Revised Replacement Energy Costs for Nuclear Power Plants

FINAL REPORT

US Nuclear Regulatory Commission

November 2011

TABLE OF CONTENTS

- Table A-5: US FOB Mine Steam Coal Price Outlooks Central Appalachian (12,500 Btu per pound, 1.5 SO_2 per MMBtu)
- Table A-6: US Operating Capacity and Generation Summary Outlook—AEO 2011
- Table A-7: US Operating Capacity and Generation Summary Outlooks—NASC Fall 2010

NOTES AND SOURCES

LIST OF ACRONYMS

AEO	Annual Energy Outlook
AEO 2011	Annual Energy Outlook 2011
CERA	IHS CERA
CIMS-NA	IHS CERA Integrated Modeling System for North America
CAIR	Clean Air Interstate Rule
DOE	US Department of Energy
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FOB	Free on board
FRCC	Florida Reliability Coordinating Council
GW	Gigawatts
HAPS	Hazardous air pollutants
HH	Henry Hub
Hg	Mercury
IGI	IHS Global Insight
ISO-NE	New England Independent System Operator
MISO	Midwest Independent System Operator
MRO	Midwest Reliability Organization
MWe	Megawatts electric
MWt	Megawatts thermal
NASC	North American Gas and Power Scenarios
NASC Fall 2010	North American Gas and Power Scenarios Fall 2010
NERC	North American Electric Reliability Corporation
NO_X	Nitrous oxide

NPCC	Northeast Power Coordinating Council
NRC	US Nuclear Regulatory Commission
NYISO	New York Independent System Operator
OPEC	Organization of the Petroleum Exporting Countries
RFC	Reliability*First* Corporation
RPS	Renewable Portfolio Standard
SERC	Southeastern Electricity Reliability Council
SERC	SERC Reliability Corporation
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
TRE	Texas Regional Entity
WTI	West Texas Intermediate crude oil
WECC	Western Electricity Coordinating Council

INTRODUCTION

IHS Global Insight was contracted by the US Nuclear Regulatory Commission (NRC) to support the NRC staff with revising the NRC's replacement energy cost estimates. This final report summarizes the final deliverables for the project.

- **Fuel and Cost Outlooks and Modeling Parameters.** This section addresses key modeling parameters that IHS used in the replacement energy cost analysis.
- **Market Areas and Criteria for Selecting Units that Were Analyzed.** This section identifies the specific market areas assessed in the analysis and the criteria that were used to select the representative units that were analyzed. The specific units that were assessed are not addressed in this summary report.
- **Analysis of Unit Outage Impacts: Wholesale Prices and the Replacement Cost of Power.** This section summarizes the replacement energy cost estimates developed for the analysis and provides guidance on how to use the results.

FUEL AND COST OUTLOOKS AND MODELING PARAMETERS

This section of the report summarizes the modeling analytics and documents the key modeling parameters used in the analysis.

Modeling Overview

As part of IHS's project to estimate replacement energy costs for nuclear power plant outages that might occur in the United States, IHS used its IHS CERA Integrated Modeling System for North America (CIMS-NA). The CIMS-NA model is an appropriate tool to use in estimating nuclear energy replacement costs. The modeling system was designed to analyze regional wholesale power, gas, and coal markets in the continental United States and Canada. In particular, the modeling system's primary application is the timely production of wholesale fuel price outlooks for all of the major gas and power trading hubs across the continental United States and provincial Canada.

The IHS CERA North American Power Group provides quarterly regional wholesale short-term (five-year) and semi-annual long-term (25-year) power price outlooks for 22 US and Canadian power trading hubs. The North American Gas Group provides monthly regional wholesale short- and long-term (25-year) gas price outlooks for 20 US and Canadian gas trading hubs.

IHS's focus on regular regional wholesale gas and power market analysis provides a sound foundation for estimating the replacement energy costs for nuclear plant outages for several reasons. First, IHS analysis is focused on the wholesale power markets as opposed to retail power markets. During a nuclear outage the replacement power will be purchased for delivery at one or more of the major wholesale trading hubs located near the nuclear plant experiencing the outage.

Second, IHS's analysis is timely. The IHS fuel teams follow wholesale market developments across the United States and Canada on a continuous basis and regularly update their fuel price outlooks throughout each year. The teams are focused on developments on the demand and supply side of the regional wholesale gas and power markets, including the analysis of legislative and regulatory actions that will have an effect on the markets as they develop.

Finally, IHS's regional gas and power outlooks are informed by teams of fuel and technology analysts that track all of the critical topic areas that impact regional wholesale gas and power prices. On the power side IHS has recognized experts analyzing all of the relevant generating sources, including coal, nuclear, hydro, and emerging renewable technologies. IHS is also analyzing long distance transmission developments to ensure that projected generation can be physically delivered to load centers. The same level of attention is given to the analysis of transportation and delivery infrastructure required to deliver projected gas volumes from the well head to the city gate on the gas side.

Comparison of IHS and EIA Fuel Price Outlooks

IHS's fuel price outlooks are compared regularly to those of other public and commercial suppliers of fuel price outlooks. The US Department of Energy (DOE) EIA Annual Energy Outlook (AEO) is the most common reference for comparison because it provides a regular (annual) regional long-term outlook for the supply and demand of energy consumed in the United States and because the underlying modeling and forecasting approaches are similar. Both begin with an economic outlook that is derived using the Macroeconomic Model of the United States (macro model) that is a proprietary commercial product of IHS CERA's sister company, IHS Global Insight (IGI). The EIA produces its own economic outlook using the IGI macro model, and IHS uses a macro outlook produced by IGI's US Macroeconomic Group. A summary comparison of the two macro outlooks is contained in the Appendix, Table A-1.

IHS compared the fuel price outlooks from the AEO Base Case (AEO 2011) with the IHS CERA North American Gas and Power Scenarios' (NASC Fall 2010 Planning Scenario) long-term fuel price outlooks.

Since the purpose of this project is to estimate the replacement energy cost of nuclear plant outages, the primary project objective is to produce a sound and well documented set of projections for the regional cost of replacement power in the regional wholesale power markets where the selected nuclear units are located. The entity responsible for supplying the replacement power would be purchasing it for delivery at one or more of the nearby wholesale power trading hubs.

EIA does not produce projections of wholesale power prices for the major US wholesale power trading hubs in AEO, and so IHS cannot directly compare AEO 2011 wholesale power price projections with its own projections. However, the EIA National Energy Modeling System (NEMS) that is used to project regional retail power prices follows a methodology that is similar to the techniques and models used by IHS to produce its regional wholesale power projections. The demand for electricity is projected by major class of service (residential, commercial, industrial, transportation, and other) in both models, and the underlying historical regional demand data used in both modeling systems is collected and published by the EIA. A comparison of the two power demand projections is contained in the Appendix, Table A-2.

The supply of electricity generated to meet the demands of the major power consuming sectors is modeled with a regional power dispatch model that is an integral sub model in the EIA NEMS and the IHS CERA CIMS-NA modeling systems. The models are not the same models, but both dispatch models are similar in all important aspects. They dispatch a collection of generating units in merit order (lowest to highest incremental cost of dispatch) until the regional power demand is met. Each generating unit is characterized by the technology and fuel it uses to generate electricity (hydro, steam coal, simple and combined-cycle gas, nuclear, wind, etc.), the unit's heat rate (input energy per unit of electric output), and the variable (fuel and variable operating and maintenance) and fixed (depreciation, debt service, taxes, and fixed operating and maintenance) costs incurred in owning and operating the unit. As in the case of the underlying demand data, the historical generating unit data is collected and published by the EIA, and it serves as the foundation for all historical generating unit data bases, public and private. A

comparison of the AEO 2011 and NASC Fall 2010 outlooks are contained in the Appendix, Tables A-6 and A-7.

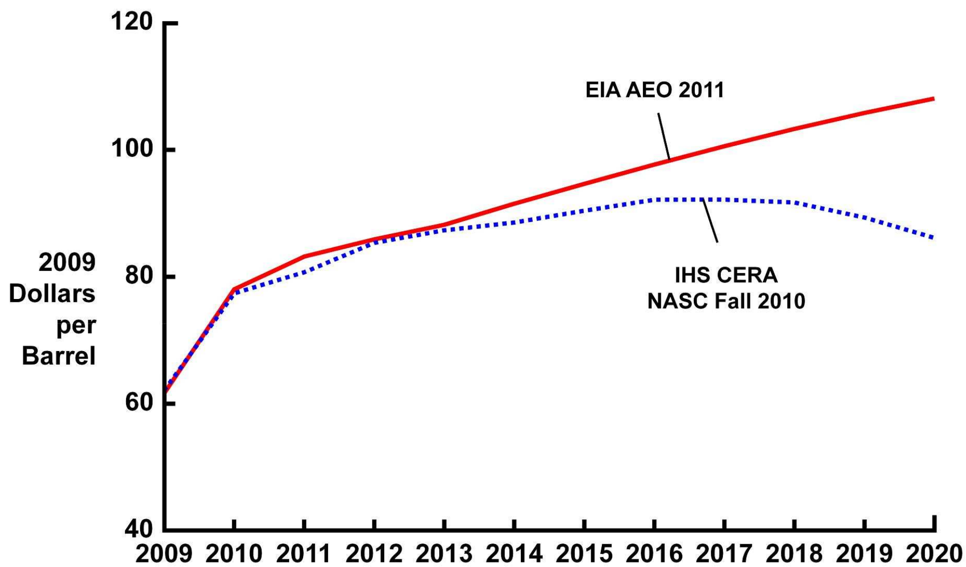
While projections of wholesale power prices depend on a variety of assumptions, differences in assumptions about the projected prices of the primary generating fuels (coal, gas, and oil) are the most critical elements in explaining the difference in wholesale power price outlooks. As a consequence IHS will focus on comparing the differences between the outlooks for oil, gas, and coal prices between the AEO 2011 and the NASC Fall 2010 outlooks. IHS will also discuss the outlooks for air emissions requirements for existing coal-fired power plants outlooks between the two projections because they also have an impact on incremental power generating costs.

Oil Price Outlooks

The role of oil in power generation is relatively small (less than 1% of generation in 2009) at this time and is unlikely to play a major role in the future. However, oil is still a major component of total energy consumption in the United States and continues to play a role in determining natural gas prices. Figure 1 shows the difference between the outlooks for the price of West Texas Intermediate (WTI) crude oil (a benchmark US wholesale crude oil price) in the AEO 2010 and the NASC Fall 2011 outlooks.

Figure 1

Comparison of WTI Oil Price Outlooks



Data Sources: See Data Appendix, Table A-4.
10108-1

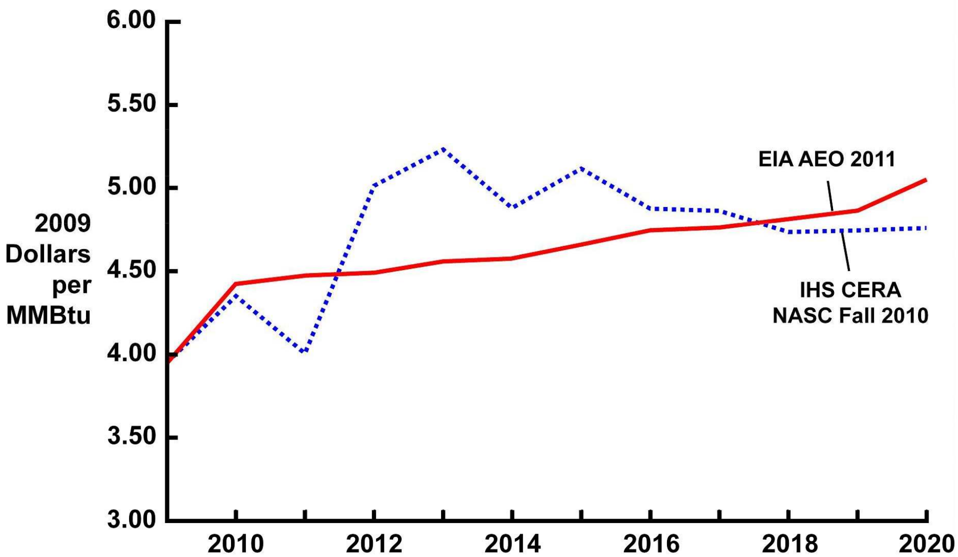
The primary difference between the two outlooks is the outlook for growth in demand. Both EIA and IHS project that world oil reserves can support world oil demand at a level in excess of 100 million barrels per day at a real price in the neighborhood of $90–$100 per barrel. IHS projects that demand growth will slow and gradually reduce the price of oil over the next ten years. It sees a combination of demographic (aging populations in North America, Western Europe, and much of Asia, including China) and socioeconomic (slowing pace of urbanization in the developing world) forces will slow the rate of growth of demand for oil. IHS also believes that higher real oil prices will act to slow the growth in world oil demand by encouraging more efficiency, especially in the transport sectors. EIA puts more emphasis on the supply side and projects a continuing gradual rise in the world oil price through 2035 because production from non-OPEC producers is not assumed to keep pace with world oil demand growth, and OPEC is assumed to keep its share of total world production constant.

Natural Gas Price Outlooks

In contrast to oil, the role of natural gas in power generation is growing and is projected to continue to grow. Natural gas now supplies about 20% of total generation, which is about the same share as nuclear power. Figure 2 illustrates the difference in outlooks for natural gas prices (the wholesale price at the Henry Hub [HH], the reference trading hub for natural gas coming out of the US Gulf producing areas) in the AEO 2011 and the NASC Fall 2010 outlooks.

Figure 2

Comparison of HH Gas Price Outlooks



Data Sources: See Data Appendix, Table A-3.
10108-2_2305

In contrast to the projections for crude oil prices, there is little difference between the AEO 2011 and the NASC Fall 2010 outlooks for the price of gas traded at the HH. Aside from year-to-year variations, there is virtually no difference between the average EIA and IHS gas price projections over the next ten years. Both outlooks are lower than those from past years and consistent with relatively recent innovations in the development of unconventional gas (gas from tight shale formations) resources in the United States. Developments in seismic imaging, directional drilling, and the fracturing of tight shale formations has lowered the cost of extracting natural gas from the shale formations dramatically. The resulting increase in technically recoverable natural gas has been characterized as a “shale gale” and is substantially changing the outlook for long-term gas supplies in North America. The pace of shale gas development has been much faster than the industry expected.

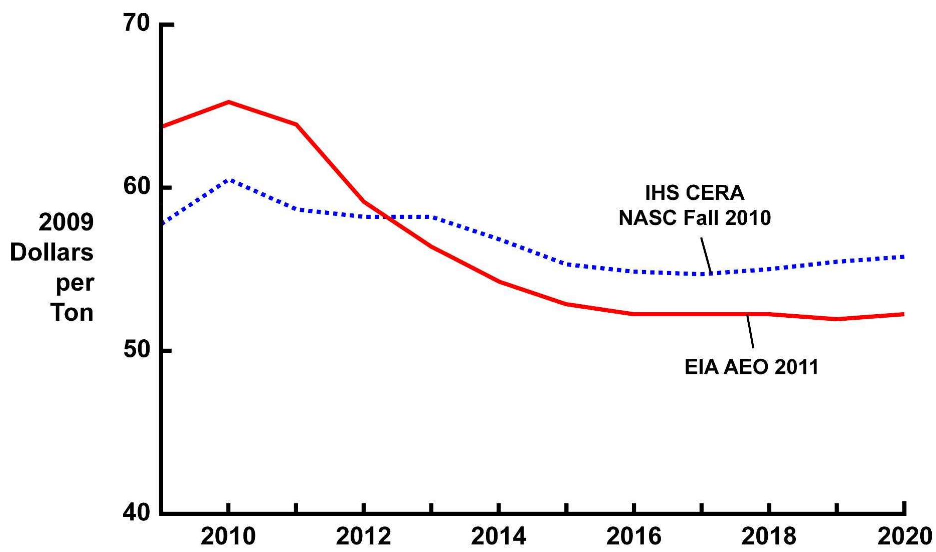
Coal Price Outlooks

There is not much difference between the trend in coal price outlooks in the AEO 2011 and NASC Fall 2010 projections over the next ten years. Historically, coal prices have not been as volatile as oil and gas prices. A combination of technological changes and relatively robust competition among suppliers has tended to keep coal prices in check. Figure 3 shows the outlook for the free on board (FOB) at the mine wholesale price of medium sulfur, Central Appalachian, coal in the United States.

Figure 3

Comparison of FOB Mine Coal Price Outlooks

(Central Appalachian, Medium Sulfur)



Data Sources: See Data Appendix, Table A-5.
10108-3_2305

Both the EIA and IHS analyze coal price trends for each of the major coal producing regions in the United States and then add transportation costs to project delivered-to-burner tip prices for each coal generating plant analyzed in their respective regional electricity dispatch analyses.

Environmental Allowance Price Outlooks

Both the EIA and IHS projections include tightening environmental requirements for existing power plants. While there is general agreement that coal plant operators will face continued pressure to reduce sulfur dioxide (SO_2), nitrogen oxide (NO_X), and mercury (Hg) emissions in the future, there is considerable uncertainty regarding the specific federal policies that will be used to implement these reductions.

While there are some differences between the EIA and IHS environmental policy assumptions and environmental allowance cost outlooks, these assumptions (and their differences) discussed below are not significant drivers influencing replacement energy cost estimates. Neither outlook assumes significant changes in the coal-fired generation due to environmental policy assumptions. EIA projects US coal-fired generation to stay flat at around 314 gigawatts (GW) between 2010–20, and IHS projects the fleet to decrease by 33 GW during this time period. More importantly, both EIA and IHS project that natural gas-fired capacity will be the generation technology on the margin in the outlook period. The cost associated with increased environmental compliance will affect the profitability of coal-fired plants for the operators, but these costs will not show up as significant drivers for the nuclear outage costs. Natural gas-fired generation will be the driver.

Two separate decisions in 2008 by the DC circuit court are requiring the US Environmental Protection Agency (EPA) to rewrite its latest round of SO_2, NO_X and Hg regulations. In February 2008 the DC circuit court found the EPA's approach to regulating mercury emissions from coal and oil fired units to be unlawful and vacated the rules until replacement regulations are adopted. New Jersey v. EPA, No. 05-1097 (DC Cir. 2008). In July 2008 the DC circuit court found EPA's new SO_2 and NO_X regulations unlawful. North Carolina v. EPA, 531 F.3d 896 (DC Cir. 2008). The court's original decision vacated the regulations but a subsequent decision allowed the rules to remain in effect until new replacement regulations are adopted by the EPA. North Carolina v. EPA, 550 F.3d 1176, 1178 (DC Cir. 2008).

The court decisions require that the structure of the new regulations will be very different compared to what they will replace. For SO_2 and NO_X, EPA is required to move away from broad emissions trading programs to more state-specific requirements that are expected to provide less opportunity for companies to trade SO_2 and NO_X emissions allowances. And for mercury, the future regulations are expected to be unit specific requirements with no opportunity for trading emissions allowances.

The EPA process for rewriting the regulations is taking several years. In the interim, the court decision vacated the agency's mercury regulations (the Clean Air Mercury Rule) but left in the SO_2 and NO_X regulations (the Clean Air Interstate Rule) until they are completely replaced by new regulations. The new SO_2 and NO_X regulations were finalize in July 2011 (but after the projections discussed in this report were developed) and the Hg regulations are expected to be finalized in December 2011.

Because of this regulatory uncertainty, the EIA and IHS projections have very different assumptions regarding specific air policies. Following the EIA's protocol in its projections that assumes current laws and regulations will remain generally unchanged through the projections, the EIA outlook includes the EPA's Clean Air Interstate Rule (even though EPA is developing regulations to override this program) and does not include any federal mercury requirements (even though EPA is expected to finalize new federal mercury requirements this year).

IHS has taken a different tack in our analysis of how we assume that new SO_2, NO_X, and Hg policies are implemented (see the Appendix for a more detailed description of the environmental policy assumptions). In light of the EPA regulatory uncertainty, the IHS projection assumes that new federal legislation is adopted that clarifies the SO_2, NO_X, and Hg requirements for coal-fired power plants. The assumed policies in the IHS projections closely track federal proposals by Senators Tom Carper and Lamar Alexander.

In the IHS outlook interstate SO_2 and NO_X emissions transport is addressed through three new regional cap-and-trade programs (national SO_2, annual NO_X East, and annual NO_X West), which take effect beginning in 2015. The IHS outlook assumes that hazardous air pollutants including mercury are addressed beginning in 2016 through unit-level performance standards. Tables 1 and 2 compare the IHS versus EIA allowance prices for SO_2 and NO_X respectively.

Table 1
Comparison of SO_2 Allowance Outlooks
(2009 dollars per short ton)

	Pollutant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
IHS Projections											
CAIR region (Eastern)	SO_2	7	6	46	106	—	—	—	—	—	—
Non-CAIR region (Western)	SO_2	4	3	23	53	—	—	—	—	—	—
New federal legislation national SO_2	SO_2					315	527	631	640	641	639
EIA Projections											
CAIR region (Eastern)	SO_2	635	630	677	744	751	814	808	807	821	821
Non-CAIR region (Western)	SO_2	318	315	338	372	263	285	283	282	287	287

Data Sources: IHS CERA North American Gas and Power Fall 2010 Planning Scenario and US DOE, EIA, AEO 2011.

Table 2
Comparison of NO_x Allowance Outlooks
(2009 dollars per short ton)

	Pollutant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
					IHS Projections						
CAIR annual NO_X	NO_x	149	47	77	161	—	—	—	—	—	—
CAIR ozone season NO_X	NO_x	39	28	15	2	—	—	—	—	—	—
Multipollutant legislation annual NO_X (Eastern)	NO_x					320	330	339	340	334	327
Multipollutant legislation annual NO_X (Western)	NO_x					1,344	1,627	1,760	1,869	1,912	1,810
					EIA Projections						
CAIR region (Eastern)	NO_x	2,218	1,843	1,877	2,040	2,140	2,164	2,160	2,262	2,380	2,441

Data Sources: IHS CERA North American Gas and Power Fall 2010 Planning Scenario and US DOE, EIA, AEO 2011.

MARKET AREAS AND CRITERIA FOR SELECTING UNITS THAT WERE ANALYZED

This section discusses the criteria used to select specific nuclear units that were analyzed it the project. Following the discussion of the selection criteria, the section summarizes the primary US market areas.

Analysis Overview

The methodology proposed by IHS for developing replacement power costs required the selection of several nuclear units in various electricity markets throughout the continental United States. For most US markets, we selected a "most critical" unit—implying that replacement costs will likely be highest in that region—and a "least critical" unit—implying that replacement costs will be much lower in that region. To select least and most critical units, we applied four criteria:

- **Congestion:** Congestion occurs on electric transmission facilities when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels. These restrictions may be imposed either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the electrical grid. If the unit is located within an area that is highly electrically congested—that is, there are very limited transmission interconnections with surrounding regions—then this would limit the options for replacement power and therefore be more costly. Conversely, units located in an area of low congestion would be more likely to experience lower replacement costs. An important, though not only, consideration for congestion criterion is where the unit lies relative to the critical congestion corridors identified in the DOE Critical Congestion Report. This report identifies two national critical congestion corridors: from Washington, DC, to Albany, NY, and from San Diego, CA, to north of Los Angeles, CA. The DOE report also identifies two "corridors of concern"[1] between i) Seattle, WA, and Portland, OR and ii) the San Francisco Bay area (see Figures 4 and 5).

- **Load Center Proximity:** If the unit is proximate to a major load center, then this would be expected to increase replacement costs.

- **Market Liquidity:** Market liquidity refers to the activity in the regional electricity market. A more liquid market, that is with a higher amount of transactions and increased visibility of costs, would tend to mitigate higher replacement costs. An illiquid market would be expected to result in somewhat higher costs.

[1] A transmission corridor that is not critical by DOE criteria, but is not far short of it and without mitigation will likely become critical in the future.

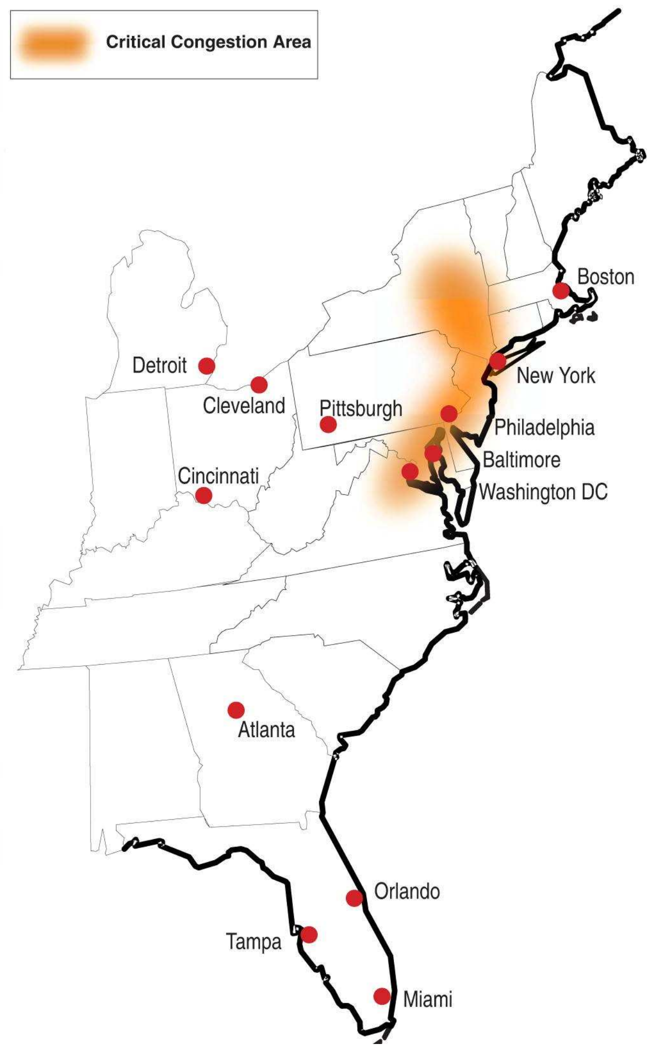
- **Size:** Nuclear units tend to fall into the category of older units less than 1,000 megawatts electric (MWe) and newer units greater than 1,000 MWe. A smaller unit would require less replacement power and therefore potentially be less expensive. A larger unit might require multiple sources of replacement and therefore be more expensive.

These criteria, and specifically the first three criteria, are independent of each other. Congestion is a function of electrical flows, which always flow from generation sources to load sinks. Thus, transmission congestion will be on lines that provide a route to a load center but are not necessarily located closely to the load center. For example, western and central Kansas and Oklahoma are becoming congested regions due to the amount of wind generation being sited in eastern New Mexico, parts of northern Texas, and western Oklahoma and Kansas. Most of that generation is trying to make its way east to the SPP load centers of Kansas City, Oklahoma City, and Little Rock.

Market liquidity is a function of the robustness of the regional market, which in turn is due primarily to historical and political factors which have influenced the development of open market structure. For example, the SPP region and the upper MISO regions are fairly robust market regions but are also characterized by small- to mid-sized load centers separated by hundreds of miles. Conversely, Atlanta and the Florida urban conglomerations are examples of large, fast growing load centers located in a region with very low market liquidity.

Figure 4

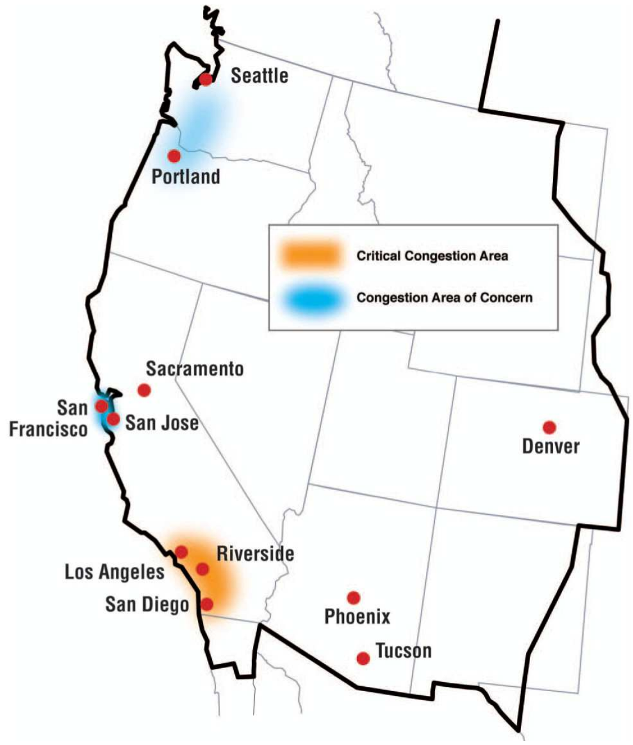
Mid-Atlantic Critical Congestion Area, 2009



Source: US DOE National Electric Transmission Study, 2009.

Figure 5

2009 Congestion Areas in the Western Interconnection



Source: US DOE National Electric Transmission Study, 2009.

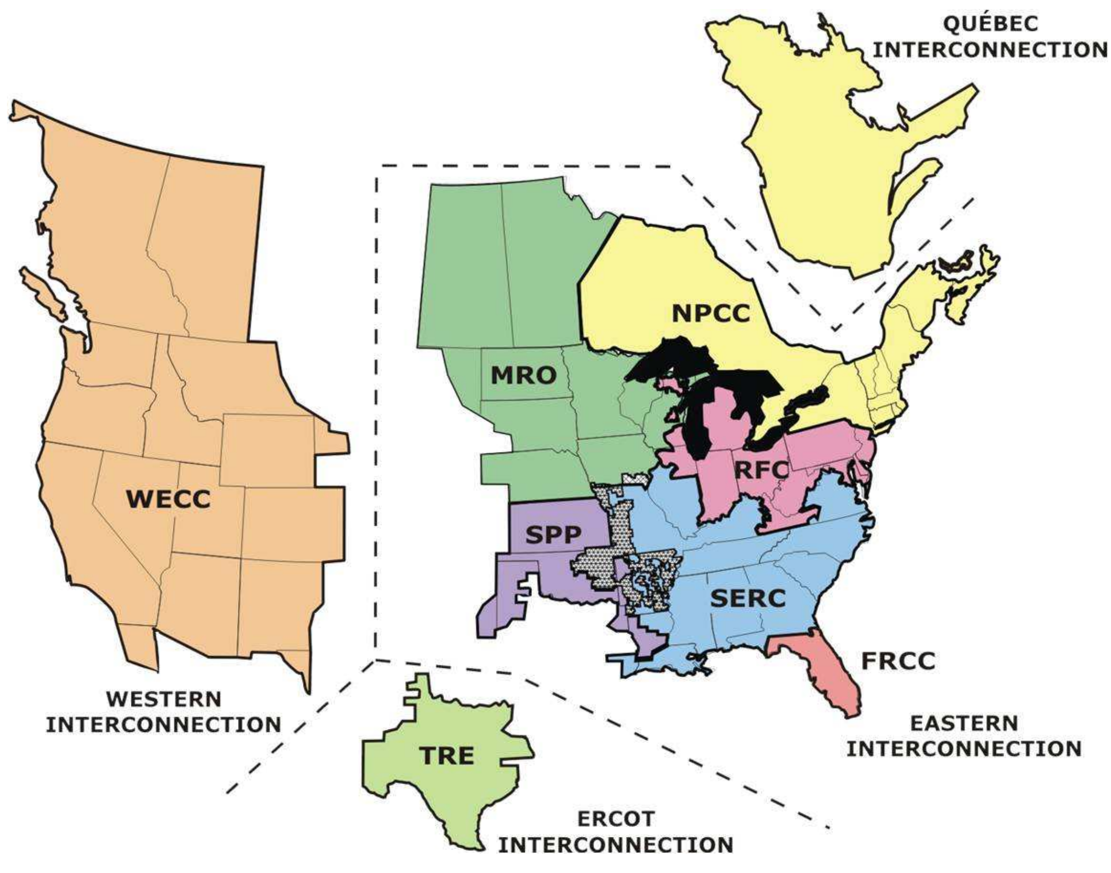
Market Areas

NERC works with eight regional entities shown in Figure 6 to improve the reliability of the bulk electric power system. The members of the regional entities come from all segments of the electric industry. Overlaid on the NERC regional entities are regional electricity “market areas”, which can be loosely defined as a geographic region in which buyers and sellers have traditionally bought and sold power and for which the transmission system can accommodate such transactions (see Figure 7). The earliest market areas developed around the northeastern “tight pools”—PJM, New York Power Pool (now the New York Independent System Operator [NYISO]) and the New England Power Pool (now the Independent System Operator-New England [ISO-NE]). Other market areas subsequently developed in Texas, California, and the Midwest. A liquid market is distinguished by a relatively high volume of transactions and open exchange(s) in which spot and futures prices are relatively transparent and upon which bilateral contracts can be based. Today, liquid electricity markets exist in PJM (which is now much expanded over its original Pennsylvania, New Jersey, and Maryland footprint to include most of the MidAtlantic and some of the Midwest), ISO-NE, NYISO, the Midwest Independent System Operator (MISO),Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT) (most of Texas). Several regions in the Western Electricity Coordinating Council

(WECC) contain market trading hubs although long distances and sparse transmission constrain the development of markets in much of the West. The Southeastern Electricity Reliability Council (SERC) region has not developed very liquid wholesale markets (see Figure 4). The development of liquid markets is important in developing replacement power costs, since replacement power will usually be sourced from the market; i.e., if a unit goes offline for a day, a week, a month, or several months, then the owner will turn to the market for replacement power in the form of spot purchases, futures, or longer-term bilateral contracts. In a liquid market the pricing of such purchases will be at (more) economically efficient prices. In a region where there are no liquid markets, replacement power has to be secured via bilateral contracts, which may not be priced at the economically efficient level.

Figure 6

North American Transmission Interconnections



Source: North American Electric Reliability Council (NERC).
<u>NERC Regions:</u> FRCC: Florida Reliability Coordinating Council; MRO: Midwest Reliability Organization; NPCC: Northeast Power Coordinating Council; RFC: Reliability*First* Corporation; SERC: SERC Reliability Corporation; SPP: Southwest Power Pool; TRE: Texas Regional Entity; WECC: Western Electricity Coordinating Council

Figure 7

North American Market Areas

Source: US Federal Energy Regulatory Commission.

ANALYSIS OF UNIT OUTAGE IMPACTS: WHOLESALE PRICES AND THE REPLACEMENT COST OF POWER

This section of the report presents findings for the impacts of unit outages on wholesale power prices and the replacement cost of power for seven power markets: New York ISO, PJM, the Midwest, SPP, the South, ERCOT, and the West.

To estimate the impact of a nuclear unit outage on the wholesale price of power and, consequently, the cost of replacing the lost electric production from the unit, IHS CERA simulated the operation of specific power markets with the selected nuclear unit included and then excluded from the market area's stock of operable generators. We used the IHS CERA Aurora Power Markets model for these simulations. Using the criteria summarized in the previous section of this report, IHS CERA identified 13 nuclear units in seven different market areas to use in its analysis. With the exception of the ERCOT market, two units were selected to represent units that were either more or less critical to electric supply in the market area. In the ERCOT region IHS CERA selected only one unit for analysis. There are only two nuclear plants in the ERCOT market. It was decided that an outage of any of the four units at the two plants would have a similar impact on the ERCOT wholesale market. In all then, IHS CERA simulated the impact on the wholesale markets of a nuclear outage at each of 13 units in seven regions of the United States.

The initial simulation of the IHS CERA Aurora Power Markets model was based, with one exception, on the assumptions IHS CERA developed for its Fall 2010 long-term (25-year) North American Gas and Power Scenarios planning case, Global Redesign, as described in the first section of this report. The exception was the treatment of carbon policy over the simulation period. In its planning scenario, IHS CERA assumed that there would be federal carbon abatement legislation that would put a price on carbon emissions. For purposes of this study, IHS CERA did a simulation of its models without a price on carbon emissions as the base case in each region of the country. The existing state level Regional Greenhouse Gas Initiative in the US Northeast is included in the base case runs of the Northeastern and PJM region markets.

The base-case run in each region was then compared with a run of the models in which one of the selected nuclear units was removed from the list of operable generating units. The IHS Aurora Power Markets model is made up of three models that simulate the 3 major North American Interconnections (Eastern, Western, and ERCOT) that comprise the bulk electric power system in the lower 48 states of the United States and parts of Canada.

For each of the 13 unit nuclear unit outages that were modeled by IHS CERA the entire interconnection in which the nuclear unit was located was redispatched to insure that all of the possible impacts of the outage on wholesale markets within the interconnection were taken into account. For the nuclear units located in the New York or New England sub regions of the Northeast Power Coordinating Council NERC reliability area, for example, there were no noticeable impacts on wholesale markets in the southern United States, but there were impacts on the neighboring PJM markets. Similarly, an outage in California had impacts on wholesale market prices in the other sub regions of the Western Interconnection.

SUMMARY OF IMPACTS AND GUIDANCE ON HOW TO USE REPORT

The wholesale price of power varies systematically across market areas and through time within market areas for several reasons. The two most important sources of variation are the fuel and technology mix of the generation fleet in the market area and the time of the day and year.

Wholesale prices in the MISO markets are generally lower than prices in the PJM market areas because gas-fired generation is on the margin for more hours of the year in PJM than it is in MISO. The hours during which coal is on the margin are lower priced hours than hours when gas is setting the price, despite the heat rate advantage a combined cycle gas unit (7,000 Btu/kWh) has relative to a typical steam coal unit (10,000 Btu/kWh). The price of gas, since the late 1990s, has been sufficiently higher relative to coal to negate the difference in efficiency between the two types of generation. Low cost hydro generation that is concentrated in the Northwest Power Pool keeps wholesale prices lower throughout most of the year than in California, where hydro resources never set the wholesale price.

Wholesale power prices are higher during the on-peak hours (day time hours) of the day as compared with the off-peak (night time hours) because average hourly loads are lower during the off-peak hours of the day and on weekends and holidays. Since generators are dispatched in merit order (from low cost to high cost alternatives), the lower the average load the lower the incremental cost of dispatched power. Similarly, power is more expensive during the summer cooling season and the winter heating season as compared with the cost of power during the "shoulder" periods in the spring and fall of the year.

Given that is not possible to predict when an outage might occur or how long it might last, the average annual 24 hour prices projected for each of the postulated nuclear unit outages are a good representation of what the price of replacement power would be for each hour of the postulated outage. The increase in the wholesale power price would increase the wholesale price of power for any market participant that had to purchase power in the spot market during the postulated outage periods. However, most power transactions take place under the terms of a contract rather than in the spot market, and the contract prices are not typically tied (or indexed to) the spot market price. It is difficult to determine what fraction of any hour's power transactions for delivery at a given price hub might be impacted by the postulated nuclear unit outages. Therefore, IHS CERA has not attempted to calculate the additional social cost that could result from the impact on the outage beyond the direct cost to purchase replacement power.

Table 3 shows a range of prices for replacement power in 2011 for a postulated outage lasting a day, a week, or a year for each of the units modeled in this study. Table 4 illustrates the results for 2020. The incremental cost of a one day outage for a particular unit is the annual cost of the outage divided by 365 days. The cost of a multiple day outage is the cost for a day multiplied by the number of days of the postulated outage.

Table 3
Cost of Postulated Nuclear Outages in 2011 (2011 dollars)

Market Area	Nuclear Unit	Unit Size (MWe)	2011 Unit Output (MWH)	NERC Region	2011 Annual Incremental Outage Cost per Day (2011 $, thousands)	2011 Annual Incremental Outage Cost per Week (2011 $, thousands)	2011 Annual Incremental Outage Cost (2011 $, millions)
New York ISO	Least Critical Unit	581	4,357	NPCC	7.325	51.274	2.674
New York ISO	Most Critical Unit	1,025	8,113	NPCC	25.211	176.478	9.202
PJM	Least Critical Unit	885	7,009	RFC	6.501	45.510	2.373
PJM	Most Critical Unit	1,161	9,126	RFC	13.086	91.602	4.776
MISO	Least Critical Unit	1,190	9,554	RFC	9.561	66.925	3.490
MISO	Most Critical Unit	1,106	9,126	RFC	18.474	129.321	6.743
SPP	Least Critical Unit	774	6,179	SPP	1.896	13.271	0.692
SPP	Most Critical Unit	1,160	9,322	SPP	27.962	195.732	10.206
South	Least Critical Unit	1,123	8,925	SERC	13.637	95.462	4.978
South	Most Critical Unit	693	5,910	SERC	149.064	1,043.447	54.408
ERCOT	Single Unit	1,131	10,910	ERCOT	32.531	227.715	11.874
West	Least Critical Unit	1,314	10,853	WECC	16.522	115.651	6.030
West	Most Critical Unit	1,131	7,346	WECC	18.953	132.670	6.918

Table 4
Cost of Postulated Nuclear Outages in 2020 (2011 dollars)

Market Area	Nuclear Unit	Unit Size (MW)	2020 Unit Output (MWH)	NERC Region	2020 Annual Incremental Outage Cost per Day (2011 $, thousands)	Incremental Outage Cost per Week (2011 $, thousands)	2020 Annual Incremental Outage Cost (2011 $, millions)
New York ISO	Least Critical Unit	581	4,370	NPCC	5.374	37.620	1.962
New York ISO	Most Critical Unit	1,025	8,733	NPCC	29.421	205.947	10.739
PJM	Least Critical Unit	885	7,087	RFC	10.735	75.143	3.918
PJM	Most Critical Unit	1,161	9,151	RFC	9.308	65.159	3.398
MISO	Least Critical Unit	1,190	9,584	RFC	9.445	66.115	3.447
MISO	Most Critical Unit	1,106	9,151	RFC	14.993	104.951	5.472
SPP	Least Critical Unit	774	6,198	RFC	2.082	14.572	0.760
SPP	Most Critical Unit	1,160	9,290	SPP	26.406	184.844	9.638
South	Least Critical Unit	1,123	8,951	SERC	14.981	104.870	5.468
South	Most Critical Unit	693	6,721	SERC	331.266	2,318.859	120.912
ERCOT	Single Unit	1,131	10,750	ERCOT	57.191	400.338	20.875
West	Least Critical Unit	1,314	10,883	WECC	19.909	139.362	7.267
West	Most Critical Unit	1,131	9,105	WECC	35.196	246.372	12.847

Given the criteria used to select the 13 nuclear units chosen for this study, the range of outcomes for any market area can be used to estimate the likely range of costs that would be incurred for a postulated outage at any nuclear unit in the United States over the next ten years.

The study has shown that the range of costs within a region can be very broad. For example, the cost of a one day outage within the New York ISO in 2011 ranges between $7,325 for the Least Critical Unit and $25,211 for the Most Critical Unit. Normalizing for the difference in the size of the plants by dividing the cost for a one day outage by the number of megawatt hours each plant produced on a typical day gives a measure of the one day outage cost per megawatt hour, as shown below.

Example 1: Calculating the Cost per Megawatt-hour of a Postulated Nuclear Outage in the New York ISO Using Table 3

Least Critical Unit outage cost per megawatt-hour:

2011 incremental cost per year for an outage at the Least Critical Unit = $2,674,000

2011 power production at the Least Critical Unit = 4,370,000 MWh

2011 average incremental cost per MWh = $2,674,000/4,370,000 = $0.61per MWh

Most Critical Unit outage cost per megawatt hour:

2011 incremental cost per year for an outage at the Most Critical Unit = $9,202,000

2011 power production at the Most Critical Unit = 8,733,000 MWh

2011 average incremental cost per MWh = $9,202,000/8,733,000 = $1.05 per MWh

Estimated range of cost for a postulated outage at Example Nuclear Unit:

Net summer capacity of Example Nuclear Unit = 861 MW

Representative capacity factor for Example Nuclear Unit = 90%

2011 estimated annual power production from Example Nuclear Unit =

861 MW x .9 x 8760 hours per year = 6,788,124 MWh

2011 estimated daily production from Example Nuclear Unit =

6,788,124 MWh per 365 days = 18,598 MWh per day

2011 estimated range of incremental cost of a one day outage at Example Nuclear Unit:

Between 18,598 x 0.61 = $11,345

And 18,598 x 1.05 = $19,527

APPENDIX

Detailed Assumptions for IHS Environmental Policies

The IHS planning scenario assumes that over the next few years, the US EPA continues moving forward with a variety of regulatory proposals targeting conventional pollutants. The new, more stringent rules are met with considerable opposition, including legal challenges, and Congress is forced to step into resolve the ensuing regulatory quagmire. In 2013 Congress passes comprehensive energy reform, including a suit of requirements around conventional pollutants.

The new law preempts a variety of conventional pollutant EPA regulations that are currently under development, including the EPA's Transport Rule for SO_2 and NO_X emissions and regulations on coal ash. Interstate SO_2 and NO_X emissions transport is addressed through three new multistate cap-and-trade programs, an annual SO_2 program, and two annual NO_X programs, one covering the east (comprised of the states currently under the Clean Air Interstate Rule) and another covering the west (comprised of the remaining contiguous United States). Unlike EPA's Transport Rule, the new law would continue to allow unlimited interstate trading of allowances. It would also allow generators to carry banked Acid Rain Program and Clean Air Interstate Rule allowances into the new programs, albeit at a discount.

Beginning in 2015 SO_2 emissions are capped at 2.0 million tons, eastern annual NO_X emissions are capped at 1.3 million tons and western annual NO_X emissions are capped at 450 thousand tons. Then during a second phase beginning in 2019, each requirement gets ratcheted down further with SO_2 emissions capped at 1.7 million tons, eastern NO_X emissions capped at 1.0 million tons and western NO_X emissions capped at 350 thousand tons. Subsequent reductions post-2020 are at the discretion of EPA, which ultimately decides to discontinue SO_2 and NO_X trading beginning in 2028 in favor of more targeted policy measures.

The new law would require EPA to develop maximum achievable control technology (MACT)—like standards by 2016 for several categories of hazardous air pollutants (HAPs), including: mercury; nonmercury metallic HAPS (e.g., antimony, cadmium, lead, etc.); acid gas HAPS (e.g., hydrogen chloride, hydrogen fluoride, and hydrogen cyanide); dioxin/furan organic HAPs; and nondioxin/furan HAPS (e.g., volatile organic compounds and polycyclic organic matter). The new standards would be required to differentiate by coal type and boiler configuration. The mercury standard, for example, would require a 90% average reduction in emissions across the entire coal fleet.

In addition to addressing the conventional air pollutants, the new law would also establish requirements around the disposal of coal ash and the use of cooling water in thermal power plants. EPA is directed to regulate coal ash as nonhazardous municipal solid waste, similar to the less stringent of the two approaches already outlined by EPA in its May 2010 draft proposal (i.e., the so-called "Subtitle D" approach). Under the new law, rather than institute a universal, across the board retrofitting requirement, thermal power plants that currently use once-through cooling would be required to retrofit on a limited, case-by-case basis with closed-loop technologies.

Table A-1
Real GDP
(billions of chained 2005 dollars)

	AEO 2011	NASC Fall 2010
2009[1]	12,881	12,987
2010	13,221	13,392
2011	13,506	13,760
2012	14,038	14,179
2013	14,586	14,560
2014	14,913	14,994
2015	15,336	15,415
2016	15,753	15,855
2017	16,168	16,259
2018	16,577	16,660
2019	16,977	17,080
2020	17,421	17,509

Source: IHS CERA North American Gas and Power Scenarios Fall 2010, US DOE, EIA, AEO 2011.
1. 2009 is an estimate in both outlooks.

Table A-2
Net Electric Energy to Grid
(terawatt-hours [TWh])

	AEO 2011	NASC Fall 2010
2009[1]	3,779	3,835
2010	3,930	3,957
2011	3,871	4,009
2012	3,907	4,110
2013	3,938	4,181
2014	3,939	4,272
2015	3,965	4,352
2016	3,991	4,439
2017	4,021	4,503
2018	4,057	4,587
2019	4,092	4,656
2020	4,125	4,738

Source: IHS CERA North American Gas and Power Scenarios Fall 2010, US DOE, EIA, AEO 2011.
1. 2009 is an estimate in both outlooks.

Table A-3
Henry Hub Natural Gas Price Outlooks
(2009 dollars per million Btu)

	AEO 2011	NASC Fall 2010
2009	3.95	3.95
2010	4.43	4.35
2011	4.48	4.01
2012	4.50	5.01
2013	4.56	5.23
2014	4.57	4.88
2015	4.66	5.12
2016	4.74	4.88
2017	4.76	4.86
2018	4.81	4.74
2019	4.87	4.75
2020	5.05	4.76

Source: IHS CERA North American Gas and Power Scenarios Fall 2010, US DOE, EIA, AEO 2011.

Table A-4
West Texas Intermediate Crude Oil Price Outlooks
(2009 dollars per barrel)

	AEO 2011[1]	NASC Fall 2010[2]
2009	61.66	62.09
2010	78.03	77.40
2011	83.21	80.72
2012	85.73	85.36
2013	88.03	87.33
2014	91.38	88.59
2015	94.58	90.44
2016	97.62	92.17
2017	100.50	92.21
2018	103.15	91.75
2019	105.71	89.36
2020	108.10	86.14

Source: IHS CERA North American Gas and Power Scenarios Fall 2010, US DOE, EIA, AEO 2011.
1. Low sulfur, light crude oil price.
2. West Texas Intermediate crude Oil Price.

Table A-5
US FOB Mine Steam Coal Price Outlooks
Central Appalachian (12,500 Btu per pound, 1.5 SO_2 pounds per MMBtu)
(2009 dollars per ton)

	EIA AEO 2011[1]	IHS CERA NASC Fall 2010[2]
2009	63.66	57.80
2010	65.24	60.47
2011	63.94	58.64
2012	59.10	58.14
2013	56.41	58.18
2014	54.22	56.82
2015	52.92	55.22
2016	52.22	54.76
2017	52.26	54.69
2018	52.19	55.04
2019	51.87	55.38
2020	52.30	55.72

Source: IHS CERA North American Gas and Power Scenarios Fall 2010, US DOE, EIA, AEO 2011.
1. FOB Mine Central Appalachian, Medium Sulfur.
2. FOB Mine Central Appalachian (12,500 Btu per pound, 1.5 SO_2 pounds per MMBtu).
.

Table A-6
US Operating Capacity and Generation Summary Outlook—AEO 2011

US Annual Summer Capacity by Fuel (gigawatts [GW])

	2009[1]	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	312.9	318.1	319.6	323.1	322.0	322.0	317.0	318.0	318.0	317.6	317.6	317.6
Oil and Natural Gas Steam[2]	114.4	113.6	112.9	112.9	112.6	105.5	99.9	96.0	94.3	93.3	93.0	93.0
Combined-cycle (CC) Combustion	197.2	198.3	201.2	203.2	203.5	203.5	203.5	203.5	203.5	203.5	203.5	203.7
Turbine/Diesel Distributed Generation	137.5	138.5	139.0	140.6	142.3	141.5	140.6	140.5	140.4	140.2	142.2	143.4
(Natural Gas)[3]	0.0	0.0	0.0	0.3	0.4	0.5	0.5	0.5	0.6	0.7	0.7	0.8
Gas/Oil Total	449.1	450.4	453.1	457.0	458.8	451.0	444.5	440.5	438.8	437.7	439.4	440.9
Nuclear Power[4]	101.0	101.1	101.2	102.4	104.5	105.0	105.7	105.9	107.2	108.5	109.8	110.5
Renewable Sources[5]	138.8	144.9	149.1	156.7	157.0	157.8	158.2	158.2	158.3	158.4	158.7	159.1
Total	**1,001.9**	**1,014.5**	**1,023.0**	**1,038.9**	**1,041.9**	**1,035.2**	**1,024.9**	**1,022.1**	**1,021.7**	**1,021.5**	**1,024.8**	**1,027.3**

Table A-6 (continued)
US Operating Capacity and Generation Summary Outlook—AEO 2011

US Annual Generation by Fuel (TWh)

	2009[1]	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	1,749	1,841	1,797	1,801	1,797	1,778	1,769	1,792	1,801	1,816	1,834	1,875
Gas and Oil	877	945	895	874	883	881	895	884	892	898	901	880
Nuclear Power	799	803	803	813	827	833	839	841	852	862	872	877
Renewable Sources	386	374	410	453	464	481	494	506	509	513	517	525
Total	**3,811**	**3,963**	**3,905**	**3,941**	**3,971**	**3,973**	**3,997**	**4,023**	**4,054**	**4,089**	**4,124**	**4,157**

Source: US DOE, EIA, AEO 2011.
1. 2009 values are estimates. EIA AEO 2011 capacity estimates are year-ending December 31
2. Includes oil-, gas-, and dual-fired capacity.
3. Primarily peak-load capacity fueled by natural gas.
4. Nuclear capacity includes 3.8 GW of uprates through 2035.
5. Includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, all municipal waste, landfill gas,other biomass, solar, fuel cells, and wind power. Facilities cofiring biomass and coal are classified as coal.

Table A-7
US Operating Capacity and Generation Summary Outlooks—NASC Fall 2010

US Average Summer Capacity by Fuel (GW)

	2009[1]	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	310.6	314.8	317.7	318.4	318.0	316.8	314.9	308.9	306.8	303.9	301.0	297.6
Gas												
Combined-cycle Gas	193.9	200.4	207.3	211.0	215.7	220.9	227.7	240.6	251.9	264.5	269.6	282.8
Combustion Turbine (CT)	121.1	123.0	125.3	129.1	130.2	135.4	140.3	144.2	146.0	148.3	151.6	153.9
Oil-CC/CT	54.2	52.5	51.7	51.4	50.8	50.6	50.0	49.3	49.3	47.6	46.4	46.1
Gas/Oil Steam	105.7	102.4	101.0	99.8	96.9	94.2	90.2	86.0	84.3	82.1	80.8	80.6
Gas/Oil Total	475.0	478.4	485.2	491.4	493.6	501.1	508.2	520.2	531.6	542.5	548.4	563.4
Nuclear	101.9	103.0	103.8	104.3	104.2	105.2	105.4	106.5	107.6	108.2	109.7	114.4
Renewables[2]	136.5	145.4	153.6	162.0	169.7	178.2	186.2	195.2	202.2	209.0	216.2	223.9
Total	**1,024.0**	**1,041.5**	**1,060.3**	**1,076.1**	**1,085.5**	**1,101.3**	**1,114.7**	**1,130.8**	**1,148.2**	**1,163.5**	**1,175.3**	**1,199.3**

Table A-7 (continued)
US Operating Capacity and Generation Summary Outlooks—NASC Fall 2010

US Annual Generation by Fuel (TWh)

	2009[1]	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	1,799	1,907	1,899	1,980	1,992	1,981	1,886	1,825	1,789	1,734	1,708	1,664
Gas and Oil	863	856	868	858	892	977	1,125	1,231	1,319	1,434	1,493	1,565
Nuclear	798	810	822	832	840	839	843	863	858	867	885	919
Renewables	375	384	419	440	456	475	498	520	537	552	569	590
Total	**3,835**	**3,957**	**4,009**	**4,110**	**4,181**	**4,272**	**4,352**	**4,439**	**4,503**	**4,587**	**4,656**	**4,738**

Source: IHS CERA North American Gas and Power Scenarios Fall 2010.
1. 2009 values are estimates. IHS CERA NASC Fall 2010 capacity estimates are monthly, production weighted, annual averages.
2. Includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, fuel cells, and wind power. Facilities cofiring biomass and coal are classified as coal.

NOTES AND SOURCES

Annual Energy Outlook 2011 Reference Case, a presentation by Richard Newell, EIA Administrator, December 16, 2010,at http://www.eia.gov/neic/speeches/newell_12162010.pdf

AEO2011 Overview, Report Number: DOE/EIA-0383(2011), US DOE, EIA, April 26, 2011, http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf

AEO2011 Overview, Main Reference Case Tables (2008-2035), at http://www.eia.doe.gov/forecasts/aeo/tables_ref.cfm

IHS CERA North American Gas & Power Scenarios, Fall 2010

National Electricity Congestion Study, US Department of Energy, December 2009, at http://congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf

Supreme Court Case New Jersey v. EPA, No. 05-1097 (DC Cir. 2008)

Supreme Court Case North Carolina v. EPA, 531 F.3d 896 (DC Cir. 2008)

Supreme Court Case North Carolina v. EPA, 550 F.3d 1176, 1178 (DC Cir. 2008)