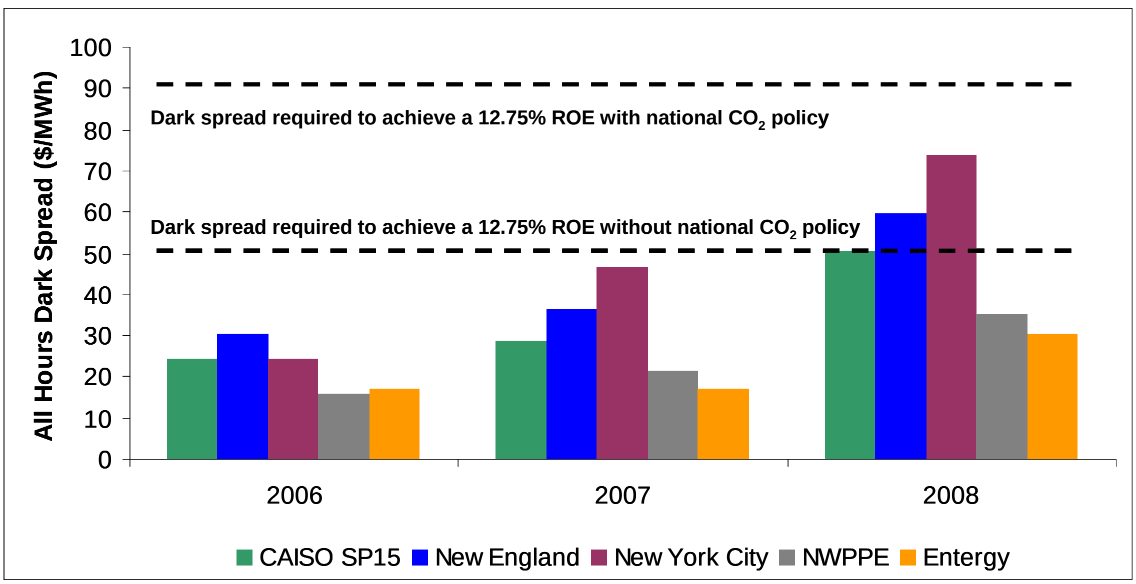
Though the spark spread provides useful information, it is most helpful for gas projects. Dark spread provides a better view of potential revenues for coal units. The dark spread captures the potential profit that can be realized by coal-generating units, because it shows the difference between energy prices and coal prices, instead of natural gas prices. As with the spark spread, the dark spread provides a good indicator of coal plant energy margins and, hence, ROI. As the dark spread increases, a baseload unit will have a higher return.

For coal generating units, a dark spread is calculated as follows:

$$\text{Dark Spread} = (\$/MWh_{market} - (Btu/kWh_{plant} * \$/MMBtu_{coal}))$$

Exhibit 2-3 shows the dark spread in the same regions. The two black horizontal lines show the average dark spread required of a supercritical PC plant to earn a 12.75 percent ROI over a 30-year period. The lines represent two scenarios: one with a federal CO_2 policy beginning in 2015, and one without any federal CO_2 legislation. As can be seen, the effect of CO_2 is dramatic. In the CO_2 case, the dark spread is above any of the regional dark spreads and, thus, would not be economically viable in any of the regions. However, it should be noted that this example is somewhat artificial because there is no federal legislated CO_2 prices in effect, so power prices are lower than they would be with a CO_2 policy in place. In the scenario without a CO_2 policy, New England and New York City show that they could economically support a new coal project for that particular year.

Exhibit 2-3
Regional Dark Spreads, 2006–2008



Source: Megawatt Daily and Bloomberg.

New York City and New England have had high dark spreads between 2006 and 2008, which indicates that coal plants in these regions would generate sufficient energy margins. These high margins convert into higher returns for equity holders. However, land restrictions in New York City and the reluctance of New England residents to have coal plants powering their homes have stifled coal development. California also has very high dark spreads, but new CO_2 emission standards in the state preclude new coal development. These regions would provide high ROIs for baseload plants. In contrast, regions like Entergy and NWPPE, with their large supplies of coal and hydro, respectively, would provide much lower margins and, therefore, likely preclude baseload investment.

2.2.3 Load Shape/Load Factor

The hourly electricity demand profile affects energy margins and, thus, will have an impact on the next type of power plant technology built. A region with a relatively constant, 24x7, year-round demand, such as that found in regions where the electricity demand includes a large proportion of refineries or chemical facilities, will more easily support new baseload generation than will a region that has pronounced peaks and valleys in its hourly demand profile. The consistency of regional demand is primarily determined by climate as well as the type of consumer demand. For example, regions such as Nevada and Arizona have a very high energy demand in the summer when temperatures rise significantly. However, they also have little in terms of an industrial base. Thus, the residential demand dominates the hourly load profile. As a result of the high cooling requirements from the residential sector, more power is required in the summer than during the rest of the year, creating a very strong peak-and-valley load shape. On the other hand, regions in the Southeast, such as parts of Texas and Louisiana where there is a large petrochemical presence, will typically have a steadier year-round hourly load profile.

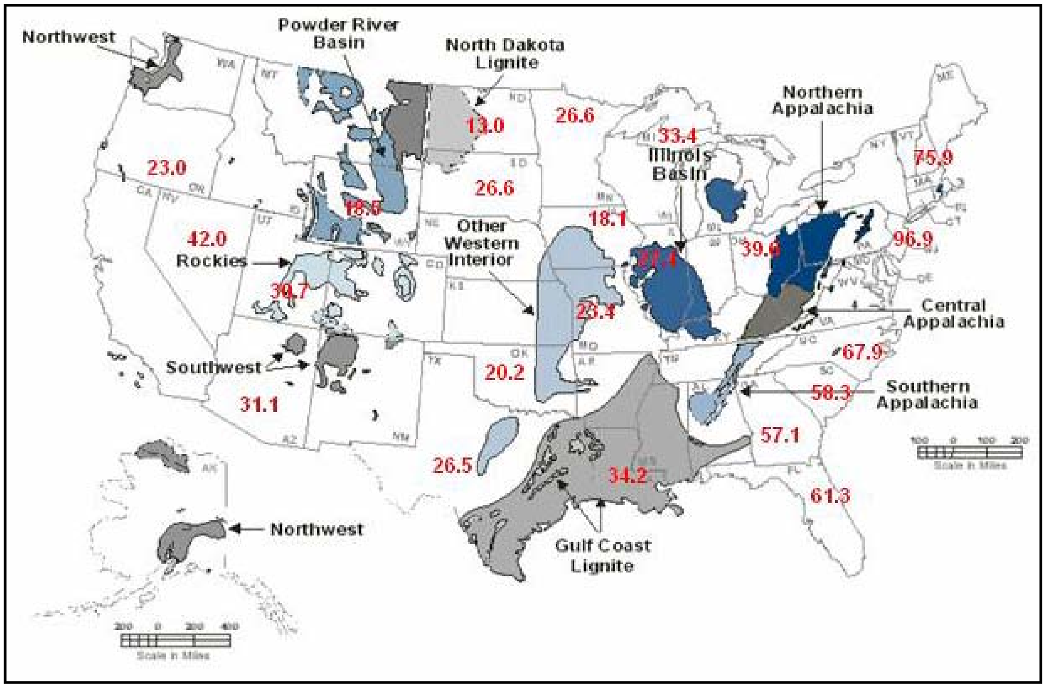
New baseload options in regions of strong peaks and deep valleys will have low capacity factors and low returns, and most likely will not be economically viable. Such regions are more conducive to a combustion turbine, which can economically provide power at a much lower capacity factor. Thus, the size and consistency of a region's energy demand profile are considerations for developers trying to decide where to site baseload generation.

2.2.4 Fuel Prices/Fuel Availability

Fuel cost is another factor that can affect the ROI of a power plant. For coal-fired baseload options, the cost of transporting coal over long distances will raise its operating costs, and, hence lower its potential ROI. Coal is mainly transported by railroad or river barge, so transportation costs can be a large percentage of the total delivered cost if the facility is located far from the source. Hence, coal plants located nearby large supplies of coal, namely Appalachia and the Powder River Basin, can produce power at a lower price and obtain higher energy margins than coal plants at the end of the supply chain. The tradeoff for these "minemouth" types of plants is the transmission line losses associated with being far away from the demand sink. Natural gas fired plants and renewables also face the tradeoff between proximity to fuel supply and transmission losses incurred in moving the power to the demand center.

Exhibit 2-4 shows the average coal price delivered to electric utilities in 2007 across the U.S. Delivered coal prices near mine locations are lower than those farther away.

Exhibit 2-4
Average Delivered Coal Prices to Electric Utility in 2007 ($/short ton)



Source: Energy Information Administration.

2.2.5 Transmission Constraints

Constraints on transmission transfers of power are the single greatest driver of regional differences in energy prices. If every region were connected and had limitless ability to send power, then all power prices across the country would equilibrate. However, large regions do suffer from transmission constraints that limit them from sending excess generation to places in need of additional generation. For example, New York City and Long Island have very high power prices due to high demand, limited land for additional generation development, and transmission import limitations. If more energy could be transmitted into these areas, cheap baseload power could flow in from western PJM, lowering the cost of energy.

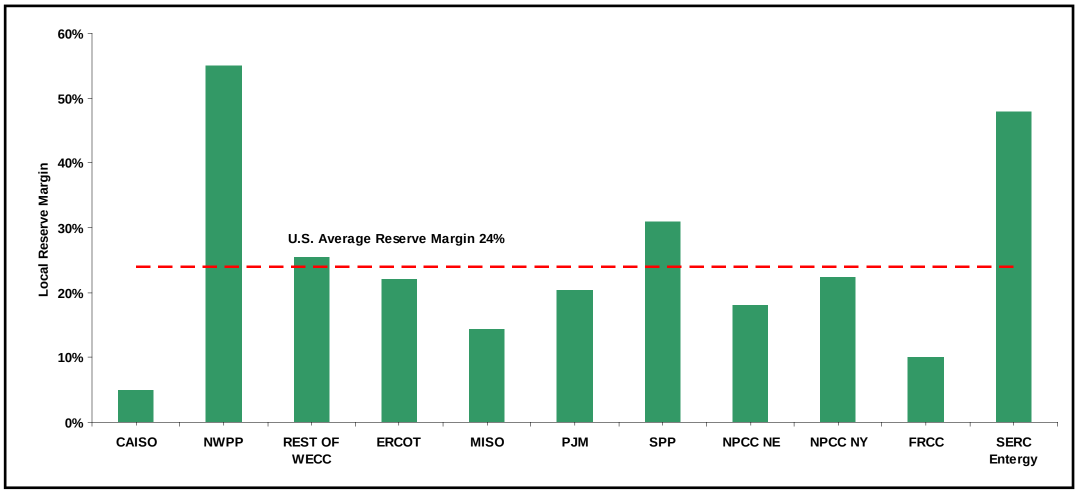
In contrast, as shown in Exhibit 2-1, Entergy has very low power prices due to a glut of generation brought online in the past decade. However, bottlenecks in transmission prevent the exporting of generation in this area to regions in need of additional power. Consequently, Entergy has a large amount of unused generation while nearby regions are in shortage and need to build capacity to meet demand. Export-constrained areas like Entergy are much less attractive to baseload developers than import-constrained regions that have higher power prices and, thus, greater potential energy margins.

2.3 Capacity Price Drivers

Another important regional driver of power price is the capacity price, which represents the payment generators receive to ensure sufficient capacity is available for system reliability. Load serving entities (LSE) in every region tend to build or contract for additional capacity as demand increases over time. When a regional LSE has sufficient capacity to meet its demand and no additional capacity is required, the region is in supply/demand balance. Every LSE maintains a certain amount of excess capacity, known as the reserve margin, to ensure that there will always be generating capacity available even in extreme times, such as transmission or generator outages. In most regions, the typical reserve margin requirement is around 15 percent above expected peak demand.

But as Exhibit 2-5 illustrates, some areas of the country have an even higher local reserve margin, implying that they have a capacity surplus. Very high reserve margins can dissuade baseload investment because the surplus of capacity shows that there are too many generators available to provide power, in turn suppressing energy prices and revenues.

Exhibit 2-5
Local Reserve Margins,[3] 2008



Source: NERC ES&D 2008.

Regions such as FRCC have a very low local reserve margin — in this case, below 10 percent. This implies that the region needs capacity and must either import it from neighboring regions or build new capacity. Similar to FRCC, California also has a very low local reserve margin. California relies largely upon imports from other parts of the west to meet its reserve margin requirements. As transmission import capability tends to be limited, local capacity tends to operate at higher levels in importing regions compared to exporting regions. Furthermore, at some point transmission capability may get congested and new local generation will be required. Thus, importing regions or those with a supply/demand deficit have a greater potential ROI for new investment.

As mentioned above, firm transmission constraints limit imports into a region and greatly improve the potential ROI of a baseload investment. For example, the latest PJM capacity auction showed a significant disparity in capacity price between western and eastern PJM; capacity prices cleared were much higher in the east. This disparity implies capacity is much more valuable in the east than the west, showing that a baseload investment would earn a better ROI in New Jersey than it would earn in western Pennsylvania.

[3] Local reserve margin tracks only local generation and does not include the firm import or export of power.

2.4 Differences in Market Structure

Market structure also plays a key role in regional differences. The type and operations of electricity markets vary regionally. For example, in much of the Northeast, there are restructured markets dominated by Independent Power Producers (IPPs). In contrast, across much of the Southeast and the West, markets served by regulated utilities prevail. Finally, in the Tennessee Valley Authority (TVA) and the Bonneville Power Administration (BPA) in the Northwest, government owned entities dominate the market.

In a regulated market, an IPP has a much harder time gaining a foothold because there is usually only one major customer, the utility. Additionally, there is very little price discovery in a regulated region since most producers and consumers keep this information confidential. As a result, project revenues are more difficult to forecast with as much certainty as can be achieved in an open, restructured market. As there is less outside competition, the local regulated utility will typically follow what it has done in the past. If that includes operating a fleet of coal-fired plants, the next baseload unit needed will most likely be a coal-fired unit.

Project revenues are more transparent and more easily assured in a market with open auctions, such as those found in any of the ISO markets. With better price discovery, IPPs have entered these markets with much more frequency than regulated markets. Furthermore, as IPPs tend to have more limited access to capital compared to utilities, IPP developers tend to build smaller facilities, which are typically combined cycle in configuration.

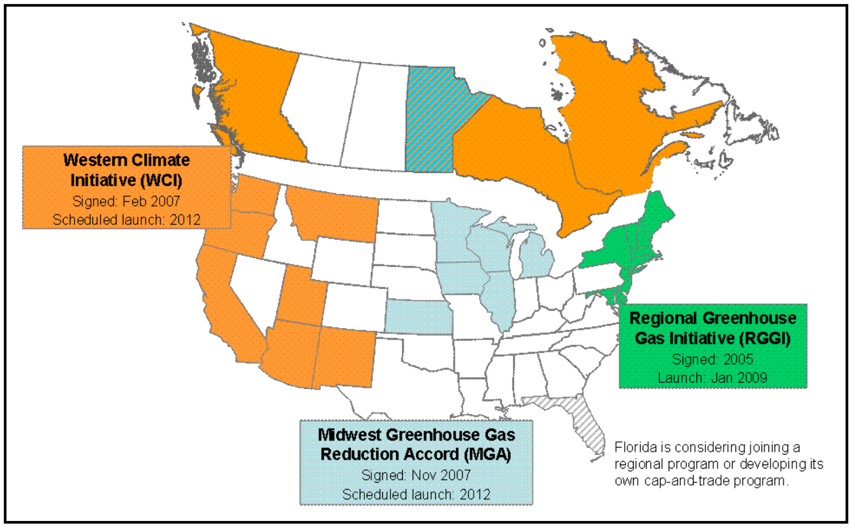
Most restructured electric markets are moving to multiple electricity products that create multiple revenue streams for power plants, such as an energy product and a capacity product. The capacity product in most cases acts as a short-term PPA, which can lessen market risk to some extent for new investments. Regions with an ancillary services market provide another source of revenue that may attract more peaking-service-type power plants such as combustion turbines. ISO-NE's locational reserves market, introduced in the second half of 2009, is an excellent example of this, as a number of new combustion turbines signed up for the locational reserves service in Connecticut.

In regions dominated by government-owned entities like TVA and BPA, new baseload power plants are built with government backing, essentially giving them access to large amounts of capital. As a result, a new baseload project financed by private industry sources would have a hard time competing.

2.5 Legislative/Regulatory Drivers

Another major factor in regional differences is state and regional legislation and regulation. For example, some areas of the country have already instituted some form of CO_2 regulation independent of any potential federal law. As seen in Exhibit 2-6, there are three such programs already in place or under development. In fact, the Regional Greenhouse Gas Initiative (RGGI) has already had an auction, placing a price on CO_2. Regional CO_2 regulations will influence the next type of generation capacity as coal-fired plants have greater CO_2 emissions on a $/MWh basis than the typical natural gas-fired combined cycle. The additional cost of carbon compliance will thus favor the natural fired technology.

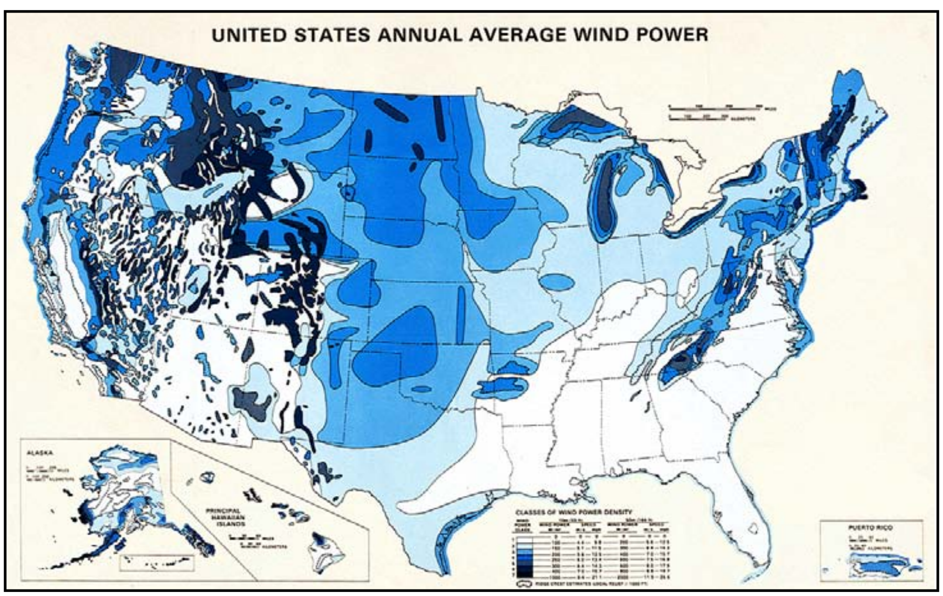
Exhibit 2-6
Regional CO_2 Policies



Source: ICF International.

Another set of regulations that will affect new investments in baseload generation is the potential federal renewable portfolio standards (RPS). As renewable options have very low variable costs, they compete directly with baseload power plants. If a federal RPS standard is passed, those areas of the country rich in renewable resources may become inundated with green generation, suppressing the need for new fossil-fired baseload investments. As can be seen in Exhibit 2-7, the regions most likely to be impacted by renewables are located where there is great potential for wind generation, such as the Midwest and western Texas.

Exhibit 2-7
United States Wind Resources



Source: National Renewable Energy Laboratory.

Other regional difference drivers are incentives and disincentives for coal development. For example, as mentioned in section 2.2.1 above, California has essentially banned coal and New England will not grant permits to new coal capacity. California has formally accomplished this through legislation, while in New England it is still informal and performed through local public activism, sometimes driven by what are called NIMBY, or “not in my backyard,” concerns. In many areas of the country, local residents and environmentalists strongly object to potential coal builds and in many instances have effectively halted coal development in places where coal generation would otherwise make economic sense. For example, New England’s high power prices could provide coal plants with a very attractive ROI, but the prevalent sentiment makes it nearly impossible to develop a coal plant there.

2.6 Siting Requirements

Another regional difference driver is the physical site of a potential baseload power plant. Since most future coal plants will utilize carbon capture technology, carbon storage costs and availability are important considerations. As shown in Volume I, there is very little potential CO_2 storage in the Northeast. As a result, new investments that require plants to capture carbon in this area may not be economically viable compared to a similar investment in regions where storage is more readily available.

Another major factor that will affect the placement of baseload generation is the availability of water. Most baseload power plants use a significant amount of water for cooling and need easy access to a large supply, such as a lake, ocean, or large river, as well as the appropriate permits to use it. For nuclear power, a location next to water is an absolute that cannot be avoided. Also, sometimes the used water cannot be discharged directly into its source. The plant must obtain permits to withdraw water and return it to the body of water at specified elevated temperatures.

To address limited water availability, new coal investments could potentially incorporate dry or hybrid cooling, but this technology is costly and will decrease efficiency. These water considerations favor regions with adequate supplies and disfavor areas with limited water or with fragile ecosystems that cannot accept additional withdrawals or heated discharges. As a result, most new baseload power plants will be located next to a body of water, which makes development in arid areas, such as the Desert Southwest, problematic.

Chapter 3
Modeled Simulation of Regional Differences

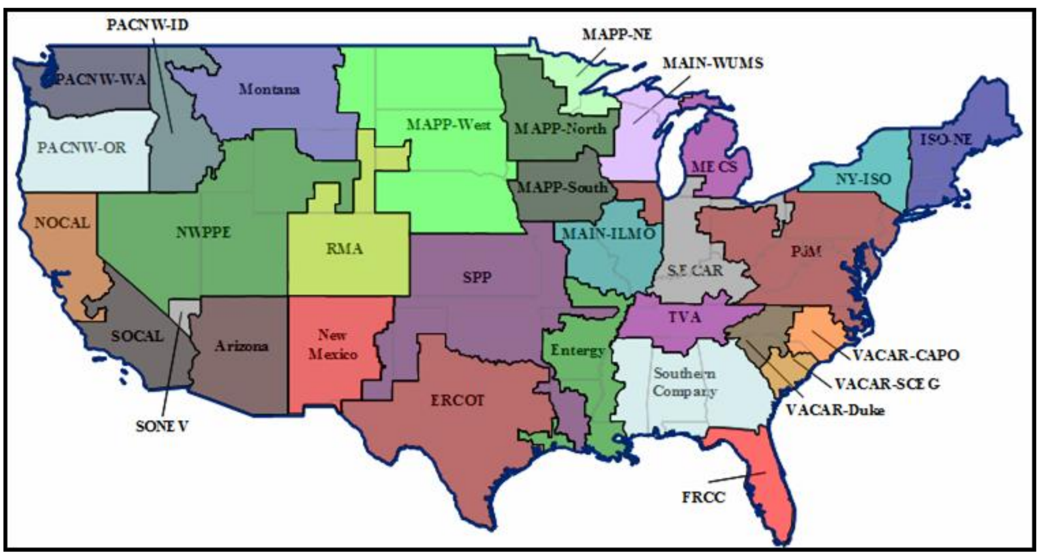
To examine the regional differences enumerated above, a total of five regions have been selected, as well as ECAR-MECS, to illustrate their effects. These regions were selected because they demonstrate the effect various regional drivers have on the profitability of new baseload investments. An analysis of the ROIs projected by new investments in these regions was conducted utilizing ICF's capacity expansion model, IPM®. As discussed in Volume II, the ROI indicates whether an investor could profitably build a plant in a particular region. The same Reference Case used in Volume II is used in this analysis.

The following regions were selected for the analysis:

- ECAR-MECS;
- ISO-NE Connecticut;
- SPP North, comprising Kansas and parts of Missouri;
- Entergy Central, comprising most of the state of Arkansas;
- ERCOT North, most of Northeastern Texas; and
- PJM West Central, most of central and western Pennsylvania.

The locations of the regions can be found in Exhibit 3-1. Please refer to Appendix A of Volume II for all other assumptions.

Exhibit 3-1
IPM® Modeling Regions



For this analysis, four investment options were examined:

- **Supercritical Pulverized Coal (SCPC):** The SCPC unit will burn bituminous coal and has activated carbon injection to reduce mercury emissions by 90 percent, and flue gas desulfurization (FGD) technology to reduce SO_2 emissions by 95 percent and mercury emissions further by 40 percent. Selective catalytic reduction (SCR) and low NO_x burners (LNB) will reduce NO_x emissions by 95 percent. The standard SCPC power plant modeled has an average capacity of 700 MW.

- **Integrated Gasification Combined Cycle with Carbon Capture and Sequestration (IGCC-CCS):** The modeled IGCC will burn bituminous coal. The IGCC unit has similar emission reduction factors as the SCPC unit, with CCS technology reducing the CO_2 emissions by 90 percent and incurring a heat rate penalty of 21 percent. Capital cost and performance characteristics are based on a standard 2x1 GE-7FA configured, 500-MW CC power island using a GE gasifier.

- **Natural Gas Combined Cycle (NGCC):** Based on 2x1 configured power island using 501G combined cycle technology with SCR and LNB for NO_x emission control. The standard NGCC power plant has a nominal capacity of 600 MW.

- **Natural Gas Combustion Turbine (CT):** Based on a GE-7FA, simple-cycle combustion turbine with a nominal capacity of 160 MW.

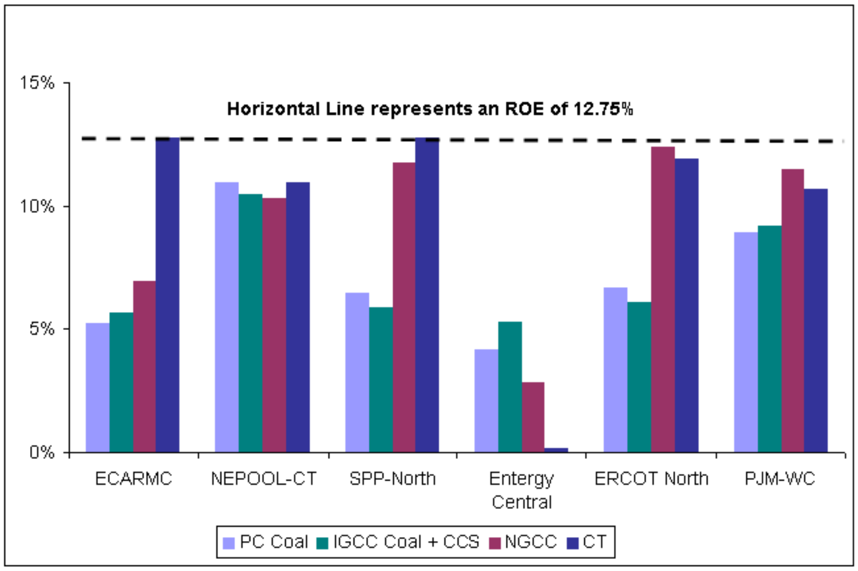
The plant investment options explored in Volume II have been narrowed to these investment options because SCPC with CCS and IGCC without CCS were not economically viable in the vast majority of cases that were run. The nuclear investment option is economically viable in most cases as well; as a result, the focus shifted to the two best coal options. To better demonstrate regional differences, a peaking option has been included that, in this case, is modeled with the cost and performance characteristics of a simple cycle GE-7FA.

We have examined plants that come online in three separate years: 2015, 2020, and 2030. This is to provide a view on how the regional differences affect investment and the way these differences evolve over time. The three exhibits below show the ROIs of the four investment options over these three time periods.

3.1 Summary of Results

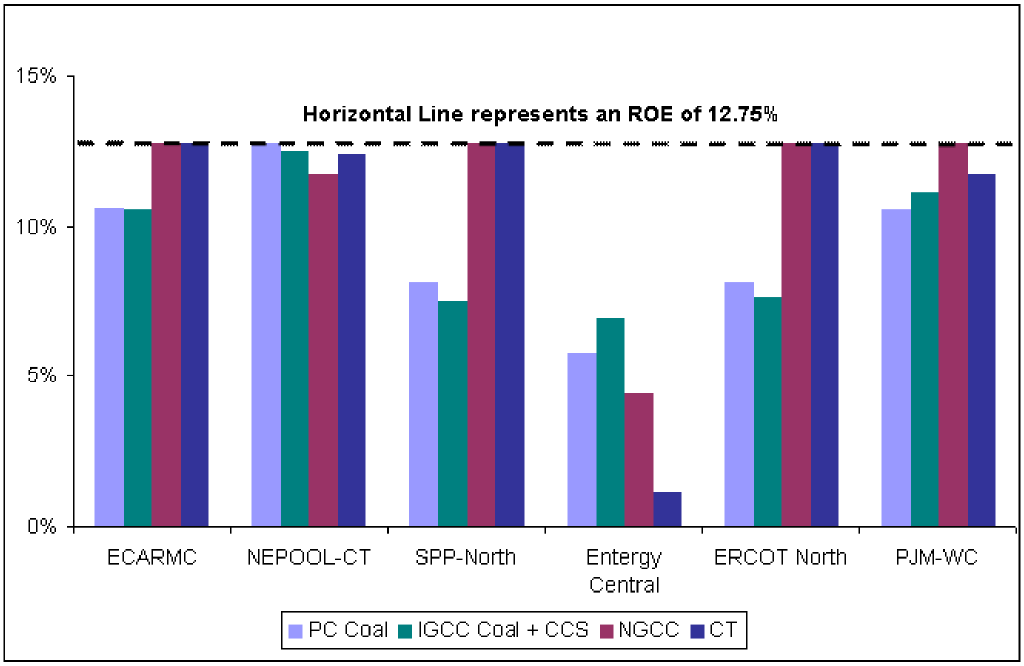
As shown in Exhibit 3-2, combustion turbine units are economical to build in SPP-North and ECAR-MECS in 2015. All of the other options remain uneconomical, as their ROI is less than the hurdle rate of 12.75 percent. The combustion turbine is built when there is not a large enough energy margin to support baseload units, yet new capacity is still needed. A combustion turbine's reliance on super-peak hours for their margins, coupled with its low capital cost and quick build-time, allow it to be built in regions that would not otherwise support any other type of generation investment.

Exhibit 3-2
2015 Regional ROIs



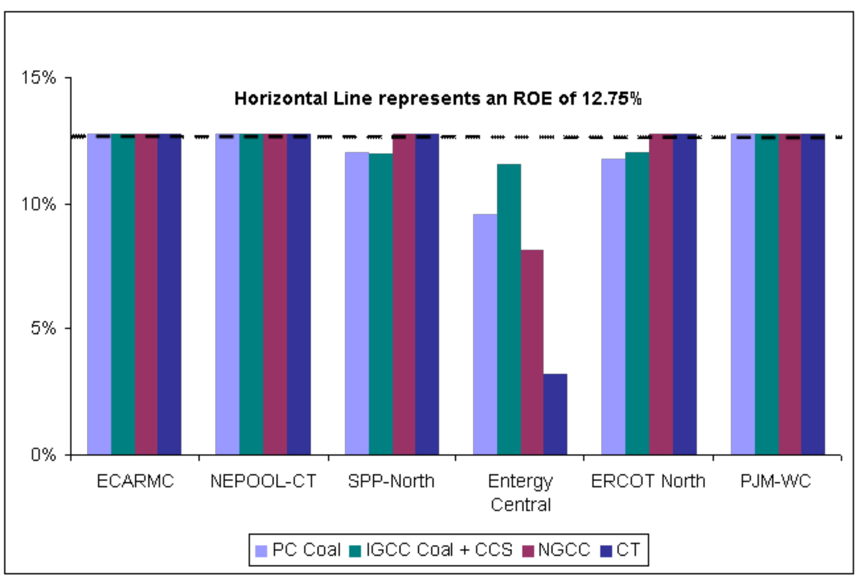
As shown in Exhibit 3-3, in 2020 the CT also becomes economical in ERCOT-North. The NGCC becomes economical by 2020 in all regions other than Entergy Central and Connecticut. The other two options still remain uneconomical. The NGCC becomes an economic option largely due to its lower carbon emissions. While some regions can support new baseload capacity, the high price of CO_2 pushes up the generation cost of pulverized coal so much that it cannot recover its costs. Conversely, in 2020, the projected CO_2 price is not high enough to support the cost of IGCC-CCS, which costs significantly more than conventional coal to build.

Exhibit 3-3
2020 Regional ROIs



As shown in Exhibit 3-4, by the year 2030, coal has become economical to build in ECAR MECS, ISO-NE Connecticut, and PJM-WC. Entergy Central still does not offer returns high enough to make any investments economical. SPP North and ERCOT-North both offer an ROI of 12.75 percent for CT and NGCC units. But both SCPC and IGCC-CCS remain an uneconomical decision in these two regions.

Exhibit 3-4
2030 Regional ROIs



3.2 ECAR-MECS – Illustrative Region from Volume II

As discussed in Volume II, MECS has a large proportion of coal capacity. This high percentage of coal capacity tends to keep power prices down, as coal is setting the price in many of the marginal hours compared to regions that are dominated by gas. In 2015, due to these low power prices, this region cannot support new coal or NGCC capacity. As a result, it builds combustion turbines in order to meet its capacity needs. However, in 2020, combined cycles become economically viable because the CO_2 price has grown so high by this point that gas is starting to displace PC in the dispatch stack. Power prices have still not yet reached the point where IGCC-CCS becomes economically viable. This is demonstrated by the fact that both IGCC-CCS and PC coal have a 10.6 percent ROI in 2020, slightly lower than the hurdle rate. However, by 2030, the CO_2 prices have driven power prices high enough that IGCC-CCS has become an economically viable option. At this point, the cost of CCS is less than the cost of carbon compliance. Thus, by 2030, ECAR-MECS can support baseload coal capacity additions.

3.3 ISO-New England Connecticut – Public Activism

Connecticut is a natural gas dominated region, with the marginal energy price being set by gas power plants in most of the hours of the year. Connecticut is also at the end of most continental gas pipelines, which is why the region has had historically high natural gas fuel prices and, consequently, some of the highest energy prices in the U.S.

As seen from the latest Forward Capacity Auction (FCA) conducted by (ISO-NE) for the capability year 2012–2013, additional new capacity is not needed. This auction cleared at the floor, the lowest allowable price in the auction, which shows that there is excess capacity in the ISO territory. At these low capacity values, new brown power generation cannot be supported economically. This excess is largely due to the increasingly prominent role demand side management (DSM) is taking in ISO-NE. The amount of DSM has grown over the past few auctions and is expected to continue growing, which will dampen the need for new capacity until at least 2015, only two years after the most recent auction. The current recession is also playing a role in the sagging demand for power.

By 2020, however, ICF projects that power prices will be high enough to grant sufficient margins for new PC. Even though the high CO_2 prices in 2020 have made coal not economically viable in most regions, the extremely high energy prices in Connecticut would give it a large enough energy margin for SCPC to pass the 12.75 percent ROI hurdle rate. However, due to the fact that New England discourages coal builds, SCPC would most likely not be built. The same is true in 2030, when every coal option is economically viable, but will also most likely not be built. Coal development in the New England area has been effectively blocked by a variety of strong public opposition, including frequent public demonstrations, aggressive regulatory efforts to curb mercury emissions, strong advocacy of greenhouse gas regulation, and prohibitive legislation such as Maine's three-year moratorium on IGCC development.[4] Individually, it's possible that none of these factors would deter coal development, but collectively they pose a formidable barrier.

[4] In April 2008, Maine enacted a bill that prohibits the development of IGCC plants for three years.

3.4 Southwest Power Pool North – Near-Term Economics for Combustion Turbines

Historically, the capacity mix in the SPP region has been dominated by gas-fired capacity — a combination of gas steam, combined cycle, cogeneration, and simple cycle combustion turbine capacity — which equaled approximately 49 percent of total capacity in 2007. Gas is a significant fuel source in SPP because the area is a natural gas supply basin as well. However, due to high variable cost and the abundance of cheap coal generation in the region, the gas capacity in SPP only generated 24 percent of the total energy. Coal, which is only 37 percent of the capacity, generates over 60 percent of SPP's energy. Combined with other baseload capacity, like hydro and nuclear, these non-gas units account for nearly three-fourths of generation in the region. This large amount of baseload generation tends to suppress power prices in the area.

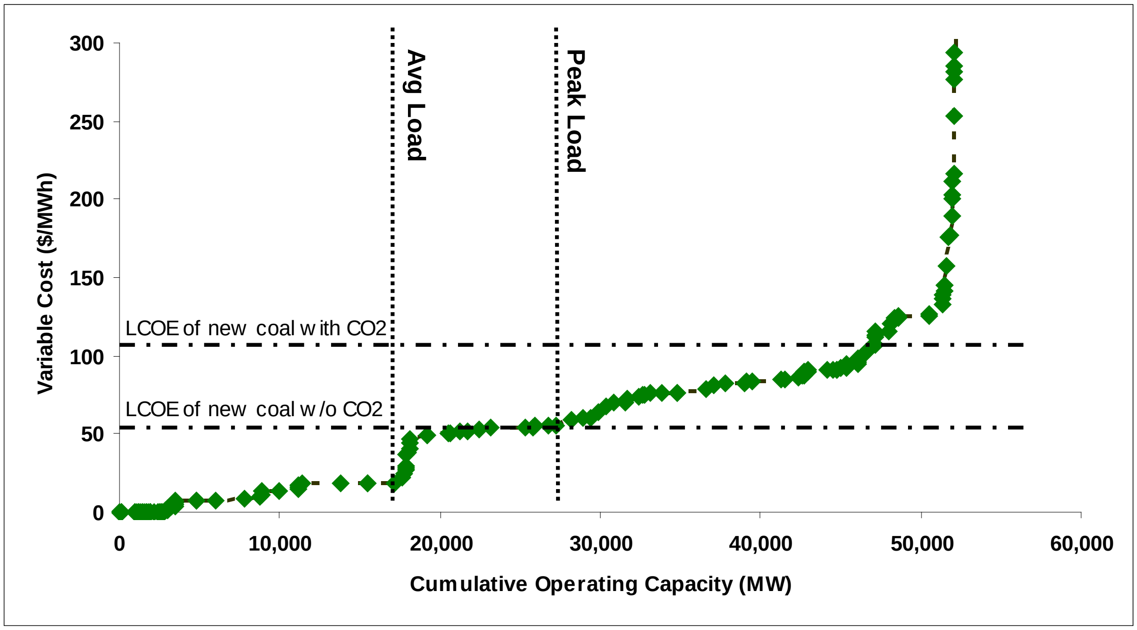
ICF modeling projects that SPP-North will need capacity in 2015. Due to lower power prices in this region, combustion turbines are a more economically viable choice to provide the necessary capacity at the lowest capital cost, as well as provide energy during peak hours. Given that coal plants set the marginal power price in most hours in this region and that coal plant variable costs rise as CO_2 prices increase, power prices start to significantly rise throughout the 2020 and 2030 periods. Pulverized coal is not economically viable because of the assumed high CO_2 prices. IGCC-CCS will also have an ROI below the hurdle rate because of the large amount of baseload capacity dampening power prices. While coal plants are not economically viable, the ROI of combined cycles passes the hurdle rate in 2020 and 2030, due to its lower initial costs and smaller exposure to rising CO_2 prices.

3.5 Entergy – Surplus Capacity

Entergy is an important example of a region with excess supply. Prior to electric market restructuring in the late 1990s, Entergy experienced a scarcity of generation capacity. However, with the onset of restructuring, newly-formed IPPs rushed into this oil/gas-fired-steam-turbine-dominated region and proceeded to fill the shortfall with combined cycles on the order of 16 GW over a five-year period. As a result, combined cycles as a percentage of total capacity went from one percent to over 20 percent. There have been several impacts of adding this large an amount of combined-cycle capacity. First, while gas is still on the margin in many hours, high production cost oil/gas steam units have been replaced with gas units at two-thirds the production cost. Second, the large build out of capacity has created a surplus. Even today, Entergy continues to have a large amount of excess capacity that holds down energy prices. Typically, excess capacity can be transferred to neighboring regions that need capacity and energy. However, Entergy also has significant transmission constraints that impede the region's ability to export power. Only transmission upgrades, high demand growth, or significant retirements could improve the economics for sustaining new baseload investment. As a result, ICF modeling shows that no new capacity investment is economically viable in 2015, 2020, or 2030 under the 12.75 hurdle rate threshold. Entergy illustrates how the significant overbuild of the past decade will continue to stifle new generation for at least 20 years.

The effect of the overbuilding of the past decade can be demonstrated by looking at the Entergy supply stack. As can be seen in Exhibit 3-5, Entergy has an extreme surplus of capacity, most of which is combined cycles. As stated above, the surplus will preclude new investment for many years. Also important is that the levelized cost of electricity (LCOE) of a new coal plant would be higher than the marginal energy price in a large portion of the hours. As such, a new coal plant investment would only be able to earn positive returns when it competes with combined cycles during half the hours in the year, which would not be enough to compensate for the thin margins it would gain when competing with other baseload during the other half of the hours in the year.

Exhibit 3-5
2007 Entergy Supply Stack



Source: SNL Financial, ICF Assumptions.

3.6 ERCOT North – Renewable Penetration

Historically, the capacity mix in ERCOT has been dominated by gas-fired steam-generating units. These units accounted for about 33 percent of total installed capacity in 2008. These steam power plants have relatively high total variable costs, due to high fuel costs and low thermal efficiency. Gas-steam units operate less than an average power plant and have accounted for only five percent of total generation in the region due to their high variable costs. While historically gas steam units have set marginal electricity prices a majority of the time, over the last several years, new combined cycles have replaced them as mid-merit generators. Nevertheless, natural gas price is the single most important factor in setting ERCOT prices. This has been a favorable condition for baseload coal investment in the past; however, interest in renewable energy may change that to some extent.

Interest in renewables in Texas started with a mild RPS requirement and favorable production tax credits (PTCs). In 2007 and 2008, Texas saw a significant amount of new wind capacity on the order of 8,000 MW. In addition, ERCOT recently approved an extremely large, multi-billion-dollar transmission expansion program (i.e., the CREZ program), which will enable wind development in the wind-resource-rich western part of ERCOT to move east, where there is sufficient electricity demand.

In the future, with carbon regulation in place, wind turbine construction costs under control, and sufficient transmission capacity to move the power, more renewable generation may come online as economically driven investments. As a result, ERCOT will see an increasing proportion of its generation coming from wind. Indeed, by 2020 and 2030, we project ERCOT will build a significant amount of renewable capacity on the order of 9 and 11 GW, respectively.

Due to the large amount of zero-variable-cost wind generation, ERCOT, and specifically ERCOT-North, will see low power. As a result, the economics for coal-fired baseload capacity in this region will not be favorable. Furthermore, we project that renewable penetration holds down prices and delays the need for additional baseload energy so significantly that new coal capacity is not economically viable in ERCOT North for at least 20 years. However, some combined cycles will be built, due to their lower initial capital outlay and their limited exposure to CO_2 prices. Additional combustion turbines will also need to be built for reliability purposes, as new intermittent wind capacity is added.

3.7 PJM-WC – Long-Term Economics for Coal

Historically, the capacity mix in PJM has been dominated by coal-fired steam-generating units, with coal power plants making up 39 percent of the capacity mix. Most of the development in PJM has been coal, due to the cheap abundant supply of the resource. Because of their low fuel costs, these power plants account for 55 percent of total generation. As such, coal steam units set marginal electricity prices a majority of the time. According to the 2006 PJM State of the Market Report, coal was on the margin 70 percent of the time and natural gas 25 percent of the time in 2006. Because PJM is a large region, the local capacity mix will vary from location to location. As one moves toward the east, gas becomes the marginal fuel more often and as one moves west, coal is more often the marginal fuel. PJM-WC is one of the coal-dominant regions in PJM and, thus, regional prices tend to be lower than in the east. Because most power plant development has happened in the western regions, these regions tend also to have a capacity surplus when compared to the east. Thus, both energy and capacity tend to flow from west to east.

ICF modeling results show that PJM-WC has enough capacity to meet its needs in 2015. As a result, power prices do not support the building of any capacity, even though PJM-WC has the ability to export surplus capacity eastward. This outcome implies some transmission congestion of firm capacity. The extent of surplus capacity and congestion was demonstrated in the latest PJM RPM capacity auction, which showed a significantly lower capacity price in western PJM compared to eastern PJM. The latest auction, held in the second half of 2009, was for the 2012–2013 capability year. If there were no transmission congestion, capacity prices would have equilibrated.

Modeling results for the year 2020 show that neither of the coal options considered are economically viable, due to the cost of carbon compliance, which is too high to vault PC above the hurdle rate, and too low to support the large capital investment necessary to build IGCC with CCS. However, by 2030, as transmission congestion is relieved and CO_2 prices increase, power prices rise to levels that support new builds of IGCC with CCS in the region.

Chapter 4
Summary and Conclusions

The decision to invest in different types of capacity across different regions varies considerably because many factors affect whether a region will provide sufficient returns to stimulate additional generation investment. Regions such as ECAR-MECS or PJM-WC are projected to not attract coal investments for a long time, primarily due to the low margins generated in the region. Another coal region, SPP-North, has so much baseload capacity that it will not have high enough margins to drive new coal investments through at least 2030. However, it still has capacity needs, and margins are sufficient for gas turbines or combined cycles. ERCOT will build gas turbines and combined cycles as well, though this is due to the large and growing presence of wind, which suppresses energy margins, rather than due to a preponderance of baseload capacity. The decision to invest should also have a timing component, as some regions are in an extreme surplus condition. Entergy suffers from developers building a significant capacity surplus; it will not need any new capacity for at least 20 years.

Note that in Volume II, it was determined that coal investments become economically viable in many different scenarios with only a slight change from the reference case. This would also hold true here. In other words, a coal plant could become economically viable if market conditions and/or technology developments were to change. Additionally, this report shows that in 2030, coal becomes an economic option even without lowering capital costs, raising availability, or replicating any of the sensitivities conducted previously.

Volume V: Evolution of the U.S. Power Market over the Last Decade

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List of Exhibits

Chapter 1
Introduction

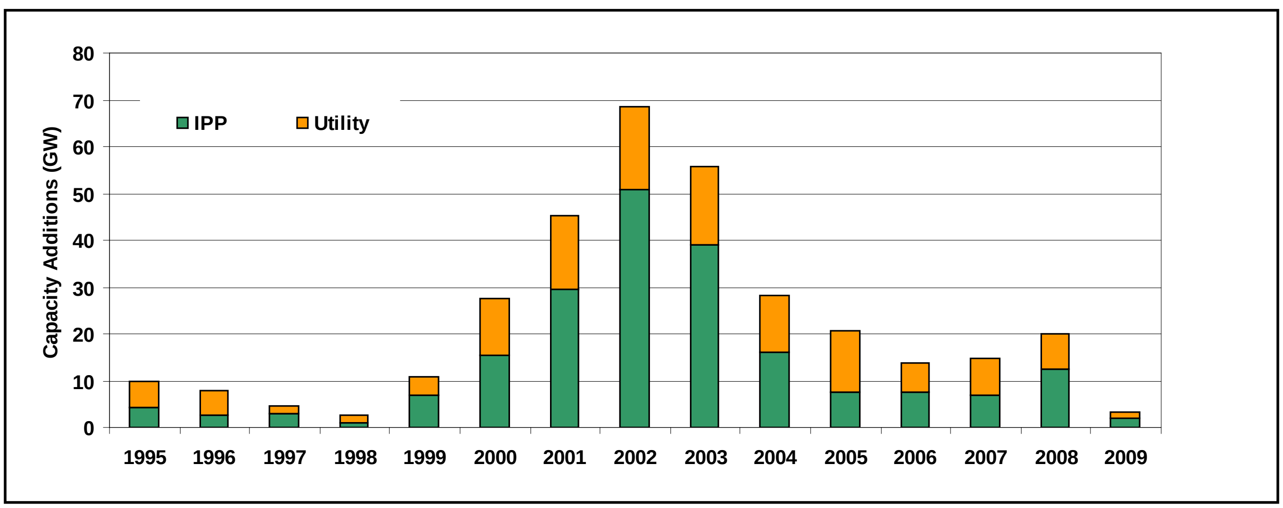
This is the fifth volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

This volume identifies and discusses key changes in the power industry over the past 20 years, and how they have affected the criteria power companies consider when making investment decisions. After a brief introduction, this volume discusses the changes seen in the world of regulated utilities that have influenced the investment decision process. This is followed by a review of changes seen from the perspective of independent power producers (IPPs). The final section provides a summary of these developments.

As the power industry has transformed over the past two decades, power companies have changed their views on new investment strategies. During that period, many markets have developed into functioning competitive wholesale power markets, with non-regulated entities being the largest investors. In the 1980s, the Public Utility Regulatory Policies Act (PURPA) brought about a new non-regulated generator that could sell power on the wholesale market. In the 1990s, the Federal Energy Regulatory Commission (FERC) passed a number of orders that which laid the foundation for a competitive power sector. In the 2000s, many changes occurred within these newly created markets that further incentivize new investments and ensure resource adequacy.

As shown in Exhibit 1-1, the non-regulated sector led the last capacity expansion, which started in early 2000. The six-year period from 2000 to 2005 saw the largest capacity build-out in U.S. history, with IPPs developing over 60 percent of the 250 GW that came online.

Exhibit 1-1
Utility and Non-Utility Generation Capacity Additions, 1995–2009



Today, however, with the disruption and devaluation of the non-regulated sector, the outlook on further deregulation of the marketplace is not clear. Many IPPs worry that unpredictable natural gas prices, high construction costs, and new environmental regulations will make investing in new merchant generation not economically viable.

This paper reviews the power industry's evolution, along with the development of functioning competitive markets and non-regulated power entities, as part of a larger effort to explore the industry's future.

Chapter 2
Recent Changes in the Utility Power Sector

2.0 Integrated Resource Planning

Since the late 1970s, integrated resource planning (IRP) has been the basic decision-making process for new investment for most utilities. IRP was originally designed to serve as a regulatory means of ensuring that a utility's expansion plan was transparent and included a broad array of alternatives. The main concept behind IRP is least-cost planning, or minimizing the revenue requirement of the utility to meet the demand for energy services. This process entails a review of all supply alternatives to meet forecasted demand at the lowest cost possible.

Over time, the IRP process has evolved, in turn changing the utility generation investment decision-making process. The "objective function" of the IRP is no longer mere cost minimization, although low costs remain an important variable. The "best" portfolio has evolved to be one that meets the demand for energy services at minimum cost, while also providing a measure of supply security, risk minimization, resource diversity, and other considerations, depending on the state commission. For example, some utilities are trying to bring demand-side management programs to the same level of consideration as traditional supply options through profit-incentive programs.

While many regulated markets have begun embracing some reforms implemented in deregulated markets, others have maintained a similar structure over the decades.

2.1 Divestiture

As part of market deregulation, many states sought to completely separate generation ownership from transmission ownership, prompting many utilities to divest their generation assets and sell them to non-regulated entities. For example, in 1996, California enacted Assembly Bill 1890, which mandated the unbundling of transmission, distribution, and generation services. Connecticut, Maine, New Hampshire, and Rhode Island enacted similar legislation requiring utilities to divest their generation assets. Although these were the only states to enact such legislation, many others strongly encouraged divestiture. The competitive forces arising from this market evolution led many investor-owned utilities (IOUs) to reevaluate how to achieve least-cost solutions. Some IOUs that were not required to divest their assets did so anyway to avoid the risks they might face in the competitive marketplace. However, many other IOUs remained in the market and fundamentally shifted their corporate strategies to function more as competitive, market-driven entities. The total number of IOUs that own generation capacity has dropped since 1997, due to these power plant divestures. To give some context, over 300 plants, representing nearly 20 percent of U.S. installed generating capacity, changed ownership between 1998 and 2001.[1]

2.2 Demand-Side Management

Many IOUs have realized that they can often provide a least-cost solution by reducing demand instead of building new capacity. As a result, the IRP process now sometimes requires power companies to include energy conservation and other demand-side management (DSM) measures in their consideration of the least-cost means for meeting the demand for energy

[1] The Electric Energy Market Competition Task Force. "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy." 2005.

services. Over the last decade, a number of state and federal programs have been implemented to incentivize DSM. Many utilities can now earn better returns on smaller DSM investments than they would earn on larger supply-side investments.

As an example, Duke Energy is working to extensively integrate energy efficiency resources to offset generation needs. Its "Save-a-Watt" (SAW) program puts DSM on equal footing with supply-side options by providing Duke with an incentive to pursue energy efficiency. Demand response options in the SAW program earn a return on a percentage of the avoided costs created by energy efficiency activity. While the highest percentage that is still economically viable from a ratepayer perspective is 100 percent of avoided costs, Duke receives between 50 and 90 percent of avoided costs, depending on the state and type of energy efficiency activity. One of its near-term goals is to cut the capacity needed in its North and South Carolina territories by 1,800 MW — the equivalent of two new coal plants — thereby allowing Duke to avoid the risks involved in the development of capital-intensive coal generation.

Currently, U.S. utilities spend approximately \$2–\$3 billion on DSM and have achieved approximately 0.2 percent incremental annual savings in terms of reduced demand. Applying this metric to the American Recovery and Reinvestment Act of 2009 (ARRA) funds, which amount to approximately \$20–\$26 billion for energy efficiency projects, would roughly imply an annual demand growth reduction of 1 to 1.5 percent for the next three years. This will likely lead to a reduction in new generation investment. The treatment and balance of efforts to reduce capacity needs relative to supply resources determine the extent to which these efforts harm or benefit ratepayers and, in turn, influence the degree to which utilities invest in them.

By focusing too intently on the lowest cost option, utilities could possibly sacrifice their stated goal of providing a reliable power system. Florida Power and Light recently found itself with a large portion of its reserve margin being met by demand resources. Upon closer investigation, it found that, at most, only 45 percent of reserves could be met by demand resources (DRs) to ensure reliability.[2]

Progress Energy Florida (PEF) stated that from 1996 until 2005, its planned reserve margin would be almost entirely met by DSM programs. PEF believes that this excessive amount of DSM created an unreliable system, especially after they discovered that when they "had a forced outage event and leaned heavily on DSM, customers began to bail out of the program."[3] PEF then realized that a certain level of physical reserves is needed to handle forced outages.[4] As a result, PEF planned to build 1,200 MW of capacity to meet their growing needs.[5]

With the renewed interest in DSM considerations in the IRP process, some utilities have experienced a reduction in system reliability as the over-reliance on DSM has delayed the building of high-availability supply investment.

2.3 High Cost of Capital and Government Incentives

The recession and economic slowdown has caused the cost of capital to rise and, in some cases, to delay new capital investment. However, power projects developed by utilities with strong balance sheets demonstrated robust performance in varying market conditions, and authorized pass-through of carbon emission costs will best weather the current financial climate.

[2] This information is based on personal communications with Florida Power and Light.
[3] "Memorandum on Levy Nuclear Power Plant," page 13, Florida Public Service Commission, July 2, 2008.
[4] Ibid.
[5] "Direct Testimony of John Benjamin Crisp On Behalf Of Progress Energy Florida," p 13, Jan 16, 2007.

Although utilities have the advantage of cost-recovery mechanisms, they alone may not guarantee a large-scale project's viability. In the current market environment, a large-scale project may need federal support, such as a loan guarantee, to ensure its viability.

To promote investment in advanced generation technologies, both state and federal governments have started providing grants and loan guarantees, which will help stimulate new generation investment by reducing the cost of financing.

2.4 Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPACT 2005) played an important role on the utility side of the industry. To offset the higher costs of advanced generation technologies, the act provides investment stimulus in the form of production tax credits and federal loan guarantees, which makes available loan guarantees of up to 80 percent of total project costs. Federal loan guarantees allow utilities to participate in multiple major projects concurrently, while avoiding the risk of possible failure due to construction cost overruns, low power prices, and other factors that could endanger a company's financial viability. EPACT 2005 also established tax credits of up to $800 million for Integrated Gasification Combined Cycle (IGCC) projects and up to $500 million for other advanced coal projects, which are primarily being pursued by utilities.

The nuclear capacity expansion projects of two utilities, SCANA Energy and Southern Company, are expected to receive federal loan guarantees through EPACT 2005 that will likely ensure their development. However, because there are limited funds, most utility nuclear projects will not receive loan guarantees and, thus, will be delayed or cancelled due to the costly implications for investors and ratepayers.

A recent challenge that has arisen for utilities is how to access federal incentives. Given their administrative nature and the cost of fulfilling the extensive application requirements and deadlines, many utilities are finding it difficult to complete the applications for government support made available by the ARRA. The inability to apply for these funds could stifle utility investment in many potential projects.

2.5 Growing Uncertainty Regarding Environmental Legislation

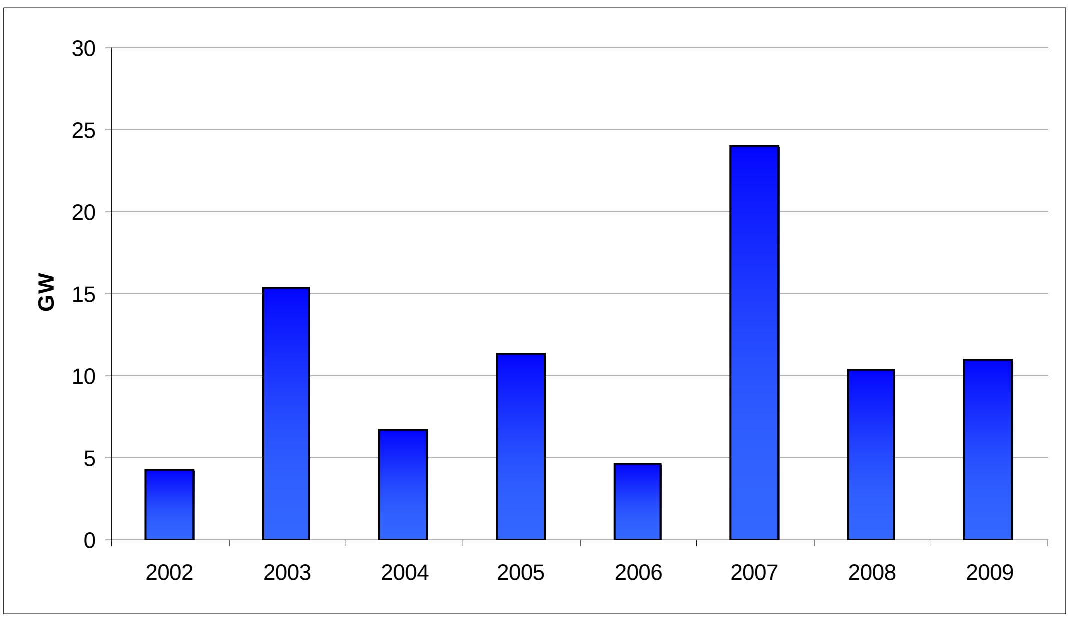
A trend that both regulated and deregulated markets face is uncertainty regarding pending environmental legislation. Going into 2008, generators were well along the path to preparing for the implementation of the Clean Air Interstate Rule (CAIR)—with emission reduction targets for nitrogen oxides (NO_x) in 2009 and sulfur dioxide (SO_2) in 2010—and the Clean Air Mercury Rule (CAMR). However, by the end of 2008, CAIR and CAMR had both been vacated by the U.S. Court of Appeals for the District of Columbia Circuit. At the end of 2008, the court temporarily reinstated elements of CAIR and remanded CAMR back to the U.S. Environmental Protection Agency (EPA) for revision. Although some form of these regulations will likely be passed eventually, these additional compliance costs most likely will not alter the financial viability of new baseload investment.

On the other hand, the imposition of a carbon dioxide (CO_2) policy could well have a real impact on investment. The passage of some form of climate change regulation in the U.S. has become increasingly likely. Numerous legislative proposals have been introduced in Congress, the most recent of which, the Waxman-Markey Bill, was passed by the House of Representatives on June 26, 2009. Of all the proposed bills, Waxman-Markey has proceeded the farthest and is one of the strictest. In its current form, Waxman-Markey calls for a phase-in of CO_2 emissions limits beginning in 2012. It will cover 68 percent of national emissions by 2012, growing to approximately 85 percent by 2016. The target of the bill is to reduce CO_2 emissions to 42 percent below 2005 levels by 2020, growing to 83 percent below 2005 levels by 2050. There will, however, be a significant number of free allowances distributed, with an amount given to merchant coal generation. The bill will also determine a way in which regulated entities can cover their CO_2 emissions by purchasing CO_2 offsets.

As CO_2 prices grow, the objective function of investors will change greatly. Because nuclear plants emit no CO_2 and new pulverized coal plants emit approximately twice the CO_2 per MWh as new combined-cycle natural gas plants, the ultimate stringency and design of CO_2 regulation will have a significant impact on what new baseload generation capacity is built. To a certain extent, the lack of new coal-fired capacity additions in the U.S. in recent years is due to the growing likelihood of CO_2 emission regulation, as well as to increases in construction costs.

Indeed, as seen in Exhibit 2-1, over 40 GW of planned coal has been cancelled in the last three years. In addition, the potential for carbon capture and storage (CCS) and other CO_2 emission reduction mechanisms will play a key role in determining the ultimate impact of CO_2 legislation.

Exhibit 2-1
Coal Capacity Cancelled



Source: Ventyx 2009.

Public and scientific community opposition to emission-heavy power generation has pressured state regulatory bodies to move away from business-as-usual practices and prepare for impending federal carbon regulation. Both public utility commissions and governors in numerous states, such as Kansas, Florida, and California, have taken prohibitive action to effectively thwart the construction of new coal generation.

For example, on four separate occasions between 2007 and 2009, the governor of Kansas vetoed a bill that would have overturned the 2007 denial of an air permit for Sunflower Electric Power's 1,400-MW Holcomb coal plant expansion. The governor emphasized the need for Kansas to prepare for carbon regulation and explore both wind power and energy efficiency. In 2009, the governor agreed to a compromise in which the expansion would be scaled down to

895 MW in exchange for the passage of a state renewable portfolio standard (RPS). However, since that time, the EPA has rejected the scaled-down plant's permit and recommended that Sunflower "consider the option of employing IGCC technology" when reapplying for the permit.[6]

In 2007, Florida's governor issued a series of executive orders aimed at reducing greenhouse gases and increasing energy efficiency. Those executive orders, in conjunction with the Florida Public Service Commission's (PSC) unanimous denial of Florida Power and Light's proposed 1,960-MW coal plant, spurred the cancellation of several other proposed coal plants. Just a year later, the Florida PSC began approving the recovery of hundreds of millions of dollars spent on new nuclear development, an additional indicator that Florida is actively working to distance itself from coal generation.

California is another state that has worked to limit coal generation investment. The state passed Senate Bill 1368 in 2006, prohibiting generation from power plants that exceed greenhouse gas emissions of 1,100 pounds of CO_2 per MWh. The standard of 1,100 lbs CO_2/MWh is equivalent to a power plant unit with an effective heat rate of a new combined cycle. Without stringent CCS control, conventional pulverized coal (PC)-fired power plants could not achieve these standards, effectively shutting them out of the California market.

Finally, another factor that could greatly affect a regulated utility's investment decision is the imposition of state RPSs with very stringent requirements. To date, 33 states have imposed an RPS, which will, in effect, delay investment in conventional supply options. California has recently imposed one of the most stringent RPSs in the nation. It mandates that 20 percent of all power must come from renewable sources by 2010, with an additional goal of 33 percent by 2020. The new trend toward RPSs demonstrates that, in any market, an increased focus on new renewable generation will delay investment in conventional fossil-fired capacity.

[6] Bleskan, Kerry. "EPA Tells Holcomb To Go Back to Drawing Board on Holcomb Permit." *SNL Financial*. July 2, 2009.

Chapter 3
Evolution of the Non-Regulated Power Sector

3.0 PURPA Era

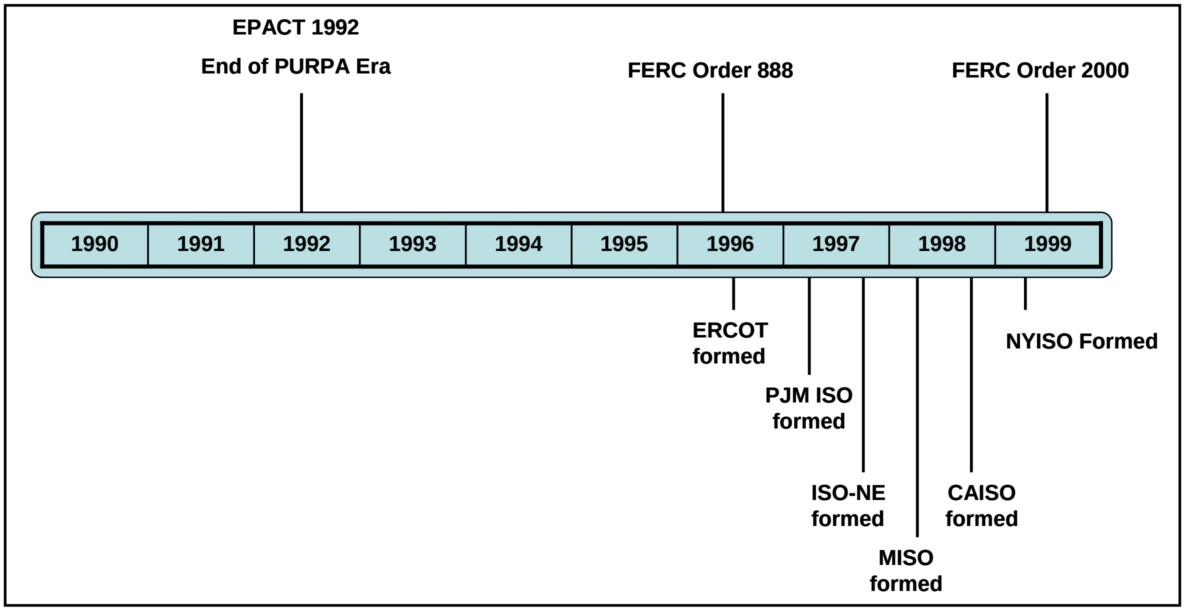
Non-utility generators have existed since paper mills and chemical plants started to use electricity. However, the passage of the Public Utilities Regulatory Policies Act (PURPA) guaranteed a market for the surplus electricity these generators could produce. Passed by Congress in 1978, PURPA established policy that made it possible for non-utilities to emerge as important power producers. PURPA was enacted in response to the energy crises of the 1970s, and sought to reduce oil and gas consumption. To do so, it required electric utilities to purchase power from qualifying cogeneration facilities and small power producers. This requirement quickly attracted non-utility generation investment, creating the opportunity for non-utilities to prove their potential to contribute to grid reliability and provide low-cost power.

By the end of the 1980s, non-utility capacity approached six percent of total U.S. capacity, producing about nine percent of national generation. The total capacity developed by non-utilities in the 1980s amounted to just one-fifth of all generation development.[7] One factor that limited the extent of non-utility growth in the 1980s was the Public Utility Holding Company Act of 1935 (PUHCA) that discouraged IPPs from entering the market by subjecting them to extensive financial regulation. The most significant factor limiting non-utility generation investment in the 1980s was transmission inaccessibility. Non-utilities were wedded to their local market because utilities would deny or severely limit transmission service to them to ensure demand for their own generation. While PURPA played a key role in the emergence of competitive power markets, it needed significant reforms, which began with the Energy Policy Act of 1992 (EPACT 1992).

Federal action taken in the 1980s and 1990s gave rise to the formation of International Organization for Standardization and Regional Transmission Organizations (RTOs) that have provided the structure necessary to enable the rapid evolution of power markets during the 2000s and the development of the non-regulated power sector seen today. Exhibit 3-1 provides a timeline overview of the major market deregulation events that took place in the 1990s. The rest of this paper discusses the key changes in the marketplace that enabled a non-regulated power sector to develop.

[7] The Electric Energy Market Competition Task Force. "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy." 2005 and Ventyx 2009.

Exhibit 3-1
Timeline of the Development of Formal Markets



3.1 Market Reforms of the 1990s

A well-connected transmission system facilitates the purchase of less expensive power from alternative suppliers, such as power marketers or IPPS across large areas. The passage of EPACT 1992 enabled wholesale customers to purchase less expensive power from IPPs and power marketers. Importantly, it also removed the PUHCA barrier to non-utility entry by creating a new power producer classification, exempt wholesale generator (EWG), which is exempt from PUHCA. EPACT 1992 additionally granted FERC the authority to order utilities to provide transmission service to non-utilities. This act, later expanded by FERC Order 888, serves as the foundation of competitive wholesale power markets.

FERC Order 888, passed in 1996, requires utilities to provide other market entities (e.g., IPPs or power marketers) with non-discriminatory open access to transmission service through the establishment of an open access transmission tariffs (OATTs). Additionally, Order 888 provided the framework for the development of independent system operators (ISOs). ISOs are FERC-approved, nonprofit organizations that maintain operational control of a divested transmission system and coordination of market activities in order to ensure reliability.

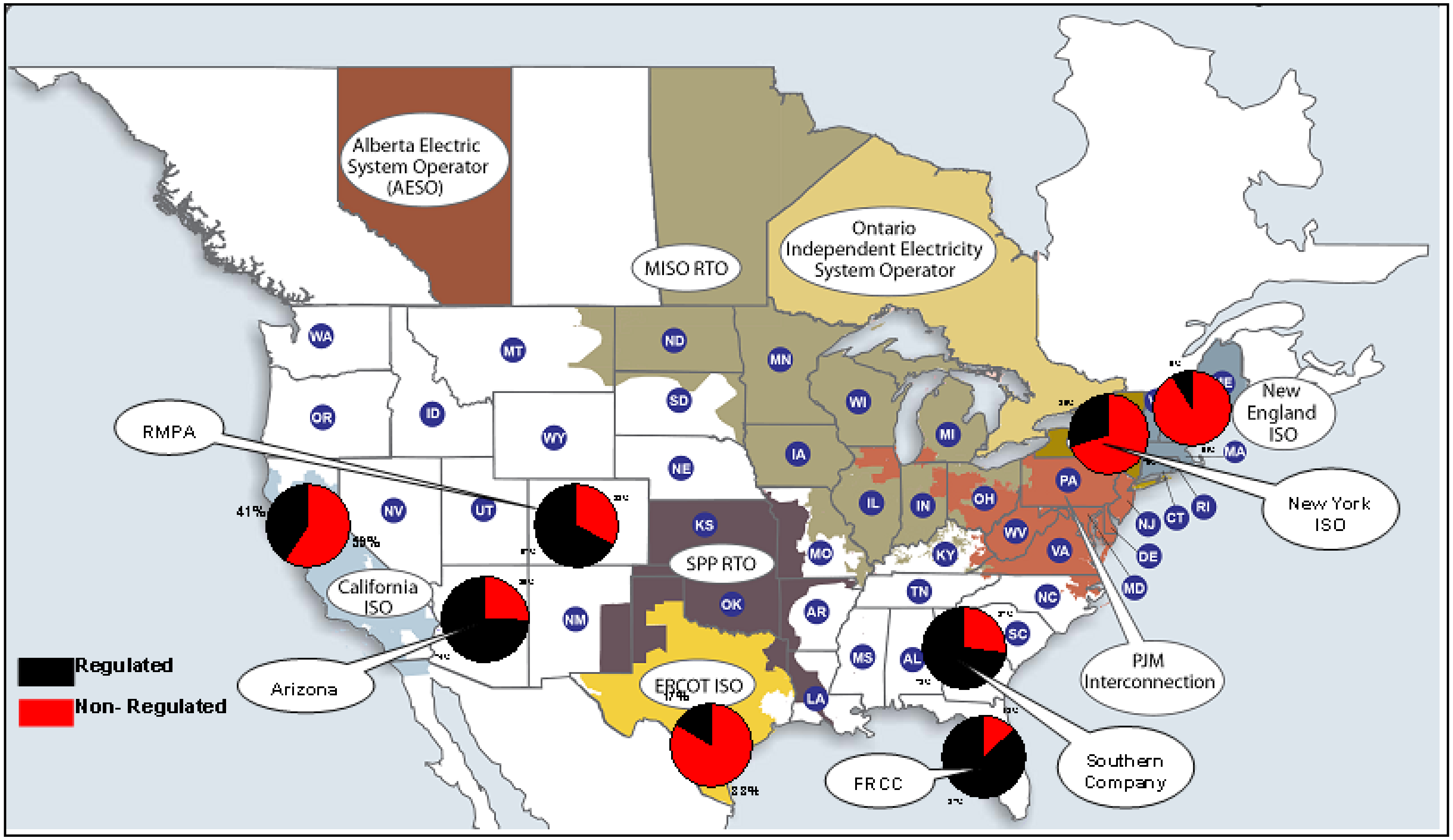
Despite FERC's efforts to provide full transmission access, many market participants complained about discriminatory transmission owner practices. These complaints suggested transmission operation and wholesale participation were not yet completely unbundled. In response to these complaints, in December 1999, FERC issued Order 2000, which helped organize regional planning and eliminated remaining transmission access discrimination by encouraging the voluntary formation of RTOs, which would have operational control of utility transmission systems.

The passage of FERC Orders 888 and 2000 led to the formation of six ISOs/RTOs, five of which fall under FERC's jurisdiction and one of which falls under Texas' regulatory jurisdiction. These ISOs/RTOs encompass all of the New England states, the Mid-Atlantic states, much of the Midwest, and portions of the Southwest, California, and Texas. The ISOs/RTOs ensure non-discriminatory transmission access, have authority over transmission system planning, and operate competitive wholesale power markets for a variety of power services.

3.2 Outcome of These Developments

Between 1996 and 1999, six ISOs/RTOs were formed: Electric Reliability Council of Texas (ERCOT); Pennsylvania-Jersey-Maryland RTO (PJM RTO); ISO New England (ISO-NE); Midwest ISO (MISO); California ISO (CAISO); and New York ISO (NYISO). Exhibit 3-2 displays the location of each ISO/RTO and the distribution of power producer participants by regulatory status.

Exhibit 3-2
ISOs/RTOs and Regulated versus Non-Regulated Regions in the U.S. as of 2009



Source: NERC and Ventyx 2009.

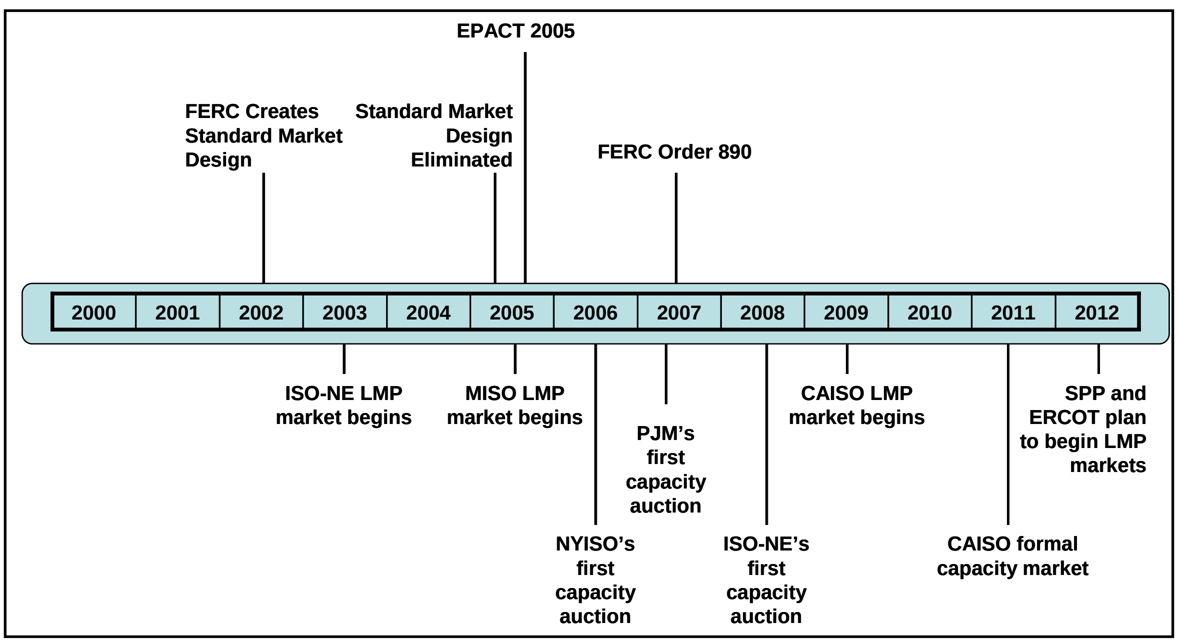
Prior to the passage of FERC Order 888, the capacity mix in the U.S. was heavily weighted towards utility generation. In fact, only about six percent of capacity in 1990 was merchant-owned.[8] In contrast, today's IPP generators represent almost 42 percent of all capacity.[9] In absolute terms, the amount of IPP capacity in the country increased from under 100 GW before the passage of Order 888, to over 450 GW today. In fact, as can be seen in Exhibit 3-2, since 1996, nearly two-thirds of all new IPP capacity has been built in deregulated markets.

The capacity mix has changed more significantly in deregulated markets than in regulated ones. As seen above, New England's capacity is over 90 percent merchant, having grown from only 41 percent prior to 1990. Similarly, New York has grown from 30 percent to 70 percent merchant generation since 1990. Conversely, Florida has grown only from 4 percent to 13 percent and Southern Company from 4 percent to 27 percent of merchant generation. The growth of merchant generation in deregulated markets is largely due to reforms enacted in the past 10 years.

3.3 Market Developments of the 2000s

Federal action in the 2000s saw FERC addressing transmission access issues that were still plaguing the wholesale power markets. FERC also introduced Standard Market Design (SMD, see below), reflecting many of the concepts already embraced by some of the deregulated markets. Exhibit 3-3 provides a timeline overview of the major market deregulation events that took place in the 1990s.

Exhibit 3-3
Timeline of the Development of New Products in Deregulated Markets



[8] The Electric Energy Market Competition Task Force. "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy." 2005 and Ventyx 2009.
[9] Ventyx 2009.

3.4 Standard Market Design

In the early 2000s, as the success of ISOs became more apparent, FERC attempted to create a new rule that would force all markets to restructure in a similar fashion. It started a new proceeding to determine rules for an SMD, which would apply to all transmission owners and utilities under FERC jurisdiction. Its goal essentially would be to mandate the formation of an ISO or RTO in a similar vein to PJM or NYISO. SMD would require: (1) an independent transmission provider (ITP) to assume responsibility for all transmission systems; (2) a locational marginal pricing (LMP) scheme with both day-ahead and real-time pricing; (3) a plan to ensure that all load serving entities (LSEs) will make commitments to meet resource adequacy needs, that is, provide for a reserve margin; (4) provide for transmission planning; and (5) establish a strong market monitoring unit. Essentially this was FERC's attempt to move away from regulated markets to ones that are fully functioning and deregulated.

After facing stiff opposition from utilities in the Southeast and Northwest, FERC's SMD was dropped in 2005. While it never became a rule, it did highlight the necessary features of an effective RTO. As a result, many markets are moving closer to a fully functioning market, such as Southwest Power Pool (SPP), which has recently announced a move to develop full nodal pricing.

3.5 Fine Tuning of New Formal Markets

Deregulated markets have shown significant development in the past decade. As highlighted in FERC's SMD, deregulated markets offer many products or services that are in common with each other. These products have brought about increased price discovery leading to greater clarity on potential revenues, even if they are uncertain. One of the first products of deregulated markets was nodal pricing, which first appeared in 1998 in PJM.

3.5.1 LMP

After the development of the ISOs, a major step in market deregulation was the creation of nodal pricing or LMP, starting in 1998 with PJM. NYISO followed suit in 1999, ISO-NE in 2003, MISO in 2005, and CAISO in 2009. The last two developed markets, SPP and ERCOT, plan to have LMP in place by 2012. After making the switch, these ISOs will have many different nodes, each with their own distinct power price, as opposed to a large regional zone with only one price. These nodes are placed at any place power moves on to or off the grid, namely generators and demand centers. Both NYISO and ISO-NE have hundreds of nodal pricing points (NY has 468 and NE has 1,006). The nodal price not only captures the cost of generation at that point, but also its contribution to transmission congestion and transmission losses.

Nodal pricing allows for a clearer picture of new capacity needs across a region. For example, a node in Philadelphia will show a higher price than a node in western Pennsylvania because of the higher energy demand and power flow constraints. Thus, IPPs are enabled to make a more informed decision when siting new generating capacity and can maximize their revenues by siting new capacity near higher price nodes.

3.5.2 Capacity Markets

Until recently, power price spikes have been the norm in all power systems. In periods of high demand, energy prices may spike to very high levels due to the fact that there is not enough capacity. Many units in a deregulated market, especially peaking units, must earn all of their revenues and cover their investment costs from these price spikes, which occur only in a few critical hours each year. As a result, energy prices must be very high in those super-peak periods to promote new investment consistent with reliability requirements.

The capacity market, a recent addition to many deregulated markets, promotes capacity investments by providing a reliable revenue stream while helping reduce price spikes. A plant can now sell the right to its capacity, guaranteeing that it will be available when called upon and capable of providing energy. Capacity markets not only provide clear incentives for new investment, but also help ensure system reliability.

The first ISO to create a market for capacity was NYISO, with a market for capacity capable of producing up to three prices: one for New York City, one for Long Island, and one for the entire state. The cause of locational differences in capacity prices is the same as the cause of locational differences in energy prices: transmission constraints. There are large transmission bottlenecks going into New York City and Long Island, which act as large demand sinks. As a result, the NYISO has mandated that New York City provide 80 percent of its own capacity, and due to even more stringent bottlenecks, Long Island must provide 99 percent of its needs internally.

The capacity market provides a capacity price based on the ability to meet targeted reserve margins, given these constraints. To provide clear market signals, NYISO operates a demand-curve mechanism, which is administratively set and periodically reviewed. This curve will set the price based on how much capacity is bid into the auction. As a result, entities bidding into the auction process will all be paid according to the price on the supply curve when it crosses the demand curve. Each LSE operating in the ISO is required to meet its local reserve margin requirements. NYISO runs this auction very frequently, conducting a strip auction, a monthly auction, and a spot auction. The strip auction takes place a full month ahead of time and covers the entire six-month summer or winter season. The monthly auction also occurs about a month in advance, but only covers one month, while the spot auction takes place roughly 5 days before the delivery period. The vast majority of capacity needed to meet reserve margin, roughly 60 to 80 percent, is bought in the spot auction, only days ahead of need.

In contrast, the two other markets with functioning capacity markets, ISO-NE and PJM, conduct auctions three years ahead of time and cover an entire year. PJM completed its first auction in 2007, and has run five additional auctions since, the last one being for the capability year 2012/2013. ISO-NE has run two capacity auctions since it started its forward capacity market (FCM) in 2008. Like New York, both ISO-NE and PJM recognize the locational value of capacity. PJM incorporates 23 local delivery areas that could all have potentially different capacity prices, recognizing the premium some regions place on new generation over others due to transmission import constraints. New England also recognizes the possibility of regional divergence in capacity price, and has built the ability for this to occur into its auction mechanism.

PJM utilizes a demand curve mirroring NYISO's auction mechanics, but ISO-NE runs its auctions in a descending clock auction, with both a floor and ceiling price administratively set. The floor is to make sure that there is always at least some price for capacity, with the idea being that even a surplus of capacity has some value in the context of greater reliability. NYISO and PJM accommodate this same point by having their demand curve price zero out many percentage points above the targeted reserve margin.

Both MISO and CAISO are moving to more formal capacity markets as a means to provide further incentives that ensure new investment occurs where it is needed. MISO switched to a month-ahead resource adequacy structure starting on June 1, 2009, under its long-term resource adequacy plan. According to the plan, each LSE has to meet its monthly resource adequacy requirements by obtaining the qualifying capacity through self generation, bilateral contracts, or monthly capacity auctions, which are voluntary and held by MISO.

CAISO is in transition to a standard capacity product market. Currently, in addition to the bilateral capacity markets, its interim capacity procurement mechanism (ICPM) helps LSEs procure capacity needed to meet their system-wide and local resource adequacy requirements. As with NYISO, ISO-NE, and PJM, California also recognizes the locational value of capacity, and created 10 local RA zones to ensure capacity is built where it is needed. The current structure will cease at the end of 2010. CAISO is working on its permanent standard capacity product (SCP) proposal to submit to FERC.

These developments have, like the development of LMP markets, increased price discovery and provided additional price certainty. IPP developers in these markets are now able to have a reliable income stream that is a safer investment option than capacity investment in regions where this product does not exist. Furthermore, formal capacity markets that recognize locational scarcity provide developers with a better understanding of where to site new capacity projects.

3.5.3 Hedging Options—CFD/FTR

Another major development in deregulated markets is the evolution of hedging power prices. Power prices are necessarily variable and, as a result, it is difficult to project future revenues from them. However, two new products in deregulated markets have started to eliminate this variability. A “contract for differences” (CFD), when used in conjunction with acquired firm transmission rights (FTRs), essentially sets a strike price for power, with the generator (or investor) receiving the profit from that set price. The certainty of returns is paid for by giving up the potential upside if power prices move above the contracted strike price. These developments first appeared when the ancillary service products first appeared in the ISOs. This certainty of returns will allow more conservative investors a way to develop new projects in the wholesale marketplace.

3.5.4 Ancillary Services

Another market element that has permitted greater price discovery is the creation of ancillary service products, which first came into operation in the early 2000s and have been growing quickly ever since. Ancillary services are real-time system reliability market services, typically provided by generation resources. Prior to the creation of ancillary service markets, generators providing the range of services required to maintain system stability would receive out-of-market cost-of-service payments (i.e., reliability must run, or RMR, payments). The old system limited generator planning and payment reliability. Marketizing ancillary services provides greater clarity, stabilizes revenue streams, and allows generators to capture the full value of their services. The main beneficiaries of ancillary service revenues are peaking and mid-merit units, due to their flexibility and high availability. Baseload units, conversely, usually do not participate as they run full-out more often.

Types of ancillary services include operating reserves, automated generation control (Regulation), reactive supply and voltage control, and system restoration and planning service (Black Start). Typically constituting the largest portion of ancillary services markets, operating reserves are a safety net of generation capacity that can quickly provide extra energy when needed due to unforeseen changes in supply or demand.

Ancillary service revenue streams vary greatly depending on a plant's size and service capabilities. In 2007, for example, a typical natural gas combined cycle in ISO-NE earned up to 1.2 percent of its total revenue from providing ancillary services; however, a typical natural gas combustion turbine earned up to 33 percent of its total revenue from providing ancillary services.[10]

ISO-NE has recently advanced the procurement of operating reserves. Not only does ISO-NE secure ancillaries on a real-time basis, but also through forward semi-annual auctions. The revenue streams flowing from this new, growing, forward market are significant enough to impact generation investment decisions, as evidenced by the recent development of several combustion turbines in Connecticut that primarily provide ancillary services.

3.5.5 Demand-Side Management—Demand Resources

Unlike the other products mentioned above, DSM resources are not new to the marketplace; furthermore, their adoption will delay new plant investments. The adoption of DSM as an alternative source of capacity could be tempered, however, by its possible negative impact on reliability. As shown earlier, Florida discovered that relying too much upon DSM caused shortages in the highest-priced hours, resulting in price spikes. This same result may happen in deregulated markets as well.

ISO-NE allowed DSM to bid into its first forward capacity auction (FCA), essentially treating them as an alternative supply option. In February of 2008, over 2,500 MW of DR cleared the first auction. This helped drive the cleared capacity price to the lowest level allowed, the floor price. Over 2,900 MW of DR cleared the second FCA (2011/2012 capability year), where prices were again driven to the floor price.

At this level of adoption, DRs are now playing a significant role in reliability planning, representing 55 percent of the total reserve margin requirements in New England. ISO-NE may be overestimating the extent to which cleared demand side capacity can reduce the need for generation facilities. ISO-NE does not de-rate demand side capacity, clearing the FCA to account for the potential unavailability that could arise if increased market penetration drives higher withdrawal rates. However, the Florida example has shown that DR unavailability increases with higher market penetration.

As demand resources grow in proportion to total resources and displace generation resources, demand reductions will be called to perform in more hours. These demand resources typically have the ability to shut off with minimal penalty. As they get called more often (ISO-NE recently forecast as many as 200 hours per year), some may simply opt out, negatively affecting system reliability.

3.5.6 Market Monitoring

As deregulated markets have become more advanced, the oversight of these markets has also improved. Many ISOs, such as NYISO, have created specific market monitoring units (MMUs), whose sole purpose is to ensure fair market competition. They have taken action in the past to enforce open markets. For example, the NYISO MMU recently took action to prevent uneconomical activity on both the buy and sell side of energy transactions. Certain generators with a large share of capacity in New York City were found to have withheld some of their

[10] ISO-NE, *2007 State of the Market Report.*

capacity to drive up capacity prices, hence driving up their profit. As a result, NYISO added a "must-offer" provision, specifying that all capacity must be offered into the capacity auction.[11]

It is also possible to game the capacity market in the opposite fashion. A monopsony (i.e., one buyer faces many sellers) power, such as a dominant LSE, could attempt to build unnecessary new generation that would lose money in the capacity market, but would recoup all its losses by depressing the capacity price to the level at which it must buy its needed supply. As a result of this possibility, the NYISO MMU set a floor on capacity prices to mitigate a precipitous fall due to this phenomenon.[12]

ISO-NE has also found that it needs to monitor capacity markets. It has imposed peak energy rents (PER), which are the revenues earned by a hypothetical peaking unit with a 22,000 Btu/kWh heat rate, and subtracts these calculated rents from the cleared FCM capacity price. The goal of this is to hedge loads against large energy price spikes, the frequency of which the capacity market was created to reduce. It also gives peaking units more revenue certainty, as they will gain most of their revenue from the capacity market, as opposed to relying on unpredictable price surges that may or may not happen. Finally, it reduces the incentives to exercise market power to cause price increases, as generators are now hedged against the development of price spikes.

The formation of MMUs allows deregulated markets to function with more openness and clarity, thereby providing a potentially safer investment option for IPPs looking to invest in new capacity in those markets.

3.6 Transmission Investment

With the development of wholesale markets, congestion on the transmission grid has increased significantly, as transmission capacity investment has not kept pace with the expansion in generating capacity and changes in trading patterns. This, in turn, has sometimes stalled new generation capacity from moving forward, due to the additional burden of high transmission upgrade costs. This is an "allocation of costs" problem and, to the extent IPPs or other users are unfairly allocated upgrade costs, the economics of new power generation construction could be set back.

In the early days of deregulation, the cost of transmission upgrades was attributed to the incremental generator (especially IPPs) that precipitated the need for the upgrade, even though the need was created by the incremental generator and existing users, and the benefits of the upgrade were available to multiple users. This resulted in huge charges for transmission expansion, which discouraged the incremental generator from making the investment.

FERC tried to address this and other transmission network issues with Order 890, issued in 2007. Order 890 requires that the transmission provider's (TP's) planning process must satisfy nine principles, one of which addresses transmission-upgrade cost allocation to new projects. The cost allocation should be fair in assigning cost to those that cause them and those that benefit. This would, in essence, relieve some cost burden that was unduly allocated to new generators. All RTOs are following these guidelines.

[11] Docket No. EL07-39-000, Reply Comments of the New York Independent System Operator.

[12] Docket No. El07-39-000. Compliance Filing of The New York Independent System Operator, Inc. Regarding the New York City ICAP Market Structure.

3.7 Carbon Legislation, State RPS, and National RES

Just as they will affect utility generation investment, impending federal climate change and renewables legislation will greatly affect IPP baseload generation investment. Existing legislation and legislative uncertainty has led to the postponement and cancellation of many IPP baseload projects. The passage of carbon legislation will fundamentally shift the marketplace and force IPPs to reevaluate their strategic approach to profit maximization.

3.8 2009 Recession and Its Impacts

The current recession has caused many investors to reevaluate their investment strategies. While the recession does not represent a fundamental shift in market economics, it will, in the near-term, delay new investment in both regulated and deregulated markets by restricting access to capital and dampening demand growth.

The current credit crisis facing the power industry has many implications for near-term projects. There are liquidity issues limiting access to capital and risks associated with legislative and regulatory uncertainty threatening credit ratings. Additionally, energy demand has decreased, curbing the potential returns of new capacity investments. Moreover, the cost of new baseload investments has increased, due to the reduced access to and high cost of debt and equity.

The financial crisis has made capital more expensive for both utility and IPP players in the short term, with the weighted average cost of capital (WACC) increasing to levels that make project financing new capacity investment a considerable challenge. Projects can lower their risks, especially their susceptibility to varying market conditions, by securing well-structured PPAs. Additionally, DOE's loan guarantee programs and direct financing for clean coal projects, as with the utilities, can play a pivotal role in making a baseload investment economically viable.

3.9 Capital Costs and Consortiums/Balance-Sheet Concerns

Prior to the most recent recession, the cost to construct new power plants increased significantly. The cost of a new plant increased approximately 50 percent from 2006 to 2008, on average, although there have been even more extreme examples. A potential IPP coal plant in Nevada saw its cost triple from 2004 to 2009, prompting the cancellation of the project. Even with the reduction in costs due to the recession, costs are still so high for some baseload options that power companies have created partnerships to spread the risk of new capital investments.

Companies typically only form consortiums to ensure the viability of the most expensive baseload generation projects, such as the new unit at the Calvert Cliffs nuclear facility being developed by the Électricité de France and Constellation Energy consortium, Unistar.

According to Moody's Investor Services, a ratings agency, investments in new nuclear capacity face the largest risks:

"From a risk mitigation perspective, the prospect of seeking business partners — particularly major multinational energy companies with some experience in the nuclear arena — might also be worth exploring as a good way to preserve liquidity and cash flow, while still reaping the benefits of new nuclear power generation."

3.10 Growing Role of Government Tax and Credit Incentives

To facilitate new investment, many government incentives have been created in recent years, especially after onset of the current recession. As with utilities, these incentives have come to play a role in IPP generation investment decisions. Securing government incentives can make or break projects struggling with debt and equity financing. The ongoing distribution of EPAct 2005 and ARRA 2009 incentives will play a key role in the advancement of many IPP projects in the near future. For example, the issuance of federal nuclear loan guarantees has determined the viability of new nuclear generation in the U.S. Of 16 nuclear loan guarantee applicants, only four are expected to be approved, of which two are IPPs. Those two projects, Unistar's Calvert Cliffs and NRG Energy's Vogtle expansions, would not likely advance without loan guarantees, especially in this challenging economic environment.

3.11 On-going Market Deregulation — Entergy

Even though most power market deregulation took place in the 1990s, efforts are still underway to deregulate additional markets. The nascent attempt by FERC to force deregulation through the SMD never took effect. As a result, there are still many markets that could potentially be deregulated, one of which is Entergy. Entergy's efforts to join the SPP RTO began in April 1998. But due to Entergy's reluctance to turn over the operational control of its transmission system to an RTO, the efforts failed and FERC ordered the proceedings to be terminated in December 2004.

Since that time, however, Entergy has crafted a plan to have SPP act as its independent coordinator of transmission (ICT). Beginning in October 2006, SPP now performs a number of functions for Entergy, including tariff administration, reliability coordination, and regional planning functions. In March 2009, the ICT established a weekly procurement process that has reduced the production costs for both Entergy and network customers and has permitted IPP market participation.

Various parties have expressed concern regarding Entergy's transmission system planning under the ICT model, prompting Entergy in June 2009 to agree that it will reconsider joining SPP and will conduct a cost/benefit analysis by the end of 2009. Entergy stated that it will also explore alternatives, such as modifying the current ICT structure and giving the ICT the authority to require Entergy to construct capacity, depending on the results of the SPP/RTO planning process.

Chapter 4
Summary

We have identified the major market developments that have changed the investment decision process of investors in power generation. Electric markets have changed significantly since the first “pure” merchant generator came online following the passage of PURPA. A second distinct market type has developed over the past 10 years: the competitive deregulated market. While regulated markets have remained relatively unchanged, resembling the power system of the early 1980s, deregulated markets have evolved and grown significantly over the past ten years. Deregulated markets now represent a significant portion of U.S. power generation and demand.

The four major market developments over the past two decades are summarized below:

- **Divestiture** — Some states have forced utilities to divest themselves of their generation and transmission assets through legislation; many more states have encouraged it. Some utilities realized that to achieve a least-cost solution, they should divest their power plants and purchase power from the market, as merchant power was pricing out lower than their average costs. In newly competitive markets, many utilities could no longer afford to run their older, inefficient power plants. As a result, and in conjunction with IPPs entering the marketplace, many utilities have completely left the power generation business and shifted to simply serving load. In essence, deregulated competitive wholesale markets have allowed many new investors into the marketplace.

- **FERC 888 and RTO Creation** — Passed in 1996, FERC Order 888 forced utilities to provide non-discriminatory market access to merchant generators. As a result, IPPs were able to sell power into different markets for the first time. The bill, in conjunction with FERC Order 2000, also established the framework for ISOs/RTOs, which have grown across the U.S., opening up investment access to many new investors.

- **Locational Marginal Pricing** — Starting around ten years ago, ISOs introduced locational marginal (also known as nodal) pricing. LMP pricing allows more certain pricing data to be known across many different points in a marketplace, as opposed to one single zonal price. These better price signals help developers site new generation in locations that are most in need and offer the highest returns.

- **Capacity Markets** — Capacity markets are one of the most recent market developments, the first starting only in 2006, but they are now fully functioning in NYISO, ISO-NE, and PJM, with planned markets in MISO and CAISO. Capacity markets provide an incentive for new plant investment by providing a revenue stream with more certain returns, allowing many more risk-averse investors to become active in the marketplace.

Looking forward, we envision that the next significant event to influence investment decisions for baseload generation investors will be the passage of national climate change legislation.

- **CO_2** — There is great uncertainty as to what form future CO_2 legislation will take. However, the latest bill, Waxman-Markey, has already passed one house of Congress, and imposes stiff regulations on CO_2 emissions. Its goal is to reduce CO_2 emissions to 82 percent below 2005 levels by 2050. Even though some allowances will be allocated to merchant coal generation at first, this will add a significant cost to power generation from fossil-fired plants, growing larger as time passes.

Volume VI: Case Studies on Recent Baseload Coal Investments

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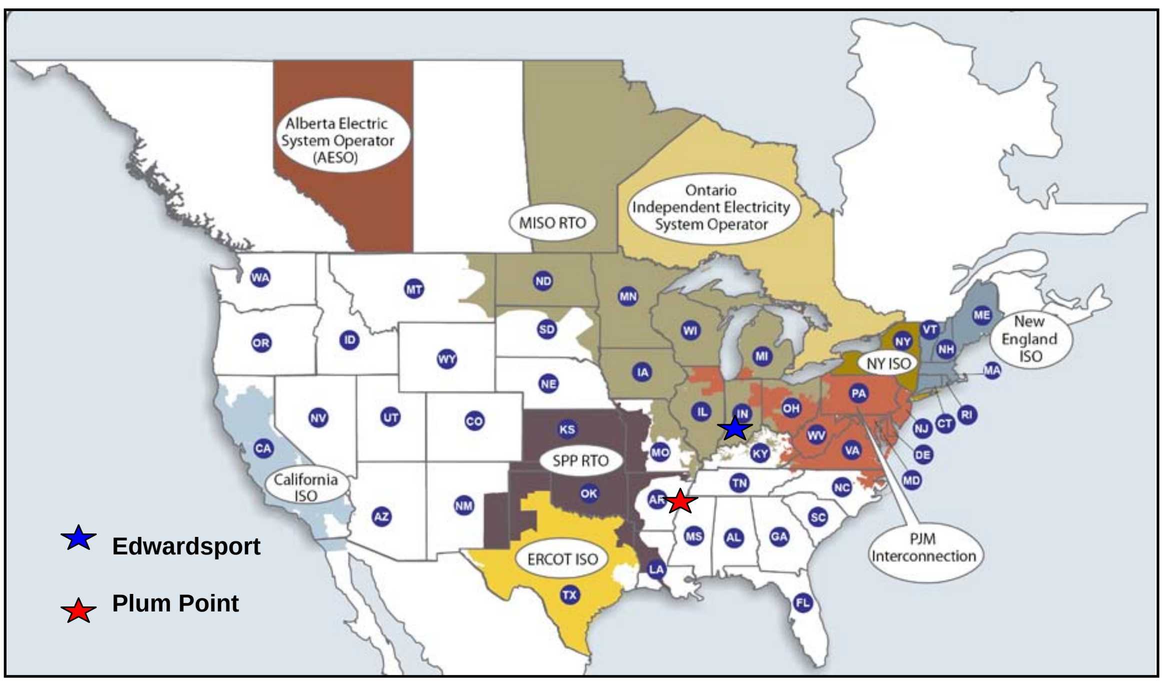
Chapter 1
Introduction

This is the sixth and final volume of a six-volume report designed to provide a detailed understanding of the key drivers and processes that affect private entities in the United States (U.S.) as they consider investing in baseload generation capacity. The report was prepared by ICF International at the request of the National Energy Technology Laboratory (NETL).

This volume uses case studies of recent baseload power projects to provide real-world examples of the investment drivers for new baseload electric generation, as discussed in the previous five volumes. For this analysis, ICF examine two power plant projects, Duke Energy's integrated gasification combined cycle (IGCC) in Edwardsport, Indiana, and LS Power's Plum Point Energy Station in Arkansas. Both case studies are designed to be coal-fired baseload power plants. The Plum Point power plant is being developed by an independent power producer (IPP) and uses a proven generation technology. The Edwardsport plant is being developed by a utility and uses a new generation technology. These two case studies provide good examples of the range of approaches that developers are using to successfully build and finance new coal-fired generation plants in their respective sectors.

The report is structured as two separate case studies, with the first reviewing Edwardsport and the second Plum Point. The location of these plants is shown in Exhibit 1-1.

Exhibit 1-1
Location of the Edwardsport and Plum Point Power Plants



At 600 MW of capacity, the Edwardsport IGCC will be the first commercial-scale IGCC plant in the United States (U.S.). It will be able to utilize local high-sulfur coal yet still produce far fewer emissions than a comparable pulverized coal (PC) plant. The Edwardsport IGCC is an

important example of utility investment in new technology. Duke had to implement a complex strategy and answer many challenges to receive approval to construct this plant. First, to mitigate high construction costs, Duke had the foresight to secure significant financial incentives at all government levels. Duke ended up receiving over $440 million in guaranteed incentives, which is almost one-quarter of the plant's estimated cost. Duke took additional steps to manage construction costs by leveraging its previous construction experience to become manager of the engineer-procure-construct (EPC) process. In evaluating its generation options, Duke considered the increasing likelihood of climate change regulation and chose an IGCC technology because it could more economically capture carbon dioxide (CO_2). Also, by choosing IGCC, Duke was able to leverage its unique previous experience[1] with this technology to effectively respond to technical questions raised in the integrated resource planning (IRP) process. Finally, Duke increased the likelihood of regulatory approval by lowering its requests for return on investment (ROI) incentives and accepting a less favorable depreciation schedule in order to limit ratepayer impacts.

The Plum Point Energy Station will be a 660-MW PC plant using proven sub-critical technology. This is an interesting case study, as it is being developed by an IPP, which will not have a "guaranteed" rate-based income on the investment. Instead, LS Power, the developer of Plum Point, worked very closely with local cooperatives and city/local governments, and offered partial ownership to them to help facilitate the project financing. In addition, LS Power was also able to gain a large amount of financing from the debt market, even though its debt is currently not investment grade. Plum Point thus offers an example of success in a market for merchant generators, as well as providing a template for the way in which these projects can be structured.

In developing these case studies, ICF relied only on publicly available resources, such as public testimony before the public utilities commission in Indiana for the Edwardsport case. In fact, the semiannual review of Duke's Edwardsport project is still ongoing, but we have limited the analysis to only the original testimony and rebuttal filing. Information for Plum Point has also come only from publicly available sources.

Finally, the views presented in this report represent ICF's views only, and have not been reviewed or endorsed by Duke Energy, LS Power, or any other parties mentioned within.

[1] Duke's Case- in-Chief Testimony, Kay Pashos, 2006.

Chapter 2
Duke Energy's Edwardsport Project

2.1 Overview of the Edwardsport IGCC Project

In September 2006, Duke Energy (Duke) filed a petition with the Indiana Utility Regulatory Commission (IURC) to request the issuance of necessary certificates to build a new coal-powered IGCC in Edwardsport, Indiana. The proposed clean-coal facility would have a capacity of approximately 630 MW and be located adjacent to the existing Edwardsport Generating Station. The new plant will be designed to burn in-state Indiana bituminous coal.

The plant will have two gasifiers, both sharing a Selexol acid-gas-removal system and a Claus process sulfur-removal system. It is configured to have two GE 7FB combustion turbine generators, each of which will have the option of operating on syngas or natural gas, two heat-recovery steam generators (HRSGs), each equipped with a selective catalytic reduction (SCR) for nitrogen oxide (NO_x) control, one GE DI 1 steam-turbine generator, and a multiple-cell cooling tower. Each gasifier train will also include an activated-carbon bed for absorption of mercury (Hg).

As will be shown in the following pages, after Duke recognized in both its 2003 and 2005 IRPs that Indiana would need new baseload capacity, it started a strategy to win support for new coal IGCC project to meet that need. Duke is one of few companies to have extensive experience with IGCC technology, and this type of plant would also enable the use of local Indiana coal. Duke has also been one of the most active and forward thinking utilities in the climate change discussion. In that context, Duke considered other alternatives, but found that IGCC would be the most effective option to address the future need for carbon control.

2.2 IRP Approach

To obtain regulatory approval for new baseload generation, a utility such as Duke must go through an Integrated Resource Planning (IRP) process. The IRP process involves evaluating a variety of resource options to determine the optimal combination of feasible and economic alternatives that will reliably meet anticipated future customer loads.

The IRP process that Duke followed, like most other IRPs, had a number of steps. The first step in the process is to develop planning objectives, assumptions, and electric load forecasts. Then, potential demand-side resource options are identified and a sensitivity analysis around the cost-effectiveness of potential electric supply-side resources is performed. In addition, the cost-effectiveness of potential environmental compliance options is assessed. Finally, demand-side, supply-side, and environmental compliance options are evaluated as part of a sensitivity and scenario analysis to select the optimal plan based on quantitative and qualitative factors such as economics, reliability, technical feasibility, and risk.

2.3 Duke's Strategy

Based on the findings in its 2003 IRP and a 2005 IRP follow-up, Duke found that it needed to add baseload capacity to meet the growing energy needs in Indiana over the next decade. This new plant would help Duke modernize its fleet by removing the existing Edwardsport plant, which was mostly constructed in the 1960s, as well as providing new baseload technology that can more easily adapt to the changing environmental climate.

2.4 Duke's Decision on IGCC Technology

2.4.1 Benefits of Coal

Duke felt that it did not have many options to consider in determining the best choice to meet Indiana's growing baseload capacity needs at that time. Oil and natural gas prices had increased significantly after the hurricanes in the fall of 2005. Disruptions and limitations in supplies affected not only the price levels, but also the volatility of prices. Although coal prices had also been rising, they had shown far less volatility, and there is no shortage of coal in the U.S.[2] In addition, the region where the proposed IGCC project will be located has abundant coal resources that are readily accessible. Ultimately, Duke considered other options, such as wind and nuclear, to meet Indiana's baseload needs, but ruled them out due to cost and logistics concerns.

After choosing coal as the new baseload option, Duke realized that increasing commodity costs and volatility in prices would provide a challenge, even with cheap coal as a generating fuel source. Sulfur dioxide (SO_2) allowance prices, which affect the cost of production for coal-fired units, had experienced price spikes and volatility similar to gas and oil prices as a result of the promulgation of the federal Clean Air Interstate Rule (CAIR), which required deep reductions in SO_2 and NO_x emissions. The company realized that volatility in the allowance prices and the cost of emissions-controlling technologies such as scrubbers would make high-sulfur coals attractive fuel sources for coal-fired plants.

However, with the depletion of Central Appalachian coal reserves and the issues with Powder River Basin coal transportation, Duke searched for lower risk and more stable coal supply alternatives. Among these coal source alternatives, Indiana has significant coal reserves of about 17.5 billion tons, but this high-sulfur Illinois Basin bituminous coal produces significant emissions. Duke attempted to come up with a solution for using abundant, accessible Indiana coal in an economically viable and environmentally clean way. Duke decided on IGCC technology as a solution, in part because it achieves 99 percent SO_2 removal, which would enable it to use higher sulfur Indiana coal resources with minimal SO_2 allowance cost.

2.4.2 Experienced with IGCC Technology

Even though IGCC is a relatively new technology, Duke has had significant experience in using this technology. In the early 1990s, Duke successfully developed an IGCC demonstration project along with Destec Energy, which resulted in the Wabash River Coal Gasification Repowering Project. At the time, the Wabash River Repowering Project was the largest of its type in the world. The demonstration project is still among the cleanest operating solid-fuel power plants. The knowledge and experience gained from this project will be applied in development of the Edwardsport Project.

[2] According to the U.S. Energy Information Administration, the United States has about 270 billion short tons of recoverable coal reserves, enough to last over 250 years at current usage rates.

2.4.3 Consideration of Other Alternatives

As stated above, other options were considered, such as nuclear energy, which produces no emissions and is a logical baseload option in a carbon-constrained world. However, Duke is pursuing the nuclear option in another location. In Indiana, the company feels that the baseload need would be better met by the coal option. In particular, because there is no existing nuclear fleet in the Midwest, permitting and siting of a new nuclear plant would take longer. Construction of a nuclear plant would also take much longer and would not meet the baseload needs as described in their IRP filings.

A coal IGCC option can also be sized better to meet current baseload needs. The IGCC unit will also allow Duke to qualify for significant federal and state clean coal investment incentives, making the project more economical. Finally, the new plant will rely on nearby Illinois Basin coal, significantly lowering fuel costs and also helping the state economy.

Renewable power was also considered as a solution. In fact, the 2005 IRP issued by Duke included a placeholder for a renewable project. In 2005, Duke issued a request for proposal (RFP) for new supply from renewable resources, such as wind, solar, biomass, hydro, or landfill gas. They received six bids, all of which were wind. In March 2006, Duke entered into a 20-year contract with one of the RFP bidders, Benton County Wind Farm, under which Duke will purchase 100 MW of wind capacity, which is estimated to operate at 35 percent capacity factor. This will help if Indiana or the Federal government implements an RPS, but it will not provide for all of Indiana's future baseload needs.

2.5 Why Edwardsport, Indiana?

In the fall of 2004, Duke assessed five potential locations in Indiana and one in Kentucky to determine the best site for an IGCC plant. In evaluating these location alternatives, a number of factors were evaluated, such as available land, electric transmission facilities, fuel delivery, water supply and quality, natural gas line proximity, and potential for CO_2 sequestration for each site.

Along with the ability for a plant to capture its carbon emissions, the ability to store the captured emissions must be considered as well. To evaluate the potential geologic sequestration at Edwardsport, Duke worked with the Indiana Geological Survey and Midwest Geological Sequestration Consortium (MGSC) to complete a feasibility assessment. It was found that there was significant storage available in which to sequester the potential plant emissions in the immediate area around Edwardsport.

After considering all of these factors, Duke chose the Edwardsport site as the preferred location for an IGCC generating plant.

2.6 Anticipated Issues

In choosing the IGCC option, Duke realized that many possible issues could arise. Duke took steps to mitigate foreseeable issues related to constructing an IGCC plant, such as high capital cost and climate change issues. Other unanticipated issues became apparent as a result of hearings with interveners.

2.6.1 Future Climate Change Legislation and other Environmental Regulations

There is a strong possibility that new regulations limiting CO_2 emissions will be promulgated (see Volume I, Chapter 3). This would increase the cost of generating electricity from carbon-emitting facilities, and ultimately result in higher prices for Duke's customers. The planned IGCC is well-placed to handle new CO_2 limitations, as it will be able to add carbon capture and sequestration (CCS) technology relatively cheaply, when compared with other coal-fired plants, even though the technology has not yet been fully commercialized. The ability to limit emissions as well as use a locally sourced, low-cost fuel will allow Duke to generate power significantly cheaper than it otherwise could.

Severe reductions of other pollutants will also be necessary. The current CAIR and Hg regulation, as well as possible additional regulations, will be very restrictive on the amount of NO_x, SO_2, and Hg that a power plant can emit. The IGCC plant will be able to capture over 99 percent of its sulfur emissions, as well as include equipment to capture its NO_x and Hg emissions. These controls will be integrated into the construction of the plant, allowing it to be one of the cleanest solid-fuel power plants in the world.

2.6.2 Cheaper to Control CO_2 Emissions through IGCC Technology

Even though IGCC has a higher initial capital cost than traditional pulverized coal, retrofitting for carbon control in the future will be cheaper. In fact, NETL estimates that the cost of equipping an IGCC plant with CCS technology will increase plant energy costs by approximately 30 percent. The increase in the cost of electricity for a supercritical PC plant is estimated to be even higher, 68 percent.[3]

2.6.3 Mitigating Capital Costs

Capital costs are high for the IGCC relative to other baseload technologies, and are susceptible to uncertainty. In fact, according to current estimates, an IGCC is 10-20 percent more expensive than a conventional coal-fired plant.[4] Consequently, anticipating the need to mitigate the risk of high costs is important. Duke pursued all available government financial incentives. Duke also did significant work prior to releasing a cost estimate to remove ambiguity.

2.6.3.1 Financial Incentives

Early in its efforts, Duke lobbied the state of Indiana, convincing it to recognize the need to add new local generation in the region, the need to support its underutilized coal industry, and the benefits of clean-coal power generation, such as IGCC. Duke's significant lobbying effort resulted in state legislation that provides financial incentives for clean-coal plants that utilize Indiana coal. The new legislation will also allow utility developers of clean-coal to earn as much as 3 percent more on equity than it could otherwise obtain. In addition, the legislation allowed Duke to utilize accelerated depreciation to obtain a more timely recovery of funds. Due to Duke's efforts, the state also passed Senate Bill 378 in 2005, which provides a 10 percent tax credit for the first $500 million invested in an IGCC project, and an additional 5 percent for all costs exceeding that, as long as it utilizes the state's coal. The estimated savings for the Edwardsport facility from this credit is over $111 million.

[3] See Volume 2: Technology Overview and Economic Viability Assessment of Base Load Generation, prepared by ICF.
[4] Ibid.

At the local level, Knox County has shown a willingness to help bring the plant's construction jobs to the area through tax incentives. In April 2006, Duke received a local tax abatement and tax incremental financing (TIF) from the county. This will provide a ten-year property tax abatement, which will save an estimated $93 million,[5] and a 30-year TIF, which will provide a 45-percent refund on all property taxes over the next 30 years, saving an estimated $106 million.[6] State and local incentives alone should save Duke over $311 million.

There are also federal investment tax credits (ITC) for IGCC and clean coal for which Edwardsport can qualify. A section of the Energy Policy Act of 2005 created an ITC of 20 percent (capped at $800 million) for IGCC development, as well as another ITC of 15 percent (capped at $500 million) for other advanced coal technologies. The $800-million credit was evenly divided among technologies that utilize bituminous, sub-bituminous, or lignite coal, as well as providing preference for IGCC projects that include capture capability. Duke applied for the maximum amount of allowed tax credits, $133.5 million, which were granted in December 2006.[7] In total, the Edwardsport facility has received or should receive over $440 million in financial incentives from federal, state, and local governments.

2.6.3.2 Upfront Engineering Design Work

Prior to the start of construction, Duke entered into an early alliance arrangement with GE Energy and Bechtel Corporation for a feasibility study of building an IGCC plant at the Edwardsport Station. Duke's goal was to be able to eliminate as many foreseeable technical issues as possible, as well as provide a firm cost estimate for the project. The study involved a technical scope description, services to be supplied, and plant performance projections such as heat rate and environmental emissions, as well as a preliminary cost estimate.

Not identifying any fatal flaws regarding the proposal in the feasibility study, Duke proceeded with the next stage of its investigation, consisting of the front-end engineering and design (FEED) study. In February 2006, the parties executed a second Technical Services Agreement to further site-specific studies intended to quantify the scope and cost of the entire IGCC project. This agreement required the contractors to develop a cost estimate for the scope of work identified in the engineering documents. In its ruling, the IROU thought that this process made the cost estimates clear and reasonable.

2.6.3.3 EPCM Approach to Construction

The main EPC and management firms hired by Duke, GE, and Bechtel will not be given full control over construction. Consistent with its recent experience in emission-control projects of over $1 billion, Duke will assume control over the management of the project to gain greater cost savings, as well as increase cost supervision and accountability. This is termed the EPCM approach.

Most other development projects are a lump-sum turnkey approach, with one primary EPC contractor taking on price and other risks, which means that the major contractor will build large contingency amounts into the contract to ensure that it will cover all possible costs and still make a profit. As a result, this standard EPC approach increases total project cost. Thus, by taking on the management of the project, Duke was able to lower overall project costs.

[5] Testimony of Mr. Rogers.

[6] Testimony of Mr. Rogers.

[7] Barber, Wayne, "IRS, DOE award $1 billion in tax credits for new coal technology," SNL, Nov 30, 2006.

However, as most project development firms do not have this in-house capability, other power companies may not be able to use Duke's EPCM approach.

2.7 Challenges Incurred in the IRP Process

Duke's IGCC proposal was opposed by many interveners in the public review phase of its IRP process. Duke found that it was challenged in three major areas: the cost of the plant, its potential reliability issues, and its potential negative impact on ratepayers.

2.7.1 Edwardsport Is Not the Least Cost

One of the major arguments raised against Edwardsport by interveners was that the IGCC project was not the least-cost option to meet increasing load needs in the region. Interveners suggested other generation investment alternatives. Some interveners suggested that the IGCC project could be replaced by 50 percent wind and 50 percent DSM. Duke countered that this would require an estimated 2060 MW of installed wind capacity (assuming a 15 percent capacity contribution from wind during the summer peak period), or, in other words, about 20 100-MW wind farms to replace half of the total IGCC project's capacity.

Duke further pointed out that an even lower level of capacity can be expected from wind, given that significant variability in the capacity value exists for new wind assets. If this were the case, then even more wind farms would be needed to match 50 percent of IGCC project's capacity. Duke considers this alternative infeasible. Furthermore, Duke argued that the levelized cost analyses calculated by the intervener for this suggestion were incomplete, might be misleading, and should not be used to make final economic decisions.[8] For instance, these analyses compared resources on a cost-per-MWh basis without taking into account the capacity value of the resource, its dispatchability, or the time of day when its MWh are provided.

However, with the many challenges brought by interveners, as well as the recent volatility in many commodities, Duke realized that it needed to be able to revise its cost estimate. Thus, in order to be able to pass through potential cost increases, Duke requested a construction cost revision provision from the IURC. Many interveners instead proposed an absolute cost cap to provide an incentive for Duke to efficiently manage construction costs. Duke argued that many factors that influence construction cost were out of its control, and it could not adhere to an absolute cap. The IURC agreed with Duke and ruled that the construction cost figure would be subject to an ongoing semiannual review.

2.7.2 Carbon Price Forecasts

Many interveners also challenged Duke's forecasted CO_2 emission allowance prices as being too low. Higher prices, of course, would have a significant impact on the economic viability of the coal plant. The forecasted prices in the company's analysis are based on the view that legislation limiting CO_2 emissions will be enacted in the future. Duke believes that Congress will be careful to adopt an approach that will not shock and disrupt the economy, particularly in the early years of implementation.[9] The CO_2 prices provided for the IRP analysis by Duke followed expected prices in the early years from a draft of New Mexico Senator Jeff Bingaman's bill, the American Clean Energy Leadership Act. But the prices in the later years are increased in the draft bill in recognition of the belief that CO_2 prices would have to increase to a level equal to the estimated cost of CCS technology.

[8] Ms. Jenner supported this view in her testimony.
[9] Petitioner's Rebuttal Testimony Volume 1. Pet. Ex. No. 18, p. 4 (Stowell Rebuttal).

In its response to interveners, Duke stated that its forecast may overstate potential CO_2 allowance prices and fail to account for key factors that mitigate the effects of CO_2 controls on the economics of coal plants, including higher natural gas prices, lower emission allowance prices for SO_2, NO_x, and Hg, lower coal prices, and the potential for extra allowance allocations.

2.7.3 IGCC Technical Issues

2.7.3.1 IGCC Is Not Reliable

Being a new technology and not being operated at a commercial scale, IGCC projects could raise doubts about their reliability. Noting this fact, some interveners have expressed concern that an IGCC plant would be less reliable than traditional PC plants, stating that IGCCs would present reliability risks without substantial benefit from improved performance.[10] The crux of intervener arguments was that current IGCC demonstration plants, which were built over 10 years ago, required several years to achieve high reliability due to startup problems. In response, Duke noted a recent study that found the source of unreliability in IGCC plants was not due to the gasification or gas processing parts of the plant. Duke stated that the demonstration projects have allowed these sources of unreliability to become well understood, and are therefore now unlikely to affect any new IGCC plant.[11]

Duke stated that the utility industry has become more accepting of IGCC technology, with several utilities preferring IGCC projects over other conventional baseload options. In 2006, over 45 IGCC projects were vying to receive part of $1 billion in tax credits for federal gasification projects. Duke was one of several applicants to receive these tax credits.

2.7.3.2 IGCC Is More Polluting than Conventional Coal

Duke justified investing in IGCC by citing the potential emissions benefits that IGCC would have over traditional coal-generation technologies. During the IRP process, many interveners challenged this argument. In rebuttal testimony, Duke enumerated the many advantages that would be provided by IGCC technology. The new IGCC would have significantly lower emissions than any existing coal plant, being able to exceed new source performance standards for all measured pollutants:, SO_2, NO_x, Hg, and particulate matter. The current plant on site at Edwardsport, which provides 160 MW of power, has a capacity factor of around 30 percent and emits roughly 11,000 tons of SO_2, NO_x, Hg, and particulates in a year. The new IGCC plant would provide almost four times more energy, while emitting only 2,200 tons of pollutants a year, even if it ran 100 percent of the time. At the same time, the new IGCC plant would be able to run on locally sourced coal, therefore helping to ensure a secure fuel supply.

Duke also mentioned that an IGCC plant has many other advantages over a traditional coal plant. It would utilize 30 percent less water and generate 50 percent less solid waste. Also, elemental sulfur emissions would be removed pre-combustion, thereby creating a salable product. IGCC plants are also more efficient; they would use much less fuel and produce less CO_2 per MWh than a conventional coal plant. Finally, if CO_2 emissions should become regulated, an IGCC is better situated to capture CO_2 than any other type of coal plant.

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[10] IIG Ex. 1, p. 13 (Phillips Direct)
[11] CATFIIWF Ex. 2, pp. 1-2 (Cortez Rebuttal)

2.7.4 Ratepayer Impact

Accounting treatment for passing the cost of the plant to the ratepayers is critical to determine Duke's return on the project. It will also determine how much electricity rates will increase.

Duke originally sought a number of ratemaking and accounting benefits to provide some relief of the large cost to build the Edwardsport IGCC. Duke was granted the ability to request up to 3 percent extra return on equity for this plant, but ended up asking for 2 percent. Duke also requested an accelerated depreciation schedule for the new asset, reducing the typical 30 years to 20 years. Duke argued that if the IURC denied this relief it, would have an adverse effect upon Duke's credit rating, exposing it to potential downgrades. Duke believes that a utility needs to maintain at least a mid-range investment debt rating in order to raise funds for infrastructure to meet growing customer demand. After the objections of interveners and to mitigate rate-payer impact, Duke voluntarily eliminated the depreciation request and dropped its incremental return on equity request to 1.5 percent. In its findings, however, the IURC ruled that an increase in ROE was not appropriate, and denied Duke's request. IURC did grant two other requests by Duke, granting construction work in progress (CWIP) treatment for the project, as well as providing timely recovery of construction and operating and maintenance costs.

2.8 Summary

The Edwardsport IGCC is the first commercial IGCC plant in the U.S. and an important example of a utility investment in new technology and vision. Typically, utilities are better able to build coal assets than IPPs, due to their financial strength, cost recovery ratemaking, and greater access to cheaper capital. Even so, an IGCC is a challenge even for a utility with these financial advantages.

To receive approval to construct this plant, Duke developed and executed a well-thought-out and multifaceted strategy. First, to mitigate high construction costs, Duke had the foresight to secure significant financial incentives at all government levels through extensive lobbying efforts. Duke ended up receiving over $440 million in guaranteed incentives, which is almost one-quarter of the plant's estimated cost. Another step Duke took to manage construction costs was to leverage its previous construction experience on emission control installments to become manager of the EPC process. This is an unusual step, but provides more cost transparency, as well as a better control on expenditures. In choosing the IGCC option, Duke anticipated likely carbon regulation and, therefore, chose a generation technology that could more economically capture CO_2. Also, by choosing an IGCC, Duke's unique experience with this technology allowed it to defend the technology from technical challenges. Finally, by lowering its requests on ROE incentives and a more favorable depreciation schedule, Duke showed a willingness to compromise to mitigate ratepayer impacts.

Chapter 3
LS Power's Plum Point Energy Station Project

3.1 Overview of the Plum Point Project

Plum Point is a nominal 660-MW subcritical PC-fired power plant, located near Osceola, Arkansas, on the Mississippi River. The project is being developed by LS Power, a leading IPP. The project was announced in April 2001 and construction began in March 2006.[12] Due to come online by August 2010, the plant will dispatch into the South-East Reliability Council (SERC) market and Entergy control area. The project is designed to burn low-sulfur sub-bituminous coal brought by rail from the Powder River Basin (PRB), with the flexibility to blend alternate coals.

Plum Point Energy Associates (PPEA), a subsidiary of LS Power, is the project developer. LS Power is involved in the development, construction, or operation of over 20,000 MW of power generation throughout the U.S.[13]

The Plum Point project is uniquely important among generation asset development projects for several reasons. First, the project is being developed by a merchant power producer with the involvement of major cooperatives and utilities in the region. Second, LS Power's share of the project is heavily financed by debt. Last, and most significant, the financing of Plum Point is a success story that reveals both the challenges of financing a new coal power project and the drivers behind its ultimate success.

3.2 The Strategy of LS Power

Investing in coal generation was essential for LS Power's new strategy of diversifying its energy assets. As shown in Exhibit 3-1, LS Power's developed energy portfolio is dominated by gas-fired units, exposing the company's revenue stream to gas price volatility. To mitigate this risk, LS power began more aggressively pursuing coal-fired generation assets, a strategic shift made apparent by the fact that five of its seven latest projects have been coal-fired.[14]

[12] Project Finance. *Power Deal of the Year 2006 - Plum Point Energy Associates*. February 2007.
[13] LS Power.
[14] Among these, the Plum Point, Sandy Creek, and Longleaf projects are under development, while the Elk Run and Sequoyah Energy projects were terminated.

Exhibit 3-1
Operating Power Plants under LS Power Portfolio

Plant Name	Technology	Total Capacity (MW)	Online Year
Lockport	Natural Gas Cogeneration	200	1992
Cottage Grove	Gas Combined Cogeneration	245	1997
Whitewater	Gas Combined Cycle Cogeneration	245	1997
Black Hawk	Natural Gas Cogeneration	230	1999
Mustang	Natural Gas Combined Cycle	487	1999
Batesville	Natural Gas Combined Cycle	837	2000
Kendall	Natural Gas Combined Cycle	1,160	2002
Total		**3,404**	**–**

Source: LS Power.

Another important aspect of LS Power's strategy is working with and gaining the support of its customers, such as investor-owned utilities, electric cooperatives, and municipal utilities, to identify and develop the best solutions for new power generation.

3.3 Regional Drivers

There are several factors that led LS Power to invest in coal generation in the Entergy control area, such as the potential for high energy margins, support from powerful cooperatives and utilities, transmission infrastructure, and strategic regional location.

Energy margins are potentially high in the Entergy region, since gas-fired units are typically on the margin due to a massive build-out of gas-fired plants in the region between 1998 and 2002. These marginal units typically have higher generation costs than baseload units such as nuclear or coal, resulting in high-energy margins. Furthermore, in 2005, Hurricane Katrina badly damaged natural gas terminals on the Gulf Coast and exposed the area's dependence on gas-fired plants, pushing wholesale prices higher.

Access to the powerful cooperatives and utilities in the region has contributed to the project's success in several ways. Each cooperative and utility having ownership in the project was responsible for its own financing and transmission from the plant to its own system. In addition, the power sales agreements made with the cooperatives and utilities diminished the uncertainty of the project's revenue stream.

The Missouri Joint Municipal Electric Utility Commission (MJMEUC), one of the biggest stakeholders in the project with 147-MW (22 percent) ownership, decided to participate in Plum Point after considering several other power supply alternatives for its members in southern Missouri and northeast Arkansas because of the following attributes of the project:[15]

- Proximity to member load,
- Fully permitted status of project,
- Attractive all-in cost of power,

[15] Meyers, Edward. *Case Study: Plum Point Energy Project – Financing a Public Power Minority Investment in a Developer Sponsored Merchant Coal Plan*, Goldman, Sachs & Co. January2007.

- Proven technology, and
- Likelihood of meeting schedule.

Furthermore, the Entergy region is located strategically to respond to market demand in five neighboring regions across the southern U.S. Being on a crossroad of regions, Plum Point also enjoys easy access to PRB coal. LS Power has a 20-year transportation contract, according to which Burlington Northern Santa Fe Railroad would utilize an existing mainline to deliver coal to Plum Point.[16]

3.4 Prime Mover – Coal

3.4.1 Gas Price Volatility and Environmental Legislation

In the selection of a prime mover technology, fuel price volatility was one of the decisive factors for the Plum Point project. Coal prices have historically been much less volatile than natural gas prices. Part of the increased volatility in natural gas prices could be attributed to the large gas-fired build-out throughout the country, especially in the Entergy market. When gas prices reached their peak in 2002, many developers revisited the coal option as an investment. The lower price volatility of coal and higher trending gas prices favor coal-fired investment options.

When the Plum Point project was launched prior to 2001, new coal projects were projected to be economically viable due to increased gas price projections and the lack of support for credible carbon legislation. At the time of project launch, U.S. legislation was designed to limit SO_2 and NO_x and regulatory discussions were moving towards controlling Hg emissions. Furthermore, while there was proposed legislation to limit carbon emissions, no bill was seriously considered to move forward. However, there was still considerable risk and uncertainty associated with the ultimate scope, timing, and stringency of future environmental regulations on the three pollutants during the planning stages of Plum Point.

To mitigate the risks associated with newer, more stringent environmental regulations, Plum Point was designed to include several emission-control features, as shown in the Exhibit 3-2.

Exhibit 3-2
Environmental Treatment and Control Equipment at Project Launch

Parameter	Treatment	Control Equipment
SO_2 Regulations	Phase II Acid Rain; CAIR	Dry Lime FGD
NO_x Regulations	SIP Call; CAIR	Selective Catalytic Reduction
CO_2 Regulations	None	None
Mercury Regulations	Tradable MACT	Carbon Injection

Source: ICF.

The Plum Point developers were also proactive on water issues. Avoiding one potential environmental issue with EPA's Section 316b (Phase 1), the plant was also designed to have a cooling tower so that water from the Mississippi River would not have to be used directly to cool the condenser.[17]

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[16] Ibid.
[17] Zachry Corp. *Zachry Enters into its Largest Contract for Coal-Fired Power Plant*.

3.4.2 Air Permits

In the past few years, many coal projects have been stopped after their air permits were denied. Even though coal air permits are often challenged, potential regulation of CO_2 emissions has caused a shift towards more air permit denials, as highlighted in previous volumes.

However, the air permit for the Plum Point project was obtained successfully. One of the key drivers was that LS Power applied for an air permit in April 2001, which was long before support for a federal CO_2 policy was considered credible by many of the industry's key players. The air permit for Plum Point Energy was granted by the Arkansas Department of Environmental Quality (ADEQ) in August 2003.

Another key factor in receiving an air permit was a coal friendly, or at least neutral, environmental regulatory body in the state. Even today, the regulatory attitude in the State of Arkansas towards coal has been milder compared to many other states. In November 2008, ADEQ approved the air permit for the American Electric Power Company (AEP) 600-MW John W Turk Jr. power plant. The air permit was the final regulatory hurdle needed for AEP to begin construction on this power plant.

3.4.3 Engineering Procurement and Construction Contract

Back in the early 2000s, coal projects were becoming more expensive in real terms because of rising costs of EPC premiums. The size and capital cost of these plants raises the risk associated with developing them, in turn making EPC contracts more expensive as the risk is shifted to contractors. Rising EPC costs have been detrimental to the economics of coal generation development.

Rising EPC costs can be explained mostly by a lack of construction capacity in the industry. In addition to stretched contractor resources, the build-out of scrubbers and environmental upgrades at the time required qualified labor, which meant higher expenses. As a result, EPC-quoted lead times had become substantially longer and their quotes were subject to major upward revisions.[18]

One of the ways LS Power was able to mitigate construction-cost risk was to secure a fixed-price contract for the Plum Point project. LS Power had an $875-million EPC contract with a joint venture of Gilbert Central Corp., Zachary Construction, and Overland Contracting (affiliate of Black & Veatch). The contract provided a guaranteed completion date of August 1, 2010, including a tight liquidated damages schedule and penalties for non-performance. The contract also included an all-risk builder's insurance and delay in start-up insurance in its price.[19]

At the time of procurement, the EPC contractors for Plum Point were constructing the Nebraska City 2 project. These two projects are of similar size and similar technology, and both have fixed EPC prices. The important distinction is that the construction contracting was a year earlier for Nebraska City 2, resulting in lower capital costs. In comparison, capital costs for Plum Point were around 35–40 percent higher. The fixed-price EPC component for Plum Point was nearly $1,325 per kW, compared with $960 per kW for Nebraska City 2. The 700-MW Longview Power project was another large merchant coal project in the PJM region.

[18] Project Finance. *Global Power Report - Black Goals*. 2006.
[19] Project Finance. Power Deal of the Year 2006 - Plum Point Energy Associates. February 2007.

Completing construction contract negotiations a year after Plum Point, the project had a 30 percent higher EPC contract price at about $1,700 per kW.[20] The increasing EPC numbers indicated the rapid cost growth for coal plants.

The cost of the Plum Point Energy Center continues to rise. It is currently estimated that it will cost an estimated $1.3 billion to build; this figure is up from the previously reported $1.0 billion.[21] However, having an EPC contract with a fixed-price hedged LS Power against a rise in costs, as realized costs would be passed on to the contractor. In addition, the liquidated damages provisions in the EPC contract provided the guarantee that LS Power and the financial investors needed regarding the completion date of the project.

3.5 Financing Structure and Balance

The Plum Point financing structure was designed to maximize leverage and provide LS Power with the flexibility it wanted to ensure profits.[22] However, being a merchant coal investment and having a high financial leverage brought concerns regarding the future economic viability of the project. LS Power also had issues with raising project finance debt with institutional investors who expressed concerns about the project's future cash flow. Additional investor concerns included the increasing EPC contract costs and the potential overbuilt capacity in the region. LS Power had to take these concerns into account while developing a project finance structure that would move the project forward. To achieve that, LS Power involved its customers in the ownership structure, secured a fixed-price EPC contract, financed the project in the Term Loan B market (discussed in detail in Section 3.5.3) and mitigated merchant exposure with a gas price hedge.

A unique aspect of the project was inviting cooperatives and electric utilities to participate in the project as interest owners. This structure helped LS Power to contract a portion of its output without dealing with PPAs. Having the cooperatives and utilities in the ownership structure also helped to lower the project's local property tax liability. For instance, the City of Osceola, which does not pay taxes, has ownership in the plant for local purposes. For federal tax purposes, however, the project was deemed to have private owners and, thus, could issue tax-exempt bonds due to a solid-waste-handling activity exception.[23] All these efforts were aimed at reducing the tax burden of the project.

3.5.1 Capitalization and Ownership Structure

Plum Point is a $975 million project, $750 million (77 percent) financed by debt capital in the Term Loan B market and the remaining $225 million (23 percent) financed with equity coming from the EIF Group.[24] Exhibit 3-3 illustrates the sources and uses of the project financing.

[20] S&P Ratings Direct. *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*. June, 2007.

[21] Ventyx. December 2008.

[22] Project Finance. Power Deal of the Year 2006 - Plum Point Energy Associates. February 2007.

[23] Project Finance. Power *Deal of the Year 2006 - Plum Point Energy Associates*. February 2007.

[24] Energy Investors Funds (EIF) was founded in 1987 as the first private equity fund manager dedicated exclusively to the independent power and electric utility industry.

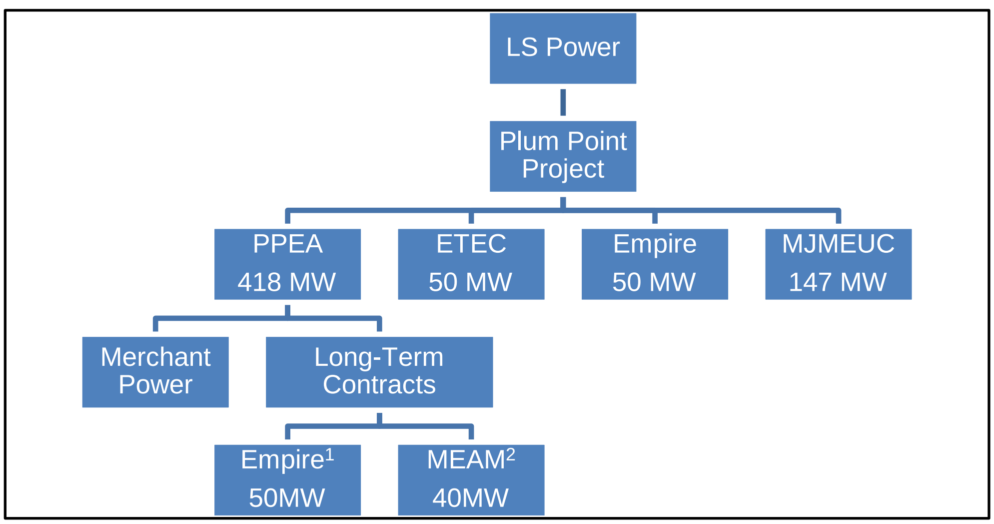
Exhibit 3-3
Source and Uses of Plum Point Project (in Million $)[25]

Sources		Uses	
1st Lien Term Loan	$ 423	Construction Costs	$ 646
Tax-Exempt Financing/Synthetic L/C	$ 102	Interest during Construction	$ 259
Revolving Credit Facility	$ 50	Revolving Credit Facility	$ 50
2nd Lien Term Loan	$ 175	Financing Fees	$ 18
Equity (from EIF Group)	$ 225	Other	$ 2
Total Sources	**$ 975**	**Total Uses**	**$975**

Source: Merrill Lynch.

As shown in Exhibit 3-4, the Plum Point project had a complex and multi-layer capitalization structure. At financial close, LS Power had ownership agreements with various parties for 287 MW[26] of its capacity, leaving 418 MW (57 percent) of the project cost to be financed by LS Power. All shareowners were responsible for securing the output sales of their capacity interest. Of LS Power's share, equity accounts for $225 million, which LS Power funded by selling a roughly 20 percent stake in the project to Energy Investors Funds (EIF) Group. The remaining cost of the project is financed through debt.[27]

Exhibit 3-4
Ownership Structure at Financial Close



[1] At Empire's option, the long-term contract can be converted into an additional 7.52% ownership interest in Plum Point from PPEA.
[2] MEAM's long-term contract converted into an ownership interest in May 2006 from PPEA.
Source: Goldman, Sachs & Co.

[25] Sondey, Ed. *Greenfield Coal,* Global Energy & Power Group - Merrill Lynch. April 6, 2006.
[26] LS signed agreements with Empire District Electric Company for a 7.5% (50 MW), East Texas Electric Cooperative for 7.5% (50 MW) and the Missouri Joint Municipal Electric Utility Commission for 22.1% (147 MW).
[27] Project Finance. Power *Deal of the Year 2006 - Plum Point Energy Associates*. February 2007.

The initial financial offering for the project consisted of a $590 million, senior–secured, first-term loan with an eight-year maturity.[28] However, the initial structure was too aggressive for the market and required two adjustments to satisfy the lenders. First, the arrangers broke down the senior debt into a first lien piece of $423 million and a second lien piece of $175 million priced 2 percent higher[29] than the first lien. LS Power was also required to increase its equity contribution from $205 million to $225 million.[30]

Inviting cooperatives and electric utilities to buy undivided interests in the project as co-participants was one of the drivers behind the successful project financing, since each party involved was responsible for its own financing, thus relieving LS Power's financial burden.

3.5.2 Long-Term Power Purchase Agreements

Securing PPA contracts in the early stages of project, albeit for a small percentage of the total capacity of the plant, helped LS Power secure predictable cash returns and reduce its credit risk, both of which provided an incentive for financial players to invest in the project. When PPEA completed the project financing and began construction, Plum Point had entered into long-term PPAs with two parties, for a total of 90 MW (see Exhibit 3-5).[31]

Exhibit 3-5
PPA Contracts of PPEA at Financial Closing

Buyer	Contract Start	Contract End	Contracted Capacity (MW)
Empire District Electric Co.	06/01/2010	06/01/2040	50
Municipal Energy Agency of Mississippi	06/01/2010	06/01/2040	40
Total	**–**	**–**	**90 MW**

In addition to the PPAs secured by PPEA, other joint owners of the project secured agreements with various parties upon financial closing.[32]

3.5.3 Loan Markets

Power project financing has traditionally relied on commercial/investment bank loans to raise debt capital. In this financing model, project loans are backed by cash flows from ownership interests of the generating assets. However, commercial bank loans have limits on financial leverage of the project and are more risk averse. Usually, lenders require the projects to have investment-grade credit ratings.

After the merchant power boom starting in the late 1990s, another financing option became available: the institutional floating rate loan market, or "Term Loan B" market. The Term Loan B

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[28] The joint lead arrangers and bookrunners of the project were Credit Suisse, Goldman Sachs, Merrill Lynch, and Morgan Stanley, while West LB was a co-manager.

[29] First lien piece was priced at LIBOR+325 bp, whereas second lien piece was priced at LIBOR+525 bp.

[30] Project Finance. Power *Deal of the Year 2006 - Plum Point Energy Associates*. February 2007.

[31] LS Power, *LS Power Affiliate Completes Financing and Starts Construction of 665 MW Arkansas Coal Plant*

[32] Missouri Joint Municipal Electric Utility Commission (MJMEUC),which owns 147 MW of the facility, signed a 40-year power purchase agreement with the City of North Little Rock for 60 MW of capacity before the financing of the project was closed. According to the contract, the city in addition to an energy payment will also make a payment ranging from $4.8 million to $9 million to upgrade transmission from Plum Point.

market has been an important source of finance for merchant assets since 2003, particularly as traditional commercial project finance loans have not been as available to sub-investment-grade assets. This loan market includes a diverse investor group composed of institutional investors, hedge funds, collateralized loan obligations (CLOs), commercial banks, and investment banking firms. Similar to private-equity investors, Term Loan B lenders were drawn to the market by the promise of attractive rates of return for a moderate amount of risk over a relatively short time horizon. Maturities for merchant plant financings in the Term Loan B market tend not to exceed ten years.[33]

When Plum Point initially needed financing, there were not many options, since banks would not have been willing to absorb that amount of leverage based on the limited off-take contracts the project had when initiated.[34] The project was deemed as a sub-investment grade project for several reasons:

- High financial leverage;
- LS Power and other cooperatives involved in the project had non-investment grade credit ratings; and
- The asset was located in an area that many lenders consider to be overbuilt.

In summary, LS Power needed to show stable revenue-stream projections to satisfy the loan markets and clear the concerns above. The company achieved that by implementing a hedge on natural gas prices.

3.5.4 Risk Hedging – Bear Put Spread

In the case of a Term Loan B transaction, the implementation of power hedges for the capacity of a project is a necessity for banks and loan holders.[35] In the case of Plum Point, only 90 MW of energy sales were contracted at the time of financial closing, leaving a large uncertainty regarding the cash returns of the project. PPEA had addressed this uncertainty with a long-term gas-price hedge. The hedge was achieved through a series of long- and short-put option contracts.

PPEA entered into a five-year gas-hedge agreement with an affiliate of Goldman Sachs to hedge approximately 84 percent of its on-peak output for 328 MW of net capacity. Specifically, PPEA purchased a put spread that protects them from natural gas prices that fall to levels below the exercise price of the long-put option.[36] This helps the project to have more predictable cash returns once the plant is operational, since there is a high correlation between on-peak power prices and natural gas prices in the region where the plant is located.

[33] Project Finance. *Global Power Report - No Longer Taboo*. 2005

[34] Project Finance. *Global Power Report - Black Goals*. 2006

[35] This is due to the fact that Loan B holder projects are mostly sub-investment grade merchant projects which don't have assets to show as a covenant for such big projects and need a promise of predictable cash returns to satisfy lenders.

[36] Meyers, Edward. *Case Study: Plum Point Energy Project – Financing a Public Power Minority Investment in a Developer Sponsored Merchant Coal Plan*, Goldman, Sachs & Co. January, 2007.

Exhibit 3-6 illustrates LS Power's 'financial balance' out of its hedging agreements with respect to sample gas price scenarios of $8.0/MMBtu and $3.0/MMBtu. Overall, LS Power would capture a margin of $2.9/MMBtu if the gas price is at $3.0/MMBtu, since both options would be exercised. The options would not be exercised if gas prices went up to $8.0/MMBtu.[37]

Exhibit 3-6
Illustrative Example of LS Power's Gas Hedge

Gas Price Scenario	Long Put @ $6.9		Short Put @ $4.0		Overall
$/MMBtu	LSP[1]	CP[2]	LSP[1]	CP[2]	LSP
8.0	–	–	–	–	–
3.0	+$3.9	-$3.9	-$1.0	+$1.0	+$2.9

[1] LSP = LS Power.
[2] CP = Counterparty.

As in the case of the Plum Point project, investors often employ bear-put spreads[38] in moderately bearish market environments, and when they want to capitalize on a modest decrease in price of the underlying asset or set a floor for its market return. If the investor's opinion is very bearish on the underlying commodity, making a simple put option purchase is preferred. An investor also turns to this spread when there is a discomfort with the cost of purchasing and holding the long-put option alone. In the case of Plum Point, LS Power wanted to decrease the premium cost of the put option at $6.9/MMBtu by selling a put option of $4.0/MMBtu and gain some premium (the price of the option) out of this sale. Thus, the total cost of this hedging for LS Power becomes:

Cost of Gas Hedging

= Premium of Long-Put Option @ $6.9 – Premium of Short-Put Option @ $4.0

The gas hedges through a series of put options helped the Plum Point project advance by reducing the uncertainty regarding its cash returns to acceptable levels at a time when only a small portion of its energy output was sold.

3.6 After the Financial Close

The aggressive financial leverage on the project had forced PPEA to hedge the uncontracted portion of its capacity to close the financial deal. After financial close, PPEA increased the percentage of Plum Point capacity that would be sold under long-term contract from 20 percent to 100 percent.[39] By doing so, it would not need to hedge its revenue stream continuously and pay for the premiums on the hedge contracts. The list of PPA contracts covering all of PPEA's energy capacity is provided in Exhibit 3-7.

[37] According to the financial arrangement, PPEA purchased a series of natural gas puts with a strike price of $6.90 per MMBtu and sold a series of puts with a strike price of $4.00 per MMBtu. This structure allows PPEA to maintain upside if natural gas prices are above $6.90, and places a floor on revenues to the extent gas prices are between $4.00 and $6.90. To the extent gas prices fell below $4.00, the project would realize the prevailing market gas price plus the spread between the put prices ($2.9 per MMBtu).

[38] The purchase of a put option on a particular underlying stock or commodity, while simultaneously writing a put option on the same underlying stock or commodity is called a bear-put spread.

Exhibit 3-7
Finalized PPA Contracts of PPEA

Buyer	Contract Start	Contract End	Contracted Capacity (MW)
Empire District Electric Co.	06/01/2010	06/01/2040	50
South Mississippi Electric Power Assoc.	06/01/2010	06/01/2040	200
Municipal Energy Agency of Mississippi	06/01/2010	06/01/2040	40
Missouri Joint Municipal Electric Utility Commission	06/01/2010	06/01/2040	50
Southwestern Illinois Coop.	06/01/2010	06/01/2040	78
Total	–	–	**418 MW**

Source: Ventyx.

As LS Power has fully contracted its capacity over time, it has rolled off almost the entire portion of the original gas hedge.

3.7 Summary

Plum Point is not only the first construction financing for a standalone coal asset in the past decade, it is also the first coal construction financing to take place in the Term B Loan market, and the first coal project to use a price hedge from a financial counterparty.[39]

Unlike many merchant coal projects that are terminated in early stages, Plum Point has been a success story for several reasons. First of all, having regional cooperatives and utilities as co-owners helped LS Power reduce its financial burden and draw lenders to the project. Signing PPA contracts further fostered the predictability of the project's revenue stream. Another factor leading the project's success was the gas hedge agreement for the uncontracted capacity of the plant to diminish any gas price, and hence power price, volatility risk. Taking place in the Term Loan B market was also essential for success, since it allowed the project to have the flexibility LS Power wanted and the ability to increase financial leverage. Developing the project in the Entergy control area also proved crucial because of the favorable environmental regulatory board's attitude towards coal and the potential for high-energy margins. Finally, the absence of support for climate change legislation at the time the project was permitted minimized lenders' concerns on future economic viability, as well as the number of grassroots challenges to the Plum Point project.

[39] Project Finance. Power *Deal of the Year 2006 - Plum Point Energy Associates*. February 2007.

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