PROTECT THE AMERICAN PEOPLE: MORATORIUM ON COAL PLANT CLOSURES ESSENTIAL

Roger Bezdek Ph.D
President
Management Information Services Inc.

Frank Clemente Ph.D*
Professor *Emeritus* of Social Science
Penn State University

June 2014

*The materials presented here are solely the responsibility of the author and do not represent Pennsylvania State University in any manner.

TABLE OF CONTENTS

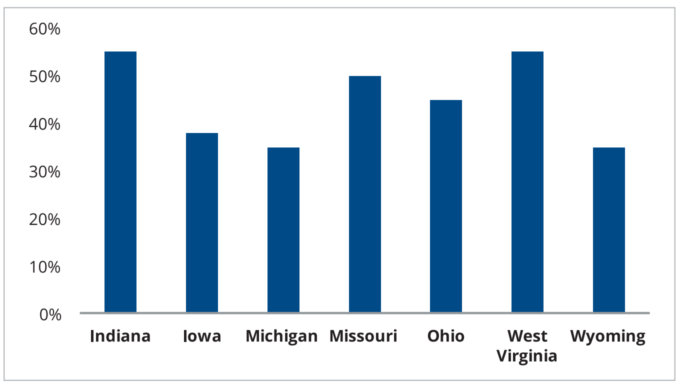
EXECUTIVE SUMMARY

Recent events in New England and elsewhere in the U.S. have demonstrated that **policies which hurt the U.S. coal fleet are placing the reliability, affordability, and security of America's electric supply system at risk:**

- These policies will significantly increase wholesale electric rates – and could increase them by as much as 80 percent – according to Dr. Julio Friedmann, Assistant Secretary for Clean Coal at the U.S. Department of Energy (DOE).[1]
- The increases will be especially harmful in certain states – such as Indiana, Iowa, Michigan, Missouri, Ohio, West Virginia, and Wyoming (Figure EX-1).
- Severe economic hardship will be imposed on people who can least afford it – low income families, minorities, children, and the elderly.

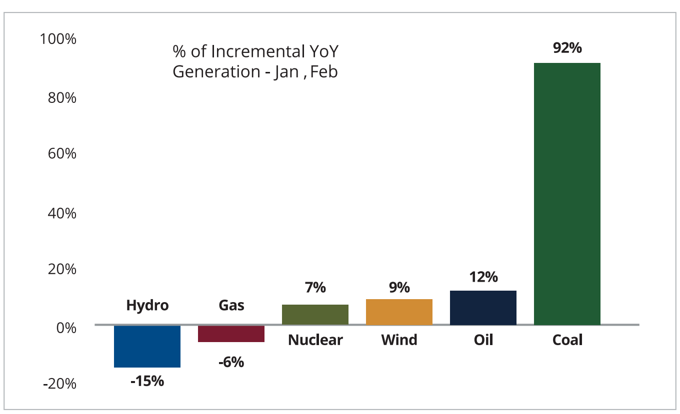
Therefore, policymakers, regulators, and electric utilities should institute an immediate moratorium on the premature closure of coal power plants and should reverse planned closures where possible.

Figure EX-1: Potential 2020 Electric Rate Increases From Coal Plant Closures



During the winter of 2014, coal was the only fuel with the ability to meet demand increases for electricity, providing 92 percent of incremental electricity in January/February, 2014 versus the same months in 2013[2] (Figure EX-2).

Figure EX-2: What Showed Up for Work During the Polar Vortex?

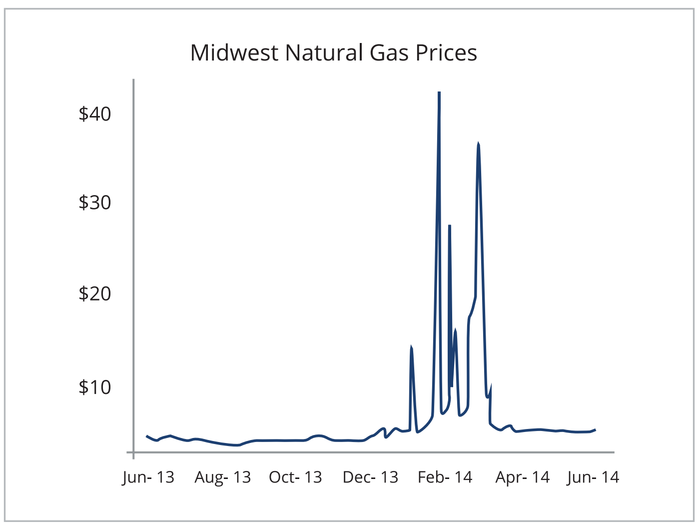


During the winter of 2013 - 2014:

- Businesses in New England and other parts of the U.S. were curtailed because of a lack of gas infrastructure.
- Natural gas power plants also had a problem getting fuel due to infrastructure issues and at one point many of them had to go offline.
- Gas-based electricity prices increased 1,000 percent as coal and oil plants scheduled for closure picked up the load.
- Without coal, parts of New England, the Midwest, and other regions would have experienced brownouts and blackouts that would have been economically disastrous and would have compromised public health and safety; in many instances it could have been life threatening.

This past winter demonstrated in real time the value of the existing coal fleet. Americans were harmed as the relentless cold indicated that prudent utility practices require large, baseload coal plants to stabilize the grid, keep society functioning, and maintain electricity availability. Many regions suffered; for example, in late January and early February 2014 some locations in the Midwest experienced gas prices as high as $35/MMBtu, and the Chicago Citygate price exceeded $40/MMBtu (Figure EX-3).

Figure EX-3: Chicago Citygate Natural Gas Prices, February 2013 – 2014 (Dollars per MMBtu)



Source: NGI nationalgasintel.com

Government policies that drive over-dependence on natural gas to replace baseload coal put the U.S. electric supply at risk and also endanger:

- The 60 million households who need gas for heating.
- A vast array of firms that use gas in daily operations.

Recent experience in New England and elsewhere represents a troubling indication of the implications of removing coal plants from the electricity generation mix:

- Spot prices of natural gas and electricity may spike significantly.
- Utility bills become unaffordable for many families during price spikes.
- Energy shortages could occur.
- What little industry is left in the Northeast may be forced to leave.
- Average electricity rates in New England are already more than 40 percent higher than the national average and may be headed to be 150 percent higher.
- New York's electricity prices are now the second highest in the country – only the geographically isolated state of Hawaii has higher prices.

New England is merely the precursor to the national problem which is emerging. With the projected closure of 60 gigawatts (GW) of coal plant capacity, virtually the entire U.S. is rapidly reaching the brink of significantly higher prices for electricity and being unable to meet either the summer or winter peak demand for power. Unless immediate steps are taken to halt coal plant closures:

- Within the decade entire regions (New England, Florida, California, the Southwest) may be at risk.
- Vast areas of the American Heartland from the Southeast to the Plains could face the difficult choice of using gas for either electric power or meeting the heating needs of millions of families, businesses, and farms.
- Forecasts indicate that by 2020, natural gas capacity will exceed coal, nuclear, and hydro capacity *combined*, creating a lack of diversity of supply issue.

The American Public Power Association has demonstrated the difficulties of replacing coal in electricity generation, and found that there must be continued reliance on America's largest energy resource:

- The U.S. has by far the world's largest coal supply, nearly 30 percent of the global total.
- Most existing coal-fueled power plants are less expensive than natural gas for electricity generation.
- The U.S. Energy Information Administration (EIA) forecasts that coal's price advantage will continue and grow larger for the next three decades.
- U.S. coal used for electricity generation has increased 170 percent since 1970 as key emission rates (SO_2, NO_X, PM_{10}) have been reduced by 90 percent.[3] Greater use of advanced technologies will continue this progress.
- Advanced "supercritical" technology is highly efficient, and other state-of-the-art technologies result in a key emissions rate that is two-thirds lower than the existing fleet with carbon dioxide (CO_2) emission rates as much as 25 percent lower than the oldest plants.[4]

Current policies are driving reduction of coal generation creating increased dependence on natural gas. However, activist groups and government officials have indicated their desire to reduce natural gas usage as well.

- Activist groups supporting the "Beyond Coal" campaign have initiated a "Beyond Natural Gas" campaign to oppose hydraulic fracturing.[5]
- Department of Energy Secretary Ernest Moniz contends that natural gas is "too carbon intensive" and must be phased out of electricity generation by 2050. [6]
- White House Senior Counselor John Podesta has endorsed the phase-out of natural gas in the electric power sector beginning in 2020. [7]
- Ronald Binz, recent nominee to chair the Federal Energy Regulatory Commission (FERC), said of gas: "On a carbon basis, you hit the wall in 2035 or so with gas. I mean, you do. And it's certainly helping my state [Colorado]...but we also have to understand that without [carbon capture and storage], I think that's a dead end, a relative dead end – it wouldn't dead end until 2035 or so – but that's when we're going to have to do better on carbon than even natural gas can do." [8]

Current policies for electrical generation threaten the abundant, reliable and affordable electricity Americans have come to rely upon; they drive coal out as a source of electrical generation, creating heavy reliance on natural gas. In the next phase, natural gas will be driven out as well. This will affect natural gas availability for direct use and power, making electricity more expensive and scarce to Americans and hurting economic growth.

In sum, policies that erode the U.S. coal fleet are placing the reliability, affordability, and security of America's electric supply system at risk. Prudence requires an immediate moratorium on coal power plant closures and planned closures should be reversed where possible.

References:

1. Aaron Larson, "CCS Could Increase Coal-Fired Electric Generation Costs By 70%–80%," Power Magazine, February 13, 2014.
2. U.S. Energy Information Administration (EIA), Electric Power Monthly, February 2014.
3. U.S. Energy Information Administration (EIA), Monthly Energy Review, Feb 2014; U.S. Environmental Protection Agency (EPA), "National Air Pollutant Emission Trends, 1900-1998 and 1970-2013;" EPA Air Markets Program Data; EIA Electric Power Monthly, March 2014.
4. EPA "National Air Pollutant Emission Trends, 1900-1998 and 1970-2013;" EPA Air Markets Program Data; EIA Electric Power Monthly, March 2014; EIA, 2012 data on coal plant heat rates.
5. http://content.sierraclub.org/campaigns/beyond-natural-gas.
6. Lisa Song, "Moniz: Shale Gas Boom a Low-Carbon Solution – for Now," InsideClimate News, February 21, 2013.
7. Darryl Banks and Gwynne Taraska, "U.S. Natural-Gas Use Must Peak by 2030," Center for American Progress, Washington, D.C., July 2013.
8. https://www.youtube.com/watch?v=FAOTt_rR0lo&feature=youtu.be&t=30m17s.

PRÉCIS - PROTECT THE AMERICAN PEOPLE: MORATORIUM ON COAL PLANT CLOSURES ESSENTIAL

> **"89 percent of our coal capacity slated for retirement in mid-2015 is called upon and running…"**
> **Nick Akins, CEO, American Electric Power [1]**

This document describes recent events to demonstrate why policymakers, regulators, and electric utilities should institute an immediate moratorium on the premature closure of productive power plants, seeking to reverse decisions that may have already been made. Energy price spikes and supply problems in New England and throughout most of the nation this winter demonstrated that **policies that hurt the U.S. coal fleet** and the nuclear fleet are imprudently placing the reliability, affordability, and security of America's electric supply system at risk. Gas prices spiked 1,000 percent in some areas in January and February 2014 and gas supply to industry and power plants had to be curtailed to accommodate residential demand. At one point about 75 percent of New England's natural gas electric generating capacity was not operating due to lack of supply or high prices caused by infrastructure issues. Coal plants slated for premature closure, such as Brayton Point (1,530 megawatts, MW) in Massachusetts, enabled many states to avoid a full blown energy crisis. In January, at least 75 percent of Southern Company's coal power plants scheduled to soon close were needed to meet consumer demand. The Tennessee Valley Authority set new records for electricity demand at the same time that many of its coal-fueled generating facilities are scheduled for closure, including two of its three highly productive Paradise Units. Without the availability of the coal plants slated to go offline, these regions would not have met power demand this past winter.

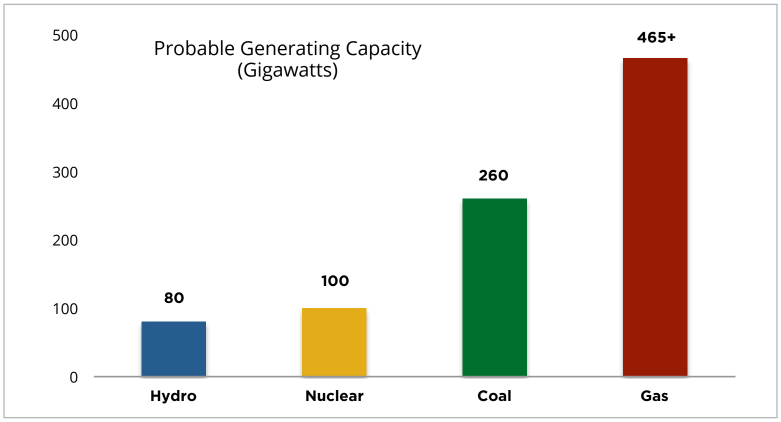
The capacity factor of America's coal plants averaged over 70 percent this past winter while many gas plants could not get fuel due to infrastructure issues. What will happen when reliable baseload coal plants are closed in the next 20 months when their licenses permanently terminate?

Volatility has been inherent in the natural gas system historically. The U.S. Energy Information Administration (EIA) has warned, "Due to limited alternatives for natural gas consumption or production in the short run, changes in supply or demand over a short period often result in large price movements."[2]

Coal generation has served as an important buffer to gas price spikes over the past 15 years. Because of new supplies of shale natural gas from non-federal lands, added storage and investments in new pipeline capacity, natural gas availability and deliverability have improved. However, government policies which mandate the premature closure of coal plants will force vast new demands on the natural gas system requiring a favorable government response that has been proven to be anything but certain. For example, the natural gas produced from non-federal lands increased 33 percent between 2009 and 2013, while on government lands production decreased 28 percent. Cutting off the most important leg from the stool on which U.S. energy reliability and affordability rests would be foolish even if the government ensured that the other legs remain robust so as to carry the increased load. In practice, however, government policies have only encouraged non-dispatchable sources incapable of meeting demand. Reducing fuel diversity removes an important protection for consumers who are dependent on affordable and reliable energy.

Dark clouds are on the horizon for families and businesses that are dependent on electric power for numerous functions. Onerous rules propagated by the U.S. Environmental Protection Agency (EPA) against coal and other sources of affordable, reliable electricity generation are upsetting the balance of America's electric power system, traditionally one of the most reliable in the world.

Skewing of America's power system – Probable U.S. Generating Capacity by 2020



By 2020 natural gas capacity will exceed that of coal, nuclear and hydro combined [3]

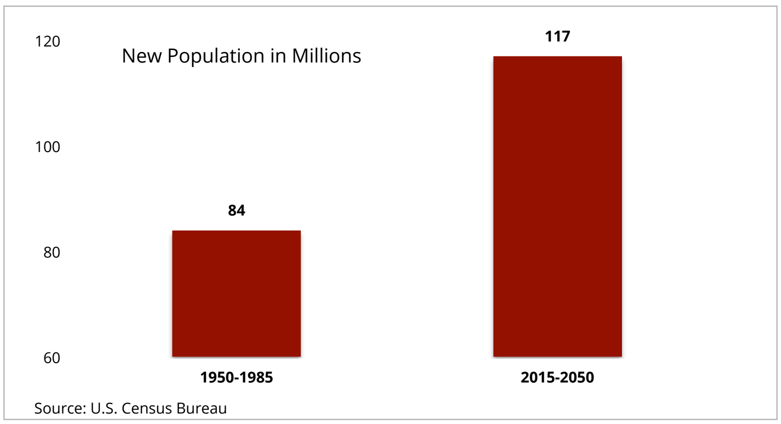
Not only are EPA regulations essentially prohibiting the construction of new coal power plants, but a confluence of related punitive rules is causing the closure of existing facilities. The EIA projects that 60 GW of coal generation capacity will be forced to close due to existing government policies – more than one sixth of the entire coal fleet. At almost 1,600 terawatt hours (TWh) of output, coal produces about 40 percent of the nation's electricity. Further, the cuts into reliable coal capacity are getting deeper into larger and more efficient power plants. Units that retired in 2010-2012 were relatively small, with an average size of 97 MW and heat rate of 10,695 BTU/KWh. In contrast, units currently scheduled for retirement are larger and more efficient: At 145 MW, the average size is 50 percent larger than earlier retirements, with an average heat rate of 10,398 BTU/kWh.[4]

The question of prudence is rapidly coming to the fore as policies force the U.S. to base the vast majority of new electricity supply on natural gas and to a lesser degree intermittent renewable power. The EIA projects that over the next decade the majority of new power plants will be gas and much of the remainder will be wind – an intermittent, non-dispatchable energy source which requires a significant amount of gas power for backup. By 2020, natural gas capacity is expected to exceed that of coal, nuclear and hydro combined.

"Even in the last year, you've seen nearly a 50 percent increase in the price of natural gas from where it was in 2012. There's a storm that's brewing." Randall Data, CEO, Babcock and Wilcox [5]

The U.S. is still a growing nation and will sorely need all of its coal plants to meet electricity demand over coming decades. Further, Thompson has demonstrated that based on current projections, age of fleet, and EPA regulations, a total of 110 GW would close by 2030, leaving the U.S. with less than 200 GW of coal capacity compared with 309 GW today.[6] By that time, the U.S. is slated to add over 40 million people, to see almost a 50 percent growth in GDP, and to build at least 27 million new homes.[7] If electricity demand returns to the pre-recession growth rate, the U.S. would need an additional 1,300 TWh by 2030 – nearly as much as the entire power consumption of France, Germany, and the United Kingdom combined.[8]

The "Boom" is Still Ahead of the U.S.



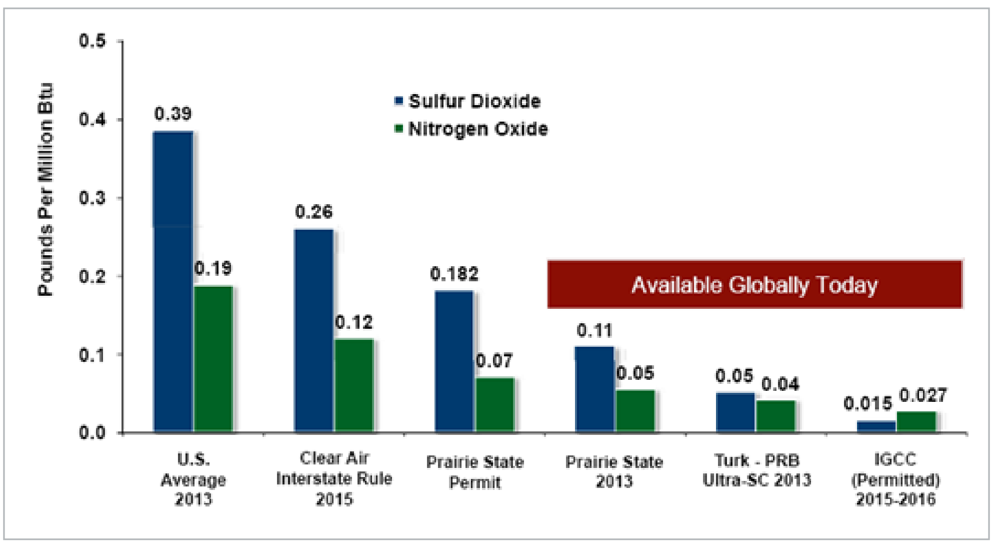
The last time the U.S. added 120 million urbanites (1960-2005)

- We used 4.1 billion metric tons of cement – the equivalent of 85 interstate highway systems.
- We used 4.8 billion metric tons of steel – enough Golden Gate Bridges to circle the Earth 4 times.
- We used 131,500 terawatt hours of electricity – enough to power France for well over two and a half centuries
- We used 40 billion tons of coal – but still have enough left for 250 years.[9]

Such demand cannot be met reliably without maintaining and expanding current coal-based capacity, let alone closing productive coal plants. Instead of closing productive coal facilities, the U.S. should be constructing state-of-the-art supercritical units like Prairie State in Illinois and Turk in Arkansas. The U.S. has shown that more coal can be used to produce more electricity, more efficiently, while reducing emissions. Advances in coal technologies drive enormous environmental improvement. Since 1970, coal used for electricity has increased around 170 percent alongside a tripling of real GDP as key emissions have decreased 90 percent per unit of power generated.[10] State-of-the-art technologies have dramatically reduced key emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulates. A combination of all of these technologies, in addition to use of sorbent injection systems, also enables highly efficient mercury removal. Utilities have invested more than $110 billion in these technologies in recent decades.[11]

> **"The idea of coal disappearing is not an effective climate change policy." John Thompson, Clean Air Task Force.** [12]

Prairie State: 21st Century Coal
CO_2 emissions drop 25 percent from the oldest operating U.S. coal plants



Electricity is the lifeblood of modern society and serves as the foundation of socioeconomic progress, the means to an ever cleaner environment and the pathway to a higher quality of life for all. In efforts to assure electric supply, regulatory commissions throughout the U.S. have developed standards of **prudence** in assessing the efficacy of energy planning decisions. The widely accepted doctrine of prudence dismisses risky decisions based on chronologically constrained data, untested hypotheses, guesses, and wishful thinking. Rather, prudence strives to base policies on caution, probability, experience, cost and empirical reality.

> **"Prudence is a principle central to the theory and practice of public utility regulation, a hallowed standard of review by which utility behaviors and decisions are judged." Janice A. Beecher, The Prudent Regulator, Michigan State University [13]**

But prudent decisions are not only the task of utilities; they are the responsibility of policymakers and regulators as well. This latter aspect of prudence is rapidly coming to the fore as the U.S. proceeds to base the vast majority of new electricity supply on natural gas and intermittent renewables in the face of warnings from established energy related agencies. Consider the case of New England, a region which could not get sufficient natural gas this winter and was so desperate for generation that utilities reverted to burning jet fuel. At one point this winter, about 75 percent of New England's gas-based electric generating capacity was not operating due to lack of supply or high prices. Consumers suffered through dramatic increases in power costs despite the contribution of low cost coal. The recent average price for a MWh of electricity in New England was $163 – that was 200 percent higher than in January 2013 and 400 percent higher than in January 2012. Yet, warnings over loss of coal capacity over the past few years have been consistently ignored. Regulators allowed the planned closing of two major coal plants (Brayton Point and Salem Harbor, 2,000+ MW combined) and one nuclear station (Vermont Yankee, 600 MW), essentially ignoring a series of concerns.

> **"The region abruptly went from a capacity surplus and low prices to a capacity shortfall and relatively high prices." Gordon van Welie, CEO of ISO-NE [14]**

Thus, despite warnings, and actual experience, New England and other regions are imprudently closing coal and nuclear plants and increasing dependence on gas. Florida will soon rely on gas for over 60 percent of its power. In fact, most of the southern tier is at increasing risk as overdependence on one source proliferates. Over 130 million people depend on natural gas to meet more than 50 percent of their electricity in summer and this is especially true for those parts of the nation where access to affordable air conditioning has ignited rapid economic and population growth. EPA rules may force Arizona to close Navajo Generating Station, a facility associated with a large Native American workforce and the source of more than one seventh of the state's electricity. Ohio is expected to lose at least 12 coal plants, Pennsylvania six, and South Carolina five. Few states will be untouched by the consequences of the loss of reliable and affordable coal-based electricity and the ever rising dependence on gas, including: 1) the 60 million households who need gas for heating, and 2) a vast array of firms that use gas in daily operations.

The U.S. has 28 percent of the world's proven coal reserves – the largest coal reserves in the world and EPA's new power plant rule will mean that these resources will not be able to be utilized by the residents of this country.[15] The National Academy of Sciences has stated:

> **"U.S. recoverable reserves of coal are well over 200 times the current annual production of 1 billion tons and additional identified resources are much larger. Thus the coal resource base is unlikely to constrain coal use for many decades to come."[16]**

But EPA's new power plant rule, which will initially affect coal, is just the beginning. For after coal's demise will come natural gas' demise. Activist groups started off with a campaign to be "Beyond Coal" but they have added a "Beyond Gas" campaign as well that will eventually mean tighter regulations that will affect natural gas availability, and place Americans in an even more unreliable and precarious situation regarding electricity supply.

References:

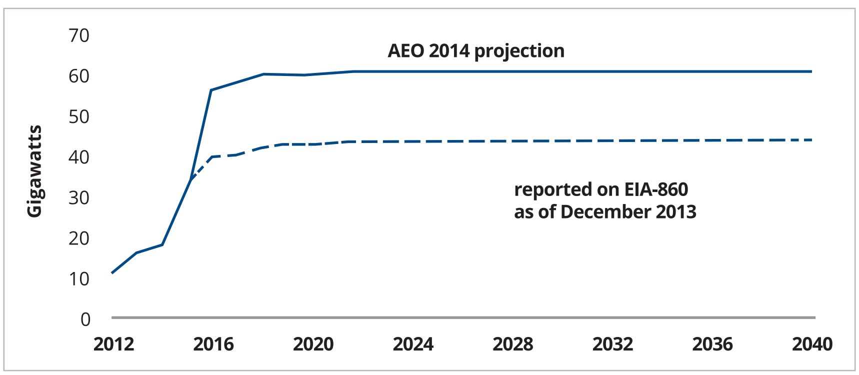
1. "Retirements play role in rising electricity prices," February 11, 2014, http://www.eenews.net/ew/2014/02/11
2. Energy Information Administration, Factors affecting natural gas prices, http://www.eia.gov/naturalgas/
3. Energy Information Administration, Electricity, Electric Power Plants Generating Capacity, http://www.eia.gov/electricity/data.cfm#gencapacity
4. Energy Information Administration, AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled, http://www.eia.gov/todayinenergy/detail.cfm?id=15031
5. Martin Rosenberg, "Coal Generation Vital," Energy Biz, March 9, 2014, http://www.energybiz.com/article/14/03/coal-generation-vital?quicktabs_6=2&quicktabs_11=1&quicktabs_4=1
6. RTO Insider, Carbon Rule Falls Unevenly on PJM States, http://www.rtoinsider.com/carbon-rule-pjm-states/
7. Energy Information Adminstration, Annual Energy Outlook 2014, http://www.eia.gov/forecasts/aeo/
8. Analysis of data from EIA "Electricity, Data, Generation & Thermal Output"
9. Analysis of data from EIA, IEA, U.S. Census Bureau, National Mining Association, USGS
10. Energy Information Administration, "Electricity, Data, Generation and Thermal Ouptut;" USDA (Shane), Real GDP Historical, December 2013; U.S. National Energy Technology Laboratory, "Fossil Energy Research Benefits: Clean Coal Technology Demonstration Program," June 2012
11. America's Power, "Mike Duncan Responds to NSPS in Federal Register," January 8, 2014, http://americaspower.org/mike-duncan-responds-nsps-publication-federal-register
12. Mario Parker and Naureen Malik, "Coal Burns Brighter as Utilities Switch from Natural Gas," Bloomberg, February 13, 2014, http://www.bloomberg.com/news/2014-02-13/coal-burns-brighter-as-utilities-switch-from-natural-gas.html
13. Janice Beecher, The Prudent Regulator: Politics, Independence, Ethics and the Public Interest, http://www.ipu.msu.edu/research/pdfs/Beecher-Prudent%20Regulator.pdf
14. Luther Turmelle, "Plant shutdowns mean higher power prices on horizon in New England," New Haven Register, February 5, 2014, http://www.nhregister.com/business/20140205/plant-shutdowns-mean-higher-power-prices-on-horizon-in-new-england
15. BP Statistical Review of World Energy, June 2013, http://www.bp.com/content/dam/bp/pdf/statistical-review/statistical_review_of_world_energy_2013.pdf
16. National Academy of Sciences, America's Energy Future, July 2009

I. WHAT ARE THE FORECASTS OF COAL PLANT CLOSURES?

The EIA in the Annual Energy Outlook (AEO) 2014 Reference Case projects that a total of 60 GW of coal capacity will retire by 2020 due to government policies already in place – Figure I-1.[1]

At the beginning of 2012 there were 1,308 coal-fueled generating units in the U.S., totaling 310 GW of capacity. In 2012 alone, 10.2 GW of coal-fueled capacity was retired, representing 3 percent of the 2012 total. Table I-1 shows the progression of coal-fueled generating unit closures between 2010 and 2012. Units that closed in 2010, 2011, or 2012 were small, with an average size of 97 MW, and inefficient, with an average tested heat rate of about 10,695 BTU/KWh. In contrast, units scheduled for closure over the next 10 years are larger and more efficient: at 145 MW, the average size is 50 percent larger than recent closures, with an average tested heat rate of 10,398 BTU/KWh.

Figure I-1: Projected Cumulative Retirements of Coal-Fueled Generating Capacity (2012-2040)



Source: U.S. Energy Information Administration

Table I-1: Coal-fueled Generating Unit Retirements

	Existing Coal-fueled Capacity (2012)	Retirements 2010	2011	2012
Total net summer capaticy (MW)	309,519	1,418	2,456	10,214
Number of units	1,308	29	31	85
Average net summer capacity (MW)	239	49	79	123
Average age at retirement	37	49	58	50
Average tested heat rate (Btu/kWh)	10,168	11,094	10,638	10,353
Capacity factor	56%	36%	33%	35%

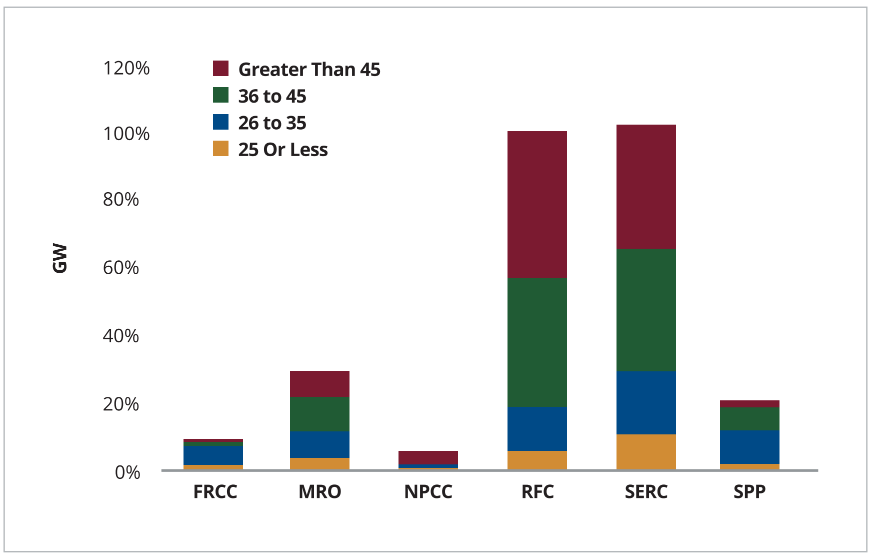
Source: U.S. Energy Information Administration

However, the EIA in its AEO 2014 shows U.S. electricity production from coal essentially unchanged from 2010 to 2040, despite impending massive coal plant closures – 60 GW.[2] This may indicate overly optimistic assumptions for existing coal-plant capacity-factor growth as unit ages progress to 66 years in 2040, and/or under utilization of existing coal-fueled capacity in favor of natural gas. EIA forecasts less than 3 GW of new capacity additions (one percent) to come on line by 2040. It is possible that that the EIA forecast assumes capacity-factor expectations that may be much higher than will be possible in 2040 based on historic coal-plant operating experience with age – an issue of concern.[3]

For example, about 85 percent of U.S. coal capacity is located in the Eastern Interconnection (EI), and 204 GW of coal capacity (75 percent of the national total) in the EI is located in two NERC regions: Reliability First Corporation (RFC) and SERC Reliability Corporation (SERC). These two regions also contain a large percentage of very old (45 years plus) coal plants, as seen in Figure 1-2.

Of the 269 GW of coal capacity in the EI, roughly one-third is located in just five states: Indiana, Illinois, Ohio, Pennsylvania, and West Virginia.[4]

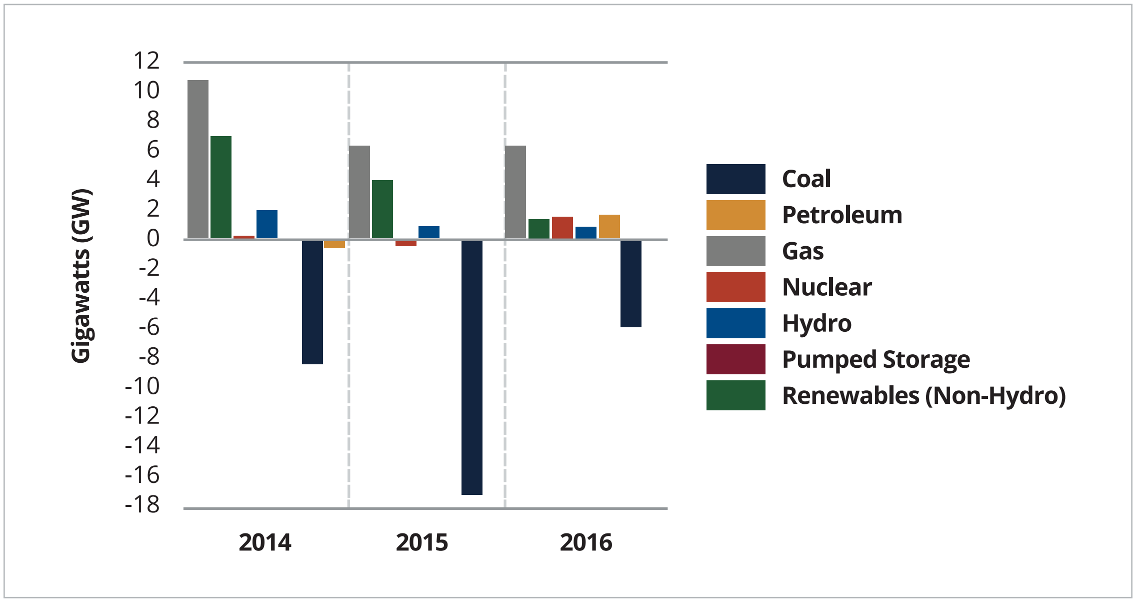
Figure I-2: Coal Capacity by Age and NERC Region in the Eastern Interconnection



Source: EPA, NEEDS v4.10_MATS

In December, 2013 NERC published its latest long term reliability assessment and found that 35 GW of coal capacity is planned to retire by 2023, with almost all of that occurring by 2017 – Figure I-3, and that another 32 GW of coal capacity closure by 2023 is "conceptual."[5]

Figure I-3: NERC-Wide Annual Planned Capacity Change



Source: North American Electric Reliability Corporation

II. NEW ENGLAND AS PRECURSOR: WE HAVE SEEN THE FUTURE, AND IT DOES NOT WORK

New England, which now relies on natural gas for over 50 percent of its generation, experienced an "energy crisis" this past winter where problems regarding price spikes, reliability, scarcity, and distribution constraints surfaced. Thus, for example:

- The *Hartford Courant* notes "Higher electricity prices have led to concerns that New England's electric grid is overly dependent on natural gas."[6]
- The *Boston Business Journal* warned: "Most consumers are unaware that New England is on the brink of a natural gas crisis."[7]
- Forbes stated "The widely predicted explosion in New England energy prices has started sooner than most people expected."[8]
- The New England Ratepayers Association warned that "Continued over-reliance on natural gas will raise electricity rates."[9]
- ISO New England warned that "Given current and anticipated levels of gas usage, potential gas unavailability threatens electric system reliability."[10]
- Lee Olivier, executive vice president and CEO of Northeast Utilities, stated "We've become a region that is overly dependent on natural gas."[11]

A 50 percent reliance on one fuel for electricity generation may not be that unreasonable if that fuel was not also used heavily by other sectors. Natural gas, however, is not only used for electric power generation and to back-up intermittent renewables in that sector, but also used to heat over 50 percent of U.S. homes and is the fuel of choice for industrial facilities, among other uses. Government policies that drive such increasing reliance should be coupled with policies to ensure that the demand can be met, but the exact opposite is true. The increase in supplies of natural gas are coming only from non-government lands, and in fact, production is down sharply on government lands.

II.A. Energy Costs in New England

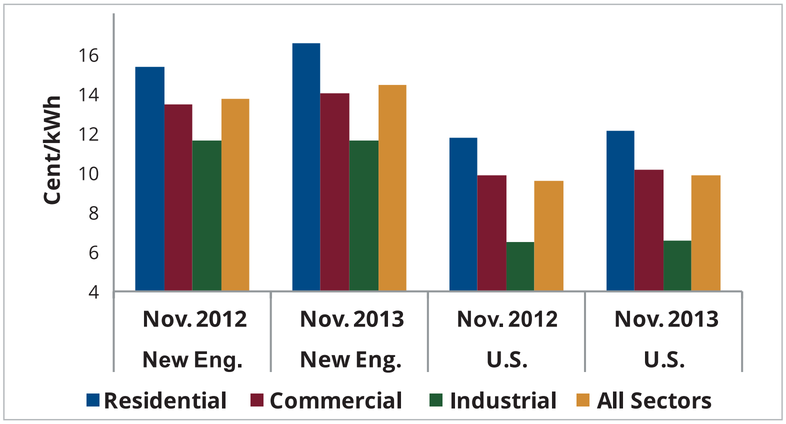
Energy costs in New England have long been well above the U.S. averages, and by some accounts are expected to grow. Figure II-1 shows that electric rates in New England are significantly higher than average U.S. rates across all sectors, that the difference is especially pronounced with respect to industrial rates, and that the divergence has increased. Figure II-2 indicates that in New England, the price volatility and price spikes of natural gas and the resultant impacts on electricity prices are long-standing problems that are worsening.

The EIA does not classify New York as part of New England, but New York has the second highest electricity rates in the country – second only to the island state of Hawaii.[12] New York's average residential electricity rate is 83 percent higher than the national average, and the state's rates are higher than even Alaska with its large land mass and small population.

II.B. Seeds of the Crisis

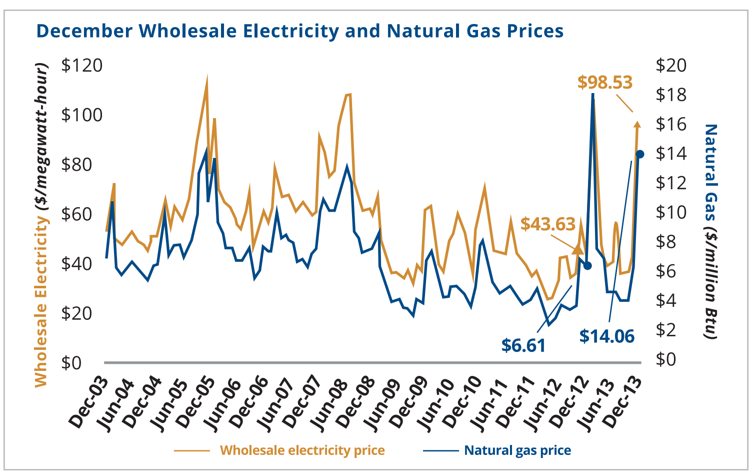
New England's energy problems derive from the region's increased reliance over the past several decades on natural gas for electricity generation, which is forecast to increase. As shown in Figure II-3, the natural gas share of electricity generation in the region increased from less than 8 percent in 1990 to over 50 percent by 2012.[13]

Figure II-1: Comparison of New England and U.S. Electricity Rates



Source: U.S. Energy Information Administration, 2014.

Figure II-2: Historical New England Electricity and Natural Gas Price Spikes



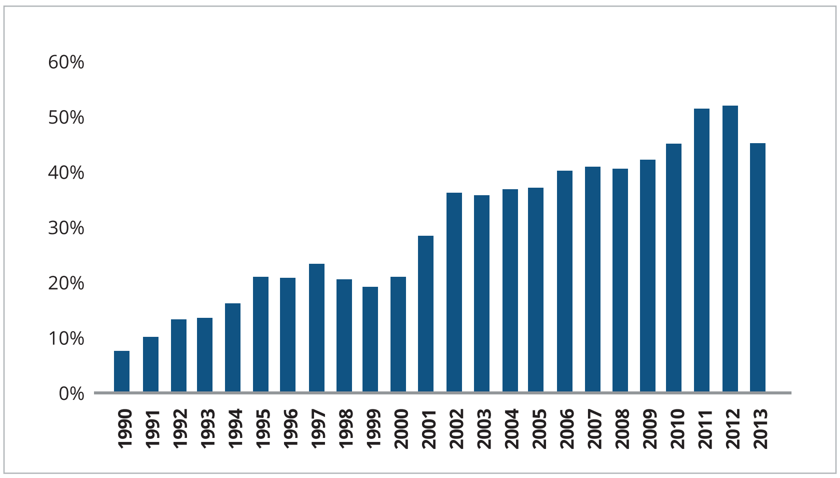
Source: U.S. Energy Information Administration.

Total consumption of natural gas by all sectors in New England increased 40 percent between 1998 and 2011, as indicated in Figure II-4. Increased use of gas for electric generation accounted for essentially all of that increase; there was no increase in gas use in the end-use sectors (i.e., residential, commercial, industrial, or "RC&I").[14]

Numerous government agencies have warned of the region's growing over-dependence on natural gas:

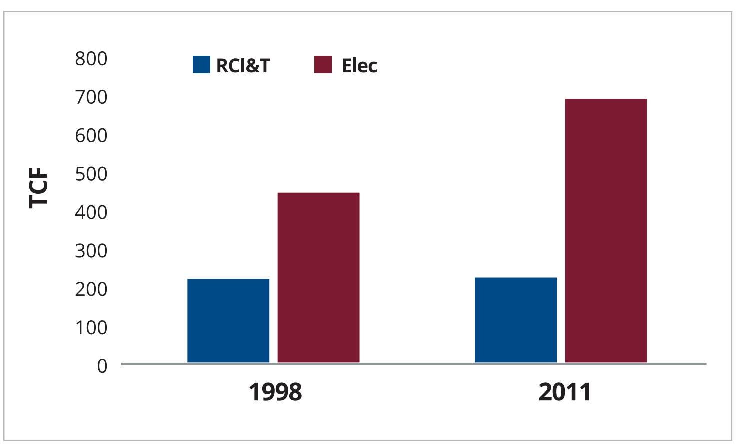
- The EIA found that New England's increased use of natural gas for electricity generation raises concerns about fuel diversity.[15]
- NERC found that the New England generation fleet is overly reliant on natural gas as a primary fuel source, and generators are heavily dependent on pipeline capacity released by the firm capacity rights holders.[16]
- FERC warned that New England faces seasonal supply and pipeline constraints and that the region faces power and natural gas market challenges due to growing competition for limited natural gas supply.[17]
- ISO-NE warned of increased risk to the region's electric system associated with reliance on natural-gas-only resources, and that gas dependence is increasing.[18]

Figure II-3: Natural Gas Portion of Electric Power in New England,1990-2013



Source: U.S. Energy Information Administration and Management Information Services, Inc.

Figure II-4: New England Natural Gas Consumption, 1998 and 2011

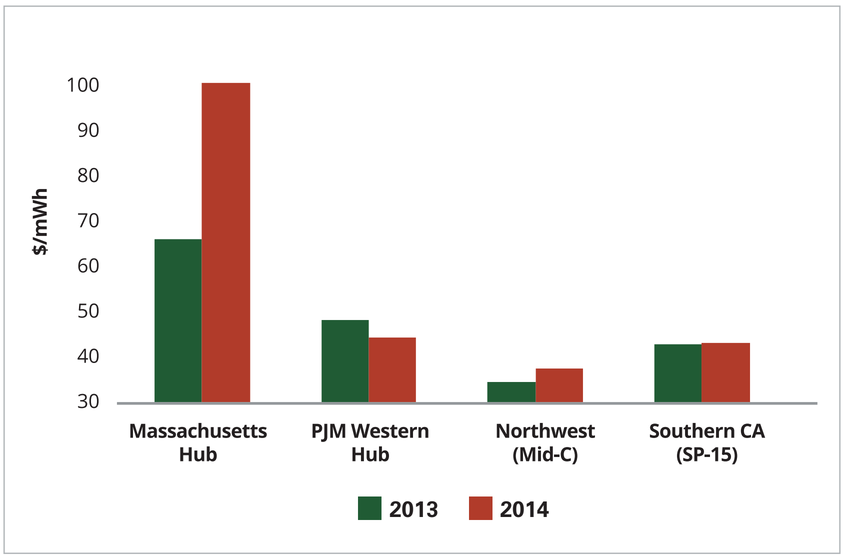


Source: U.S. Energy Information Administration.

II.C. Worse is to Come

As bad as the situation currently is in New England, it is likely to get much worse. Electricity and natural gas prices are high and are increasing. Price volatility, price spikes, and periodic shortages are likely to continue and worsen. FERC compiled futures prices for power and natural gas at key regional markets as of October 1, 2013.[19] FERC's Winter 2013-2014 Energy Market Assessment anticipated that New England future (2014) natural gas prices would reach nearly $12/MMBtu and that electricity prices would reach $100/MWh – Figure II-5. That forecast was made in October 2013 when FERC was anticipating a "warm winter." [20] Ominously, the weather in New England during the winter of 2013-2014 was not "warm."

Figure II-5: FERC Electricity Future Prices

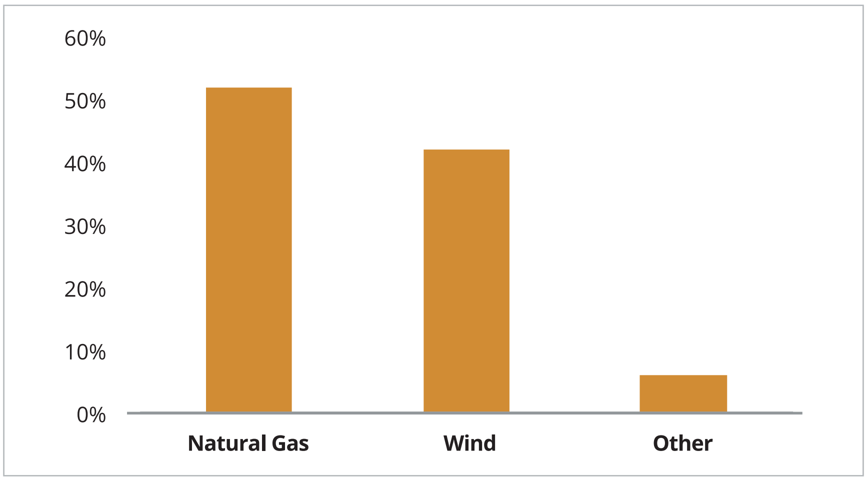


Source: Federal Energy Regulatory Commission.

II.D. The Hole Gets Deeper

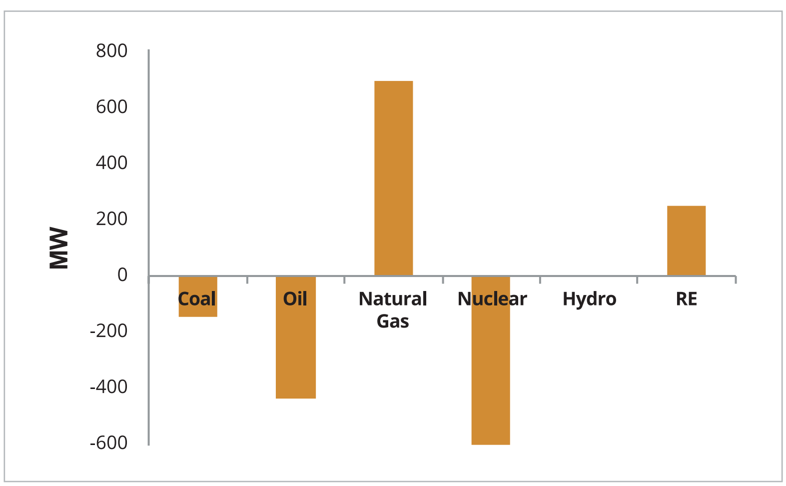
Examining new generator proposals submitted to ISO New England indicates that New England's choice for its future fuel sources is almost entirely natural gas and non-hydro renewables[21] – Figure II-6. This imbalance is reflected in the latest NERC long term reliability assessment, which finds that in New England all new capacity will be natural gas and renewables, while coal, oil, and nuclear capacity will decline[22] – Figure II-7.

Figure II-6: Current Proposals for New Generating Capacity in New England



Source: New England ISO.

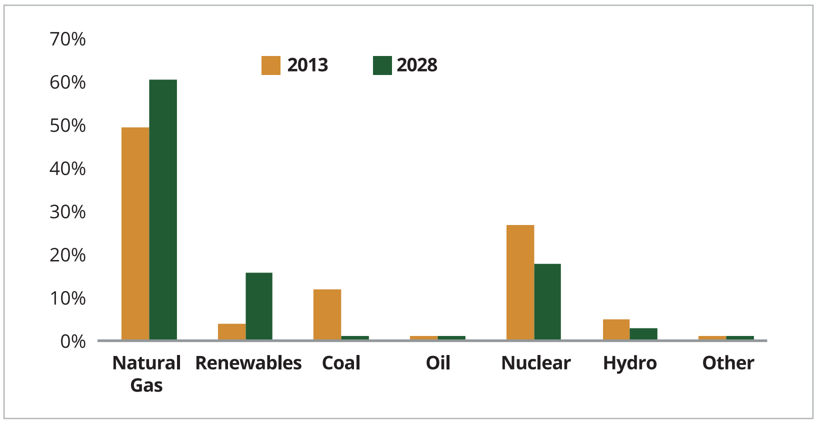
Figure II-7: Cumulative Planned Capacity Change, 2014-2023



Source: National Energy Reliability Corporation.

In 2013, a group of electric utilities, gas utilities, and state governments (Association of Energy Service Companies or AESC) commissioned a long-term study of future New England electricity capacity and generation.[23] The projected mix of New England electricity generation in the Base Case is shown in Figure II-8, which indicates the future dominance of natural gas and non-hydro renewables with gas backup. Within 14 years, the region is forecast to be relying on natural gas and non-hydro renewables (which require natural gas for backup) for about 80 percent of its electricity.

Figure II-8: New England Electric Generation (GWH), 2013 and 2028

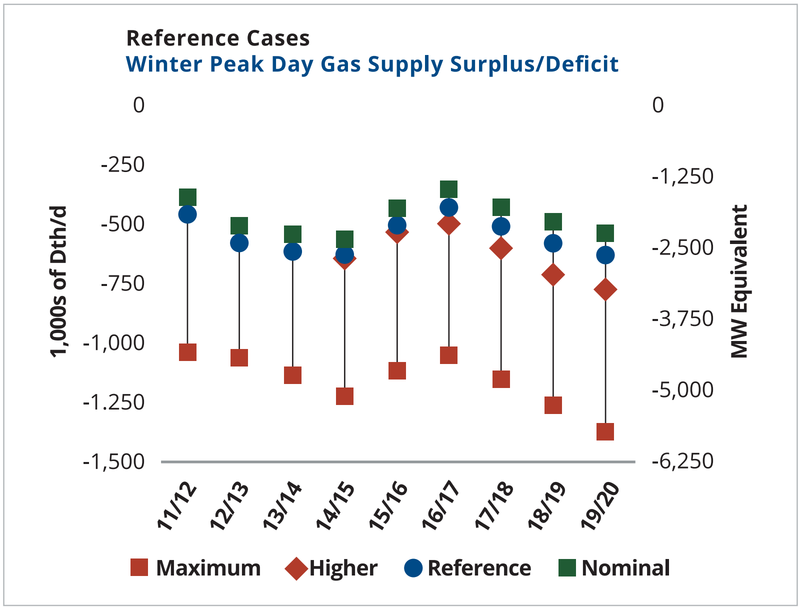


Source: Synapse Energy Economics, Inc.

ISO New England (in its AESC study) assessed the adequacy of the natural gas infrastructure in New England to serve the combined needs of the core natural gas market and the regional generation fleet.[24] Figure II-9 illustrates the major finding: In each of the scenarios and cases examining gas supply and demand under winter design day conditions there is not enough gas supply capability remaining to meet the anticipated power sector gas demand after local distribution company (LDC) firm demands are fully met.

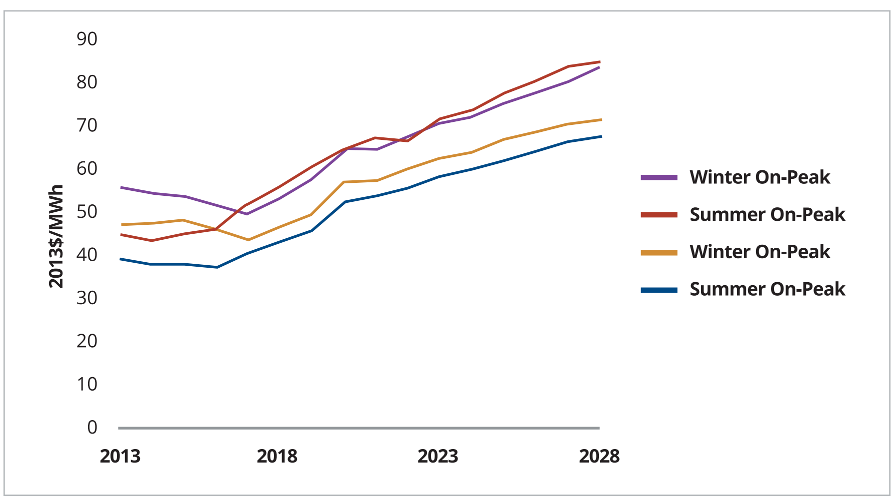
As expected, forecasts of future electricity prices in New England indicate that they will remain higher than the national averages and some indicate that they will increase more rapidly. Figure II-10 shows the AESC forecasts of real (2013 dollars) wholesale electricity prices in central Massachusetts through 2028.[25] The EIA forecasts that New England electricity prices will remain 40 percent – 50 percent higher than the U.S. average. Accordingly, in 2028 New England electricity prices may be more than 1.4 and 2.5 times the U.S. average.[26] This is not welcome news for a region that is already struggling economically and is attempting to attract new business and industry.

Figure II-9: New England Electric Sector Surplus/Deficit Availability to Meet Winter Peak Power Demand – Reference Case Results



Source: ICF International.

Figure II-10: Real Wholesale Electricity Price Forecast for Central Massachusetts (2013 dollars)



Source: Synapse Energy Economics, Inc.

II.E. Conclusion: New England at Risk

Thus, as recent events have demonstrated, **policies that hurt the U.S. coal fleet** are placing the reliability, affordability, and security of New England's electric supply system at risk:

- New England has gone from having a little over five percent of its electricity generated by natural gas and non-hydro renewable energy (RE) to currently about 55 percent.
- The winters of 2012-13 and 2013-14 revealed serious problems of price spikes, reliability, shortages, scarcity, distribution constraints, etc.
- Worse conditions are likely, as New England continues to homogenize its fuel mix: It is planning to rely on natural gas and non-hydro renewable energy (requiring backup) for about 80 percent of its electricity.
- 3,135 MW will be retired by June 2017, including Brayton Point (1,530 MW coal); Salem Harbor (750 MW coal); Vermont Yankee (600 MW nuclear); and Norwalk Harbor (350 MW oil).
- Worsening capacity shortages are forecast by 2020: 250 MW – 1,250 MW.
- New England electric rates are currently more than 1.4 times the U.S. average, and may be headed in next decade to be 2.5 times the U.S. average.

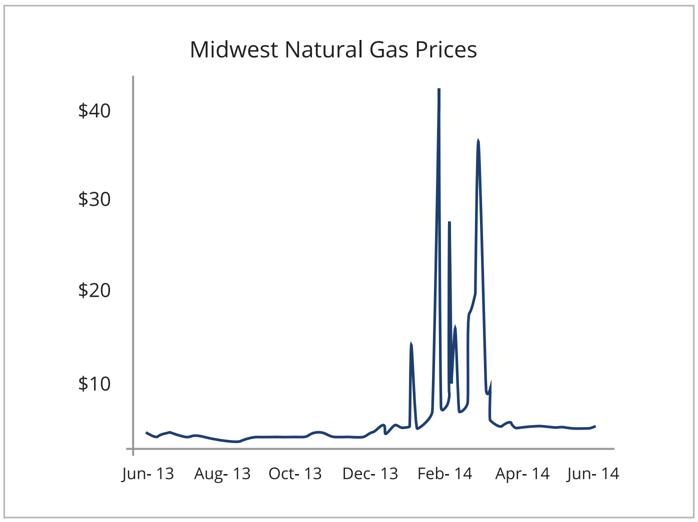
The bottom line is that New England faces a worsening near term energy crisis. At one point in January 2014, 75 percent of all the gas-fueled power plants were shut down and about 40 percent of electricity was being provided by coal and oil.[27] However, these are the same oil and coal plants that are scheduled to be retired in the near future, and thus many of the non-gas-fueled power plants that were the mainstay of the load in New England will no longer be available. Over the course of the next few years things are likely to get much worse for the region. The recent average price for a MW of electricity was $163 – 200 percent higher than in January 2013 and 400 percent higher than in January 2012, and the omens for 2015 and beyond are bleak. Numerous warnings have been issued by ISO New England, FERC, NERC, EIA, New England Ratepayers Association, industry and trade groups, and the media, but they are being ignored. Political leaders and decision-makers have bet the region's energy future almost exclusively on natural gas and renewable energy and the consequences could be disastrous.

III. OTHER AREAS ALSO HAD PROBLEMS THIS WINTER

III.A. Higher Prices Amid Questionable Supply

The winter of 2013-2014 demonstrated in real time the value of the existing coal fleet. Price spikes and infrastructure bottlenecks nationwide are hurting real people in real time as the relentless cold indicated that prudent utility practices require large, baseload coal plants to stabilize the grid, keep society functioning, and maintain electricity availability. Other regions besides New England experienced similar problems during the winter of 2013-14. For example, in late January and early February 2014 some locations in the Midwest experienced gas prices as high as $35/MMBtu, and the Chicago citygate price exceeded $40/MMBtu – Figure III-1.

Figure III-1: Chicago Citygate Natural Gas Prices, February 2013 – 2014 (Dollars per MMBtu)

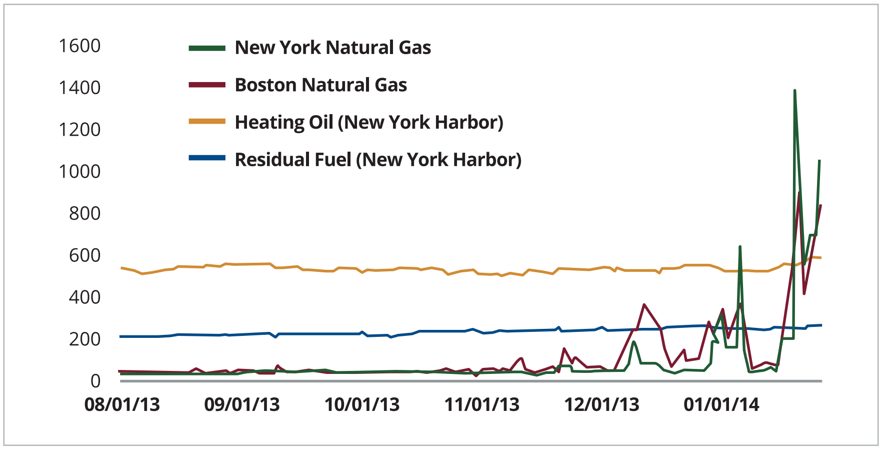


Source: NGI nationalgasintel.com

A Houston-based marketer working the Chicago Citygates stated that it was getting more difficult to get gas into the area. Pipes were starting to "break" and LDCs such as Nicor and Nipsco had to respond to difficulties on Natural Gas Pipeline Company of America Midwest and ANR. "The LDCs are putting out their critical notices in response to the problems of the pipelines."[28]

The EIA found that extreme cold weather in the Northeast increased natural gas demand beyond the capacity of the natural gas delivery system that supplies New York and New England.[29] As a result, the spot price of natural gas rose above the price of distillate and residual fuel oil (on an energy-equivalent basis) in the Northeast – Figure III-2. Because decisions regarding the dispatch of electric generation units are generally based on variable operating costs, the use of oil for power generation increases when natural gas prices are higher than distillate or residual fuel prices in cases where fuel-switchable or oil-only units are available to operate.

Figure III-2: Northeast Power Market Fuel Prices (Dollars per MWH)



Source: U.S. Energy Information Administration.

In addition, elsewhere in late January and early February 2014, in the U.S.:[30]

- Pipeline constraints increased localized prices to a premium – prices serving New York City briefly surpassed $90/MMBtu in the last week of January.
- Dominion East Ohio Gas asked its customers to conserve and use less gas exactly when the coldest weather in a generation struck – the first time a winter conservation request had to be issued.
- Public utility commissions in Ohio and Pennsylvania urged consumers to conserve, especially electricity. "I have been on the commission since 2008. This is the first time we have had to issue a winter conservation request," stated Pennsylvania Public Utility Commission Chairman Robert Powelson.
- West Coast spot natural gas prices increased to records and propelled electricity prices higher as forecasts showed frigid air sweeping into the Northwest.
- Prices at West Coast points increased $10 or more to increase averages above $20/MMBtu: PG&E Citygate added $14.57 to average $22.64; SoCal Border increased $11.91 to average $19.69, and gas on Alliance increased $11.74 to $20.33.
- Deliveries to the Algonquin Citygates rose $1.15 to $24.35, gas at Iroquois Waddington was quoted at $21.70, up $8.49, and gas on Tennessee Zone 6 200L gained $9.68 to reach $29.72.
- The Northern Natural Ventura price settled at $43.82, an increase of $34.45, the highest gains of the day posted by any market point; the demarcation price was $26.65 higher at $36.11; deliveries on ANR SW increased $17.36 to $25.89; gas on Michcon increased by $13.71 to reach at $22.06; and deliveries to consumers rose $18.28 to $27.20.
- On-peak power at the mid-Columbia hub in southern Washington near the Oregon border doubled, increasing $110.94 to $216.32/MWh, the highest since April 2001; on-peak electricity at Northern California's NP15 hub, which includes San Francisco, increased $106.38 to $193/MWh; and power at the SP15 hub, which includes deliveries to Los Angeles and San Diego, increased $77.40, or 92 percent, to $161.68 – both hub prices were the highest since July 2007.

- Spot natural gas on the Ruby pipeline to the Malin, Oregon, hub in the Northwest more than tripled, increasing $21.54 to $29.45/MMBtu, after intraday prices rose to $35 – both intraday and closing prices were the highest since 2001.
- Spot gas also increased to all-time highs in California, Wyoming, and Colorado, while gas at Canada's AECO hub for deliveries to the U.S. increased the most in six years.
- In Northern California, spot gas at PG&E's Citygate more than doubled, rising $13.73 to settle at $21.79 after intraday prices surged to $35.
- Southern California Gas Co.'s Citygate price increased 62 percent to settle at $11.94 after intraday prices climbed to $30.
- Californians were urged to voluntarily reduce their electricity use after frigid weather caused a shortage of natural gas at Southern California power plants.
- Throughout the Midwest, pipeline notices proliferated as fast as temperatures fell: Notices were issued by Algonquin, ANR, Columbia, El Paso, Michcon, NGPL, Northern Natural and PG&E, as well as Tetco, Tennessee, and Transco.
- El Paso Natural Gas warned that it was at a "high risk" of declaring a "strained operating condition" or "critical operating condition" due to low linepack.
- NGPL invoked force majeure due to a mechanical problem with a Compressor Station in Bollinger County, Missouri.

Market watchers reported that January 2014 was the most volatile they have experienced in years. Volatility, a measure of the size and frequency with which the natural gas market changes in value, reached its highest level since September 2009 at the end of January 2014. Stephen Schork, editor of "The Schork Report," an energy investment newsletter, stated, "It's back to the wild, wild west days in natural gas. From 2001 to 2008, this is the way natural gas used to trade."[31] Teri Viswanath, director of Commodity Strategy, Natural Gas for BNP Paribas, stated that these conditions have not been seen in the last decade: "We are breaking cash delivered prices in nearly all consuming regions today. This is the sort of behavior that we witnessed more than a decade ago where 'storage' rationing sent prices higher in all regions of the country.[32] A Midwest utility buyer stated that "things are pretty crazy around here," and gas pipelines across the continent were issuing multiple critical notices, warning of pipeline restrictions as the cold intensified.[33]

It is a classic tale of unintended consequences, tied to the move away from using low and stable priced coal as an energy source. Facing stringent new federal clean air rules, electric companies are not upgrading coal-fueled power plants. Instead, they have been shutting down or replacing them with new generators that burn natural gas. Thus, the gas for heating and electric industries have become interconnected and are competing for gas delivered over a pipeline system that was not designed to serve electric utilities to this extent.

III.B. Market Chaos and Price Spikes

Driven by unusually cold weather and a series of brutal winter storms – the "Polar Vortex," January 2014, set numerous records for natural gas demand, and spot markets in the Northeast reached highs never before seen in more than 12 years of record keeping.[34]

Spot prices for natural gas hit records near $100/MMBtu in several areas, while Henry Hub prices topped $5.60/MMBtu the last week of January, a level not seen since early 2010. According to the EIA, natural gas storage levels fell to 1,923 Bcf on January 31, a drop of almost 1,000 Bcf for the month. That figure represents the lowest level since May 2013, and the lowest for an end-of-January total since 2004. The EIA also noted that as of January 17, cumulative net withdrawals for the 2013–2014 season had already set an all-time record.

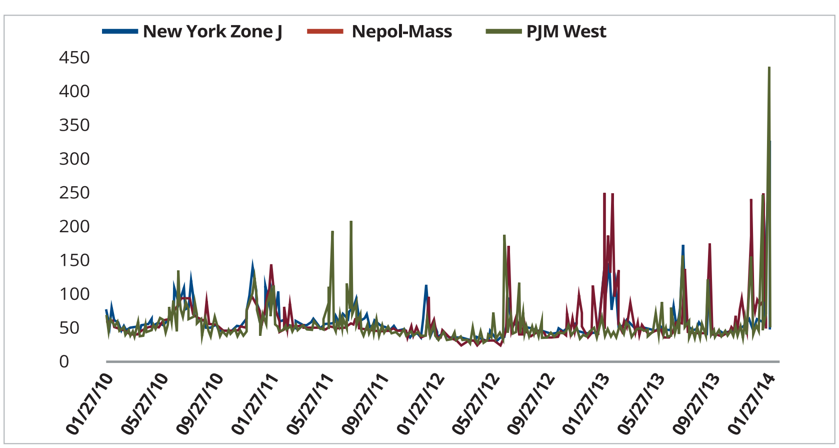
As expected, the impact on power generation was intense. Numerous pipeline companies had to issue operational flow orders restricting delivery, and no interruptible service was available on the worst days of the Polar Vortex. According to ICF International: PJM lost 20 percent of its capacity on January 7, 38 GW; the Midwest Independent System Operator (MISO) lost 28 GW, 20 percent of its total; the New York Independent System Operator (NYISO) lost around 10 percent, about 4 GW; and ISO-New England (ISO-NE), having increased its dual-fuel capacity after last winter's debacle, was successfully able to transition to fuel oil, and lost only about 1.5 GW of capacity, around five percent. Even the Electric Reliability Council of Texas (ERCOT) lost about five percent of its capacity. To put those figures in perspective, PJM had never lost more than nine percent of its capacity due to weather. Even with the lost capacity, PJM, NYISO, MISO, ISO-NE, and ERCOT all set or neared records for peak demand.

Even when the severe weather eased, the impact continued to be felt. The enormous demand for gas sent ripples across the country, and California ISO (CAISO), though largely spared cold weather that hit the rest of the nation, still found itself short of gas. On February 6, CAISO was forced to issue a conservation alert because of gas shortages in Southern California.

These problems sent wholesale electricity prices skyrocketing across the country. Day-ahead prices topped $500/MWh on several days. On January 23, 2014, PJM had to seek FERC approval to exceed its electricity price cap of $1,000/MWh in attempt to increase power supplies. Real-time, hourly prices during Jan. 7-8 climbed into the $800/MWh range, with 15-minute periods topping $2,000/MWh.

All of this requires a rethinking of the future of power generation in the U.S. as most spot markets across the Northeast reached highs never seen before. In New England, spot power prices at the Massachusetts hub for January 23 reached $395/MWh, while New York Zone J spot prices for January 24 reach a new all-time high of $427/MWh. In PJM, Western hub prices for January 22 reached as high as $442/MWh – Figure III-3.

Figure III-3: Peak Spot Power Index ($/MWh)

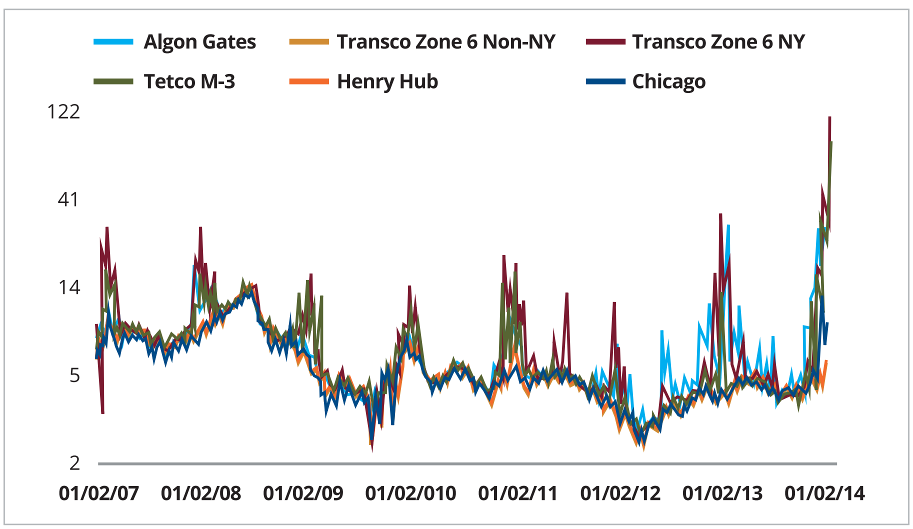


Source: SNL Energy.

In New England, natural gas-fueled capacity accounts for 15,843 MW, or 43 percent, of the region's 36,839 MW of winter capacity; in New York, gas-fueled plants account for 21,895 MW, or almost 53 percent, of New York's 41,538 MW of total winter capacity, and in PJM, gas accounts for 61,566 MW, or about 30 percent, of the region's 202,630 MW of total winter capacity. This is still less than the 77,461 MW, or 38 percent, of coal capacity, that exists today. But extensive coal plant closures are being planned to meet federal government regulations.

The increased dependence on natural gas has come with a cost, as gas prices have exhibited increased volatility, especially in 2014 – Figure III-4. In New England, the widely watched Algonquin Citygate broke into the triple digits in late November 2013 and reached an index of $32.25/MMBtu by gas on December 16, 2013. By January 23, the hub reached an index of $77.60/MMBtu, its highest ever recorded in 12 years of record-keeping. In New York, Transco Zone 6 NY averaged above $10/MMBtu most days in January 2014, which included an all-time high index of $120.75/MMBtu for January 22, almost double its previous all-time high. Even the typically more subdued markets have sprung to action in January. Despite its close proximity to the Marcellus Shale, Tetco-M3 reached a high of $91.67/MMBtu on January 23, more than double its previous high recorded almost 10 years ago, while in the Midwest, Chicago Citygate ran to as high as $12.80/MMBtu on January 6, its highest point in 5.5 years.

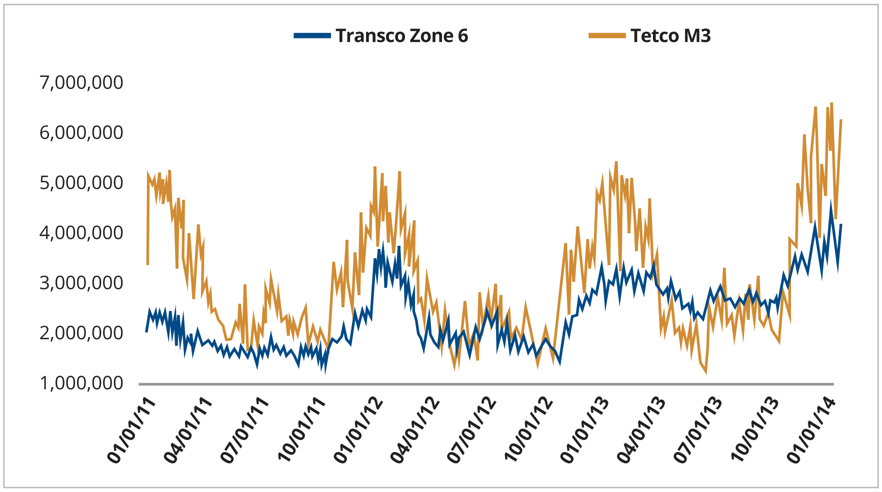
Figure III-4: Spot Natural Gas Prices ($/MMBtu)



Source: SNL Energy.

Natural gas prices have been especially volatile when pipeline capacity has been insufficient to meet peak loads. Pipeline data indicate that natural gas deliveries in the winter of 2013-2014 have increased within the heavy demand zones, well above previous winters – Figure III-5. The pipeline congestion and subsequent price spikes are troubling for power generation because most power plants receive the gas to run their plants just in time through interruptible contracts that are bumped when the demand to heat homes and businesses, which hold firm contracts, is so high there is no spare capacity left on the pipelines. In such instances, plants are forced to shut when they are needed most, for lack of adequate fuel.

Figure III-5: Scheduled Pipeline Deliveries – Intraday 2 Cycle (Dth/d)



Source: SNL Energy.

III.C. Potential Regional Problems

During the extreme "polar vortex" cold snap in early January 2014, forced outages in PJM approached 40 GW, or 20 percent of PJM's total generating capacity, with up to one-third of the outages in PJM due to lack of gas delivery capability to generators that rely on interruptible capacity. MISO lost 28,736 MW, or 22 percent of its total generation.

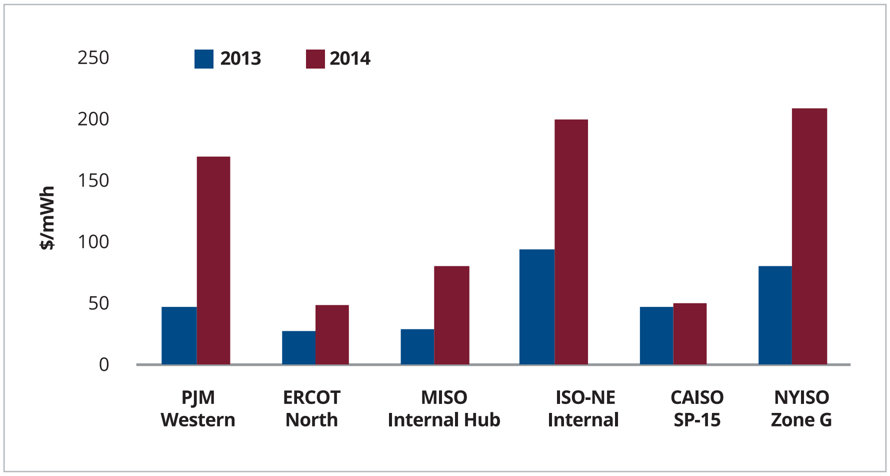
High demand and unit outages posed problems again during a cold snap through January 24, but unlike the first round of cold, "The prolonged, extremely cold weather is causing high demand for electricity. As a result, PJM and its members are managing a very tight power supply. The prolonged cold requires some generating units to operate more often and for more hours than normal. It also stresses generator components. Any resulting unplanned shutdowns can further tighten power supplies."[35]

During both cold snaps, real-time prices reacted with extreme spikes up to – and above, when accounting for congestion costs and ancillary services – the $1,800/MWh price cap. During shortages in PJM, the energy component of the locational marginal price, or LMP, is capped at $1,000/MWh plus twice the reserves penalty factor of $400/MWh.

EBW Analytics predicts that natural gas demand growth in the 2015-2017 timeframe will likely exceed expectations and that the potential for simultaneous increases in demand across multiple sectors is unparalleled.[36] It finds that rising power sector demand, industrial growth in the Gulf, increasing natural gas exports to Mexico, and as many as five large LNG export projects are all anticipated before the end of the decade. Ramp-up in supply may be insufficient to meet demand in the intermediate term, since producers, cautious about increasing capital expenditures, are more focused on high-return oil plays and less likely to increase gas production quickly, and the required midstream build-out of gathering, processing, and pipeline infrastructure exacerbate supply constraints. There is thus a serious risk that prices could spike in the intervening years.

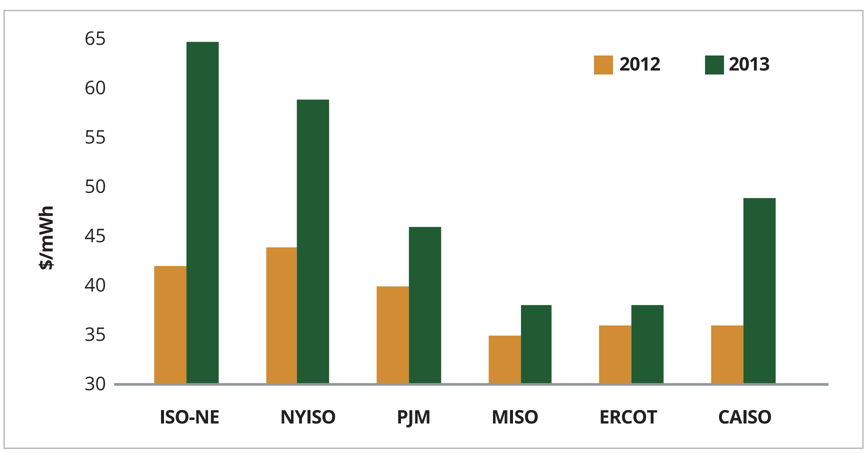
Accordingly, the electric power market will become more susceptible to price shocks – Figures III-6 and III-7. Planned and unplanned closures of coal plants due to upcoming EPA requirements are likely to reduce reserve margins, leaving markets more exposed to price spikes. As fuel mixes shift toward natural gas, electricity and natural gas for heating will become increasingly co-dependent, with less coal-fueled generation available to insulate electricity markets from gas price spikes.

Figure III-6: Average Day-Ahead January Peak Electricity Prices at Selected Hubs, 2013 and 2014



Source: EBW Analytics Group.

Figure III-7: Electricity Price Increases Due to Natural Gas Prices: Regional Peak Electricity Prices From Select Hubs in 2012 and 2013



Source: EBW Analytics Group.

Longer term, unprecedented demand increases threaten to disrupt the natural gas market and create significant upside risks. U.S. LNG export projects could add 6-8 Bcf/d of demand as early as 2017. Burgeoning industrial projects could add an incremental 1-3 Bcf/d of demand, and EPA rules – including Mercury and Air Toxic Standards (MATS) and new CO2 performance standards – could increase power sector consumption of natural gas by 4-6 Bcf/d as coal and nuclear capacity retires. Importantly, these shifts in power generation heighten the interdependence between natural gas and electricity markets, increasing the price risks to both commodities.

Natural gas supplies may not be able to keep up with the increased demand. On the supply side, reduced Canadian imports and increased exports to Mexico will reduce U.S. net imports, while shale reserves may not have the ability to quickly increase production commensurate with an unprecedented increase in demand. Further, drilling economics have encouraged natural gas producers to shift production toward oil, limiting the production response to higher natural gas prices. And while non-federal production of natural gas is up, production on government lands is down sharply. Even if production is able to keep pace, limited midstream infrastructure build-out – including the necessary gathering, distribution, and intrastate and interstate pipelines – could lead to bottlenecks, and creates the risk of increasing prices. This is exacerbated by increasing requirements for government permits and additional conditions that further slow infrastructure response.

Major risks include:

- Ruling by the U.S. Court of Appeals on EPA's MATS rule
- EPA victory before the U.S. Supreme Court on Cross-State Air Pollution Rule (CSAPR)
- Issuance June 2, 2014 of EPA's proposed restrictions on CO_2 emissions from existing fossil-fueled power plants
- New federal regulatory requirements affecting hydraulic fracturing on federal and nonfederal lands

Among the most noteworthy regional risks are the potential for the continued deadlock over the resource adequacy issue to become an increasingly serious problem in ERCOT, and the potential for announcements of further nuclear closures in the Northeast. Other possible developments could have a more widespread impact.

PJM

Recent price spikes during extreme weather events demonstrated that tremendous price volatility is possible even with PJM's relatively large reserve margin. The frequency and severity of price spikes is likely to increase as federal environmental regulations drive down the reserve margin. January 2014 revealed a vulnerability to winter price spikes that will likely worsen over time, and during periods of extremely cold weather, natural gas demand grows dramatically for both space heating and power sector demand. While space heating demand is met by firm pipeline rights, power sector demand is met by interruptible transport. During periods of peak demand, interruptible transport is cut off, increasing forced outages at natural gas-fired generators, driving scarcity pricing. As coal units retire and dependence on natural gas-fired generation grows, this susceptibility to scarcity pricing will likely be exacerbated.

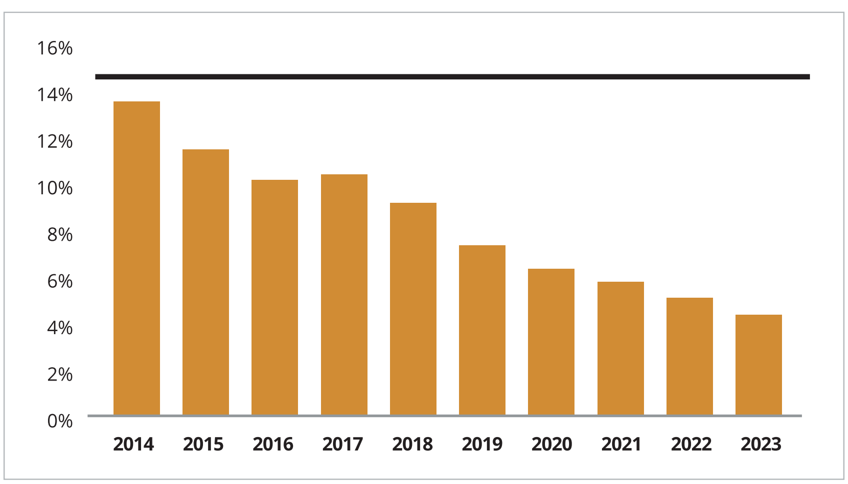
Beyond 2014, a declining reserve margin could increase the frequency and severity of price spikes. The 12.6 GW of coal-fueled generation that is scheduled to retire by 2015 will erode PJM's existing reserve margin to 17.7 percent, primarily due to MATS. Load growth, CSAPR, and greenhouse gas regulations could erode this margin even further. NERC estimates that by 2023, as much as 19 GW of coal capacity could be retired in PJM.[37]

ERCOT

Demand is likely to rise faster than projected due to the ongoing oil and gas boom, industrial projects, and LNG projects seeking to take advantage of low gas prices. These are exacerbated by forecasts that are underestimating load growth. ERCOT recently revised its economic forecast downward, increasing its reserve margin without changing the amount of existing physical generation. However, low gas prices are driving the building of LNG export terminals (anticipating the 2015 widening of the Panama Canal) and of industrial facilities along the Texas Gulf Coast. At the same time, increased natural gas and oil drilling rates have noticeably increased electricity demand, particularly in West Texas. Without explicitly accounting for these concurrent increases, system planning efforts are likely to significantly underestimate future load growth.

The extreme weather seen in August 2011 caused peak power prices for ERCOT North to average $225/MWh for the whole month, severely impacting electricity costs for end users. The underlying causes of that event – inadequate reserve margins, growing electricity demand, and a forecast that underestimates extreme weather – have not been adequately addressed by ERCOT. The possibility of severe scarcity pricing is likely to persist and even increase in the next few years. Figure III-8 indicates that ERCOT's summer reserve margin is already below the minimum 15 percent and will decline to dangerously unacceptable levels within nine years.[38]

Figure III-8: ERCOT Anticipated Summer Reserve Margin



Source: North American Electric Reliability Corporation

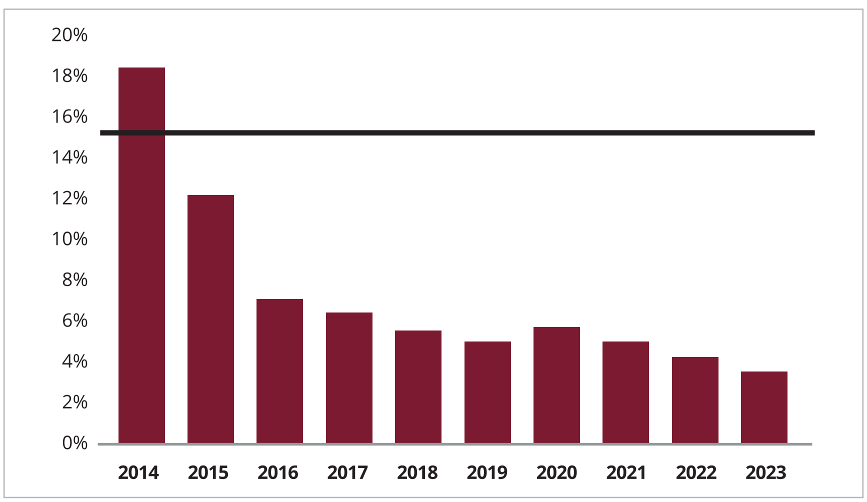
Midcontinent Independent System Operator, Inc. (MISO)

Prices in MISO have been low historically because of low-cost coal; however, due to EPA rules, nearly half of coal-fueled capacity either needs to retrofit its units –requiring significant capital expenditures – or close. If these plants are closed, reserve margins will decrease and scarcity pricing will become more likely, pushing prices higher. The winter of 2013-14 demonstrated MISO's vulnerability to scarcity pricing. Very cold weather led to forced generator outages and repeated incidents of scarcity pricing. In January 2014, on-peak prices at the Indiana Trading Hub averaged $25/MWh higher than any month in the past three years.

Half of all coal-fueled generation in MISO will have to retrofit or retire to comply with EPA regulations. To date, only 6 GW of coal-fueled generation has announced closure, while a quarter of capacity is at a high risk of closure. Further, the operating costs of retrofitted units will increase due to the parasitic load of operating the additional pollution controls and will increase electricity prices. In addition, EPA's carbon emission rule for existing generating units, released June 2, 2014, could have a disproportionate impact on MISO.

MISO plans to close over 8,600 MW of coal capacity by 2016, which represents 7.5 percent of the region's capacity.[39] Figure III-9 shows that if this capcity is retained, it will be nearly enough to avoid the anticipated capacity shortages expected in MISO.

Figure III-9: MISO Anticipated Summer Reserve Margins

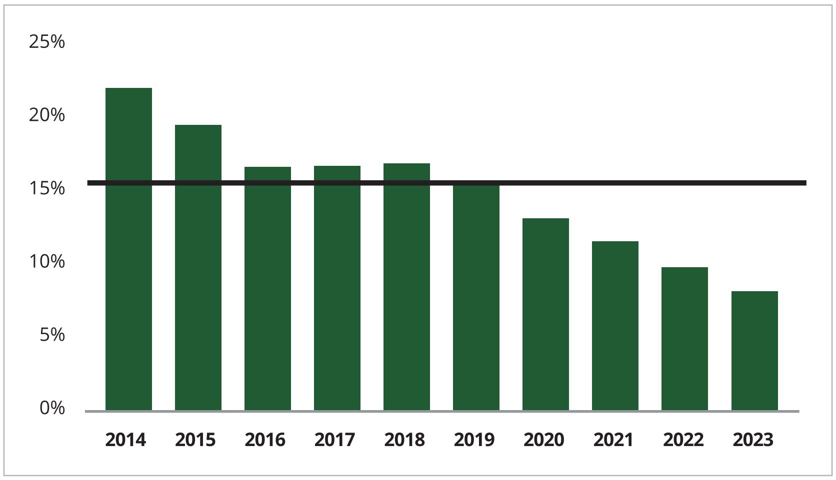


Source: North American Electric Reliability Corporation

SERC-E

SERC-E is an assessment area covering portions of North and South Carolina, excluding SERC entities that are in PJM. The SERC-E assessment area includes 4.4 million customers over 32,000 square miles. SERC-E plans to retire 1,400 MW of coal capacity by 2018, which represents 5.1 percent of the region's capacity.[40] Figure III-10 shows that if this capcity is retained, it will be nearly enough to avoid the anticipated capacity shortages expected in SERC-E.

Figure III-10: SERC-E Anticipated Summer Reserve Margins



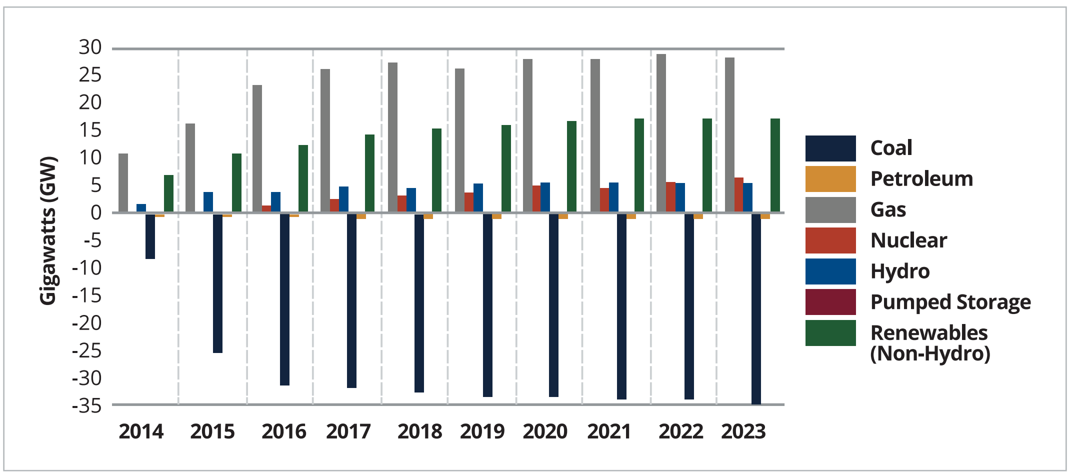
Source: North American Electric Reliability Corporation

IV. WHAT ARE THE IMPLICATIONS FOR THE U.S. OF THE COAL PLANT CLOSURES?

IV.A. What is Supposed to Replace the Coal Plants, and How Soon?

As shown in Figure IV-1, NERC forecasts that in the U.S., by 2023: Coal capacity will decrease by 35 GW (and may decrease by an addition 32 GW "conceptual"), natural gas capacity will increase by 29 GW (and may increase by an addition 108 GW "conceptual"), and that non-hydro renewable energy capacity will increase by 18 GW (and may increase by an addition 159 GW "conceptual").[41] Thus, in terms of planned capacity changes over the next nine years, 35 GW of coal will be closed and 47 GW of natural gas and renewable energy will be added.

Figure IV-1: NERC-Wide Cumulative Planned Capacity Change (2014–2023)



Source: North American Electric Reliability Corporation

According to NERC, the amount of coal-fueled generation during peak is expected to decline substantially, as 39.4 GW of closures and derates outpace 4.3 GW of new additions, resulting in a net reduction of 35.1 GW by 2023. Most unit closures are planned between 2014 and 2016, when requirements of environmental regulations become effective. A large portion of closures will occur in PJM, with 9.6 GW of announced coal closures during the assessment period. NERC-wide coal-fueled unit closures totaled 3.5 GW in 2011 and 8.9 GW in 2012.

Despite 15.2 GW of planned closures of mostly older, less-efficient units, total gas-fired generation continues to grow, with a net increase of 28.6 GW by 2023. Several new units will become operational between 2014 and 2017, concurrent with the anticipated closures of several coal-fueled units. A majority of these new units will be built within WECC (10.6 GW), PJM (8.5 GW), FRCC (5.5 GW), and ERCOT (4.6 GW).

Approximately 1.2 GW of petroleum-fired generation will be taken out of service during the assessment period. In many cases, units with gas as the primary fuel type are able to switch to oil in response to gas supply shortages. NPCC-New England and NPCC-New York have a combined total of 12.6 GW of gas-fired capacity that uses oil as a secondary fuel source.

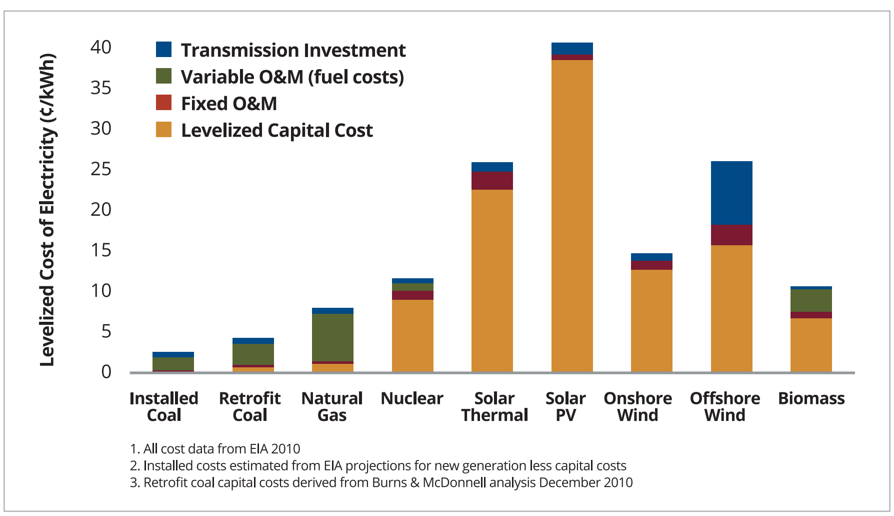
Electricity generation from nuclear power plants will increase by approximately 6.7 GW by 2023, primarily due to the planned addition of five units, totaling approximately 5.6 GW. All additional units are planned within SERC. Unit uprates will also contribute to increased capacity from existing plants throughout NERC.

Generation from renewable energy (wind, solar, biomass, and geothermal), accounts for over 50 GW of nameplate capacity additions during the next 10 years (7.5 GW on-peak). These new resources are built in large part as a response to federal tax credits, state-level policies (Renewable Portfolio Standards), and federal requirements. The share of NERC-wide on-peak generation from renewable fuels (excluding hydropower) grows by 17.5 GW, from 2 percent to 3.7 percent during the next decade. In terms of on-peak contribution, electricity from solar power accounts for the largest increase, growing by 9.1 GW. In recent years, a majority of new solar resources has come online in the southwestern portion of WECC (WECC-DSW and WECC-CALS), and this trend is expected to continue.

IV.B. Cost, Reliability, and Price Impacts

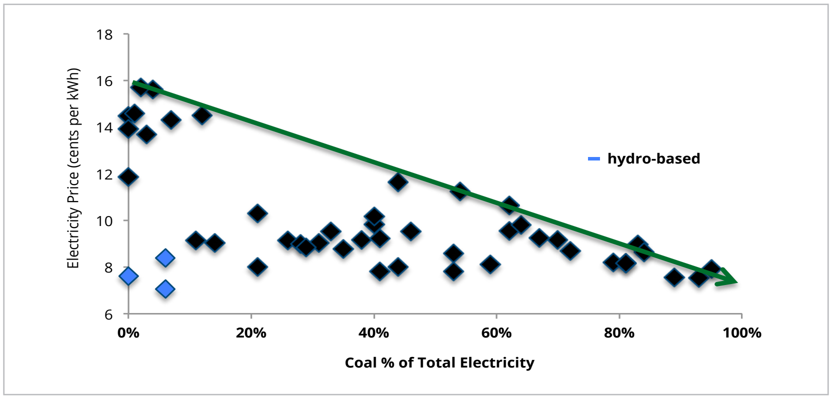
The implications for the U.S. of displacement of coal for electricity generation are potentially dire. Figure IV-2 compares the cost of coal-fueled generation to other types, including natural gas and renewables. Existing coal-fueled generation is clearly the least expensive.[42]

Figure IV-2: Levelized Costs of Electricity by Generation Sources



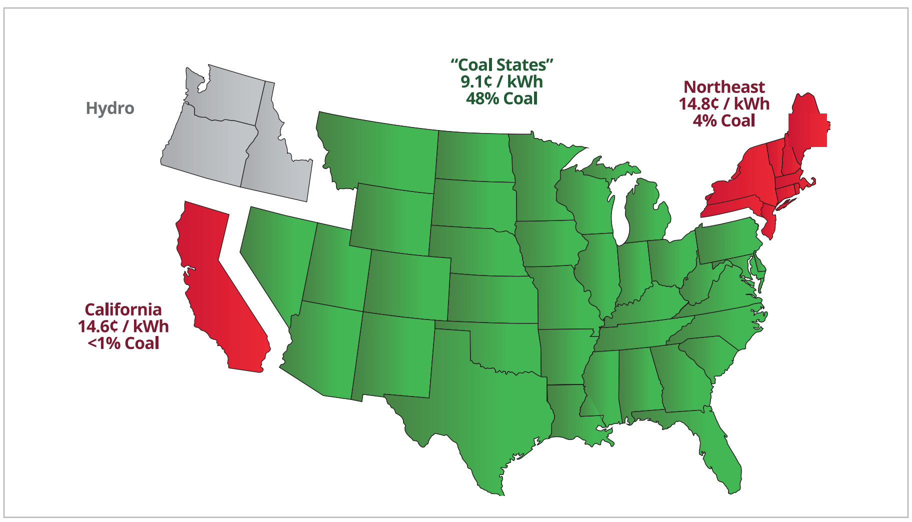
As shown in Figure IV-3, there is an inverse relationship between electricity prices and a state's use of coal to generate electricity: The higher percentage of coal used to generate electricity, the lower the electricity rate.[43] Figure IV-4 shows that it would be primarily the middle U.S. states that would be most negatively affected by a shift from coal for electricity generation.

Figure IV-3: Relationship Between Coal Generation & Electricity Prices by State



Source: U.S. Energy Information Administration.

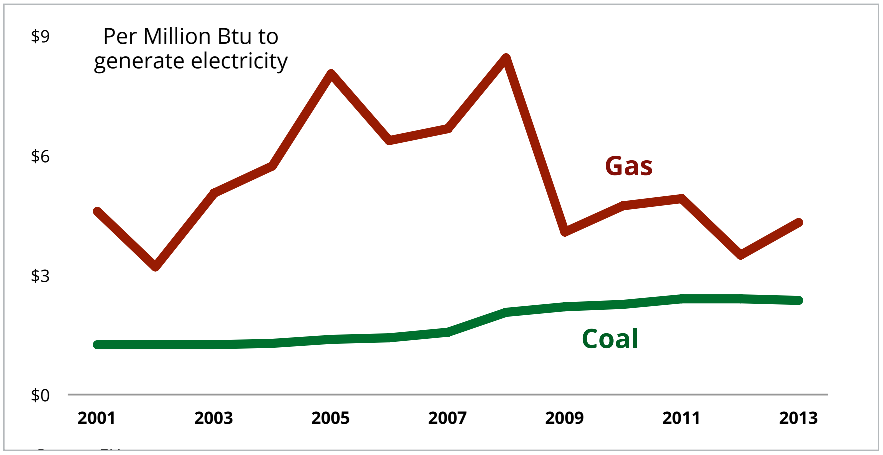
Figure IV-4: U.S. Electricity Prices



Sources: U.S. EIA, 2013 data, Mar. 2014. Average retail electricity prices per kWh. Weighted average of CA and NE states equals 14.7 cents per kWh. ID, OR, WA excluded due to hydropower.

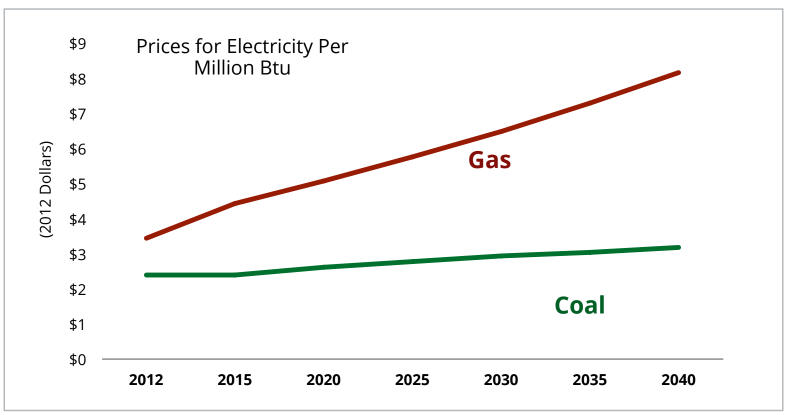
Natural gas has historically been subject to greater price volatility than coal – Figure IV-5 shows the stability of coal prices versus natural gas prices. And while new supplies and infrastructure are helping to stabilize that situation, the bottom line is that while the future price of natural gas is unknown, price volatility will likely continue due to its numerous uses and sectors that demand it. This is only exacerbated by government policies that drive demand for natural gas. In addition, according to the latest EIA forecasts, natural gas prices will remain higher than coal, and coal's price advantage is expected to increase every year – Figure IV-6.[44]

Figure IV-5: Volatility of Natural Gas Prices Compared to Coal Prices



Source: U.S. Energy Information Administration.

Figure IV-6: Forecast Natural Gas and Coal Prices for Electric Power Producers



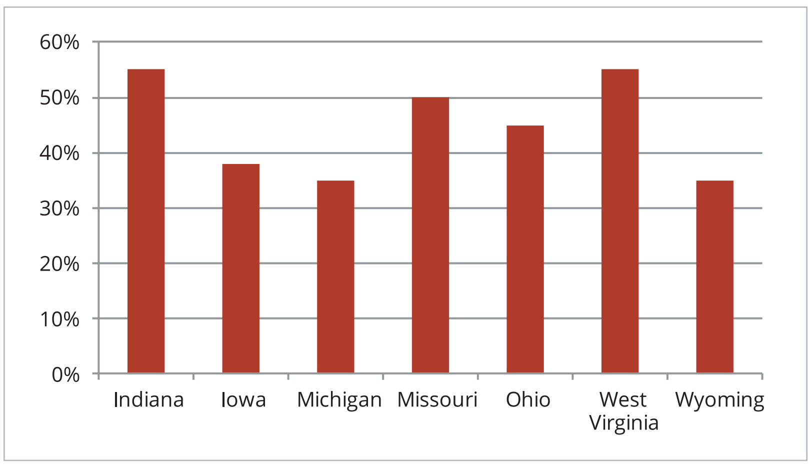
Source: U.S. Energy Information Administration.

IV.C. Rate Impacts on Economies and Families

The impending closure of 60 GW (or more) of coal capacity due to MATS threatens the U.S. electric system with serious problems relating to baseload power, price spikes, instability, scarcity, weather-related disruptions, and brownouts and blackouts. These closures *were already planned before the EPA's June 2, 2014 existing plant rule.* That rule will only hasten additional closures. It will also increase overall U.S. electric rates, and it will be especially harmful to those states currently having the largest portion of their electricity generated by coal. These are the states located in the lower right hand portion of Figure IV-3 and include states in the Midwest, the Southeast, and others such as Alabama, Illinois, Indiana, Iowa, Michigan, Missouri, Nebraska, Ohio, West Virginia, Wisconsin, and Wyoming. These and other states will be disproportionately harmed by very large electric rate increases, decreased reliability, and price spikes.[45] For example, by 2020 (Figure IV-7):

- In Indiana, electric rates could increase 50 percent (or more) above what they would have been without the coal plant closures.
- In Iowa, electric rates could increase 35-40 percent above what they would have been without the coal plant closures.
- In Michigan, electric rates could increase 30-40 percent above what they would have been without the coal plant closures.
- In Missouri, electric rates could increase 50 percent (or more) above what they would have been without the coal plant closures.
- In Ohio, electric rates could increase 40-50 percent above what they would have been without the coal plant closures.
- In West Virginia, electric rates could increase 50 percent (or more) above what they would have been without the coal plant closures.
- In Wyoming, electric rates could increase 30-40 percent above what they would have been without the coal plant closures.

Figure IV-7: Potential 2020 Electric Rate Increases From Coal Plant Closures



Source: Management Information Services, Inc.

Rate increases of this magnitude due to withdrawal of a large amount of baseload capacity are not hypothetical. For example, in June 2013, Southern California Edison, the majority owner of the San Onofre nuclear generating station (SONGS) midway between Los Angeles and San Diego, announced that it was permanently retiring the 2,250 MW plant which had been offline since January 2012. With SONGS shut, a number of superannuated gas-fired plants had to be pressed back into service and large amounts of replacement power had to be purchased.

According to the EIA, the closure of SONGS is, at least in part, to blame for a 59 percent increase in wholesale electricity prices for California in the first half of 2013.[46] EIA analysts found that "The increase was largely the result of the continued outage of SONGS. This factor also caused a large and unusual separation in power prices between the northern and southern parts of the state's electric system."[47]

A June 2013 letter to customers from San Diego Gas and Electric (SDG&E) President Jessie J. Knight Jr. warned of 15-30 percent rate increases due to closure of SONGS.[48] In reality, the actual rate schedule implemented in September 2013 was even worse than this, and some SDG&E residential customers experienced rate increases of 40 percent.[49]

Energy costs have economic effects similar to those of taxes: When energy and utility prices increase not because of genuine changes in the market but rather because of arbitrary government restrictions, then the energy and utility price hikes act as a "hidden tax" that have economically constrictive impacts; it decreases sales, GDP and jobs. Conversely, if government removes some of its artificial constraints on energy production, then the resulting fall in energy and utility costs has the effect of a "tax cut" and carries economically stimulating effects by putting more money in the hands of consumers and businesses, thus increasing sales and creating jobs.

The crucial point is that when the price changes are due to government restrictions, then the loss to energy consumers is not counterbalanced by the gain to energy producers. In other words, it is not the case that when energy customers pay higher prices, that this represents a boon to utilities and other energy producers who then will have an incentive to expand production and hire more workers. On the contrary, the government restrictions cancel out the benefits of the higher prices; the government restrictions hurt energy producers and consumers. This is the sense in which they act like an outside tax hike imposed on the entire private sector.

Like tax increases and decreases, changes in energy costs have both direct and indirect effects on the economy. Electricity price increases act like a tax increase, reducing incomes of energy consumers and ratepayers. Supply-side impacts from electric rate increases depress business development and economic output and produce adverse effects on the economy and jobs: 1) businesses will be increasingly non-competitive; 2) some businesses will disappear; 3) new businesses will not be created; and 4) electric customers will have less money to spend.[50]

Thus, the electric rate increases resulting from the coal plant closures will have harmful economic and jobs impacts – disproportionately affecting certain states.[51] For example, in 2020:

- In Indiana, state GDP is expected to decrease by $20 billion, nearly 200,000 jobs are expected to be destroyed, and the state and local governments are expected to lose $1.8 billion in tax revenues.
- In Missouri, state GDP is expected to decrease by more than $15 billion, 130,000 jobs are expected to be destroyed, and the state and local governments are expected to lose $1.6 billion in tax revenues.
- In Ohio, state GDP is expected to decrease by $25 billion, more than 220,000 jobs are expected to be destroyed, and the state and local governments are expected to lose $2.3 billion in tax revenues.

Thus, while U.S. GDP would be seriously impacted, the effects in individual states could be even more severe: State economies would be seriously harmed, industry and commerce would be devastated, millions of jobs would be destroyed, and state and local government revenues and budgets decimated. Further, since many of the states that would be most seriously harmed are in the industrial heartland, U.S. industrial competitiveness would be diminished, U.S. manufacturing output would shrink, U.S. exports would decrease, and the anticipated U.S. industrial renaissance would be stillborn.

Further, energy costs and utility rate increases are highly regressive and even modest increases in energy costs and utility rates have serious impacts on the middle class, the working poor, minorities, the less affluent, and seniors on fixed incomes.[52] Therefore, energy cost increases of the magnitude involved here would have disastrous impacts on large segments of the U.S. population, especially those in the most seriously impacted states. For example, in many states families would have to spend an additional $1,000 per year on utilities. For many families this would be a serious burden – especially since millions of people will lose their jobs. Many Americans would have to trade off utility costs for purchases of other necessities, such as food and medicine. The number of families eligible for the Low Income Home Energy Assistance Program (LIHEAP) would increase dramatically and a large percentage of Americans could be forced into energy poverty. The most harshly impacted would be children, minorities, the disabled, and the elderly, and demand for welfare, food assistance, and other support programs would skyrocket – at a time when government budgets are being devastated. Homelessness would increase (inability to pay utility bills is the second leading cause of homelessness, after domestic abuse), and states with high percentages of retirees, such as Florida and Arizona, would be especially hard hit.

VI. THE BOTTOM LINE - PROTECT THE AMERICAN PEOPLE: MORATORIUM ON COAL PLANT CLOSURES ESSENTIAL

Policymakers, regulators, and electric utilities should institute an immediate moratorium on the premature government induced closure of coal power plants and should also reverse planned closures where possible. As recent events in New England and elsewhere in the U.S. have demonstrated, **policies that hurt the U.S. coal fleet** are placing the reliability, affordability, and security of America's electric supply system at risk. These policies will also increase electric rates. These increases will be especially harmful in certain states, and they will impose severe economic hardship on people who can least afford it.

Currently, the most economic alternative to coal-fueled electricity is natural gas. The premature closure of coal power plants due to government policies will force an increasing dependence on natural gas to replace baseload coal. Real problems may occur if this becomes a government induced over-dependence on natural gas at a time when the government is undertaking steps to make it more difficult to produce, transport and consume natural gas. Not only does this put the U.S. electric supply at risk but it also endangers 1) the 60 million households that need gas for heating and 2) a vast array of firms that use gas in daily operations.

During the winter of 2013-14, businesses in New England and other parts of the U.S. were curtailed because of lack of gas. In fact, even gas power plants could often not get fuel and at one point many of them had to go offline. Gas-based electricity prices increased 1,000 percent as coal and oil plants actually scheduled for closure picked up the load. What would have happened in New England without coal? What would have happened in the Midwest without coal? What would have happened is that these regions and others would have experienced brownouts and blackouts that would have been economically disastrous and would have compromised public health and safety; in many instances it could have been life threatening. Importantly, once a coal plant officially closes, its license permanently terminates.

Recent experience in New England and elsewhere represents a troubling indication of the implications of removing coal plants from the electricity generation mix:

- Spot prices of natural gas and electricity have increased dramatically.
- Utility bills are becoming unaffordable for many families.
- Energy shortages are occurring.
- What little industry is left in the region is being decimated.
- Average electricity rates in New England are already more than 40 percent higher than the national average and may be headed to be as much as 150 percent higher than the U.S. average.
- New York's electricity prices are now the second highest in the country – only the geographically isolated state of Hawaii has higher prices.

Ominously, New England is merely the precursor to a national problem regarding adequacy of the electric grid and its capacity, which is quickly emerging. With the projected closure of 60 GW of coal plants due to MATS, virtually the entire U.S. is rapidly reaching the brink of not only higher prices for electricity, but also facing the specter of not being able to meet either the summer or winter peak demand for power. Unless immediate steps are taken to halt coal plant closures, within the decade entire regions (New England, Florida, California, Southwest) will depend on gas for over 60 percent of their electricity. Further, vast areas of the American heartland from the Southeast to the Plains will face the difficult choice of using gas for either electric power or meeting the heating needs of millions of families, businesses, and farms. Forecasts indicate that by 2020, natural gas capacity will exceed coal, nuclear, and hydro capacity *combined*. Rather than retiring viable coal plants, the U.S. should be constructing additional supercritical facilities to both significantly reduce emissions as well as meet the electricity needs of the 430 million people who will populate America in the next generation.

The American Public Power Association has warned of the potential danger of replacing coal with gas in electricity generation.[53] The U.S. has by far the world's largest coal supply; existing coal plants are less expensive than new natural gas plants for electricity generation and EIA forecasts that coal's price advantage over natural gas in the generating sector will continue and grow even larger over the next three decades.

The electrical generating and transmission system of the United States is the most complicated machine ever built. However, government policies are seriously threatening the ability to generate and distribute the type of electricity Americans have counted on for generations, namely, reliable and affordable energy upon which our very way of life depends. Through regulation, the government is moving to outlaw the largest source in our generation system – coal. While we become increasingly dependent on natural gas, activist groups and government officials have indicated their intent to phase out natural gas as well. The resulting planned removal of two-thirds of the fuels that provides our electricity, warms our homes and powers our economy is a serious matter that should concern all Americans.

Thus, in sum:

- **Policies that hurt the U.S. coal fleet** are placing the reliability, affordability, and security of America's electric supply system at risk.
- New England is merely the precursor to the national problem which is rapidly emerging.
- With the projected closure of 60 GW of coal due to MATS by 2017 (18 percent of capacity), the U.S. generating system and electric grid are at risk.
- Electric rates will likely increase, perhaps as high as 80 percent.
- These increases will especially harm certain states, and will cause economic hardship for people who can least afford it, including the 48 million Americans who live in poverty.
- In some areas, the U.S. will not be able to meet either the summer or winter peak demand for power.
- Prudence requires an immediate moratorium on coal power plant closures caused by government restrictions.
- Planned closures should be reversed where possible.

End Notes

1. U.S. Energy Information Administration, "AEO2014 Projects More Coal-Fired Power Plant Closures by 2016 Than Have Been Scheduled," February 14, 2014.
2. U.S. Energy Information Administration, Annual Energy Outlook 2014, early release, December 16, 2013.
3. EIA apparently believes that many coal plants are under-utilized and should be able to run at 80 percent to 85 percent capacity factor. If plants are running at 70 percent capacity factor, they can generate significantly more electricity when they are fully utilized, which EIA is modeling before NEMS will build more capacity. However, EIA has not yet conducted sufficient research to determine that 66 year old average age units can average 77 percent capacity factor – or higher. There is a huge gap in baseload plant renewal if historic operating performance with age remains true. Analyses by Mitsubishi-Hitachi, Consol, AEP, Alstom, B&W, and other firms generally find that coal plants were designed for 30-40 year life spans, and that existing plants over 50 years old begin to perform and dispatch poorly with major maintenance and efficiency improvements stymied by New Source Review regulations. See the discussion in Roger Bezdek and Robert Wendling, "Economic, Environmental, and Job Impacts of Increased Efficiency in Existing Coal-Fired Power Plants," Journal of Fusion Energy, Volume 32, Number 2 (April 2013), pp. 215-220.
4. ICF Incorporated "Current State and Future Direction of Coal-fired Power in the Eastern Interconnection," Final Study Report for EISPC and NARUC, June 2013.
5. North American Electric Reliability Corporation, 2013 Long-Term Reliability Assessment, December 2013.
6. Brian Dowling, "U.S. Energy Secretary Plans to Review New England's Natural Gas Shortage," Hartford Courant, January 30, 2014.
7. Jon Chesto, "Energy Experts Offer Solutions to Prevent a New England Natural Gas Crisis," Boston Business Journal, March 1, 2013.
8. Ibid.
9. England Ratepayers Association, "Continued Over-Reliance on Natural Gas Will Raise Electricity Rates," November 19, 2013.
10. ISO New England, Addressing Gas Dependence, July, 2012.
11. Coal and Energy, February 19, 2014, p. 2.
12. Energy Information Administration, Electric Power Monthly, Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, www.eia.gov/electricity/monthly/epm_ table_ grapher.cfm?t=epmt_5_6_a.
13. Data derived from U.S. Energy Information Administration, Electric Power Monthly, through January 2014.
14. Ibid.
15. U.S. Energy Information Administration, "Northeast Grows Increasingly Reliant on Natural Gas For Power Generation," Electricity Monthly Update, November 12, 2013.
16. National Electricity Reliability Corporation, 2013–2014 Winter Reliability Assessment, November 2013.
17. Federal Energy Regulatory Commission, 2012 State of the Markets Report, Washington, D.C., 2012, www.ferc.gov/oversight.
18. ISO New England, Addressing Gas Dependence, July, 2012.
19. Federal Energy Regulatory Commission, Winter 2013-14 Energy Market Assessment, Report to the Commission, Washington, D.C., Docket No. AD06-3-000, October 2013.
20. Ibid.
21. ISO New England, Inc., "2013 Regional Energy Outlook," 2013.
22. National Energy Reliability Corporation, 2013 Long-term Reliability Assessment, December 2013.
23. Synapse Energy Economics, Inc., "Avoided Energy Supply Costs in New England: 2013," prepared for the Avoided-Energy-Supply-Component Study Group, July 12, 2013.
24. ICF International, "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs," prepared for ISO New England Inc., June 15, 2012.
25. Synapse Energy Economics, Inc., "Avoided Energy Supply Costs in New England: 2013," prepared

for the Avoided-Energy-Supply-Component Study Group, July 12, 2013.
26. U.S. Energy Information Administration, Annual Energy Outlook 2014, 2014.
27. Jim Thompson, "Market Commentary," Coal and Energy, February 19, 2014, pp. 1-3.
28. Naureen S. Malik, "West Coast Gas, Power Surge on Frigid Northwest Cold Forecasts," Bloomberg, February 5, 2014.
29. U.S. Energy Information Administration, "Fuel-switching From Natural Gas to Oil Helps Moderate Northeast Winter Natural Gas Demand," February 5, 2014.
30. See Naureen S. Malik, "West Coast Gas, Power Surge on Frigid Northwest Cold Forecasts," Bloomberg, February 5, 2014; John Funk, "Power Plants Fired by Gas Instead of Coal Could Mean Higher Home Heating Bills and Costly New Pipelines," The Plain Dealer, January 31, 2014; Michael R. Blood, "Low on Natural Gas, California Told to Power Down," Associated Press February 7, 2014; James Burgess, "Winter Storms Send Natural Gas Prices to 4-Year High," Christian Science Monitor, February 6, 2014..
31. Malik, op. cit.
32. Steis, op. cit.
33. Steis
34. Everett Wheeler and Peter Marrin, "Gas Reliance Under Renewed Scrutiny After Epic Power Price Spikes," SNL Financial, January 27, 2014.
35. Ibid. A representative from PJM would not comment on specific plant outages but did note the heavy reliance on gas-fired generation in the eastern reaches of PJM, a dependence that was highlighted by the loss of both Calvert Cliffs nuclear reactors on 1-21-14.
36. EBW Analytics Group,, Energy Risk Report, February 7, 2014.
37. North American Electric Reliability Corporation, 2013 Long-Term Reliability Assessment, December 2013.
38. Ibid.
39. Ibid.
40. Ibid.
41. Ibid.
42. EIA has estimated average LCOEs for generating technologies that are brought online in 2019, as represented in the National Energy Modeling System (NEMS) for the AEO2014 Reference case; see www.eia.gov/forecasts/aeo/electricity_generation.cfm.
43. This is not hypothetical. A recent study by the American Wind Energy Association illustrates that electricity prices are rising more than four times the national average in nine of the 11 states with the most wind power consumption; James Taylor, "Wind Industry Study: Electricity Prices Skyrocketing in Largest Wind Power States," Forbes, February 27, 2014.
44. U.S. Energy Information Administration, Annual Energy Outlook 2014, early release, December 16, 2013.
45. Estimates based on the portion of a state's electricity generated by coal and the likely costs involved in converting from coal to other generation sources.
46. Morgan Lee, "Power Prices up 59 percent After Nuke Shutdown," San Diego Union-Tribune, July 23, 2013.
47. U.S. Energy Information Administration, "Extended Nuclear Plant Outages Raise Southern California Wholesale Power Prices," Today in Energy, March 26, 2013.
48. Adam Townsend, "SDGE Warns of Pending Bill Hikes After San Onofre Closure," San Clemente Patch, July 06, 2013; Adam Townsend, "SDGE Warns of Pending Bill Hikes After San Onofre Closure," San Clemente Patch, July 06, 2013.
49. "SDG&E Announces Drastic 2013 Rate Increases," CalState Solar, July 17, 2013.
50. Roger Bezdek, "Energy Costs: The Unseen Tax? A Case Study of Arizona," Presented at the National Taxpayers Conference, Chandler, Arizona, October 2013.
51. These estimates are based on the quantitative economic impacts of the rate increases; see the discussion in Section II.H and Appendices II and III of "The Social Costs of Carbon? No, the Social Benefits of Carbon," prepared by Management Information Services, Inc. for the American Coalition for Clean Coal Electricity, Washington, D.C., January 2014.
52. "The Social Costs of Carbon? No, the Social Benefits of Carbon," op. cit.
53. American Public Power Association, "Implications of Greater Reliance on Natural Gas For Electricity Generation," 2010.

PROTECT THE AMERICAN PEOPLE: MORATORIUM ON COAL PLANT CLOSURES ESSENTIAL

June 2014