ENERGY FOCUS

US Power markets: Charging the battery

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Signs are emerging that the recovery of power demand may be stronger than the industry was anticipating for 2010. Weather, no doubt, has helped, yet it has not been the only driver of increased power consumption. Trend-line recovery in electricity demand is driven by a rebound in industrial activity, although the rebound of loads has not been uniform across the country. Not surprisingly, the regions that experienced the biggest plunge in demand for power during the recession were those with the highest concentrations of power intensive industries. These regions are now staging a comeback. Still, power demand fell for two consecutive years in the recession, and we believe it will be a few years before weather-normalized US demand reverts to the 2007 peak levels.

Displacement of coal-fired plants by gas-fueled units remains an important factor in certain power markets in the US. Given US natural gas balances, we expect this dynamic to persist for the rest of 2010 and into 2011. Lower hydro generation offset gains in nuclear power plant utilization in the first half of the year, but ample June precipitation has improved Pacific Northwest reservoir levels and runoff, and y/y hydro comparisons should remain positive for the rest of the summer. Additions of new wind and coal-fired plants are pushing gas out of the stack in some parts of the country.

The recovery in prices is lagging the recovery in demand. The markets grew fat with spare capacity during the consumption pullback, and even in the regions of strongest growth, heat rates have not strengthened commensurately. Soft gas prices are helping to keep power prices contained. We believe even a healthy pace of demand recovery would not be enough to meaningfully tighten power markets this year and next.

Power demand: charging up

The lights went dim at many power generation facilities over the past two years as the economy slowed down just when the nation added a record amount of wind generation capacity and demand response programs gathered steam. For the first time in almost a century, power demand dropped for two years in a row in 2008 and 2009. Pinched by the slump in demand, utilities were cautiously expecting a very modest recovery of power consumption in 2010.

Signs of a recovery in demand are emerging

But signs of recovering power demand are already emerging, and point to a healthy rebound. Our view has been that US-level power demand (weather normalized) would grow 2.1% in 2010, helped by a resurgence of industrial production. Weekly electric output is up 4.4% y/y for the first 33 weeks of the year, after a 4.4% y/y drop over the same period in 2009. Weather, no doubt, has helped, and before we turn to the raw data, we acknowledge that parsing power data and especially adjusting the data for weather can lead to different results depending on the approach. We review both unadjusted and weather-adjusted results.

Weather has boosted loads…

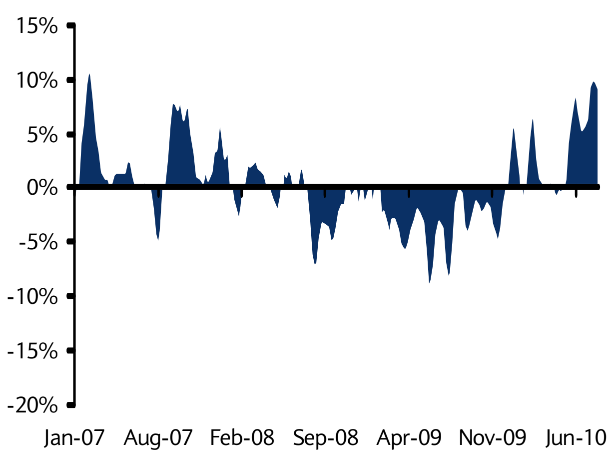
Similar to natural gas consumption, the cold winter boosted power loads, and generation averaged 3% higher y/y in the first three months of 2010. A scorching start to the summer cooling season has continued to support loads: May, June, and July have counted 16%, 17%, and 14% more cooling degree days (CDDs), respectively, than the 10-year normal. Power demand is up 7% y/y from the start of the cooling season in May through mid-August.

Weather has masked a robust trend-line recovery of power demand

…but it is trend-line demand that is driving consumption higher

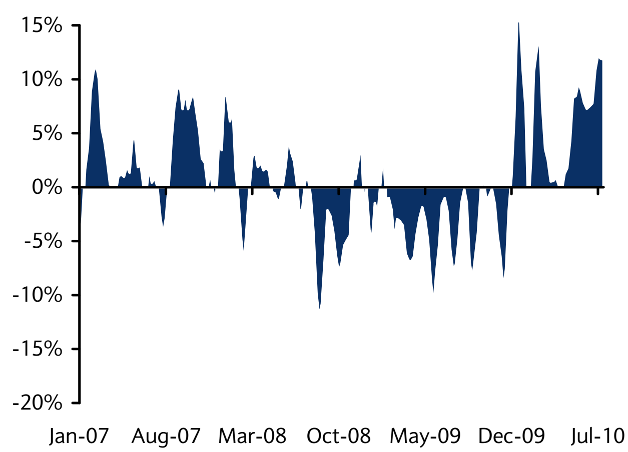
Weather is just one driver of increased power consumption. Adjusting aggregate power use for weather shows a healthy rebound of trend-line demand of 1.8% y/y in 2010 so far. Indeed, the cold winter and hot start of the summer has masked a robust recovery of industrial demand. In the first quarter of 2010, industrial power use rose 3.8% y/y (unadjusted), while overall electricity sales grew by 3.7% (unadjusted). This compares with a 14.9% drop y/y in the first quarter of 2009 for industrial demand and a 4.1% drop in overall power generation. The pullback in power consumption in 2009 was rooted to some extent in mild summer weather, but it was the industrial sector that led the declines. Strengthening industrial consumption should now lead overall power demand higher in 2010.

Figure 1: Total US load growth, 4-wk avg % y/y change



Source: EEI, Barclays Capital

Figure 2: Southeast load growth, 4-wk avg % y/y change



Source: EEI, Barclays Capital

The recovery of loads has been a regional story…

The recovery of loads has not been uniform across the country. EEI (around-the-clock electric output) data suggest that the principal regions propelling this demand recovery are the Southeast and the Gulf regions (Figure 1 and Figure 2), where loads have picked up by between 4 and 8% y/y through mid-August, unadjusted for weather variations (Figure 3). The Midwest is also showing some demand recovery, with the Central Industrial region up 7%. Other regions do not show clear gains in the EEI data. Consumption growth has been registered across PJM, NYISO, and NEPOOL, with these regions reporting record consumption months this summer, but the gains in these cases have been mostly weather related. Not surprisingly, the regions that experienced the biggest plunge in demand for power during the recession were those with the highest concentrations of power intensive industries. These regions are now staging a comeback.

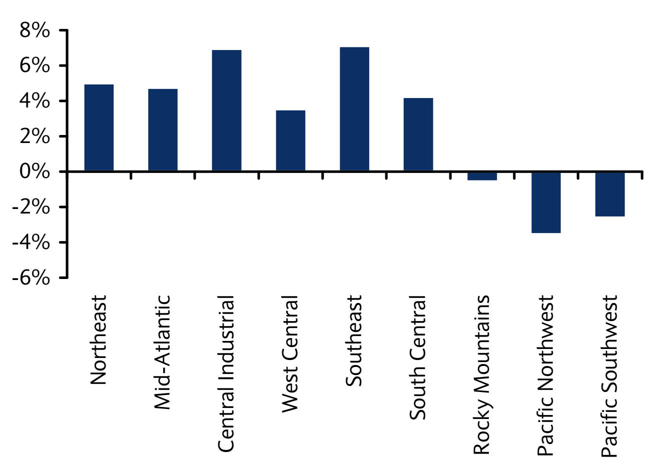
… and is not sufficient to tighten the markets in the near term

It is unclear whether the electricity consumption gains in these regions will overcome lacklustre demand in the remaining areas of the country. At a national level, it raises the question: will weather-adjusted growth spread over the rest of the country, or will it remain a regional story? So far, industrial power consumption has recovered in line with the industrial activity rebound (Figure 4). Still, power demand fell for two consecutive years, and it will take a few years for demand at the national level to revert to the 2007 peak levels.

Our economists expect Industrial Production to grow by 5.7%, and GDP to strengthen by 3.0% this year, a solid recovery from last year's 2.4% drop (*Global Economics Weekly, July 16, 2010)*. Yet, this number reflects a recent revision lower, driven by slower-than-expected Q2 10 GDP. Our economics team notes that the largest boost to manufacturing activity, which came from inventory restocking, has already passed. From here on, manufacturing activity should be more sensitive to final demand. In addition, consumer spending on goods slowed in Q2 10, and this appears to be behind the deceleration in production. Our economists look for consumer spending growth to pick up modestly in Q3 10, based on their view that the fundamental drivers of consumption – better labor income growth and less negative wealth effects – remain intact. If this is correct, the recent slowdown in production will prove to be a pause in a still solid growth environment.

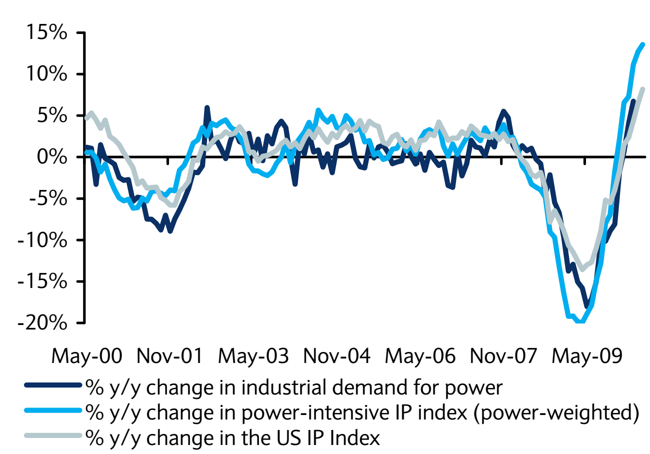
Although EEI data suggest recovering consumption, NERC is expecting peak summer demand to be lower in 2010 than last year, which seems to be inconsistent with a demand rebound story. A drop in peak power consumption would mean that not only

Figure 3: Load growth by region, % y/y change, YTD



Source: EEI, Barclays Capital

Figure 4: Power consumption indicators



Source: Federal Reserve, EIA, Barclays Capital are the markets not going to tighten this year, but also in fact, they will become even looser, as power generation capacity remains commissioned. Given that summer was milder in most regions last year, a return to normal weather this year, coupled with recovering industrial loads, would automatically yield higher peak summer loads in 2010. Weather is always the important driver of peak demand, and the hot weather is boosting peak demands in many regions well past last year's levels. In fact, several regions have already reported unofficial peak demand records.

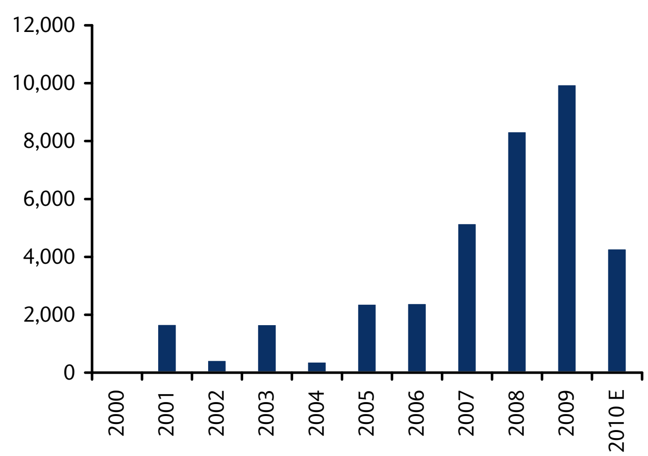
Demand response programs shave peak demand growth

Demand response programs shave peak demand

Demand response programs have been a notable feature of power generation markets over the past few years, and have contributed to the reduction of on-peak demand. Demand response programs offer payments to customers for the right to interrupt service to all or a portion of a facility or home (interruptible customers), offer payments to customers to reduce loads during certain periods, or try to effect a change in consumption patterns in response to changes in the price of electricity. These programs aim to reduce consumption when demand reaches capacity levels in order to boost system reliability. Regulated utilities have had demand response programs for years, in the form of interruptible load.

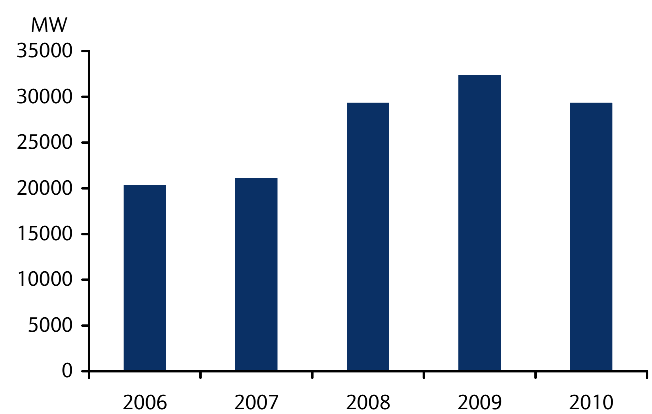
Effectively, demand response resources act as capacity resources, as they shave peak power demand. FERC has been pushing for markets (ISOs) to treat demand response as the equal of supply resources, but this has helped to fuel the debate about the dependability of these resources. We note that demand response was called upon to trim load during the recent hot weather in the Northeast. Participation in demand response expanded rapidly in 2008 and 2009, but this year the slower economy is eliminating some of the potential demand resources, and resulting in lower demand response resources (Figure 6). To the extent that capacity values wane in PJM, NEPOOL and NYISO, the value of demand response should fall too. Some ISOs are exploring whether to allow demand to participate in short term capacity and ancillary service markets. NERC expects a reduction in demand response of about 3,000 MW compared with last year. This effectively means a loss of 3,000 MW of capacity. Yet, with FERC's push, demand response is likely to grow in the years ahead.

Figure 5: Wind capacity additions, MW



Source: AWEA, Barclays Capital

Figure 6: NERC summer peak demand response projections



Source: Federal Reserve, EIA, Barclays Capital

Generation capacity growing despite unfavorable power prices

We have noted in the past that forward power prices do not cover the costs to build new generation facilities. Since we last analyzed power prices and costs, forward prices have moderated, while costs for most baseload facilities have remained largely unchanged, leaving only a growing gap. Yet, new generation facilities are coming on line. We expect to see more than 5,000 MW of new coal-fired generation arrive this year, with construction plans pointing toward net coal capacity additions both this year and next. As well, by the end of 2010, we expect wind generation capacity will grow 4,000–5,000 MW (Figure 5). These new facilities typically push gas out of the stack in regions where the new capacity is added if capacity additions outpace load growth.

NERC projects that this year total existing generation capacity for its constituent regions will increase by about 0.7%, equivalent to 7,500 MW for the summer peak. Among the newly added generation plants for 2009 are 11,000 MW of new gas-fired capacity, and about 7,000 MW of wind capacity (nameplate) based on NERC's estimate, spaced across the year. Given the variability of wind, accounting for wind capacity for on-peak generation is challenging. NERC's assumptions for on-peak capacity from wind plants, as a percentage of total installed capacity, range from 0 in one region (which has no wind resources connected to the grid) to 22% of capacity assumed running during peak.

Wind generation faces headwinds

Additions of wind power plants, while sizeable in scale, are trending lower than we had previously anticipated. The past few years have seen a record build out of wind power plants, mostly driven by two types of projects – merchant developers, who seek to generate profits by selling wind into hoped-for high priced wholesale power markets, and developers who solely pursue Purchase Power Agreements (PPAs) with utilities seeking to meet renewable generation requirements. A merchant plant can sell into the PPA market, of course. Several factors are driving this slowdown in both merchant and PPA-backed wind developments:

- **No need to build more generation.** Following two years of declines, loads pulled back to 2005 levels, leaving ample spare capacity and reserve margins. Although we expect a healthy recovery of power demand, it will likely take more than two years for loads to grow back to 2007 levels for the country as a whole. Rapid development of wind projects over the past two years was in part driven by the desire to add capacity in constrained markets. In many regions the combination of capacity additions and load declines have obviated the need to build power plants for the time being.
- **High costs hurt both merchant and PPA economics.** The recession-driven pullback in loads, coupled with lower gas prices, has pressured power prices significantly lower than in 2008-2009. Costs to build wind generation have not seen a comparable pullback, squeezing profitability and in many cases rendering the projects uneconomic altogether. That has put many merchant wind project developers on the sidelines, and has also affected utilities' appetite for PPA agreements. This has not completely stalled the PPA market, as there remain several state-level programs that require utilities to contract for renewable projects. PPAs, to cover the cost of wind plants commissioned over the past few years must feature power prices that are quite a bit above the wholesale price for bulk power.
- **Some states have met their renewables requirement.** Texas has built out wind capacity the fastest, adding more than 8,000 MW in the past five years, after the state mandated an ambitious Renewable Portfolio Standard (RPS). Texas' RPS mandates 5,880 MW of renewable energy by 2015, and a target of 10,000 MW by 2025. The program has been

so successful that its 10-year goal was met in just over six years. Today, the state has more than 9,505 MW of wind capacity, which contributed 8.8% of total generation in March 2010—a notable gain from the 6.3% level in March 2009. This means that Texas is unlikely to continue building wind projects at the recent pace, and in fact 2010 is expected to see the addition of only 450 MW, compared with 2,300 MW built in 2009, and 2,700 MW built in 2008.

- **Too much wind is operationally difficult to manage.** Some parts of the country that have added significant wind capacity over the past few years are already grappling with managing wind generators' impact on the grid. Such instances are visible in power markets in Texas and the Midwest. Wind energy, by nature, is intermittent and cannot be relied upon to meet the shape of the load fluctuations throughout the day. Low (effectively, negative) operational costs put wind energy as a baseload resource. Too much wind power in a given part of the day can displace other generation resources and depress prices to zero and even negative levels, while a sudden drop in wind generation can necessitate the quick start-up of other plants and cause prices to spike. To maintain the stability of the grid, peaking gas units are generally required to fill the gaps of wind generation and ensure that loads are reliably met. Hydro can be a good balancing resource for wind, but is not available in size in markets such as Texas. The difficulty of managing large amounts of wind generation effectively limits the share of the load that can be met by wind.

Recovering power loads combined with somewhat lower demand response are moving to tighten the markets relative to 2009 levels, while new supply works in the opposite direction. However, given the depth of the demand pullback in 2008 and 2009, it is unlikely that economic recovery will spur enough load growth in 2010 to tighten power markets in general to levels seen in 2007. That said, impressive load growth in the Southeast and Gulf regions should restore demand levels to pre-recession levels much sooner.

Progress made on allocating transmission costs

Standing before a continued expansion of renewables in the US is the dilemma of how to allocate the costs of the new interstate electric transmission systems needed to move renewable energy to load centers. Wind in particular is faced with the issue that there is great wind resource in a central corridor of the US, but this area is far from the populated states that need the power. The southeast, for example, has both large loads and poor wind resources. But building large, multi-state transmission systems requires that the participating states and utilities determine who pays for what. Do power consumers in Missouri have to pay for transmission running through their state that is intended to move Kansas-based wind power to Illinois?

One of the authors of this report attended the 2009 summer NARUC conference (state utility regulators) and was struck by the fact that the regulators in attendance clearly recognized the challenge of allocating transmission costs, especially given the ambitious renewables targets of many states. Yet, at that time, these regulators seemed to be far from a workable scheme to allocate these interstate costs. ERCOT, by contrast, is an intrastate entity, making transmission cost allocation far easier.

Fast forward one year to this summer's NARUC conference. Regulators have made considerable progress debating and resolving cost allocation methodologies. Credit the ISOs for their work, at the prodding of FERC, in crafting methodologies. These have often been fiercely debated, amended, and re-filed, with steady progress toward new tariff structures to handle cost allocation. Not that all debate has been settled, but efforts are moving toward resolution. This suggests that imported power to fill renewable mandates may not be so far off.

Fighting for share to fuel power generation

Higher nuclear capacity utilization has been offset by lower hydro in H1 10, but hydro has recovered since

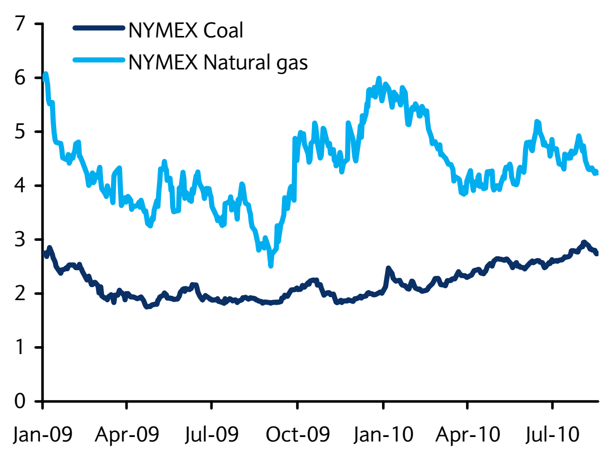
The fuel mix of installed capacity in the US is relatively unchanged from last year. However, this is not so for utilization rates. The first half of 2010 has been marked with a higher utilization of the nuclear fleet, as nuclear output has grown by 1.1% versus the same period in 2009. The spring nuclear plant maintenance and refuelling season was nearly as deep as in 2009, but took place earlier in the year, with nuclear generation bottoming in the 14th week this year versus the 18th week in 2009. Nuclear output should peak over the next two months before the fall maintenance and refueling season starts to cut into utilization rates in September.

Lower hydropower output has been counteracting higher nuclear plant runs. From January through May, hydro generation, mainly in the Pacific Northwest, ran substantially below last year's levels as scarce winter precipitation left reservoir and runoff levels fairly low. In fact, 2010 is still expected to be the 8th driest year of the past 50 (see *Natural Gas Kaleidoscope: Whetting summer's gas appetite,* May 25, 2010). Still, this represents an improvement in the water supply forecasts since we last wrote about hydro power in May, and in June hydro generation turned higher than last year, helped by plentiful rain that replenished reservoir levels and increased stream flows. For the rest of the summer, water supply forecasts indicate that hydro generation will exceed last year's levels by roughly 1,300 MW in July and August, the equivalent of about 250 MMcf/d of gas use.

Coal-to-gas displacement remains a prominent feature of the power markets in 2010 and 2011

In 2009, the power industry showed a dramatic, previously untested, ability to shift fuel use. Although it has happened before that different fuel prices have come into competition, even resulting in the use of one fuel instead of the other at times, the scale has been small. Most of this experience comes from running oil-burning units instead of gas-fired units (or running oil in dual-fueled units) when oil was cheaper than gas, or vice versa. But in recent years the industry has never displaced coal units in size. Last year's recession-driven power demand collapse combined with depressed natural gas prices to idle a number of coal-fired plants. For the first time, the natural gas market managed to steal a significant share of power generation demand away from coal.

Figure 7: Coal and gas prices, prompt month, $/MMBtu



Source: Bloomberg, Barclays Capital

Figure 8: Maximum incremental gas demand as gas displaces coal as a function of gas price (at a CAPP coal price of $60/short ton), for contestable* market only

Gas price (Henry Hub, $/MMBtu)	Displaced coal (MW)	Incremental gas demand (Bcf/d)	Observed incremental gas demand (Bcf/d)
6.00	4,200	0.6	N/A
5.50	10,400	1.4	1.5
5.00	41,000	5.7	3.0
4.50	127,600	17.7	3.5
4.00	180,000	24.9	5.3

*Load in the Southeast, eastern portion of SPP, and the Mid-Atlantic.
Source: Platts, Bloomberg, Barclays Capital

Our prior research highlighted that coal displacement has been concentrated in three regions: the Southeast (SERC), the eastern portion of the SPP power market, and the Mid-Atlantic (including Pennsylvania and New York). This is the contestable market. These regions draw on relatively higher-priced Appalachian coal, with prices high enough to lose share to gas. Yet while prompt month Appalachian prices have been at a premium to other coals in the US, the spread between gas and coal is defined mostly by the volatility in gas prices (Figure 7).

We isolated the operational coal plants in the contestable market to illustrate the theoretical gas demand that could result as gas prices fall, finding that the incremental gas demand rockets higher as gas prices sink. We took into account unit-specific heat rates, NOx and SOx emissions rates, variable operations, and fuel transport costs to compare coal and gas operating costs. But three factors alter the reality compared with the theoretical results. First, not all these plants are running all the time as loads fluctuate. Second, to displace coal with gas, spare gas-fired capacity must be available. Third, there is quite a range of coal prices for these plants, rather than the uniform price used in our calculations. Thus, as Figure 8 highlights, the actual amount of displaced coal as a function only of gas price is higher than the theoretical amount down to about $5.00 natural gas, then is well below the theoretical amount as gas prices move lower.

The balance between coal-fired and gas-fired generation remains a carefully weighted one in 2010. The recovery of loads in the Southeast region in the first half of 2010 (owing to both recovering industrial demand and weather effects) has allowed both gas-fired and coal-fired generation to rebound from last year's lows. The resulting strength in gas consumption has alleviated some of the need to displace coal in the mid-Atlantic markets, but has not eliminated it all together. Robust domestic gas production growth continues to pressure gas prices lower (*Energy Focus: Natural Gas: Hotter markets or just hot weather?,* August 4, 2010), and our analysis indicates the level of excess gas supply will force some level of coal displacement in 2010 and 2011 to balance the gas market. Thus, even with load on the rebound, the output of coal units should recover, but not nearly to 2007 utilization levels, as gas-fired units keep coal plants from re-capturing market share lost in 2009.

Will CATR crater coal generation?

Coal plant shutdowns could tighten markets in the longer run

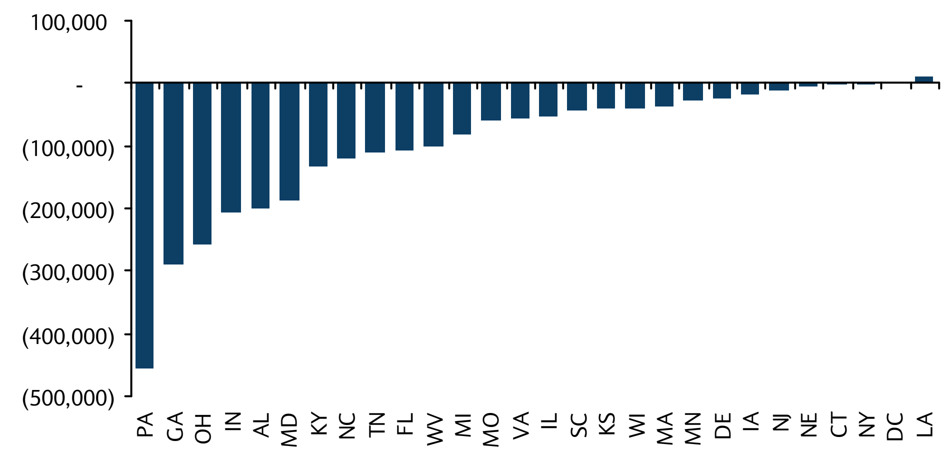
A significant scale of coal plant shutdowns could tighten the market in the longer term. The Kerry Graham Lieberman (KGL) climate bill offered incentives for the retirement of existing coal units, but the bill failed to build momentum for a cap-and-trade program, and is now largely viewed as sidelined. Although climate change legislation should eventually emerge for debate, the EPA's newly proposed Clean Air Transport Rule (CATR) that regulates SOx and NOx, could affect the markets sooner. CATR proposes to set pollution limits for 31 states and the District of Columbia, allowing limited interstate trading. Instead, CATR imposes state-level emissions budgets. The proposal sets 2014 as the target year for compliance, with aims to reduce SOx emissions by 71% from 2005 levels and NOx emissions by 52% from 2005 levels by then. Reductions will begin to take effect as early as 2012. Although the industry was prepared for a state-level approach, the effective date of the new rule was earlier than anticipated.

The rule, when finalized, is likely to spur the retirement of a number of existing coal-fired plants. It will not be cost effective to install new emissions control equipment on a number of older units to meet not only CATR, but additional environmental regulations expected in the next two years. The question remains: how much capacity would be affected and within what timeframe?

The states with the greatest shortfall of allowances will likely be Pennsylvania, Georgia, Ohio, Indiana, and Alabama

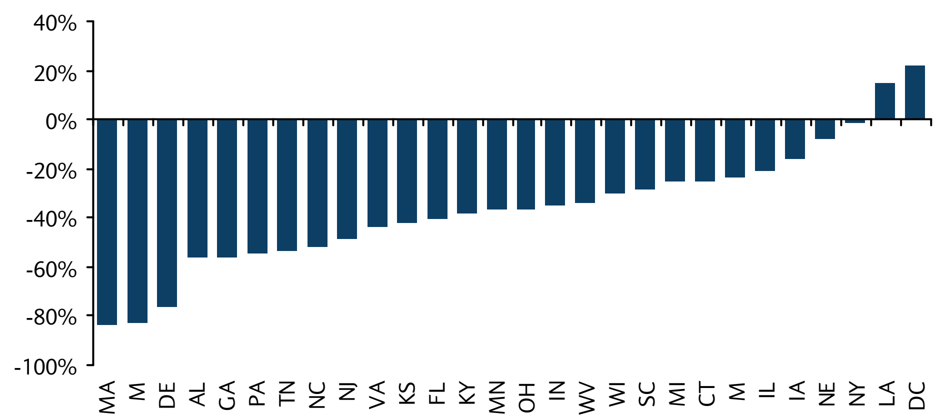
A comparison between the proposed 2012 SO2 emissions allocations and reported state emissions in 2008 shows that the states with the greatest shortfall of allowances will likely be Pennsylvania, Georgia, Ohio, Indiana, and Alabama (Figure 9). The five states account for 53% of the overall shortfall for the states where SO2 emissions will be regulated under CATR. Pennsylvania, Ohio, and Indiana are also among the top five states with coal-fired generation, and their shortfall in allowances in part reflects the large amount of coal capacity relative to other generation resources. In percentage terms, however, the steepest cuts in emissions would have to be achieved by Massachusetts, Maryland, and Delaware, each of which would be required to cut SO2 emissions by more than 75% from 2008 levels by 2012 (Figure 10).

Figure 9: Shortfall of proposed CATR 2012 SO2 emission allocations vs. 2008 SO2 state emission levels, tons



Source: EPA, Barclays Capital

Figure 10: Shortfall of proposed CATR 2012 SO2 emission allocations vs. 2008 SO2 state emission levels, percent of 2008 levels



Source: EPA, Barclays Capital

The response to new emissions regulations will differ by state…

The response to the newly enacted emissions restrictions will differ by state. Some states are already focused on limiting coal plant emissions and put emission reductions at the top of their priority list when considering power generation. Colorado, among others, has already moved to reduce NOx emissions, and is seeking to replace or repower the plants with natural gas or renewables. (Note that Colorado is not regulated under the CATR.) Other states view the availability of cheap, coal-fired electricity as a key driver of economic growth, and would be much more cautious about the effect on customer rates in making decisions to shut down coal units. For such states, the utility will work with state regulators (e.g., the utility commission) to moderate the effects on customer rates, which may have a significant influence on the timing and pace of emissions upgrades. A utility will not move forward with capital improvements on a regulated unit without reaching an agreement with the PUC on how to recover the expense.

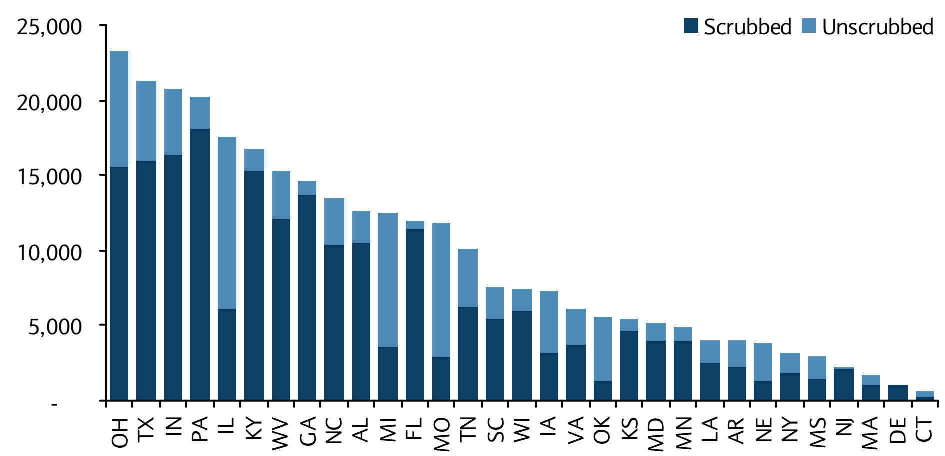
Yet, other states may actually see a benefit from retiring existing coal-fired generation. In the Midwest, for example, the economic slowdown has cut electricity demand and left as much as 30% surplus capacity in some states. The lack of need for capacity could make a shutdown decision far easier, while in other regions, the retirement of cheap-to-operate, fully depreciated plants may only boost power prices. The Southeast is a region where loads have recovered and capacity will be at a premium.

… but the decision to upgrade or shut down plants will be made on a case-by-case basis

Ultimately, however, the decision to upgrade or shut down a coal plant will be made on a case-by-case basis. When thinking about coal-fired generation, it is important to remember that not all coal plants were created equal. There are many types of coal plants, but for simplicity, we will broadly divide them into two categories – supercritical and subcritical. Supercritical units run at much higher temperatures, and as a result, tend to be more efficient. Similar to an automobile, one way to emit less is to get more out of each unit of fuel. By generating more electricity per unit of coal, they emit less per kWh than a subcritical unit (with the same emissions controls). Supercritical units tend to be larger capacity plants as well. Subcritical units are generally smaller, and operate at lower temperatures and higher heat rates. Because they tend to emit more per unit of fuel consumed, subcritical coal-fired units would generally be at the most risk of being shut down as a result of more stringent emissions regulations.

Many coal-fired units already have emissions controls (Figure 11). For the states covered under CATR, 69% of the nameplate capacity have scrubbers installed. For those units that are not already scrubbed, the economics of installing additional equipment to meet newly enacted emissions standards would have to compare favorably with alternatives to build new (likely gas-fired) generation, purchase power, or purchase additional emission allowances. This in itself is not simple math, as each plant will have different considerations. Thus, the decision to retire coal-fired plants will be done on a case-by-case basis. Various emissions

Figure 11: Coal-fired generation by state, nameplate capacity, MW



Source: SNL, Barclays Capital

control technologies can range widely in costs, but also have varying degrees of effectiveness. In addition, a series of regulations have yet to be decided (mercury, particulates, and ultimately, CO_2), forcing operators to make commitments now against a backdrop of an uncertain future. An operator must also consider, among others, the downtime needed to install the equipment, any resulting loss of revenues (generally for merchant operators), the cost of labor, and the cost of capital. More credit-challenged utilities or merchant generators might find the financing of emissions control equipment difficult. Forward power prices and regulatory constructs for the rate of recovery of capital expenses will dictate the extent to which future revenues justify the investment.

A new gas-fired plant is often the default point of comparison

The economic analysis for a coal plant that must be replaced often includes a comparison with a new natural gas-fired plant. Although gas may be the default choice for capacity replacement, regulators are still very hesitant to turn to natural gas. One of the authors of this report recently attended the annual meeting of the National Association of the Regulatory Utility Commissioners (NARUC) and was struck by the fact that while commissioners readily recognized the newfound abundance of natural gas, gas prices are still viewed as being volatile; therefore, regulators are skeptical that gas will be a cheap alternative for new power generation. The memory of the gas price volatility of 2005 and 2008 is perhaps too recent. Coal prices, on the other hand, are viewed as stable, and stability has a strong advantage from the perspective of the regulators. While new coal plants are challenging to site and permit, existing coal plants are challenging to displace.

Although details of the regulation are still being ironed out, some analysts are already estimating potential scenarios for the power markets. Our equity analysts estimate that the rule could result in 20-30 GW of potential coal plant retirements (*U.S. Utilities & Power, EPA's CATR Proposal Released*, July 7, 2010). The range of estimates of coal plant retirements is quite wide, with some suggesting as much as 60 GW of capacity shuttered. In addition, the retirements are concentrated in a few market regions. Plant retirements of significant scale would certainly affect reserve margins in regions that might see a large amount of shuttered capacity. This would shift a chunk of the lost coal generation to gas-fired units, while also shrinking reserve margins. These together would boost power prices. Forecasting the likely scale and timeframe of generation retirements has always been difficult and the impact of CATR will take some time to understand. So far, the amount of capacity that has been announced for retirement is quite small, and most of the coal plants slated for closure did not operate often. If history is any indicator of the future, the amount of coal capacity that will be shuttered will fall below forecasters' expectations, and the closures will be strung out for a longer period than anticipated.

Power prices lag the recovery in demand

Power prices are lagging the recovery of demand

Power prices are lagging the rebound in loads as the markets grew fat with spare capacity during the consumption pullback. Of course, power prices are also heavily influenced by weather and by natural gas prices. To normalize for the impact of natural gas prices, and thus also to some extent for weather, as gas and power prices would both tend to rally or fall on a weather event, we use heat rates (simply the price of power divided by the price of gas at a particular location) as a better indicator of the state of the power markets.

Load recovery has not strengthened heat rates

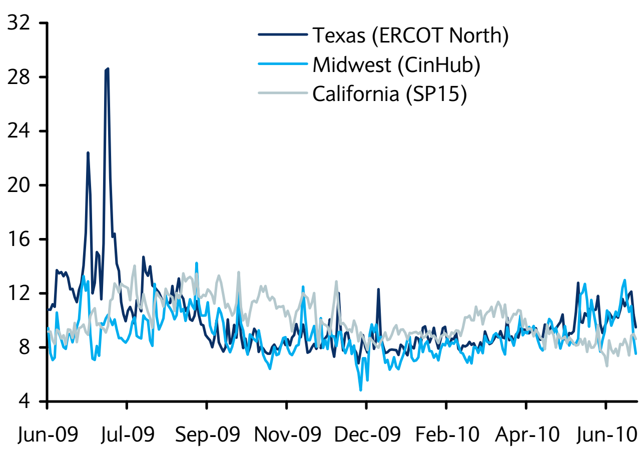
To the extent there has been load growth, it has not moved the needle much on heat-rate liquidations. Over the past couple of months, hot weather has caused short-term spikes in heat rates in NEPOOL, PJM, New York, and CinHub. Some strengthening is evident for all these points, but there is no clear growth trend as of yet. Heat rates in Texas, part of the South Central region which has had the strongest load growth so far, are showing only a marginal recovery since the beginning of the year and are lower than 2009 levels, as some very focused hot weather last year in Texas had caused heat rates to spike. Thus, despite load recovery in Texas, heat rates are not moving higher. In SP15, heat rates actually moderated, pressured in part by a rebound of hydro generation in June and July.

The forward markets are largely mirroring this sentiment, and forward prices have sagged along with the natural gas forward curves (Figure 14). Forward heat rates have remained largely unchanged as power markets lack their own driver and prices broadly follow natural gas. The northeast markets have been somewhat of an exception, as forward heat rates there have jumped, contrary to what fundamentals would suggest (Figure 15), although to levels no higher than in recent history. This dynamic has been largely a reflection of a pronounced weakness in forward gas prices coupled with weather-driven strength in the front of the power curve, rather than expectations for a tightening power market in the region. Forward gas prices have fallen particularly hard in the northeast as the region is poised to be increasingly well supplied with growing Marcellus production, new LNG regasification terminals and the Rockies Express pipeline (Figure 16).

Even the healthy recovery of demand is not sufficient to tighten the markets and lift heat rates in the next 12 to 18 months

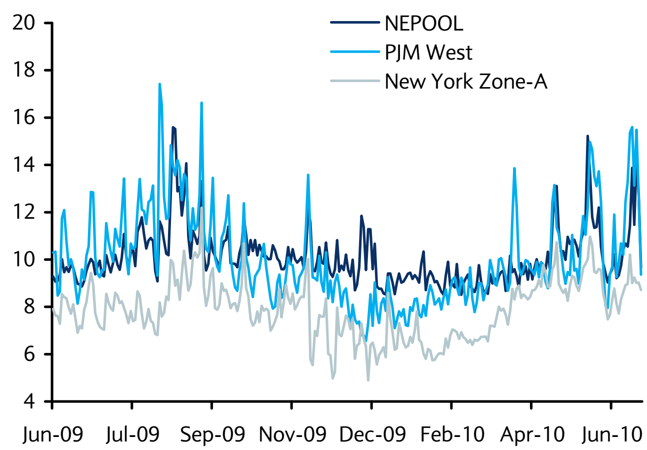
Heat rates ahead will be defined by the race between competing trends in supply and demand. Even with the healthy pace of demand recovery, as we discussed above, it will take a few years for demand to revert to the 2007 peak levels. Meanwhile, new capacity continues to come to market. The most meaningful shift in supply looks likely to come from the retirement of existing coal units, but this is a few years out. Thus the power markets are not poised to tighten significantly in the next two years, in our view.

Figure 12: Heat rate liquidations, on-peak, MMBtu/MWh



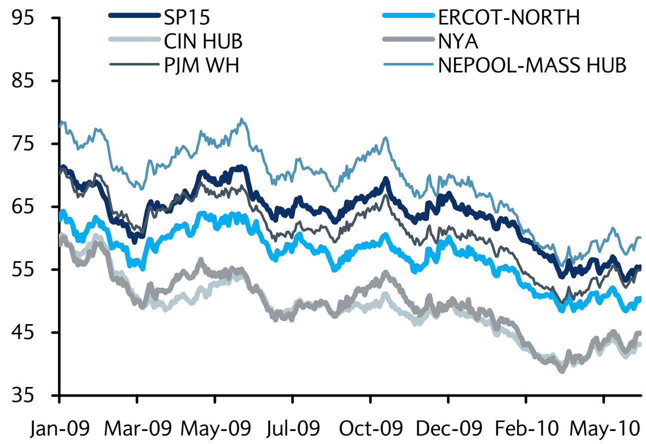
Source: Platts, Barclays Capital

Figure 13: Heat rate liquidations, on-peak, MMBtu/MWh



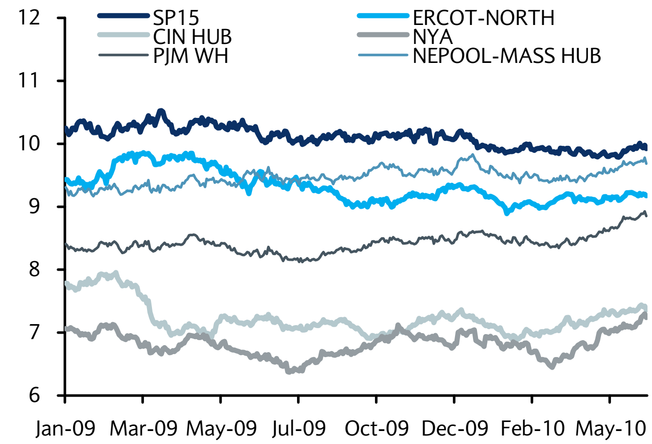
Source: Platts, Barclays Capital

Figure 14: On-peak forward power prices, calendar 2011 - 2012



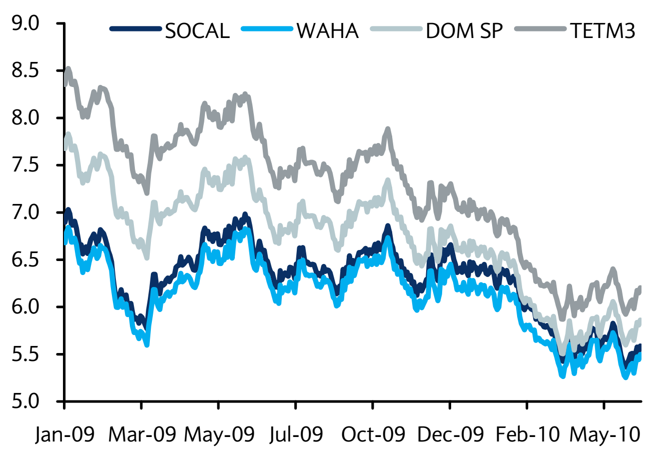
Source: Barclays Capital

Figure 15: On-peak forward heat rates, calendar 2011 – 2012



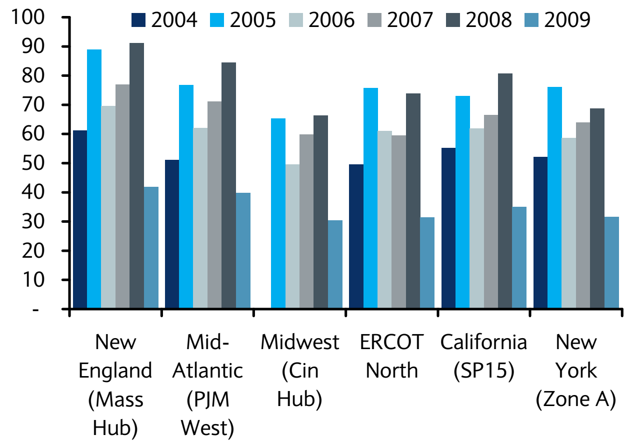
Source: Barclays Capital

Figure 16: Forward gas prices, calendar 2011 - 2012



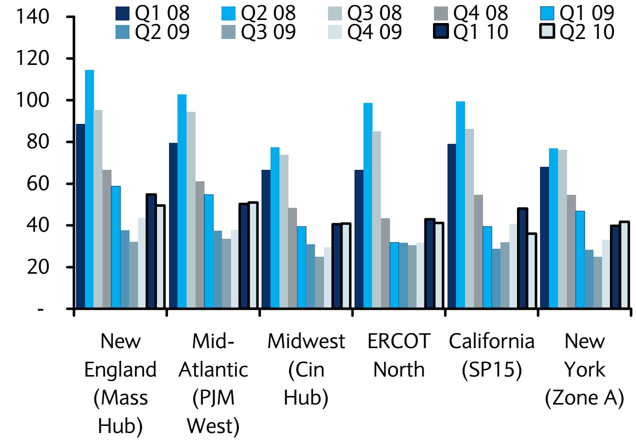
Source: Barclays Capital

Figure 17: Annual on-peak power prices ($/MWh)



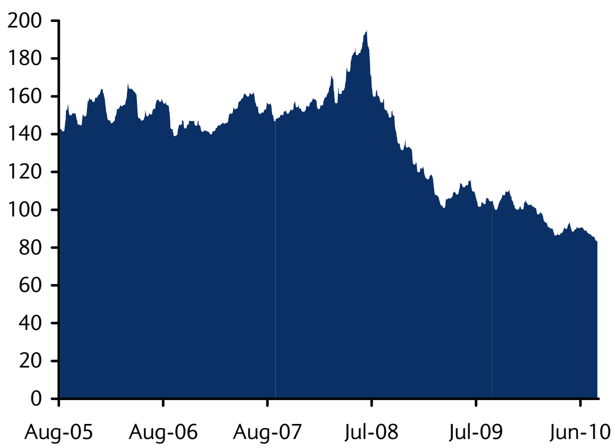
Source: ICE, Barclays Capital

Figure 18: Quarterly on-peak power prices ($/MWh)



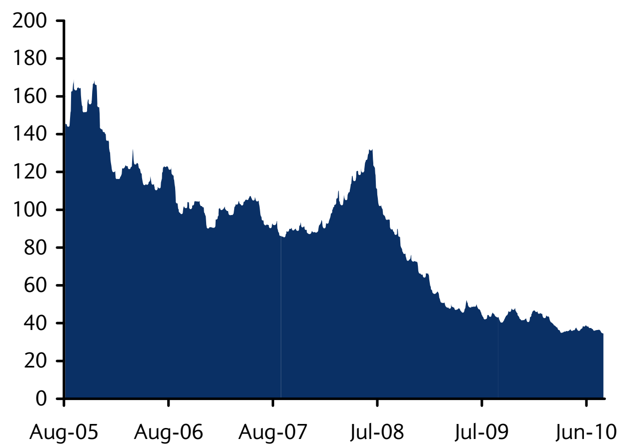
Source: ICE, Barclays Capital

Figure 19: Barclays Capital US Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)



Source: ICE, Barclays Capital

Figure 20: Barclays Capital US Power Index, 1y Forward Strip, Monthly Rolling (December 6, 2004 = 100)

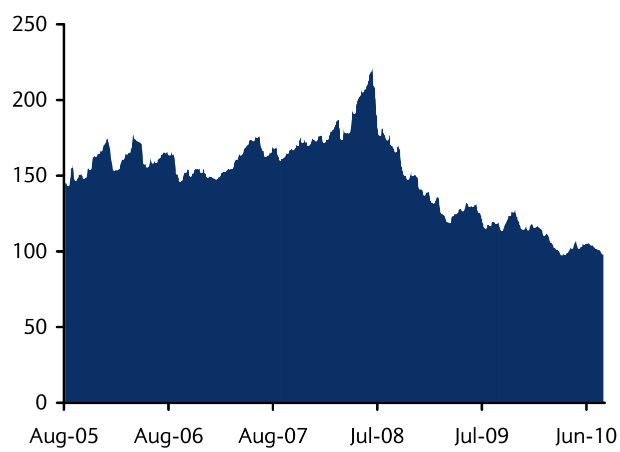


Source: ICE, Barclays Capital

Figure 21: Barclays Capital Northeast (Mass Hub) Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)

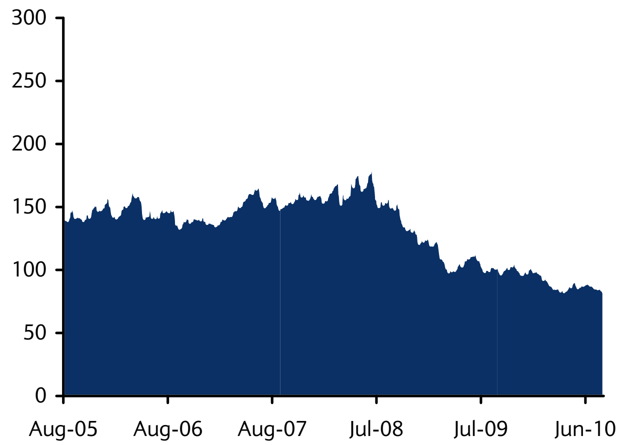
Source: ICE, Barclays Capital

Figure 22: Barclays Capital PJM (West) Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)



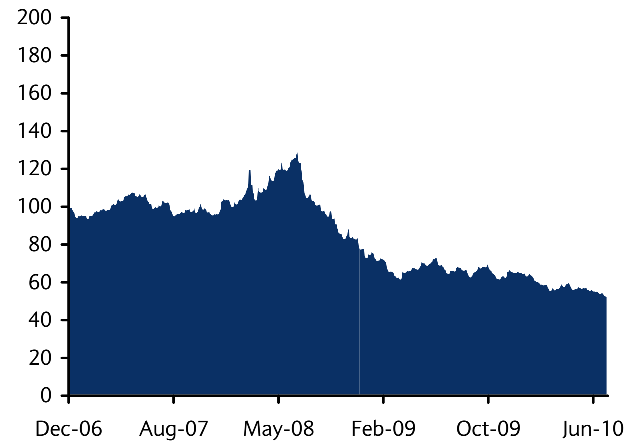
Source: ICE, Barclays Capital

Figure 23: Barclays Capital Midwest (Cin Hub) Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)



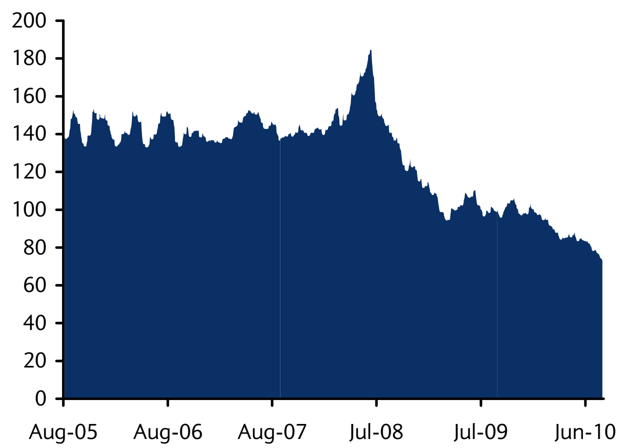
Source: ICE, Barclays Capital

Figure 24: Barclays Capital ERCOT North Zone Power Index, 3y Forward Strip, Annually Rolling (December 6, 2006 = 100)



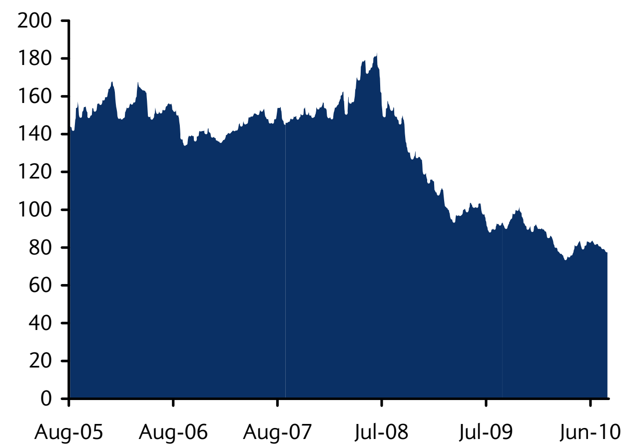
Source: ICE, Barclays Capital

Figure 25: Barclays Capital West (California SP15) Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)



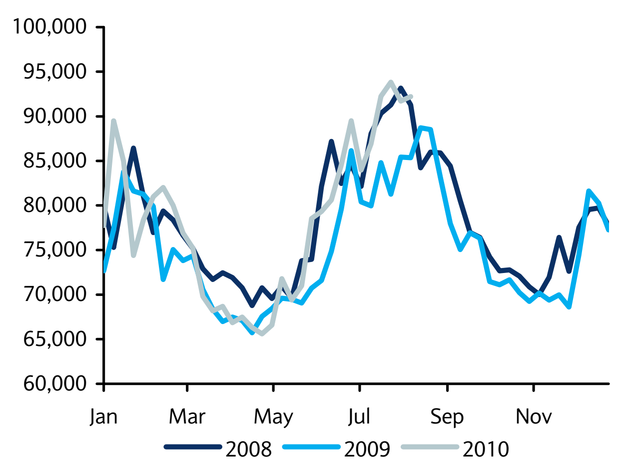
Source: ICE, Barclays Capital

Figure 26: Barclays Capital New York Zone A Power Index, 3y Forward Strip, Annually Rolling (December 6, 2004 = 100)



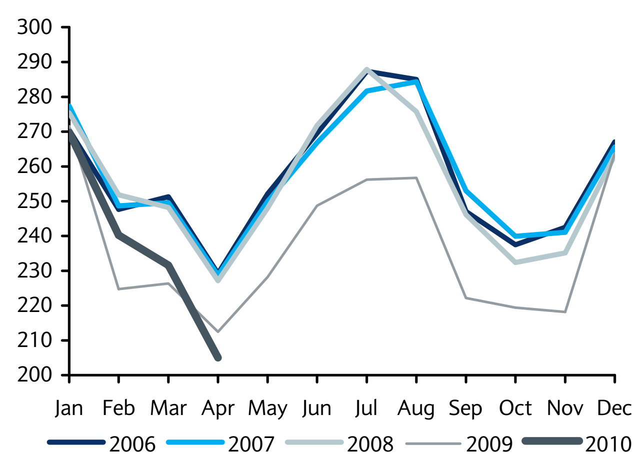
Source: ICE, Barclays Capital

Figure 27: US electricity output (TWh)



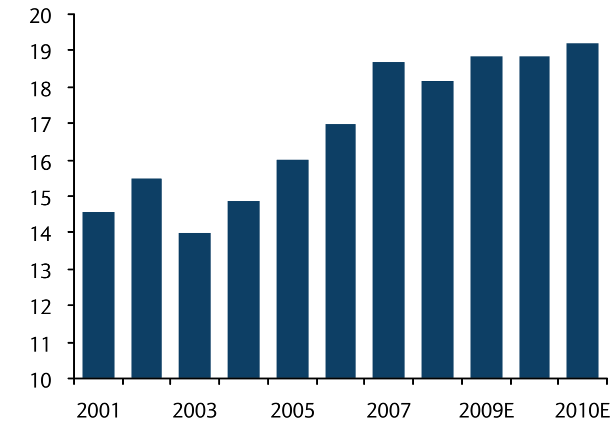
Source: ICE, Barclays Capital

Figure 28: US baseload (nuclear, hydro and coal) plant output (TWh)



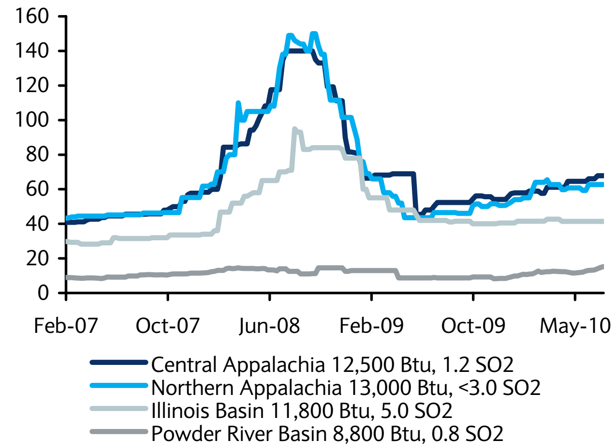
Source: Bloomberg, Barclays Capital

Figure 29: Gas demand for power (Bcf/d)



Source: EIA, Barclays Capital

Figure 30: US spot prices for benchmark coal ($/short ton)

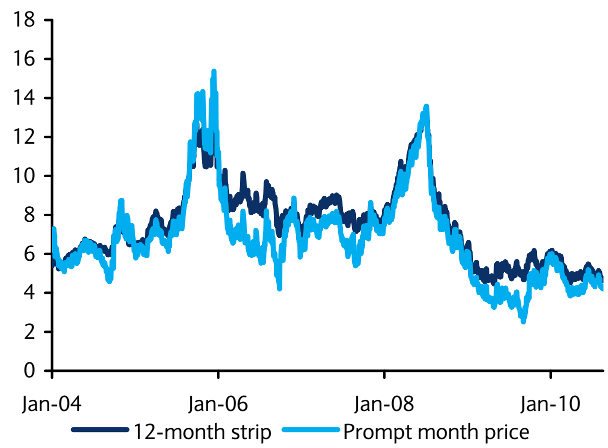


Source: EIA, Barclays Capital

Figure 31: International coal spot prices (US$/mt)

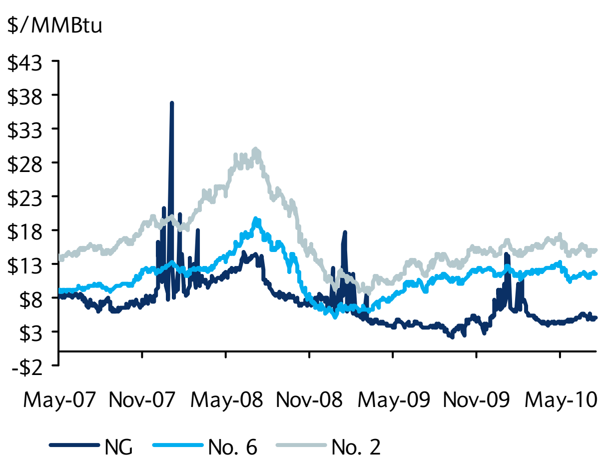
Source: EEX, Barclays Capital

Figure 32: Natural gas prices ($/MMBtu)



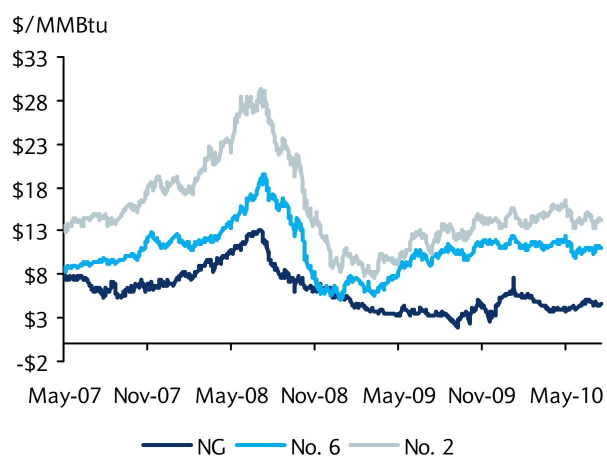
Source: Bloomberg, Barclays Capital

Figure 33: Fuel switching economics, New York City ($/MMBtu)



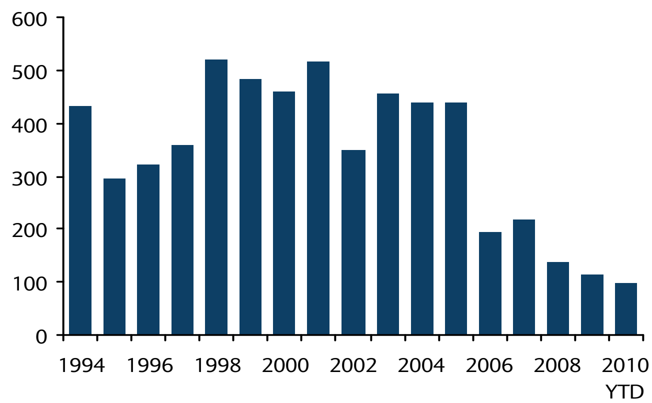
Source: Bloomberg, Barclays Capital

Figure 34: Fuel switching economics, US Gulf Coast ($/MMBtu)



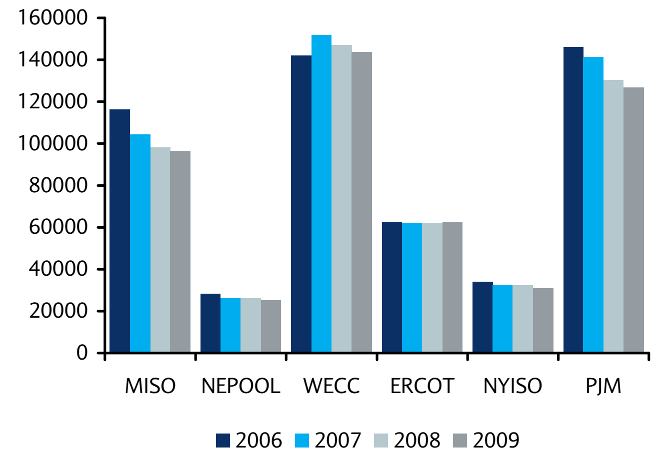
Source: Bloomberg, Barclays Capital

Figure 35: Oil consumption in power generation (thousand barrels per day)



Source: EIA, Barclays Capital

Figure 36: Annual peak regional power demand (MW)



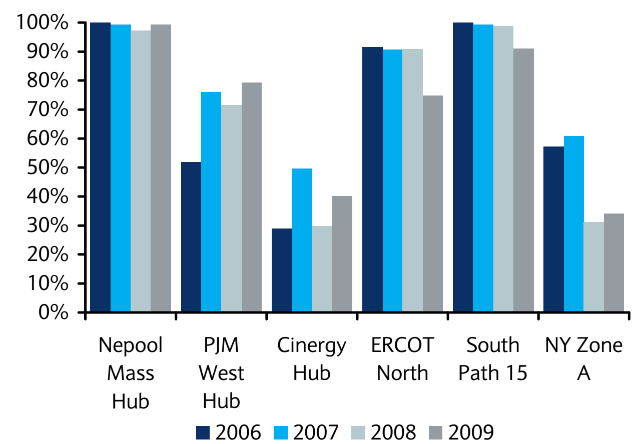
Note: Some peak demand figures are preliminary. Source: MISO, NEPOOL, CAISO, ERCOT, NYISO, PJM, AESO, Barclays Capital

Figure 37: Peak demand (MW)

Region	2007	2008	2009 *
MISO	104292	98256	96510
NEPOOL	26145	26138	25081
WECC	151713	147004	143564
ERCOT	62101	62120	62397
NYISO	32169	32432	30844
PJM	141383	130300	126805

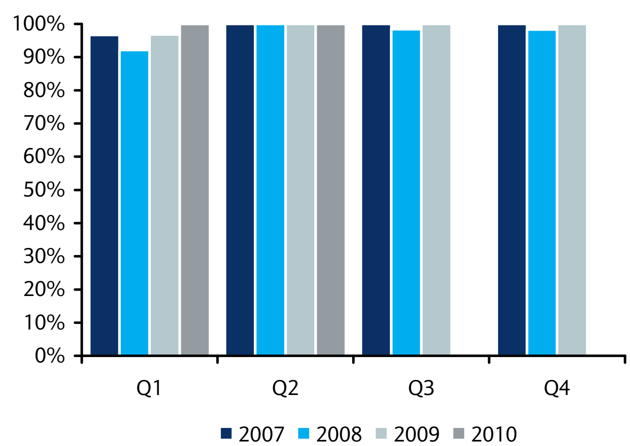
Note: *Preliminary. Source: ERCOT, EIA, MISO, PJM, NYISO, NEPOOL, WECC, CAISO, AESO, NERC, Barclays Capital

Figure 38: Percent of days when gas-fired power plants were on the margin



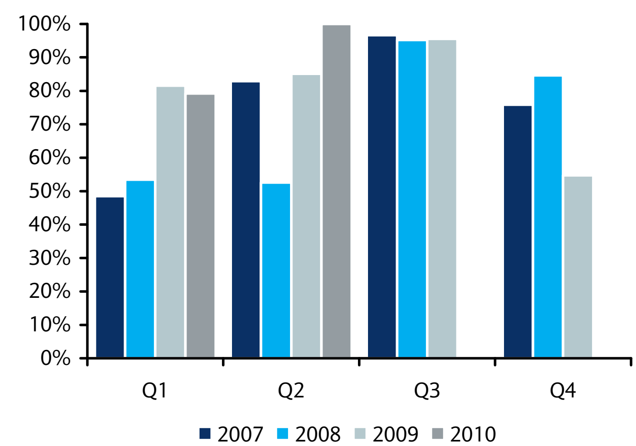
Source: ICE, Barclays Capital

Figure 39: Percentage of days when gas-fired power plants were on the margin (Mass Hub)



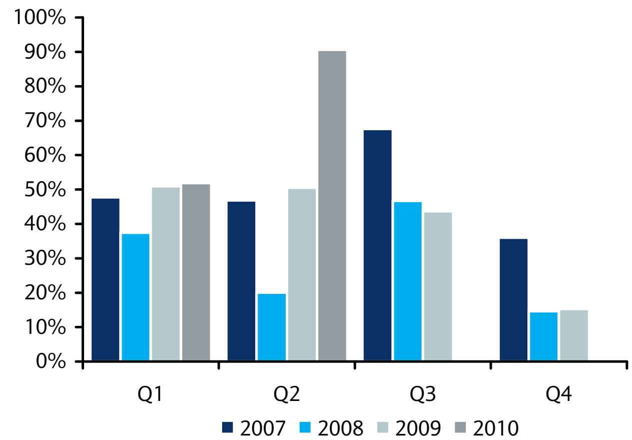
Source: EIA, ICE, Barclays Capital

Figure 40: Percentage of days when gas-fired power plants were on the margin (PJM West)



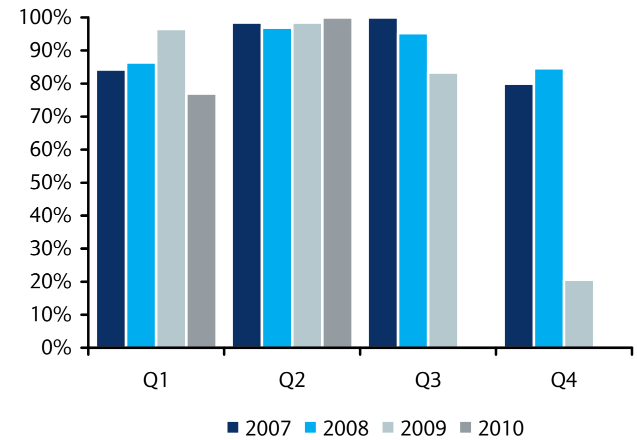
Source: ICE, Barclays Capital

Figure 41: Percentage of days when gas-fired power plants were on the margin (Cin Hub)



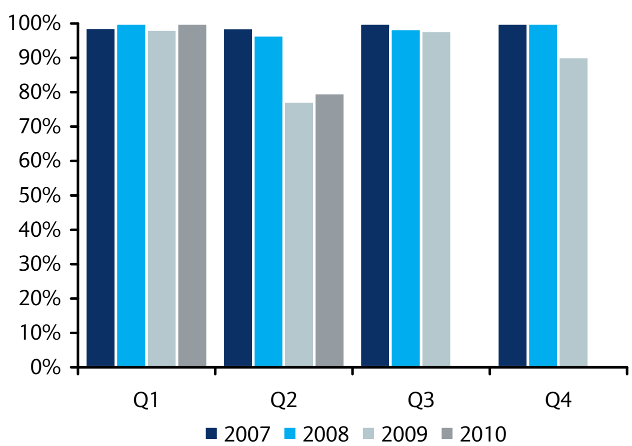
Source: ICE, Barclays Capital

Figure 42: Percentage of days when gas-fired power plants were on the margin (ERCOT North)



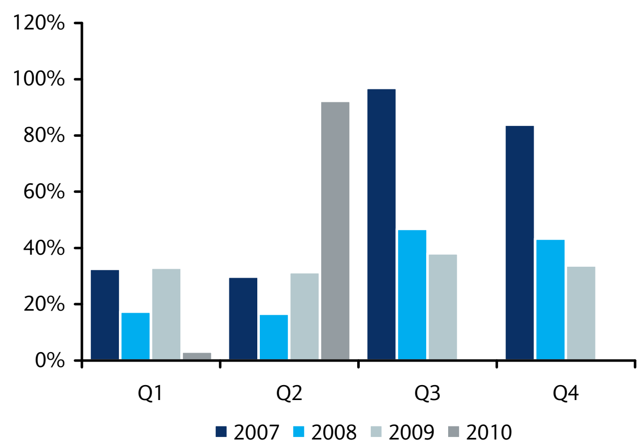
Source: ICE, Barclays Capital

Figure 43: Percentage of days when gas-fired power plants were on the margin (SP15)



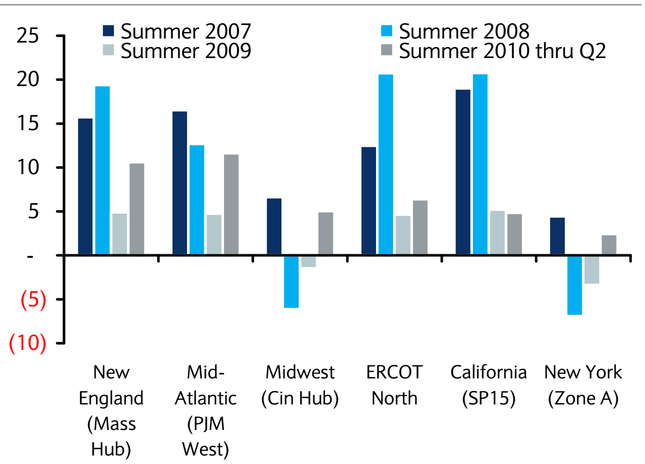
Source: ICE, Barclays Capital

Figure 44: Percentage of days when gas-fired power plants were on the margin (New York Zone A)



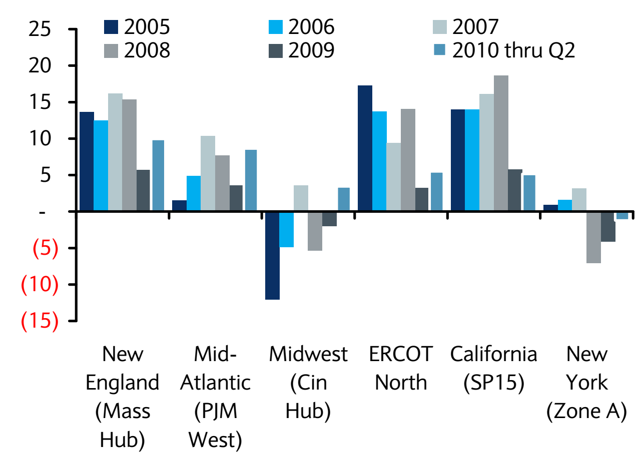
Source: ICE, Barclays Capital

Figure 45: Summer peak spark spreads ($/MWh, assuming 7.5 MMBtu/MWh heat rate and $2 variable operations and maintenance cost)



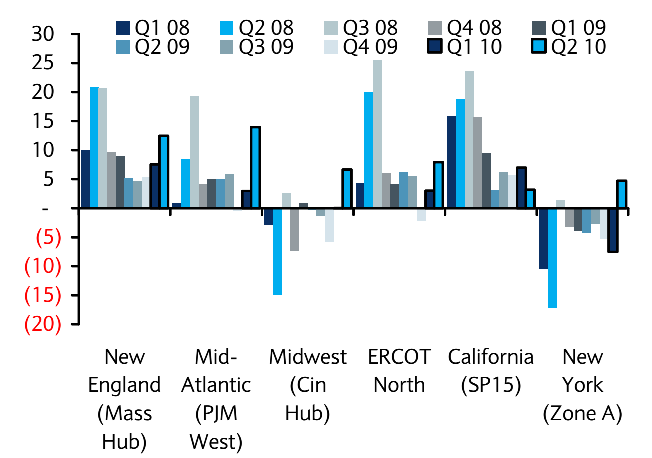
Source: ICE, Barclays Capital

Figure 46: Annual peak spark spreads ($/MWh, assuming 7.5 MMBtu/MWh heat rate and $2 variable operations and maintenance cost)



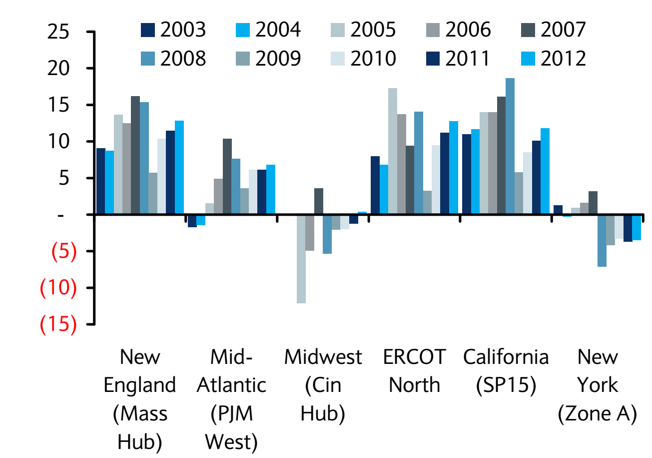
Source: ICE, Barclays Capital

Figure 47: Quarterly peak spark spreads ($/MWh, assuming 7.5 MMBtu/MWh heat rate and $2 variable operations and maintenance cost)



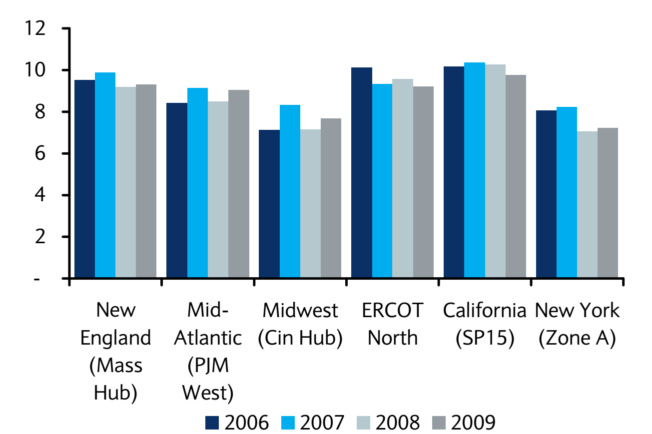
Source: ICE, Barclays Capital

Figure 48: Historical and forward peak spark spreads ($/MWh, assuming 7.5 MMBtu/MWh heat rate and $2 variable operations and maintenance cost)



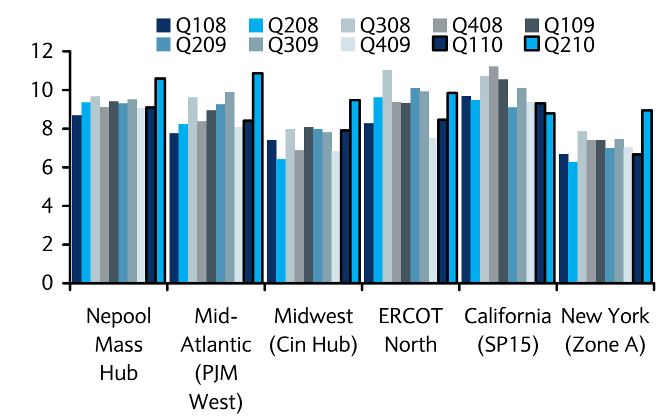
Source: ICE, Barclays Capital

Figure 49: Annual on-peak heat rates (MMBtu/MWh)



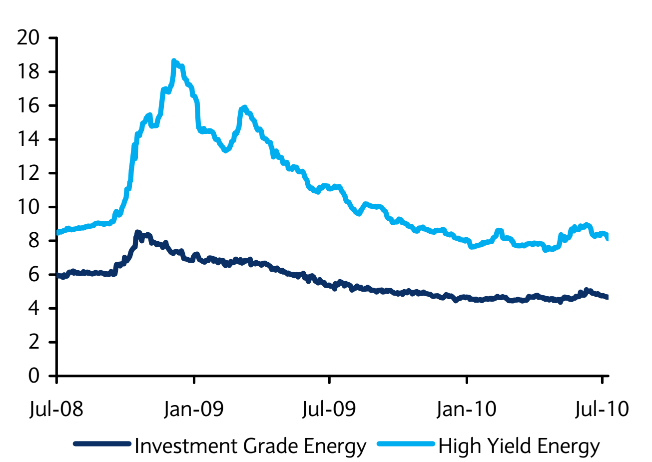
Source: EIA, Barclays Capital

Figure 50: Quarterly on-peak heat rates (MMBtu/MWh)



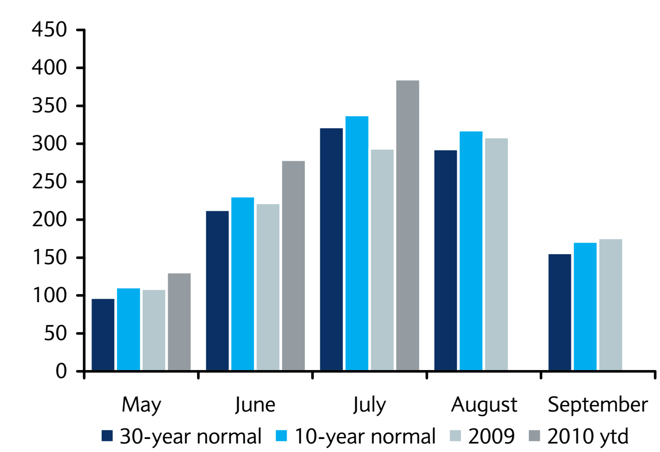
Source: EIA, Barclays Capital

Figure 51: Proxy borrowing costs (yields of secondary bonds, %)



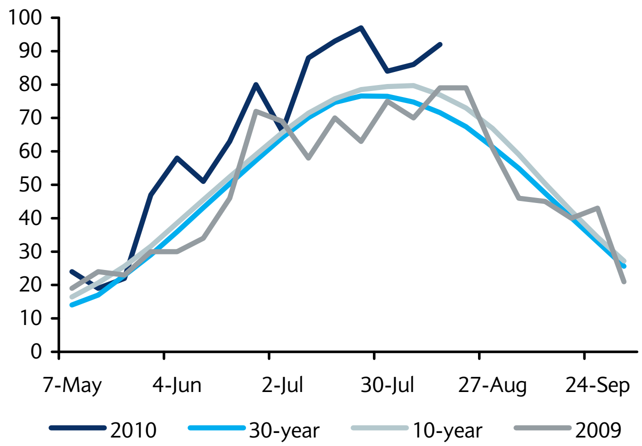
Source: Barclays Capital

Figure 52: Summer 2009 compared with 10- and 30-year average (cooling degree days)



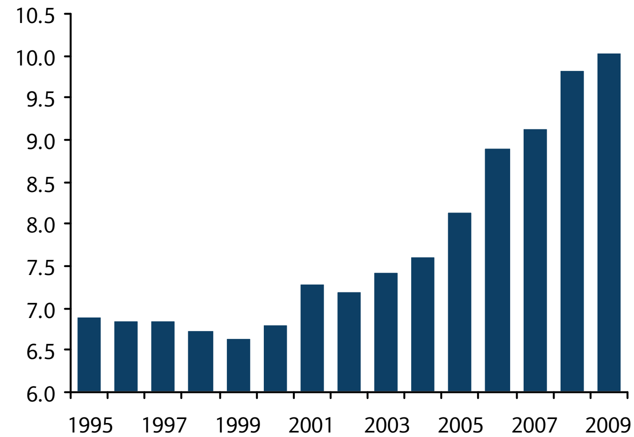
Source: Barclays Capital

Figure 53: US population-weighted heating degree days, winter season



Source: NWS, Barclays Capital

Figure 54: US retail electricity prices (cents/kWh)



Note: EIA, Barclays Capital

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