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# Potential Coal Plant Retirements: 2012 Update

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**Contents**





## Introduction

The energy market outlook and emerging environmental regulations have changed substantially since we last studied the potential for coal plant retirements in December 2010.[1] The decrease in spot and forward gas prices combined with low demand for power have caused projected energy margins and the cost of replacement power to decrease, altering the economics for coal units towards retirement versus retrofit decisions. On the market side, the projected energy margins for coal plants have decreased and the need for capacity has been deferred. On the regulatory front, two of the major Environmental Protection Agency (EPA) rules (CSAPR and MATS) were finalized with less restrictive requirements on the compliance deadlines and equipment than previously predicted. More recently, a federal court order vacated the CSAPR, adding an increased level of uncertainty regarding the timing and requirements under a potential future proposal by the EPA. This recent ruling may increase the role of the EPA's existing Regional Haze Rule for coal-fired plants in the Eastern Interconnect. In addition, the EPA's proposed 316(b) rules on cooling water intake structures were less onerous than some predictions with no universal requirement to install cooling towers.

These recent conditions have resulted in an acceleration of announcements to retire coal plants, same as early as this year. As of July 2012, approximately 30 GW of coal plant capacity (roughly 10% of total coal capacity) had announced plans to retire by 2016. Some of these announcements may be reversed if market conditions improve for coal units, but it appears more likely that many additional units will join the retirement list if the currently foreseen market conditions continue as expected over the next few years.

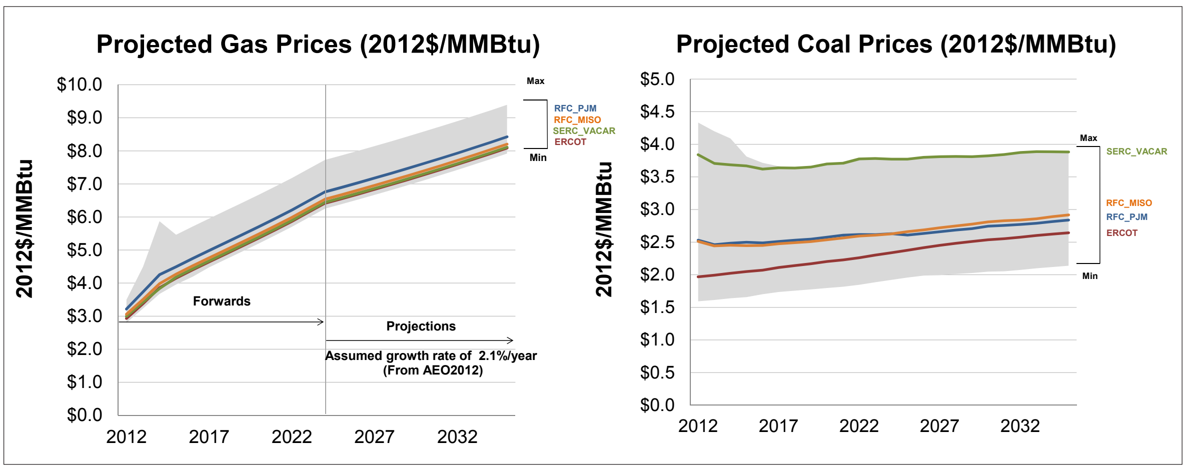
In this study, we have revised our previous coal plant retirement analysis to reflect the most recent market and regulatory outlook facing coal plants. Of course, there is no certainty in either factor, so to reflect the remaining regulatory uncertainty, we have developed strict and lenient regulatory scenarios. These scenarios involve different mixes of environmental control equipment assumed required in order to reduce emissions of mercury, acid gases, $SO_2$, and $NO_x$. We find that 59 GW to 77 GW (for lenient versus strict scenarios, respectively) of coal plant capacity are likely to retire instead of retrofit with environmental equipment. These retirements occur absent any future regulations restricting carbon emissions. Generally, these results are about 25 GW higher than the retirement levels we projected in December 2010 due mainly to lower expected gas prices, despite the somewhat more lenient environmental regulations we currently envision. The details of our assumed market and regulatory outlook and scenarios and key conclusions follow.

# SECTION 1 MARKET AND REGULATORY OUTLOOK

The assumed market outlook for gas prices used in this study is based on forwards (as of April 2012) on regional prices. For future coal prices, we relied on regional projections in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2012 (AEO2012) as the market information on regional coal forwards and futures is limited.

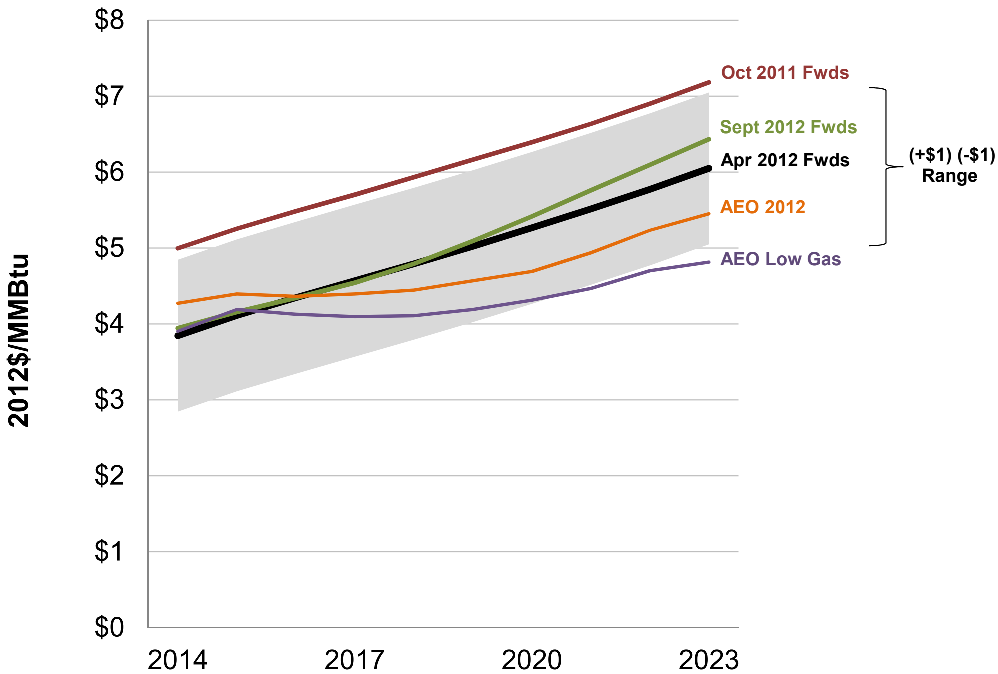
Figure 1 shows our assumed range of gas and coal prices during 2012-2035 across NERC subregions as well as assumed prices for selected regions. The base case gas prices start at the $3-4/MMBtu range in 2012, increase to $4-5/MMBtu in 2015, and are then assumed to reach $6-8/MMBtu by 2025 (all in constant 2012 dollars). This is about a 6% per year average real growth rate between 2012 and 2025. If the annual inflation rate is 1.95%,[2] this will result in nominal gas prices around $7.3/MMBtu 10 years from now. For the coal prices, we applied regional coal prices in the range of $2-4/MMBtu in 2012. These are assumed to stay approximately at the same level in real terms (2012 dollars) afterwards, consistent with the regional projections in AEO2012. In contrast, our previous (December 2010) retirement study assumed substantially higher gas prices at the $5-6/MMBtu range in 2012 and 2015, but lower prices at $6-7/MMBtu in 2025. Coal prices were assumed to be level at approximately $2/MMBtu in real dollars, lower than our current predictions.

## Figure 1 Projected Gas and Coal Prices



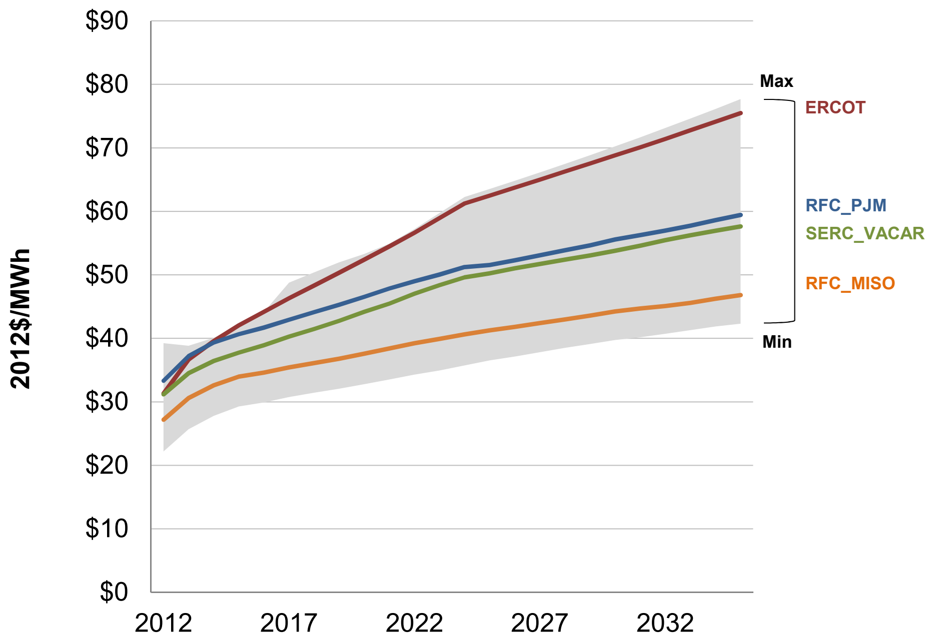

Since the changes in forward gas prices since our prior analysis had a large influence on the updated projected coal retirements and retrofits, we also examined scenarios to reflect the substantial uncertainty in future gas prices. Our +$1/MMBtu gas scenario (relative to April 2012 forwards) in Figure 2 roughly captures the amount of change in forward gas prices since October 2011 (in effect, testing what would happen if the declines were reversed). Our -$1/MMBtu gas price scenario (again relative to April 2012 forwards) reflect the possibility that the currently low spot price of around $3/MMBtu at Henry Hub does not move up as foreseen in the forward prices above, but instead grows only slightly to reach $5/MMBtu (in real 2012 dollars) by 2023. This -$1/MMBtu scenario is roughly consistent with the low gas price forecast ("5-year investment recovery with low gas price") scenario in the EIA's recent release of its AEO2012.

**Figure 2 Projected Henry Hub Gas Price Ranges (2012$/MMBtu)**




In a similar manner, we developed the corresponding regional wholesale electricity prices by using the quoted prices for April 2012 forwards for each region, then growing them at the weighted-average rate of growth in gas and coal prices (weights depending on the proportion of time that each fuel tends to be on the margin in each region). Figure 3 shows the resulting range of annual average power prices across NERC subregions, starting at $22-39/MWh in 2012, increasing to $29-42/MWh in 2015, and $37-63/MWh by 2025 (all in constant 2012 dollars). In comparison, the December 2010 retirement study assumed slightly lower power prices, especially by 2025 — averaging $29/MWh in 2012, decreasing to $28/MWh in 2015, and increasing to $30/MWh in 2025.

## Figure 3 Projected Power Prices (2012$/MWh)




Our analysis focuses on the implications of having to install moderate versus more elaborate and more expensive controls under MATS, CSAPR, or potentially similar regulations on coal plants. The MATS rule was finalized in December 2011 and requires a set of control equipment to reduce emissions of hazardous air pollutants (mercury, acid gases, and non-mercury metals). The MATS compliance deadline is April 2015 with a one-year extension that could be requested by state permitting authorities (and another one-year extension that could be granted by the EPA under limited circumstances). The types of equipment needed for compliance with MATS include dry and wet FGD, baghouses, ACI, DSI, and SCR.

CSAPR was finalized in July 2011 (with minor adjustments afterwards) with a goal of reducing emissions of $SO_2$ and $NO_x$ in 27 eastern U.S. states under a cap-and-trade program subject to regional caps. The CSAPR regulation was intended to be effective as of the beginning of 2012, but a recent court order vacated the rule. We do not offer an opinion on whether it will be appealed, replaced, or revised, except to recognize that the future environmental regulations remain uncertain. For instance, enforcement of the Regional Haze Rules for the coal plants in the eastern states could have similar impacts and obligations to a revised CSAPR rule, which aimed to reduce $SO_2$ and $NO_x$ emissions. In this study, we assume the compliance deadline to install the assumed retrofits (for compliance with MATS and a replacement rule or regulation for the vacated CSAPR) is 2016 for both sets of regulations.

To reflect the ongoing uncertainty in the implementation of these regulations and plants' retrofit compliance strategies, we have developed both strict and lenient regulatory scenarios requiring different mixes of equipment. (These are not based on any assessment of attaining other levels of environmental improvement; they are simply what-if variations to demonstrate how the cost of the retrofit equipment itself affects the results.)

As shown in Table 1, under the lenient regulatory scenario we assume that coal plants would need only SNCRs for $NO_x$ control, and a combination of DSI, baghouse, and wet FGD to reduce emissions of $SO_2$, mercury, acid gases, and other hazardous metals (depending on unit size and plant location). Due to the recent court order vacating the EPA's CSAPR, we expect that our lenient regulatory scenario reflects the current outlook, though substantial uncertainty still exists with respect to future EPA actions. Under the strict regulatory scenario, we assumed SCRs are mandatory for $NO_x$ control, and a combination of DSI, baghouse, ACI, and wet FGD will be required to reduce emissions of $SO_2$, mercury, acid gases, and other hazardous metals, again depending on unit size and plant location. (In our earlier study, we had assumed that all coal units would need to install both SCR and wet FGD, which have larger capital costs compared to the mix of equipment we assume in this study, and hence would imply more requirements.)

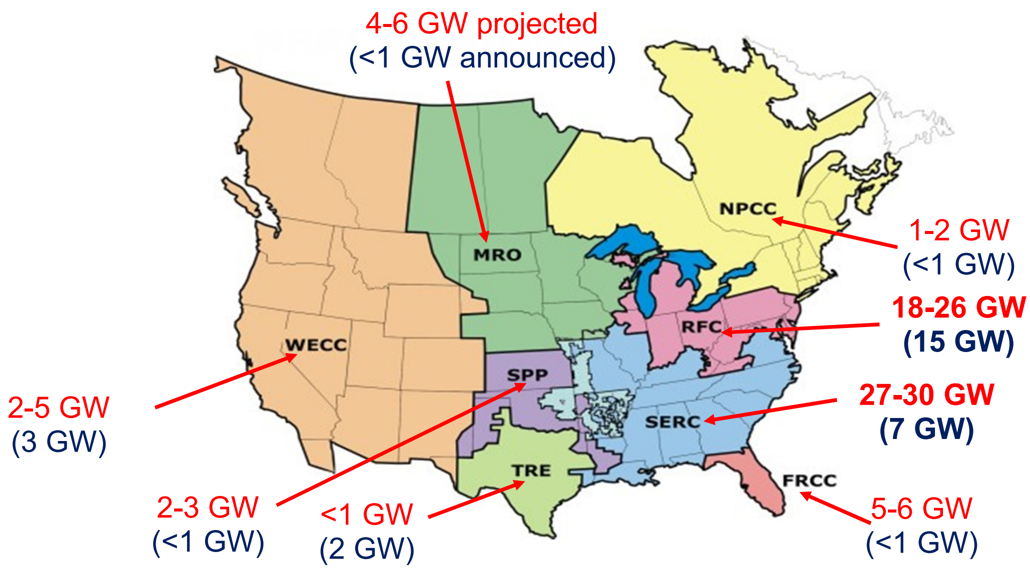
### Table 1 Regulatory Scenarios

| | Required Retrofit Equipment |
|---|---|
| Lenient EPA Regulations | ♦ SNCR and ACI on all units<br>♦ DSI and Baghouse on units in WECC and on small units (< 200 MW) in other regions<br>♦ Wet FGD on large (>= 200 MW) units outside WECC |
| Strict EPA Regulations | ♦ SCR on all units<br>♦ DSI, ACI, and Baghouse on units in WECC and on small (< 200 MW) units in other regions<br>♦ Wet FGD on large (>= 200 MW) units outside WECC |

## SECTION 2 PROJECTED COAL PLANT RETIREMENTS

We estimate that the current outlook for market conditions (forwards as of April 2012) and environmental regulations will result in 59-77 GW of coal plant retirements by 2016 (the range reflecting lenient versus strict environmental regulations). As shown in Figure 4, NERC regions SERC and RFC have the largest shares of retirements, with 27-30 GW in SERC and 18-26 GW in RFC. These two regions also contain a large fraction of the 30 GW of already announced coal plant retirements, with 7 GW in SERC and 15 GW in RFC.

### Figure 4 Announced and Projected Coal Retirements by NERC Region

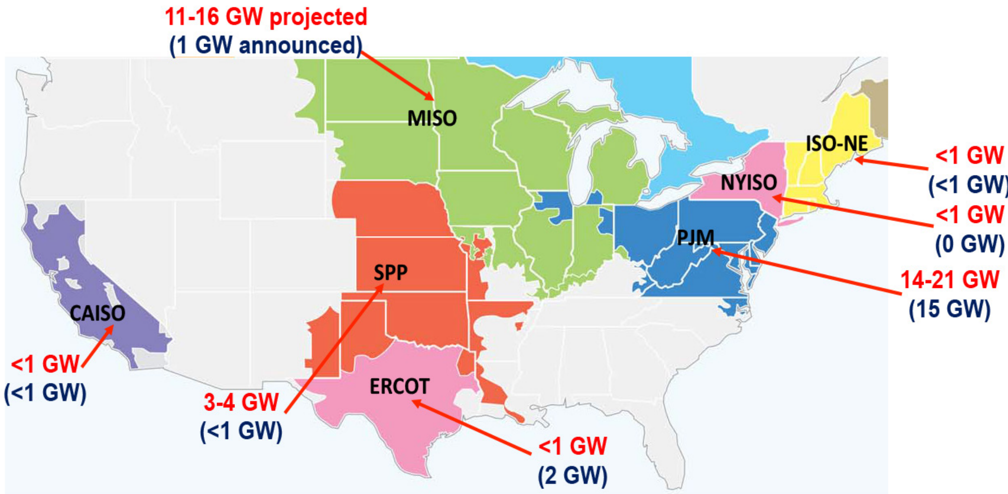



**Source:** The map is from the North American Electric Reliability Corporation (NERC) website, and is the property of NERC. The map is available at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_Color_072512.jpg. This content may not be reproduced in whole or any part without the prior express written permission of NERC. The figures showing the announced and projected coal retirements were added to the map by the authors of this study.

These estimates are slightly higher than NERC has indicated it expects to retire (according to NERC's Long Term Reliability Assessment study from November 2011). We expect that the differences between our retirement outlook and the NERC's estimates are due to a continuing decline in gas prices since the 2011 NERC study, as well as differences in methodology.

Figure 5 summarizes the same results but focuses on RTOs rather than NERC reliability regions. Among these regions, we expect the fewest retirements in CAISO (less than 1 GW), SPP (3-4 GW), and ERCOT (less than 1 GW), while PJM will have the most retirements in coal plant capacity (14-21 GW), followed by 11-16 GW in the MISO region. As shown in Table 2, these RTO regions also have the greatest portion of their total coal fleet and their region-wide current generation retired. Our projections for these two regions are fairly consistent with the ranges of coal plant retirements that were recently estimated by PJM (11-25 GW) and MISO (3-22 GW), though those entities used somewhat different methods than ours in developing their projections. Additionally, 13 GW out of the announced 15 GW of coal plant retirements in PJM are in our list of projected retirements.

## Figure 5 Announced and Projected Coal Retirements by ISO/RTO Region




**Source:** Copyright © ISO/RTO Council, all rights reserved. The figures showing the announced and projected coal retirements as well as the RTO names were added to the map by the authors of this study.

## Table 2 Projected Retirements by ISO/RTO region

| ISO/RTO Region | Coal Retirement (GW) | % of Coal Capacity | % of Total Capacity |
|---|---|---|---|
| PJM | 14-21 | 18-27% | 8-11% |
| MISO | 11-16 | 17-24% | 9-13% |
| SPP | 3-4 | 12-16% | 4-6% |
| ISO-NE | 0.8 | 33% | 3% |
| NYISO | 0.5 - 0.6 | 20-24% | 1-2% |
| ERCOT | 0.4 | 2% | 0% |
| CAISO | 0.1 - 0.2 | 5-10% | 0-0% |

While we do not foresee these magnitudes of retirements creating large-region resource adequacy problems, they may cause local difficulties for some subregions or generation owners and utilities that are highly reliant on the affected units. That is, retirements and retrofits will be especially challenging for coal plant owners that will need to retrofit or retire a large portion of their coal fleet. Nationwide, out of the 939 coal plant owners with total generation fleet exceeding 100 MW, 33 are projected to retire more than half of their coal capacity and 140 are projected to retrofit more than half of their coal capacity. Table 3 shows the distribution of these coal plant owners across NERC regions. A large fraction of these coal plant owners are in the RFC region.

## Table 3 Number of Strongly Affected Coal Plant Owners with more than 100 MW Total Generation Capacity under the Strict Scenario

| NERC Regions | Total | > 50% of Total Fleet Retiring | > 50% of Total Fleet Retrofitting |
|---|---|---|---|
| MRO | 81 | 6 | 19 |
| SERC | 150 | 3 | 31 |
| RFC | 179 | 11 | 39 |
| WECC | 217 | 3 | 21 |
| NPCC | 108 | 3 | 5 |
| FRCC | 32 | 4 | 2 |
| ERCOT | 111 | 1 | 9 |
| SPP | 61 | 2 | 14 |
| **Total** | **939** | **33** | **140** |

In addition to analyzing the potential coal plant retirements under the current market outlook, we assessed the sensitivity of the results to the strictness of the regulations (strict and lenient) and market scenarios (+/- $1 gas, and base case gas plus $30/ton $CO_2$ price starting in 2020).

## Table 4 Projected Retirements of Coal Capacity (GW)

| | | Market Scenario | | | | |
|---|---|---|---|---|---|---|
| | | Base (Recent Fwds) | Base Gas $-1/MMBtu | Base Gas $+1/MMBtu | Base $+5/MWh in Power Prices | Base $+30/ton $C0_2$ in 2020 |
| Regulatory Scenario | Lenient | 59 | 115 | 21 | 61 | 127 |
| | Strict | 77 | 141 | 35 | 77 | 149 |

Table 4 demonstrates that lower gas prices plus strict regulations could cause almost half of the U.S. coal fleet to retire — likely an untenable situation. In contrast, +$1/MMBtu higher gas prices would essentially stop retirements from increasing above announced levels to date. A $5 feedback effect on prices does not have a significant impact on base case retirements, but a carbon policy with $30/ton $CO_2$ prices starting in 2020 would cause major retirements comparable to a $1 drop in gas prices. We have applied a $30/ton price beginning abruptly — rather than phased in gradually from a much lower starting level — on the presumption that no carbon policy is likely until there is a strong and perhaps urgent national consensus that a policy is needed. If so, it must start with a fairly high price to materially affect carbon emissions. We also have ignored the likelihood that there would be grandfathered waivers or transitional allowances to blunt the burden of rapid compliance on existing units. Therefore, this is likely a very aggressive scenario compared to what is more politically likely.

## SECTION 3 PRICE FEEDBACK EFFECTS

If, as we predict, a substantial quantity of coal plants will retire by around 2015, this will affect the supply curve for power and perhaps the price of fuels (gas and coal) as well. Therefore, it is plausible that there will be at least a transitory increase in wholesale energy prices. We generally expect that the effects on wholesale energy prices will not be very large or long-lasting such that the feedback effect would be large enough to alter the results significantly.

For a few years beginning around 2015, the projected retirements are likely to cause some inward shifting of the supply curve, which will tend to raise energy prices and also foreshorten the time until new capacity is needed. However, because most parts of the country are fairly long on capacity for the next few years, in part due to the protracted recession and gas entry, capacity scarcity premiums are not likely to be significant. Even if/where observed, such premiums can only persist as long as it takes for new capacity to be developed — generally a few years.

The impacts of retirements on energy prices are more complex, depending on whether the retired capacity affects the cost of the marginal units setting the market price. Retirement of coal plants in the future will require the increased use or development of some other generation resources to replace the electricity production that these plants would have otherwise provided. Sources of this replacement electricity will include existing and new gas-fired generation, remaining compliant coal plants that were retrofitted or operating below capacity, new renewable resources, and future additional energy efficiency programs.

Due to the low gas prices expected in the near term, we expect a large portion (but not all) of the coal capacity that retires will be replaced with gas generation, which could raise the price of natural gas from the levels prevailing today (and assumed in this retirement analysis). As an upper bound on the potential increase in gas demand in the electric sector, we calculated the gas required to replace the 2011 generation output of all projected coal plant retirements (59 GW) by 2016 in our lenient base case scenario. The retiring coal plants generated approximately 266 TWh in 2011. Using an assumed 8,000 Btu/kWh heat rate for the average gas plant providing the replacement power, about 2 tcf/year (or about 6 Bcf/d) of gas would be needed. This additional gas demand represents about 10% of the total natural gas consumption in the United States in 2011 (23 tcf/year) — large enough that it could result in modest increases in natural gas prices.

While not directly focused on this question, a recent study[3] by the EIA concluded that a hypothetical (not predicted, just assumed) rapid increase of 6 Bcf/d in gas demand due to U.S. LNG exports beginning in the next few years could result in an approximate 15% increase in gas prices in the near term and a 10% increase in gas prices in the long term. This would be equivalent to about a $0.50/MMBtu increase in gas prices, which would then translate downstream into approximately a $3-5/MWh increase in power prices. Overall, we expect the net effects of capacity, supply shifts, and gas prices to be in the $4-10/MWh range for the next few years, and less thereafter — enough to be helpful to retrofitting plants and to existing, unaffected baseload units, but not likely enough to reverse the decision to retire for most units with more costly compliance.

## SECTION 4 CAPITAL EXPENDITURE ON RETROFITS AND NEW GENERATION

We estimate that compliance with the emerging EPA regulations will lead a large number of coal plants to install the necessary control equipment instead of retiring. Baghouse and ACI installations are projected to constitute the most common approach to control among retrofits, with 121-132 GW coal plant capacity installing baghouses and 136-183 GW of coal plant capacity installing ACIs. In addition, we estimate that 48-52 GW of wet FGDs and 8-15 GW of DSIs will be installed. In the lenient regulation scenario, 99 GW of SNCR retrofits are expected, while 106 GW of SCR retrofits are projected under the strict regulation scenario. The projected wet FGD retrofits are higher under the lenient regulation scenario (52 GW) than in the strict regulation scenario (48 GW) due to more units choosing to retire instead of retrofitting under the latter.

Table 5 shows the projected amount of new generation capacity from gas CCs and CTs to replace the retiring coal capacity owned by regulated entities. We estimate 49-57 GW of replacement capacity will be needed by 2016. This is significant but not unprecedented. In comparison, total new generation capacity that came online over the last five years (2007-2011) in the United States was 97 GW. And at present, some of the larger RTOs have nearly this much announced entry in their transmission interconnect application queues (though much of that will not be built). For instance, PJM currently has approximately 110 GW of capacity in their generation queue.

### Table 5 Projected Coal Capacity to be Retrofitted or Replaced (GW)

| | | SCR | SNCR | Wet Scrubber | Baghouse | ACI | DSI | Total* | Replacement Capacity |
|---|---|---|---|---|---|---|---|---|---|
| Regulatory Scenario | Lenient | 0 | 99 | 52 | 132 | 183 | 15 | 226 | 49 |
| | Strict | 106 | 0 | 48 | 121 | 136 | 8 | 212 | 57 |

Finally, we estimated the total capital expenditures on retrofits and replacement capacity by 2016. As shown in Tables 6 and 7, we estimate $126-144 billion of capital expenditures under the market outlook using April 2012 forwards. The projected capital expenditures do not change as much as the changes in retirements across market scenarios ($112-169 billion). This relatively robust result is due to the similarity of capital costs between new gas plants and multiple retrofits. For example, a small coal plant (200 MW) would need to spend about $1,000/kW to install a dry FGD and a baghouse if it is retrofitted, while retiring and replacing the plant with a new gas CC would require approximately the same capital expenditure. It is also caused by smaller units retiring in the stricter scenarios, reducing the total costs of retrofits even when those are more expensive requirements per plant. The per kW costs of retrofitting also do not increase significantly, because only the larger plants tend to conduct the retrofits, spreading the compliance costs over a larger capacity.

### Table 6 Costs of Retrofits (2012 $ Billion @ $/kW on Retrofitting Units)

| Regulatory Scenario | Base (Recent Fwds) | Base Gas $-1/MMBtu | Base Gas $+1/MMBtu | Base $+5/MWh in Power Prices | Base $+30/ton $CO_2$ in 2020 |
|---|---|---|---|---|---|
| | **Market Scenario** | | | | |
| Lenient | $78B @ $345/kW | $51B @ $297/kW | $98B @ $373/kW | $78B @ $348/kW | $49B @ $304/kW |
| Strict | $87B @ $410/kW | $52B @ $349/kW | $115B @ $455/kW | $89B @ $422/kW | $49B @ $345/kW |

### Table 7 Costs of Replacement Capacity (2012 $ Billion)

| Regulatory Scenario | Base (Recent Fwds) | Base Gas $-1/MMBtu | Base Gas $+1/MMBtu | Base $+5/MWh in Power Prices | Base $+30/ton $CO_2$ in 2020 |
|---|---|---|---|---|---|
| | **Market Scenario** | | | | |
| Lenient | $48B | $90B | $14B | $51B | $108B |
| Strict | $56B | $106B | $24B | $61B | $120B |

## Conclusion

The questions concerning what impact the new air quality regulations will have on power prices and resource adequacy continue to be important and difficult to answer definitively. This 2012 reassessment indicates that somewhat more retirements are likely (about 25 GW) than we foresaw in late 2010. However, that change is primarily due to changing market conditions, not environmental rule revisions, which have trended towards more lenient requirements and schedules.

We do not envision broad area reliability problems unless gas prices fall about $1/MMBtu or more below current forward prices and/or a very strict carbon policy were to be introduced around 2020. Nonetheless, the financial implications are substantial, such that even the most viable plants and power plant owners will have some anxiety about the riskiness of their decisions to retrofit and their ability to obtain financing for the initial expenditures. Once those are completed, however, the coal fleet should be back to being profitable much like would have occurred absent the environmental rules.

## Endnotes

1 Celebi, Metin, Frank C. Graves, Gunjan Bathla, and Lucas Bressan, "Potential Coal Plant Retirements Under Emerging Environmental Regulations," *The Brattle Group, Inc.*, December 8, 2010.

2 Federal Reserve Bank of St. Louis.

3 U.S. Energy Information Administration, "Effect of Increased Natural Gas Exports on Domestic Energy Markets," January 2012. Available at: http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf.

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Dr. Celebi provides expertise in electricity markets and the analysis of environmental and climate policy. He has consulted primarily in the areas of electricity spot pricing and market design, and has experience in developing and analyzing climate policies, assessing generation market power, LMP modeling, and merger analysis. He has also consulted and published on the interaction of resource planning and environmental/ climate policies within the electric sector, likely impacts of climate policies on natural gas demand, and impacts of environmental policies on coal plant retirements.

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