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# Growth From Subtraction

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**COMMENT**

## Impact of EPA Rules on Power Markets

**Our take**: Upcoming EPA policy to limit coal plant emissions is the best chance for a deregulated power market recovery, reversing fundamentals hurt by dismal commodity prices. We see opportunity with 'cleaner' generators in 'dirtier' markets like FE, AYE, EXC, and RRI. EPA rules should also boost rate base and EPS growth opportunities for Regulated Utilities – notably AEP, DTE, SO and CMS – although effective management of the regulatory process will be key.

We still see a lot of policy work on the horizon and acknowledge we may be early, but we think EPA rules will be a dominant investment theme for 2011 with heavy focus on likely stock movement in 1H11 between draft mercury rules in March and the PJM capacity auction in May. **Our favorite names to play the EPA activity are upgraded FE-AYE and Outperform RRI**. Highlights:

- **50+ GW of coal plant closures realistic.** Our base case assumes ~60 GW of coal plant closures within a total US fleet of 340 GW where 103 GW have no environmental controls and an additional 58 GW lack scrubber units key to mercury emission reductions.
- **Compliance expected from 2013-2017.** We assume delays to EPA's mandated 2015 compliance targets to reflect agency discretion and the logistical reality of replacing and upgrading so much capacity; that said, we think closures start in 2013 in response to new rules but also in acceptance that today's forward commodity prices leave many plants uneconomic before trying to cover new capex obligations.
- **$70-100 BN Capex for compliance or replacement.** We see significant investment to upgrade existing non-compliant plants and maintain regional 15% reserve margins. Higher capex will support higher structual growth opportunities for regulated utilities.
- **Reshaping fuel demand.** Coal plant retirements could lower steam coal demand by 157-324 MM tons per year (15-31%). With natural gas generation as a replacement option, demand from a 22 TCF base could grow 1.8-3.7 TCF (+8-16%) with an incremental 1.2-2.5 TCF (+5-10%) to meet 5-year power demand growth depending on generation mix.
- **Markets most impacted** will be MISO, SERC, PJM-West, and SPP, accelerating reversion to 15% reserve margins. Merchant plants in Eastern MISO and PJM-W should be the biggest winners with limited benefit in PJM-E, NEPOOL, and NYISO.
- **A 4–5 year acceleration to power market recovery.** We see EPA policy accelerating the tightening of market conditions and rebound in generation earnings by 4- 5 years, making the recovery more "investible".

**DISCLOSURE APPENDIX CONTAINS IMPORTANT DISCLOSURES, ANALYST CERTIFICATIONS, INFORMATION ON TRADE ALERTS, ANALYST MODEL PORTFOLIOS AND THE STATUS OF NON-U.S ANALYSTS. FOR OTHER IMPORTANT DISCLOSURES, visit www.credit-suisse.com/ researchdisclosures or call +1 (877) 291-2683.** U.S. Disclosure: Credit Suisse does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

# Executive Summary

We think the proposed and expected rules from the EPA to lower coal plant emissions of sulfur dioxide (SOx), nitrogen oxide (NOx), mercury (Hg), and other hazardous air pollutants (HAPs) will be a significant turning point in the outlook for both merchant power plants and vertically integrated regulated utilities. The EPA rules for reducing coal plant emissions will come in two discrete rules: CATR (Clean Air Transport Rule) to shape SOx and NOx emissions and a MACT (Maximum Achievable Control Technology) rule to address mercury and other HAPs (Exhibit 1).

The CATR and MACT rules from EPA should represent a turning point for power market fundamentals

With these rules we see the need for a combination of closing non-compliant plants and making significant capital investment in others to reach compliance; either way, supply-demand fundamentals will tighten from the oversupplied conditions we see today that have contributed to depressed power prices and generator earnings.

Merchant plant closures will improve supply-demand and longer-term could help commodity prices

- For competitive power generators, the EPA rules will help to fix one of the three legs of the power investment thesis – power market supply – and could eventually help to fix another – commodity prices – by shifting the mix of power supply toward more natural gas fired generation that will increase demand (and likely pricing) for natural gas while lowering demand for domestic steam coal.
- For regulated utilities, we see the EPA rules creating an earnings growth opportunity as companies attend to their higher emitting plants through a combination of newbuild construction (we assume natural gas plants) and environmental capex to retrofit existing coal plants. Annual growth rate could increase by 1- 4% to comply with the rules depending on utility.

Regulated Utility EPS growth rates could increase 1-4% by utility

We appreciate making investment decisions on expected governmental policy carries some valid reasons for concern but think the EPA actions are more 'viable' than past expectations around Congressional action on climate change (carbon) or renewables since this EPA 'event' is mostly about enforcement of existing laws where the health and societal good benefits are of limited debate at this point. We think the industry will run into logistical challenges in meeting the EPA's proposed timelines while ensuring system reliability, leading us to assume an additional two years for compliance although we think the reprieve will be predicated on an actionable plan by owners (meaning that they will need to be busy during the entire process and can't just wait until final compliance date).

We see EPA as lower risk policy investing than waiting on Congress

**Exhibit 1: EPA Calendar**

| RPM Auction Year | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 |
|---|---|---|---|---|---|---|---|
| | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **CATR** | | Apr 2011 Final Rule | | | | | |
| | 7/10/2010 CATR proposed | Compliance Period | | | | 2 Year Extension Period | |
| **Mercury MACT** | | 3/16/2011 Draft Rule 11/16/2011 Final Rule | Compliance Period | | | 2 Year Extension Period | |

*Source: EPA, Company data, Credit Suisse estimates*

## Prefer Cleaner Generators in Dirtier Markets

The most compelling investment opportunities in our view will come in the de-regulated power markets where the EPA rules will help to accelerate a rebalancing in supply-demand fundamentals with particular help in regions where less remediated coal plants are common, leading us to the mantra of 'buy cleaner power generators in dirtier markets'.

Favored Integrateds are FE / AYE, IPP is RRI, Regulateds are AEP, DTE and SO

Of this, we prefer Outperform rated FirstEnergy (FE), Allegheny (AYE) and are interested in Neutral rated Exelon (EXC) amongst the Integrateds and RRI Energy (RRI) amongst the IPPs. We see good opportunity for rate base growth in coal heavy regulated utilities like AEP, DTE, SO, and CMS where considerable capex will be required although the key to retaining value for all utilities will be successful management of the regulatory process.

For the Competitive Power stocks we are updating our earnings estimates to incorporate our new baseline assumption that 60 GW of small coal plants lacking significant environmental controls are closed nationally. We do not see significant upward estimate moves until 2013 given existing hedges in place and our view that closures will be spread over 2013 – 17 time period. The biggest upside to estimates will come at FE–AYE ad EXC. Our new price targets incorporate this scenario, partly offset by a lower impact from carbon emission rules in light of the current political environment and environmental prioritization at EPA on these more readily addressable pollutants.

Integrateds with the most earnings leverage to policy are EXC, FE, and AYE but not starting until 2013

**Exhibit 2: Earnings Estimates New versus Old**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AYE | 1,207 | 1,284 | 1,147 | 1,161 | 1,335 | 1,485 | 1,227 | 1,248 | 1,071 | 1,187 | 1,501 | 1,696 | 2% | -3% | -7% | 2% | 12% | 14% |
| D | 4,958 | 4,849 | 5,054 | 5,424 | 5,607 | 5,905 | 4,959 | 4,779 | 4,970 | 5,464 | 5,744 | 6,111 | 0% | -1% | -2% | 1% | 2% | 3% |
| EIX | 3,779 | 3,987 | 3,913 | 4,223 | 4,590 | 4,851 | 3,684 | 3,879 | 3,907 | 4,299 | 4,732 | 5,013 | -3% | -3% | 0% | 2% | 3% | 3% |
| ETR | 3,829 | 3,856 | 3,815 | 3,817 | 3,810 | 3,900 | 3,728 | 3,713 | 3,639 | 3,719 | 3,737 | 3,834 | -3% | -4% | -5% | -3% | -2% | -2% |
| EXC | 5,966 | 6,128 | 5,282 | 5,349 | 5,481 | 5,856 | 5,966 | 6,077 | 5,209 | 5,542 | 6,156 | 6,874 | 0% | -1% | -1% | 4% | 12% | 17% |
| FE | 3,329 | 3,545 | 3,406 | 3,463 | 3,667 | 3,734 | 3,292 | 3,362 | 3,311 | 3,593 | 3,939 | 4,218 | -1% | -5% | -3% | 4% | 7% | 13% |
| NEE | 4,787 | 4,944 | 5,451 | 5,778 | 6,058 | 6,435 | 4,787 | 4,939 | 5,402 | 5,764 | 6,045 | 6,432 | 0% | 0% | -1% | 0% | 0% | 0% |
| PEG | 3,705 | 3,719 | 3,723 | 3,947 | 4,175 | 4,373 | 3,767 | 3,790 | 3,734 | 4,092 | 4,455 | 4,633 | 2% | 2% | 0% | 4% | 7% | 6% |
| **Average** | | | | | | | | | | | | | **-1%** | **-2%** | **-3%** | **1%** | **5%** | **7%** |
| | | | | | | | | | | | | | | | | | | |
| RRI | 317 | 354 | 362 | 411 | 496 | 543 | 293 | 334 | 390 | 460 | 612 | 696 | -7% | -6% | 8% | 12% | 24% | 28% |

| | Old EPS | | | | | | New EPS | | | | | | % Change | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| AYE | 2.09 | 2.27 | 1.65 | 1.67 | 2.21 | 2.74 | 2.16 | 2.21 | 1.40 | 1.77 | 2.81 | 3.57 | 4% | -3% | -15% | 6% | 28% | 30% |
| D | 3.40 | 3.28 | 3.32 | 3.53 | 3.61 | 3.83 | 3.41 | 3.21 | 3.23 | 3.58 | 3.76 | 4.05 | 0% | -2% | -3% | 1% | 4% | 6% |
| EIX | 3.34 | 3.29 | 2.71 | 2.93 | 3.36 | 3.58 | 3.30 | 3.05 | 2.72 | 3.08 | 3.67 | 3.94 | -1% | -7% | 0% | 5% | 9% | 10% |
| ETR | 6.69 | 6.94 | 6.72 | 6.53 | 6.60 | 7.04 | 6.69 | 6.89 | 6.55 | 6.64 | 6.80 | 7.26 | 0% | -1% | -3% | 2% | 3% | 3% |
| EXC | 3.93 | 3.99 | 3.10 | 3.00 | 2.98 | 3.18 | 3.93 | 3.94 | 3.03 | 3.18 | 3.61 | 4.16 | 0% | -1% | -2% | 6% | 21% | 31% |
| FE | 3.65 | 3.62 | 3.29 | 3.37 | 3.75 | 3.87 | 3.66 | 3.35 | 3.19 | 3.74 | 4.43 | 5.03 | 0% | -7% | -3% | 11% | 18% | 30% |
| NEE | 4.45 | 4.42 | 4.69 | 4.78 | 5.18 | 5.74 | 4.45 | 4.41 | 4.62 | 4.75 | 5.16 | 5.73 | 0% | 0% | -2% | 0% | 0% | 0% |
| PEG | 3.09 | 2.95 | 2.88 | 3.13 | 3.49 | 3.86 | 3.05 | 2.88 | 2.79 | 3.22 | 3.76 | 4.12 | -1% | -2% | -3% | 3% | 8% | 7% |
| **Average** | | | | | | | | | | | | | **0%** | **-3%** | **-4%** | **4%** | **11%** | **14%** |

*Source: Company data, Credit Suisse estimates*

**Exhibit 3: Target Price New vs Old**

| | Target Price | | | Tot. Return | | | Rating | |
|---|---|---|---|---|---|---|---|---|
| | Old | New | % Chg | Div Yield | Old | New | Old | New |
| AYE | $23.00 | $28.00 | 22% | 2.6% | 1.5% | 23.0% | N | O |
| D | $37.00 | $39.00 | 5% | 4.1% | -12.2% | -7.6% | N | N |
| EIX | $37.00 | $37.00 | 0% | 3.6% | 9.9% | 9.9% | N | N |
| ETR | $86.00 | $81.00 | -6% | 4.3% | 15.9% | 9.4% | O | N |
| EXC | $46.00 | $47.00 | 2% | 4.9% | 12.1% | 14.4% | N | N |
| FE | $41.50 | $43.00 | 4% | 5.9% | 17.9% | 21.9% | N | O |
| NEE | $58.00 | $58.00 | 0% | 3.7% | 10.5% | 10.5% | O | O |
| PEG | $36.00 | $36.00 | 0% | 4.2% | 15.3% | 15.3% | N | N |
| RRI | $5.50 | $6.00 | 9% | 0.0% | 58.5% | 72.9% | O | O |

*Source: Company data, Credit Suisse estimates*

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# Report Highlights

In the full length report we walk through the major issues around EPA policy in detail to provide greater context and data behind our observations and conclusion. Below are the key takeaways from our analysis:

## The US Coal Fleet – What's at Risk?

***See page 20 for more***

We can realistically envision coal plant retirements in response to EPA rules exceeding 50 GW (50,000 MW) on the installed 340 GW fleet with another ~100 GW requiring fairly hefty investment to meet anticipated EPA emissions rules. We assume the EPA's targeted compliance dates of late 2014 / early 2015 will be ultimately extended by another 2 years to allow for the logistical challenges of meeting compliance targets (the investment projects are large and time consuming) as well as to support system reliability during the implementation process. With this time frame we assume a ratable closure of plants over the 2013-2017 period as we think the upside down economics of today's commodity price curves for natural gas and coal will lead owners to start retiring projected money losing plants earlier rather than running at a loss until the final days of the enforcement period.

We assume 60 GW of coal capacity will be closed in 2013 – 17 time period

A little more detail on these thoughts:

**Today's coal fleet**

Coal generation is a vital electricity resource for the US, accounting for just over half of all electricity produced. Unfortunately, the fleet is getting old (Exhibit 4) with many of the plants lacking the environmental controls necessary to meet future EPA compliance rules meaning shut-down or significant equipment upgrades will be required.

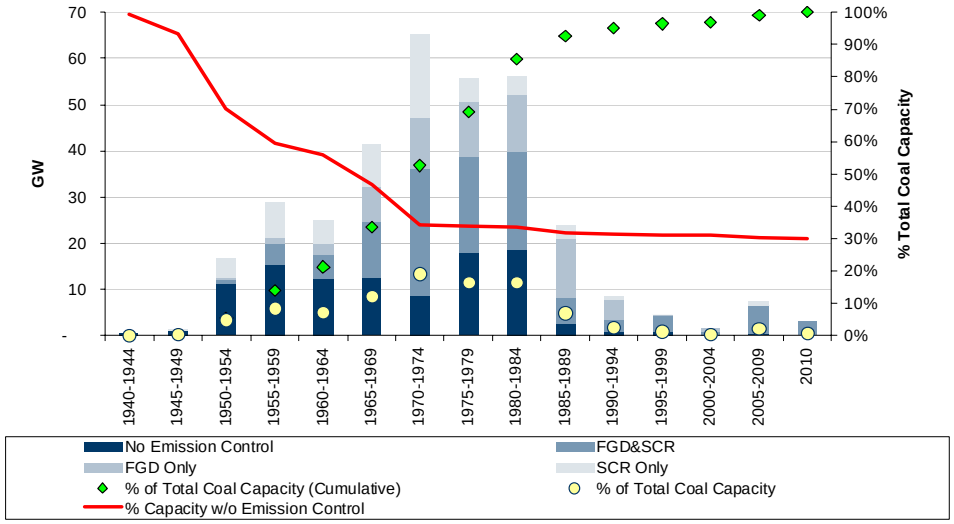
After including the 26 GW of planned upgrades over the next 5 years, the 340 GW US coal fleet will still have 103 GW lacking any major emission controls, 65 GW having a scrubber but not a SCR, 58 GW having a SCR but not a scrubber, and 115 GW having all major control equipment.

103 GW of 340 GW US coal fleet lack any emission controls

As an easy measuring stick for plant vulnerability, we focus on scrubber installations (aka FGD or flue gas desulfurization unit) since this is the most broadly effective tool for lowering mercury emission levels to meet mercury MACT standard which targets emission rates consistent with the best 12% of the fleet, or about a 90% removal rate. We see 161 GW, or 47% of the total US coal fleet, lacking scrubbers with many likely exposed to some heightened level of capital investment for scrubbers or other alternative compliance options to meet mercury reduction targets; if not, the plants look vulnerable to closure.

161 GW coal plants lack scrubbers which is a key tool for mercury reduction

**Exhibit 4: Coal Plant Vintage (Including Planned Emission Control)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

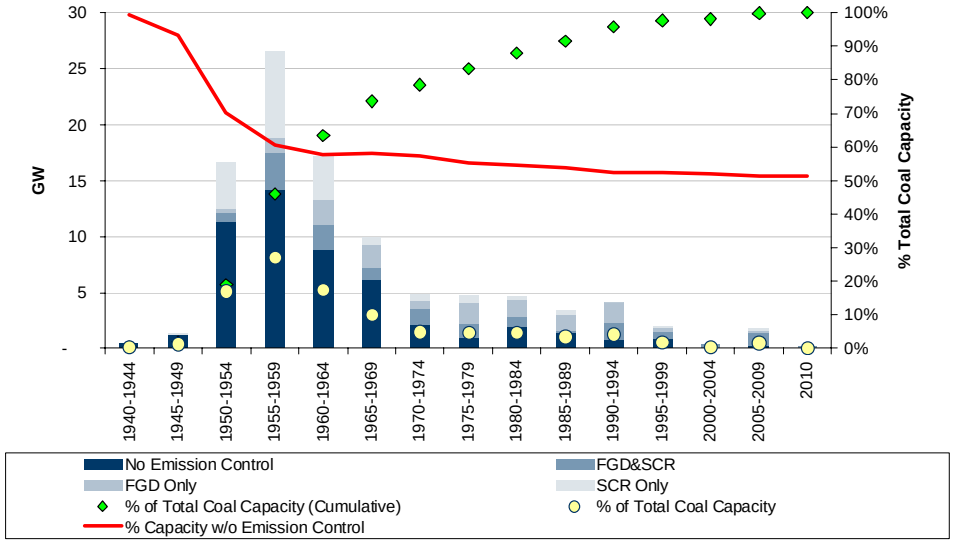
Small coal plants are a more vulnerable subset

We expect part of the US coal fleet 'at risk' to be closed and part for owners to invest the capital in environmental control equipment to keep the plant going. In Exhibit 5 we narrow our focus to just look at the 'small' coal plants (<300 MW of capacity). We think this subset is important because they are the hardest to economically justify for large equipment upgrades in part because the environmental control costs are non-linear (they're more expensive on a unit of capacity basis at a small coal plant) and because these plants are generally older and less efficient in energy conversion which further strains the economic justification for reinvesting large amounts of capital.

…with 69 GW lacking scrubbers of which 50 GW have no emission controls

Of the small fleet, 50 GW are over 40 years old and have no environmental controls; if we broaden the conversation to plants lacking scrubbers, the fleet at risk grows to 69 GW (or 20% of the total US coal fleet). When we think about the fleet at risk for retirement, we find comfort in a 60 GW closure baseline in large part from the small plants at risk with the realization some will survive but many plants over 300 MW will instead face closure for equally challenged economics.

**Exhibit 5: Small Coal Plant Vintage (Including Planned Emission Control)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

### Weak forwards make investment even harder to justify

If the EPA rules were not bad enough for coal generators, we think a large chunk of the US coal fleet is vulnerable to closure simply due to crummy economics where we see coal pricing at a premium to natural gas out the forward curve when adjusting on an electricity equivalent basis (Exhibit 6 and Exhibit 7). Awful energy margins suggest to us that owners should be reevaluating their coal fleets due to pure energy economics before even taking on the burden of a capex for environmental control equipment.

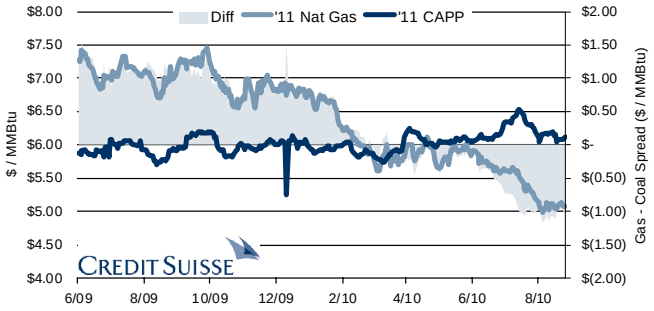
Forward coal and natural gas prices leave many coal plants uneconomic today

We have seen some operators already make this decision but many have ignored this economic reality, in our minds reflecting a combination of (a) eternal optimism that commodity prices will revert to benefit coal plants (b) coal plant dispatch decisions being made on realized commodity prices that benefit from legacy in the money hedges for both coal and transport that defers the reality of poor economics for a time and (c) some fading hope that carbon or other US policy would deliver a set of incentives to close plants and therefore less urgency to do so without remuneration.

…lending comfort to idea that closures will come before the "last possible moment" for EPA compliance

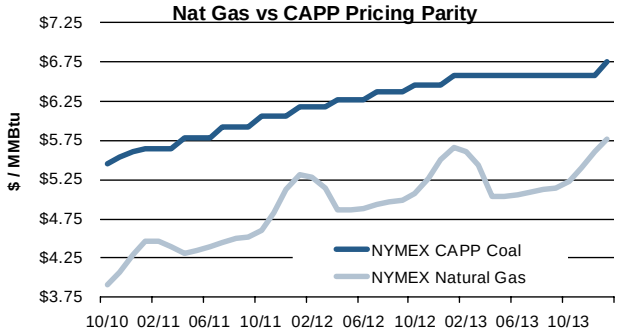
In contrast to many who think generators will wait until the last possible moment to close at risk coal plants, we think owners will be more motivated to close plants as they realize that the environmental capex obligations are unavoidable and the realized / projected energy margins are inadequate to justify running the plants (before they try to afford the capex). Clearly some game theory will exist for plants that are 'on the bubble' as owners wait for others to close which should improve market pricing but we see a realistically healthy chunk of the fleet 'under the bubble'.

**Exhibit 6: 2011 CAPP Coal / NYMEX Natural Gas Parity**




*Source: Company data, Credit Suisse estimates*

**Exhibit 7: 2010 – 13 Gas vs CAPP Pricing Parity**

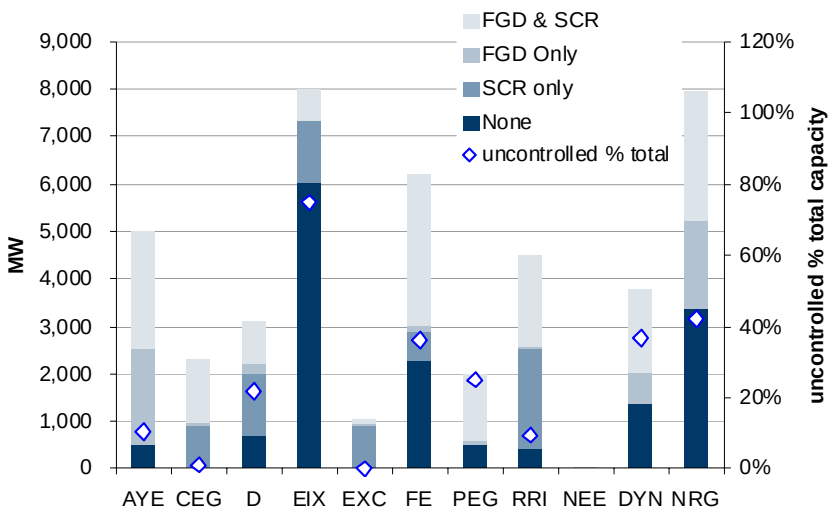



*Source: Company data, Credit Suisse estimates*

## Whose Plants are at Risk?

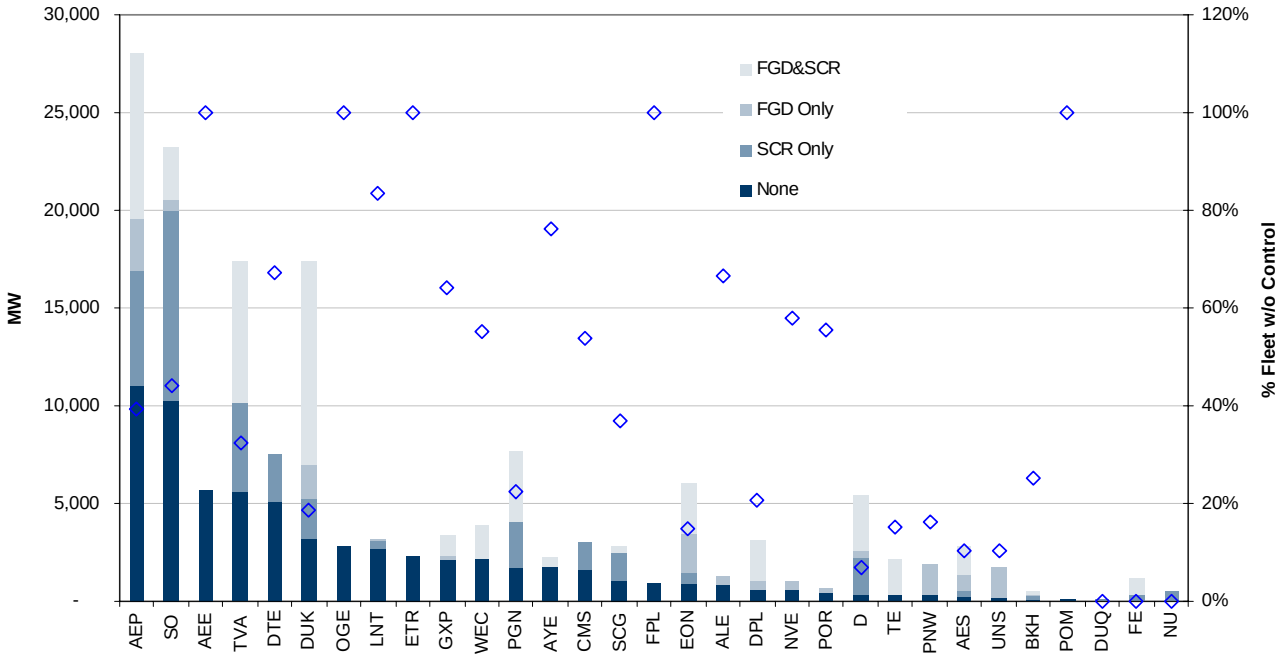
We see the company specific implications of EPA policy as interesting when considering that 15-30% of the US coal fleet is at risk of either closure or needing significant capex to stay in operation. In Exhibit 8 and Exhibit 9 we show the merchant and regulated plants, respectively, by company that we think will require attention. In Appendix IV of the appendix note to this report we show the plant by plant breakdown of each company's existing coal fleet including vital statistics like capacity, output, existing controls, etc.

**Exhibit 8: Integrateds Companies Coal Plants Capacity By Emission Control**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 9: Regulated Coal Plants Capacity By Emission Control**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

For Merchant plants, EIX and NRG face the most gross MWs needing attention with decisions balanced between energy margins and viable compliance alternatives.

For the Regulateds, AEP, SO, and DTE will have the most work to do as far as upgrade or replacement decisions. As a percentage of existing regulated coal fleet, the most work will be at AEE and OGE.

We think the implications of coal plant vulnerability will vary widely with the regulated utilities seeing the investments as positive to rate base and earnings growth (see below).

For the merchants, the loss of capacity will be a headline concern but we interestingly see closures as an opportunity for the operators since (a) the small plants are generally low earnings contributors and (b) tightening market conditions will boost energy and capacity revenues for the surviving fleet, creating a net benefit to earnings.

## Lots of Capex to Come

***See page 42 for more***

The obligation to either replace or retrofit such a large piece of the power generation fleet will require considerable capital investment above and beyond the industry's already elevated spending level. We see total investment this decade to meet EPA compliance realistically in the $70-100 BN range with a wider range depending on assumptions around cost to comply and decisions between retrofit versus newbuild; the range jumps to $110-150 BN if we assume plants lacking scrubbers will also need to be addressed (Exhibit 10). Looking to the regulated utility capex obligations that will drive rate base and earnings growth, capex could be in the $50-70 BN range, $80 -110 BN when tacking on plants without scrubbers (Exhibit 11).

Overall capex for upgrades and replacement could be $70 -100 BN of which $ 50 – 70 BN could be at regulated utilities

Beyond the impact and opportunity for power generators, this elevated level of spending should create opportunities for Engineering and Construction (E&C companies) as they take on the construction projects that will inevitably happen.

Watch for E&C company opportunities

**Exhibit 10: Capex Requirement (Retrofit / Replace Un-Controlled Coal Plants)**

| $ BN | % of Coal Plants with No Emission Control to Retrofitted | | | | | |
|---|---|---|---|---|---|---|
| Blended Emission Control Cost | $/KW | 0% | 25% | 50% | 75% | 100% |
| | 300 | 115 | 96 | 77 | 57 | 38 |
| | 350 | 115 | 97 | 80 | 62 | 45 |
| | 400 | 115 | 99 | 83 | 67 | 51 |
| | 450 | 115 | 101 | 86 | 72 | 57 |
| | 500 | 115 | 102 | 89 | 77 | 64 |
| | 550 | 115 | 104 | 93 | 81 | 70 |
| | 600 | 115 | 105 | 96 | 86 | 77 |
| | 650 | 115 | 107 | 99 | 91 | 83 |
| | 700 | 115 | 109 | 102 | 96 | 89 |

*Source: Company data, Credit Suisse estimates*

**Exhibit 11: Capex Requirement (Retrofit / Replace All Un-Controlled Regulated Coal Plants)**

| $ BN | % of Coal Plants with No Emission Control to Retrofitted | | | | | |
|---|---|---|---|---|---|---|
| Blended Emission Control Cost | $/KW | 0% | 25% | 50% | 75% | 100% |
| | 300 | 89 | 74 | 59 | 44 | 30 |
| | 350 | 89 | 75 | 62 | 48 | 35 |
| | 400 | 89 | 77 | 64 | 52 | 39 |
| | 450 | 89 | 78 | 67 | 56 | 44 |
| | 500 | 89 | 79 | 69 | 59 | 49 |
| | 550 | 89 | 80 | 72 | 63 | 54 |
| | 600 | 89 | 81 | 74 | 67 | 59 |
| | 650 | 89 | 83 | 77 | 70 | 64 |
| | 700 | 89 | 84 | 79 | 74 | 69 |

*Source: Company data, Credit Suisse estimates*

## Demand for Natural Gas and Coal Likely to Change

***See page 60 for more***

A clear carry through impact to the commodity and equity markets will come with a rebalancing in the mix of electricity production in the US as coal plants face retirement with replacement coming primarily from natural gas fired plants. As we discussed above, not only do the coal plants face capital obligations but the forward curves today show the plants as disadvantaged relative to gas plants.

Fuel mix for the Power industry will change

Looking at the shift in demand for natural gas and coal under our two scenarios – one that 60 GW of coal is retired and the other that all plants lacking both scrubbers and SCRs are closed at 103 GW – would point to a significant redistribution in energy demand for electricity generation.

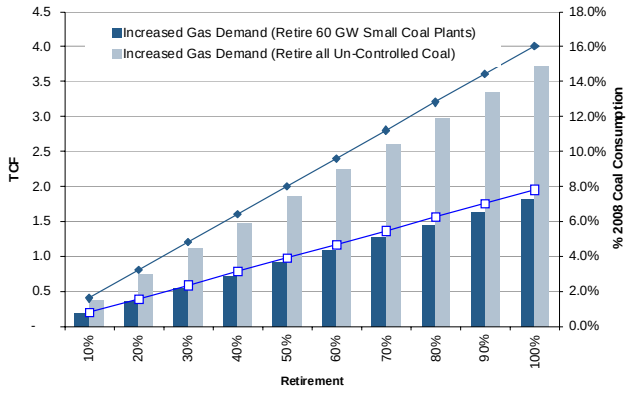
Steam coal demand could fall by 15-31% with implementation

In Exhibit 13, coal demand in turn would fall by 157-324 MM tons annually on an Eastern equivalent tonnage basis, representing a 15 -31% drop in steam coal demand. In Exhibit 12, natural gas demand would increase in the 1.8 - 3.7 TCF / year range (7.8 -16.0% to current demand) over next 5 – 7 years just from the coal retirement cycle (before taking into account market share gains with future demand growth). Even more interesting to us, when we take into account natural gas needed to meet future power demand growth we

Overall natural gas demand could grow by 8-16% with plant closures on top of 5-10% growth to meet electricity demand growth

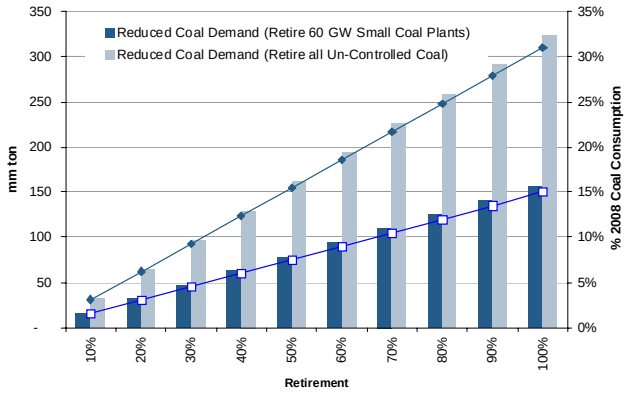
could area another 1.2 – 2.5 TCF in 7 years, bringing total change in natural gas demand from the power sector to 3.0 – 4.3 TCF under the 60 GW retirement scenario (Exhibit 14 and Exhibit 15).

**Exhibit 12: Natural Gas Demand Increase From Coal Plant Closure**



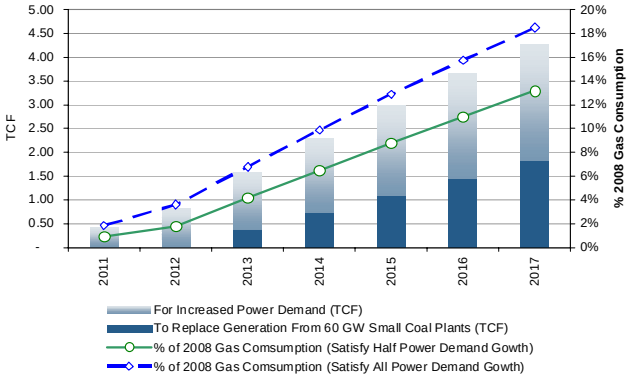

*Source: Company data, Credit Suisse estimates*

**Exhibit 13: Coal Demand Decrease from Coal Plant Closure**



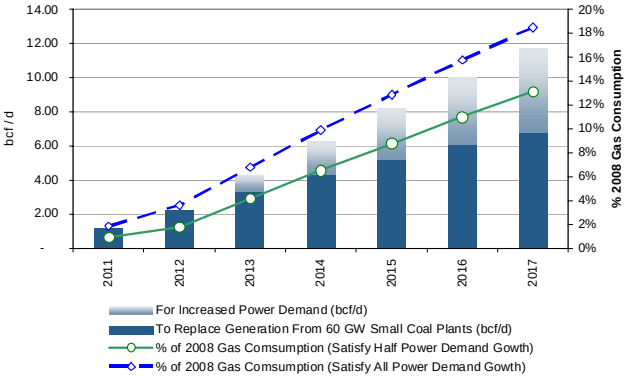

*Source: Company data, Credit Suisse estimates*

**Exhibit 14: Increase in Gas Demand from both Coal Plant Closures and Power Demand Growth (TCF)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 15: Increase in Gas Demand from both Coal Plant Closures and Power Demand Growth (bcf/d)**




*Source: Company data, Credit Suisse estimates*

# Merchant Earnings Broadly Higher with Some Outsized Winners

***See page 53 for more***

We could see broad based opportunity for the power generators with enforcement of the EPA rules mostly through tightening power markets that will support higher energy and capacity prices (where available). The upside will come through both a shift to higher cost plants setting the marginal price of electricity as well as a willingness to wait for the 'right' pricing signals before building new assets (most visibly with higher capacity prices), a situation that does not exist in the market today.

EPA policy will lead to tighter power markets and faster return to replacement cost economics

**Our scenarios**

To appreciate the market impact we ran three discrete scenarios in our economic dispatch model (supply-demand) that is built up by plant and by region on an hourly basis, allowing us to better appreciate the changes in both plant utilization and marginal plant dispatch economics that set market clearing power prices.

We also believe this approach adds to the robustness of the closure impact conversation since we see the net benefits to generators of tightening markets standing as more beneficial than the impact to them of retiring some marginal power plants. We think most EPA conversations have been too narrow in scope to talk about who is at risk due to losing capacity rather than appreciating the lift that will come to the surviving power plants. Our scenarios are:

- 35 GW are closed, representing half of the small coal fleet today that lacks scrubbers
- 60 GW are closed, representing all of the small coal plants having no environmental controls plus half of the small plants that have SCRs but no scrubbers
- 103 GW are closed, representing all the coal plants that have no environmental controls but assumes plants with either just a scrubber or just a SCR are retrofitted

We are using the 60 GW closure scenario for our updated earnings estimates which we think more reasonably captures the likely decision tree for operators. For the competitive generators we also ran this scenario on a mark-to-market (MTM) basis as well using current commodity price forwards. We are reluctant to use value the MTM scenario because we think changing market conditions will ultimately support somewhat different price outcomes.

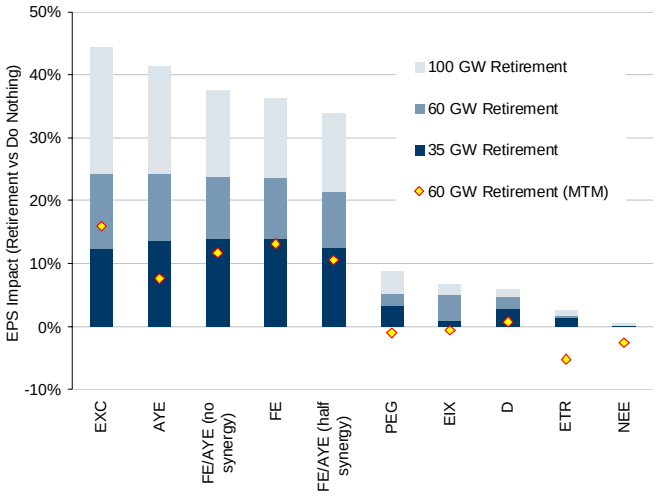
**Earnings estimate implications**

The most significant mantra to take from this EPA analysis is to own cleaner generators in dirtier markets, which we see as those with nuclear, CCGTs, and remediated coal plants in markets where coal is more commonly on the margin and in turn vulnerable to closure. From our earnings estimate runs, we see the biggest EPS benefits coming at FE-AYE, EXC, and RRI while the most indifferent stocks to EPA policy include NEE, ETR, and PEG as shown in Exhibit 16 and Exhibit 17.

Own "cleaner" generators in "dirties" markets

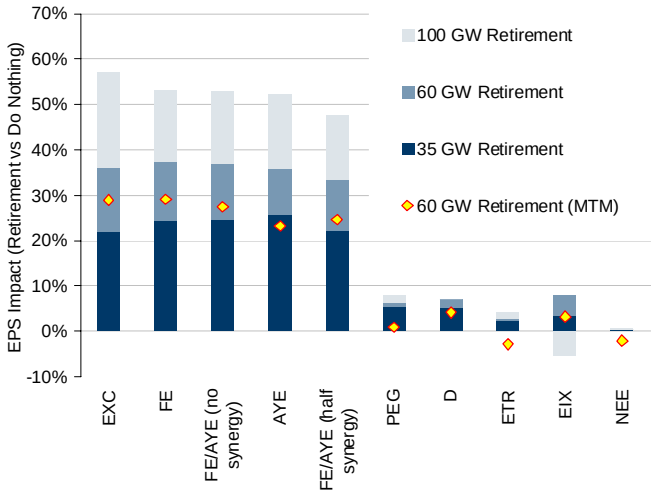
In Appendix III we show the earnings and share price implications for the different scenarios in the future.

**Exhibit 16: 2014 EPS Impact from Coal Plant Retirements**




*Source: Company data, Credit Suisse estimates*

**Exhibit 17: 2015 EPS Impact from Coal Plant Retirements**

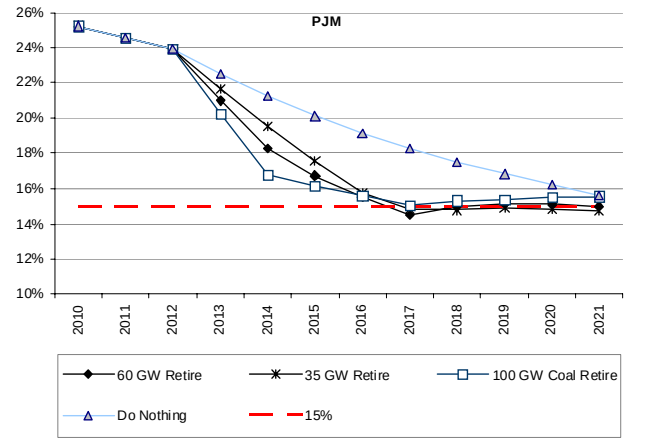



*Source: Company data, Credit Suisse estimates*

We should point out that EPA policy is in many ways just an acceleration in tightening power markets that we would have expected to occur over time (Exhibit 18 and Exhibit 19); the upside for the stocks is that the tangibility of closures and nearness in time to see benefit in earnings estimates will help investors, in our opinion, become more willing to pay for the recovery story in the deregulated power markets rather than obsessing over troughing earnings in 2012 and currently depressed commodity prices.

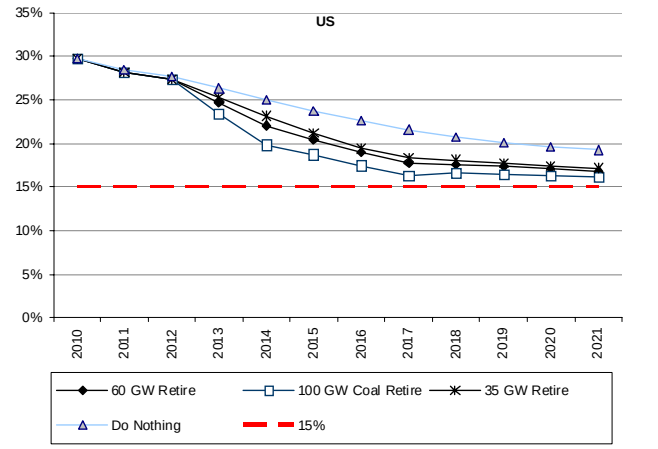
EPA rules simply accelerate an inevitable market tightening by 4- 5 years, making a recovery more investible

**Exhibit 18: PJM Reserve Margin**




*Source: Company data, Credit Suisse estimates*

**Exhibit 19: US Reserve Margin**




*Source: Company data, Credit Suisse estimates*

# Regulateds: Rate Base Growth Opportunity Ahead

***See page 57 for more***

We find it easy to get caught up in the excitement of tightening deregulated power markets and simply overlook the opportunity (and maybe threat for some) to come with the new EPA rules that will necessitate either environmental capex or newbuild construction to ensure system reliability.

EPA policy could boost utility EPS growth rate by 1 – 4%

In Exhibit 20 we show the MWs of capacity exposed to EPA rules for each of the Regulated Utilities, splitting to show all plants lacking environmental equipment and then narrowing to show the small plants that lack equipment and more at risk to requiring new plant construction.

We can then convert the potential investment into an earnings growth opportunity over the next five years in Exhibit 20, assuming $600 / KW for environmental capex on the over 300 MW units and $900 / KW for new CCGTs to replace the smaller coal plants, using an earned ROE of 9.5% and taking into account equity dilution to fund the construction cycle maintaining a generic 50% equity layer. We appreciate that not all closed MWs will need to be replaced since many utilities have reserve margin headroom today but we think the earnings impact is illustrative of where the trend will be headed.

Regulated utility winners could be GXP, OGE and DTE although fair regulatory treatment is vital for value accretion

Using these inputs we see a potential equity issuance adjusted bump in annual EPS growth rates by 1 – 4% for the group.

**Exhibit 20: Regulated Utilities MWs exposed to EPA policy and EPS Impact**

| | Generation Mix | | Implied Capital Expenditures | | | | EPS Impact | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Un-Scrubbed Plant (Not Inc. Planned Emission Ctrl) | | Replace Small Plant with CCGT $900/kW | Retrofit Big Plant $600/kW | Total Implied Capex | % Net PPE | Incremental Diluted EPS | 5-Year EPS CAGR | 7-Year EPS CAGR | Cumulative Earnings Growth |
| Ticker | Small (MW) | Large (MW) | $MM | $MM | $MM | (%) | $ / Share | % | % | % |
| ALE | 518 | 365 | 466 | 219 | 685 | 42% | 0.83 | 3.8% | 2.7% | 20.6% |
| GXP | 759 | 1,400 | 683 | 840 | 1,523 | 23% | 0.46 | 3.1% | 2.2% | 16.5% |
| LNT | 1,210 | 1,425 | 1,089 | 855 | 1,944 | 33% | 0.75 | 3.1% | 2.2% | 16.5% |
| OGE | - | 2,854 | - | 1,712 | 1,712 | 29% | 0.76 | 3.1% | 2.2% | 16.4% |
| AEE | 564 | 5,090 | 508 | 3,054 | 3,561 | 20% | 0.63 | 3.1% | 2.2% | 16.3% |
| DTE | 1,661 | 3,391 | 1,495 | 2,034 | 3,530 | 28% | 0.91 | 3.0% | 2.1% | 15.9% |
| AEP | 4,402 | 6,632 | 3,962 | 3,979 | 7,941 | 23% | 0.72 | 2.7% | 2.0% | 14.5% |
| XEL | 805 | 4,117 | 724 | 2,470 | 3,194 | 17% | 0.32 | 2.7% | 1.9% | 14.1% |
| SO | 5,259 | 4,970 | 4,733 | 2,982 | 7,715 | 20% | 0.43 | 2.7% | 1.9% | 14.1% |
| WEC | 1,715 | 419 | 1,543 | 251 | 1,794 | 20% | 0.70 | 2.6% | 1.9% | 13.9% |
| CMS | 1,236 | 404 | 1,112 | 242 | 1,355 | 14% | 0.25 | 2.6% | 1.8% | 13.5% |
| EON | 443 | 446 | 399 | 268 | 667 | 1% | 0.02 | 2.4% | 1.7% | 12.5% |
| SCG | 1,061 | - | 955 | - | 955 | 11% | 0.36 | 2.2% | 1.6% | 11.7% |
| NVE | 576 | - | 518 | - | 518 | 6% | 0.11 | 2.2% | 1.6% | 11.4% |
| DPL | 414 | 230 | 373 | 138 | 511 | 18% | 0.21 | 2.2% | 1.6% | 11.4% |
| POR | - | 391 | - | 234 | 234 | 6% | 0.15 | 2.1% | 1.5% | 11.0% |
| AYE | 532 | - | 479 | - | 479 | 5% | 0.14 | 2.1% | 1.5% | 10.9% |
| UNS | 173 | - | 156 | - | 156 | 6% | 0.19 | 2.0% | 1.4% | 10.5% |
| ETR | 2 | 2,352 | 2 | 1,411 | 1,413 | 6% | 0.37 | 2.0% | 1.4% | 10.3% |
| DUK | 2,657 | 560 | 2,391 | 336 | 2,727 | 7% | 0.10 | 2.0% | 1.4% | 10.3% |
| AES | 302 | - | 271 | - | 271 | 1% | 0.02 | 2.0% | 1.4% | 10.3% |
| PGN | 747 | 964 | 672 | 579 | 1,251 | 6% | 0.21 | 1.9% | 1.3% | 9.8% |
| TE | 326 | - | 294 | - | 294 | 5% | 0.07 | 1.9% | 1.3% | 9.8% |
| BKH | 125 | - | 112 | - | 112 | 5% | 0.14 | 1.9% | 1.3% | 9.7% |
| PNW | 312 | - | 281 | - | 281 | 3% | 0.13 | 1.8% | 1.2% | 9.1% |
| NEE | - | 952 | - | 571 | 571 | 2% | 0.07 | 1.7% | 1.2% | 8.9% |
| D | 367 | - | 330 | - | 330 | 1% | 0.03 | 1.5% | 1.1% | 7.6% |
| TVA | 5,634 | - | 5,071 | - | NA | NA | n/a | n/a | n/a | n/a |
| **Total** | **31,872** | **36,961** | **28,685** | **22,177** | **45,791** | **10%** | | **2.3%** | **1.6%** | **11.9%** |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

We see the biggest incremental EPS growth opportunity coming at GXP, AEE, and DTE although effectively managing the regulatory process in a way that allows for timely recovery of capex will be vital to converting this investment opportunity into shareholder value. We will need to focus on the environmental capex mechanisms on a jurisdictional basis as plans are crafted by utilities to address the EPA rules.

# Risks to Today's Investment Thesis

We appreciate that changes in estimates and industry outlook based on proposed and expected policy changes does engender some level of risk that the world does not play out exactly as we expect. Below we address some of the major issues that could still come up and work against the thesis.

**Congressional intervention with comprehensive pollutant rules**

Congress has taken up several attempts in the past to execute comprehensive energy legislation to broadly address airborne pollutants. Some believe that EPA's actions are simply to spur Federal action but it remains evident to us that Congress is nowhere near passing competing legislation. If we see Congress get involved, we think the effort will be more reactive to uproar from the coal producers and coal generators although this feels unlikely until the rules are effective, at which point we think a healthy chunk of the stock investment opportunity will be reflected in the stocks.

Separately, and not to be confused with today's SOX, NOX, and mercury conversation, the EPA has also started down the path toward regulating greenhouse gases / carbon (also commonly referred to as 'stationary sources'). Given today's low popularity for carbon rules we could see more Congressional intervention on this topic than the other airborne pollutant rules that have been on the books for years.

That said, a potential point of disruption could come from a new Congress putting limits on the EPA's budget that could impede implementation of the CATR and MACT rules although we will wait to see how much momentum this effort actually takes; our gut tells us budgetary defunding of programs will be targeted on other more highly politicized fronts.

**EPA extends timeline for enforcement which we already assume.**

We see some limits to the EPA's ability to delay rule implementation based on how the Clean Air Act was written and have doubts whether the administration will be in a rush to abandon another environmental lobby initiative. But, as we show in Exhibit 1, we do assume that compliance with the CATR and MACT rules will be extended beyond the legally set dates primarily for logistical and reliability reasons. And, as discussed on page 8, we also think that the dismal forward curves for commodities will provide adequate motivation for some to start closing plants earlier even if the EPA offers more timing headroom.

**Use of Lesser Remediation Methodologies to meet Standards.**

A few companies are pursuing cheaper remediation approach with a combination of PRB coal / baghouse / ACI / SNCR / TrONA (see page 28 for more). We can envision more uptake of this approach assuming early adopters are able to consistently demonstrate adequate pollutant removal rates but the capital costs are still not insignificant (albeit less than the scrubber / SCR / ACI approach) such that a large part of the fleet will still not be well suited for even making this investment in the current commodity price environment.

**Courts remand the rules, again**

We expect many lawsuits to be filed after the rules go effective (no lawsuits before) but the EPA appears to be within their legal bounds (and are actually legally obligated to take such action). We remain cautious of the litigation risk but are doubtful about injunctive relief to blockage the rules since: (a) we did not see last time with passage of CAIR (CATR's predecessor); and (b) enforcement of pollutant reduction was not the focus of last remand; the courts issues with the rules had much more to do with design and stringency than appropriateness.

**Natural Gas Price Recovery**

Many factors could lead to rapid natural gas price recovery, including: increased demand (see page 62 for more), natural disaster, decreased production, increased shale drilling regulations. We appreciate that all of these factors could swing the economics in such a way that reinvestment in the coal plants will trump plant closures, but in that environment we see the stocks working on a rise in power prices. Interestingly, the generators best levered to EPA policy are also the ones with the most earnings leverage to higher natural gas prices allowing the investments to win, even if for the wrong reasons.

**Game Changing Technology**

We believe recent heightened interest in energy efficiency, new generation methodology (like Bloom Box), evolving renewable resources, and innovative approaches to environmental remediation could all eventually significantly change power market dynamics as we view them today and the overall U.S. fleet composition. We are not aware of a game changing technology commercially at hand today, leading us to put a low probability that the thesis will not work because of some disruptive product introduction.

# Definitions Tear Sheet

**MW** (megawatt): a unit rate of energy conversion; 1 GW = 1000 MW; 1 MW = 1000 KW.

**Plant Heat Rate:** amount of fuel required to produce 1KWh of electrical output.

**Market Clearing Heat Rate**: marginal clearing energy price divided by natural gas price (ie Market Heat Rate = Marginal Power Price / Natural Gas)).

**Reserve Margin**: amount of unused available capacity of a power system.

## EMISSIONS OF CONCERN FROM COAL PLANTS

**Sulfur Dioxide (SOx)**: causes acid rain and atmospheric particulates

**Nitrogen Oxide (NOx)**: causes brown haze and atmospheric particulates

**Mercury (Hg)**: causes birth defects, central nervous and endocrine system damage

## EPA RULES

**CAIR (Clean Air Interstate Rule):** *Issued 3/10/2005*; the predecessor **SOx** and **NOx** rule to CATR that was remanded back to the EPA due to its interstate trading program that did not adequately protect 'down wind' states. CAIR is still the ruling law until CATR is finalized.

**CATR (Clean Air Transport Rule)**: *Proposed 7/6/2010 to be finalized 4/2011*; the to be successor of the remanded CAIR. CATR sets emission caps for **SOx** and **NOx** for 31 eastern states and DC and should satisfy the courts with its abandonment of intrastate trading (albeit fattened allowances for higher emitting states).

**CAMR (Clean Air Mercury Rule)**: *Issued 3/15/2005*; a cap and trade program to reduce mercury by 70% that was vacated by courts due to its adapted approach not meeting Maximum Achievable Control Technology (MACT) standards as required by law .

**MACT (Maximum Achievable Control Technology)**: A non-trading based standard that mandates targeted compliance equal to the top 12% of plants.

**HAP (Hazardous Air Pollutant) MACT**: *To be issued 3/2011 and finalized 11/2011*; a mercury aimed standard that is expected to require compliance levels set to no lower than the top 12% of plants, generally thought of as a ~ 90% removal level for Mercury.

## TECHNOLOGY REMEDIATION CHOICES

**Eastern Coal: FGD / SCR / Activated Carbon**:

- **FGD** (Flue Gas Desulfurization): a scrubber to remove **SOx** (>95% removal)**.**
- **SCR** (Selective Catalytic Reduction): separates **NOx** into water and nitrogen and is then absorbed by a catalyst bed (>90% removal).
- **Activated Carbon**: a sorbent that bonds to **mercury** and is collected by the FGD (>90%).

**Western Coal: Dry Sorbent Injection / SNCR / Baghouse / Activated Carbon:**

- **DSI** (Dry Sorbent Injection): injects a dry sorbent like TrONA that bonds to **SOx** (40-70% removal traditionally; now nearing on 90%).
- **SNCR** (Selective non-catalytic Reduction): separates **NOx** into water and nitrogen but lacks absorbent catalyst bed (30% at low temperatures to 75% at high temperatures).
- **Baghouse**: fabric filter to collect particulates, including **TrONA** and Activated Carbon (99% removal).
- **Activated Carbon**: a sorbent that bonds to **mercury** collected by the baghouse (>90%).

# Policy Is Coming

We appreciate EPA rules aimed at changing coal plant emissions, and in turn leading to mass closures, has been 'around the corner' for over a decade, leaving a natural level of skepticism. This time wont be any different. Our view is that the debate over the need for emission reductions or availability of viable remediation tools has been largely put to rest; the time for delays has come to an end plus the zeal in enforcement by the current Administration / EPA leadership should sustain forward progress on enforcement of rules written into law years ago. With court mandated deadlines for new rules quickly approaching, we think the industry and investors need to prepare and position for appreciably more stringent coal plant emissions rules for NOx, SOx, and Hazardous Air Pollutants (HAPs) that include mercury. Exhibit 21 shows the expected schedule for the new rules.

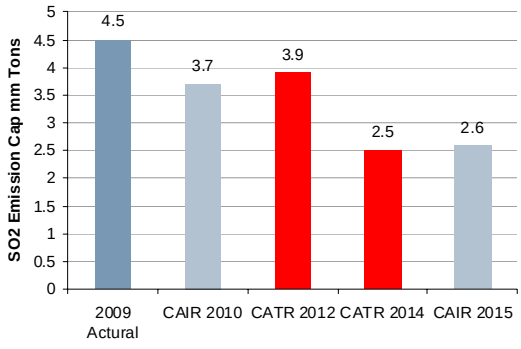
**Exhibit 21: EPA Calendar**

| Timeline | Draft Rule | Final Rule | Compliance Date (Est.) | Compliance Date (Est.) |
|---|---|---|---|---|
| CAIR (NOx) | Jul-10 | Apr-11 | 2012 / 2014 | 2 Years |
| CAIR (SOx) | Jul-10 | Apr-11 | 2012 / 2014 | 2 Years |
| Mercury MACT | 3/16/2011 | 11/16/2011 | 11/16/2014 | 2 Years |

*Source: Company data, Credit Suisse estimates*

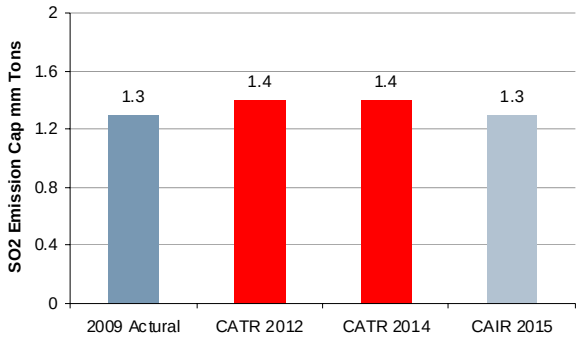
The EPA unveiled the Clean Air Transport Rule (CATR) on July 6, 2010, setting emission caps for SOx and NOx for 31 eastern states and DC. As shown in Exhibit 22 - Exhibit 23, the CATR rule imposes similar emission caps as Clean Air Interstate Rule (CAIR, which was challenged by environmentalists and remanded to EPA by the courts for re-write, hence the need for CATR) but with the target compliance date one year earlier (2014 vs 2015). We think compliance with the new rules will be a challenge for some but will ultimately not be the primary source of pain, in large part due to more readily available compliance alternatives as well as allowable trading of intrastate emission credits that could shield some plants.

**Exhibit 22: CATR vs CAIR for SOx Emission Cap (CATR states)**




*Source: Company data, Credit Suisse estimates, EPA*

**Exhibit 23: CATR vs CAIR for NOx Emission Cap (CATR states)**




*Source: Company data, Credit Suisse estimates, EPA*

The key piece of regulation in our opinion will be for Hazardous Air Pollutants, in particular mercury. The EPA is required by the courts to release a 'draft rule' on or before March 16, 2011, with a final rule expected by November 16th that sets into motion a three-year grace period to become compliant - although slippage could always happen which we assume will give a two year extension for those moving forward on good faith basis. The coming EPA mercury regulation will be a national standard and will apply to each plant individually without a trading mechanism.

More importantly, as required by the Clean Air Act for Hazardous Air Pollutant, the mercury regulation will be MACT (Maximum Achievable Control Technology) based, requiring plant emission levels to be no higher than the average of the best 12% of the fleet, or a ~90% removal rate for mercury. The definition of "the fleet" is where we could see flexibility for the mercury rule as there could be multiple MACT standards for coal plants burning different types of coal or with different boiler technologies, which presumably could lower the reduction requirements for some coal plants but raise requirements for others.

**How to lower emissions**

The electric utility industry has been working diligently on SOx / NOx reduction since 2005 when CAIR took effect, albeit with less focus on mercury due to limited removal technologies and a longer dated compliance period relative to the original SOx / NOx rules. Nonetheless it looks to us the pending rules will be a significant turning point for the U.S. power markets which seems inevitable to be far reaching and penetrate both competitive and regulated markets.

As summarized in Exhibit 24, there are different emission control technologies for SOx / NOx with varying levels of capex / efficacy.

- We should point out that for plants burning eastern coal, scrubber (aka FGD, or Flue Gas Desulfurization unit) is the only solution for SOx reduction of more than 90%.
- In our opinion the MACT standard for mercury posts a bigger challenge for the US coal fleet, since 90+% mercury reduction has been traditionally considered possible only with a combination of scrubber, SCR, and activated carbon injection (ACI).
- Newly designed activated carbon in combination with baghouse, PRB coal, and TrONA (or other sodium bicarbonate alternatives) can achieve up to 90% mercury reduction, which arguably could be viable alternative solution to achieve MACT compliance (hot topic under debate today).

**Exhibit 24: Emission Control Technologies**

| | CATR | | | | Mercury MACT | |
|---|---|---|---|---|---|---|
| | Sulfur Oxide (SOx) | | Nitrogen Oxide (NOx) | | Mercury (Hg) | |
| | Scrubber | Dry Sorbent Injection | SCR | SNCR | Scrubber / SCR | Baghouse w/ ACI |
| Removal Rate | 95%+ | <70% | 70-95% | 30-75% | >90% | 80-90% |
| Capex | $300 - 500 / kW | $50 / kW | $200-300 / kW | $30 - 75 / kW | $450 - 700 / kW | $150 /KW |
| Reagent | Limestone | TrONA | Ammonia | Ammonia or urea | Activated Carbon | Activated Carbon |
| Reagent Cost | - | - | 0.47 | 0.47 | 0.94 | 0.94 |
| Parasitic Load | 3-5% | 0% | 0 | 0 | 3-5% | 0.50% |
| Coal Efficiency | Eastern / Western | Western | Eastern / Western | Eastern / Western | Eastern / Western | Eastern / Western(1) |

*(1) Brominated Activated Carbon for Western Coal*

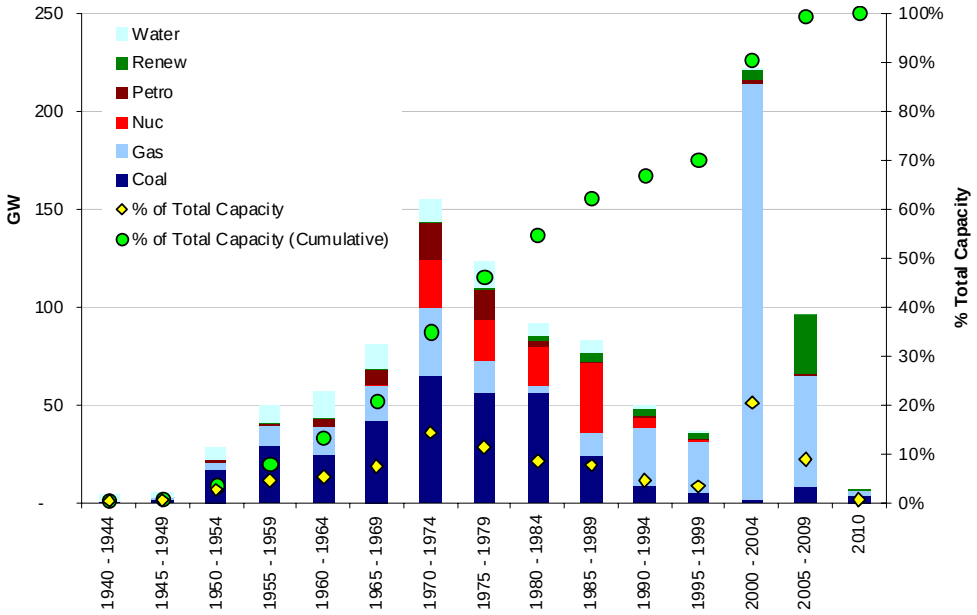
*Source: Company data, Credit Suisse estimates, EPA*

# The Coal Fleet Has Issues

The root of the EPA conversation is understanding the US generation fleet to appreciate what is at risk with coming rules. To help put the US coal generation fleet in context, Exhibit 25 shows mix of power plant capacity by vintage year and fuel type. Half of US generation capacity is more than 30 years old with coal plants being the oldest compared to nuclear or natural gas fired plants.

US generation fleet is old (half was built more than 30 years ago), with coal plants being the oldest

**Exhibit 25: US Power Plants by Vintage and Fuel Type**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

## Coal Plants: Old and Emitting

Exhibit 26 shows the coal fleet today by vintage year and mix of control technologies.

- **Emitting: A large portion of the US coal fleet (103 GW or more than 30% of coal capacity) has no emission controls** at all despite significant progress made since 2005 due to lengthy design and construction process of retrofitting, significant capex requirement and persistent uncertainty around the regulatory environment. We should note in this chart we are giving credit to pipeline emission controls (those under construction or even just being planned). If only counting equipment in place today, coal capacity lacking emission controls increases to 37% of the coal fleet (128 GW).

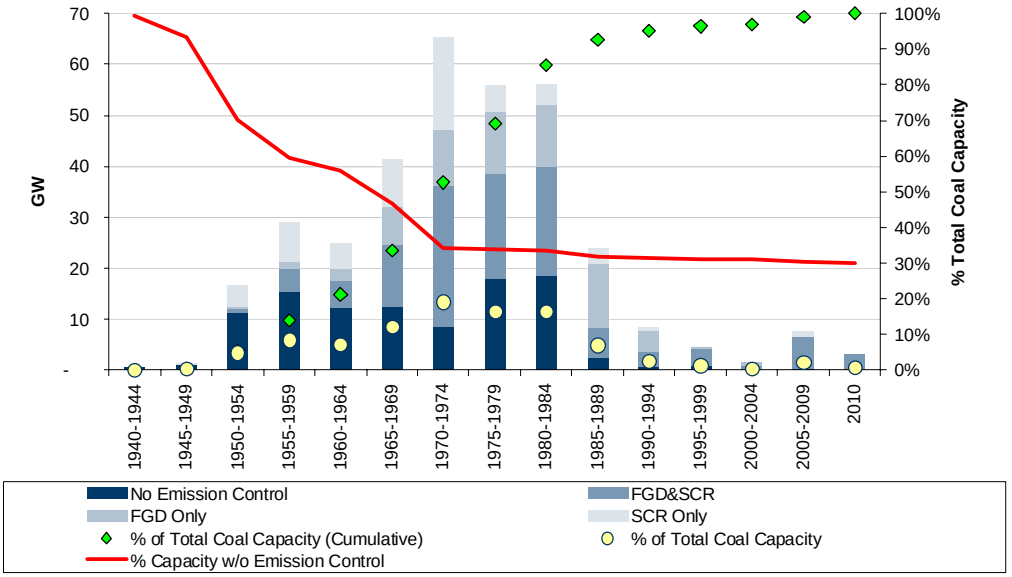
More than 30% (103 GW) of US Coal fleet has no emission control equipment installed.

- **On the bubble**: In addition to plants with no control equipments (103 GW or 30%), of the 340 GW US coal fleet 58 GW (17%) have a scrubber but not a SCR and 65 GW (19%) have a SCR but no scrubber. A number of these plants will also be exposed to reinvestment of closure decisions as well.

- **Old**: **70% of the US coal fleet is over 30 years old and 33% of the fleet is over 40 years old**, in our minds further challenging the decision around making the environmental equipment upgrades necessary to sustain the fleet. Since coal plants are depreciated over 40 years much of the fleet is today largely depreciated (some offset from ongoing capex), likely leaving regulated utilities more motivated to replace or upgrade since the assets are not likely contributing much to earnings since rate base values are low.

33% of the US coal fleet (114 GW) is over 40 years old, and fully depreciated

**Exhibit 26: Coal Plant Vintage (Including Planned Emission Control)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

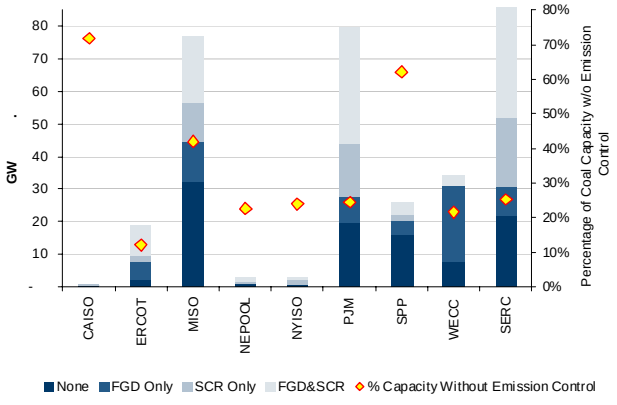
# Coal Fleet Breakdown by Market

In Exhibit 27 - Exhibit 30 we show breakdown of coal fleet capacity and generation by emission profile and region to identify markets with biggest need for equipment upgrades or plant closure.

MISO, SPP, PJM and SERC are the dirtiest power markets

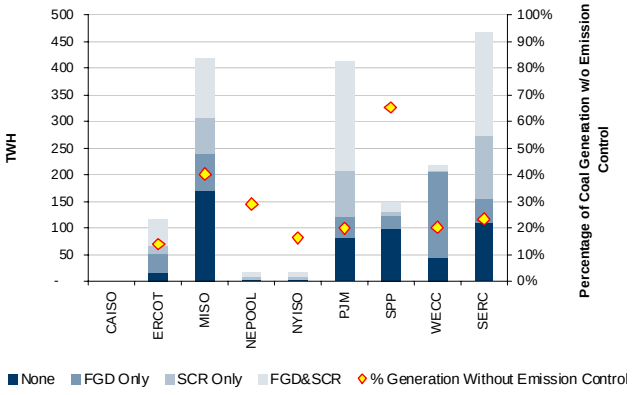
- **MISO has the biggest exposure to EPA policy** in absolute and relative terms with 32 GW lacking any controls and only 20 GW fully controlled. Potential to reshape this market with time seems high to us. PJM also has significant work ahead with 20 GW lacking any controls and 36 GW fully controlled.
- **MISO and SPP have the dirtiest relative coal fleets** with 42% and 62% capacity lacking environmental controls. More remarkably, only 27% and 40%, respectively, have bother scrubbers and SCRs in place.
- **MISO and SERC have the most coal plant capacity at risk** (32GW and 22 GW respectively), from a gross MW of capacity perspective,

**Exhibit 27: Coal Plant Capacity by Emission Control (Inc. Planned)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 28: Coal Plant Generation by Emission Control (Inc. Planned)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 29: Table: Coal Plant Capacity by Emission Control (Inc. Planned)**

| | FGD&SCR | FGD Only | SCR Only | None | Total |
|---|---|---|---|---|---|
| CAISO | - | 135 | 46 | 461 | 642 |
| | *0%* | *21%* | *7%* | *72%* | |
| ERCOT | 9,393 | 5,287 | 1,928 | 2,296 | 18,904 |
| | *50%* | *28%* | *10%* | *12%* | |
| MISO | 20,468 | 12,270 | 11,952 | 32,341 | 77,030 |
| | *27%* | *16%* | *16%* | *42%* | |
| NEPOOL | 1,343 | 214 | 666 | 652 | 2,875 |
| | *47%* | *7%* | *23%* | *23%* | |
| NYISO | 998 | 223 | 1,063 | 718 | 3,001 |
| | *33%* | *7%* | *35%* | *24%* | |
| PJM | 35,634 | 8,119 | 16,405 | 19,553 | 79,711 |
| | *45%* | *10%* | *21%* | *25%* | |
| SPP | 3,631 | 4,002 | 2,201 | 16,087 | 25,922 |
| | *14%* | *15%* | *8%* | *62%* | |
| WECC | 3,323 | 23,561 | 211 | 7,469 | 34,564 |
| | *10%* | *68%* | *1%* | *22%* | |
| SERC | 34,079 | 8,832 | 21,435 | 21,787 | 86,134 |
| | *40%* | *10%* | *25%* | *25%* | |
| Other | 5,940 | 2,331 | 2,318 | 1,448 | 12,037 |
| | *49%* | *19%* | *19%* | *12%* | |
| **Total** | **114,808** | **64,973** | **58,224** | **102,814** | **340,820** |
| | ***34%*** | ***19%*** | ***17%*** | ***30%*** | |

*Source: Company data, Credit Suisse estimates*

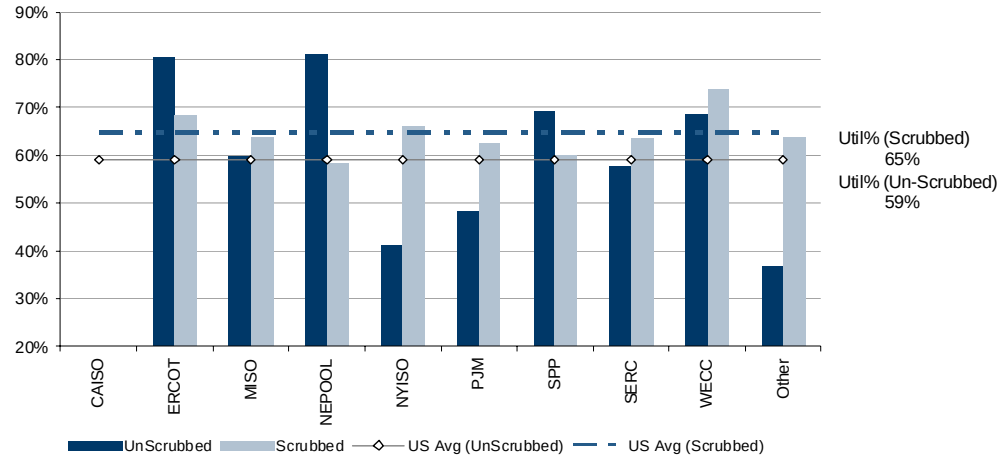
**Exhibit 30: Table: Coal Plant Generation by Emission Control (Inc. Planned)**

| TWH | FGD&SCR | FGD Only | SCR Only | None | Total |
|---|---|---|---|---|---|
| CAISO | - | - | - | - | - |
| | *0%* | *0%* | *0%* | *0%* | |
| ERCOT | 50 | 36 | 14 | 16 | 116 |
| | *43%* | *31%* | *12%* | *14%* | |
| MISO | 114 | 72 | 65 | 169 | 419 |
| | *27%* | *17%* | *15%* | *40%* | |
| NEPOOL | 9 | - | 3 | 5 | 16 |
| | *53%* | *0%* | *18%* | *29%* | |
| NYISO | 7 | 1 | 5 | 3 | 16 |
| | *43%* | *7%* | *34%* | *16%* | |
| PJM | 205 | 40 | 86 | 83 | 413 |
| | *50%* | *10%* | *21%* | *20%* | |
| SPP | 17 | 26 | 8 | 97 | 149 |
| | *12%* | *18%* | *5%* | *65%* | |
| WECC | 13 | 161 | 1 | 45 | 220 |
| | *6%* | *73%* | *1%* | *20%* | |
| SERC | 195 | 45 | 118 | 110 | 468 |
| | *42%* | *10%* | *25%* | *23%* | |
| Other | 30 | 15 | 14 | 5 | 64 |
| | *47%* | *23%* | *22%* | *7%* | |
| **Total** | **639** | **396** | **314** | **532** | **1,881** |
| | ***34%*** | ***21%*** | ***17%*** | ***28%*** | |

*Source: Company data, Credit Suisse estimates*

Contrary to conventional wisdom, generation output from un-scrubbed plants has been substantial with an observed 60% capacity factor, only about 5% lower than scrubbed plants (Exhibit 31).

**Exhibit 31: Capacity Factor of Scrubbed vs Un-Scrubbed Coal Plant (2008)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

# Focus On Small Coal Plants (Older and Dirtier)

Narrowing our coal fleet focus, the coal plants most likely vulnerable to potential closure will be smaller units where the comparable cost of reaching environmental compliance is higher (equipment costs are non-linear) and the plants are broadly older, making investment even harder to justify. Exhibit 32 shows the break down of the small coal plants – measured by units below 300 MW.

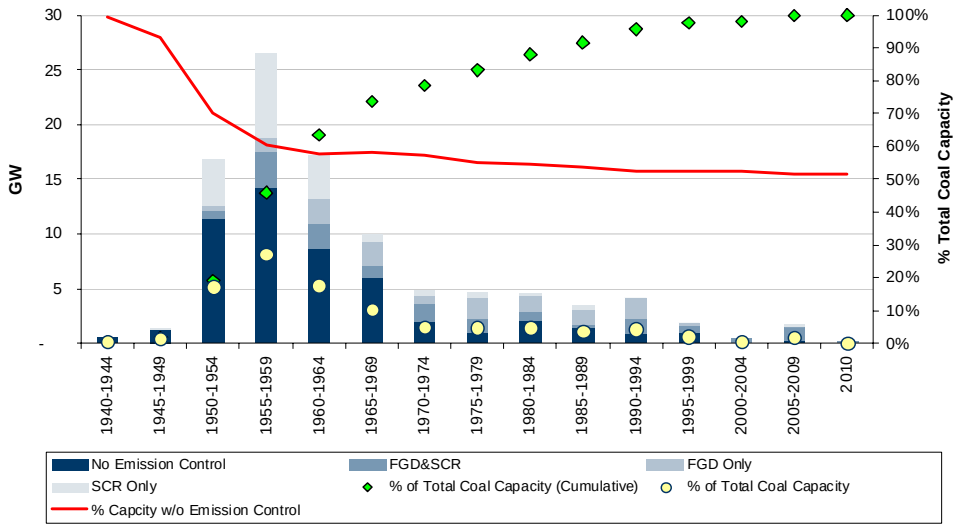
- More than 70% of small coal plants (72 GW) were built over 40 years ago and should be mostly depreciated (Exhibit 35);
- 50% lacking any control equipment (50 GW) versus 30% for all US coal plants; the number of plants lacking scrubber is 69 GW leaving even more exposure to mercury emission rules.
- Biggest exposure is in MISO, PJM, WECC, and SERC (Exhibit 35 - Exhibit 38)
- Utilization is 48% for small un-scrubbed coal plants, lower than US average but still considerable (Exhibit 39). The conventional wisdom that small plants don't run is not broadly accurate.

>70% of small coal plants are over 40 years old

50% of small coal plants have no emission controls

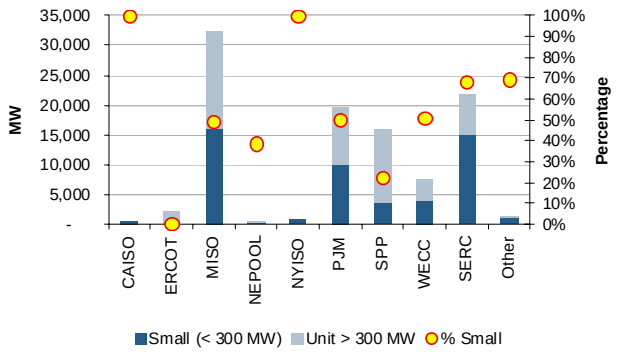
In Exhibit 35 - Exhibit 38, we show generation and capacity of small coal plants. Similar to what we saw with the larger coal units, the generation output at risk from the small plants reasonably follows installed capacity.

**Exhibit 32: Small Coal Plant Vintage (Including Planned Emission Control)**




*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 33: Small Un-Scrubbed vs Total Un-Scrubbed Plants**



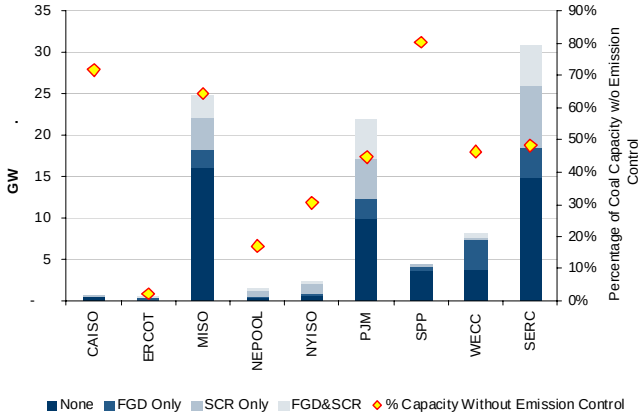

*Source: Company data, Credit Suisse estimates*

**Exhibit 34: Table: Small Un-Scrubbed Plants (MW)**

| | Small (< 300 MW) | Total | % Small |
|---|---|---|---|
| CAISO | 461 | 461 | 100% |
| ERCOT | 12 | 2,296 | 1% |
| MISO | 15,985 | 32,341 | 49% |
| NEPOOL | 252 | 652 | 39% |
| NYISO | 718 | 718 | 100% |
| PJM | 9,841 | 19,553 | 50% |
| SPP | 3,646 | 16,087 | 23% |
| WECC | 3,785 | 7,469 | 51% |
| SERC | 14,877 | 21,787 | 68% |
| Other | 1,008 | 1,448 | 70% |
| **Total** | **50,586** | **102,814** | **49%** |

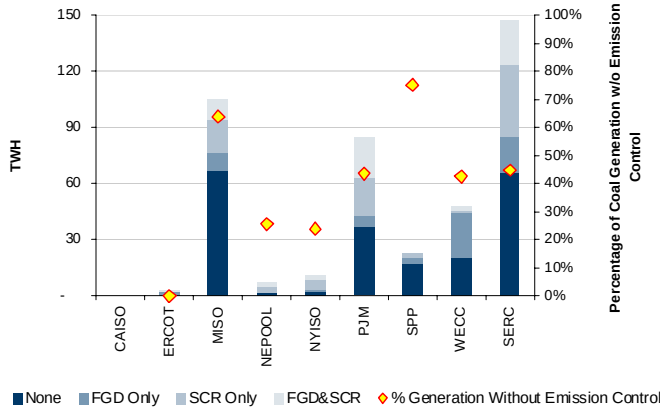
*Source: Company data, Credit Suisse estimates*

**Exhibit 35: Small Coal Plant Capacity by Emission Control**




*Source: Company data, Credit Suisse estimates*

**Exhibit 36: Small Coal Plant Generation by Emission Control**




*Source: Company data, Credit Suisse estimates*

**Exhibit 37: Table: Small Coal Plant Capacity by Emission Control (Inc. Planned)**

| | FGD&SCR | FGD Only | SCR Only | None | Total |
|---|---|---|---|---|---|
| CAISO | - | 135 | 46 | 461 | 642 |
| | *0%* | *21%* | *7%* | *72%* | |
| ERCOT | 184 | 349 | 8 | 12 | 553 |
| | *33%* | *63%* | *1%* | *2%* | |
| MISO | 2,756 | 2,289 | 3,774 | 15,985 | 24,803 |
| | *11%* | *9%* | *15%* | *64%* | |
| NEPOOL | 355 | 214 | 666 | 252 | 1,486 |
| | *24%* | *14%* | *45%* | *17%* | |
| NYISO | 343 | 223 | 1,063 | 718 | 2,346 |
| | *15%* | *9%* | *45%* | *31%* | |
| PJM | 4,940 | 2,375 | 4,865 | 9,841 | 22,021 |
| | *22%* | *11%* | *22%* | *45%* | |
| SPP | - | 569 | 318 | 3,646 | 4,533 |
| | *0%* | *13%* | *7%* | *80%* | |
| WECC | 554 | 3,605 | 211 | 3,785 | 8,154 |
| | *7%* | *44%* | *3%* | *46%* | |
| SERC | 4,819 | 3,700 | 7,484 | 14,877 | 30,880 |
| | *16%* | *12%* | *24%* | *48%* | |
| Other | 1,090 | 409 | 251 | 1,008 | 2,757 |
| | *40%* | *15%* | *9%* | *37%* | |
| **Total** | **15,039** | **13,866** | **18,684** | **50,586** | **98,175** |
| | ***15%*** | ***14%*** | ***19%*** | ***52%*** | |

*Source: Company data, Credit Suisse estimates*

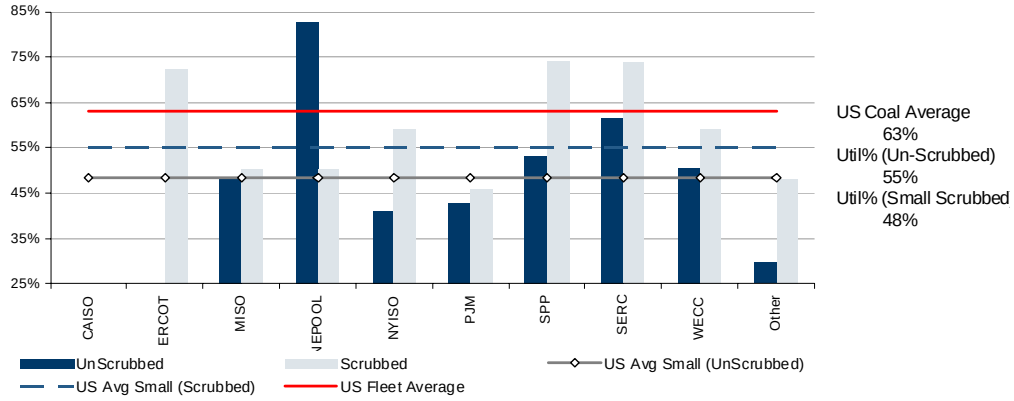
**Exhibit 38: Table: Small Coal Plant Generation by Emission Control (Inc. Planned)**

| TWH | FGD&SCR | FGD Only | SCR Only | None | Total |
|---|---|---|---|---|---|
| CAISO | - | - | - | - | - |
| | *0%* | *0%* | *0%* | *0%* | |
| ERCOT | 1 | 2 | - | - | 3 |
| | *25%* | *75%* | *0%* | *0%* | |
| MISO | 11 | 10 | 18 | 67 | 105 |
| | *10%* | *9%* | *17%* | *64%* | |
| NEPOOL | 2 | - | 3 | 2 | 7 |
| | *35%* | *0%* | *39%* | *26%* | |
| NYISO | 2 | 1 | 5 | 3 | 11 |
| | *16%* | *10%* | *50%* | *24%* | |
| PJM | 22 | 5 | 21 | 37 | 85 |
| | *25%* | *6%* | *25%* | *44%* | |
| SPP | - | 4 | 2 | 17 | 23 |
| | *0%* | *16%* | *9%* | *75%* | |
| WECC | 2 | 24 | 1 | 20 | 48 |
| | *5%* | *49%* | *3%* | *43%* | |
| SERC | 23 | 19 | 39 | 66 | 147 |
| | *16%* | *13%* | *26%* | *45%* | |
| Other | 4 | 2 | 1 | 3 | 10 |
| | *38%* | *22%* | *14%* | *27%* | |
| **Total** | **67** | **67** | **90** | **215** | **438** |
| | ***15%*** | ***15%*** | ***21%*** | ***49%*** | |

*Source: Company data, Credit Suisse estimates*

Remarkably, although these plants are small and old, they are significant contributors to our electricity needs: on average they are dispatched at 48%, only 15% lower than US average (63%)

**Exhibit 39: Capacity Factor of Small Plants (2008)**




*Source: Company data, Credit Suisse estimates*

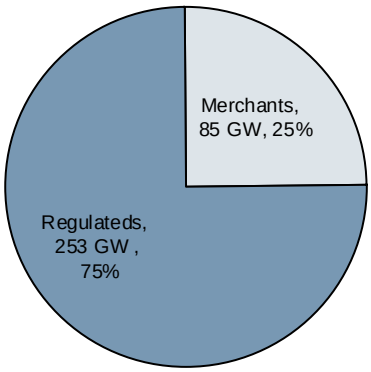
# Regulated vs Merchant

We also break down coal capacity in terms of its regulatory status:

Un-scrubbed coal plants are 75% regulated

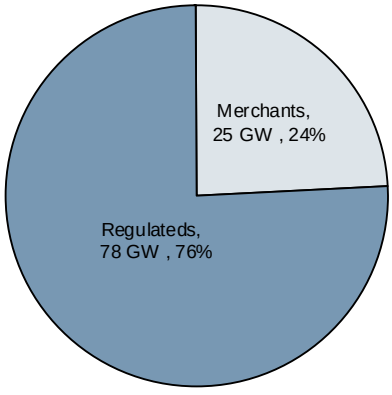
- 76% of all coal plants are regulated (Exhibit 40).
- About the same percentage (75%) of un-scrubbed coal plants are owned by regulated utilities (Exhibit 41) which shows utilities are not necessarily following a different strategy than their merchant counterparts despite the more transparent cost recovery mechanism.
- Merchant generation capacity lacking any environmental controls is most prevalent in PJM followed by MISO (Exhibit 42 - Exhibit 43).

**Exhibit 40: Coal Plants Regulateds vs Merchants**



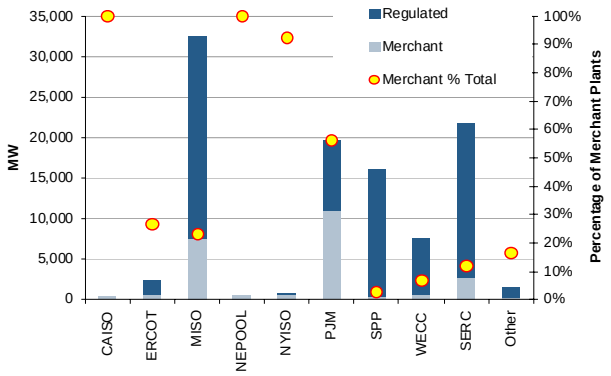

*Source: Company data, Credit Suisse estimates*

**Exhibit 41: Un-Scrubbed Coal Plants Regulateds vs Merchants**




*Source: Company data, Credit Suisse estimates*

**Exhibit 42: Coal Plants Without Emission Controls: Regulated vs Merchants Capacity**



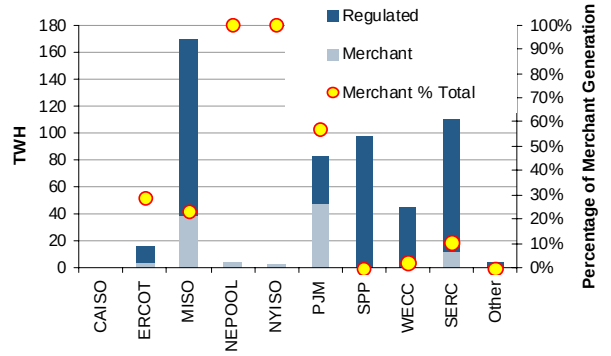

*Source: Company data, Credit Suisse estimates*

**Exhibit 43: Table: Coal Plants Without Emission Control: Regulated vs Merchants Capacity**

| Region | Regulated | Reg. % Total | Merchant | Merchant % Total | Total |
|---|---|---|---|---|---|
| CAISO | | *0%* | 461 | *100%* | 461 |
| ERCOT | 1,684 | *73%* | 612 | *27%* | 2,296 |
| MISO | 24,775 | *77%* | 7,566 | *23%* | 32,341 |
| NEPOOL | - | *0%* | 652 | *100%* | 652 |
| NYISO | 54 | *7%* | 664 | *93%* | 718 |
| PJM | 8,572 | *44%* | 10,981 | *56%* | 19,553 |
| SPP | 15,609 | *97%* | 479 | *3%* | 16,087 |
| WECC | 6,960 | *93%* | 509 | *7%* | 7,469 |
| SERC | 19,143 | *88%* | 2,644 | *12%* | 21,787 |
| Other | 1,209 | *83%* | 239 | *17%* | 1,448 |
| **Total** | **78,006** | ***76%*** | **24,808** | ***24%*** | **102,814** |

*Source: Company data, Credit Suisse estimates*

**Exhibit 44: Coal Plants Without Emission Controls: Regulated vs Merchants Generation**




*Source: Company data, Credit Suisse estimates*

**Exhibit 45: Table: Coal Plants Without Emission Control: Regulated vs Merchants Generation**

| Region | Regulated (TWH) | Reg. % Total | Merchant (TWH) | Merchant % Total | Total |
|---|---|---|---|---|---|
| CAISO | 0 | | 0 | | - |
| ERCOT | 12 | *71%* | 5 | *29%* | 16 |
| MISO | 130 | *77%* | 39 | *23%* | 169 |
| NEPOOL | - | *0%* | 5 | *100%* | 5 |
| NYISO | - | *0%* | 3 | *100%* | 3 |
| PJM | 35 | *43%* | 47 | *57%* | 83 |
| SPP | 97 | *100%* | - | *0%* | 97 |
| WECC | 44 | *98%* | 1 | *2%* | 45 |
| SERC | 98 | *90%* | 11 | *10%* | 110 |
| Other | 5 | *100%* | - | *0%* | 5 |
| **Total** | **421** | ***79%*** | **111** | ***21%*** | **532** |

*Source: Company data, Credit Suisse estimates*

# Emission Controls in the Pipeline

We should point out that the coal plant emission control data we have shown so far are "pro forma" to include FGDs and SCRs under construction and those with a firm installation date (Exhibit 46). In total, **33 GW of FGDs (scrubbers) and 19 GW of SCRs / SNCRs are already on the way**, reflecting the industry's effort to comply with the Clean Air Interstate Rule (to be replaced by Clean Air Transport Rule). Interestingly, most of the planned / under construction projects are for regulated power plants (81% of scrubbers ) while less (64% of SCRs) - we think reflecting the more cautious approach of merchants in a lower commodity price environment where policy uncertainty has frozen investment decisions.

33GW and 19 GW of FGD and SCR are to be installed, though the installation pace is much slower than that in 2007-09.

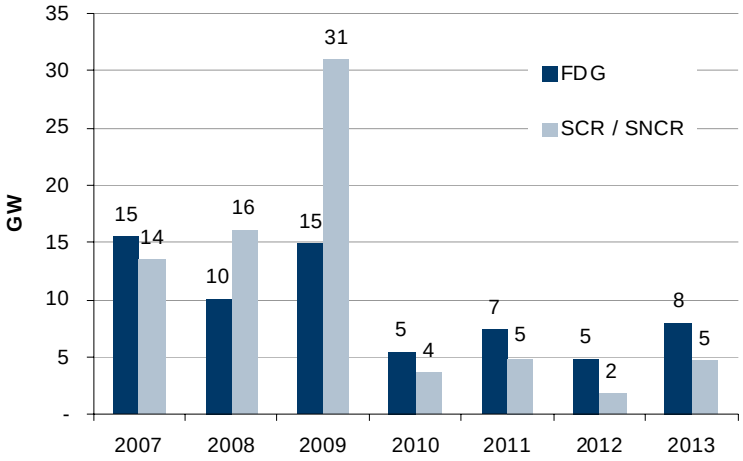
**Though still at a decent pace, construction activity is slowing compared to 2007 – 2009** (Exhibit 47), in our minds reflecting less low hanging fruit that is more economical to retrofit. The current level of activity also suggests that bandwidth remains in the system to increase activity once owners are in a better informed position to make investment decisions.

**Exhibit 46: Emission Control Planned / Under Construction (MW)**

| Year | All Plants | | Regulated Plants | | Merchant Plants | |
|---|---|---|---|---|---|---|
| | FGD | SCR / SNCR | FGD | SCR / SNCR | FGD | SCR / SNCR |
| 2010 | 5,393 | 3,657 | 3,003 | 356 | 2,389 | 3,301 |
| 2011 | 7,421 | 4,901 | 6,181 | 2,119 | 1,240 | 2,782 |
| 2012 | 4,839 | 1,802 | 3,716 | 1,802 | 1,123 | - |
| 2013 | 7,974 | 4,671 | 7,106 | 4,671 | 869 | - |
| 2014 | 3,309 | 411 | 2,575 | 411 | 734 | - |
| 2015+ | 4,023 | 3,197 | 4,023 | 2,600 | - | 597 |
| **Total** | **32,958** | **18,639** | **26,603** | **11,959** | **6,354** | **6,680** |

*Source: Company data, Credit Suisse estimates*

**Exhibit 47: Emission Control Construction Activity (In Service Year)**

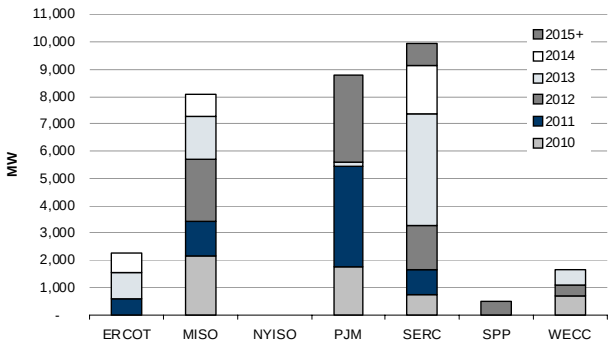



*Source: Company data, Credit Suisse estimates*

From a regional perspective (Exhibit 48 and Exhibit 49), planned emission controls are more concentrated in "dirtier regions" where there is higher generation capacity coming from un-scrubbed coal plants and will be under emission control limits by CATR (MISO and PJM). SERC also has significant FGD / SCRs planned, reflecting state policies to lower coal plant emission levels like the Clean Smokestacks bill passed by the North Carolina General Assembly.

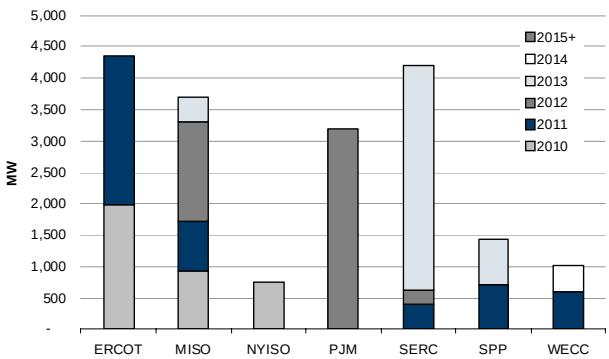
Most FGD / SCR installations are planned in MISO / PJM / SERC

**Exhibit 48: Planned FGD (Scrubbers) By Region**




*Source: Company data, Credit Suisse estimates*

**Exhibit 49: Planned SCR By Region**




*Source: Company data, Credit Suisse estimates*

# Compliance Technology Options / Alternatives

There are different types of emission control technologies for SOx, NOx and mercury, each with different efficacy, capex requirement and operating cost implications. We summarize the technologies in the table below (Exhibit 50) and discuss in detail starting in Appendix I, on page 64.

**Exhibit 50: Emission Control Technologies**

| | CATR | | | | Mercury MACT | |
|---|---|---|---|---|---|---|
| | Sulfur Oxide (SOx) | | Nitrogen Oxide (NOx) | | Mercury (Hg) | |
| | Scrubber | Dry Sorbent Injection | SCR | SNCR | Scrubber / SCR | Baghouse w/ ACI |
| Removal Rate | 95%+ | <70% | 70-95% | 30-75% | >90% | 80-90% |
| Capex | $300 - 500 / kW | $50 / kW | $200-300 / kW | $30 - 75 / kW | $450 - 700 / kW | $150 /KW |
| Reagent | Limestone | TrONA | Ammonia | Ammonia or urea | Activated Carbon | Activated Carbon |
| Reagent Cost | - | - | 0.47 | 0.47 | 0.94 | 0.94 |
| Parasitic Load | 3-5% | 0% | 0 | 0 | 3-5% | 0.50% |
| Coal Efficiency | Eastern / Western | Western | Eastern / Western | Eastern / Western | Eastern / Western | Eastern / Western(1) |

*(1) Brominated Activated Carbon for Western Coal*

*Source: Company data, Credit Suisse estimates*

As the EPA regulations are moving toward a more holistic emission requirement - by "holistic" we mean enforcement of reduction requirements for all three major pollutants - we look at combinations of technologies that meet the limits under both CATR for SOx / NOx and MACT for mercury. Interestingly, the type of coal burned will have an impact on remediation approaches and efficacy of these approaches:

Two Options to control all three pollutants: SOx, NOx and mercury

- **Eastern Coal: FGD / SCR / Activated Carbon (ACI)**: This is the most effective approach but also the most expensive with capex in the range of $450 – 700 / KW. Unfortunately this is the only effective solution to reduce SOx for plants burning bituminous (Eastern) coal without switching to PRB coal which often requires major boiler modification and significant capex investment. The upside is that high mercury removal rates are common with this equipment suite.

FGD / SCR is expensive in capex (~$450 – 700 / KW) but cheap in operating cost ($3 / MWh)

- **Western Coal: Dry Sorbent Injection / TrONA / SNCR / Baghouse / Activated Carbon**: This approach is the cheapest for pollutant reduction in terms of capex, but only works well for sub-bituminous (Western) coal which has low sulfur content. The Baghouse / ACI reportedly can reduce up to 90% mercury emission (to be compliance with MACT) at less than 1/3 of capex required for FGD / SCR combination, although experiments are still on-going on whether the high water mark of 90% mercury reduction is consistently achievable on a long run basis. We hear optimism from select generators and consultants although meaningful doubts might lead the 'risk adjusted' decision away from this option.

Baghouse / ACI / SNCR / TrONA is cheap in capex (~$150 / KW) but expensive in operating cost ($5+ / MWh), and less effective

Since it is generally cheaper to retrofit PRB burning plants, we analyze un-scrubbed coal plants by coal type. We found approximately 62 GW of un-scrubbed plants are burning PRB coal, representing 60% of un-scrubbed capacity, which is interesting since less than 40% of total US coal plants burn PRB coal. This means disproportional coal plants burning PRB could remain un-scrubbed, most likely due to (1) low sulfur contents in PRB coal, and (2) CAIR covered 28 states mostly in the east.

We should point out, however, that about 2/3 of small un-scrubbed plants burn Eastern coal which still leaves them with only the most expensive compliance alternative. Of those small plants burning PRB, most are in MISO where even a lower capital cost investment alternative might still not make economic sense given remarkably depressed prices in the region.

# Cost of Retrofit (Clean is Not Cheap)

We appreciate that our conversation about the coal fleet has provided a lot of numbers, but for some the most important numbers will be the capex required to meet EPA standards. Below we help put some numbers around the prospective investment obligations and impact to operating expenses; lower capex generally means more operating expenses.

## Substantial Capital Investment

Lots of capital needed for retrofit …

**Retrofitting a coal plant with FGD and SCR ($450 – 700 / KW) is not much cheaper than constructing a brand new CCGT ($750 – 1000 / KW) before taking into account uncertainties about eventual US carbon emission policy and outlook for coal prices relative to natural gas prices.**

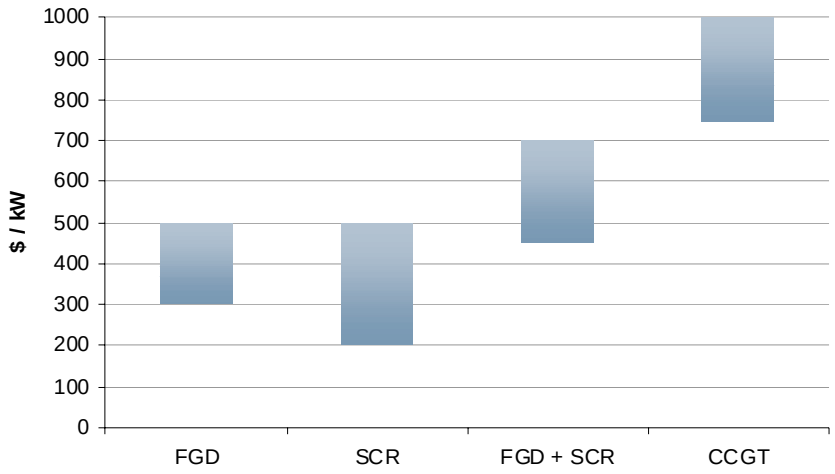
Capex for FGD ranges from $300 / KW to $500 / KW

- FGD costs range from more than $ 300 / KW for large plants with unit size over 500 MW to as high as $500 / KW for smaller unit due to economies of scale and higher difficulty in installation at more constrained locations. Putting this in context, a new CCGT costs about $750 - $1,000 / KW to construct (Exhibit 51).

Capex for SCR ranges from $150 / KW to $300 / KW

- SCRs are in the range of $150 – 300 / KW. SNCRs are cheaper (could cost as low as $13 MM per unit according to EIX), but do not reduce NOX as effectively as an SCR ( 0.15 lb / MMBtu NOx with SNCR vs 0.07 lb / MMBtu with SCR relative to CATR cap at 0.14 lb / MMBtu). Small plants with access to interstate NOx credits are likely users of SNCRs.
- With the most strict form of MACT, mercury reduction would most likely require retrofitting coal plants with both an FDG and SCR. Taken together with more nominal cost of activated carbon injection (ACI), the cost of mercury compliance could be $450 – 700 / KW for a un-scrubbed plant which is almost as expensive as building a new CCGT. If there were to be a separate MACT for sub-bituminous coal burning plants set at a lower than 90% standard, installation of a baghouse might be sufficient at $150 / kW although this would likely mean a higher level of compliance for Eastern (bituminous) coal burners that would make the investment decision harder for even larger coal plants.

**Exhibit 51: Capex Requirement**




*Source: Company data, Credit Suisse estimates*

In Exhibit 52 we show some recently completed retrofit projects and associated costs which largely jive with the numbers discussed above.

**Exhibit 52: Recent FGD / SCR Investment Capex**

| Company | Plant | Retrofit | Capacity (MW) | Total Capex | $/KW |
|---|---|---|---|---|---|
| AYE | Fort Martin | FGD | 1107 | 522.7 | $ 472 |
| | Hatfield | FGD | 1710 | 786.2 | $ 460 |
| FPL | Scherer 4 | SCR, FGD | 646 | 392.6 | $ 608 |
| | St Johns River Power 1 | SCR | 177 | 45 | $ 254 |
| | St Johns River Power 2 | SCR | 177 | 45 | $ 254 |
| TE | Big Bend | SCR | 1599 | 279 | $ 174 |
| PEG | Mercer | SCR | 648 | 129 | $ 199 |
| D | Brayton | SCR | 879 | 139 | $ 158 |

*Source: Company data, Credit Suisse estimates*

## Meaningful Increase in Operating Cost

Retrofitting is not only spendy on the investment capex side, but could also meaningfully increase operating costs. **Scrubbers and SCRs increase operating costs at a coal plant by $3 - 4 / MWh.** The increased O&M primarily comes from (1) cost of reagents including limestone, Urea and Activated Carbon; (2) 3-5% parasitic load which is for electricity consumed to run the environmental controls and (3) increased labor and material handling costs. **The Baghouse / TrONA alternative, while cheaper in terms of capex, could cost more than $5 / MWh.**

FGD & SCR increases operating cost by $2- 3/ MWh

We show our assumptions and calculation for each of the cost items mentioned above in Exhibit 53. We should point out our calculation only provides a point of reference with actual costs varying depending on different boiler technologies, location of the plants (transportation costs) and combination of emission control equipment installed.

TrONA and Activated Carbon could cost more than $5 / MWh

- **SOx Reduction**

**Limestone** is most often used sorbent in the FGD system for SOx capture in the flue gas. The ratio of limestone to SOx is 1.7:1 based on how they react with each other chemically.

Various reagents needed to reduce emission (we need a Chemistry refresher for this!)

For plants burning lower sulfur sub-bituminous coal (PRB), an alternative solution for SOx reduction is to use **Dry Sorbent Injection** with **TrONA** as reagent since it requires significantly lower upfront capex investment**,** decent efficacy (up to 70% removal which could get SOx emission levels to 0.24 lb / MMBtu for coal plants burning low sulfur PRB with 0.8 lb / MMBtu sulfur content, and 0.15 lb/ MMBtu if burning ultra compliance coal containing 0.5 lb / MMBtu SOx, such as those used by EIX's Midwest Gen fleet). As a reference to these reduction levels, CATR phase II SOx cap implies ~ 0.25 lb / MMBtu SOx emission. TrONA becomes less efficient and prohibitively expensive for bituminous coal with sulfur content higher than 2 lb / MMBtu. A major swing factor in this cost will be transportation since the sodium bicarbonate comes from the PRB region which involves high movement costs.

Limestone for SOx reduction

- **NOx: Ammonia / Urea**

Both SCR and SNCR use Ammonia as reagent although Urea also works in an SNCR.

Ammonia / Urea for NOx reduction

- **Mercury Reduction: Activated Carbon**

Activated Carbon is a form of carbon that has been processed to be extremely porous to have a very large surface area available for absorption. It can be used with Baghouses (primary function is to control Particulate Matter emission, for detail see page 64) or in conjunction with FGD for mercury removal. The cost of activated carbon almost doubles if

Activated Carbon for mercury reduction

it is used for PRB coal since to be effective for PRB coal, the activated carbon has to be treated with Halogen such as Chlorine or Bromine to be able to capture elemental mercury found in PRB coal.

**Exhibit 53: Reagents Cost / MWh**

| | Pollutant Removal | SO2 | | Mercury | | NOx | |
|---|---|---|---|---|---|---|---|
| | | Wet FGD | DSI | Sub-Bituminous | Bituminous | | |
| | Reagents | Limestone | TrONA | Brominated Activated Carbon | Activated Carbon | Ammonia | |
| (1) | Pollutant Content (lb / mmbtu) *(1)* | 2.5 | 0.8 | 0.001 | 0.001 | 0.45 | |
| (2) | Heat Content of Coal (btu / lb) | 12500 | 8800 | 12,500 | 8,800 | 12,500 | |
| (3) | Heat rate of Coal Plant (mmbtu / mwh) | 10 | 10 | 10 | 10 | 10 | |
| (4) | Reagent to Pollutant ratio (lb / lb) | 1.7 | 7 | 15,000 | 10,000 | 3.50 | |
| (5) | Reagent Cost ($/ton) | 20 | 125 | 4,000 | 2,000 | 60 | |
| | | | | | | | |
| (6) | Pollutant generated (lb / mwh) *(2)* | 25 | 8 | 0.01 | 0.01 | 4.50 | (1) x (3) |
| (7) | Reagent required (lb / mwh) | 42.5 | 56 | 0.47 | 0.3 | 15.75 | (4) x (6) |
| (8) | Reagent required (ton / mwh) | 0.02 | 0.03 | 0.0002 | 0.0002 | 0.01 | (7) / 2000 |
| (9) | **Reagent Cost ($/mwh)** | **0.43** | **3.50** | **0.94** | **0.30** | **0.47** | (8) x (5) |
| | *(1) gram / mmbtu for mercury* | | | | | | |
| | *(2) gram / mwh for mercury* | | | | | | |

*Source: Company data, Credit Suisse estimates*

## Parasitic Load

Scrubbers / SCRs / baghouses require electricity to run which takes away the plants ability to sell as much power while retaining all the cost. FGD / SCR reduces plant's net capacity by approximately 3 – 5%, which equates to $1.5 – 2.5 / MWH in lost energy / capacity revenue (Exhibit 54). Baghouse needs less power to run (less than 1% parasitic load) costing ~ $0.26 / MWH.

Last but not least – Halogen! Halogen is needed for mercury removal from PRB coal.

**Exhibit 54: Cost of Parasitic Load / MWH**

| | Parasitic Load | FDG / SCR | Baghouse | |
|---|---|---|---|---|
| (11) | Parasitic Load | 3% | 1% | |
| (12) | Plant Revenue ($ / MWH) | 48 | 48 | |
| (13) | Lost Energy Margin ($/ MWH) | 1.44 | 0.24 | (11) x (12) |
| (14) | Capacity Revenue ($ / MW-Day) | 50 | 50 | |
| (15) | Lost Capacity Revenue ($/ MWH) | 0.10 | 0.02 | (14)*(11)/24/0.65 |
| (16) | **Total Lost in Margin** | **1.54** | **0.26** | (15) + (13) |

*Source: Company data, Credit Suisse estimates*

## Put Everything Together

In addition to variable costs, there is also increased fixed cost for additional labor and material handling. We estimate $2 MM per year (based on incremental needs of 20 full time employees at $100,000 fully loaded cost per person). Adding everything together (Exhibit 55), we are seeing more than $3 / MWH in increase operating cost of FGD / SCR and $5 + / MWh for Baghouse / TrONA. We need to emphasize that the higher operating costs are incremental to the carrying cost of the equipment investment, further stressing the retrofit economics.

**Exhibit 55: Emission Control Operating Cost**

| Total Operating Cost | FGD / SCR | TrONA / Baghouse |
|---|---|---|
| Limestone Cost / MWh | 0.43 | - |
| TrONA Cost / MWh | | 3.50 |
| Activated Carbon / MWh | 0.30 | 0.94 |
| Ammonia / MWh | 0.47 | 0.47 |
| Parasitic Load Cost / MWh | 1.54 | 0.26 |
| **Total Variable Cost / MWh** | **2.73** | **5.17** |
| Fixed Cost for Labor and Material Handling ($MM) | 2.00 | 2.00 |
| Allocated Fixed Cost per MWh ($/MWh) | 0.70 | 0.70 |
| **Total Cost / MWh** | **$ 3.44** | **$ 5.87** |

*Source: Company data, Credit Suisse estimates*

# The Economics of Retrofit vs Newbuild

We have seen a number coal plant retirement announcements and attribute the increase to a combination of awful energy margin for the plants in a high coal price / low gas price environment with expected EPA rules acting as the final straw. The pace of announcements seem to have pick up after EPA issued CATR in early July this year. In August and September First Energy (FE), Tennessee Valley Authority (TVA), and Duke Energy (DUK) announced plans to mothball or retire more than 4000 MW of coal plants. The momentum seems to indicate companies are looking out to final remediation costs and deciding to close smaller plants while keeping larger plants alive for the time being.

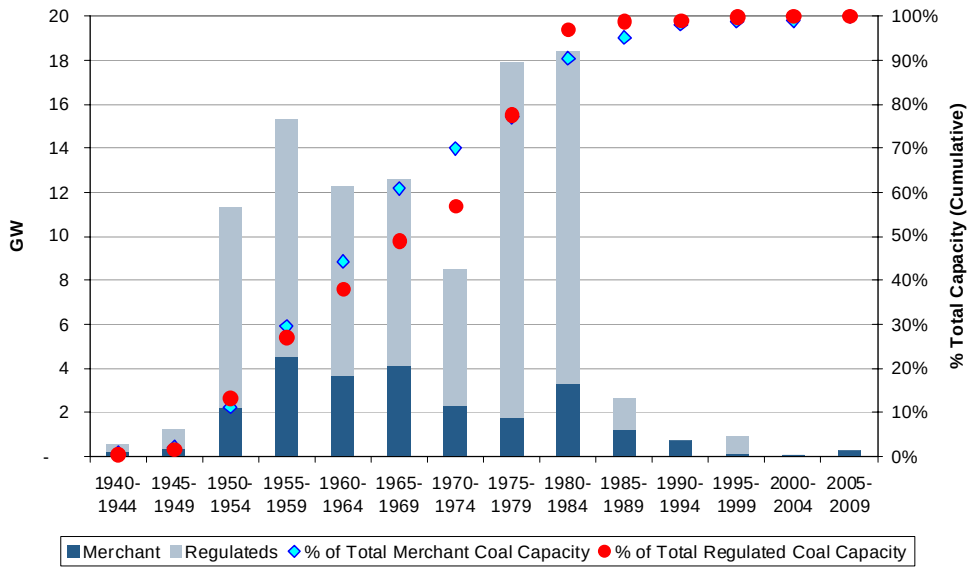
4000+ MW of coal plant mothballing / closures announced this summer

## More than 50 GW Coal Capacity Could Retire

Of the 103 GW of coal plants with no emission controls, more than 78% (or almost 80 GW) are over 30 years old (Exhibit 56) with about half (50 GW) less than 300 MW in size (Exhibit 59). Considering the magnitude of capacity exposed, we think 50+ GW of coal plants will face closure. When we tack on plants without scrubbers (58 GW), unique plant circumstances, and commodity forwards favoring natural gas as cheap to coal (Exhibit 57) we see room for even more capacity at risk.

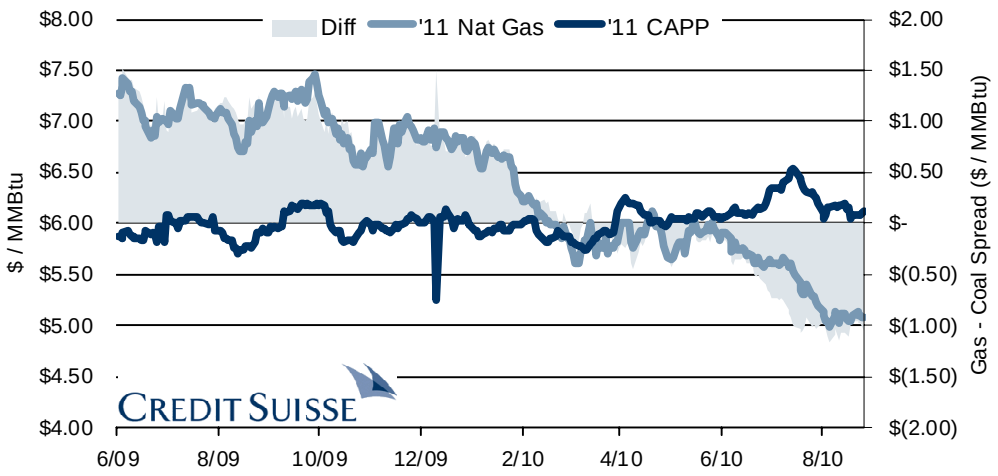
We see at least 50 GW of coal plants as prime candidates for closure

**Exhibit 56: Coal Plants Lacking Emission Controls Vintage**



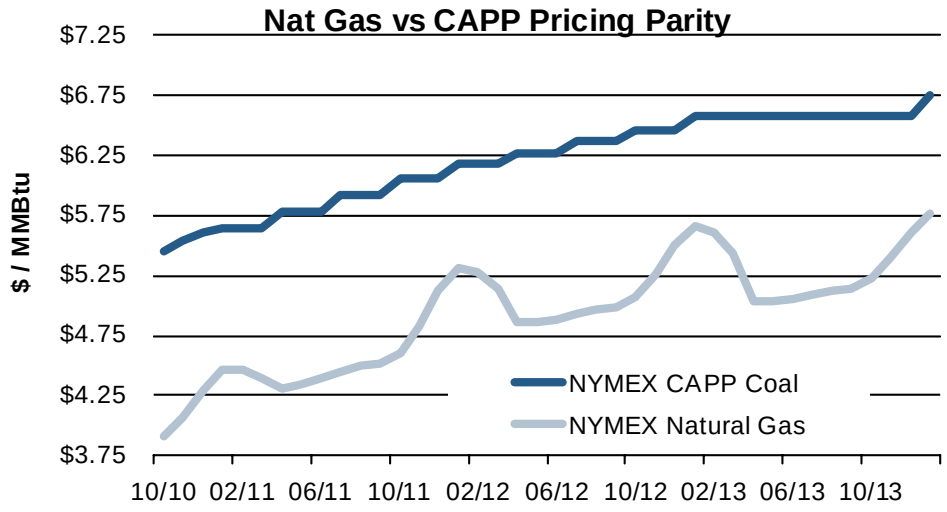

*Source: Company data, Credit Suisse estimates*

**Exhibit 57: 2011 CAPP Coal / NYMEX Natural Gas Parity**




*Source: Company data, Credit Suisse estimates*

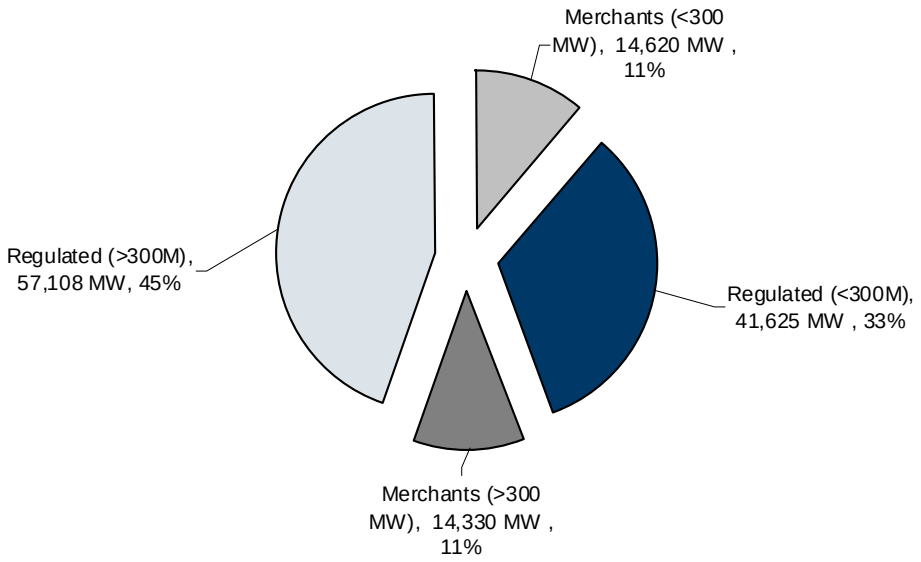
**Exhibit 58: 2010 - 13 CAPP Coal / Natural Gas Parity**




*Source: Company data, Credit Suisse estimates*

We have spent time in our report discussing at length the configuration of the US generation fleet and the plants likely most vulnerable to closure – those lacking major environmental controls and especially the subset of smaller plants. Exhibit 59 shows an easy to appreciate breakdown of the plants at risk as we see the fleet today after taking into consideration the pending and planned environmental equipment upgrades slated for the next 5 years.

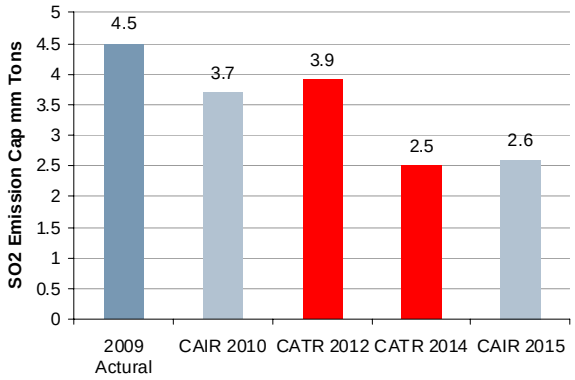
**Exhibit 59: Breakdown of Coal Plants with No Emission Controls**




*Source: Company data, Credit Suisse estimates*

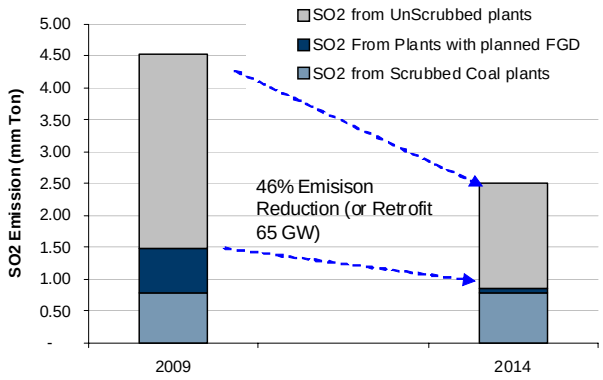
While we think mercury rules will be more transformative due to more demanding compliance standards, a look at just the already proposed SOx targets is helpful to appreciate what lies ahead. As shown in Exhibit 60: CATR rules require significant SOx emission reductions. With more than 67% of SOx emission in 2009 from plants with no FGD installed or planned, we estimate that to be in compliance with CATR's phase II SOX cap of 2.5 mm tons, emissions from plants with no FGD will need to be reduced by 46% (Exhibit 61) which would require 51% of these plants (65 GW in CATR states) to have FGD installed assuming 90% SOX reduction. The MW to be retrofitted will be lower if some coal plants are shutdown.

**Exhibit 60: CATR SOx Emission Cap**




*Source: Company data, Credit Suisse estimates, EPA*

**Exhibit 61: Implication of SOx Emissions Cap**




*Source: Company data, Credit Suisse estimates, EPA*

**Exhibit 62: Announced Coal Retirements**

| Announcement Date | Company | Total MW | | | | | |
|---|---|---|---|---|---|---|---|
| 8/18/2009 | PGN | 397 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | H.F. Lee | 397 | 2017 | 1951 | 1,582 | 713 | 45% |
| 12/1/2009 | PGN | 1088 | | | | | |
| | L.V. Sutton | 600 | 2017 | 1954 | 2,885 | 1,317 | 55% |
| | Cape Fear | 316 | 2017 | 1956 | 1,816 | 779 | 66% |
| | W.H. Weatherspoon | 172 | 2017 | 1949 | 735 | 360 | 49% |
| 9/1/2009 | DUK | 1841 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Buck 3,4 | 113 | 2011 | 1941 | 238 | 585 | 24% |
| | Cliffside 1-4 | 198 | 2011 | 1940 | 474 | 537 | 27% |
| | Dan River 1-3 | 276 | 2012 | 1949 | 1,030 | 467 | 43% |
| | Riverbend 8-11 | 64 | 2012 | 1955 | NA | NA | NA |
| | Buck 7-9 | 62 | 2012 | 1956 | NA | NA | NA |
| | Dan River 4-6 | 48 | 2012 | 1952 | NA | NA | NA |
| | Riverbend 4-7 | 454 | 2015 | 1952 | 1,953 | 861 | 49% |
| | Buck 5,6 | 256 | 2015 | 1953 | 1,066 | 516 | 48% |
| | Lee 1-3 | 370 | 2014 | 1952 | 1,583 | 712 | 49% |
| 9/4/2009 | AEP | 3470 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Philip Sporn 5 | 440 | 2010 | 1960 | 1,833 | 1,061 | 48% |
| | Conesville 3 | 165 | 2012 | 1962 | 797 | 834 | 55% |
| | Muskingum River 2, 4 | 395 | 2012 | 1956 | 2,284 | 1,411 | 66% |
| | Muskingum River 1, 3 | 395 | 2014 | 1955 | 2,473 | 1,411 | 71% |
| | Picway 5 | 90 | 2015 | 1955 | 329 | 173 | 42% |
| | Glen Lyn 6 | 235 | 2015 | 1944 | 1,108 | 592 | 54% |
| | Glen Lyn 5 | 90 | 2015 | 1957 | 295 | 148 | 37% |
| | Kammer 1-3 | 600 | 2017 | 1958 | 3,115 | 1,403 | 59% |
| | Sporn 1-4 | 580 | 2018 | 1950 | 3,108 | 1,564 | 61% |
| | Tanners Creek 1-3 | 480 | 2019 | 1952 | 2,664 | 1,361 | 63% |
| 2/3/2010 | NRG | 334 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Indian River 1-3 | 334 | 2011 | 1957 | 1,119 | 888 | 38% |
| 12/2/2009 | EXC | 746 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Cromby | 147 | 2011 | 1954 | 599 | 228 | 47% |
| | Eddystone 1-2 | 599 | 2012 | 1960 | 1,859 | 873 | 35% |
| 3/8/2010 | XEL | 1408 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Valmont | 186 | 2017 | 1964 | 1,185 | 491 | 73% |
| | Cherokee | 717 | 2022 | 1957 | 4,535 | 2,089 | 72% |
| | Pawnee | 505 | 2017 | 1981 | 3,527 | 1,787 | 80% |
| 8/12/2010 | FE | 1588 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | Bay Shore 2-4 | 499 | 2011 | 1959 | NA | 2,216 | NA |
| | Eastlake 1-4 | 577 | 2011 | 1953 | 3,594 | 3,964 | 71% |
| | Ashtabulsa | 256 | 2011 | 1958 | 1,192 | 718 | 53% |
| | Lake Shore | 256 | 2011 | 1962 | 1,162 | 718 | 52% |
| 8/19/2010 | BKH | 43 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | W.N Clark | 42.5 | 2010 | 1955 | MA | 156 | NA |
| 9/9/2010 | BKH | 35 | | | | | |
| | Osage Power Plant | 34.5 | 2010 | 1948 | NA | NA | NA |
| 8/24/2010 | TVA | 1161 | | | | | |
| | Unit Name | Capacity (MW) | Retirement Year | In Service Year | 2008 Generation (MWh) | 2008 Coal Burn ('000 tons) | 2008 Capacity Factor |
| | John Sevier 1,2 | 356 | 2015 | 1955 | 2,390 | 1,005 | 77% |
| | Widows Creek 1-6 | 678 | 2015 | 1953 | 3,660 | 2,198 | 62% |
| | Shawnee 10 | 127 | 2015 | 1955 | 865 | 467 | 78% |

*Source: Company data, Credit Suisse estimates*

# The Decision: Live or Let Die

Given the expensive and soon to be "mandatory" nature of emission controls, we think the question to ask for companies with uncontrolled coal plants will be if they are planning to retire / mothball or retrofit plants in the coming years. **Our analysis indicates the current commodity price environment does not support retrofit for either regulated or merchant coal plants**, although the retirement decision-making process is different for regulated or merchant coal plants and we show our thought process in Exhibit 63.

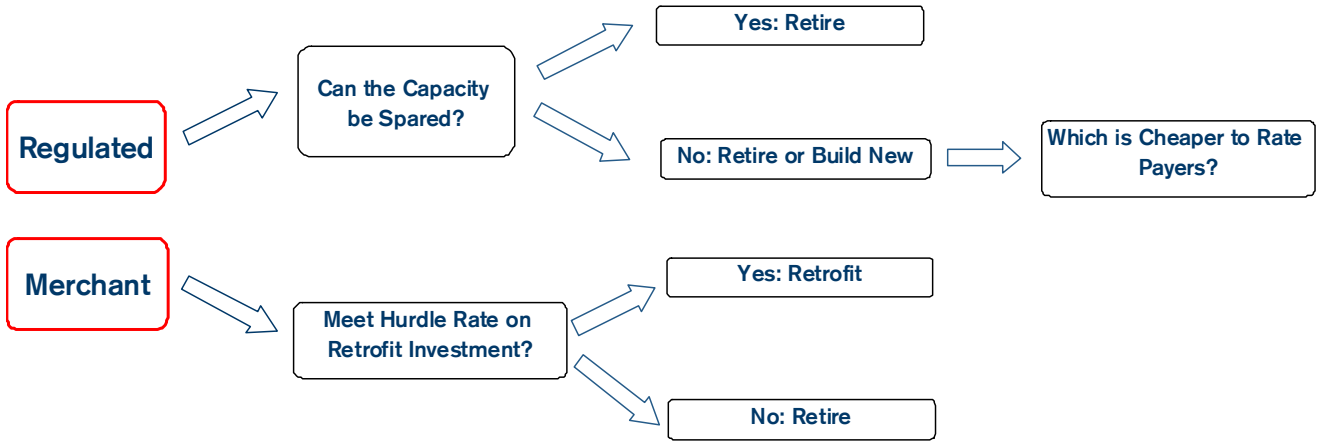
Retrofit decision making process could be different for merchant vs regulated coal plants …

As regulated utilities generally can pass through investment capex in customer rates if it is the cheaper alternative (especially if required by federal or state regulations), the decision for regulated coal plants is straight forward: companies should compare the impact on rates of retrofit versus building new generation. The other issue to consider will be reliability concerns although with a time cushion replacement generation is a viable alternative.

For merchant generators, retrofit investment should be no different than any other type of investment – namely, the investment has to be NPV positive and should meet a reasonable IRR or ROE hurdle rate. What makes this decision hard is the high level of uncertainty in the current power market: not only in terms of commodity prices that drive electricity but also the potential impact of legislation EPA policy that addresses carbon emissions. The other complication is that the retrofit / closure decision will not occur in a vacuum such that plants "on the bubble" for investment could be attractively economic as other plants are pulled from the market. In house power market forecasters will be busy.

… Our analysis indicates current commodity environment does not support retrofit for either regulated or merchant coal plants

**Exhibit 63: Plant Retirement / Retrofit Decision Tree**




*Source: Company data, Credit Suisse estimates*

### Merchant Coal Plants: To Invest or To Retire?

Whether the retrofit requires only installation of an FGD, an SCR or both, the initial capex investment will be sizable. To decide whether or not to retrofit, the companies need to form a view on:

For merchants, whether or not to retrofit will depend on return on investment

- Forward natural gas and power prices;
- Cost of coal and rail transport in the future; and

- Utilization factor of the coal plant taking into consideration the cost of generation, forward prices and retirement of other coal plants in the vicinity.

Return on investment depends on natural gas price, coal price and utilization factor of the plants

With countless hours devoted to better understanding market pricing dynamics, we must admit none of the factors mentioned above is easy to forecast. Consequently, we think mothballing or reducing plant runtime to seasonal dispatch will probably be the more popular choice near-term which essentially buys time before a final decision, in hopes that more clarity will emerge from the market. That said, Phase I of CATR is quickly approaching with commencement in 2012 and Phase II in 2014; considering that designing, permitting and building a scrubber can easily take four years, the luxury of waiting is not that bountiful today. We expect companies owning merchant coal plants to make up their mind after EPA publishes the draft rule on mercury on March 16th, 2011.

Based on current forward commodity prices (Exhibit 57) where coal generation is uneconomic out the curve relative to natural gas, we see a more compelling argument for retirement than retrofit. Somewhat to our surprise generators are not responding to observed commodity prices today, but this can best be explained by operators dispatch patterns which are based on existing power and coal price hedges which buoy economics above break-even (effectively they are giving up the positive NPV of the 'in the money' hedges).

We show required dark spreads to earn a 12% ROE on the retrofit investment assuming different levels of capex, remaining life and dispatch factor of the plant (Exhibit 64). Major takeaways from this exercise:

For merchants, we see more compelling argument for retiring than retrofit given current power market forwards

For retrofit, $25 / MWh or more dark spread is required for 12% ROE

- Assuming the coal plant's initial investment has been completely recovered, our analysis shows for scrubber / SCR to be economical (12% return on equity) at $600 / KW combined cost, **a dark spread of $25 / MWH is required for a coal plant with 20 year remaining life, +$50/MW-Day capacity prices and 70% utilization rate**. Current dark spread forwards for PJMW and MISO are in the teens (Exhibit 66 - Exhibit 69), which does not support the investment decision. Even for plants with a 40 year remaining life, the required dark spread is over $20 / MWH, which still makes the investment decision a tough choice.
- But if our math is right, retiring 60 GW un-scrubbed coal plants will add $5 -10 / MWH to power prices and at least that much to dark spreads (see page 47 for detail), which helps swing the decision to retrofit for newer and bigger coal plants.
- **78% of the 103 GW un-scrubbed coal plants are older than 30 years** (built before 1980) and 52% older than 40 years as shown in Exhibit 56, signaling to us more plants are likely to be retired rather than retrofitted.
- We use a capacity payment of $50 / MW-Day in our "economical dark spread" calculation, which admittedly could be higher if coal plants begin to retire en masse. **At $200 / MW-day, it "only" requires $19 / MWH dark spread for scrubber / SCR installation to be economical** (same assumption of $600 / KW cost and 20 year remaining life), which gets us closer to today's forwards.
- The capacity price assumption is an interesting variable; since not all merchants have the capacity payment we think the investment decision could prove more difficult in energy only markets since the visibility to earning a target return is more difficult.
- Useful life of the coal plant is also a relevant conservation to us since the time horizon is heavily dependent upon assumptions about New Source Review (NSR) enforcement as well as carbon rules; a 40-year life extension would largely make impossible the Administration's goal of an 80% reduction of US carbon emission by 2050.

**Exhibit 64: Dark Spread Required for 12% ROE (Eastern Coal)**

| Retrofit Capex $/KW | Remaining Life | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 5 | 10 | 15 | 20 | 25 | 30 | 35 | 40 |
| 300 | 26.5 | 21.4 | 19.7 | 18.9 | 18.4 | 18.1 | 17.8 | 17.6 |
| 400 | 31.9 | 25.2 | 23.0 | 21.8 | 21.2 | 20.7 | 20.4 | 20.2 |
| 500 | 37.4 | 29.0 | 26.2 | 24.8 | 23.9 | 23.4 | 23.0 | 22.7 |
| 600 | 42.8 | 32.8 | 29.4 | 27.7 | 26.7 | 26.0 | 25.6 | 25.2 |
| 700 | 48.3 | 36.5 | 32.6 | 30.7 | 29.5 | 28.7 | 28.1 | 27.7 |
| 800 | 53.8 | 40.3 | 35.8 | 33.6 | 32.3 | 31.4 | 30.7 | 30.2 |

| Retrofit Capex $/KW | Capacity Payment ($ / MW- Day) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 25 | 50 | 75 | 100 | 125 | 150 | 175 | 200 |
| 300.0 | 20.4 | 18.9 | 17.4 | 16.0 | 14.5 | 13.1 | 11.6 | 10.2 |
| 400.0 | 23.3 | 21.8 | 20.4 | 18.9 | 17.5 | 16.0 | 14.6 | 13.1 |
| 500.0 | 26.2 | 24.8 | 23.3 | 21.9 | 20.4 | 19.0 | 17.5 | 16.0 |
| 600.0 | 29.2 | 27.7 | 26.3 | 24.8 | 23.3 | 21.9 | 20.4 | 19.0 |
| 700.0 | 32.1 | 30.7 | 29.2 | 27.7 | 26.3 | 24.8 | 23.4 | 21.9 |
| 800.0 | 35.1 | 33.6 | 32.1 | 30.7 | 29.2 | 27.8 | 26.3 | 24.9 |

*Source: Company data, Credit Suisse estimates*

For plants burning sub-bituminous (PRB) coal, we use $150 / KW for emission controls assuming alternative TrONA / ACI / baghouse solution is ultimately to be MACT compliant by EPA. We found the dark spreads required are lower but should note that many of these plants do not collect any, or at least significant, capacity payments which in turn still necessitates dark spreads closing in on $20/MWh.

For PRB burning plants, we still see $20 / MWh or more dark spread required for 12% ROE, given lack of capacity market

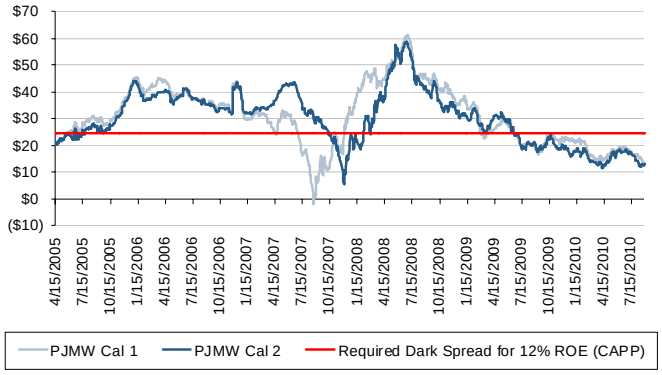
**Exhibit 65: Dark Spread Required for 12% ROE (Western Coal)**

| Retrofit Capex $/KW | Remaining Life | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 5 | 10 | 15 | 20 | 25 | 30 | 35 | 40 |
| 150 | 23.0 | 20.5 | 19.7 | 19.3 | 19.1 | 18.9 | 18.8 | 18.7 |
| 250 | 28.3 | 24.2 | 22.9 | 22.2 | 21.8 | 21.5 | 21.3 | 21.2 |
| 350 | 33.7 | 27.9 | 26.0 | 25.1 | 24.5 | 24.1 | 23.8 | 23.6 |
| 450 | 39.0 | 31.6 | 29.2 | 27.9 | 27.2 | 26.7 | 26.3 | 26.1 |
| 550 | 44.4 | 35.3 | 32.3 | 30.8 | 29.9 | 29.3 | 28.9 | 28.5 |
| 650 | 49.7 | 39.0 | 35.4 | 33.7 | 32.6 | 31.9 | 31.4 | 31.0 |

| Retrofit Capex $/KW | Utilization | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 50% | 55% | 60% | 65% | 70% | 75% | 80% | 85% |
| 150 | 21.0 | 20.5 | 20.0 | 19.6 | 19.3 | 19.0 | 18.8 | 18.5 |
| 250 | 25.1 | 24.1 | 23.4 | 22.7 | 22.2 | 21.7 | 21.3 | 20.9 |
| 350 | 29.1 | 27.8 | 26.7 | 25.8 | 25.1 | 24.4 | 23.8 | 23.3 |
| 450 | 33.1 | 31.5 | 30.1 | 28.9 | 27.9 | 27.1 | 26.3 | 25.6 |
| 550 | 37.1 | 35.1 | 33.4 | 32.0 | 30.8 | 29.7 | 28.8 | 28.0 |
| 650 | 41.1 | 38.8 | 36.8 | 35.1 | 33.7 | 32.4 | 31.3 | 30.4 |

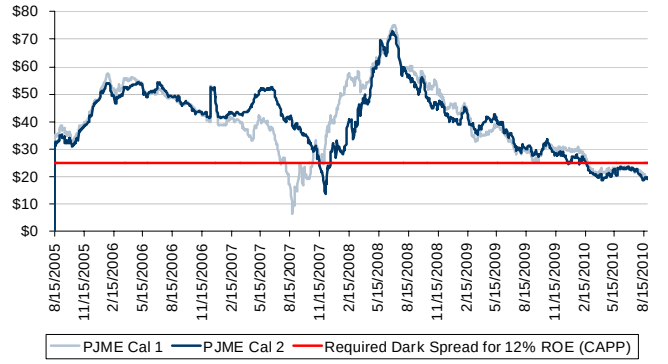
*Source: Company data, Credit Suisse estimates*

**Exhibit 66: PJMW Dark Spread**



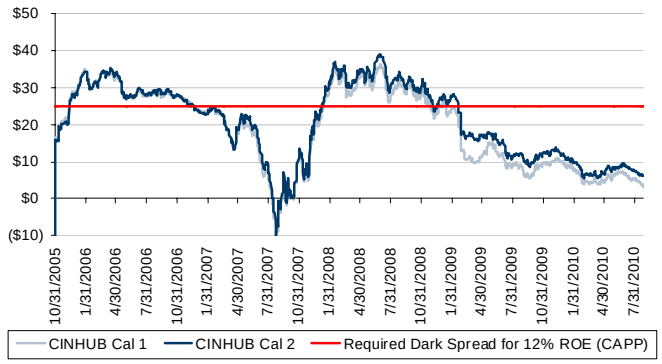

*Source: Company data, Credit Suisse estimates*

**Exhibit 67: PJME Dark Spread**



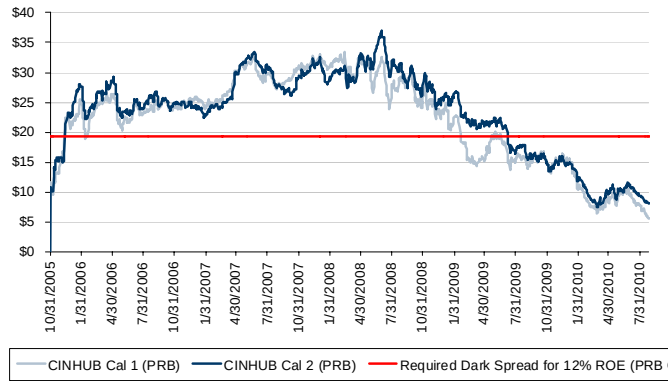

*Source: Company data, Credit Suisse estimates*

**Exhibit 68: MISO Dark Spread (CAPP)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 69: MISO Dark Spread (PRB Coal)**




*Source: Company data, Credit Suisse estimates*

**Regulated Coal Plants: Retrofit or Build New?**

Regulated utilities have a very different challenge when approaching the retrofit versus newbuild decision since the basic mandate of a utility is to provide reliable electric service at a reasonable cost. A simple upgrade or closing analysis for a merchant generator is not an adequate response for a regulated utility. Here management must take a more holistic approach to assessing the investment decision considering system integrity and reliability at a more demanding standard than de-regulated generators. The upshot for the utilities is, however, that most old coal plants are fully / mostly depreciated today so approved investments will be additive to earnings power.

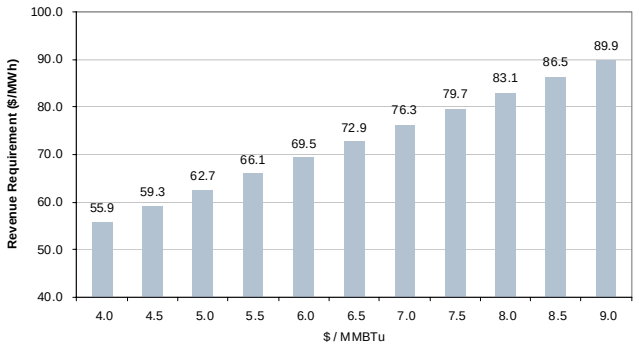
Regulated utilities need to assess grid integrity when making any retirement decision

To help frame the investment decisions we analyze the customer rate impact comparing retrofitting and construction of a brand new CCGT (calculation as shown in Exhibit 73). We use the best retrofit decision (combination of FGD / SCR) since full compliance will lessen future policy risk. In Exhibit 70 and Exhibit 71, we show energy equivalent price to earn a 12% ROE on the two investments; Exhibit 72 marries these two exhibits by showing the $ / MWh intersection point with changing fuel cost assumptions. **Our key observations:**

- .**If we assume the forward curve is correct** (below $6/ MMBTU for gas and above $80 / ton for CAPP coal**), revenue requirements for a new CCGT investment are clearly lower than retrofit.**
- **If long term gas price is $7 / MMBTU or above, retrofit would be the cheaper option.**
- We think the observed volatility in commodity prices in recent years will complicate this trade off significantly and lead many utilities to 'split the baby' by doing a mix of newbuild CCGT and coal plant retrofits.

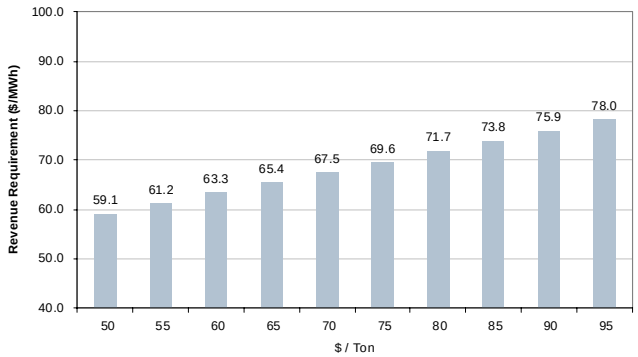
Current forwards clearly support building CCGT vs retrofit, although commodity price volatility in recent years and fuel diversification concerns may adds incentive to retrofit

**Exhibit 70: Revenue Requirement for CCGT ($/MWh)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 71: Revenue Requirement for Retrofit ($/MWh)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 72: Difference in Revenue Requirement ($/MWH) CCGT New Build vs Retrofit**

| | | Coal Price ($/ton) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 50 | 55 | 60 | 65 | 70 | 75 | 80 | 85 | 90 | 95 |
| Gas Price ($ / MMBtu) | 4.0 | (3.2) | (5.3) | (7.4) | (9.5) | (11.6) | (13.7) | (15.8) | (17.9) | (20.0) | (22.1) |
| | 4.5 | 0.2 | (1.9) | (4.0) | (6.1) | (8.2) | (10.3) | (12.4) | (14.5) | (16.6) | (18.7) |
| | 5.0 | 3.6 | 1.5 | (0.6) | (2.7) | (4.8) | (6.9) | (9.0) | (11.1) | (13.2) | (15.3) |
| | 5.5 | 7.0 | 4.9 | 2.8 | 0.7 | (1.4) | (3.5) | (5.6) | (7.7) | (9.8) | (11.9) |
| | 6.0 | 10.4 | 8.3 | 6.2 | 4.1 | 2.0 | (0.1) | (2.2) | (4.3) | (6.4) | (8.5) |
| | 6.5 | 13.8 | 11.7 | 9.6 | 7.5 | 5.4 | 3.3 | 1.2 | (0.9) | (3.0) | (5.1) |
| | 7.0 | 17.2 | 15.1 | 13.0 | 10.9 | 8.8 | 6.7 | 4.6 | 2.5 | 0.4 | (1.7) |
| | 7.5 | 20.6 | 18.5 | 16.4 | 14.3 | 12.2 | 10.1 | 8.0 | 5.9 | 3.8 | 1.7 |
| | 8.0 | 24.0 | 21.9 | 19.8 | 17.7 | 15.6 | 13.5 | 11.4 | 9.3 | 7.2 | 5.1 |
| | 8.5 | 27.4 | 25.3 | 23.2 | 21.1 | 19.0 | 16.9 | 14.8 | 12.7 | 10.6 | 8.5 |
| | 9.0 | 30.8 | 28.7 | 26.6 | 24.5 | 22.4 | 20.3 | 18.2 | 16.1 | 14.0 | 11.9 |

*Source: Company data, Credit Suisse estimates*

We show simple income statement for both a CCGT and a coal plant with retrofit to help illustrate our observations (Exhibit 73).

**Exhibit 73: Assumptions and Revenue Requirement Calculation**

| Assumptions (CCGT) | | Retrofit Assumptions | |
|---|---|---|---|
| Capacity (MW) | 500 | Capacity (MW) | 500 |
| Gas Price ($/MMBtu) | 6.50 | Gas Price ($/MMBtu) | 6.50 |
| | | Coal Price | 70.00 |
| | | Coal Transportation | 20.00 |
| | | Coal Price ($ / Ton) | 90.00 |
| Heat Rate | 6.80 | Heat Rate | 10.50 |
| Utilization | 65% | Utilization | 70% |
| | | Parasitic Load | 3% |
| Capital Cost ($/ KW) | 900 | Capital Cost ($/ KW) | 600 |
| Market Heat Rate | 8.5 | Market Heat Rate | 8.5 |
| O&M / MWh | 5.00 | O&M / MWh | 10.00 |
| | | Addt'l O&M / MWh (Retrofit) | 3.00 |
| Tax Rate | 35% | Tax Rate | 35% |
| Interest Rate | 6.5% | Interest Rate | 6.5% |
| Equity Capital Structure | 50% | Equity Capital Structure | 50% |
| Depreciable year | 40 | Depreciable year | 20 |
| **Capex ($MM)** | 450 | **Capex ($MM)** | 300 |
| Generation / Year (GWH) | 2,847 | Generation / Year (GWH) | 3,066 |

| Income Statement ($MM) | | | Income Statement ($MM) | | |
|---|---|---|---|---|---|
| + | Revenue | 207 | + | Revenue | 207 |
| - | Fuel Cost | 126 | - | Fuel Cost | 116 |
| | **Gross Margin** | **82** | | **Energy Gross Margin** | **91** |
| - | O&M | 14 | - | O&M | 39 |
| - | Depreciation | 11 | - | Depreciation | 15 |
| - | Interest Expense | 15 | - | Interest Expense | 10 |
| - | Income Tax | 15 | - | Income Tax | 10 |
| | **Net Income** | **27** | | **Net Income** | **18** |
| | Required ROE | 12.0% | | Required ROE | 12.0% |
| | Revenue Requirement $/MWh | 72.88 | | Revenue Requirement $/MWh | 67.51 |

*Source: Company data, Credit Suisse estimates*

### Retrofit / Replacement Capex for the Industry

**Our analysis indicates the current commodity price environment does not support retrofit for either regulated or merchant coal plant.** Absent a major shift in commodity price forwards, we think retirement is the right choice for most un-scrubbed coal plants. The uncertainty in carbon policy will also make the decision to retire more compelling. That said, factors that will change the pricing environment and move the needle towards retrofitting do exist.

To clean up all un-scrubbed coal plants, we estimate retrofit capex in the range of $38 -89 BN., while replace all with CCGT will cost $96 – 127 BN.

- **On the revenue side:** retirement of a portion of coal plants will tighten reserve margins and should improve both energy, and capacity payment (discussed in

detail on page 47). We see significant upside in energy and capacity prices in PJM specifically, if 60 GW of un-scrubbed coal plants were to retire nationally which helps make retrofitting the remaining un-scrubbed fleet a more economical choice. We think the key for the industry is to be rational – the paradigm shift in pricing will not happen if everyone waits for others to close down coal plants.

- **On the input side**: reduction in coal demand as a result of less generation from coal plants could significantly change the supply / demand dynamics of the coal market and dampen the rising coal cost.

To retrofit all of the 128 GW currently un-scrubbed coal plants, we estimate capex requirements of $38 - 89 BN. To replace all of them with CCGTs, total investment would be in the $96 – 127 BN range. Putting this number in context, we should note annual industry capex is approximately $85 BN / year.

In Exhibit 74 we show potential capex for the electric utility industry assuming 25%, 50%, 75% and 100% of coal plants with no emission control are retrofitted with both FGD and SCR and the rest replaced by CCGTs. In Exhibit 75, we focus on regulated plants only.

**Exhibit 74: Total investment sensitivity to retrofit (add FGD and SCR) coal fleet lacking emission controls**

| $ BN | % of Coal Plants with No Emission Control to be Scrubbed | | | | | |
|---|---|---|---|---|---|---|
| Blended Emission Control Cost | $/KW | 0% | 25% | 50% | 75% | 100% |
| | 300 | 115 | 96 | 77 | 57 | 38 |
| | 350 | 115 | 97 | 80 | 62 | 45 |
| | 400 | 115 | 99 | 83 | 67 | 51 |
| | 450 | 115 | 101 | 86 | 72 | 57 |
| | 500 | 115 | 102 | 89 | 77 | 64 |
| | 550 | 115 | 104 | 93 | 81 | 70 |
| | 600 | 115 | 105 | 96 | 86 | 77 |
| | 650 | 115 | 107 | 99 | 91 | 83 |
| | 700 | 115 | 109 | 102 | 96 | 89 |

*Source: Company data, Credit Suisse estimates*

**Exhibit 75: Total investment sensitivity to retrofit (add FGD and SCR) regulated Coal fleet lacking emission controls**

| $ BN | % of Coal Plants with No Emission Control to be Scrubbed | | | | | |
|---|---|---|---|---|---|---|
| Blended Emission Control Cost | $/KW | 0% | 25% | 50% | 75% | 100% |
| | 300 | 89 | 74 | 59 | 44 | 30 |
| | 350 | 89 | 75 | 62 | 48 | 35 |
| | 400 | 89 | 77 | 64 | 52 | 39 |
| | 450 | 89 | 78 | 67 | 56 | 44 |
| | 500 | 89 | 79 | 69 | 59 | 49 |
| | 550 | 89 | 80 | 72 | 63 | 54 |
| | 600 | 89 | 81 | 74 | 67 | 59 |
| | 650 | 89 | 83 | 77 | 70 | 64 |
| | 700 | 89 | 84 | 79 | 74 | 69 |

*Source: Company data, Credit Suisse estimates*

**FGD / Scrubber Exposure**

Obviously, if we were to expand our retrofit universe to reach full compliance at also the partially scrubbed plants (i.e. those with only FGD or only SCR) the capex requirement will be much higher. In Exhibit 76 and Exhibit 77, we show capex requirement of over $100 BN for the industry and in the range of $75 – 110 BN if focusing on the regulated coal fleet only.

**Exhibit 76: Total Investment Sensitivity to Add FGDs and SCRs on Coal Fleet Lacking one or both Emission Controls**

| $ BN | SCR | | | | |
|---|---|---|---|---|---|
| FGD | $/ KW | 75 | 150 | 225 | 300 |
| | 300 | 73 | 87 | 101 | 115 |
| | 350 | 83 | 97 | 111 | 124 |
| | 400 | 92 | 106 | 120 | 134 |
| | 450 | 102 | 116 | 130 | 144 |
| | 500 | 112 | 126 | 140 | 154 |
| | 550 | 122 | 136 | 150 | 164 |
| | 600 | 132 | 145 | 159 | 173 |
| | 650 | 141 | 155 | 169 | 183 |
| | 700 | 151 | 165 | 179 | 193 |

*Source: Company data, Credit Suisse estimates*

**Exhibit 77: Total Investment Sensitivity to Add FGDs and SCRs on Regulated Coal Fleet Lacking one or both Emission Controls**

| $ BN | SCR | | | | |
|---|---|---|---|---|---|
| FGD | $/ KW | 75 | 150 | 225 | 300 |
| | 300 | 54 | 65 | 75 | 86 |
| | 350 | 61 | 72 | 83 | 93 |
| | 400 | 68 | 79 | 90 | 100 |
| | 450 | 75 | 86 | 97 | 108 |
| | 500 | 83 | 93 | 104 | 115 |
| | 550 | 90 | 101 | 111 | 122 |
| | 600 | 97 | 108 | 118 | 129 |
| | 650 | 104 | 115 | 126 | 136 |
| | 700 | 111 | 122 | 133 | 144 |

*Source: Company data, Credit Suisse estimates*

# Impact on Power Market: Scenarios, Power Prices and Reserve Margins

The revenue impact for generators from large scale coal plant closures will be two fold: (1) energy prices should rise when un-scrubbed coal plants are removed leaving marginal price setters less efficient, and (2) increase in capacity payment as reserve margins tighten faster than otherwise expected. For the impact on the capacity prices, we focus on PJM since it is the only region with both a capacity market and a sizable un-scrubbed coal fleet.

## Scenario Summary

We examined five scenarios with variations in magnitude and timing of coal plant closure in order to assess potential power market implications.

Three coal retirement scenarios: 35 GW, 60 GW and 100 GW

- **(1) 60 GW Retirement**: Retire all small plants with no emission controls and half of those lacking scrubbers ratably within 5 years from 2013 to 2017, assuming EPA allows room to negotiate on timing for rule compliance. We think small units broadly will struggle to justify large capital investment leading to more closures than conventional wisdom although realistically some small units will survive while other bigger plants will not.

The 60 GW retirement scenario is our base case.

- **(2) 35 GW Retirement**: Retire half of small plants without scrubbers (~70 GW) ratably from 2013 to 2017. We see this scenario as leaving tremendous burden on plant retrofits that feels unrealistic with the current commodity price outlook.
- **(3) 100 GW Retirement**: a more extreme case where all 103 GW coal plants lacking any environmental controls are shut down ratably by 2017. We see this scenario more as indicative of an extreme possibility; realistically closure rate of this level would also pull from the 58 GW of plants lacking scrubbers and 65 GW of those lacking SCRs. We think commodity prices would likely reset enough before reaching this closure level to keep it from happening.
- **(4) MTM 60 GW retirement**: Same sets of coal plant closures as scenario (1), but instead of using Credit Suisse price deck for natural gas, we use current forwards for this scenario;
- **(5) Do nothing case** where EPA rules does not lead to any cola plant retirements.

We should note in our scenario (1), (2) and (4) we use a broader definition of plants at risk to include those with an SCR or an SNCR installed but no scrubbers given: **(a)** the crummy economics of these high heat rate plants, **(b)** their at risk nature of many as provided by companies so far, and **(c)** the high capex for scrubber installation due to high cost structure. For scenario (3) we dial back the at risk fleet to plants with no emission control technology in part to reflect the view that some bigger plants with SCRs will survive.

**Exhibit 78: Retirement and Newbuild Assumptions**

| Capacity (MW) | Retirement (2013-17) | | | Newbuild Projection (2013-17) | | |
|---|---|---|---|---|---|---|
| MW to Retire | 60 GW | 35 GW | 100 GW | 60 GW | 35 GW | 100 GW |
| PJM | 24,474 | 12,237 | 19,553 | 5,000 | 1,050 | 11,000 |
| ERCOT | 16 | 8 | 2,296 | 0 | 0 | 0 |
| ISO New England | 585 | 293 | 652 | 0 | 0 | 0 |
| ISO New York | 1,249 | 625 | 718 | 0 | 0 | 0 |
| MISO | 17,872 | 8,936 | 32,341 | 5,250 | 0 | 19,000 |
| SERC | 18,619 | 9,310 | 21,787 | 13,500 | 4,750 | 24,000 |
| SPP | 3,805 | 1,903 | 16,087 | 0 | 0 | 9,750 |
| **US** | **59,928** | **29,964** | **102,814** | **23,750** | **5,800** | **64,500** |

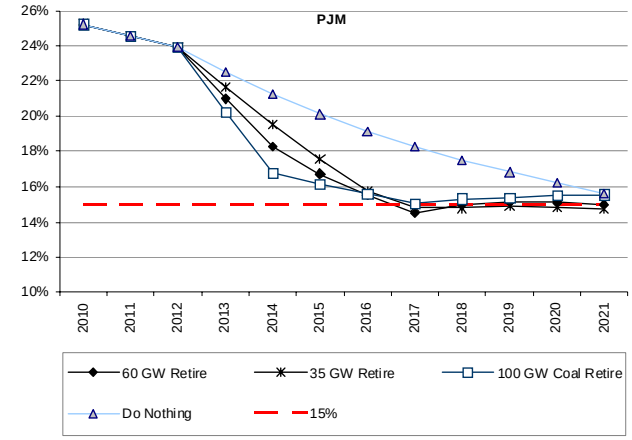
*Source: Company data, Credit Suisse estimates*

# Reserve Margin Implications – Regaining 4 Years

In Exhibit 79 - Exhibit 84 we show reserve margins using the four scenarios we discussed above. We should note that without coal plant retirement reserve margins for all markets are above 15% (the typical target level for ISOs) and remain so until late this decade. Coal plant retirements "reset" the supply stack of the power market and serves to remove excess capacity. In all retirement cases, the regional power markets with dirty coal exposure (notably MISO, SERC, SPP and PJM) will reach the desired 15% reserve margin 4 years or more earlier than "do nothing" and will need newbuild construction in order to maintain the reserve margin at 15%. Markets with little un-scrubbed coal plants such as NEPOOL, NYISO, ERCOT, and CAISO, however, will see limited impact.

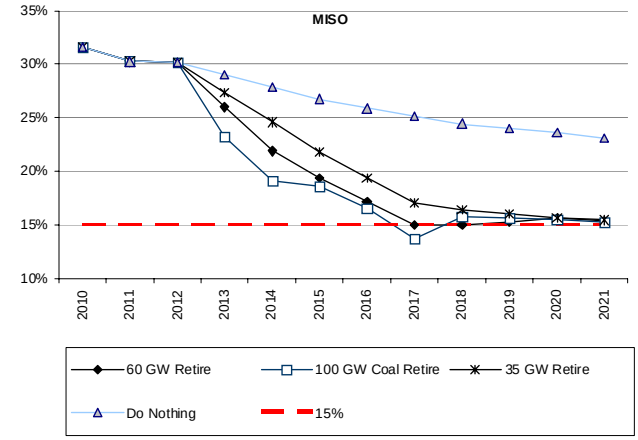
In PJM, MISO, and SERC, reserve margin will reach the 15% long run target 4 or more years earlier under our retirement scenarios than baseline

**Exhibit 79: PJM Reserve Margin**



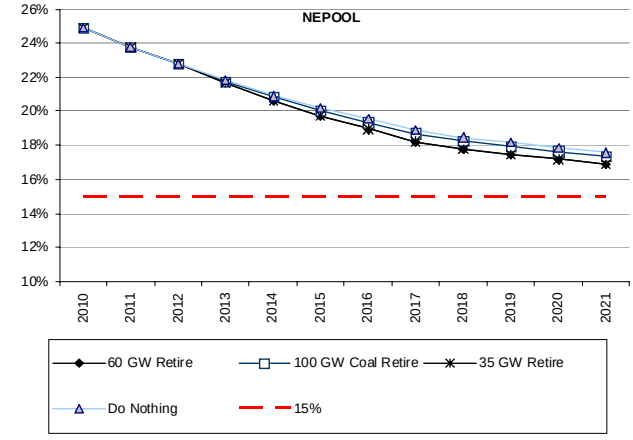

*Source: Company data, Credit Suisse estimates*

**Exhibit 80: MISO Reserve Margin**



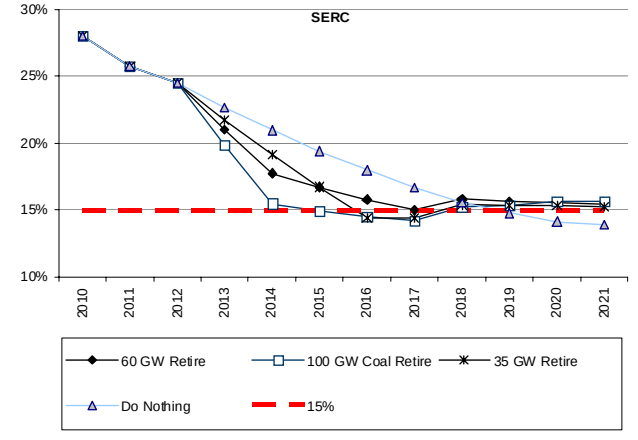

*Source: Company data, Credit Suisse estimates*

**Exhibit 81: NEPOOL Reserve Margin**



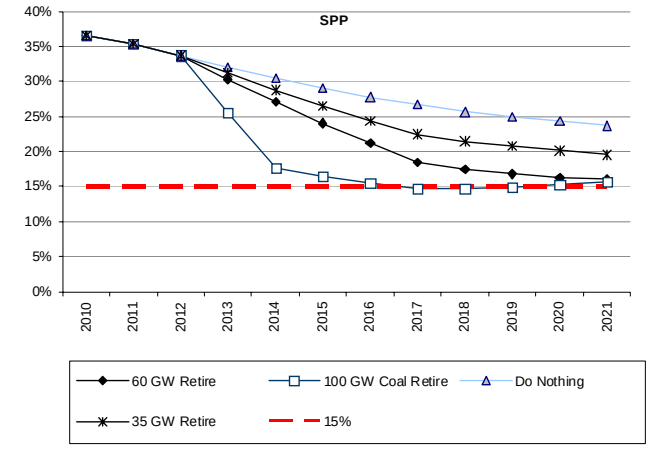

*Source: Company data, Credit Suisse estimates*

**Exhibit 82: SERC Reserve Margin**



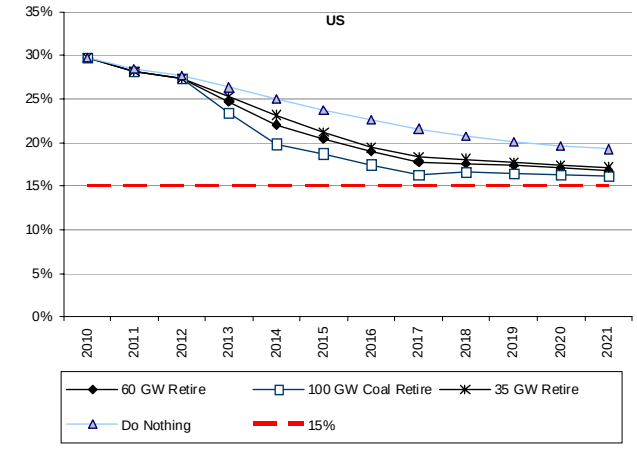

*Source: Company data, Credit Suisse estimates*

**Exhibit 83: SPP Reserve Margin**




*Source: Company data, Credit Suisse estimates*

**Exhibit 84: US Reserve Margin**




*Source: Company data, Credit Suisse estimates*

# Newbuild Requirement

We approached newbuild requirement with the goal of maintaining a 15% reserve margin under our three coal plant closure scenarios. With most reserve margins over 20% today, we see new plants construction requirement to maintain a 15% balanced market at less than our projected retirements which should help make the compliance less onerous from a capital perspective. Importantly, as shown in Exhibit 86, the new plant construction obligations are not totally onerous in a historical context under any of the scenarios, helping to de-risk some natural fears of EPA policy.

With reserve margin over 20% today, we need less newbuild than retirement MW to maintain 15% reserve margin

- **60 GW Retirement**: As most regional markets have a reserve margin in excess of 20% today due to last decades' significant capacity additions and two years in a row of negative demand growth in 2008/9, **new capacity required to keep the reserve margin above 15% is a smaller number (~24 GW) than total capacity at risk of retirement**. In addition, we see the need for newbuild mostly after or in 2015 with PJM, MISO, and SERC having the biggest needs.

24 GW newbuild is required if 60 GW small coal plants were to retire

- **35 GW Retirement (half small coal plants lacking FGD)**: we see only ~ 6 GW newbuild needed in 2017 to maintain reserve margin above 15%.

- **100 GW All Un-Scrubbed Coal Retirement**: 64 GW were to be built to support a 15% reserve margin. We think the planning for permit / construction needs to start today, to allow adequate time for newbuild (Exhibit 87 - Exhibit 92).

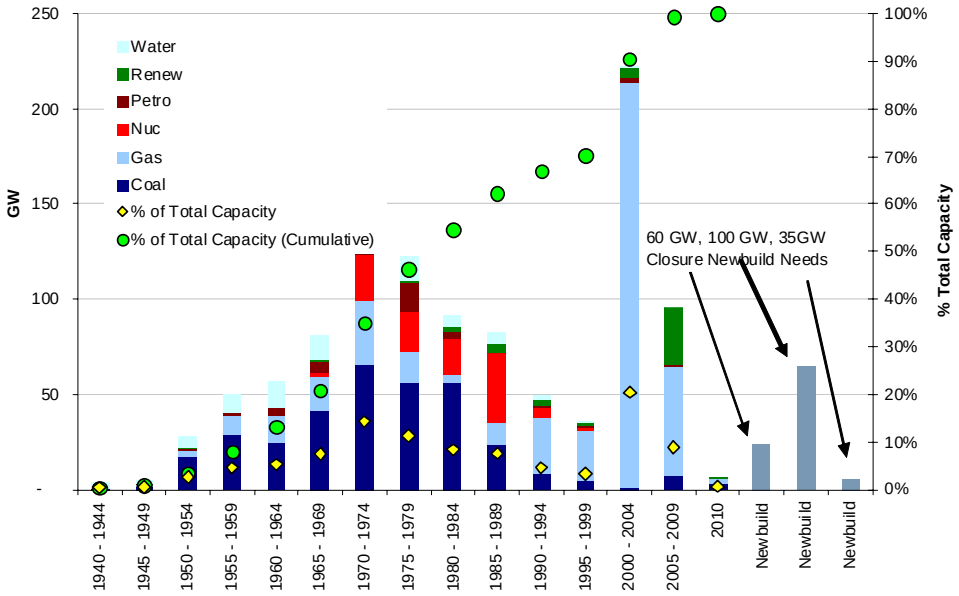
64 GW newbuild is required if small un-scrubbed coal plants were to retire

**Exhibit 85: Capacity to be Retired vs Newbuild**

| Capacity (MW) | Retirement (2013-17) | | | Newbuild Projection (2013-17) | | |
|---|---|---|---|---|---|---|
| MW to Retire | 60 GW | 35 GW | 100 GW | 60 GW | 35 GW | 100 GW |
| PJM | 24,474 | 12,237 | 19,553 | 5,000 | 1,050 | 11,000 |
| ERCOT | 16 | 8 | 2,296 | 0 | 0 | 0 |
| ISO New England | 585 | 293 | 652 | 0 | 0 | 0 |
| ISO New York | 1,249 | 625 | 718 | 0 | 0 | 0 |
| MISO | 17,872 | 8,936 | 32,341 | 5,250 | 0 | 19,000 |
| SERC | 18,619 | 9,310 | 21,787 | 13,500 | 4,750 | 24,000 |
| SPP | 3,805 | 1,903 | 16,087 | 0 | 0 | 9,750 |
| **US** | **59,928** | **29,964** | **102,814** | **23,750** | **5,800** | **64,500** |

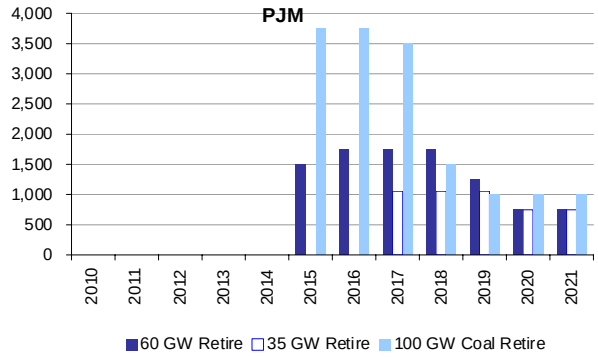
*Source: Company data, Credit Suisse estimates*

**Exhibit 86: 1940 – Present Capacity Addition**



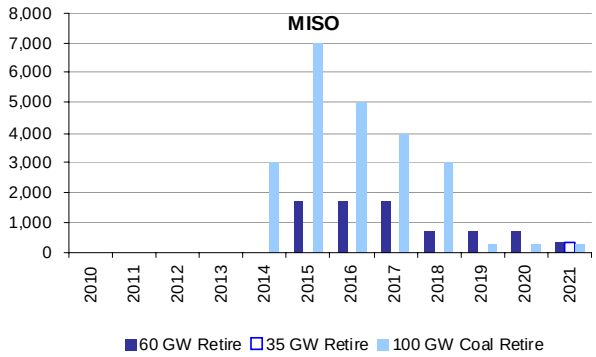

*Source: Energy Velocity Company data, Credit Suisse estimates*

**Exhibit 87: PJM Newbuild**



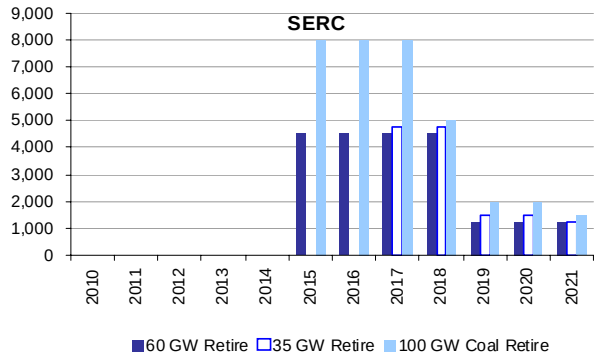

*Source: Company data, Credit Suisse estimates*

**Exhibit 88: MISO Newbuild**



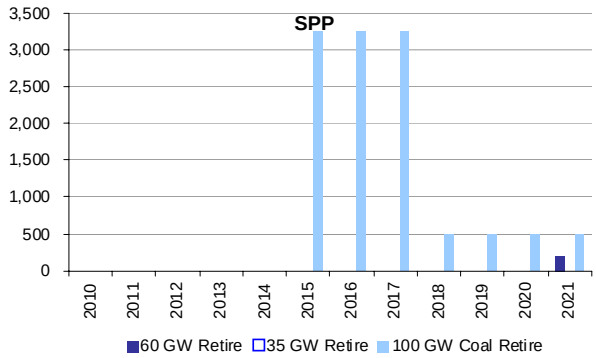

*Source: Company data, Credit Suisse estimates*

**Exhibit 89: SERC Newbuild**



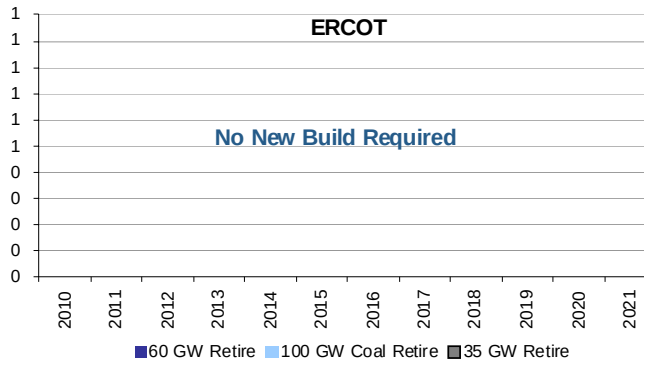

*Source: Company data, Credit Suisse estimates*

**Exhibit 90: SPP Newbuild**



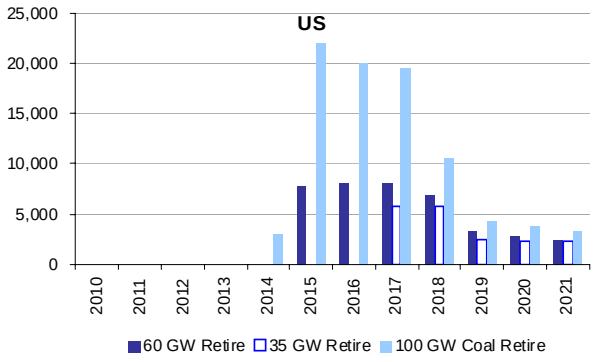

*Source: Company data, Credit Suisse estimates*

**Exhibit 91: ERCOT Newbuild**




*Source: Company data, Credit Suisse estimates*

**Exhibit 92: US Newbuild**




*Source: Company data, Credit Suisse estimates*

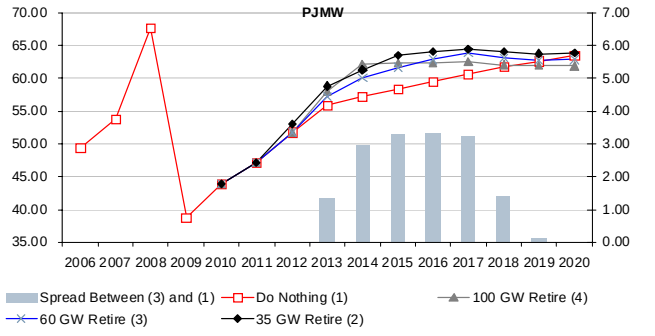
# Impact on Energy Prices

In Exhibit 93 - Exhibit 96 we show the impact on power prices under our four scenarios. As reserve margins tightens faster with coal retirements, we see power prices $5 – 10 / MWh higher than the "do nothing" scenario in regions with dirty coal plant exposures until later in this decade when market equilibrium rise to the point of sustaining a balanced 15% reserve margin and market clearing power prices should converge on the different scenarios. We should note PJM is the most relevant deregulated market since MISO, SPP, and SERC are mostly regulated and plant closure behavior will likely be different while markets such as NEPOOL, NYISO, CAISO and ERCOT have limited dirty coal exposure.

$5 / MWh or more increase in ATC power prices in PJMW and MISO but negligible in other de-regulated regions

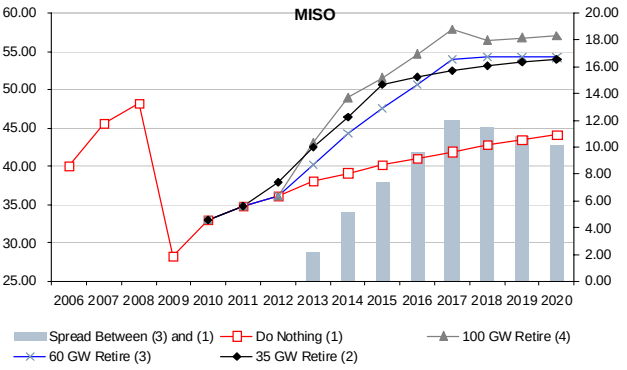
Looking at Exhibit 94 we model a fairly significant step up in electricity prices for MISO given the huge density of at risk coal units; in reality we see pricing help in the competitive Western Illinois market but do not expect as broad of a price step up considering how heavily regulated most of MISO is today (77% of at risk fleet) leaving more of the spending to come with rate base growth overwriting market pricing signals.

**Exhibit 93: PJMW Power Price**



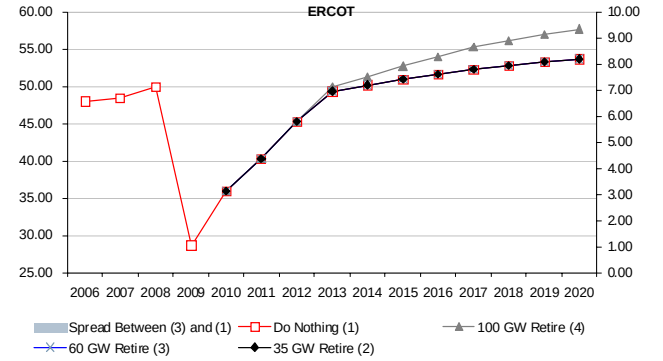

*Source: Company data, Credit Suisse estimates*

**Exhibit 94: MISO Power Price**



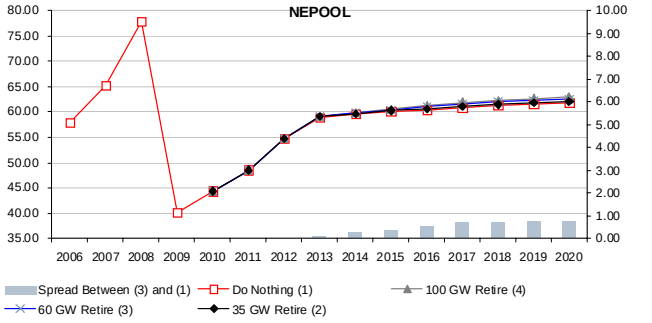

*Source: Company data, Credit Suisse estimates*

**Exhibit 95: ERCOT Power Price**




*Source: Company data, Credit Suisse estimates*

**Exhibit 96: NEPOOL Power Price**




*Source: Company data, Credit Suisse estimates*

# Impact on Capacity Payments

We see changes in power prices with shifting supply-demand fundamentals as important but think capacity prices are essential, not to be overlooked particularly in the RTO region of PJM. **We see RTO capacity payments rebounding toward $100 / MW-day for next auction as plants are targeted for closure or at least bid at their real economic cost**.

As we look at potential closure scenarios, we see much of the economic support to newbuild construction or environmental retrofit decisions dependent up on capacity payment. To help simplify a more complicated calculation, we use the historical relationship between CONE (Const of New Entry) and reserve margin as shown in Exhibit 97, to calculate future capacity prices as we shift reserve margin assumptions in response to our retirement scenarios.

We think RTO capacity payment will rebound to $100 / MW-Day in the next PJM RPM auction

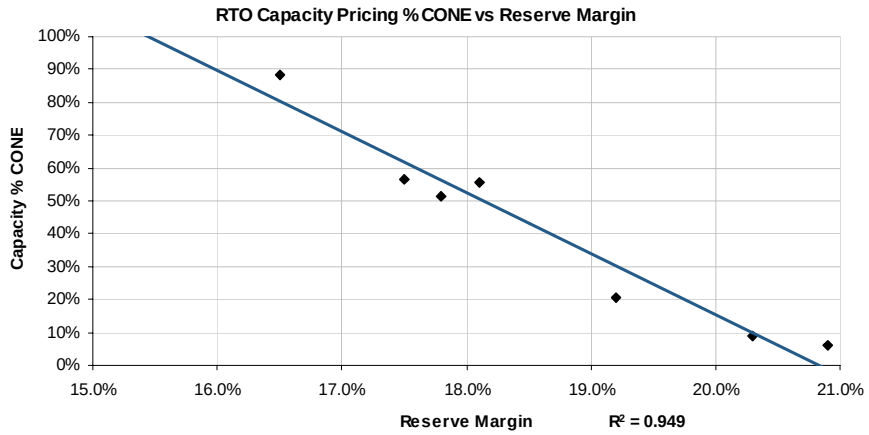
We forecast capacity payment from relationship between reserve margin and capacity payment as percentage of net CONE

**Exhibit 97: Historical RPM Auction Results for RTO**

| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 |
|---|---|---|---|---|---|---|---|
| Capacity Price ($/MW-Day) | 40.80 | 111.92 | 102.04 | 174.29 | 110.00 | 16.46 | 27.73 |
| Reserve Margin | 19.20% | 17.50% | 17.80% | 16.50% | 18.10% | 20.90% | 20.30% |
| CONE ($/MW-Day) | 197.29 | 197.83 | 197.83 | 197.83 | 197.83 | 276.09 | 317.95 |
| Capacity Price % of CONE | 21% | 57% | 52% | 88% | 56% | 6% | 9% |

*Source: PJM, Credit Suisse estimates*

**Exhibit 98: RTO Capacity Price % CONE vs Reserve Margin**




*Source: Company data, Credit Suisse estimates*

### Reserve Margin Forecast

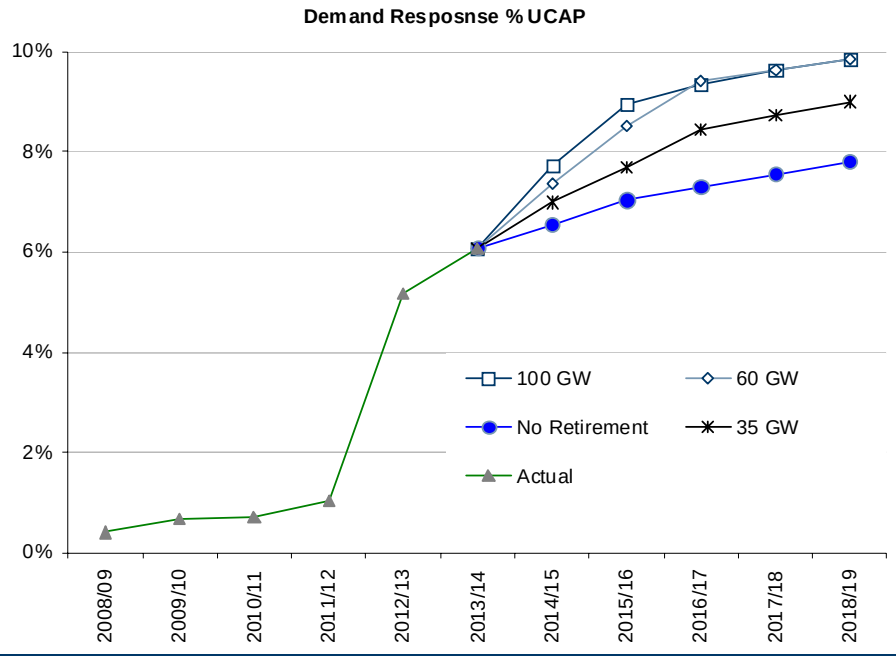
One of the two major drivers in capacity price calculation is the reserve margin forecast which will benefit with time from demand growth and coal plant retirement, partly offset by demand response market share gains.

Growth in Demand Response could mitigate decrease in reserve margin from coal plant closure…

We think demand growth is an important and often overlooked market driver. Demand response grew from 1.4 GW in the '11/'12 planning year to more than 9 GW in '13/'14 in RTO alone. Even with fast growth so far, we can see more to come as demand response accounted for only 6.1% of cleared capacity in RTO for 2013/14, while significantly higher at 8.7% and 7.5% of cleared capacity for MAAC and EMAAC. There were 3.6+ GW of Demand Response offered but not clearing the last auction at $28 / MW-day for RTO. We think as plant closures tighten reserve margins and create a signal for higher capacity payments, we will see more demand response clear the auction. We would not be surprised if in the long run demand response grows to account for close to 10% of system resource (Exhibit 99) as basically seen in MAAC and NEPOOL. The growth in Demand Response will slow the sharp decrease in reserve margins if looking at plant closures in a vacuum.

We see demand growth account for 10% of system resource given adequate price signal

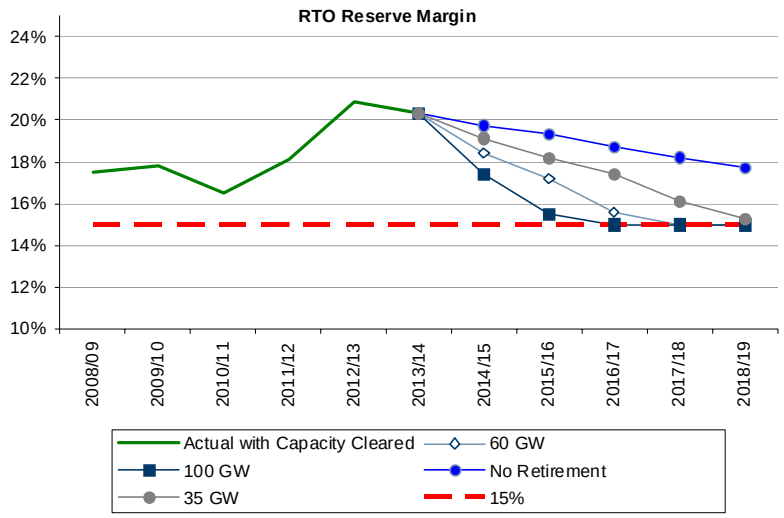
**Exhibit 99: Demand Response Under Different Retirement Scenario**




*Source: Company data, Credit Suisse estimates*

Putting plant closure and demand response growth together, we forecast reserve margins in RTO under our four scenarios (Exhibit 100). Even with growth in demand response, reserve margins could reach 15% as early as 2015/16 with actual timing depending on magnitude / rate of coal plant closure.

**Exhibit 100: RTO Reserve Margin**




*Source: Company data, Credit Suisse estimates*

## Net CONE

The other variable to consider for capacity payment is net CONE, which is revenue requirement necessary to earn an economic return on new plant investment less expected energy margin from running the plant. Below we show the ROE for both CCGT and a gas peaker at different energy / capacity prices (Exhibit 101 and Exhibit 102). We found in the $ 6 / 7 gas environment (which we think is right range for long run natural gas price**), the capacity payment needs to be $225 – 250 / MW-day to support a 10% ROE**, which is clearly a long way away from current gas forwards in the 5's and the last capacity auction below $30 / MW-Day.

We see $225 – 250 / MW-Day as reasonable range for net CONE …

**Exhibit 101: CCGT New Build ROE @ $900 / KW, 8.5 Market HR, 6.8 Plant HR, 65% Utilization**

| Gas Px | Power Px | Spark Spread | Capacity $ / MW-Day | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $ / MMBTu | $/MWh | $/MWh | - | 50 | 75 | 100 | 125 | 150 | 175 | 200 | 225 | 250 |
| 4.0 | 34.0 | 6.8 | -3.5% | -2.2% | -1.0% | 0.3% | 1.5% | 2.8% | 4.0% | 5.3% | 6.5% | 7.8% |
| 4.5 | 38.3 | 7.7 | -2.8% | -1.5% | -0.3% | 1.0% | 2.2% | 3.5% | 4.7% | 6.0% | 7.2% | 8.5% |
| 5.0 | 42.5 | 8.5 | -2.1% | -0.8% | 0.4% | 1.7% | 2.9% | 4.2% | 5.4% | 6.7% | 7.9% | 9.2% |
| 5.5 | 46.8 | 9.4 | -1.4% | -0.1% | 1.1% | 2.4% | 3.6% | 4.9% | 6.1% | 7.4% | 8.6% | 9.9% |
| 6.0 | 51.0 | 10.2 | -0.7% | 0.6% | 1.8% | 3.1% | 4.3% | 5.6% | 6.8% | 8.1% | 9.3% | 10.6% |
| 6.5 | 55.3 | 11.1 | 0.0% | 1.3% | 2.5% | 3.8% | 5.0% | 6.3% | 7.5% | 8.8% | 10.0% | 11.3% |
| 7.0 | 59.5 | 11.9 | 0.7% | 2.0% | 3.2% | 4.5% | 5.7% | 7.0% | 8.2% | 9.5% | 10.7% | 12.0% |
| 7.5 | 63.8 | 12.8 | 1.4% | 2.7% | 3.9% | 5.2% | 6.4% | 7.7% | 8.9% | 10.2% | 11.4% | 12.7% |
| 8.0 | 68.0 | 13.6 | 2.1% | 3.4% | 4.6% | 5.9% | 7.1% | 8.4% | 9.6% | 10.9% | 12.1% | 13.4% |
| 8.5 | 72.3 | 14.5 | 2.8% | 4.1% | 5.3% | 6.6% | 7.8% | 9.1% | 10.3% | 11.6% | 12.8% | 14.1% |
| 9.0 | 76.5 | 15.3 | 3.5% | 4.8% | 6.0% | 7.3% | 8.5% | 9.8% | 11.0% | 12.3% | 13.5% | 14.8% |

*Source: Company data, Credit Suisse estimates*

**Exhibit 102: Gas Peaker ROE @ $700 / KW, 11 On Peak Market HR, 9 Plant HR, 15% Utilization**

| Gas Px | Power Px | Spark Spread | Capacity $ / MW-Day | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $ / MMBTu | $/MWh | $/MWh | - | 50 | 75 | 100 | 125 | 150 | 175 | 200 | 225 | 250 |
| 4.0 | 44.0 | 8.00 | -4.0% | -2.4% | -0.8% | 0.8% | 2.4% | 4.0% | 5.6% | 7.3% | 8.9% | 10.5% |
| 4.5 | 49.5 | 9.00 | -3.8% | -2.2% | -0.5% | 1.1% | 2.7% | 4.3% | 5.9% | 7.5% | 9.1% | 10.7% |
| 5.0 | 55.0 | 10.00 | -3.5% | -1.9% | -0.3% | 1.3% | 2.9% | 4.5% | 6.1% | 7.7% | 9.4% | 11.0% |
| 5.5 | 60.5 | 11.00 | -3.3% | -1.7% | -0.1% | 1.6% | 3.2% | 4.8% | 6.4% | 8.0% | 9.6% | 11.2% |
| 6.0 | 66.0 | 12.00 | -3.0% | -1.4% | 0.2% | 1.8% | 3.4% | 5.0% | 6.6% | 8.2% | 9.8% | 11.5% |
| 6.5 | 71.5 | 13.00 | -2.8% | -1.2% | 0.4% | 2.0% | 3.6% | 5.3% | 6.9% | 8.5% | 10.1% | 11.7% |
| 7.0 | 77.0 | 14.00 | -2.5% | -0.9% | 0.7% | 2.3% | 3.9% | 5.5% | 7.1% | 8.7% | 10.3% | 11.9% |
| 7.5 | 82.5 | 15.00 | -2.3% | -0.7% | 0.9% | 2.5% | 4.1% | 5.7% | 7.4% | 9.0% | 10.6% | 12.2% |
| 8.0 | 88.0 | 16.00 | -2.1% | -0.4% | 1.2% | 2.8% | 4.4% | 6.0% | 7.6% | 9.2% | 10.8% | 12.4% |
| 8.5 | 93.5 | 17.00 | -1.8% | -0.2% | 1.4% | 3.0% | 4.6% | 6.2% | 7.8% | 9.5% | 11.1% | 12.7% |
| 9.0 | 99.0 | 18.00 | -1.6% | 0.0% | 1.6% | 3.3% | 4.9% | 6.5% | 8.1% | 9.7% | 11.3% | 12.9% |

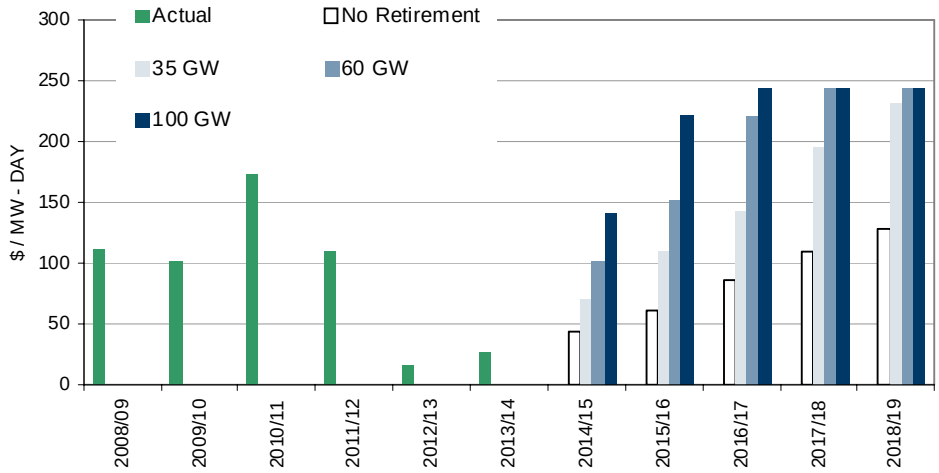
*Source: Company data, Credit Suisse estimates*

## Capacity Payment Forecast

Based on our forecasts for reserve margins and net CONE, we show capacity prices under a range of outcomes (Exhibit 103). We see capacity payments approaching $100 / MW-day for the next auction if generators make responsible economic decisions and start to retire low quality coal plants in 2013 (under our 60 GW retirement scenario). Under the all un-scrubbed coal plant closure (100 GW) scenario, our reserve margins reaches 15% in 16/17, boosting RTO capacity payments to about as high as EMAAC prices.

We forecast RTO capacity payment close to $100 / MW-Day for '14/15 planning year under our "60 GW" retirement scenarios

**Exhibit 103: RTO Capacity Revenue Forecast**




*Source: Company data, Credit Suisse estimates*

## Earnings Impact

From the increase in capacity payments alone, we see a significant lift in earnings for companies with RTO exposure. Edison International (EIX) is the only company in our coverage universe that stands to lose if it were to shut down all un-scrubbed coal fleet when required capex by the mercury MACT becomes prohibitive assuming their proposed alternative compliance approach does not work; we think this is a punitive outcome for EIX but does reflect the challenge and uncertainty associated with environmental control compliance strategies. In Exhibit 104 we show the increase in EBITDA and EPS from our scenario assuming 60 GW are closed and Exhibit 105 shows impact from all un-scrubbed coal plants closure (100 GW).

**Exhibit 104: EPS / EBITDA Impact (60 GW Coal Plants Closure versus "Do Nothing")**

| EBITDA Impact | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|
| AYE | 122 | 187 | 270 | 260 | 207 | 199 |
| D | 39 | 58 | 82 | 76 | 56 | 54 |
| EIX | 100 | 153 | 218 | 208 | 162 | 155 |
| EXC | 199 | 313 | 464 | 467 | 395 | 382 |
| FE | 252 | 396 | 582 | 580 | 485 | 468 |
| NEE | 15 | 24 | 36 | 36 | 31 | 30 |
| PEG | - | - | - | - | - | - |
| RRI | 49 | 69 | 98 | 79 | 37 | 32 |

| EPS Impact | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|
| AYE | 0.47 | 0.72 | 1.03 | 1.00 | 0.79 | 0.76 |
| D | 0.04 | 0.06 | 0.09 | 0.08 | 0.06 | 0.06 |
| EIX | 0.20 | 0.30 | 0.44 | 0.41 | 0.32 | 0.31 |
| EXC | 0.20 | 0.31 | 0.46 | 0.46 | 0.39 | 0.38 |
| FE | 0.54 | 0.84 | 1.24 | 1.24 | 1.03 | 1.00 |
| NEE | 0.02 | 0.04 | 0.06 | 0.06 | 0.05 | 0.05 |
| PEG | - | - | - | - | - | - |
| RRI | 0.09 | 0.13 | 0.18 | 0.14 | 0.07 | 0.06 |

| RTO Capacity ($ / MW-Day) | | | | | | |
|---|---|---|---|---|---|---|
| 60 GW Retire | 101.16 | 151 | 220 | 243 | 243 | 243 |
| Do Nothing | 44.29 | 61 | 87 | 109 | 129 | 133 |

*Source: Company data, Credit Suisse estimates*

**Exhibit 105: EPS / EBITDA Impact (100 GW Coal Plants Closure versus "Do Nothing")**

| EBITDA Impact | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|
| AYE | 209 | 338 | 319 | 261 | 208 | 200 |
| D | 60 | 89 | 72 | 44 | 19 | 16 |
| EIX | 77 | 35 | (96) | (235) | (370) | (376) |
| EXC | 341 | 565 | 551 | 473 | 403 | 389 |
| FE | 425 | 693 | 662 | 550 | 449 | 432 |
| NEE | 26 | 44 | 43 | 36 | 31 | 30 |
| PEG | - | - | - | - | - | - |
| RRI | 107 | 175 | 163 | 130 | 99 | 95 |

| EPS Impact | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 |
|---|---|---|---|---|---|---|
| AYE | 0.80 | 1.30 | 1.22 | 1.00 | 0.80 | 0.77 |
| D | 0.07 | 0.10 | 0.08 | 0.05 | 0.02 | 0.02 |
| EIX | 0.15 | 0.07 | (0.19) | (0.47) | (0.74) | (0.75) |
| EXC | 0.34 | 0.56 | 0.54 | 0.46 | 0.40 | 0.38 |
| FE | 0.91 | 1.48 | 1.41 | 1.17 | 0.96 | 0.92 |
| NEE | 0.04 | 0.07 | 0.07 | 0.06 | 0.05 | 0.05 |
| PEG | - | - | - | - | - | - |
| RRI | 0.20 | 0.32 | 0.30 | 0.24 | 0.18 | 0.17 |

| RTO Capacity ($ / MW-Day) | | | | | | |
|---|---|---|---|---|---|---|
| 100 GW Retire | 141 | 222 | 243 | 243 | 243 | 243 |
| Do Nothing | 44 | 61 | 87 | 109 | 129 | 133 |

*Source: Company data, Credit Suisse estimates*

# Mostly Winners and Bigger Winners

Rarely in our experience do the words 'we're from the government and we're here to help' translate into widespread opportunity to profit but our math would suggest EPA policy action could help basically all of our companies although some are positioned to benefit much more than others. The typical response to such a statement is that "aren't those closing plants at risk" which they are for those plants, but rarely does a company only own small, high polluting plants. By culling the herd of bad plants, the good plants can more than offset the losses. For regulated utilities this is mostly a game of rate base growth to the level regulators will allow a fair recovery on capital to be spent.

## Integrateds and Independent Power Producers

Biggest winners are FE, AYE, EXC and RRI

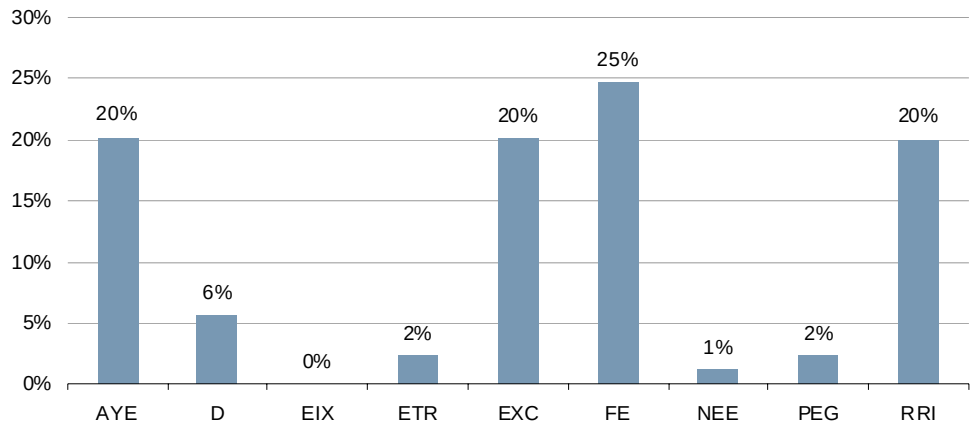
Intuitively, in deregulated markets the companies that benefit most from EPA regulation and associated coal plant retirement are those with clean plants in dirty markets. We see FE, AYE, EXC, and RRI being the biggest winners from coal plant closures while gas-on-gas market participants PEG, ETR and NEE are likely to see the least impact.

**Sensitivities to plant Closures**

To fully appreciate each stocks sensitivities to various closure outcomes we ran three ranging scenarios (i) 35 GW closure, representing half of the small coal fleet today that lacks scrubbers, (ii) 60 GW closure, representing all of the small coal plants lacking environmental controls plus half of the small plants that have SCRs but no scrubbers, and (iii) 103 GW closure, representing all the coal plants that lack all environmental controls but assumes plants with either just a scrubber or just a SCR are retrofitted. *See Appendix III for 2010-20 company-by-company earnings sensitivities.*

From these scenarios we are able to see where the greatest sensitivities lie and in Exhibit 106 we see biggest beneficiaries are within the coal heavy Western PJM; specifically FE, AYE, EXC and RRI.

**Exhibit 106: Impact on Valuation**



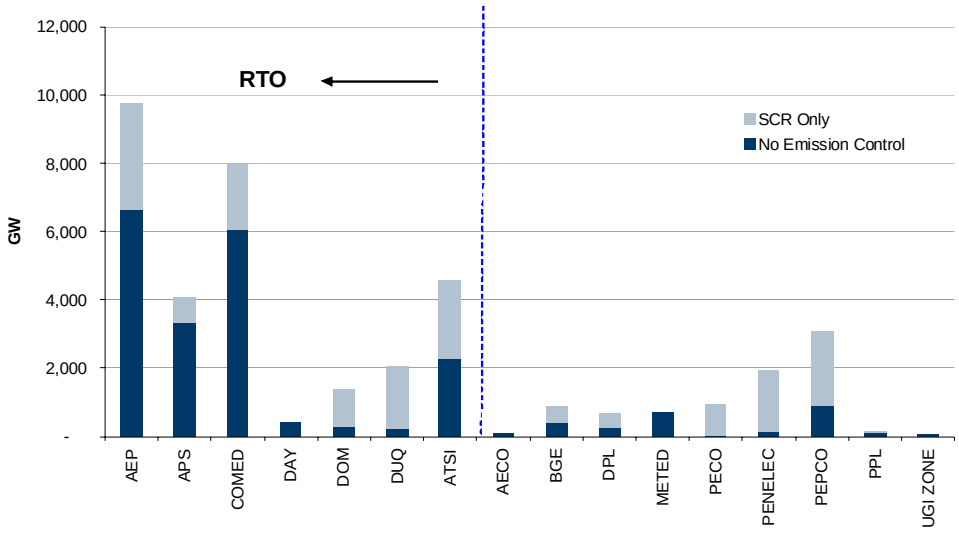

Double digit increase in target price for FE, EXC and AYE

*Source: Company data, Credit Suisse estimates*

**PJM – West is the Best**

PJM's RTO market looks to be the obvious winner from EPA policy with Exhibit 107 illustrating the sizable coal fleets at risk with the standout opportunities being within AYE's APS and FE's ATSI zones.

**Exhibit 107: Un-Scrubbed Coal Capacity in PJM Zones**



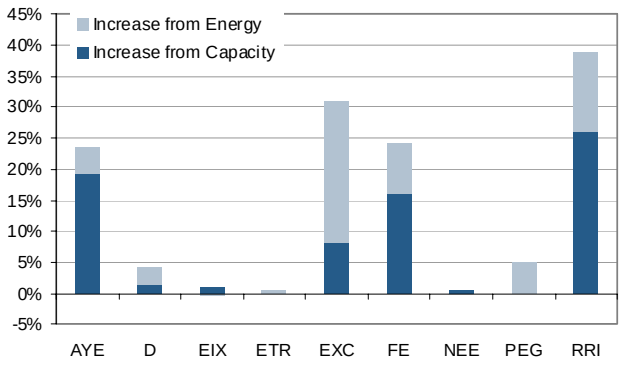

*Source: Company data, Credit Suisse estimates*

## Capacity vs Energy

PJM's de-regulated market offers both energy and capacity payment. The purpose of the capacity market is to put into place proper incentives for newbuild by offering 3-year forward capacity payments (aka monetary signal) to help facilitate and de-risk needed newbuild. We believe that the least efficient coal plant will be retired first which is likely not to nudge energy prices anywhere near newbuild economics so therefore require capacity markets to fill the gap in order to maintain the requisite 15% reserve margin (capacity markets are further discussed on page 48).

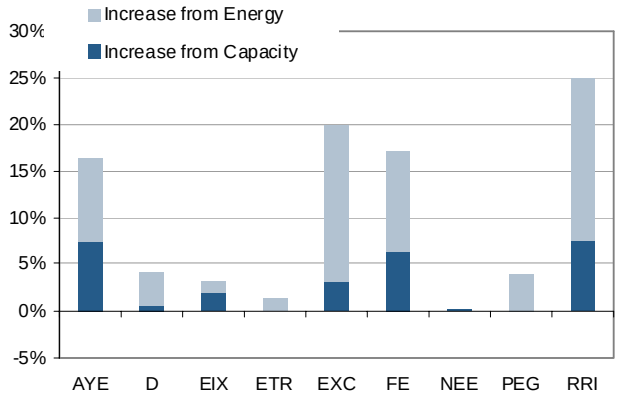
Exhibit 108 and Exhibit 109 help illustrate the source of revenues between energy and capacity and again RTO located providers benefit more on a relative basis given the currently depressed capacity payment vs the higher priced eastern PJM participants. Also when breaking apart the energy and capacity the more coal heavy names like AYE and RRI benefit more from capacity payments as their fuel costs inflate with market power price however EXC and FE's lower cost nuclear plant benefit more from energy.

**Exhibit 108: 2015 EBITDA Impact (All Un-Scrubbed Coal Retire)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 109: 2015 EBITDA Impact (60 GW Small Coal Retire)**

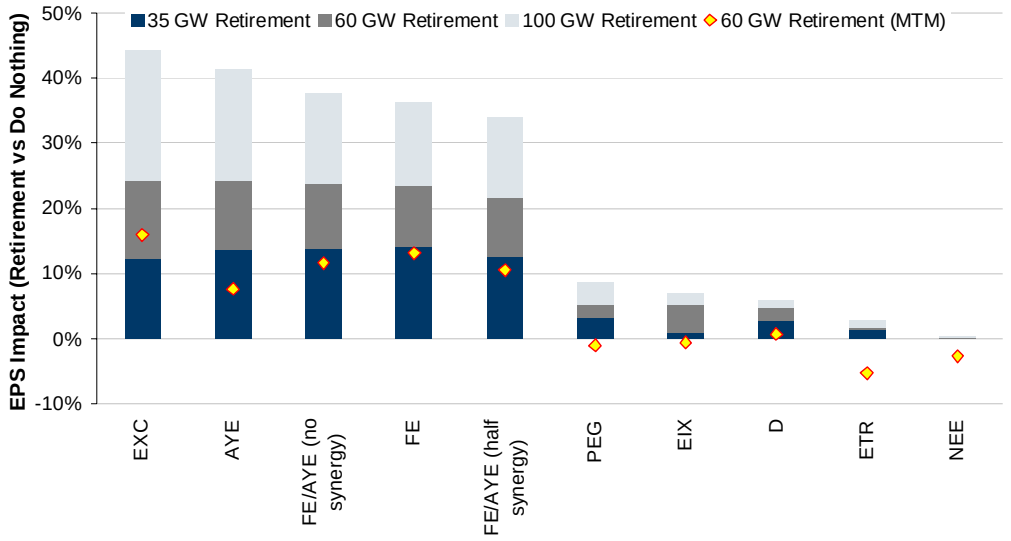



*Source: Company data, Credit Suisse estimates*

### Year by Year Earnings Impact

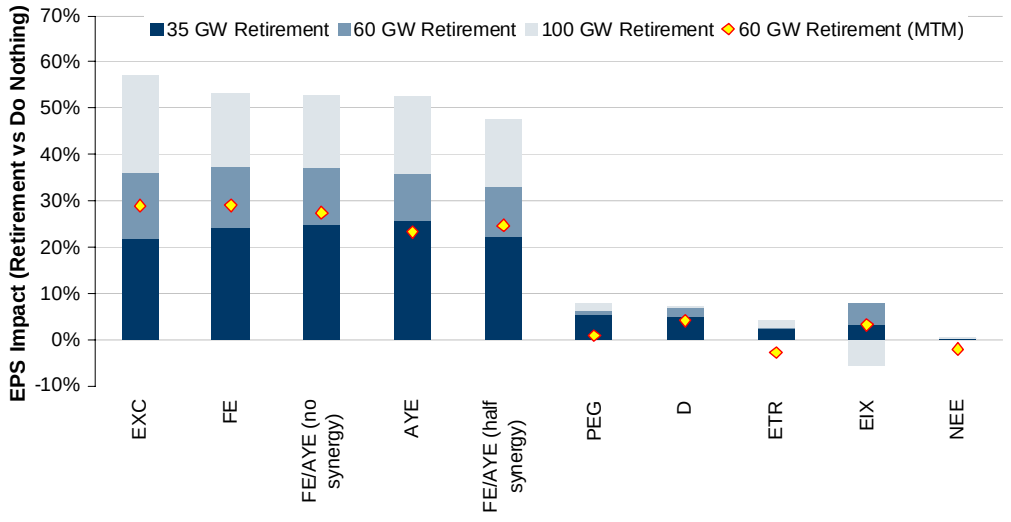
In Exhibit 110 - Exhibit 112 we show earnings impact in 2014/15/16 under our coal closure scenarios.

**Exhibit 110: 2014 EPS Impact From Coal Plant Retirements**



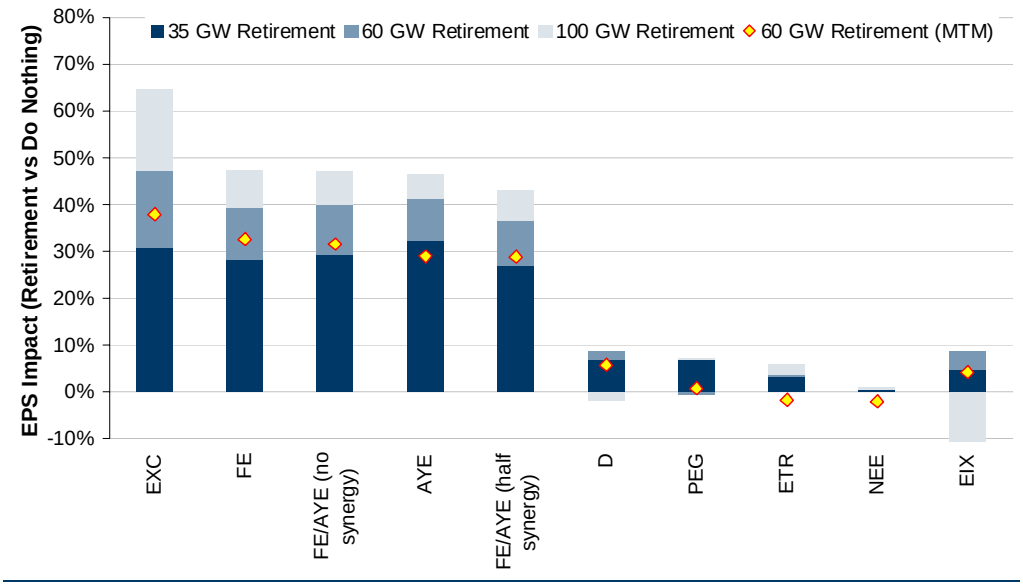

*Source: Company data, Credit Suisse estimates*

**Exhibit 111: 2015 EPS Impact From Coal Plant Retirements**




*Source: Company data, Credit Suisse estimates*

**Exhibit 112: 2016 EPS Impact From Coal Plant Retirements**




*Source: Company data, Credit Suisse estimates*

# Regulated Companies

EPA policy could be catalyst for next build cycle for the regulated companies

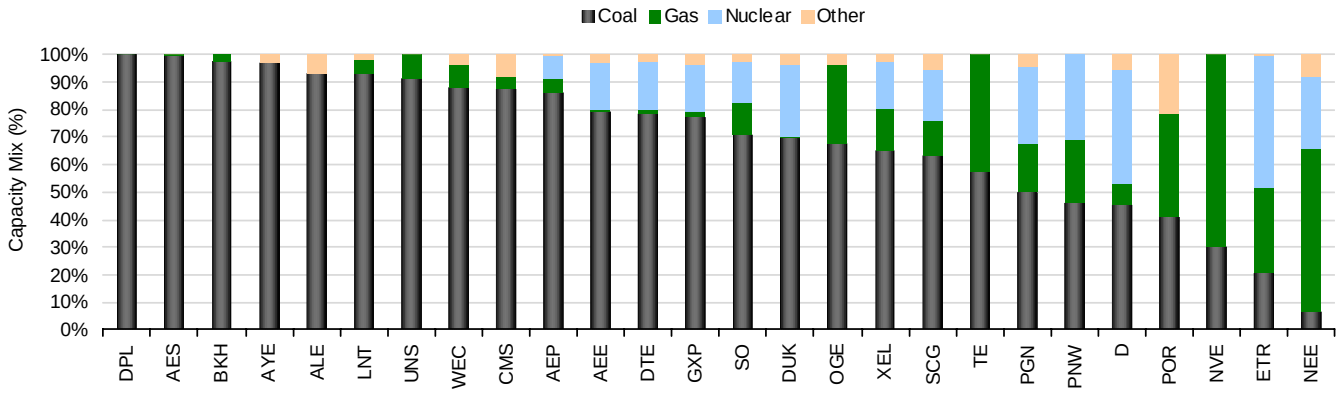
We see likely EPA policy as a catalyst to the next rebuild cycle with the decision tree being much different than for its competitive peers since Regulateds will take a broader look at system reliability and fuel diversity when making decisions between newbuild and retrofit. On average we see the EPA rules as prospectively boosting EPS growth rates by ~2% for the group through higher levels of spending net of equity funding (Exhibit 114), with 3+% growth prospects of ALE, GXP, LNT, OGE and DTE.

**The Regulated Approach**

Coal generation is clearly the backbone of today's regulated utility fleet – as shown in Exhibit 113 – which will make the reinvest versus replace decision different than the approach taken by merchant generators. We think the decision making process for Regulateds will be more holistic in nature and incorporate considerations beyond near-term economics; most notably: (a) benefits of diversified fuel mix, (b) local politics and dependence of local economy on fuel type, meaning shutting down coal facilities in Virginia or other coal heavy states seems less likely with retrofit a more palatable alternative, and (c) sourcing and infrastructure in place of current fuel supply with mine-mouth coal plants likely having more staying power.

As it pertains to the regulatory process, each PUC presides over cost of capital mechanisms, allowed rate base, accounting mechanisms, and all other items that broadly determine the utility's customer rates. Recovery of environmental remediation is unique in every jurisdiction but broadly environmental compliance costs are passed directly to customers (treated like fuel expense) although larger scale capital programs will likely require rate cases to help de-risk and solidify terms of the spending. A full rate case normally takes 6-18 months.

**Exhibit 113: Regulated Generation Capacity Mix (%)**

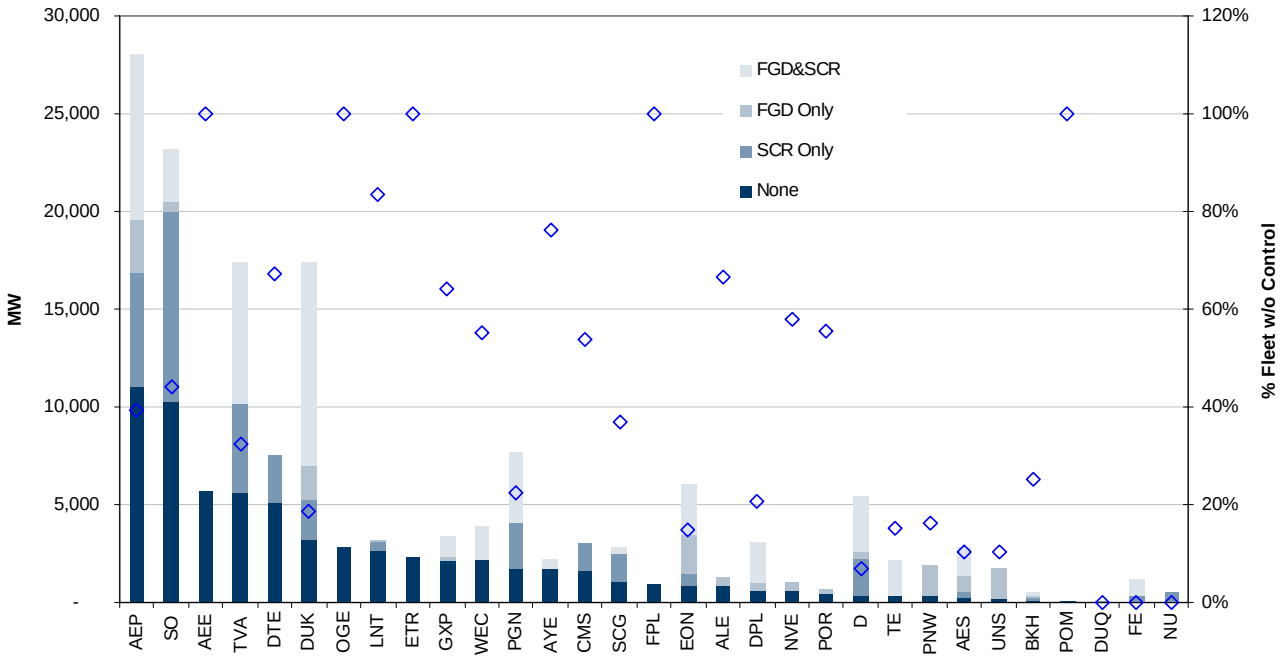



*Source: SNL Financial*

Looking to the clean versus dirty coal conversation, Exhibit 114 shows the respective regulated company's coal plant emission profiles. Not surprisingly, the biggest coal users AEP and SO have the biggest un-scrubbed coal capacity.

.

**Exhibit 114: Regulated Utilities Coal Plants By Emission Control**




*Source: Company data, Credit Suisse estimates*

### Impact on Growth from Environmental Remediation

Consistent with our approach to competitive markets, our analysis in Exhibit 115 provides a 'middle of the road impact' scenario for the regulated companies assuming all small coal plants lacking any emission controls will be replaced by CCGTs and all big plants with no controls will be retrofitted with a scrubber and SCR.

ALE, GXP see the biggest earnings growth from the EPA policy; AEP, DTE and SO also benefit significantly

We should note the math in Exhibit 115 - Exhibit 118 assumes the utilities are willing to maintain current reserve margins; with many markets currently over supplied the utilities might use some plant closures to simply better balance their supply-demand dynamics.

Exhibit 115 calculates implied EPS growth lift and incremental growth rates using the calculated replacement capex along with an earned 9.5% ROE on new environmental investment, 50% equity ratio, and retention ratio of 25% of net income to offset future equity issuance needs (or a 75% payout ratio). The biggest winners on earnings growth are those with higher percentages of un-scrubbed coal.

**Exhibit 115: Capex / EPS Impact**

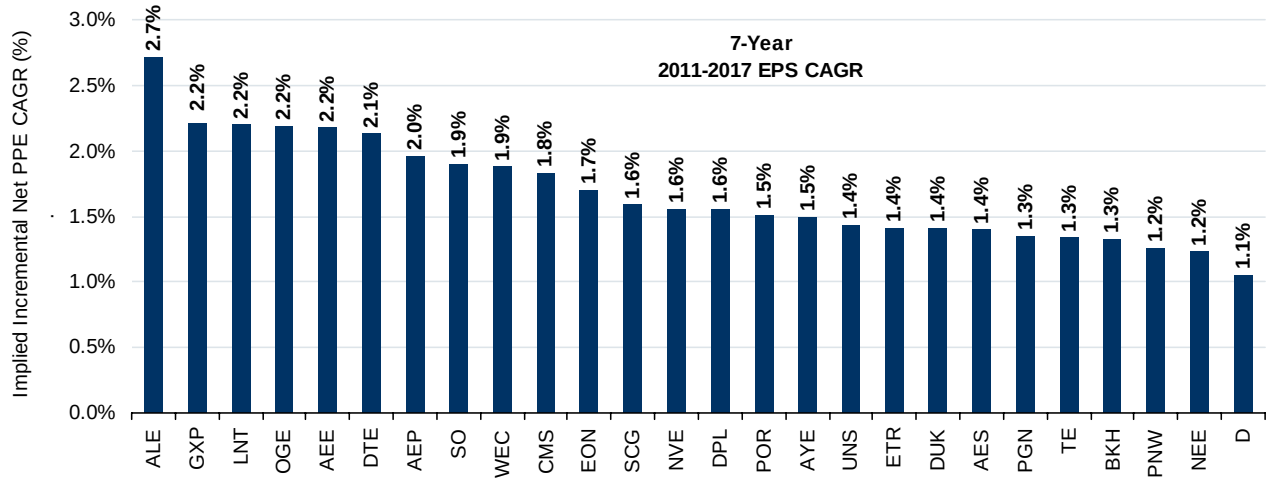
| | Generation Mix | | Implied Capital Expenditures | | | | EPS Impact | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Un-Scrubbed Plant (Not Inc. Planned Emission Ctrl) | | Replace Small Plant with CCGT $900/kW | Retrofit Big Plant $600/kW | Total Implied Capex | % Net PPE | Incremental Diluted EPS | 5-Year EPS CAGR | 7-Year EPS CAGR | Cumulative Earnings Growth |
| Ticker | Small (MW) | Large (MW) | $MM | $MM | $MM | (%) | $ / Share | % | % | % |
| ALE | 518 | 365 | 466 | 219 | 685 | 42% | 0.83 | 3.8% | 2.7% | 20.6% |
| GXP | 759 | 1,400 | 683 | 840 | 1,523 | 23% | 0.46 | 3.1% | 2.2% | 16.5% |
| LNT | 1,210 | 1,425 | 1,089 | 855 | 1,944 | 33% | 0.75 | 3.1% | 2.2% | 16.5% |
| OGE | - | 2,854 | - | 1,712 | 1,712 | 29% | 0.76 | 3.1% | 2.2% | 16.4% |
| AEE | 564 | 5,090 | 508 | 3,054 | 3,561 | 20% | 0.63 | 3.1% | 2.2% | 16.3% |
| DTE | 1,661 | 3,391 | 1,495 | 2,034 | 3,530 | 28% | 0.91 | 3.0% | 2.1% | 15.9% |
| AEP | 4,402 | 6,632 | 3,962 | 3,979 | 7,941 | 23% | 0.72 | 2.7% | 2.0% | 14.5% |
| SO | 5,259 | 4,970 | 4,733 | 2,982 | 7,715 | 20% | 0.43 | 2.7% | 1.9% | 14.1% |
| WEC | 1,715 | 419 | 1,543 | 251 | 1,794 | 20% | 0.70 | 2.6% | 1.9% | 13.9% |
| CMS | 1,236 | 404 | 1,112 | 242 | 1,355 | 14% | 0.25 | 2.6% | 1.8% | 13.5% |
| EON | 443 | 446 | 399 | 268 | 667 | 1% | 0.02 | 2.4% | 1.7% | 12.5% |
| SCG | 1,061 | - | 955 | - | 955 | 11% | 0.36 | 2.2% | 1.6% | 11.7% |
| NVE | 576 | - | 518 | - | 518 | 6% | 0.11 | 2.2% | 1.6% | 11.4% |
| DPL | 414 | 230 | 373 | 138 | 511 | 18% | 0.21 | 2.2% | 1.6% | 11.4% |
| POR | - | 391 | - | 234 | 234 | 6% | 0.15 | 2.1% | 1.5% | 11.0% |
| AYE | 532 | - | 479 | - | 479 | 5% | 0.14 | 2.1% | 1.5% | 10.9% |
| UNS | 173 | - | 156 | - | 156 | 6% | 0.19 | 2.0% | 1.4% | 10.5% |
| ETR | 2 | 2,352 | 2 | 1,411 | 1,413 | 6% | 0.37 | 2.0% | 1.4% | 10.3% |
| DUK | 2,657 | 560 | 2,391 | 336 | 2,727 | 7% | 0.10 | 2.0% | 1.4% | 10.3% |
| AES | 302 | - | 271 | - | 271 | 1% | 0.02 | 2.0% | 1.4% | 10.3% |
| PGN | 747 | 964 | 672 | 579 | 1,251 | 6% | 0.21 | 1.9% | 1.3% | 9.8% |
| TE | 326 | - | 294 | - | 294 | 5% | 0.07 | 1.9% | 1.3% | 9.8% |
| BKH | 125 | - | 112 | - | 112 | 5% | 0.14 | 1.9% | 1.3% | 9.7% |
| PNW | 312 | - | 281 | - | 281 | 3% | 0.13 | 1.8% | 1.2% | 9.1% |
| NEE | - | 952 | - | 571 | 571 | 2% | 0.07 | 1.7% | 1.2% | 8.9% |
| D | 367 | - | 330 | - | 330 | 1% | 0.03 | 1.5% | 1.1% | 7.6% |
| TVA | 5,634 | - | 5,071 | - | NA | NA | n/a | n/a | n/a | n/a |
| **Total** | **31,872** | **36,961** | **28,685** | **22,177** | **45,791** | **10%** | | **2.3%** | **1.6%** | **11.9%** |

*Source: Company data, Credit Suisse estimates*

### A Growth Opportunity

In seeking to measure opportunity from likely EPA regulation, we measure prospective growth on an asset and earnings per share basis. In this analysis we assume a 5-year compliance cycle (2013-2017) but annualize over a 7-year period (2011-17) on the belief that EPA remediation will move slowly at first and then be fully implemented once EPA policy is finalized.

**Exhibit 116: 2011-2017 EPS CAGR**

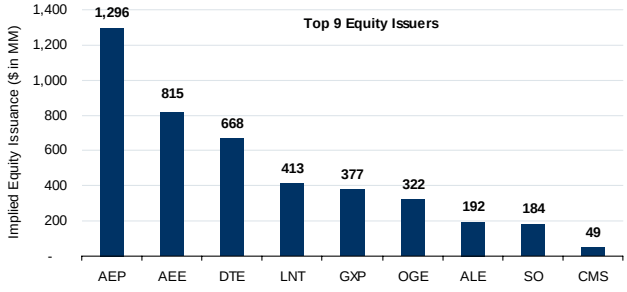



*Source: Company data, Credit Suisse estimates*

## Equity Issuance

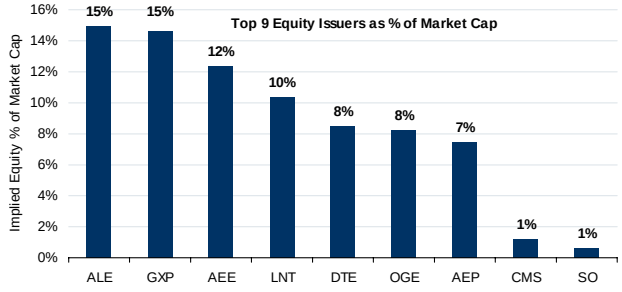
Exhibit 117 and Exhibit 118 highlight the top 9 expected equity issuances required to support the environmental related capex in absolute and relative to market cap terms. Clearly EPA capex could crowd-out other spending priorities which would lessen the funding needs shown but we think the analysis provides an interesting look at future funding requirements on an even footing.

**Exhibit 117: Top 9 Equity Issuers (absolute)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 118: Top 9 Equity Issuers Relative to Market Cap**




*Source: Company data, Credit Suisse estimates*

# Impact on Coal and Natural Gas Demand

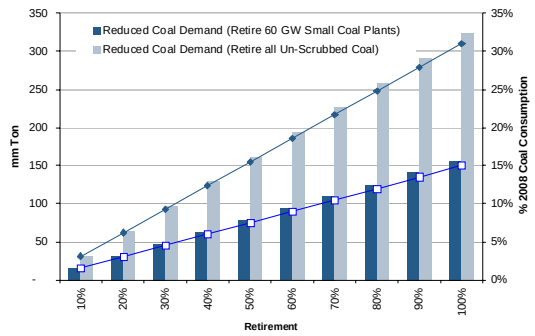
While we focus much of our work on the impact of EPA regulation on the power sector, implementation of CATR for SOx / NOx and MACT for mercury will have flow through implications for long-term natural gas and coal demand.

## Coal Demand Clearly At Risk

We think EPA regulations, especially the mercury MACT standard, will lead to a decline in US steam coal consumption as some portion of non-compliant plants are retired rather than retrofitted. As shown in Exhibit 119 and Exhibit 119, using 2008 data we see 324 MM tons (or 31%) of the ~1 BN tons US steam coal market was from coal plants lacking any environmental controls. Narrowing the analysis to small coal plants (60 GW), coal consumption was 157 MM tons / year or 15% of US stream coal market.

8 – 15% of US steam coal market could disappear

**Exhibit 119: Impact on Coal Demand from Coal Plant Retirement**




*Source: Company data, Credit Suisse estimates*

**Exhibit 120: Impact on Coal Demand from Coal Plant Retirement**

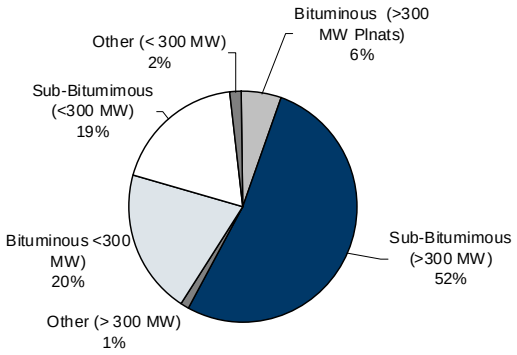
| Retirement | 100 GW | | 60 GW | |
|---|---|---|---|---|
| Percentage | Reduced Coal Demand | % 2008 Coal Comsumption | Reduced Coal Demand | % 2008 Coal Comsumption |
| 10% | 32 | 3% | 16 | 2% |
| 20% | 65 | 6% | 31 | 3% |
| 30% | 97 | 9% | 47 | 5% |
| 40% | 129 | 12% | 63 | 6% |
| 50% | 162 | 16% | 78 | 8% |
| 60% | 194 | 19% | 94 | 9% |
| 70% | 227 | 22% | 110 | 11% |
| 80% | 259 | 25% | 125 | 12% |
| 90% | 291 | 28% | 141 | 14% |
| 100% | 324 | 31% | 157 | 15% |

*Source: Company data, Credit Suisse estimates*

We think there could be an argument made for higher impact to the sub-bituminous coal market since it represents more than 70% of coal consumed by un-scrubbed coal plants in 2008 (Exhibit 121), most likely as a result of western coal's lower sulfur contents, and western states not covered by CAIR. With the coming mercury MACT standard, coal plants in western states will be required to install emission control which they have been able to avoid so far. That said, as western states are mostly regulated, the investment decision could be hard to predict.

More interesting, however, is the breakdown of coal supply at risk when looking to the smaller plants which we think are more vulnerable to closure in Exhibit 122 and Exhibit 123 . Here we see half of the coal supply at risk is from bituminous (eastern) coal.

**Exhibit 121: Coal Consumption by Coal Plants with No Emission Controls**




*Source: Company data, Credit Suisse estimates*

**Exhibit 122: Un-Controlled Coal Plant by Type of Coal Burned (MW)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 293 | 38 | 130 | 461 |
| ERCOT ISO | - | 2,284 | 12 | 2,296 |
| Midwest ISO | 6,633 | 24,812 | 897 | 32,341 |
| New England ISO | 252 | 400 | - | 652 |
| New York ISO | 718 | - | - | 718 |
| PJM ISO | 12,802 | 6,152 | 599 | 19,553 |
| SPP | 539 | 15,547 | 2 | 16,087 |
| WECC | 2,270 | 5,200 | - | 7,469 |
| SERC | 13,846 | 7,185 | 757 | 21,787 |
| Other | 996 | 452 | - | 1,448 |
| **Total** | **38,349** | **62,070** | **2,396** | **102,814** |
| *%* | *37%* | *60%* | *2%* | *100%* |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 123: Un-Controlled Plants Coal Burn by Type of Coal (MM ton)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 1 | 0 | 0 | 1 |
| ERCOT ISO | - | 10 | 0 | 10 |
| Midwest ISO | 15 | 90 | 4 | 110 |
| New England ISO | 1 | 2 | - | 2 |
| New York ISO | 1 | - | - | 1 |
| PJM ISO | 25 | 20 | 3 | 48 |
| SPP | 2 | 58 | - | 60 |
| WECC | 7 | 20 | - | 26 |
| SERC | 30 | 30 | 1 | 61 |
| Other | 2 | 2 | - | 3 |
| **Total** | **84** | **231** | **9** | **324** |
| *% Regional Supply* | *26%* | *71%* | *3%* | *100%* |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 124: Un-Controlled Small Coal Plant by Type of Coal Burned (MW)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 293 | 38 | 130 | 461 |
| ERCOT ISO | - | - | 12 | 12 |
| Midwest ISO | 5,221 | 10,345 | 419 | 15,985 |
| New England ISO | 252 | - | - | 252 |
| New York ISO | 718 | - | - | 718 |
| PJM ISO | 8,962 | 644 | 235 | 9,841 |
| SPP | 539 | 3,106 | 2 | 3,646 |
| WECC | 1,781 | 2,003 | - | 3,785 |
| SERC | 12,821 | 1,299 | 757 | 14,877 |
| Other | 556 | 452 | - | 1,008 |
| **Total** | **31,143** | **17,888** | **1,555** | **50,586** |
| *%* | *62%* | *35%* | *3%* | *100%* |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 125: Un-Controlled Small Plants Coal Burn by Type of Coal (MM ton)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 1 | 0 | 0 | 1 |
| ERCOT ISO | - | - | 0 | 0 |
| Midwest ISO | 11 | 35 | 1 | 47 |
| New England ISO | 1 | - | - | 1 |
| New York ISO | 1 | - | - | 1 |
| PJM ISO | 16 | 2 | 2 | 21 |
| SPP | 2 | 11 | - | 13 |
| WECC | 5 | 7 | - | 13 |
| SERC | 28 | 5 | 1 | 34 |
| Other | 1 | 2 | - | 3 |
| **Total** | **66** | **62** | **5** | **133** |
| *% Regional Supply* | *49%* | *47%* | *4%* | *100%* |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 126: Total Coal Plant by Type of Coal Burned (MW)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 401 | 38 | 203 | 642 |
| ERCOT ISO | - | 7,659 | 11,245 | 18,904 |
| Midwest ISO | 27,424 | 44,774 | 4,833 | 77,030 |
| New England ISO | 2,475 | 400 | - | 2,875 |
| New York ISO | 1,938 | 1,063 | - | 3,001 |
| PJM ISO | 61,910 | 11,972 | 5,829 | 79,711 |
| SPP | 539 | 23,236 | 2,147 | 25,922 |
| WECC | 10,570 | 23,363 | 630 | 34,564 |
| SERC | 65,080 | 18,046 | 3,008 | 86,134 |
| Other | 9,966 | 1,445 | 627 | 12,037 |
| **Total** | **180,302** | **131,996** | **28,522** | **340,820** |
| *%* | *53%* | *39%* | *8%* | *100%* |

*Source: Energy Velocity, Company data, Credit Suisse estimates*

**Exhibit 127: Coal Burn by Type of Coal (MM ton)**

| Region | Bituminous (Eastern) Coal | Sub-Bituminous (Western) Coal | Other | Total |
|---|---|---|---|---|
| California ISO | 1 | 0 | 0 | 2 |
| ERCOT ISO | - | 32 | 51 | 83 |
| Midwest ISO | 71 | 156 | 26 | 253 |
| New England ISO | 7 | 2 | - | 8 |
| New York ISO | 5 | 4 | - | 9 |
| PJM ISO | 143 | 41 | 20 | 204 |
| SPP | 2 | 86 | 9 | 97 |
| WECC | 34 | 87 | 2 | 123 |
| SERC | 155 | 71 | 8 | 235 |
| Other | 24 | 6 | 1 | 31 |
| **Total** | **441** | **485** | **117** | **1,044** |
| *% Regional Supply* | *42%* | *46%* | *11%* | *100%* |

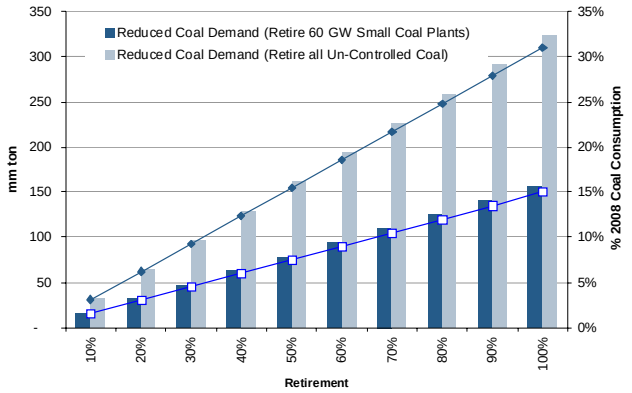
*Source: Energy Velocity, Company data, Credit Suisse estimates*

# Natural Gas Demand Could Find a 5%+ bump

As coal plants respond to CATR by closure or retrofit to be in compliance with 2012 / 2014 Phase I/II SOx cap, we expect incremental gas demand as early as 2012, although given phase I cap is only 18% lower than 2009 emission levels (versus 2014 target of 44% lower) we think the bigger impact to gas markets will probably begin in 2013. In Exhibit 128 and Exhibit 129 we show the change in natural gas demand assuming replacement of at risk coal plants with higher efficiency CCGTs. From this we see a 1.8 – 3.7 TCF increase in gas demand (+8-16% US gas consumption) all else equal.

Increase in Gas Demand could be 1.8 – 3.7 TCF / year

**Exhibit 128: Impact on Gas Demand from Coal Plant Retirement**




*Source: Company data, Credit Suisse estimates*

**Exhibit 129: Impact on Gas Demand from Coal Plant Retirement**

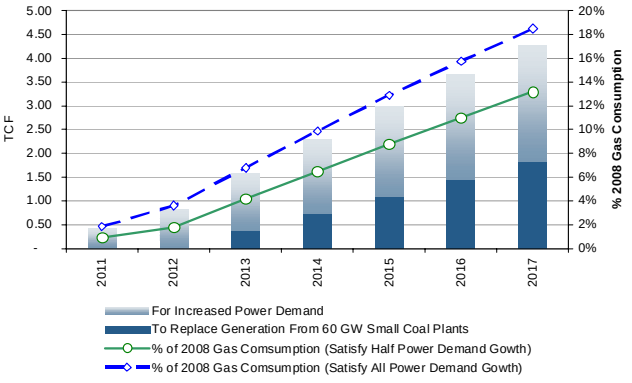
| Retirement | 100 GW | | 60 GW | |
|---|---|---|---|---|
| Percentage | Increased Nat Gas Demand (TCF) | % 2008 Gas Comsumption | Increased Nat Gas Demand (TCF) | % 2008 Gas Comsumption |
| 10% | 0.37 | 1.6% | 0.18 | 0.8% |
| 20% | 0.74 | 3.2% | 0.36 | 1.6% |
| 30% | 1.12 | 4.8% | 0.54 | 2.3% |
| 40% | 1.49 | 6.4% | 0.73 | 3.1% |
| 50% | 1.86 | 8.0% | 0.91 | 3.9% |
| 60% | 2.23 | 9.6% | 1.09 | 4.7% |
| 70% | 2.61 | 11.2% | 1.27 | 5.5% |
| 80% | 2.98 | 12.8% | 1.45 | 6.3% |
| 90% | 3.35 | 14.4% | 1.63 | 7.0% |
| 100% | 3.72 | 16.0% | 1.82 | 7.8% |

*Source: Company data, Credit Suisse estimates*

## Plus More Demand From Power Usage Growth

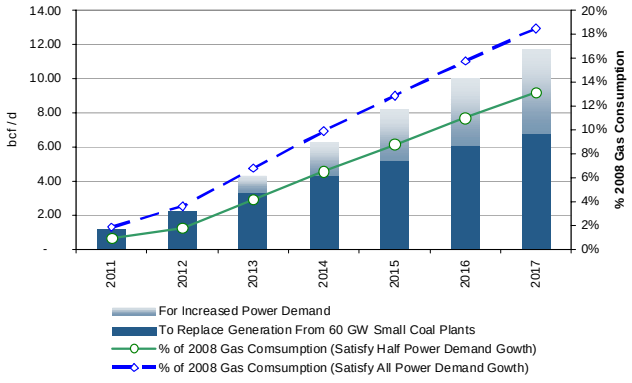
Gas fired generation will also need to satisfy incremental power demand (we think ~1.5% a year), which on a 7 year outlook would add another ~ 2.5 TCF on natural gas demand assuming natural gas is used to meet all power demand growth. Under a more realistic scenario that includes wind generation growth we see gas consumption accounting for half of the incremental power growth. Exhibit 130 and Exhibit 131 show the demand growth by year. The two growth rate outcomes reflect (a) over 60 GW coal plant retirements closure scenarios, and (b) half of market share for natural gas to meet electricity demand growth (we like the half assumption today). Raising overall natural gas growth by 13% in next seven years could create some interesting changes in pricing dynamics.

**Exhibit 130: Incremental Natural Gas Demand from Power Demand Growth and Coal Plant Retirement (TCF)**




*Source: Company data, Credit Suisse estimates*

**Exhibit 131: Incremental Natural Gas Demand from Power Demand Growth and Coal Plant Retirement (bcf / d)**



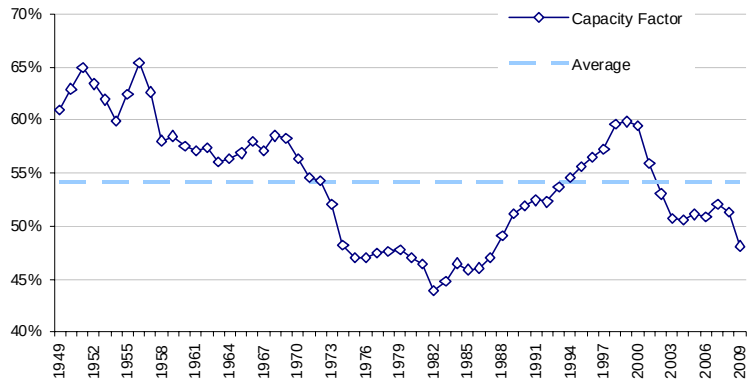

*Source: Company data, Credit Suisse estimates*

# Can the Lost Coal Generation Be Replaced by CCGTs?

In 2009, capacity factor for the US generation fleet was below historical average, which prompted us to ask the question – can the existing fleet accommodate coal plant retirement? As coal plants are generally base load providers, nuclear plants are dispatched at nearly 100% of the time excluding refueling outages, and the intermittent nature of renewables makes them unsuitable as base load, we focus on Combined Cycle gas plants within the existing fleet to backfill lost capacity and output due to coal plant retirements.

In Exhibit 132 we calculate the required increase in capacity factor for combined cycle gas plants to completely back fill for un controlled coal generation. We found with the exception of MISO and SPP, most regions conceptually seem to be able to absorb the generation loss by dispatching CCGTs more, however, this exercise does not take into account the reserve margin requirements at peak demand, which in our mind, will be the driving factor for new construction when coal retirement starts.

**Exhibit 132: US Generation Fleet Capacity Factor**




*Source: EIA, Energy Velocity, Credit Suisse estimates*

**Exhibit 133: Can Increased Runtime from Combined Cycle Replace Retired Coal Plants**

| CCGT | 2009 Capacity (GW) | 2008 Util% pro-forma | 2008 Generation from Un-Scrubbed Coal (TWH) | CCGT Util% Increase to Backfill Lost Coal | CCGT Util% |
|---|---|---|---|---|---|
| California ISO | 14 | 47% | - | 0% | 47% |
| ERCOT ISO | 33 | 36% | 16 | 6% | 42% |
| Midwest ISO | 14 | 12% | 169 | 134% | 146% |
| New England ISO | 14 | 32% | 5 | 4% | 36% |
| New York ISO | 9 | 37% | 3 | 3% | 40% |
| PJM ISO | 26 | 16% | 83 | 36% | 52% |
| SPP | 12 | 24% | 97 | 94% | 119% |
| SERC | 41 | 25% | 110 | 31% | 55% |
| WECC | 31 | 40% | 45 | 17% | 57% |
| Other | 25 | 28% | 5 | 2% | 30% |
| **Total** | **219** | **29%** | **532** | **28%** | **57%** |

| CCGT | 2010-13 Capacity Addition (GW) | 2013 Capacity | 2008 Util% (pro forma) | 2008 generation from Un-Scrubbed Coal (TWH) | 2008 -13 Demand Growth (TWH) | CCGT Util% |
|---|---|---|---|---|---|---|
| California ISO | 5 | 19 | 47% | - | 1 | 47% |
| ERCOT ISO | 1 | 34 | 36% | 16 | 32 | 52% |
| Midwest ISO | 0 | 14 | 12% | 169 | 17 | 159% |
| New England ISO | 0 | 14 | 32% | 5 | (1) | 35% |
| New York ISO | 1 | 10 | 37% | 3 | (2) | 38% |
| PJM ISO | 2 | 28 | 16% | 83 | 14 | 55% |
| SPP | - | 12 | 24% | 97 | 7 | 126% |
| SERC | - | 41 | 25% | 110 | 48 | 69% |
| WECC | 9 | 40 | 40% | 45 | 12 | 56% |
| Other | 2 | 28 | 28% | 5 | 8 | 33% |
| **Total** | **21** | **240** | **29%** | **532** | **147** | **62%** |

*Source: EIA, Company data, Credit Suisse estimates*

# Appendix I - Emission Control Technologies

We appreciate significant pages and words have been devoted to discussing the implications of EPA policy and the inevitable need for significant investment in order for plants to attain allowable emissions levels. To help put some intellectual context around how these standards are to be met, we thought an explanation of how the equipment that will be added actually works would be helpful.

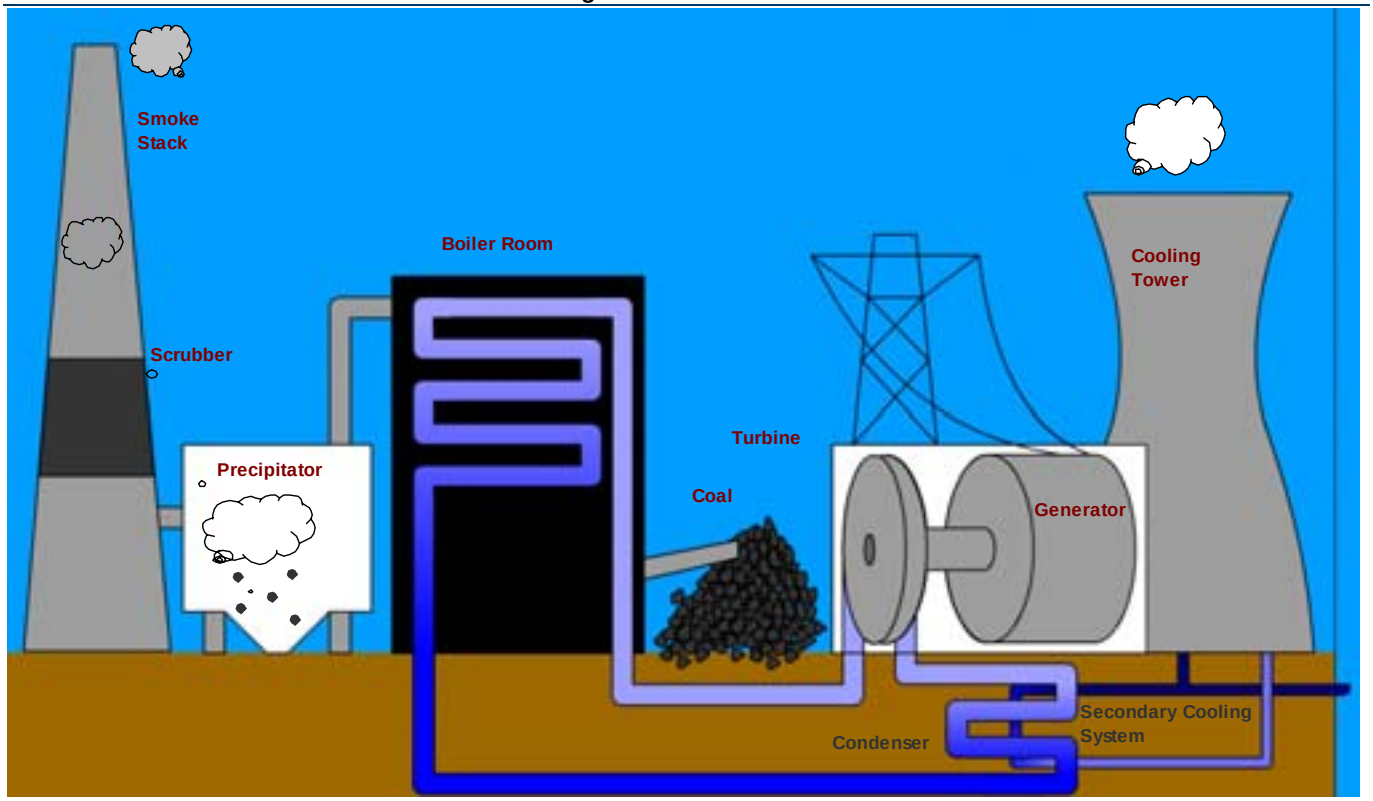
How does coal plant generate electricity from burning coal?

Exhibit 134 provides an easy to follow diagram of a coal plant. Following the exhibit from the center to the right, coal is moved into the boiler room where it is ignited, heating water in the water pipe covered walls of the boiler. The water turns to steam which is then delivered to the generator, turning the 'engine' and producing electricity which is then delivered to the electricity grid. Part of the steam is captured for re-use and part is released into the atmosphere through the cooling tower – for those who have driven by a power plant, the clouds billowing from the plants are generally released steam and not shocking amounts of pollutants (although coal plants do emit pollutants as well).

Going left from the boiler room, the waste product from coal combustion is delivered to a precipitator to capture large particles and is then delivered up through the smoke stack and ideally a scrubber where finer and more focused pollutant matter is captured. The remaining post combustion waste exits the top of the smoke stack into the atmosphere.

That out of the way, we can now focus on how the different pieces of the environmental control system works and what we are trying to eliminate.

**Exhibit 134: Power Plant and Emission Control Diagram**




http://www.its-about-time.com/investinesart/coalplantvirtualtour.swf

*Source: Its-about-time.com*

# What we want to remove and why

Coal generators are leading emitters of three major pollutants Sulfur Dioxide (SOx), Nitrogen Oxide (NOx), and mercury (Hg), each of which have specific environmental impacts that should in good conscience be reduced:

- Sulfur Dioxide (SOx): acid rain and atmospheric particulates,
- Nitrogen Dioxide and Nitrogen Monoxide (NOx): brown haze and atmospheric particulates, and
- Mercury (Hg): birth defects, central nervous and endocrine system damage

Before drudging through the details of remediation, Exhibit 135 highlights the mechanisms we believe are best poised to remediate both SOx and NOx emissions under the CATR rules and mercury under the MACT rule. Interestingly, the type of coal burned will have an impact on remediation approaches and efficacy of these approaches.

**Eastern Coal:**

- **FGD / SCR / Activated Carbon**: This is the most effective approach but also most expensive (capex in the range of $450 –700 / KW) and, unfortunately, the only effective solution to reduce SOx for plants burning eastern coal.

**Western Coal:**

- **Dry Sorbent Injection (TrONA) / SNCR / Baghouse / Activated Carbon.** This is the cheapest for pollutants reduction in terms of capex, but dry sorbent injection only works well for lower sulfur western coal with performance levels still somewhat open for debate.

**Exhibit 135: Emission Control Technologies**

| | CATR | | | | Mercury MACT | |
|---|---|---|---|---|---|---|
| | Sulfur Oxide (SOx) | | Nitrogen Oxide (NOx) | | Mercury (Hg) | |
| | Scrubber | Dry Sorbent Injection | SCR | SNCR | Scrubber / SCR | Baghouse w/ ACI |
| Removal Rate | 95%+ | <70% | 70-95% | 30-75% | >90% | 80-90% |
| Capex | $300 - 500 / kW | $50 / kW | $200-300 / kW | $30 - 75 / kW | $450 - 700 / kW | $150 /KW |
| Reagent | Limestone | TrONA | Ammonia | Ammonia or urea | Activated Carbon | Activated Carbon |
| Reagent Cost | - | - | 0.47 | 0.47 | 0.94 | 0.94 |
| Parasitic Load | 3-5% | 0% | 0 | 0 | 3-5% | 0.50% |
| Coal Efficiency | Eastern / Western | Western | Eastern / Western | Eastern / Western | Eastern / Western | Eastern / Western(1) |

*(1) Brominated Activated Carbon for Western Coal*

*Source: Company data, Credit Suisse estimates, EIA*

# SOx Emission Control

There are three commonly used SOx remediation alternatives available today: (a) dry scrubbers, (b) wet scrubbers, and (c) dry sorbent injection.

**Wet and Dry Scrubbers**

The term scrubber generally describes pollution control devices that use a sorbent to remove sulfur dioxide (SOx) from flue gases through chemical reactions. Retrofitting a coal plant with a scrubber is not much different than building an on-site chemical plant. The formal name for scrubber is flue gas desulfurization (FGD) unit and a scrubber is classified as either "wet" or "dry".

*Wet Scrubbers*

- In the wet scrubbing process, a liquid sorbent (such as limestone) is sprayed into the scrubber and comes into contact with SOx in the flue gas. Through chemical reactions a wet slurry waste containing sulfur is created, which is then captured.

- Wet scrubbing can achieve very high levels of SOx reductions, routinely ~95% with some up to 99% removal. Approximately 85% of the FGD systems installed in the US are wet scrubbers.

*Dry Scrubbers*

- In a dry scrubber, particles of dry sorbent (such as slaked lime) instead of liquid sorbent are injected into the flue gas. The flue gas leaving the absorber is not saturated with moisture, hence the name "dry".
- Dry scrubbing has traditionally achieved respectable levels of SOx control (up to 80% removal).

**Dry Sorbent Injection (DSI) / TrONA**

- DSI system injects dry sorbent (generally sodium or calcium based reagents, such as **TrONA**) into the flue gas that bonds with SOx and can be collected in gathering devices, such as baghouses or electrostatic precipitators.
- TrONA is one of the more often used reagents and is also commonly used to produce detergent. TrONA looks bountiful today with deposits exceeding 100 billion tons in the Green River Basin, Wyoming.
- DSI systems have traditionally achieved more modest levels of SOx removal in the range of 40-70%, although new designs have reached removal rates up to 90% SOx when mixed with lower sulfur PRB coal.
- DSI systems are usually easily retrofitted to existing coal plants and have lower capital costs (approximately $50 / KW). Offsetting this is the increased quantity of soluble compound in the fly ash that may prevent the fly ash from being sold as a concrete additive.

## NOx Emission Control

There are two primary sources of NOx when burning fossil fuels: fuel and thermal NOx, Fuel NOx results from the combustion of nitrogen in the coal, while thermal NOx is formed when nitrogen in the air reacts with oxygen during combustion.

**Selective Catalytic Reduction (SCR)**

- The basic principle of SCR is the **reduction** of NOx to nitrogen and water by the reaction of NOx and ammonia within a **catalyst** bed, hence the name "selective catalytic reduction". Commonly used catalysts include titanium oxides, vanadium oxides, platinum and palladium.
- An SCR can provide headline reductions in NOx emissions approaching 100% but in practice commercial SCR systems can meet control targets of over 90%.

**Selective Non-Catalytic Reduction (SNCR)**

- An SNCR is similar in principle to SCR in that it uses an ammonia based chemical process to reduce NOx into nitrogen and water. The difference is that SNCR does not have a catalyst bed (hence the name "non-catalytic reduction"), which decreases its remediation levels to 30% at low temperatures to 75% at high temperatures (versus SCR steady state removal of >90%).

No solid or liquid waste is produced from either method.

**Low NOx Burner (LNB)**

- Low NOx Burners reduce NOx production by delaying the mix of fuel with air, allowing the early stage of combustion to take place at a low air / fuel ratio which lowers the temperature of combustion and reduces generation of NOx. LNB is frequently

supplemented with Open Fire Air (OFA), which is air introduced into the furnace downstream of the low NOx burner to LNB to reduce carbon monoxide and unburned carbon in coal ash. With LNB and OFA, NOx reductions vary from 60 – 70%.

## Particulate Matter (PM) Control

Separate from SOx and NOx, the Clean Air Act requires the EPA to set National Ambient Air Quality Standards (NAAQS) for particulate matters. The reason why we bring it up is that the pollutant control devises that capture Particulate Matter are helpful in mercury removal.

**Electrostatic Precipitators (ESP)**

- Electrostatic precipitators have been used for particulate control since 1923. They use an intense electric field that drives the negatively charged particular matters to the collecting electrodes.
- ESP's removal efficiency is determined by its size, treatment time, and the ratio of the surface area of the collection electrodes. Electrostatic precipitator's overall collection efficiencies can exceed 99.9% and efficiencies in excess of 99.5% are common.

**Fabric Filters (Baghouses)**

- Fabric filter is conceptually simple and acts like the name implies – a system of tightly woven fabric that flue gas passes through and leaves particulates collected in the fabric. The capture systems are quite large; for an average 250 MW plant the baghouse is a compilation of up to 5,000 discrete bags that stretch 20-30 feet long and 5-12 inches in diameter. Baghouses are often are capable of 99.9% removal efficiencies.

## Mercury

The DOE reports that ~37% of the coal borne mercury is removed during coal cleaning processes (pre-burn) and about 50% of the remaining mercury is captured by the industry's existing pollution control systems. Capturing the remaining mercury emissions can be achieved through two approaches: activated carbon injection or multi-pollutant control.

**Multi-Pollutant Control**

- Mercury control can generally achieved by a suite of pollution control of SOx, NOx and particulate matter. A mercury removal rate of >90% has been experienced at coal plants equipped with FGD, SCR and Electrostatic Precipitators / Baghouse. Adding Activated Carbon further increases the mercury removal rate.

**Activated Carbon Injection (ACI)**

- This is one of the simplest approaches to controlling mercury emissions from coal plants. In this process mercury in the flue gas attaches to the large porous area of activated carbon which then is collected by either an ESP or baghouse. Generally speaking, baghouses with activated carbon can achieve a mercury removal rate up to 90% although the costs are high. Using ESP, the removal rate will be lower (<70%).
- For this process to be effective for PRB coal, activated carbon has to be treated with Halogen such as Chlorine or Bromine (Chlorine is naturally occurring in coal, but its concentration is much lower in PRB coal than in eastern coal) which can be quite expensive (could double the cost).

Important thing to know here is baghouse or an ESP is needed if the plant uses activated carbon to reduce mercury

# Appendix II - EPA Regulation

EPA, under Obama administration, has become increasingly visible in shaping the nations environmental policy. We think the two pieces of regulations for coal emission that EPA is working on today (Clean Air Transport Rule and mercury MACT Standard) will be the catalyst for the industry's next investment cycle and play an integral role in deciding the future asset mix of US generation flee. We discuss their respective background below.

## Clean Air Transport Rule (CATR)

CAIR was remanded to EPA by court since its cap and trade program failed to protect downwind states

By way of background, on **March 10, 2005**, EPA issued Clean Air Interstate Rule, a rule that capped emission of sulfur dioxide (SOx) and nitrogen oxides (NOx) in 28 eastern United States and District of Columbia. CAIR features a cap and trade program for SOx and NOx allowing purchase of allowances to offset emission.

Litigation began soon after CAIR was put in place from both environmentalists and the utility industry. On **December 23, 2008**, in the case of *North Carolina v. EPA,* the U.S. Court of Appeals for the D.C. Circuit ruled on petitions for review of CAIR, including their provisions establishing the CAIR NOx and SOx trading programs. The court deemed CAIR "flawed" as EPA can not provide evidence the cap and trade program improves air quality for down wind states. The Court remanded the rules to EPA without vacating them, which leaves CAIR and the trading programs in place until next version of CAIR (CATR) is finalized.

OH, PA, GA will have more work to do for CATR compliance

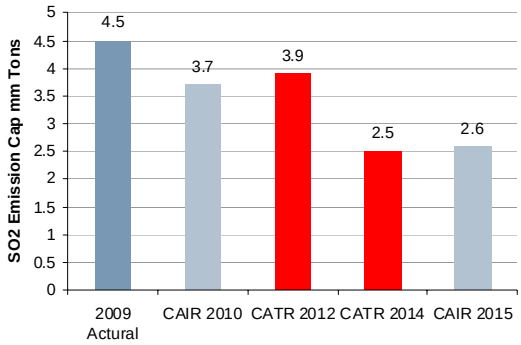
EPA issued Clean Air Transport Rule (CATR) proposal on July 6th, 2010, setting emission caps for SOx and NOx for 31 eastern states and DC. As shown in Exhibit 136 and Exhibit 137, the CATR rule imposes similar emission cap as CAIR but with compliance date one year earlier (2014 vs 2015). Without the national trading program, states with higher emissions that were allocated higher allowance in the SOx / NOx trading program will be under higher pressure to catch up giving difference in existing emission level. As shown in Exhibit 138, Ohio, Pennsylvania, Indiana, and Georgia are the top emission states in terms of contribution to the national SOX inventory.

Implementation of CATR will be in two phases. In 2012, CATR states need to have SOX emission below Phase I cap (3.9 MM tons or 0.39 lb / MMBtu); by 2014 CATR will further reduce national SOX emissions to 2.5 MM tons (Phase II, 0.25 lb / MMBtu).

CATR does not target significant NOx reductions. In 2012, CATR states are required to be compliant with Phase I cap (1.4 MM tons) which is higher than 2009 actual emission level 1.3 MM tons. The story does not end here however, as the EPA believes additional NOx reduction will be needed to achieve ozone standards. Therefore the agency plans to propose Transport II in summer 2011 and finalize in summer 2012. There is no assurance how low the NOx cap could go but industry sources generally agree the risk is bounded,

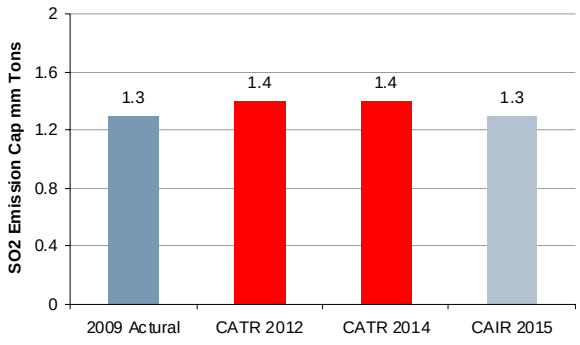
In terms of time frames, CATR allows Inter-year trading which means utilities can borrow ahead which provides cushion in compliance timing. Also worth noting, CATR will have limited regional trading for SOx and NOx but not at the national level since trading allows emission generated in upwind states to be offset by allowance bought from downwind states, and the court found the lack of locational emission protection to be flawed.

**Exhibit 136: CATR vs CAIR for SOX Emission Cap (CATR states)**




*Source: Company data, Credit Suisse estimates, EPA*

**Exhibit 137: CATR vs CAIR for NOx Emission Cap (CATR states)**




*Source: Company data, Credit Suisse estimates, EPA*

# Mercury Rule

On **March 15, 2005,** EPA issued CAMR (Clean Air Mercury Rule) to permanently cap and reduce mercury emissions from coal-fired power plants for the first time.

The goal of CAMR was to reduce utility emissions of mercury from 48 tons a year to 15 tons, a reduction of nearly 70% in a two step approach with full compliance targeted for 2018.

On **February 8, 2008**, the D.C. Circuit vacated CAMR on the ground that EPA violated the Clean Air Act Section 112 as section 112 requires regulation of emissions of hazardous air pollutants, including Mercury, through enforcement of Maximum Achievable Control Technology (MACT) Standard as opposed to the adopted cap and trade approach. Again, the goal of the court decision was to better address localized pollutants which were lost in a cap and trade system.

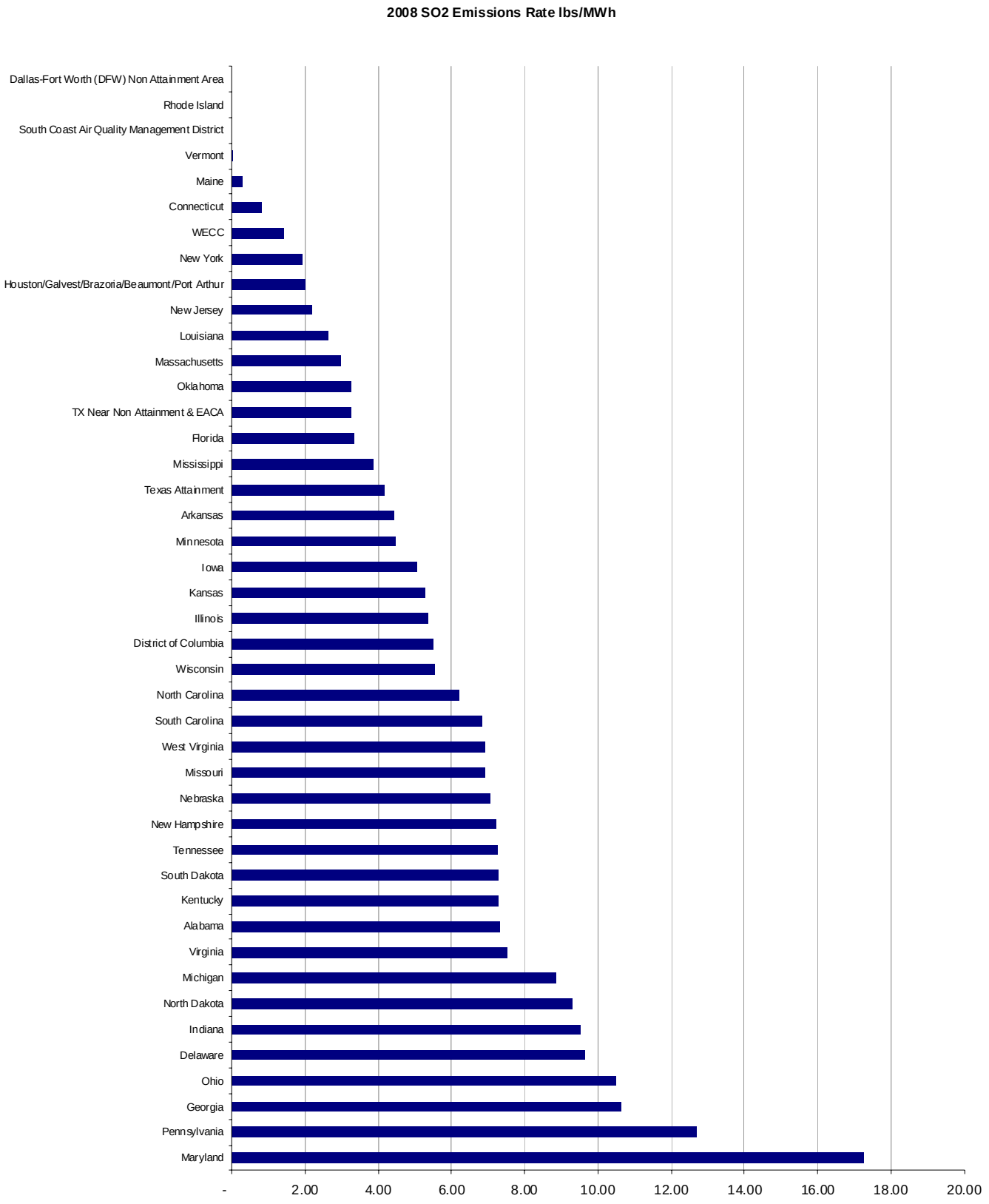
CAMR was vacated since Clean Air Act requires hazardous pollutant regulation to be MACT based

EPA is drafting a new mercury rule with a mandatory date of March 16th, 2011 or earlier. The new rule must conform with the MACT (Maximum Achievable Control Technology) Standard which means each unit over 25 MW must be as good as the average of the top 12% of plants, generally thought of as a ~ 90% removal level. The MACT rule will not allow for credit trading between plants although some relief could come (selectively) if the EPA sets different compliance standards for different coal plant configurations like size, boiler pressure / temperature or coal mix, which would allow some to comply below 90%, while others would be held to a higher MACT standard.

Once the rulemaking process is complete (EPA is shooting to finalize the rule by November 16th, 2011), affected utilities would have three years (by 2015) to comply with the standard.

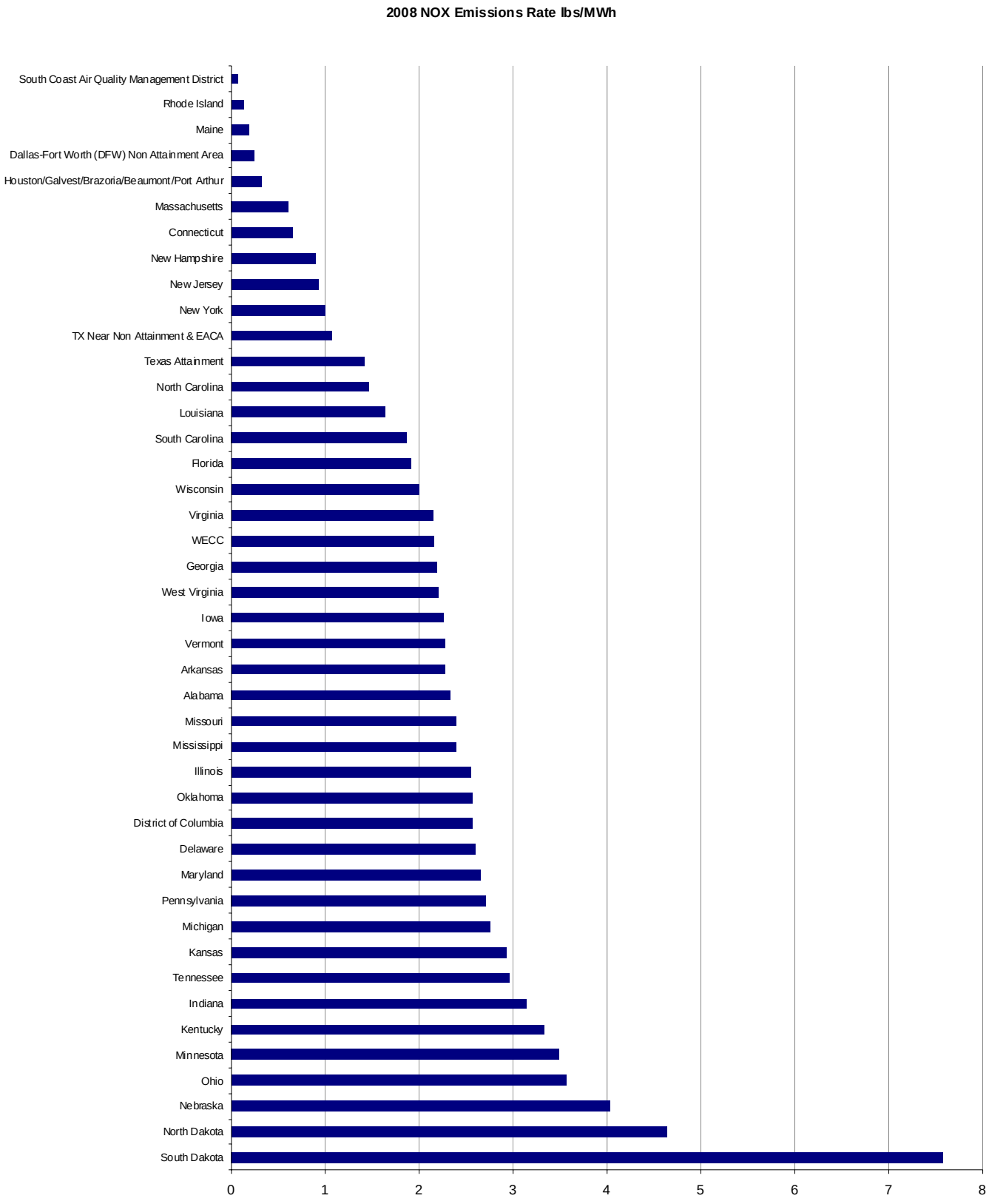
We expect Mercury rule to have profound impact on the electric industry, requiring significant capex based on the suite of equipment needed to demonstrably reach high removal rate.

## Exhibit 138: **2008 State Level SOX Emission (lbs / MWh)**



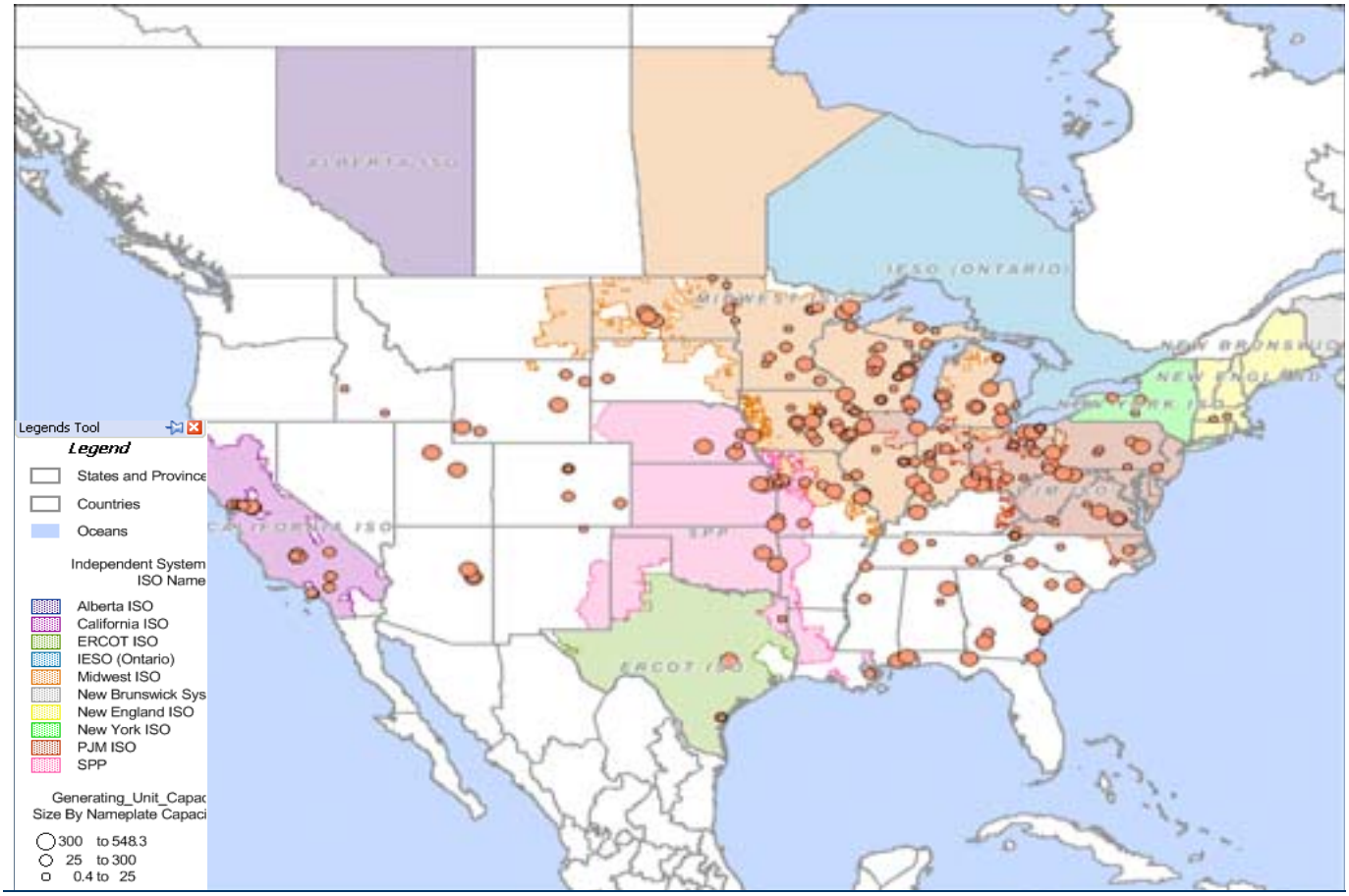

*Source: Company data, Credit Suisse estimates, Energy Velocity*

## Exhibit 139: 2008 State Level NOx Emission (lbs / MWh)




*Source: Company data, Credit Suisse estimates, Energy Velocity*

**Exhibit 140: Location of Un-Scrubbed Coal Plants**




*Source: Energy Velocity, Credit Suisse estimates*

# Appendix III – Earnings Under Closure Scenarios

**Exhibit 141: 2010 – 2020 EPS (No Retirements)**

| No Retirements | EPS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 2.16 | 2.21 | 1.40 | 1.67 | 2.27 | 2.63 | 3.16 | 3.63 | 3.61 | 4.21 | 4.59 |
| D | 3.41 | 3.21 | 3.23 | 3.52 | 3.59 | 3.78 | 3.95 | 4.10 | 4.31 | 4.45 | 4.57 |
| EIX | 3.30 | 3.05 | 2.72 | 3.05 | 3.49 | 3.65 | 3.93 | 4.26 | 4.25 | 4.62 | 4.73 |
| ETR | 6.69 | 6.89 | 6.55 | 6.58 | 6.68 | 7.07 | 7.19 | 7.38 | 7.59 | 8.01 | 8.01 |
| EXC | 3.93 | 3.94 | 3.03 | 2.95 | 2.91 | 3.05 | 3.28 | 3.49 | 3.66 | 3.95 | 3.95 |
| FE | 3.66 | 3.32 | 3.08 | 3.33 | 3.58 | 3.66 | 4.50 | 4.45 | 4.76 | 5.17 | 5.49 |
| NEE | 4.45 | 4.41 | 4.62 | 4.75 | 5.15 | 5.72 | 6.18 | 6.54 | 6.78 | 7.30 | 7.18 |
| PEG | 3.04 | 2.88 | 2.77 | 3.13 | 3.58 | 3.87 | 4.15 | 4.31 | 4.55 | 4.71 | 4.92 |
| FE/AYE (no synergy) | 3.55 | 3.32 | 2.81 | 3.11 | 3.53 | 3.74 | 4.57 | 4.71 | 4.93 | 5.46 | 5.84 |
| FE/AYE (half synergy) | 3.55 | 3.46 | 3.09 | 3.46 | 3.91 | 4.16 | 5.00 | 5.15 | 5.37 | 5.91 | 6.29 |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 142: 2010 – 2020 EBITDA (No Retirements)**

| No Retirements | EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 1,227 | 1,248 | 1,071 | 1,159 | 1,350 | 1,459 | 1,597 | 1,680 | 1,640 | 1,748 | 1,795 |
| D | 4,959 | 4,779 | 4,970 | 5,415 | 5,588 | 5,871 | 6,101 | 6,321 | 6,564 | 6,731 | 6,870 |
| EIX | 3,684 | 3,879 | 3,907 | 4,284 | 4,635 | 4,865 | 5,085 | 5,291 | 5,421 | 5,551 | 5,640 |
| ETR | 3,728 | 3,713 | 3,637 | 3,703 | 3,705 | 3,784 | 3,789 | 3,807 | 3,826 | 3,895 | 3,860 |
| EXC | 5,966 | 6,077 | 5,207 | 5,295 | 5,415 | 5,735 | 6,113 | 6,442 | 6,679 | 7,029 | 7,073 |
| FE | 3,292 | 3,349 | 3,255 | 3,401 | 3,548 | 3,604 | 4,011 | 3,985 | 4,131 | 4,308 | 4,437 |
| NEE | 4,787 | 4,939 | 5,402 | 5,762 | 6,040 | 6,425 | 6,702 | 6,892 | 7,048 | 7,227 | 7,007 |
| PEG | 3,764 | 3,786 | 3,720 | 4,018 | 4,311 | 4,456 | 4,583 | 4,593 | 4,668 | 4,682 | 4,707 |
| FE/AYE (no synergy) | 4,520 | 4,597 | 4,327 | 4,560 | 4,898 | 5,062 | 5,608 | 5,665 | 5,771 | 6,056 | 6,233 |
| FE/AYE (half synergy) | 4,520 | 4,687 | 4,502 | 4,785 | 5,138 | 5,327 | 5,873 | 5,930 | 6,036 | 6,321 | 6,498 |
| RRI | 293 | 334 | 390 | 437 | 515 | 557 | 592 | 633 | 663 | 678 | 689 |

*Source: Company data, Credit Suisse estimates*

**Exhibit 143: 2010 – 2020 P/E (No Retirements)**

| No Retirements | P/E | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 10.8x | 10.5x | 16.6x | 13.9x | 10.3x | 8.8x | 7.4x | 6.4x | 6.4x | 5.5x | 5.1x |
| D | 13.0x | 13.8x | 13.7x | 12.5x | 12.3x | 11.7x | 11.2x | 10.8x | 10.3x | 9.9x | 9.7x |
| EIX | 10.6x | 11.4x | 12.8x | 11.4x | 10.0x | 9.5x | 8.9x | 8.2x | 8.2x | 7.5x | 7.4x |
| ETR | 11.5x | 11.2x | 11.8x | 11.7x | 11.5x | 10.9x | 10.7x | 10.4x | 10.1x | 9.6x | 9.6x |
| EXC | 10.9x | 10.9x | 14.2x | 14.6x | 14.8x | 14.1x | 13.1x | 12.3x | 11.7x | 10.9x | 10.9x |
| FE | 10.1x | 11.2x | 12.0x | 11.1x | 10.4x | 10.1x | 8.2x | 8.3x | 7.8x | 7.2x | 6.8x |
| NEE | 12.2x | 12.3x | 11.8x | 11.4x | 10.5x | 9.5x | 8.8x | 8.3x | 8.0x | 7.4x | 7.6x |
| PEG | 10.6x | 11.2x | 11.7x | 10.3x | 9.1x | 8.4x | 7.8x | 7.5x | 7.1x | 6.9x | 6.6x |
| FE/AYE (no synergy) | 10.4x | 11.2x | 13.2x | 11.9x | 10.5x | 9.9x | 8.1x | 7.9x | 7.5x | 6.8x | 0.0x |
| FE/AYE (half synergy) | 10.4x | 10.7x | 12.0x | 10.7x | 9.5x | 8.9x | 7.4x | 7.2x | 6.9x | 6.3x | 0.0x |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 144: 2010 – 2020 EV/EBITDA (No Retirements)**

| No Retirements | EV/EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 6.4x | 6.6x | 7.8x | 7.5x | 6.6x | 6.1x | 5.4x | 5.0x | 5.0x | 4.6x | 4.3x |
| D | 8.7x | 9.2x | 9.2x | 8.7x | 8.7x | 8.4x | 8.2x | 8.0x | 7.8x | 7.6x | 7.6x |
| EIX | 7.1x | 7.1x | 7.4x | 7.2x | 7.0x | 6.8x | 6.5x | 6.3x | 6.1x | 5.8x | 5.6x |
| ETR | 6.8x | 7.0x | 7.2x | 6.9x | 6.8x | 6.6x | 6.5x | 6.3x | 6.2x | 6.0x | 5.9x |
| EXC | 6.5x | 6.6x | 7.9x | 8.1x | 8.1x | 7.9x | 7.5x | 7.2x | 7.0x | 6.6x | 6.6x |
| FE | 8.1x | 7.9x | 8.2x | 8.1x | 7.8x | 7.8x | 7.0x | 7.0x | 6.7x | 6.4x | 6.1x |
| NEE | 8.7x | 8.9x | 8.6x | 8.3x | 8.0x | 7.6x | 7.2x | 6.9x | 6.6x | 6.3x | 6.4x |
| PEG | 6.7x | 6.8x | 7.1x | 6.5x | 6.0x | 5.8x | 5.5x | 5.3x | 5.1x | 5.0x | 4.9x |
| FE/AYE (no synergy) | 7.7x | 7.6x | 8.2x | 8.0x | 7.5x | 7.3x | 6.6x | 6.4x | 6.3x | 5.9x | 5.6x |
| FE/AYE (half synergy) | 7.7x | 7.5x | 7.9x | 7.6x | 7.2x | 6.9x | 6.3x | 6.2x | 6.0x | 5.6x | 5.4x |
| RRI | 10.2x | 8.4x | 6.7x | 6.1x | 5.1x | 4.7x | 4.3x | 3.9x | 3.5x | 3.2x | 3.2x |

*Source: Company data, Credit Suisse estimates*

**Exhibit 145: 2010 – 2020 EPS Impact (60 GW Retirement 2013-2017)**

| 60 GW Retirement | EPS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 2.16 | 2.21 | 1.40 | 1.77 | 2.81 | 3.57 | 4.46 | 5.14 | 4.86 | 5.26 | 5.47 |
| D | 3.41 | 3.21 | 3.23 | 3.58 | 3.76 | 4.05 | 4.30 | 4.51 | 4.68 | 4.79 | 4.88 |
| EIX | 3.30 | 3.05 | 2.72 | 3.08 | 3.67 | 3.94 | 4.28 | 4.59 | 4.42 | 4.66 | 4.66 |
| ETR | 6.69 | 6.89 | 6.55 | 6.64 | 6.80 | 7.26 | 7.46 | 7.73 | 7.96 | 8.40 | 8.41 |
| EXC | 3.93 | 3.94 | 3.03 | 3.18 | 3.61 | 4.16 | 4.82 | 5.39 | 5.48 | 5.70 | 5.63 |
| FE | 3.66 | 3.35 | 3.19 | 3.74 | 4.43 | 5.03 | 6.27 | 6.36 | 6.50 | 6.71 | 6.78 |
| NEE | 4.45 | 4.41 | 4.62 | 4.75 | 5.16 | 5.73 | 6.20 | 6.56 | 6.80 | 7.33 | 7.20 |
| PEG | 3.05 | 2.88 | 2.79 | 3.22 | 3.76 | 4.12 | 4.41 | 4.55 | 4.69 | 4.77 | 4.91 |
| FE/AYE (no synergy) | 3.55 | 3.34 | 2.90 | 3.45 | 4.37 | 5.11 | 6.38 | 6.71 | 6.70 | 7.00 | 7.12 |
| FE/AYE (half synergy) | 3.55 | 3.48 | 3.17 | 3.80 | 4.75 | 5.54 | 6.82 | 7.15 | 7.15 | 7.45 | 7.58 |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 6.1% | 24.3% | 35.7% | 41.0% | 41.6% | 34.5% | 24.9% | 19.1% |
| D | 0.0% | 0.0% | 0.0% | 1.5% | 4.7% | 7.0% | 8.8% | 9.9% | 8.6% | 7.7% | 6.9% |
| EIX | 0.0% | 0.0% | 0.0% | 0.9% | 5.2% | 7.8% | 8.7% | 7.8% | 4.1% | 0.9% | -1.5% |
| ETR | 0.0% | 0.0% | 0.1% | 0.9% | 1.8% | 2.7% | 3.7% | 4.7% | 4.9% | 4.9% | 5.0% |
| EXC | 0.0% | 0.0% | 0.1% | 7.8% | 24.2% | 36.2% | 47.0% | 54.4% | 49.7% | 44.4% | 42.3% |
| FE | 0.0% | 0.8% | 3.8% | 12.2% | 23.7% | 37.4% | 39.4% | 43.0% | 36.7% | 29.9% | 23.5% |
| NEE | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.2% | 0.2% | 0.3% | 0.3% | 0.3% | 0.4% |
| PEG | 0.1% | 0.1% | 0.6% | 3.0% | 5.2% | 6.3% | 6.3% | 5.6% | 3.1% | 1.2% | -0.2% |
| FE/AYE (no synergy) | 0.0% | 0.6% | 3.0% | 10.9% | 23.8% | 36.9% | 39.8% | 42.3% | 35.9% | 28.2% | 21.9% |
| FE/AYE (half synergy) | 0.0% | 0.6% | 2.8% | 9.8% | 21.5% | 33.2% | 36.4% | 38.8% | 33.0% | 26.1% | 20.5% |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 146: 2010 – 2020 EBITDA Impact (60 GW Retirement 2013-2017)**

| 60 GW Retirement | EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 1,227 | 1,248 | 1,071 | 1,187 | 1,501 | 1,696 | 1,899 | 2,000 | 1,874 | 1,911 | 1,903 |
| D | 4,959 | 4,779 | 4,970 | 5,464 | 5,744 | 6,111 | 6,414 | 6,684 | 6,887 | 7,023 | 7,131 |
| EIX | 3,684 | 3,879 | 3,907 | 4,299 | 4,732 | 5,013 | 5,259 | 5,450 | 5,488 | 5,542 | 5,572 |
| ETR | 3,728 | 3,713 | 3,639 | 3,719 | 3,737 | 3,834 | 3,856 | 3,893 | 3,914 | 3,985 | 3,949 |
| EXC | 5,966 | 6,077 | 5,209 | 5,542 | 6,156 | 6,874 | 7,666 | 8,297 | 8,349 | 8,544 | 8,420 |
| FE | 3,292 | 3,362 | 3,311 | 3,593 | 3,939 | 4,218 | 4,785 | 4,793 | 4,831 | 4,891 | 4,891 |
| NEE | 4,787 | 4,939 | 5,402 | 5,764 | 6,045 | 6,432 | 6,711 | 6,903 | 7,059 | 7,239 | 7,019 |
| PEG | 3,767 | 3,790 | 3,734 | 4,092 | 4,455 | 4,633 | 4,762 | 4,750 | 4,748 | 4,699 | 4,681 |
| FE/AYE (no synergy) | 4,520 | 4,610 | 4,383 | 4,781 | 5,440 | 5,914 | 6,684 | 6,792 | 6,704 | 6,803 | 6,795 |
| FE/AYE (half synergy) | 4,520 | 4,700 | 4,558 | 5,006 | 5,680 | 6,179 | 6,949 | 7,057 | 6,969 | 7,068 | 7,060 |
| | | | | | | | | | | | |
| RRI | 293 | 334 | 390 | 460 | 612 | 696 | 755 | 794 | 771 | 745 | 723 |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 2.4% | 11.2% | 16.3% | 18.9% | 19.0% | 14.2% | 9.4% | 6.0% |
| D | 0.0% | 0.0% | 0.0% | 0.9% | 2.8% | 4.1% | 5.1% | 5.7% | 4.9% | 4.3% | 3.8% |
| EIX | 0.0% | 0.0% | 0.0% | 0.3% | 2.1% | 3.0% | 3.4% | 3.0% | 1.2% | -0.2% | -1.2% |
| ETR | 0.0% | 0.0% | 0.0% | 0.4% | 0.8% | 1.3% | 1.8% | 2.2% | 2.3% | 2.3% | 2.3% |
| EXC | 0.0% | 0.0% | 0.0% | 4.7% | 13.7% | 19.9% | 25.4% | 28.8% | 25.0% | 21.6% | 19.0% |
| FE | 0.0% | 0.4% | 1.7% | 5.7% | 11.0% | 17.0% | 19.3% | 20.3% | 16.9% | 13.5% | 10.2% |
| NEE | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 0.2% | 0.2% | 0.2% | 0.2% |
| PEG | 0.1% | 0.1% | 0.4% | 1.9% | 3.3% | 4.0% | 3.9% | 3.4% | 1.7% | 0.4% | -0.6% |
| FE/AYE (no synergy) | 0.0% | 0.3% | 1.3% | 4.8% | 11.1% | 16.8% | 19.2% | 19.9% | 16.2% | 12.3% | 9.0% |
| FE/AYE (half synergy) | 0.0% | 0.3% | 1.2% | 4.6% | 10.5% | 16.0% | 18.3% | 19.0% | 15.5% | 11.8% | 8.7% |
| | | | | | | | | | | | |
| RRI | 0.0% | 0.0% | 0.0% | 5.3% | 18.8% | 25.0% | 27.5% | 25.5% | 16.4% | 9.9% | 5.0% |

*Source: Company data, Credit Suisse estimates*

**Exhibit 147: 2010 – 2020 P/E Impact (60 GW Retirement 2013-2017)**

| 60 GW Retirement | P/E | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 10.8x | 10.5x | 16.6x | 13.1x | 8.3x | 6.5x | 5.2x | 4.5x | 4.8x | 4.4x | 4.2x |
| D | 13.0x | 13.8x | 13.7x | 12.4x | 11.8x | 10.9x | 10.3x | 9.8x | 9.4x | 9.2x | 9.1x |
| EIX | 10.6x | 11.4x | 12.8x | 11.3x | 9.5x | 8.8x | 8.1x | 7.6x | 7.9x | 7.5x | 7.5x |
| ETR | 11.5x | 11.2x | 11.8x | 11.6x | 11.3x | 10.6x | 10.3x | 10.0x | 9.7x | 9.2x | 9.2x |
| EXC | 10.9x | 10.9x | 14.2x | 13.5x | 11.9x | 10.3x | 8.9x | 8.0x | 7.8x | 7.5x | 7.6x |
| FE | 10.1x | 11.1x | 11.6x | 9.9x | 8.4x | 7.4x | 5.9x | 5.8x | 5.7x | 5.5x | 5.5x |
| NEE | 12.2x | 12.3x | 11.8x | 11.4x | 10.5x | 9.5x | 8.8x | 8.3x | 8.0x | 7.4x | 7.5x |
| PEG | 10.6x | 11.2x | 11.6x | 10.0x | 8.6x | 7.9x | 7.3x | 7.1x | 6.9x | 6.8x | 6.6x |
| FE/AYE (no synergy) | 10.4x | 11.1x | 12.8x | 10.8x | 8.5x | 7.2x | 5.8x | 5.5x | 5.5x | 5.3x | 5.2x |
| FE/AYE (half synergy) | 10.4x | 10.7x | 11.7x | 9.8x | 7.8x | 6.7x | 5.4x | 5.2x | 5.2x | 5.0x | 4.9x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

| % Chg from No Retirements | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AYE | 0.0x | 0.0x | 0.0x | -0.8x | -2.0x | -2.3x | -2.1x | -1.9x | -1.7x | -1.1x | -0.8x |
| D | 0.0x | 0.0x | 0.0x | -0.2x | -0.6x | -0.8x | -0.9x | -1.0x | -0.8x | -0.7x | -0.6x |
| EIX | 0.0x | 0.0x | 0.0x | -0.1x | -0.5x | -0.7x | -0.7x | -0.6x | -0.3x | -0.1x | 0.1x |
| ETR | 0.0x | 0.0x | 0.0x | -0.1x | -0.2x | -0.3x | -0.4x | -0.5x | -0.5x | -0.5x | -0.5x |
| EXC | 0.0x | 0.0x | 0.0x | -1.1x | -2.9x | -3.7x | -4.2x | -4.3x | -3.9x | -3.3x | -3.2x |
| FE | 0.0x | -0.1x | -0.4x | -1.2x | -2.0x | -2.8x | -2.3x | -2.5x | -2.1x | -1.7x | -1.3x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x |
| PEG | 0.0x | 0.0x | -0.1x | -0.3x | -0.5x | -0.5x | -0.5x | -0.4x | -0.2x | -0.1x | 0.0x |
| FE/AYE (no synergy) | 0.0x | -0.1x | -0.4x | -1.2x | -2.0x | -2.7x | -2.3x | -2.3x | -2.0x | -1.5x | 5.2x |
| FE/AYE (half synergy) | 0.0x | -0.1x | -0.3x | -1.0x | -1.7x | -2.2x | -2.0x | -2.0x | -1.7x | -1.3x | 4.9x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 148: 2010 – 2020 EV/EBITDA Impact (60 GW Retirement 2013-2017)**

| 60 GW Retirement | EV/EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 6.4x | 6.6x | 7.8x | 7.3x | 5.9x | 5.1x | 4.4x | 4.0x | 4.2x | 3.9x | 3.8x |
| D | 8.7x | 9.2x | 9.2x | 8.6x | 8.4x | 8.0x | 7.7x | 7.5x | 7.4x | 7.3x | 7.2x |
| EIX | 7.1x | 7.1x | 7.4x | 7.2x | 6.8x | 6.6x | 6.3x | 6.0x | 5.9x | 5.7x | 5.6x |
| ETR | 6.8x | 7.0x | 7.2x | 6.9x | 6.8x | 6.5x | 6.3x | 6.2x | 6.0x | 5.8x | 5.7x |
| EXC | 6.5x | 6.6x | 7.9x | 7.7x | 7.0x | 6.4x | 5.7x | 5.1x | 5.0x | 4.8x | 4.7x |
| FE | 8.1x | 7.9x | 8.1x | 7.6x | 6.9x | 6.4x | 5.6x | 5.5x | 5.3x | 5.2x | 5.1x |
| NEE | 8.7x | 8.9x | 8.6x | 8.3x | 8.0x | 7.6x | 7.2x | 6.8x | 6.6x | 6.3x | 6.4x |
| PEG | 6.7x | 6.8x | 7.1x | 6.4x | 5.8x | 5.5x | 5.2x | 5.1x | 5.0x | 4.9x | 4.9x |
| FE/AYE (no synergy) | 7.7x | 7.6x | 8.1x | 7.6x | 6.7x | 6.1x | 5.3x | 5.1x | 5.0x | 4.9x | 4.8x |
| FE/AYE (half synergy) | 7.7x | 7.5x | 7.8x | 7.2x | 6.4x | 5.8x | 5.1x | 4.9x | 4.9x | 4.7x | 4.6x |
| | | | | | | | | | | | |
| RRI | 10.2x | 8.4x | 6.7x | 5.6x | 3.8x | 2.9x | 2.1x | 1.5x | 1.2x | 1.1x | 1.1x |

| % Chg from No Retirements | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AYE | 0.0x | 0.0x | 0.0x | -0.2x | -0.7x | -1.0x | -1.0x | -1.0x | -0.8x | -0.6x | -0.5x |
| D | 0.0x | 0.0x | 0.0x | -0.1x | -0.3x | -0.4x | -0.4x | -0.5x | -0.4x | -0.4x | -0.4x |
| EIX | 0.0x | 0.0x | 0.0x | 0.0x | -0.2x | -0.2x | -0.3x | -0.3x | -0.2x | -0.1x | 0.0x |
| ETR | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.2x | -0.2x | -0.2x | -0.2x |
| EXC | 0.0x | 0.0x | 0.0x | -0.4x | -1.1x | -1.5x | -1.8x | -2.0x | -2.0x | -1.8x | -1.8x |
| FE | 0.0x | 0.0x | -0.2x | -0.5x | -0.9x | -1.3x | -1.4x | -1.5x | -1.4x | -1.2x | -1.0x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x |
| PEG | 0.0x | 0.0x | 0.0x | -0.1x | -0.2x | -0.3x | -0.3x | -0.2x | -0.2x | -0.1x | 0.0x |
| FE/AYE (no synergy) | 0.0x | 0.0x | -0.1x | -0.4x | -0.8x | -1.2x | -1.3x | -1.4x | -1.2x | -1.0x | -0.9x |
| FE/AYE (half synergy) | 0.0x | 0.0x | -0.1x | -0.4x | -0.8x | -1.1x | -1.2x | -1.3x | -1.1x | -1.0x | -0.8x |

*Source: Company data, Credit Suisse estimates*

**Exhibit 149: 2010 – 2020 EPS Impact (35 GW Retirement 2013-2017)**

| 35 GW Retirement | EPS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 2.16 | 2.21 | 1.40 | 1.73 | 2.57 | 3.30 | 4.18 | 4.92 | 5.04 | 5.71 | 6.02 |
| D | 3.41 | 3.21 | 3.22 | 3.56 | 3.69 | 3.97 | 4.22 | 4.44 | 4.66 | 4.81 | 4.91 |
| EIX | 3.30 | 3.05 | 2.72 | 3.04 | 3.52 | 3.77 | 4.11 | 4.44 | 4.42 | 4.74 | 4.76 |
| ETR | 6.69 | 6.89 | 6.55 | 6.63 | 6.78 | 7.23 | 7.41 | 7.67 | 7.90 | 8.33 | 8.34 |
| EXC | 3.93 | 3.94 | 3.03 | 3.07 | 3.27 | 3.72 | 4.29 | 4.84 | 5.13 | 5.51 | 5.54 |
| FE | 3.66 | 3.34 | 3.14 | 3.57 | 4.08 | 4.55 | 5.76 | 5.97 | 6.44 | 6.74 | 7.00 |
| NEE | 4.45 | 4.41 | 4.62 | 4.75 | 5.16 | 5.73 | 6.19 | 6.56 | 6.80 | 7.32 | 7.20 |
| PEG | 3.05 | 2.88 | 2.78 | 3.19 | 3.69 | 4.08 | 4.44 | 4.60 | 4.79 | 4.88 | 5.03 |
| FE/AYE (no synergy) | 3.55 | 3.33 | 2.86 | 3.31 | 4.02 | 4.66 | 5.90 | 6.33 | 6.72 | 7.18 | 7.48 |
| FE/AYE (half synergy) | 3.55 | 3.47 | 3.13 | 3.66 | 4.40 | 5.08 | 6.33 | 6.77 | 7.17 | 7.64 | 7.94 |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 3.6% | 13.6% | 25.7% | 32.3% | 35.4% | 39.5% | 35.5% | 31.0% |
| D | 0.0% | -0.1% | -0.2% | 0.9% | 2.8% | 4.9% | 6.7% | 8.2% | 8.1% | 8.0% | 7.5% |
| EIX | 0.0% | 0.0% | 0.0% | -0.4% | 0.9% | 3.2% | 4.6% | 4.3% | 4.0% | 2.6% | 0.7% |
| ETR | 0.0% | 0.0% | 0.1% | 0.7% | 1.4% | 2.2% | 3.0% | 3.8% | 4.0% | 4.0% | 4.2% |
| EXC | 0.0% | 0.0% | 0.0% | 4.2% | 12.3% | 21.8% | 30.7% | 38.5% | 40.3% | 39.7% | 40.0% |
| FE | 0.0% | 0.5% | 2.1% | 7.1% | 14.0% | 24.3% | 28.0% | 34.1% | 35.3% | 30.5% | 27.6% |
| NEE | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.2% | 0.2% | 0.3% | 0.3% | 0.3% | 0.3% |
| PEG | 0.1% | 0.1% | 0.4% | 1.8% | 3.3% | 5.3% | 6.9% | 6.7% | 5.2% | 3.6% | 2.4% |
| FE/AYE (no synergy) | 0.0% | 0.3% | 1.7% | 6.4% | 13.9% | 24.7% | 29.1% | 34.3% | 36.3% | 31.6% | 28.2% |
| FE/AYE (half synergy) | 0.0% | 0.3% | 1.6% | 5.7% | 12.6% | 22.2% | 26.7% | 31.5% | 33.4% | 29.3% | 26.2% |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 150: 2010 – 2020 EBITDA Impact (35 GW Retirement 2013-2017)**

| 35 GW Retirement | EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 1,227 | 1,248 | 1,071 | 1,176 | 1,435 | 1,631 | 1,837 | 1,958 | 1,926 | 2,014 | 2,017 |
| D | 4,959 | 4,777 | 4,963 | 5,444 | 5,682 | 6,041 | 6,341 | 6,621 | 6,873 | 7,040 | 7,162 |
| EIX | 3,684 | 3,879 | 3,907 | 4,277 | 4,652 | 4,928 | 5,179 | 5,382 | 5,502 | 5,600 | 5,639 |
| ETR | 3,728 | 3,713 | 3,638 | 3,716 | 3,731 | 3,825 | 3,843 | 3,877 | 3,898 | 3,969 | 3,933 |
| EXC | 5,966 | 6,077 | 5,208 | 5,428 | 5,791 | 6,425 | 7,135 | 7,772 | 8,073 | 8,442 | 8,424 |
| FE | 3,292 | 3,356 | 3,287 | 3,514 | 3,780 | 4,004 | 4,567 | 4,639 | 4,834 | 4,940 | 5,025 |
| NEE | 4,787 | 4,939 | 5,402 | 5,764 | 6,044 | 6,431 | 6,710 | 6,902 | 7,058 | 7,238 | 7,018 |
| PEG | 3,766 | 3,788 | 3,729 | 4,064 | 4,401 | 4,607 | 4,783 | 4,786 | 4,815 | 4,777 | 4,762 |
| FE/AYE (no synergy) | 4,520 | 4,604 | 4,358 | 4,690 | 5,215 | 5,635 | 6,405 | 6,598 | 6,760 | 6,954 | 7,042 |
| FE/AYE (half synergy) | 4,520 | 4,694 | 4,533 | 4,915 | 5,455 | 5,900 | 6,670 | 6,863 | 7,025 | 7,219 | 7,307 |
| | | | | | | | | | | | |
| RRI | 293 | 334 | 390 | 447 | 560 | 652 | 727 | 785 | 812 | 815 | 805 |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 1.4% | 6.3% | 11.8% | 15.1% | 16.6% | 17.4% | 15.2% | 12.4% |
| D | 0.0% | 0.0% | -0.1% | 0.5% | 1.7% | 2.9% | 3.9% | 4.7% | 4.7% | 4.6% | 4.2% |
| EIX | 0.0% | 0.0% | 0.0% | -0.2% | 0.4% | 1.3% | 1.9% | 1.7% | 1.5% | 0.9% | 0.0% |
| ETR | 0.0% | 0.0% | 0.0% | 0.3% | 0.7% | 1.1% | 1.4% | 1.8% | 1.9% | 1.9% | 1.9% |
| EXC | 0.0% | 0.0% | 0.0% | 2.5% | 6.9% | 12.0% | 16.7% | 20.6% | 20.9% | 20.1% | 19.1% |
| FE | 0.0% | 0.2% | 1.0% | 3.3% | 6.5% | 11.1% | 13.9% | 16.4% | 17.0% | 14.7% | 13.2% |
| NEE | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| PEG | 0.0% | 0.1% | 0.2% | 1.1% | 2.1% | 3.4% | 4.4% | 4.2% | 3.1% | 2.0% | 1.2% |
| FE/AYE (no synergy) | 0.0% | 0.2% | 0.7% | 2.8% | 6.5% | 11.3% | 14.2% | 16.5% | 17.1% | 14.8% | 13.0% |
| FE/AYE (half synergy) | 0.0% | 0.2% | 0.7% | 2.7% | 6.2% | 10.7% | 13.6% | 15.7% | 16.4% | 14.2% | 12.5% |
| | | | | | | | | | | | |
| RRI | 0.0% | 0.0% | 0.0% | 2.2% | 8.7% | 17.1% | 22.7% | 24.0% | 22.5% | 20.3% | 16.9% |

*Source: Company data, Credit Suisse estimates*

**Exhibit 151: 2010 – 2020 P/E Impact (35 GW Retirement 2013-2017)**

| 35 GW Retirement | P/E | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 10.8x | 10.5x | 16.6x | 13.4x | 9.0x | 7.0x | 5.6x | 4.7x | 4.6x | 4.1x | 3.9x |
| D | 13.0x | 13.8x | 13.7x | 12.4x | 12.0x | 11.1x | 10.5x | 10.0x | 9.5x | 9.2x | 9.0x |
| EIX | 10.6x | 11.4x | 12.8x | 11.4x | 9.9x | 9.2x | 8.5x | 7.8x | 7.9x | 7.3x | 7.3x |
| ETR | 11.5x | 11.2x | 11.8x | 11.6x | 11.4x | 10.7x | 10.4x | 10.1x | 9.8x | 9.2x | 9.2x |
| EXC | 10.9x | 10.9x | 14.2x | 14.0x | 13.1x | 11.5x | 10.0x | 8.9x | 8.4x | 7.8x | 7.8x |
| FE | 10.1x | 11.1x | 11.8x | 10.4x | 9.1x | 8.2x | 6.4x | 6.2x | 5.8x | 5.5x | 5.3x |
| NEE | 12.2x | 12.3x | 11.8x | 11.4x | 10.5x | 9.5x | 8.8x | 8.3x | 8.0x | 7.4x | 7.5x |
| PEG | 10.6x | 11.2x | 11.7x | 10.2x | 8.8x | 7.9x | 7.3x | 7.0x | 6.8x | 6.6x | 6.4x |
| FE/AYE (no synergy) | 10.4x | 11.1x | 12.9x | 11.2x | 9.2x | 8.0x | 6.3x | 5.9x | 5.5x | 5.2x | 5.0x |
| FE/AYE (half synergy) | 10.4x | 10.7x | 11.8x | 10.1x | 8.4x | 7.3x | 5.9x | 5.5x | 5.2x | 4.9x | 4.7x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0x | 0.0x | 0.0x | -0.5x | -1.2x | -1.8x | -1.8x | -1.7x | -1.8x | -1.4x | -1.2x |
| D | 0.0x | 0.0x | 0.0x | -0.1x | -0.3x | -0.5x | -0.7x | -0.8x | -0.8x | -0.7x | -0.7x |
| EIX | 0.0x | 0.0x | 0.0x | 0.1x | -0.1x | -0.3x | -0.4x | -0.3x | -0.3x | -0.2x | 0.0x |
| ETR | 0.0x | 0.0x | 0.0x | -0.1x | -0.2x | -0.2x | -0.3x | -0.4x | -0.4x | -0.4x | -0.4x |
| EXC | 0.0x | 0.0x | 0.0x | -0.6x | -1.6x | -2.5x | -3.1x | -3.4x | -3.4x | -3.1x | -3.1x |
| FE | 0.0x | -0.1x | -0.3x | -0.7x | -1.3x | -2.0x | -1.8x | -2.1x | -2.0x | -1.7x | -1.5x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x |
| PEG | 0.0x | 0.0x | 0.0x | -0.2x | -0.3x | -0.4x | -0.5x | -0.5x | -0.4x | -0.2x | -0.2x |
| FE/AYE (no synergy) | 0.0x | 0.0x | -0.2x | -0.7x | -1.3x | -2.0x | -1.8x | -2.0x | -2.0x | -1.6x | 5.0x |
| FE/AYE (half synergy) | 0.0x | 0.0x | -0.2x | -0.6x | -1.1x | -1.6x | -1.6x | -1.7x | -1.7x | -1.4x | 4.7x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 152: 2010 – 2020 EV/EBITDA Impact (35 GW Retirement 2013-2017)**

| 35 GW Retirement | EV/EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 6.4x | 6.6x | 7.8x | 7.4x | 6.2x | 5.3x | 4.6x | 4.2x | 4.1x | 3.8x | 3.6x |
| D | 8.7x | 9.2x | 9.2x | 8.7x | 8.5x | 8.1x | 7.8x | 7.6x | 7.4x | 7.3x | 7.2x |
| EIX | 7.1x | 7.1x | 7.4x | 7.2x | 7.0x | 6.7x | 6.4x | 6.1x | 5.9x | 5.7x | 5.6x |
| ETR | 6.8x | 7.0x | 7.2x | 6.9x | 6.8x | 6.5x | 6.3x | 6.2x | 6.0x | 5.8x | 5.7x |
| EXC | 6.5x | 6.6x | 7.9x | 7.8x | 7.5x | 6.9x | 6.2x | 5.7x | 5.4x | 5.0x | 4.9x |
| FE | 8.1x | 7.9x | 8.2x | 7.8x | 7.3x | 6.9x | 6.0x | 5.8x | 5.5x | 5.3x | 5.1x |
| NEE | 8.7x | 8.9x | 8.6x | 8.3x | 8.0x | 7.6x | 7.2x | 6.9x | 6.6x | 6.3x | 6.4x |
| PEG | 6.7x | 6.8x | 7.1x | 6.4x | 5.9x | 5.6x | 5.2x | 5.1x | 4.9x | 4.8x | 4.8x |
| FE/AYE (no synergy) | 7.7x | 7.6x | 8.1x | 7.7x | 7.0x | 6.5x | 5.6x | 5.3x | 5.1x | 4.8x | 4.7x |
| FE/AYE (half synergy) | 7.7x | 7.5x | 7.8x | 7.4x | 6.7x | 6.2x | 5.4x | 5.1x | 4.9x | 4.7x | 4.5x |
| | | | | | | | | | | | |
| RRI | 10.2x | 8.4x | 6.7x | 5.9x | 4.6x | 3.8x | 3.1x | 2.6x | 2.1x | 1.9x | 1.9x |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0x | 0.0x | 0.0x | -0.1x | -0.4x | -0.7x | -0.8x | -0.8x | -0.9x | -0.8x | -0.7x |
| D | 0.0x | 0.0x | 0.0x | 0.0x | -0.2x | -0.3x | -0.3x | -0.4x | -0.4x | -0.4x | -0.4x |
| EIX | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.1x | -0.1x | -0.1x |
| ETR | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.1x | -0.2x | -0.2x | -0.2x |
| EXC | 0.0x | 0.0x | 0.0x | -0.2x | -0.6x | -1.0x | -1.3x | -1.5x | -1.6x | -1.6x | -1.7x |
| FE | 0.0x | 0.0x | -0.1x | -0.3x | -0.5x | -0.9x | -1.0x | -1.2x | -1.2x | -1.1x | -1.0x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x |
| PEG | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.2x | -0.3x | -0.3x | -0.2x | -0.2x | -0.1x |
| FE/AYE (no synergy) | 0.0x | 0.0x | -0.1x | -0.2x | -0.5x | -0.8x | -1.0x | -1.1x | -1.2x | -1.0x | -0.9x |
| FE/AYE (half synergy) | 0.0x | 0.0x | -0.1x | -0.2x | -0.5x | -0.8x | -0.9x | -1.0x | -1.1x | -1.0x | -0.9x |
| | | | | | | | | | | | |
| RRI | 0.00 | 0.00 | 0.00 | (0.15) | (0.50) | (0.91) | (1.19) | (1.33) | (1.40) | (1.36) | (1.28) |

*Source: Company data, Credit Suisse estimates*

**Exhibit 153: 2010 – 2020 EPS Impact (100 GW Retirement 2013-2017)**

| 100 GW Retirement | EPS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 2.16 | 2.21 | 1.40 | 1.84 | 3.20 | 4.01 | 4.63 | 4.90 | 4.56 | 4.98 | 5.13 |
| D | 3.41 | 3.21 | 3.23 | 3.58 | 3.80 | 4.05 | 4.23 | 4.34 | 4.47 | 4.59 | 4.68 |
| EIX | 3.30 | 3.05 | 2.72 | 3.15 | 3.73 | 3.74 | 3.67 | 3.58 | 3.39 | 3.63 | 3.60 |
| ETR | 6.69 | 6.89 | 6.55 | 6.61 | 6.73 | 7.15 | 7.31 | 7.53 | 7.76 | 8.18 | 8.19 |
| EXC | 3.93 | 3.94 | 3.03 | 3.46 | 4.20 | 4.79 | 5.39 | 5.82 | 5.75 | 6.03 | 5.99 |
| FE | 3.66 | 3.37 | 3.27 | 3.98 | 4.88 | 5.60 | 6.64 | 6.41 | 6.38 | 6.52 | 6.57 |
| NEE | 4.45 | 4.41 | 4.62 | 4.76 | 5.17 | 5.75 | 6.24 | 6.62 | 6.88 | 7.43 | 7.33 |
| PEG | 3.05 | 2.89 | 2.80 | 3.28 | 3.89 | 4.18 | 4.42 | 4.52 | 4.66 | 4.75 | 4.89 |
| FE/AYE (no synergy) | 3.55 | 3.35 | 2.96 | 3.65 | 4.86 | 5.71 | 6.72 | 6.65 | 6.49 | 6.76 | 6.84 |
| FE/AYE (half synergy) | 3.55 | 3.49 | 3.23 | 4.00 | 5.23 | 6.13 | 7.15 | 7.09 | 6.94 | 7.21 | 7.30 |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 10.4% | 41.3% | 52.4% | 46.5% | 34.9% | 26.2% | 18.2% | 11.8% |
| D | 0.0% | 0.0% | 0.0% | 1.7% | 5.9% | 7.1% | 6.8% | 5.8% | 3.8% | 3.1% | 2.4% |
| EIX | 0.0% | 0.0% | 0.0% | 3.0% | 6.9% | 2.3% | -6.6% | -15.9% | -20.2% | -21.5% | -23.9% |
| ETR | 0.0% | 0.0% | 0.0% | 0.4% | 0.8% | 1.2% | 1.6% | 2.0% | 2.1% | 2.2% | 2.3% |
| EXC | 0.0% | 0.0% | 0.1% | 17.2% | 44.4% | 57.0% | 64.5% | 66.5% | 57.1% | 52.7% | 51.4% |
| FE | 0.0% | 1.4% | 6.3% | 19.5% | 36.3% | 53.1% | 47.4% | 44.1% | 34.1% | 26.3% | 19.7% |
| NEE | 0.0% | 0.0% | 0.0% | 0.1% | 0.4% | 0.6% | 0.9% | 1.2% | 1.5% | 1.8% | 2.1% |
| PEG | 0.2% | 0.2% | 1.0% | 4.8% | 8.7% | 7.9% | 6.4% | 4.9% | 2.4% | 0.8% | -0.6% |
| FE/AYE (no synergy) | 0.0% | 1.0% | 5.0% | 17.5% | 37.6% | 52.9% | 47.1% | 41.1% | 31.8% | 23.7% | 17.2% |
| FE/AYE (half synergy) | 0.0% | 1.0% | 4.6% | 15.7% | 34.0% | 47.6% | 43.1% | 37.7% | 29.3% | 22.0% | 16.0% |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 154: 2010 – 2020 EBITDA Impact (100 GW Retirement 2013-2017)**

| 100 GW Retirement | EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 1,227 | 1,248 | 1,071 | 1,207 | 1,607 | 1,804 | 1,930 | 1,932 | 1,799 | 1,848 | 1,833 |
| D | 4,959 | 4,779 | 4,970 | 5,471 | 5,784 | 6,113 | 6,343 | 6,530 | 6,701 | 6,844 | 6,957 |
| EIX | 3,684 | 3,879 | 3,907 | 4,334 | 4,762 | 4,902 | 4,934 | 4,921 | 4,972 | 5,048 | 5,084 |
| ETR | 3,728 | 3,713 | 3,638 | 3,710 | 3,719 | 3,806 | 3,818 | 3,844 | 3,865 | 3,935 | 3,900 |
| EXC | 5,966 | 6,077 | 5,210 | 5,837 | 6,772 | 7,514 | 8,210 | 8,654 | 8,531 | 8,776 | 8,675 |
| FE | 3,292 | 3,371 | 3,347 | 3,708 | 4,147 | 4,472 | 4,929 | 4,784 | 4,745 | 4,779 | 4,773 |
| NEE | 4,787 | 4,939 | 5,402 | 5,767 | 6,054 | 6,447 | 6,734 | 6,938 | 7,103 | 7,293 | 7,077 |
| PEG | 3,769 | 3,792 | 3,742 | 4,138 | 4,550 | 4,677 | 4,762 | 4,722 | 4,721 | 4,683 | 4,664 |
| FE/AYE (no synergy) | 4,520 | 4,619 | 4,419 | 4,915 | 5,754 | 6,276 | 6,859 | 6,717 | 6,544 | 6,626 | 6,606 |
| FE/AYE (half synergy) | 4,520 | 4,709 | 4,594 | 5,140 | 5,994 | 6,541 | 7,124 | 6,982 | 6,809 | 6,891 | 6,871 |
| | | | | | | | | | | | |
| RRI | 293 | 331 | 385 | 516 | 719 | 773 | 790 | 778 | 730 | 705 | 677 |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | 0.0% | 0.0% | 4.1% | 19.0% | 23.7% | 20.9% | 15.0% | 9.7% | 5.7% | 2.1% |
| D | 0.0% | 0.0% | 0.0% | 1.0% | 3.5% | 4.1% | 4.0% | 3.3% | 2.1% | 1.7% | 1.3% |
| EIX | 0.0% | 0.0% | 0.0% | 1.2% | 2.7% | 0.8% | -3.0% | -7.0% | -8.3% | -9.1% | -9.9% |
| ETR | 0.0% | 0.0% | 0.0% | 0.2% | 0.4% | 0.6% | 0.8% | 1.0% | 1.0% | 1.0% | 1.0% |
| EXC | 0.0% | 0.0% | 0.1% | 10.2% | 25.1% | 31.0% | 34.3% | 34.3% | 27.7% | 24.9% | 22.7% |
| FE | 0.0% | 0.7% | 2.8% | 9.0% | 16.9% | 24.1% | 22.9% | 20.1% | 14.9% | 10.9% | 7.6% |
| NEE | 0.0% | 0.0% | 0.0% | 0.1% | 0.2% | 0.3% | 0.5% | 0.7% | 0.8% | 0.9% | 1.0% |
| PEG | 0.1% | 0.1% | 0.6% | 3.0% | 5.5% | 5.0% | 3.9% | 2.8% | 1.1% | 0.0% | -0.9% |
| FE/AYE (no synergy) | 0.0% | 0.5% | 2.1% | 7.8% | 17.5% | 24.0% | 22.3% | 18.6% | 13.4% | 9.4% | 6.0% |
| FE/AYE (half synergy) | 0.0% | 0.5% | 2.0% | 7.4% | 16.6% | 22.8% | 21.3% | 17.7% | 12.8% | 9.0% | 5.7% |
| | | | | | | | | | | | |
| RRI | 0.0% | -0.7% | -1.2% | 17.9% | 39.4% | 38.8% | 33.4% | 23.0% | 10.2% | 4.1% | -1.7% |

*Source: Company data, Credit Suisse estimates*

**Exhibit 155: 2010 – 2020 P/E Impact (100 GW Retirement 2013-2017)**

| 100 GW Retirement | P/E | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 10.8x | 10.5x | 16.6x | 12.6x | 7.3x | 5.8x | 5.0x | 4.7x | 5.1x | 4.7x | 4.5x |
| D | 13.0x | 13.8x | 13.7x | 12.3x | 11.6x | 10.9x | 10.5x | 10.2x | 9.9x | 9.6x | 9.5x |
| EIX | 10.6x | 11.4x | 12.8x | 11.1x | 9.3x | 9.3x | 9.5x | 9.7x | 10.3x | 9.6x | 9.7x |
| ETR | 11.5x | 11.2x | 11.8x | 11.7x | 11.4x | 10.8x | 10.5x | 10.2x | 9.9x | 9.4x | 9.4x |
| EXC | 10.9x | 10.9x | 14.2x | 12.4x | 10.2x | 9.0x | 8.0x | 7.4x | 7.5x | 7.1x | 7.2x |
| FE | 10.1x | 11.0x | 11.3x | 9.3x | 7.6x | 6.6x | 5.6x | 5.8x | 5.8x | 5.7x | 5.6x |
| NEE | 12.2x | 12.3x | 11.8x | 11.4x | 10.5x | 9.4x | 8.7x | 8.2x | 7.9x | 7.3x | 7.4x |
| PEG | 10.6x | 11.2x | 11.6x | 9.9x | 8.3x | 7.8x | 7.3x | 7.2x | 7.0x | 6.8x | 6.6x |
| FE/AYE (no synergy) | 10.4x | 11.1x | 12.5x | 10.1x | 7.6x | 6.5x | 5.5x | 5.6x | 5.7x | 5.5x | 5.4x |
| FE/AYE (half synergy) | 10.4x | 10.6x | 11.5x | 9.3x | 7.1x | 6.0x | 5.2x | 5.2x | 5.3x | 5.1x | 5.1x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0x | 0.0x | 0.0x | -1.3x | -3.0x | -3.0x | -2.3x | -1.7x | -1.3x | -0.9x | -0.5x |
| D | 0.0x | 0.0x | 0.0x | -0.2x | -0.7x | -0.8x | -0.7x | -0.6x | -0.4x | -0.3x | -0.2x |
| EIX | 0.0x | 0.0x | 0.0x | -0.3x | -0.6x | -0.2x | 0.6x | 1.5x | 2.1x | 2.1x | 2.3x |
| ETR | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.2x | -0.2x | -0.2x | -0.2x | -0.2x |
| EXC | 0.0x | 0.0x | 0.0x | -2.1x | -4.5x | -5.1x | -5.1x | -4.9x | -4.3x | -3.8x | -3.7x |
| FE | 0.0x | -0.2x | -0.7x | -1.8x | -2.8x | -3.5x | -2.6x | -2.5x | -2.0x | -1.5x | -1.1x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.1x | -0.1x | -0.2x |
| PEG | 0.0x | 0.0x | -0.1x | -0.5x | -0.7x | -0.6x | -0.5x | -0.3x | -0.2x | -0.1x | 0.0x |
| FE/AYE (no synergy) | 0.0x | -0.1x | -0.6x | -1.8x | -2.9x | -3.4x | -2.6x | -2.3x | -1.8x | -1.3x | 5.4x |
| FE/AYE (half synergy) | 0.0x | -0.1x | -0.5x | -1.5x | -2.4x | -2.9x | -2.2x | -2.0x | -1.6x | -1.1x | 5.1x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 156: 2010 – 2020 EV/EBITDA Impact (100 GW Retirement 2013-2017)**

| 100 GW Retirement | EV/EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 6.4x | 6.6x | 7.8x | 7.2x | 5.4x | 4.7x | 4.3x | 4.1x | 4.3x | 4.1x | 4.0x |
| D | 8.7x | 9.2x | 9.2x | 8.6x | 8.3x | 8.0x | 7.8x | 7.7x | 7.6x | 7.5x | 7.4x |
| EIX | 7.1x | 7.1x | 7.4x | 7.1x | 6.8x | 6.7x | 6.7x | 6.8x | 6.7x | 6.6x | 6.5x |
| ETR | 6.8x | 7.0x | 7.2x | 6.9x | 6.8x | 6.5x | 6.4x | 6.3x | 6.1x | 5.9x | 5.8x |
| EXC | 6.5x | 6.6x | 7.9x | 7.2x | 6.3x | 5.7x | 5.1x | 4.8x | 4.7x | 4.4x | 4.4x |
| FE | 8.1x | 7.9x | 8.0x | 7.3x | 6.5x | 6.0x | 5.3x | 5.4x | 5.3x | 5.2x | 5.2x |
| NEE | 8.7x | 8.9x | 8.6x | 8.3x | 8.0x | 7.6x | 7.1x | 6.8x | 6.5x | 6.2x | 6.3x |
| PEG | 6.7x | 6.8x | 7.0x | 6.3x | 5.7x | 5.5x | 5.2x | 5.1x | 5.0x | 4.9x | 4.9x |
| FE/AYE (no synergy) | 7.7x | 7.6x | 8.0x | 7.3x | 6.3x | 5.7x | 5.1x | 5.1x | 5.1x | 4.9x | 4.9x |
| FE/AYE (half synergy) | 7.7x | 7.4x | 7.7x | 7.0x | 6.0x | 5.4x | 4.9x | 4.9x | 4.9x | 4.7x | 4.7x |
| | | | | | | | | | | | |
| RRI | 10 | 8 | 7 | 5 | 3 | 2 | 2 | 2 | 1 | 1 | 1 |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0x | 0.0x | 0.0x | -0.3x | -1.2x | -1.3x | -1.1x | -0.9x | -0.7x | -0.5x | -0.3x |
| D | 0.0x | 0.0x | 0.0x | -0.1x | -0.3x | -0.4x | -0.4x | -0.3x | -0.2x | -0.2x | -0.1x |
| EIX | 0.0x | 0.0x | 0.0x | -0.1x | -0.2x | -0.1x | 0.2x | 0.5x | 0.7x | 0.8x | 0.9x |
| ETR | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.1x | -0.1x |
| EXC | 0.0x | 0.0x | 0.0x | -0.8x | -1.8x | -2.2x | -2.4x | -2.4x | -2.3x | -2.2x | -2.2x |
| FE | 0.0x | -0.1x | -0.2x | -0.7x | -1.3x | -1.8x | -1.6x | -1.6x | -1.4x | -1.2x | -1.0x |
| NEE | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | 0.0x | -0.1x | -0.1x | -0.1x | -0.1x |
| PEG | 0.0x | 0.0x | 0.0x | -0.2x | -0.3x | -0.3x | -0.3x | -0.2x | -0.1x | -0.1x | 0.0x |
| FE/AYE (no synergy) | 0.0x | 0.0x | -0.2x | -0.6x | -1.3x | -1.6x | -1.5x | -1.4x | -1.2x | -1.0x | -0.8x |
| FE/AYE (half synergy) | 0.0x | 0.0x | -0.2x | -0.6x | -1.2x | -1.5x | -1.4x | -1.3x | -1.1x | -0.9x | -0.7x |
| | | | | | | | | | | | |
| RRI | 0.0x | 0.1x | 0.1x | -1.1x | -2.0x | -2.2x | -2.4x | -2.4x | -2.1x | -1.9x | -1.8x |

*Source: Company data, Credit Suisse estimates*

**Exhibit 157: 2010 – 2020 EPS Impact (60 GW Retirement 2013-2017) – MTM**

| 60 GW Retirement MTM | EPS | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 2.16 | 2.11 | 1.18 | 1.43 | 2.44 | 3.24 | 4.07 | 4.70 | 4.40 | 4.77 | 4.93 |
| D | 3.41 | 3.20 | 3.17 | 3.43 | 3.62 | 3.94 | 4.18 | 4.38 | 4.54 | 4.66 | 4.75 |
| EIX | 3.30 | 2.99 | 2.59 | 2.87 | 3.47 | 3.77 | 4.10 | 4.39 | 4.22 | 4.45 | 4.45 |
| ETR | 6.69 | 6.85 | 6.31 | 6.09 | 6.33 | 6.87 | 7.06 | 7.31 | 7.52 | 7.94 | 7.94 |
| EXC | 3.93 | 3.93 | 2.97 | 2.97 | 3.37 | 3.94 | 4.52 | 5.02 | 5.10 | 5.32 | 5.24 |
| FE | 3.66 | 3.17 | 2.88 | 3.36 | 4.05 | 4.72 | 5.96 | 6.05 | 6.18 | 6.39 | 6.44 |
| NEE | 4.45 | 4.41 | 4.53 | 4.63 | 5.02 | 5.60 | 6.05 | 6.42 | 6.59 | 7.10 | 7.01 |
| PEG | 3.03 | 2.73 | 2.62 | 2.99 | 3.54 | 3.90 | 4.18 | 4.29 | 4.42 | 4.48 | 4.58 |
| FE/AYE (no synergy) | 3.55 | 3.17 | 2.58 | 3.03 | 3.94 | 4.76 | 6.00 | 6.31 | 6.29 | 6.58 | 6.67 |
| FE/AYE (half synergy) | 3.55 | 3.31 | 2.85 | 3.38 | 4.32 | 5.18 | 6.43 | 6.75 | 6.73 | 7.03 | 7.13 |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | -4.3% | -16.0% | -14.1% | 7.6% | 23.2% | 28.8% | 29.5% | 21.9% | 13.2% | 7.3% |
| D | 0.0% | -0.2% | -1.7% | -2.8% | 0.7% | 4.1% | 5.7% | 6.9% | 5.4% | 4.8% | 4.0% |
| EIX | 0.0% | -1.9% | -4.6% | -6.1% | -0.6% | 3.1% | 4.1% | 3.2% | -0.5% | -3.6% | -6.0% |
| ETR | 0.0% | -0.6% | -3.6% | -7.4% | -5.2% | -2.9% | -1.8% | -1.0% | -1.0% | -0.9% | -0.9% |
| EXC | 0.0% | -0.4% | -1.8% | 0.5% | 15.9% | 28.9% | 37.8% | 43.8% | 39.3% | 34.8% | 32.4% |
| FE | 0.0% | -4.7% | -6.4% | 0.9% | 13.1% | 29.0% | 32.5% | 36.0% | 29.9% | 23.7% | 17.4% |
| NEE | 0.0% | -0.1% | -2.0% | -2.6% | -2.6% | -2.1% | -2.1% | -1.9% | -2.7% | -2.8% | -2.4% |
| PEG | -0.3% | -5.4% | -5.5% | -4.6% | -1.0% | 0.8% | 0.7% | -0.3% | -2.8% | -4.9% | -6.8% |
| FE/AYE (no synergy) | 0.0% | -4.6% | -8.3% | -2.4% | 11.7% | 27.4% | 31.5% | 33.9% | 27.5% | 20.5% | 14.3% |
| FE/AYE (half synergy) | 0.0% | -4.4% | -7.6% | -2.2% | 10.5% | 24.6% | 28.8% | 31.1% | 25.3% | 19.0% | 13.4% |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

**Exhibit 158: 2010 – 2020 EBITDA Impact (60 GW Retirement 2013-2017) – MTM**

| 60 GW Retirement MTM | EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 1,227 | 1,222 | 1,010 | 1,097 | 1,404 | 1,622 | 1,819 | 1,918 | 1,796 | 1,836 | 1,827 |
| D | 4,959 | 4,773 | 4,918 | 5,327 | 5,616 | 6,017 | 6,312 | 6,580 | 6,776 | 6,922 | 7,033 |
| EIX | 3,684 | 3,850 | 3,843 | 4,189 | 4,633 | 4,936 | 5,178 | 5,366 | 5,407 | 5,462 | 5,491 |
| ETR | 3,728 | 3,701 | 3,572 | 3,571 | 3,615 | 3,736 | 3,762 | 3,795 | 3,816 | 3,885 | 3,851 |
| EXC | 5,966 | 6,060 | 5,150 | 5,315 | 5,913 | 6,660 | 7,378 | 7,950 | 8,013 | 8,221 | 8,102 |
| FE | 3,292 | 3,274 | 3,164 | 3,421 | 3,776 | 4,097 | 4,670 | 4,683 | 4,722 | 4,790 | 4,791 |
| NEE | 4,787 | 4,936 | 5,342 | 5,682 | 5,957 | 6,356 | 6,635 | 6,833 | 6,960 | 7,135 | 6,941 |
| PEG | 3,756 | 3,657 | 3,599 | 3,913 | 4,298 | 4,498 | 4,625 | 4,609 | 4,608 | 4,560 | 4,530 |
| FE/AYE (no synergy) | 4,520 | 4,495 | 4,174 | 4,518 | 5,180 | 5,719 | 6,489 | 6,601 | 6,519 | 6,626 | 6,618 |
| FE/AYE (half synergy) | 4,520 | 4,585 | 4,349 | 4,743 | 5,420 | 5,984 | 6,754 | 6,866 | 6,784 | 6,891 | 6,883 |
| | | | | | | | | | | | |
| RRI | | 301 | 338 | 383 | 546 | 644 | 698 | 733 | 713 | 689 | 667 |
| | | | | | | | | | | | |
| **% Chg from No Retirements** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| AYE | 0.0% | -2.1% | -5.7% | -5.3% | 4.0% | 11.2% | 14.0% | 14.2% | 9.5% | 5.0% | 1.8% |
| D | 0.0% | -0.1% | -1.0% | -1.6% | 0.5% | 2.5% | 3.5% | 4.1% | 3.2% | 2.8% | 2.4% |
| EIX | 0.0% | -0.7% | -1.7% | -2.2% | 0.0% | 1.5% | 1.8% | 1.4% | -0.3% | -1.6% | -2.6% |
| ETR | 0.0% | -0.3% | -1.8% | -3.6% | -2.4% | -1.3% | -0.7% | -0.3% | -0.3% | -0.2% | -0.2% |
| EXC | 0.0% | -0.3% | -1.1% | 0.4% | 9.2% | 16.1% | 20.7% | 23.4% | 20.0% | 17.0% | 14.6% |
| FE | 0.0% | -2.2% | -2.8% | 0.6% | 6.4% | 13.7% | 16.4% | 17.5% | 14.3% | 11.2% | 8.0% |
| NEE | 0.0% | -0.1% | -1.1% | -1.4% | -1.4% | -1.1% | -1.0% | -0.9% | -1.2% | -1.3% | -0.9% |
| PEG | -0.2% | -3.4% | -3.3% | -2.6% | -0.3% | 1.0% | 0.9% | 0.3% | -1.3% | -2.6% | -3.7% |
| FE/AYE (no synergy) | 0.0% | -2.2% | -3.5% | -0.9% | 5.7% | 13.0% | 15.7% | 16.5% | 13.0% | 9.4% | 6.2% |
| FE/AYE (half synergy) | 0.0% | -2.2% | -3.4% | -0.9% | 5.5% | 12.3% | 15.0% | 15.8% | 12.4% | 9.0% | 5.9% |
| | | | | | | | | | | | |
| RRI | | -9.6% | -13.3% | -12.4% | 5.9% | 15.7% | 17.9% | 15.9% | 7.5% | 1.6% | -3.2% |

*Source: Company data, Credit Suisse estimates*

Exhibit 159: **2010 – 2020 P/E Impact (60 GW Retirement 2013-2017) – MTM**

| 60 GW Retirement MTM | P/E | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 10.8x | 11.0x | 19.7x | 16.2x | 9.5x | 7.2x | 5.7x | 4.9x | 5.3x | 4.9x | 4.7x |
| D | 13.0x | 13.8x | 13.9x | 12.9x | 12.2x | 11.2x | 10.6x | 10.1x | 9.7x | 9.5x | 9.3x |
| EIX | 10.6x | 11.6x | 13.4x | 12.1x | 10.0x | 9.2x | 8.5x | 7.9x | 8.2x | 7.8x | 7.8x |
| ETR | 11.5x | 11.3x | 12.2x | 12.6x | 12.2x | 11.2x | 10.9x | 10.5x | 10.2x | 9.7x | 9.7x |
| EXC | 10.9x | 10.9x | 14.4x | 14.5x | 12.7x | 10.9x | 9.5x | 8.5x | 8.4x | 8.1x | 8.2x |
| FE | 10.1x | 11.7x | 12.9x | 11.0x | 9.2x | 7.9x | 6.2x | 6.1x | 6.0x | 5.8x | 5.8x |
| NEE | 12.2x | 12.3x | 12.0x | 11.7x | 10.8x | 9.7x | 9.0x | 8.5x | 8.2x | 7.7x | 7.8x |
| PEG | 10.7x | 11.9x | 12.4x | 10.8x | 9.2x | 8.3x | 7.7x | 7.5x | 7.3x | 7.2x | 7.1x |
| FE/AYE (no synergy) | 10.4x | 11.7x | 14.4x | 12.2x | 9.4x | 7.8x | 6.2x | 5.9x | 5.9x | 5.6x | 5.6x |
| FE/AYE (half synergy) | 10.4x | 11.2x | 13.0x | 11.0x | 8.6x | 7.2x | 5.8x | 5.5x | 5.5x | 5.3x | 5.2x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

| % Chg from No Retirements | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AYE | 0.0x | 0.5x | 3.2x | 2.3x | -0.7x | -1.7x | -1.6x | -1.5x | -1.2x | -0.6x | -0.3x |
| D | 0.0x | 0.0x | 0.2x | 0.4x | -0.1x | -0.5x | -0.6x | -0.7x | -0.5x | -0.5x | -0.4x |
| EIX | 0.0x | 0.2x | 0.6x | 0.7x | 0.1x | -0.3x | -0.4x | -0.3x | 0.0x | 0.3x | 0.5x |
| ETR | 0.0x | 0.1x | 0.4x | 0.9x | 0.6x | 0.3x | 0.2x | 0.1x | 0.1x | 0.1x | 0.1x |
| EXC | 0.0x | 0.0x | 0.3x | -0.1x | -2.0x | -3.2x | -3.6x | -3.7x | -3.3x | -2.8x | -2.7x |
| FE | 0.0x | 0.6x | 0.8x | -0.1x | -1.2x | -2.3x | -2.0x | -2.2x | -1.8x | -1.4x | -1.0x |
| NEE | 0.0x | 0.0x | 0.2x | 0.3x | 0.3x | 0.2x | 0.2x | 0.2x | 0.2x | 0.2x | 0.2x |
| PEG | 0.0x | 0.6x | 0.7x | 0.5x | 0.1x | -0.1x | -0.1x | 0.0x | 0.2x | 0.4x | 0.5x |
| FE/AYE (no synergy) | 0.0x | 0.5x | 1.2x | 0.3x | -1.1x | -2.1x | -1.9x | -2.0x | -1.6x | -1.2x | 5.6x |
| FE/AYE (half synergy) | 0.0x | 0.5x | 1.0x | 0.2x | -0.9x | -1.8x | -1.7x | -1.7x | -1.4x | -1.0x | 5.2x |
| | | | | | | | | | | | |
| RRI | | | | | | | | | | | |

*Source: Company data, Credit Suisse estimates*

Exhibit 160: **2010 – 2020 EV/EBITDA Impact (60 GW Retirement 2013-2017) – MTM**

| 60 GW Retirement MTM | EV/EBITDA | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| AYE | 6.4x | 6.7x | 8.3x | 8.0x | 6.4x | 5.5x | 4.7x | 4.3x | 4.5x | 4.3x | 4.2x |
| D | 8.7x | 9.2x | 9.3x | 8.9x | 8.6x | 8.2x | 7.9x | 7.7x | 7.5x | 7.4x | 7.4x |
| EIX | 7.1x | 7.2x | 7.6x | 7.4x | 7.0x | 6.7x | 6.4x | 6.2x | 6.1x | 5.9x | 5.8x |
| ETR | 6.8x | 7.0x | 7.3x | 7.2x | 7.0x | 6.7x | 6.6x | 6.4x | 6.3x | 6.1x | 6.0x |
| EXC | 6.5x | 6.6x | 8.0x | 8.0x | 7.4x | 6.6x | 6.0x | 5.5x | 5.4x | 5.1x | 5.1x |
| FE | 8.1x | 8.1x | 8.5x | 8.0x | 7.3x | 6.7x | 5.9x | 5.8x | 5.6x | 5.5x | 5.4x |
| NEE | 8.7x | 8.9x | 8.7x | 8.4x | 8.2x | 7.7x | 7.3x | 7.0x | 6.7x | 6.5x | 6.6x |
| PEG | 6.7x | 7.0x | 7.4x | 6.8x | 6.1x | 5.8x | 5.5x | 5.4x | 5.3x | 5.3x | 5.3x |
| FE/AYE (no synergy) | 7.7x | 7.8x | 8.5x | 8.1x | 7.1x | 6.4x | 5.6x | 5.4x | 5.3x | 5.2x | 5.1x |
| FE/AYE (half synergy) | 7.7x | 7.7x | 8.2x | 7.7x | 6.8x | 6.1x | 5.3x | 5.2x | 5.1x | 5.0x | 4.9x |
| | | | | | | | | | | | |
| RRI | 10.2x | 9.4x | 8.0x | 7.1x | 4.7x | 3.5x | 2.8x | 2.3x | 1.9x | 1.7x | 1.8x |

| % Chg from No Retirements | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AYE | 0.0x | 0.2x | 0.5x | 0.5x | -0.2x | -0.6x | -0.7x | -0.7x | -0.5x | -0.3x | -0.2x |
| D | 0.0x | 0.0x | 0.1x | 0.2x | 0.0x | -0.2x | -0.3x | -0.3x | -0.3x | -0.2x | -0.2x |
| EIX | 0.0x | 0.1x | 0.1x | 0.2x | 0.0x | -0.1x | -0.1x | -0.1x | 0.0x | 0.1x | 0.2x |
| ETR | 0.0x | 0.0x | 0.1x | 0.3x | 0.2x | 0.1x | 0.1x | 0.1x | 0.1x | 0.1x | 0.1x |
| EXC | 0.0x | 0.0x | 0.1x | 0.0x | -0.7x | -1.2x | -1.5x | -1.7x | -1.6x | -1.5x | -1.5x |
| FE | 0.0x | 0.2x | 0.3x | 0.0x | -0.5x | -1.0x | -1.1x | -1.2x | -1.1x | -0.9x | -0.7x |
| NEE | 0.0x | 0.0x | 0.1x | 0.1x | 0.1x | 0.1x | 0.1x | 0.1x | 0.2x | 0.2x | 0.1x |
| PEG | 0.0x | 0.3x | 0.3x | 0.2x | 0.1x | 0.0x | 0.0x | 0.1x | 0.2x | 0.3x | 0.4x |
| FE/AYE (no synergy) | 0.0x | 0.2x | 0.3x | 0.1x | -0.4x | -0.9x | -1.0x | -1.1x | -0.9x | -0.7x | -0.6x |
| FE/AYE (half synergy) 0 | 0.0x | 0.2x | 0.3x | 0.1x | -0.4x | -0.8x | -0.9x | -1.0x | -0.9x | -0.7x | -0.5x |
| RRI | 0.0x | 1.0x | 1.3x | 1.0x | -0.5x | -1.1x | -1.5x | -1.6x | -1.5x | -1.5x | -1.3x |

*Source: Company data, Credit Suisse estimates*

**Companies Mentioned** *(Price as of 22 Sep 10)*
Allegheny Energy Inc. (AYE, $23.25, OUTPERFORM, TP $28.00)
Alliant Energy Corp. (LNT, $35.95)
Ameren Corp. (AEE, $27.81)
American Electric Power Co., Inc. (AEP, $36.43, OUTPERFORM, TP $40.00)
Black Hills Corporation (BKH, $30.26)
Calpine (CPN, $12.49)
CenterPoint Energy, Inc. (CNP, $15.41)
Central Vermont Pub Serv (CV, $19.98)
CMS Energy (CMS, $18.01, OUTPERFORM [V], TP $17.50)
Con Edison (ED, $48.52, NEUTRAL, TP $48.00)
Constellation Energy Group Inc. (CEG, $32.00, RESTRICTED)
Dominion Resources (D, $44.21, NEUTRAL, TP $39.00)
DPL (DPL, $25.76)
DTE Energy (DTE, $46.12, NEUTRAL, TP $47.00)
Duke Energy (DUK, $17.98, NEUTRAL, TP $17.00)
Dynegy Inc. (DYN, $4.63, RESTRICTED [V])
Edison International (EIX, $34.81, NEUTRAL, TP $37.00)
El Paso Electric Co (EE, $23.24)
Entergy Corporation (ETR, $77.05, NEUTRAL, TP $81.00)
Exelon Corporation (EXC, $42.92, NEUTRAL, TP $47.00)
FirstEnergy (FE, $37.07, OUTPERFORM, TP $43.00)
Great Plains Energy (GXP, $18.92)
Integrys Energy Group Inc. (TEG, $50.73)
ITC Holdings Corp (ITC, $60.83, OUTPERFORM, TP $63.00)
Minnesota Power Inc. (ALE, $35.91)
Mirant Corporation (MIR, $9.75)
NextEra Energy Inc. (NEE, $54.31, OUTPERFORM, TP $58.00)
Northeast Util (NU, $29.24)
NRG Energy (NRG, $21.01, RESTRICTED)
NSTAR (NST, $38.67)
NV Energy Inc (NVE, $12.88, NEUTRAL, TP $13.00)
OGE (OGE, $40.21)
Pepco Holdings Inc. (POM, $18.40, RESTRICTED)
PG&E Corporation (PCG, $45.17, NEUTRAL, TP $45.00)
Pinnacle West Capital Corp. (PNW, $40.92, OUTPERFORM, TP $40.00)
Progress Energy (PGN, $44.42, NEUTRAL, TP $40.00)
Public Services New Mexico (PNM, $11.12)
Public Svc Ent (PEG, $32.40, OUTPERFORM, TP $36.00)
RRI Energy Inc. (RRI, $3.47, OUTPERFORM [V], TP $6.00)
SCANA Corporation (SCG, $40.20)
Sempra Energy (SRE, $53.60)
Southern Company (SO, $37.47, NEUTRAL, TP $37.00)
TECO Energy (TE, $17.28, NEUTRAL, TP $16.00)
Unisource Energy Corp (UNS, $32.88, NEUTRAL, TP $34.00)
Wisconsin Energy (WEC, $57.85)

# Disclosure Appendix

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***An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

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|---|---|---|
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