ELECTRIC GENERATION INVESTMENT IN A TIME OF NATURAL GAS PRICE AND CARBON PRICING UNCERTAINTY: A MODELING ANALYSIS

by

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ABSTRACT

Low current and forecasted natural gas prices are spurring investment in new gas-fired electric generation in the eastern United States. In both regulated territories and organized electricity markets, natural gas power is beginning to displace significant amounts of retiring coal generation. However, the market price of natural gas has historically been volatile and unpredictable. If gas prices rise substantially from current forecasts in the next two decades, will customers face sharply higher electricity prices? What if a carbon tax accompanies this outcome? This modeling analysis sheds light on these questions by modeling long-term capacity expansion based on current assumptions, and then assessing how economic dispatch in three regions - the Southeast, PJM Interconnection, and ISO New England – will respond to alternate versions of future gas prices and carbon taxes.

The results indicate that heavily gas-dependent regions like ISO New England would absorb the imposition of a carbon tax without major electricity price increases, but that they would face substantial price increases with sustained, elevated natural gas prices. The results also suggest that portfolios in the Southeast and PJM will skew more heavily to natural gas generation in the future if investment decisions are made under current conditions and assumptions. If this occurs, these two regions could face sharp electricity price increases with either higher-than-expected natural gas prices or the imposition of a carbon tax.

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INTRODUCTION

The United States electricity system currently sits at the nexus of three complicated phenomena. The first is the sudden glut of natural gas that has resulted from technological advances in gas drilling in shale formations around the country. The newfound abundance has sent natural gas prices plummeting to decade-low levels and allowed natural gas-fired electricity generation to outcompete electricity from other fuel sources, most notably coal.

The second phenomenon is the building consensus in the energy industry that a market price on the emissions of carbon dioxide is inevitable. Though the date on which it will be imposed and the form that it will take are uncertain, many electric utilities now factor in some form of carbon pricing in their long-term modeling and planning.[1]

The third phenomenon is the restructuring of the electricity markets. Congress has, in recent decades and through several major laws,[2] established a national policy of increased competition in the wholesale electricity markets. The Federal Energy Regulatory Commission (FERC) has acted to implement this policy through a number of landmark orders beginning in 1996.[3] These orders have sought to grant open access to the transmission grid for independent power producers, prevent undue discrimination in the provision of transmission service, and encourage the formation of Regional Transmission Organizations (RTOs) to operate the electric grid in a fair and efficient manner.[4] These actions led to major

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[1] As an example, see Duke Energy's 2012 Integrated Resource Plan, at 106, filed with the North Carolina Utilities Commission 4 Sep 2012. In its internal modeling reference case, Duke Energy assumes a $17 per ton carbon price in 2020, and increasing thereafter, based on a cap-and-trade system. Available at: http://www.duke-energy.com/investors/regulatory-information.asp

[2] Most notably the 1978 Public Utility Regulatory Policies Act, the 1992 Energy Policy Act, and the 2005 Energy Policy Act.

[3] Most notably Order Nos. 888 (mandating open access transmission tariffs), 2000 (establishing rules for Regional Transmission Organizations), 890 (preventing undue discrimination and preference in transmission service), and 1000 (mandating transmission planning and cost allocation by transmission-owning and –operating public utilities). (ferc.gov)

[4] Id.

changes in the electric sector, with fully two-thirds of US electricity customers now in regions with organized wholesale electricity markets.[5] The restructuring movement largely stalled following the California energy crisis in 2000-2001, but some experts believe that all regions will require independent operation of the transmission grid (through an RTO or similar entity) if the goals of open access transmission service and true market competition in power generation are to be achieved.[6]

This study looks at the interactions of these three phenomena. It analyzes how different scenarios for natural gas prices and carbon taxes comparatively impact a non-RTO (traditionally-regulated as a public utility monopoly) region with a plurality of coal generation (the regulated Southeast); a RTO region with a plurality of coal generation (PJM Interconnection); and a RTO region with a plurality of natural gas generation (ISO New England). Using the AURORAxmp model, I first project electric generation capacity expansion under reference case conditions. I then project and assess generation dispatch choices and wholesale electricity prices under different natural gas price and carbon tax scenarios to see how each region adapts to changing conditions. The objective is to determine whether one set of regional characteristics is superior in minimizing the risk of rising electricity prices to ratepayers should reality deviate from current conditions and forecasts.

The analysis seeks answers to the following three questions:

1. Does overinvestment in natural gas generation based on current assumptions risk dramatic increases in wholesale electricity prices if A) natural gas prices rise higher than expected; (B) a carbon tax is imposed within the decade; or C) some combination of the two occurs?

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[5] ISO/RTO Council. Available at http://www.isorto.org/site/c.jhKQIZPBImE/b.2603295/k.BEAD/Home.htm

[6] MIT's William W. Hogan and the COMPETE Coalition, an advocacy group, have been two of the more outspoken voices on this point. More information at http://www.hks.harvard.edu/about/faculty-staff-directory/william-hogan and http://www.competecoalition.com/about.

2. Do the results suggest that electric market restructuring is advantageous in reducing price risk for ratepayers?
3. Do the findings suggest that policymakers and regulators should consider the risk of overinvestment in natural gas capacity when evaluating integrated resource plans, nuclear power policies, or renewable power policies?

Section I describes the three regions and their market structures. Section II provides background on natural gas prices, carbon emissions reduction methods, and electricity market restructuring. Section III describes AURORAxmp, the modeling software used for the analysis. Section IV outlines the methodology of the analysis. Section V presents the findings of the analysis. Finally, Section I offers conclusions and policy implications of the findings.

SECTION I: THE REGIONS & ELECTRICITY MARKETS

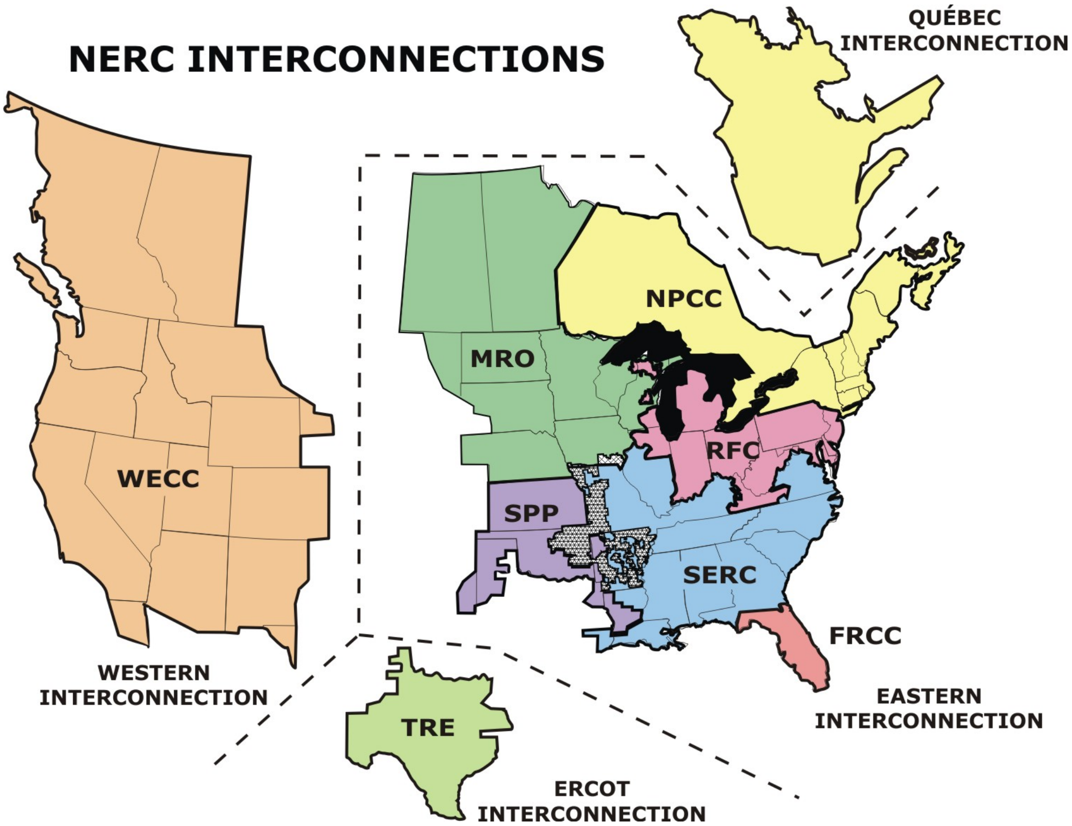
I model and study three regions in this analysis. Two of the three, PJM Interconnection (PJM) and ISO New England, have clearly defined operating territories in the modeling software. To capture a third territory that is almost entirely composed of traditionally-regulated (also known as vertically-integrated) electric utilities, I custom-define a region that I refer to as "the Southeast" in this report.

As shown in Figure 1, the US electric grid is divided into three largely independent interconnections: the Eastern Interconnection, the Western Interconnection, and the ERCOT Interconnection (Texas). The entity that sets electric reliability standards for the North American grid, the North American Electric Reliability Corporation (NERC), divides the Eastern Interconnection into six regions, one of which is the Southeast Electric Reliability Corporation, or SERC (also shown in Figure 1). SERC is further divided into sub-regions, as shown in Figure 2. The VACAR (Virginia-Carolinas) sub-region includes territory in

Virginia that is part of the PJM region, and territory in North Carolina and South Carolina where the major investor-owned utilities remain traditionally regulated. The latter is sometimes referred to as VACAR South. To prevent overlap between the Southeast region, as defined in this study, and the PJM region, I include VACAR South in the Southeast region and exclude the Virginia portion of VACAR.

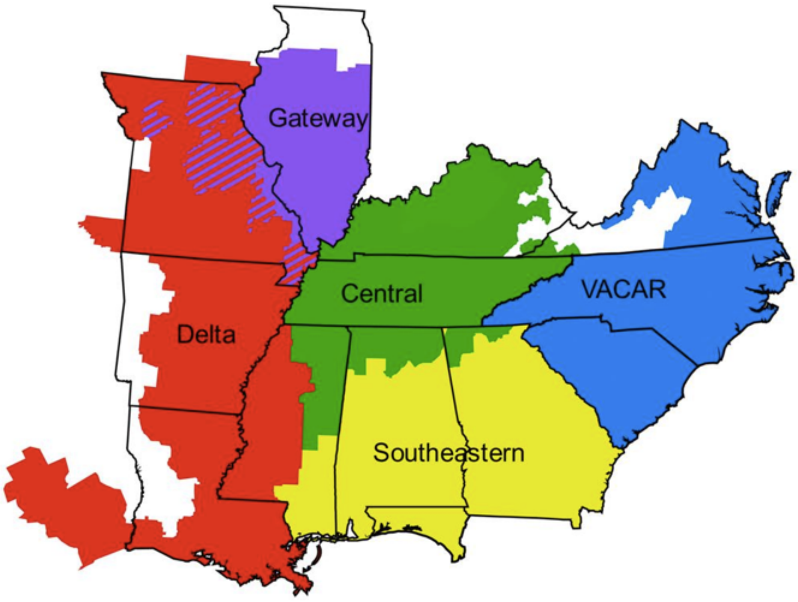
Therefore, the Southeast region is here defined as all of the Southeast and Central sub-regions plus VACAR South. This territory encompasses all of North Carolina, South Carolina, Georgia, Alabama, and Tennessee, large portions of Kentucky and Mississippi, and a small portion of the Florida panhandle.

Figure 1: Interconnections of the US electric grid and the NERC regions



Source: ERCOT.com

Figure 2: SERC sub-regions



Source: SERC1.org

PJM Interconnection and ISO New England are regional transmission organizations (RTOs) operating in what are termed "restructured regions." Restructuring refers to the partial deregulation of the generation and retail sales of electricity. Companies owning generation assets or selling electricity to customers operate competitively through market mechanisms, while companies owning electricity transmission and distribution assets remain regulated as public utilities.

To promote open competition in generation and retail, the RTOs act as independent entities serving three primary functions for their territory: managing the wholesale electricity markets; operating the high-voltage electric grid; and coordinating the planning process for new generation and transmission assets.[7,8] PJM covers part or all of 13 states and the District of Columbia and serves roughly 60 million customers (see Figure 3).[9] ISO New England

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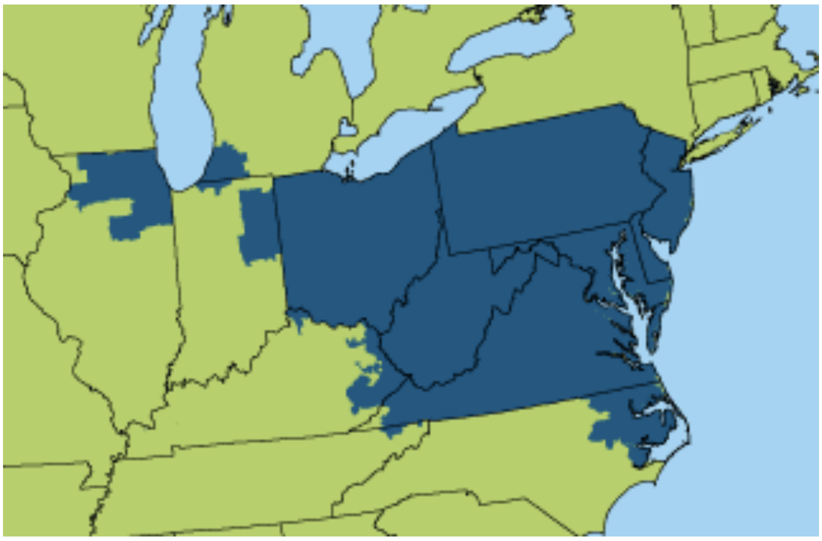
[7] Company Profile: Overview. ISO New England, 2013. Available at: http://www.iso-ne.com/aboutiso/co_profile/overview/index.html

[8] Who we are. PJM Interconnection, 2013. Available at: http://www.pjm.com/about-pjm/who-we-are.aspx

[9] Id.

covers Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, serving 14 million customers (see Figure 4).[10,11]

Figure 3: PJM Region



Source: PJM.com

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[10] Company Profile: Overview. ISO New England, 2013. Available at: http://www.iso-ne.com/aboutiso/co_profile/overview/index.html

[11] Inside Grid and Markets: Key Facts. ISO New England, 2013. Available at: http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/

Figure 4: ISO New England Region

Source: ISO-NE.com

In contrast to the restructured markets of PJM and ISO New England, the Southeast region largely operates under the traditional, vertically-integrated market structure for public utilities. In this structure, electric utility companies own and operate generation and transmission assets and receive a regulated rate of return on those capital assets for investors. In return for limited, pre-determined profits, the companies are granted a monopoly over their service territory.

The process by which new generation capacity is added to the system is also different in traditionally-regulated and restructured regions. In the Southeast, utility companies maintain annual Integrated Resource Plans, which detail their plans to meet future growth in demand for electricity within their service territories, factoring in reserve margins that act as a buffer should projections prove inaccurate. Reserve margins are typically in the range of 12-15 percent. The plans are then submitted for approval to the state public utility commissions for each state in which the company provides service. Also active in this process are consumer advocates, who protect the interests of customers of the utilities and advocate on behalf of those customers for low-cost, reliable electricity service.

By contrast, capacity additions in PJM and ISO-NE occur through forward-looking capacity auctions administered by each RTO. They estimate future demand growth and add to that amount a reserve margin. They then conduct capacity auctions several years prior to the service year in question. Market participants, among them companies owning generation assets, may then bid into the open, transparent auction. A clearing price is determined based on the lowest-cost suite of generating capacity, and all generators with bids at or under that clearing price are paid at the clearing price in return for being available to generate at a given time.[12] This payment is known as a capacity payment.

Capacity payments are different from energy payments. The former is paid to an entity that is committing to be *available* to generate if the RTO calls upon it to do so. Owners of generation assets receive energy payments in return for actual generation of electricity. These energy payments are determined by energy markets, such as day-ahead markets and real-time markets, that are also managed by RTOs. Forward-looking capacity markets have developed because energy markets were not providing enough future certainty to promote adequate investment in future generation. Thus, capacity markets (and payments) provide an additional, guaranteed revenue stream to owners and incent their investment in the new generation that will help to meet future electricity demand.

Despite the difference in market structures and operations, two of the regions, the Southeast and PJM, have roughly similar electricity generation profiles, in which coal and nuclear power combine to make up at least three-quarters of output. In 2011, both had 45-50

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[12] Reliability Pricing Model. PJM Interconnection, 2012. Available at: http://www.pjm.com/markets-and-operations/rpm.aspx

percent coal-fired generation, 25-35 percent nuclear generation, 10-20 percent gas-fired generation, 2-5 percent hydropower generation, and a little over 2 percent non-hydro renewable generation (including biomass) (see Table 1).[13]

Table 1: 2011 Net Generation by Fuel Type

Fuel	Southeast	PJM	ISO New England
Coal	46.2	47.3	6.2
Natural Gas	18.6	12.8	50.7
Nuclear	27.4	34.6	27.5
Hydro	5.3	1.9	7.9
Biomass	2.1	1.2	6.1
Wind	<1.0	1.3	<1.0

Data source: SNL Energy, with permission, accessed 5 Dec 2012.

By contrast, ISO New England is a predominantly natural gas-powered region. In 2011, 51 percent of its generation came from gas. This high reliance upon natural gas makes ISO New England valuable in the study because it resembles what the other regions may look like in a decade if the current trend of shifting away from coal and toward natural gas continues.

The Southeast region has historically enjoyed some of the lowest electricity prices in the country (See Figure 5). The low rates are seemingly the result of low-cost coal and nuclear generation. Both coal and nuclear power plants require vast upfront capital investments but then enjoy lower variable costs because their fuel inputs, coal and uranium, have been inexpensive. In the past, the high upfront capital investments of these plants were

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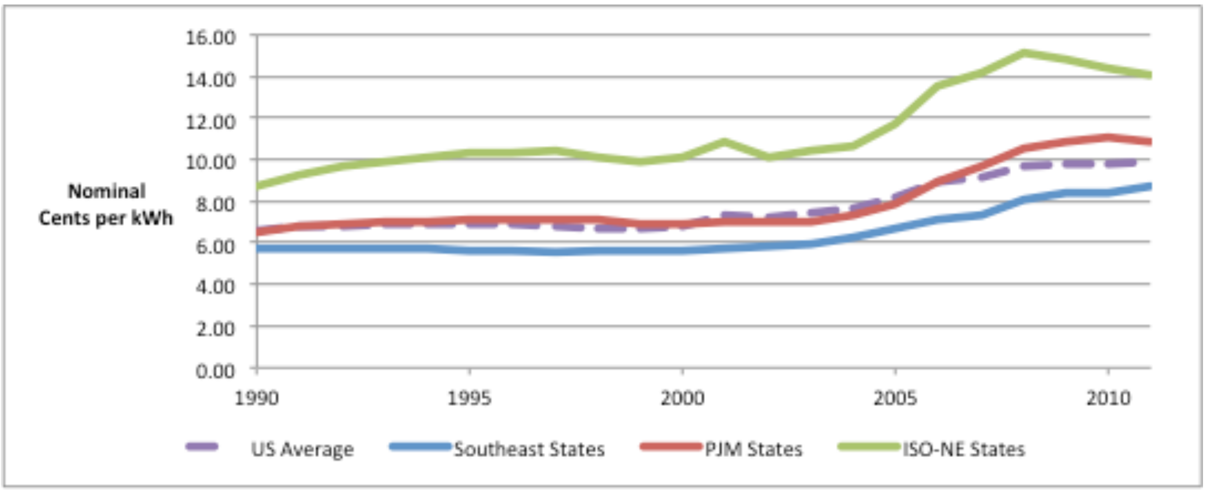
[13] SNL Energy, with permission. Accessed 5 Dec 2012.

not an impediment because the stability of the regulated market structure made financing for the plants available and relatively low-cost.

Figure 5: Average Annual Electricity Prices 1990-2011[14]



Data source: U.S. Energy Information Administration

The rapidly-declining cost of natural gas in recent years has begun to upend this dynamic. With few exceptions, new natural gas-fired generation has even been able to outcompete new nuclear generation, which, due to extensive and lengthy permitting, requires an immense capital investment and patient investors. As such, 78 percent of the net generating capacity additions in the Southeast between 2005 and 2012 has been natural gas-fired.[15] As shown in Figures 6 and 7, the same trend has been affecting forward capacity auctions in PJM and ISO New England.[16] The vast majority of new capacity in last year's 2015-2016 PJM auction was natural gas generation.[17] While the quantity of *total* new

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[14] Due to the limited availability of precise data for the regional boundaries of PJM and the Southeast (as defined in this study), for this chart, the PJM states include those states that are entirely or predominantly within the PJM territory, namely Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia. Likewise, the Southeast states here include Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee.

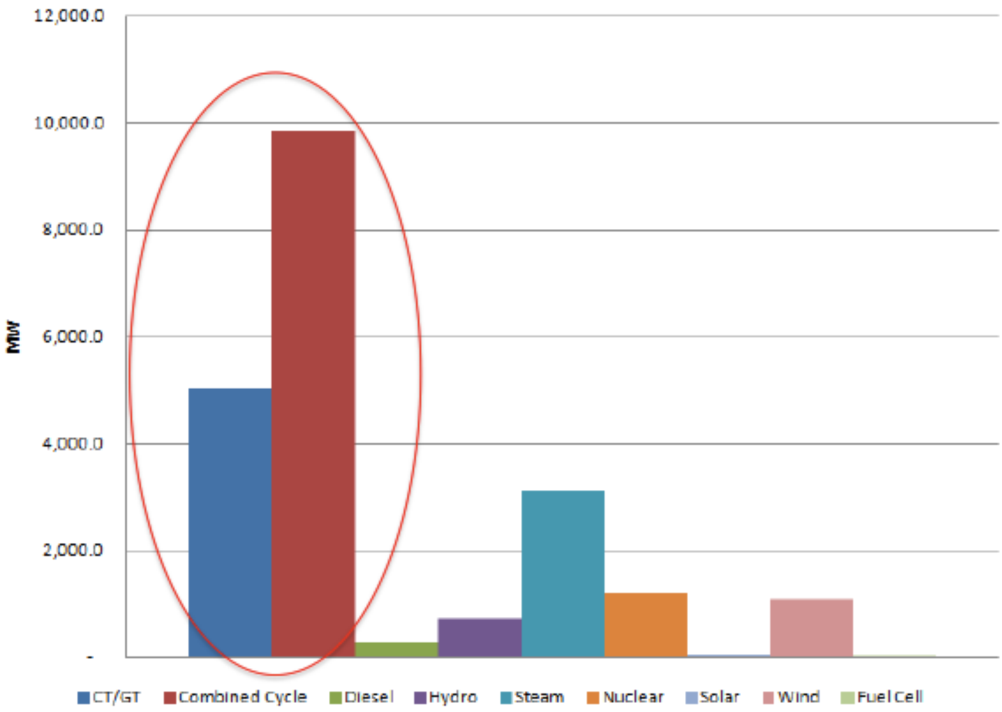
[15] SNL Energy, with permission. Accessed 5 Dec 2012.

[16] Participation in capacity markets (as opposed to energy markets) is not perfectly representative of changing dispatch patterns, but it is a one proxy for overall new generation investment patterns.

[17] 2015/2016 Reliability Pricing Model Base Residual Auction Results Report. PJM Interconnection, 2012.

capacity in ISO New England's recent 2016-2017 auction was far less than in PJM's, 78 percent of the 878 megawatts that were added was natural gas-fired.[18]

Figure 6: New Generating Capacity in the 2015/2016 PJM Capacity Auction



Source: PJM.com

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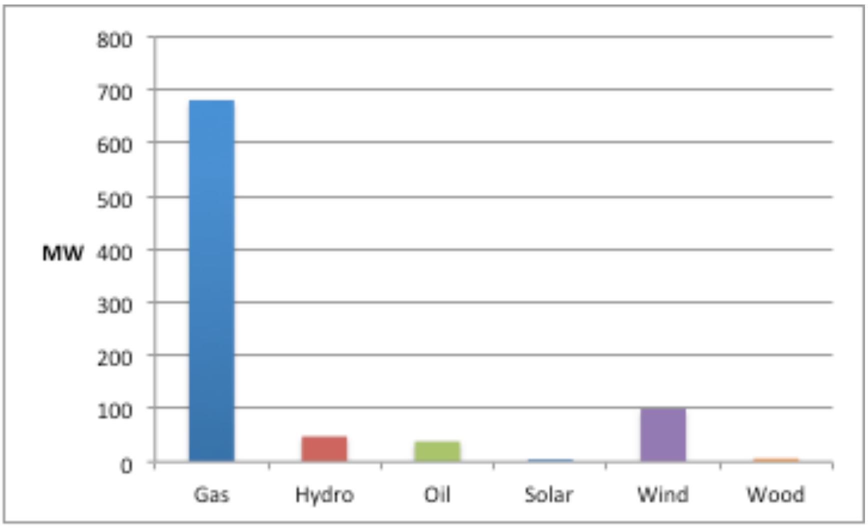
[18] Forward Capacity Auction 2016-17 Obligations. ISO New England, 2013. Available at: http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp17/fca17/index.html

Figure 7: New Generating Capacity in the 2016-17 ISO-NE Forward Capacity Auction



Source: ISO-NE.com

SECTION II: THE THREE PHENOMENA: BACKGROUND & ROLE IN THE ANALYSIS

Natural Gas Prices

Technological advances in combining horizontal drilling and hydraulic fracturing in shale formations containing natural gas have boosted domestic gas production over the past five years, sending the natural gas price on the US market to ten-year lows.[19] The result is that Energy Information Administration (EIA) estimates for unproved technically recoverable resources[20] of shale gas have changed greatly across EIA's Annual Energy Outlook reports from 2008 to 2012. As shown in the "shale gas total" row of Table 2, EIA estimates of reserves began a sharp increase in 2009 and reached a peak of nearly eight times the 2008 estimate in 2011, before being scaled back by nearly 42 percent in 2012.[21]

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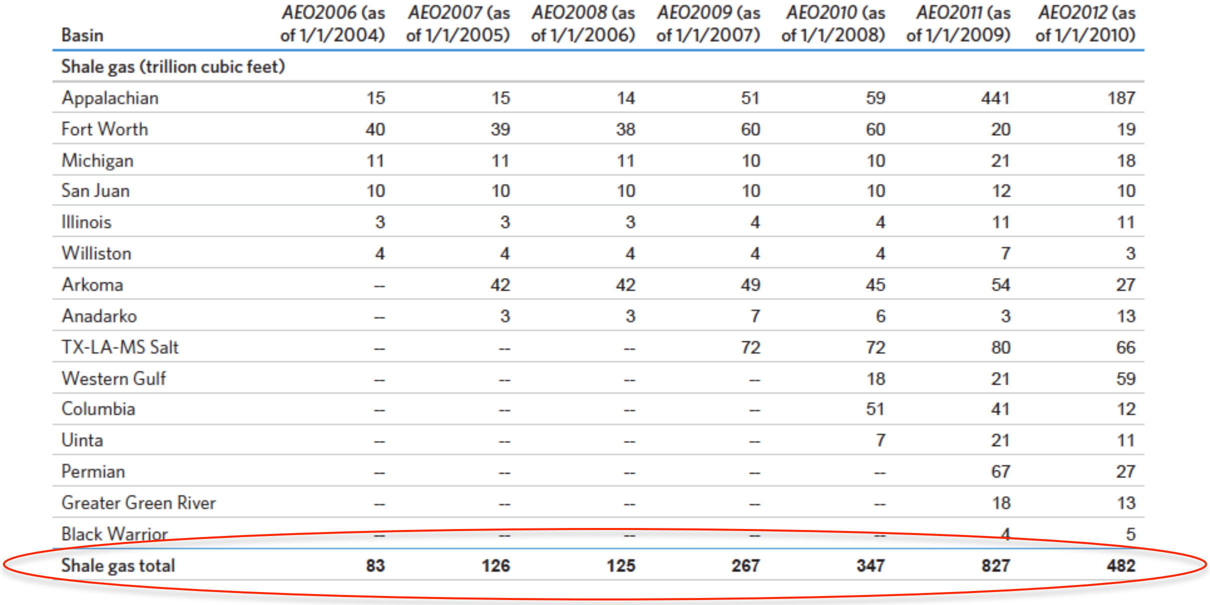
[19] US Energy Information Administration.

[20] EIA defines "unproved resources" as volumes of gas that are estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology. Contrast these with "proved resources," which are defined as volumes expected to be produced, with reasonable certainty, under existing economic and operating conditions. Both definitions from EIA's Annual Energy Outlook 2012.

[21] Annual Energy Outlook 2012. US Energy Information Administration, 2012.

Table 2: EIA Estimates for Technically Recoverable Resources of Shale Gas

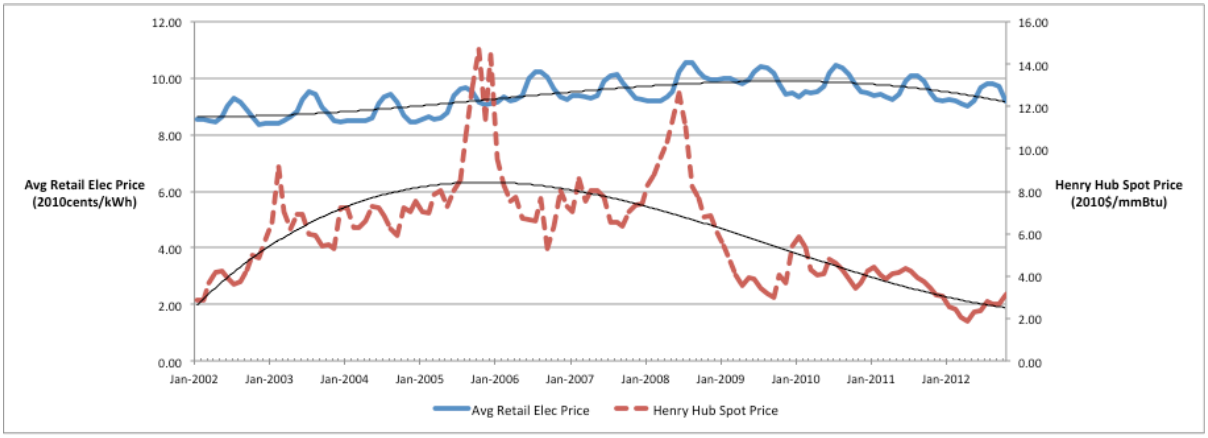


Basin	*AEO2006* (as of 1/1/2004)	*AEO2007* (as of 1/1/2005)	*AEO2008* (as of 1/1/2006)	*AEO2009* (as of 1/1/2007)	*AEO2010* (as of 1/1/2008)	*AEO2011* (as of 1/1/2009)	*AEO2012* (as of 1/1/2010)
Shale gas (trillion cubic feet)							
Appalachian	15	15	14	51	59	441	187
Fort Worth	40	39	38	60	60	20	19
Michigan	11	11	11	10	10	21	18
San Juan	10	10	10	10	10	12	10
Illinois	3	3	3	4	4	11	11
Williston	4	4	4	4	4	7	3
Arkoma	–	42	42	49	45	54	27
Anadarko	–	3	3	7	6	3	13
TX-LA-MS Salt	–	–	–	72	72	80	66
Western Gulf	–	–	–	–	18	21	59
Columbia	–	–	–	–	51	41	12
Uinta	–	–	–	–	7	21	11
Permian	–	–	–	–	–	67	27
Greater Green River	–	–	–	–	–	18	13
Black Warrior	–	–	–	–	–	4	5
Shale gas total	**83**	**126**	**125**	**267**	**347**	**827**	**482**

Source: US Energy Information Administration

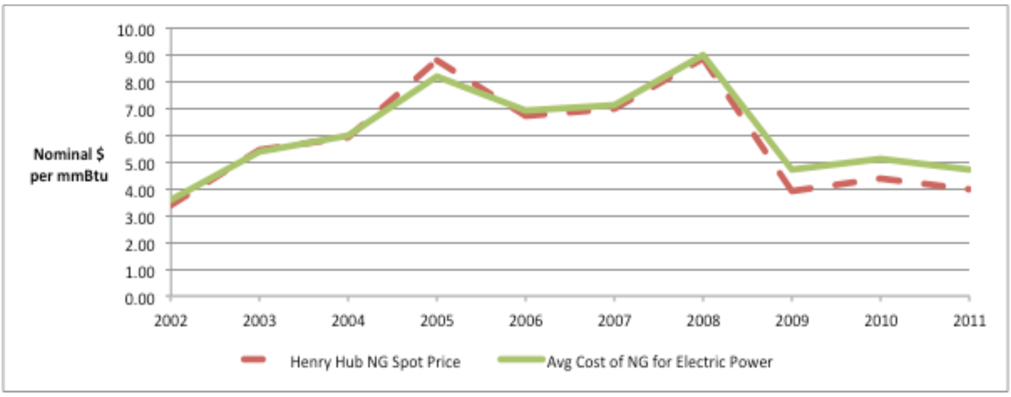
Sustained lower natural gas prices should logically lead to lower retail electricity prices in regions that have generation portfolios with a substantial portion of gas-fired power plants. Shorter-term fluctuations in fuel prices, be they natural gas, coal, or uranium, have only modest impacts on electricity prices because utilities “hedge out” such fluctuations through futures contracts. This is evidenced by the lack of a strong or immediate correlation between average retail electricity prices and natural gas spot prices shown in Figure 8. This lack of correlation occurs despite extremely close correlation between natural gas spot prices and the average cost of natural gas for the electric power industry, as shown in average annual terms in Figure 9.

Figure 8: Average Retail Electricity Price vs. Henry Hub Spot Price



Data source: U.S. Energy Information Administration

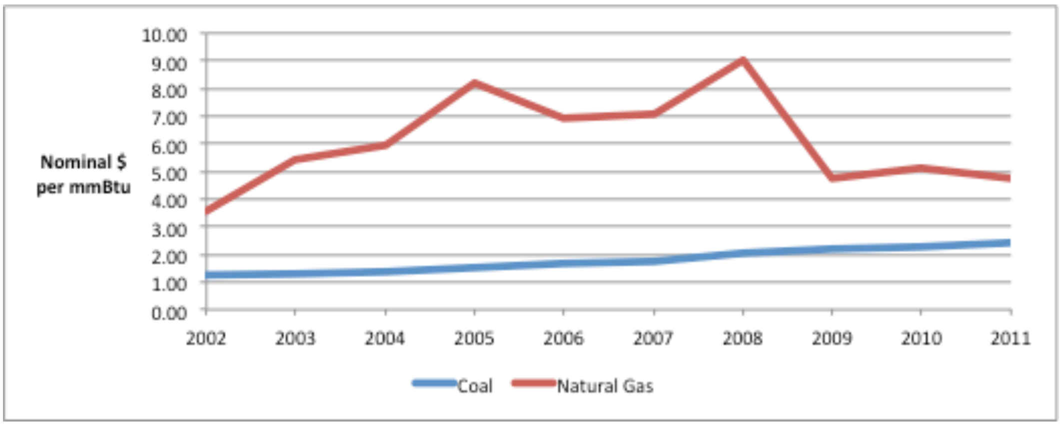
Figure 9: Avg Natural Gas Cost for Electric Power Industry vs. Henry Hub Spot Price



Data source: U.S. Energy Information Administration

The time limitations of hedging strategies means that new capacity investments must account for fuel price uncertainty. Given the momentous shift in the last five years in expectations about future natural gas price stability, we must ask the question: if current forecasts of low, stable gas prices spur a disproportionate investment in new gas generation, do ratepayers face the risk of markedly higher electricity prices if gas prices revert to their historical volatility? The wisdom of large-scale investment in new gas generation is, at least in part, based upon an assumption that gas prices will for the foreseeable future exhibit the price stability long seen only in coal and uranium as fuel inputs. This may come to pass, but it is certainly not supported by past evidence. Consider the comparison of the average annual cost of coal and natural gas as inputs to electric power generation from 2002-2011 in Figure 10.

Figure 10: Average Cost of Fuel for Electric Power Industry: Coal vs. Natural Gas



Data source: U.S. Energy Information Administration

Natural gas has historically been a volatile and unpredictable commodity. Consider Henry Hub spot prices from 1997 to 2012 plotted next to EIA's reference case Henry Hub price forecast for the period 2013-2035, shown in Figure 11. While model forecasts obviously smooth out the daily and monthly volatility seen in real-world markets, the long-term plot highlights just how rosy a picture current forecasts paint for large natural gas consumers like power plants. Consistently low prices and long-term stability of this nature have not been seen in natural gas markets since spot prices began to float in 1993 following wellhead price deregulation.[22]

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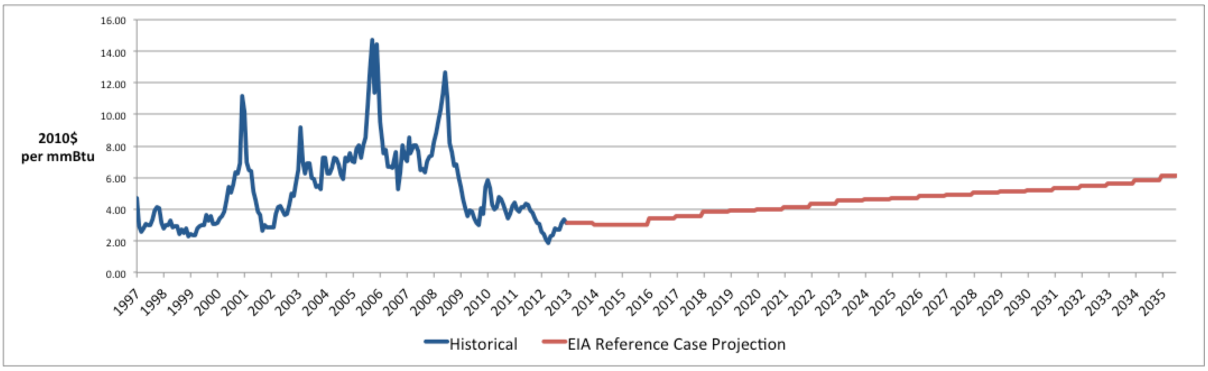
[22] The History of Regulation. NaturalGas.org. 2011. Available at: http://www.naturalgas.org/regulation/history.asp.

Figure 11: Henry Hub Historical Spot Prices & EIA 2013 Reference Case Prices



Data source for historical prices: U.S. Energy Information Administration; data source for projections: EIA Annual Energy Outlook 2013 Early Release

Based on the pattern of recent capacity additions in the Southeast and PJM, the power sector is projected to rely more heavily on natural gas, at least in the near term. If this pattern continues, the impacts of changes to gas prices on electricity prices will logically increase over time. As EIA states in its 2012 outlook:

> *The electric power sector shows the greatest sensitivity to natural gas prices, with natural gas use for electricity generation being more responsive to changes in fuel prices than is consumption in the other sectors, because much of the electric power sector's fuel consumption is determined by the dispatching of existing generation units based on the operating cost of each unit, which in turn is determined largely by the costs of competing fuels – especially coal and natural gas.*[23]

ISO New England expresses a similar sentiment when describing the recent history of electricity prices in the region:

> *Volatility in the price of natural gas and oil, which together fuel more than 60% of the region's generating units, has kept overall wholesale electricity prices high—a trend that likely will continue until the region reduces its reliance on these fuels to produce electricity.*[24]

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[23] Annual Energy Outlook 2012, at 62. US Energy Information Administration, 2012.

[24] Company Profile: History. ISO New England, 2013. Available at: http://www.iso-ne.com/aboutiso/co_profile/history/index.html

This notion may seem antiquated in the face of the current glut of natural gas in the US, but it still emphasizes the risk of lack of diversification. Just as diversifying a financial investment portfolio is sound practice, the same may be said for an electric generation portfolio, particularly when failing to do so means betting that a historically volatile commodity like natural gas will diverge from past behavior and exhibit prolonged low, stable prices.

The risks of gas prices diverging significantly from EIA's forecast may be small, but they undoubtedly exist. One likely impact is increased demand from the electric power sector due to coal plant retirements. According to a December 2012 report from the Brattle Group, between 59 and 77 gigawatts of coal capacity nationwide is likely to retire in coming years rather than retrofit with environmental control equipment.[25] That capacity represents between 17 and 22 percent of total US 2011 generating capacity.[26] If the current pattern of replacing retiring coal capacity with natural gas capacity continues, the increased demand for gas as a fuel will put upward pressure on gas spot and futures prices. Furthermore, localized gas prices are, to some extent, determined by limits on natural gas transportation capacity in a region or state. Greater than 70 percent of the projected coal capacity retirement is in the SERC and RFC regions, so these regions may see more stark price effects if gas transportation infrastructure does not keep up with the increased demand.

Another potential factor that could push natural gas price higher is the extent to which gas prices are tied to oil prices, given that they are often extracted in tandem. The relationship between oil and gas prices has weakened since 2009 with the dramatic increase in shale gas production (see Figure 12). Prior to 2009, oil and gas prices were somewhat strongly correlated. Figures 13 and 14 are scatter plots of oil and gas prices in the same month from 1997 to 2008, and from 2009 to 2012. The former shows an R-squared of 0.57, whereas the

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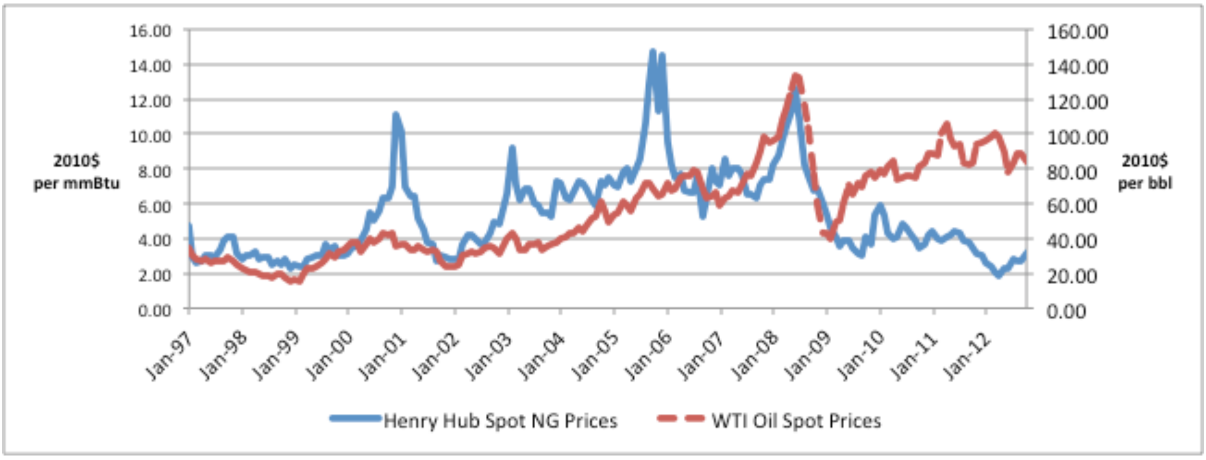
[25] Celebi, Metin, Frank Graves, and Charles Russell. "Potential Coal Plant Retirements: 2012 Update," Oct 2012, at 7 Available at: www.brattle.com/_documents/UploadLibrary/Upload1082.pdf

[26] Based on EIA data available at: http://www.eia.gov/electricity/capacity/

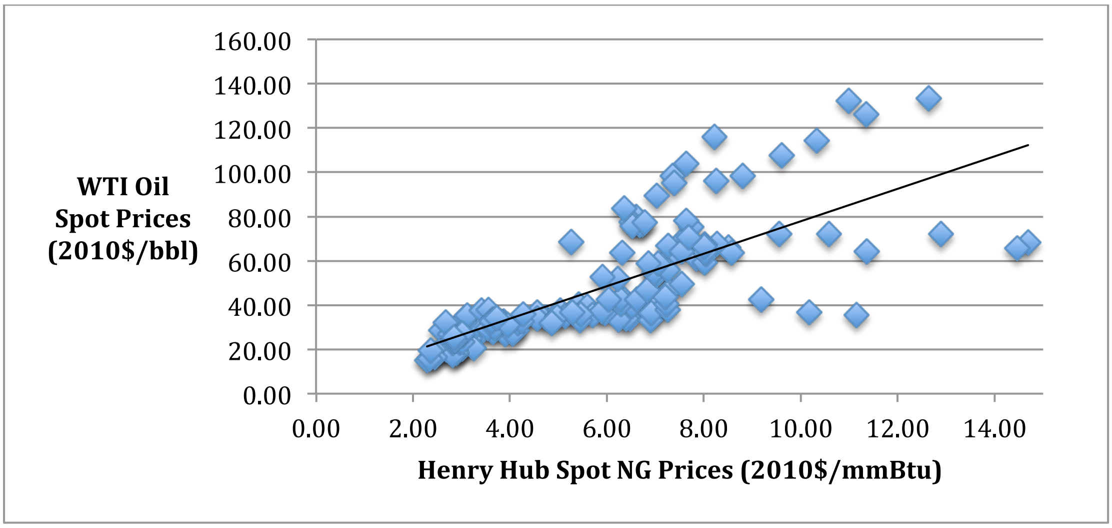
more recent correlation has an R-squared of only 0.16. It is unclear if the current lack of correlation will continue or if the historic relationship will return. Currently, with oil spot prices high and gas spot prices low, drilling assets are moving to more lucrative shale oil plays, and co-production of oil and gas may push the price spread closer to tighter historical levels. Such a pattern may drive natural gas prices higher.

Figure 12: Henry Hub Spot NG Prices vs. WTI Spot Oil Prices 1997-2012



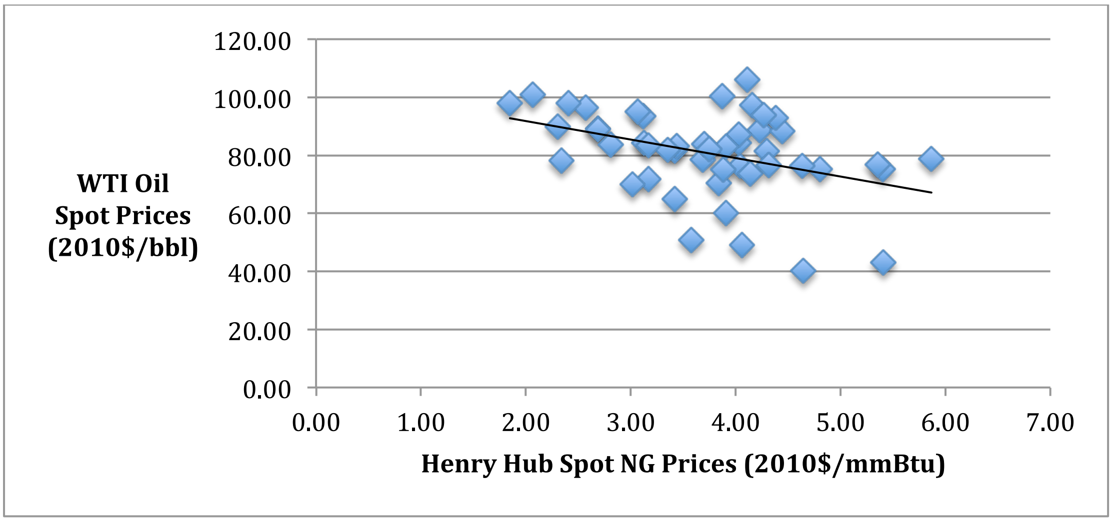
Data source: U.S. Energy Information Administration

Figure 13: Henry Hub Spot NG Prices & WTI Spot Oil Prices 1997-2008



Data source: U.S. Energy Information Administration

Figure 14: Henry Hub Spot NG Prices & WTI Spot Oil Prices 2009-2012



Data source: U.S. Energy Information Administration

A third potential factor is an increase in natural gas exports over the long term. Gas exports in a quantity to impact US spot prices appears unlikely in the near term due to the time required to construct liquefaction facilities and export terminals. However, the period of interest for this analysis is over twenty years. Global natural gas price spreads could certainly spur infrastructure investments over the time period large enough to influence US gas prices. In fact, there is evidence of significant political support, particularly from Republicans, for increasing natural gas exports.[27] A change in Congressional or White House leadership, or a policy change on the part of Democrats, could provide the policy support to allow gas exports to countries with which we do not share free trade agreements. Such a policy shift could then spur the necessary export infrastructure in years to come.

Other developments that could affect the price of natural gas over the medium to long term include higher-than-expected shale gas production costs,[28] sharper than expected well

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[27] Colman, Zack. "Rep. Ryan talks natural-gas exports with German chancellor." E2Wire. The Hill, 2013. Available at: http://thehill.com/blogs/e2-wire/e2-wire/290597-rep-ryan-talks-natural-gas-exports-with-german-chancellor

[28] As EIA explains in its Annual Energy Outlook 2012, production is not simply a function of the potential to get gas out of the well, but also the *cost* of doing so. A well may be "stimulated" many times through repeated

decline rates,[29] and new federal or state environmental regulations. The point is that many factors do, or potentially could, impact natural gas prices, and some combination of the aforementioned factors may, over the long-term, increase gas prices substantially above current forecasts.

This study attempts to capture these uncertainties through two natural gas price scenarios for the period 2013-2035. In addition to a reference case of stable prices based on EIA projections in its Annual Energy Outlook 2013 Early Release, I create an alternative gas price condition based on volatility in spot prices seen from 1999-2007 (see Figure 15). I do this by altering the forecasted EIA reference case price for each year, beginning in 2020, by the percent change from the previous corresponding year seen during the 1999-2007 period. In other words, 2020 prices reflect the same percentage price change seen from 1998 to 1999, 2021 prices reflect the percentage price change seen from 1999 to 2000, and so on. The result is gas prices that behave from 2020-2028 in identical fashion, in percentage terms, to what was seen from 1999-2007. For the remainder of the study time horizon, 2029-2035, gas prices increase annually by three percent, the average annual growth rate seen during the 1999-2007 period. I refer to this condition as “2020 NG shock.” This alternate price forecast is displayed graphically along with the reference case in Figure 16.

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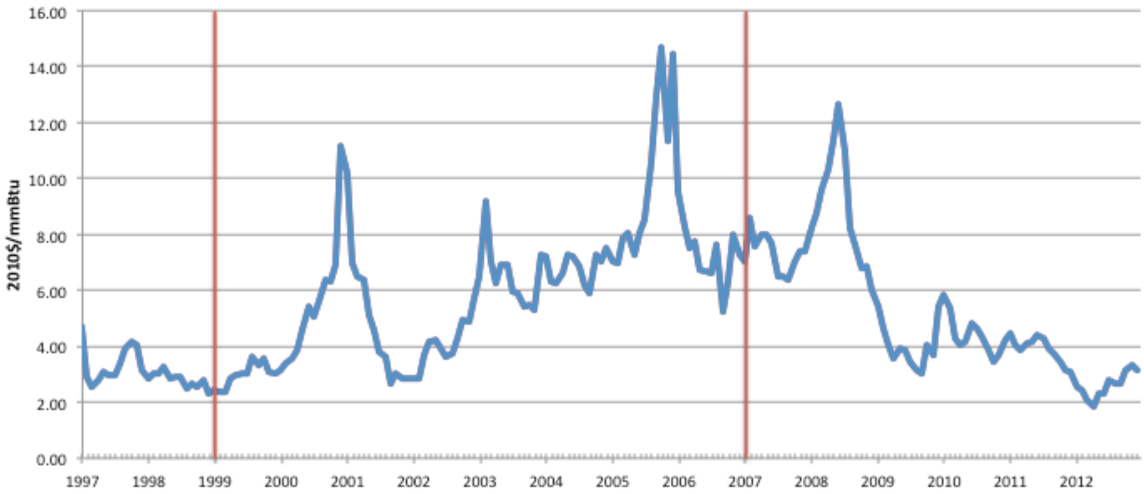
hydraulic fracturing, but the capital cost of doing so can be high, so the resulting production will not always justify the cost. Drilling for gas in shale formations is still relatively new, so if many wells produce less gas than expected after initial rounds of fracturing, additional fracturing to produce the expected gas may be uneconomical.

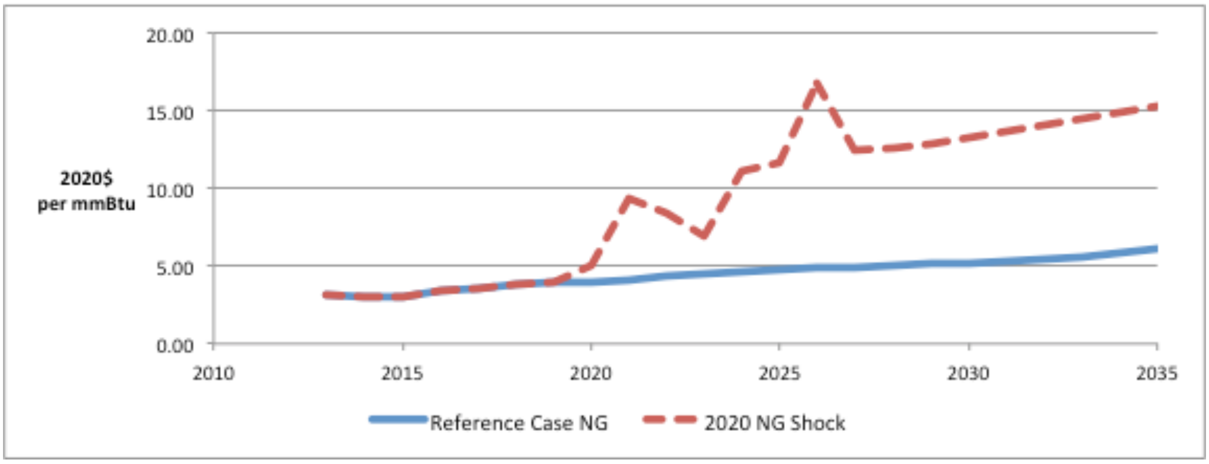
[29] The decline rate for a well is the rate at which production declines over time, usually many years. Some critics of EIA’s projections claim that EIA uses optimistic decline rates in its modeling. One such critic is petroleum geologist and energy consultant, Arthur Berman, whose critiques are summarized in a posting on the oil and gas blog, Oil Drum, available at http://www.theoildrum.com/node/8212.

Figure 15: Henry Hub Spot Prices 1997-2012



Data source: US Energy Information Administration

Figure 16: Natural Gas Conditions in the Analysis



Carbon Pricing

Despite the failure to pass national energy and climate legislation in 2009, most industry and policy experts expect that a mechanism for internalizing the negative externality of carbon dioxide emissions will eventually become law in the US. In this study, I examine the impact that one such mechanism, a national carbon tax, may have on wholesale electricity prices in the Southeast, PJM, and ISO-New England regions.

Policymakers, economists, and researchers have proposed numerous mechanisms to curtail carbon emissions in recent years. Two of these mechanisms, a carbon tax and a cap-and-trade system, are widely preferred by economists because of their ability to find the least-cost method of reaching emissions reductions.

A carbon tax seeks to curtail emissions by fixing the price of emitting carbon dioxide and allowing the free market to determine the resulting quantity emitted. Firms that emit will determine what portion, if any, of their emissions can be reduced for a lower cost than the tax, and what portion for which paying the tax is more economical. Firms will then adjust operations or install control equipment to abate the first portion, and simply pay the tax for the latter portion, thus minimizing their cost of compliance.

By contrast, a cap-and-trade system curtails emissions by fixing the quantity of emissions that is allowed in aggregate, and then allocating or auctioning off emission permits equal to that quantity. Firms again determine their individual marginal cost of abating each unit of emissions, and then are free to trade emissions allowances among themselves such that they minimize their total cost. Again, the result is the least-cost method of reaching the economy-wide emissions reduction target.

The carbon tax and cap-and-trade methods, while economically-efficient, face political challenges because the ease with which they can be publicized as imposing new taxes on businesses and (as the costs are passed down) consumers. This criticism has been particularly effective given the recent recession and sluggish recovery.

An alternative strategy is for federal or state policymakers to mandate that a certain percentage of electricity generation come from “clean” or renewable resources. At the federal level, this is commonly known as a Clean Energy Standard. In his 2011 and 2012 State of the Union addresses, President Obama urged Congress to pass a Clean Energy Standard that would require the US to produce 80 percent of its electricity from “clean energy sources,” which presumably would include natural gas.[30] This policy, or one like it, has not yet passed Congress. However, its goal, at least in part, is to reduce greenhouse gas emissions by spurring demand for and production of power generation that emits less carbon dioxide.

A similar policy at the state level is commonly known as a Renewable Portfolio Standard (RPS). RPS policies are now in place in 29 states, the District of Columbia, and two US territories.[31] An additional eight states and two territories have nonbinding renewable portfolio goals.[32] Unlike President Obama's proposed Clean Energy Standard, RPS policies mandate or encourage a percentage of each utility's electricity sales to be derived from entirely renewable sources, which excludes nuclear and gas-fired generation.

A final mechanism to curtail carbon emissions is through US Environmental Protection Agency (EPA) regulation of greenhouse gas emissions or associated pollutants under the Clean Air Act. In 2007, the US Supreme Court found in *Massachusetts v. EPA*[33] that the EPA must declare whether or not greenhouse gases constitute a pollutant as defined in the Clean Air Act. In 2009, the EPA reached a finding that the emissions of six key greenhouse gases do constitute a threat to public health and welfare and must be regulated under the Act.[34] Earlier this year, EPA proposed a Carbon Pollution Standard for New Power Plants that would set national limits on the amount of carbon pollution that power plants can emit.[35] Neither this regulation nor any other specifically targeted at greenhouse gas emissions from stationary sources, like power plants, under the Clean Air Act have been finalized, and

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[30] President Obama's State of the Union address to Congress, 25 Jan 2011. Available at: http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address. President Obama's State of the Union address to Congress, 24 Jan 2012. Available at: http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address.

[31] Database of State Incentives for Renewables and Efficiency (DSIRE). Available at: Dsireusa.org

[32] Id.

[33] Massachusets, et al., Petitioners *v.* Environmental Protection Agency et al. 415 F. 3d 50

[34] Regulatory Initiatives: Climate Change. US Environmental Protection Agency, 2012. Available at: http://www.epa.gov/climatechange/EPAactivities/regulatory-initiatives.html#stationary

[35] Id.

questions remain as to how precisely EPA will act in regulating carbon emissions under this statute.[36]

Other EPA rules targeting pollutants associated with power plant operations will likely have the side effect of reducing carbon dioxide emissions. The Mercury and Air Toxics Standards, finalized in 2011, targets heavy metals and acid gases from coal- and oil-fired power plants.[37] Also in 2011, EPA finalized the Cross State Air Pollution Rule, which would have imposed emissions limitations on power generation facilities in upwind states because of their adverse air quality impacts – in terms of ozone and fine particulate matter – on downwind states. However, the DC Circuit Court vacated the rule, and its future is now uncertain.[38] EPA issued in 2010 a proposed rule related to coal combustion residuals that would regulate, for the first time, coal ash that is produced from the burning of coal for power generation.[39] Finally, EPA has proposed new standards for cooling water intake structures at all existing power generating facilities.[40] These last two rules are in still in the development stage but could be promulgated in coming years.

My analysis will focus on a national carbon tax mechanism due to its simplicity for modeling purposes, its economic efficiency, and its reintroduction into the policy debate through, among other avenues, its inclusion in the recently-released Congressional

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[36] Monast, Jonas and Jeremy M. Tarr. Primer on GHG Regulation of Stationary Sources Under the Clean Air Act: Interaction of Tailoring Rule and Proposed NSPS. Working Paper, 2012. Available at: http://nicholasinstitute.duke.edu/climate/policydesign/primer-on-ghg-regulation-of-stationary-sources-under-the-clean-air-act/at_download/paper

[37] Mercury and Air Toxics Standards. U.S. Environmental Protection Agency, 2012. Available at: http://www.epa.gov/mats/

[38] Cross-State Air Pollution Rule. U.S. Environmental Protection Agency, 2012. Available at: http://www.epa.gov/airtransport/CSAPR/index.html

[39] Coal Combustion Residuals – Proposed Rule. U.S. Environmental Protection Agency, 2012. Available at: http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm

[40] Cooling Water Intake Structures – CWA §316(b). U.S. Environmental Protection Agency, 2012. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm

Progressive Caucus 2014 budget proposal.[41] I will examine three different carbon tax levels to offer a more robust analysis.

The first level is no carbon tax and will act as a baseline in the modeling of each region. The second and third levels are based on scenarios included in the 2012 International Monetary Fund's report, *Fiscal Policy to Mitigate Climate Change: A Guide for Policymakers*.[42] In the report, the authors use results from Stanford University's energy modeling forum (EMF-22) to identify ranges of emissions prices, beginning in 2020, that could stabilize atmospheric carbon dioxide concentrations at 450, 550, and 650 parts per million (ppm).[43]

In their summary, the authors report that imposing a carbon tax of roughly $20 per ton in 2020 and increasing that tax at 3-5 percent annually (in real terms) offers a reasonable likelihood of stabilizing the atmospheric concentration at 650 ppm, or a mean projected warming of about 3.6°C. They further state that a starting tax of roughly $40 per ton in 2020 and increasing similarly is recommended for stabilization at 550 ppm, or a mean projected warming below 3°C.[44]

These two carbon tax levels serve as the "low carbon tax" ($20 per ton starting in 2020) and "high carbon tax" ($40 per ton starting in 2020) conditions in my analysis. For both conditions, the tax level rises by five percent annually in real terms through the end of the study period in 2035. The two non-zero carbon tax conditions are displayed in Figure 17.

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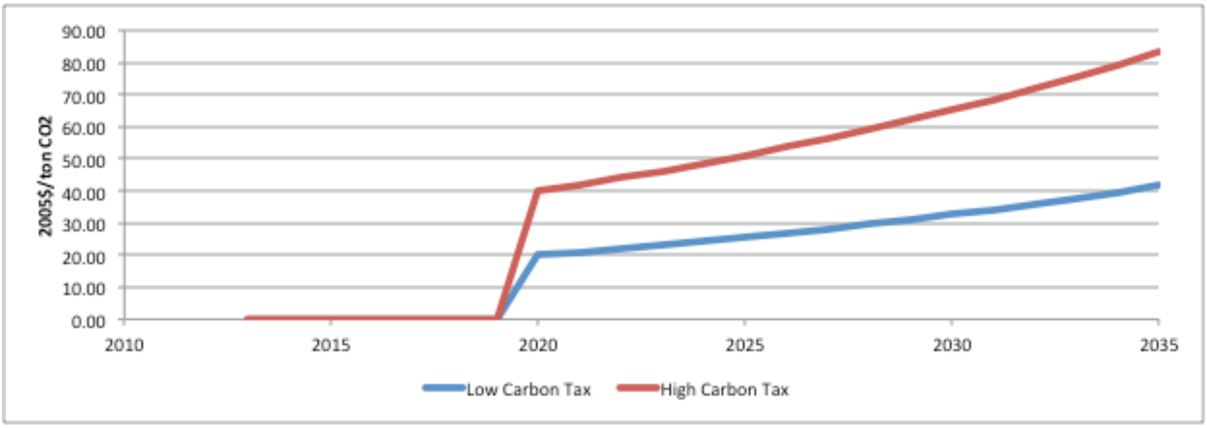
[41] Available at: http://cpc.grijalva.house.gov/back-to-work-budget/

[42] Fiscal Policy to Mitigate Climate Change: A Guide for Policymakers. International Monetary Fund. 2012.

[43] Id. at 57.

[44] Id. at 49.

Figure 17: Carbon tax conditions in the analysis



Electric Market Restructuring

Several studies have examined the relative performance of RTO and non-RTO markets.[45] The metric of interest is commonly wholesale or retail electricity prices because this is the metric that is directly felt by electricity customers. These studies, however, have been retrospective. My analysis incorporates different natural gas price and carbon tax scenarios to offer insight into how such factors would comparatively affect the three regions' future electricity prices and generation portfolios.

The recent economic recession significantly lowered economy-wide electricity consumption, but merely acted to slow rising retail electricity prices (see Figures 18 and 19). Economic growth is once again positive, and electricity demand is expected to grow, based on EIA projections. It is therefore reasonable to assume that concerns over accelerating electricity price increases will also return. The lower prices of natural gas have and will act to tamp down the increases, but the degree and duration of this effect is uncertain. My analysis will seek to shed some light on this uncertainty.

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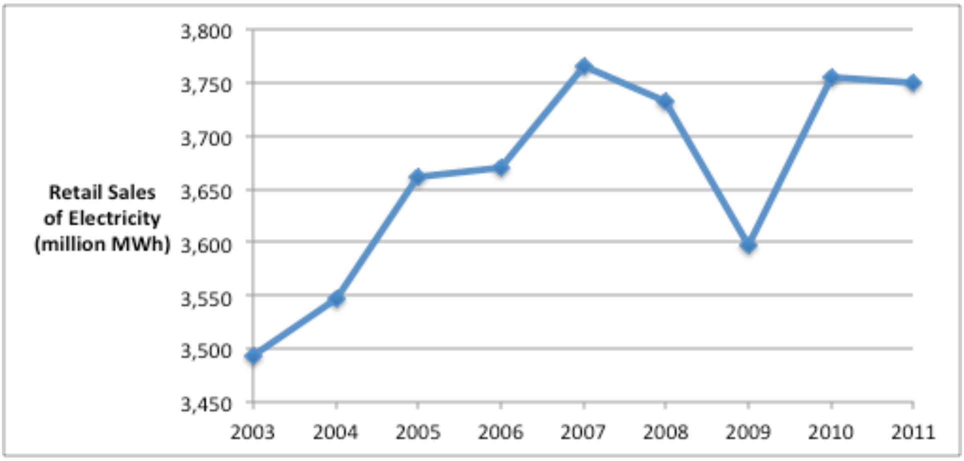
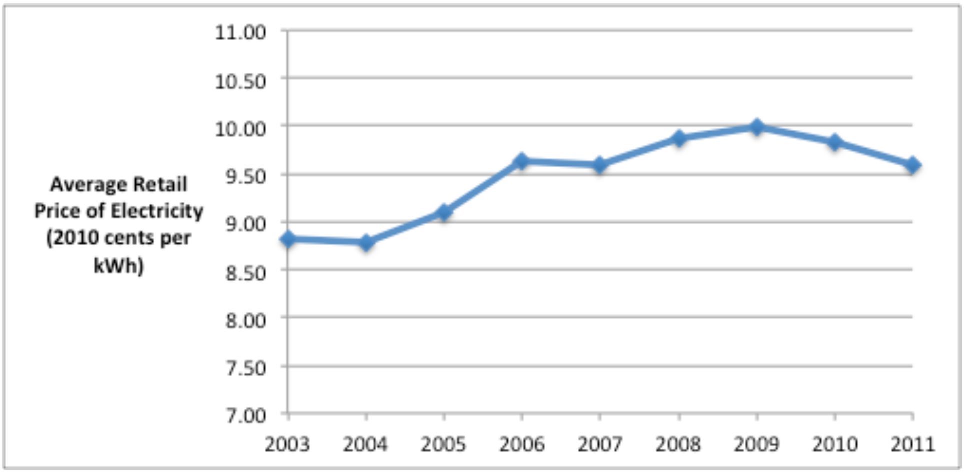
[45] These include "Retail Electric Rates in Deregulated and Regulated States: 2009 Update," American Public Power Association, 2010; Bodmer, Edward, "The Deregulation Penalty: Losses for Consumers and Gains for Sellers," 2009; "Retail Electric Price Rate of Change in PJM States is Lower Than the National Average," COMPETE Coalition, 2012.

Figure 18: Retail Electricity Sales 2003-2011



Data source: US Energy Information Administration

Figure 19: Average Retail Electricity Prices 2003-2011



Data source: US Energy Information Administration

In FERC's capacity as the regulator that seeks to ensure just and reasonable rates and foster competition in wholesale electricity markets, it too is concerned with wholesale electricity prices. Wholesale prices serve as a measure of the benefits of competition that are delivered to electricity customers in the form of least-cost service. Given long-established national policy of promoting increased competition in electricity generation, FERC is also concerned with the relative performance of utilities in traditionally-regulated territories and competitive wholesale generation markets.

FERC staff recently issued a report outlining performance metrics for non-RTO regions.[46] This report followed a similar one for RTO regions that was precipitated by a Government Accountability Office report that recommended FERC collect more data in order to better assess RTOs' costs and benefits.[47] Based on this more comprehensive data collection on performance metrics for both RTO and non-RTO regions, FERC will be better equipped to analyze not only benefits and costs within the regions, but also best practices.

Put another way, this development suggests that regulators will be assessing relative performance of regions and may seek to mandate certain operational characteristics that ensure reliability while minimizing electricity prices. FERC's landmark Order No. 1000, issued in 2011, sought, in part, to accomplish something similar with the construction of new electric transmission infrastructure by mandating inter-regional planning and the adoption of a cost allocation methodology in all regions.[48] It is reasonable to assume that similar actions related to wholesale market operations could follow in the future.

One of the leading researchers in this area, William Hogan of MIT,[49] has suggested that true open access and non-discriminatory transmission service may actually require an RTO-type market design. Mr. Hogan cites political obstacles as possibly the only reason FERC has not mandated this market design nationwide.[50]

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[46] "Performance Metrics in Regions Outside ISOs and RTOs." Commission Staff Report, Federal Energy Regulatory Commission, October 2012. Available at: http://www.troutmansandersenergyreport.com/wp-content/uploads/2012/10/AD12-8-Staff-Report.pdf

[47] "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance." Government Accountability Office, September 2008. GAO-08-987. Available at: http://www.gao.gov/products/GAO-08-987

[48] Full order available at: http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

[49] William W. Hogan is the Raymond Plank Professor of Energy Policy at the Massachusetts Institute of Technology and a past president of the International Association for Energy Economics. He has written extensively on the transition to a more competitive electricity market. More information available at: http://www.hks.harvard.edu/about/faculty-staff-directory/william-hogan

[50] Bewick, John A. "Bill Hogan: Unbundled." Public Utilities Fortnightly, November 2012. Available at: http://www.fortnightly.com/fortnightly/2012/11/bill-hogan-unbundled

Lastly, proponents of restructured markets, like Mr. Hogan and the COMPETE Coalition, cite ratepayer protection (i.e. avoided electricity price increases) as one of the major benefits of this market design.[51] In regulated markets, like the Southeast, investor-owned electric utilities do not bear the risk of failed investments if those investments have been pre-approved by state utility commissions. This approval grants the utilities the right to recoup those costs from their customers. An oft-cited example is the large build-out of natural gas power plants in the mid to late 1990s when natural gas prices were low. Gas prices moved sharply upward shortly thereafter, and many of those gas plants sat idle for nearly all hours in the year because power from alternate sources was then cheaper to produce. However, ratepayers still bore the cost of construction of the plants.

Contrast this, as Mr. Hogan does, with companies in restructured markets that faced the same dilemma. Instead of being able to pass construction costs on to ratepayers, many of these companies were forced into bankruptcy.[52] Thus, their investors bore the cost of the idled power plants rather than ratepayers. Proponents of restructured markets therefore argue that the risks in those markets are properly borne by the investors that are making the investment decisions. In regulated markets, ratepayers must rely upon their public utility commissions to determine - nearly always without the benefit of sophisticated modeling tools and vast experience - which investments are in the public interest and which are not.

For all these reasons, continued research on the operations of RTO and non-RTO markets and their relative abilities to adjust to changing policy and market dynamics is necessary, wise, and useful.

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[51] Id.

[52] Id.

SECTION III: AURORAXMP MODELING OVERVIEW

AURORAxmp is a power market model produced by the company, EPIS, Inc. As the company describes, it designed AURORAxmp "to provide the industry with a fast, accurate tool for planning and analysis" of the electric power sector.[53] The model's functions include electric market price forecasting; resource and contract valuation and net power costs; long-term capacity expansion modeling; and risk analysis.[54] I was granted use of the model through the Nicholas Institute for Environmental Policy Solutions at Duke University, which holds a license for AURORAxmp.

Two of AURORAxmp's functions proved valuable for this analysis: the long-term capacity expansion modeling, and the electric market price forecasting. The capacity expansion modeling uses market economics to build and retire generating resources over a specified time horizon. As EPIS describes, "AURORAxmp estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm."[55] Environmental constraints are also accounted for. The estimated prices and hourly dispatch determine relevant energy and capacity revenues and construction and operating costs, which are then used to calculate market values for existing and new resources. Using these market values, the model then optimizes capacity expansion over time.[56]

The power market price forecasting function in AURORAxmp forecasts wholesale electricity prices using multi-zone, transmission-constrained dispatch. The model simulates supply and demand on an hourly basis and optimizes unit commitment to determine on-peak,

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[53] About Us. EPIS, Inc., 2013. Available at: epis.com/company

[54] Power Market Forecasting. EPIS, Inc., 2013. Available at: epis.com/aurora_xmp/power_forecasting.php

[55] Optimized Resource Expansion. EPIS, Inc., 2013. Available at: epis.com/aurora_xmp/long_term_expansion.php

[56] Id.

off-peak, and average wholesale prices for zones, trading hubs, and operating pools. For organized electricity markets, the model employs bidding logic to simulate more realistic market decisions.[57] The user can adjust assumptions and all inputs, including the cost of emissions. Importantly for the price forecasting done in this study, the model does not have perfect foresight in regard to input variables like fuel prices. Therefore, dispatch of available resources will adjust “on the fly” to changes in those variables, allowing observation of the impacts of those changes using scenario analysis.

SECTION IV: ANALYTICAL APPROACH

Over the long term, portfolios can change in response to economic and policy realities. Existing resources can be uprated, retired, or mothballed, and new resources can be constructed and come online. But the investment and construction of electric generating units – particularly fossil fuel and nuclear units – require long lead times. A utility or region cannot immediately adjust its portfolio of generation assets in response to unexpected conditions. Over the short-term, it can only adjust the dispatch of existing resources to meet load with minimal cost increases. These cost increases ultimately translate to higher wholesale electricity prices.

Thus, my goal here is to assess the effect on wholesale electricity prices of each region’s adjustment to alternate future conditions after it has built its generating portfolio based on an expectation of low gas prices and no carbon tax. To accomplish this, I create six distinct natural gas price and carbon tax scenarios, and then utilize two of AURORAxmp’s capabilities: long-term capacity expansion modeling and economic dispatch modeling. Finally, I compare wholesale prices in each region for each scenario.

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[57] Power Market Price Forecasting. EPIS, Inc., 2013. Available at: epis.com/aurora_xmp/price_forecasting.php

The natural gas price conditions and carbon tax conditions described in Section II are crossed to create six distinct scenarios. Scenario 1 represents the baseline conditions, and Scenarios 2-6 represent alternate natural gas price and carbon price futures (see Table 3). See Appendix A for the complete natural gas and carbon tax conditions for each scenario.

Table 3: Scenario List

	No carbon tax	**Low carbon tax**	**High carbon tax**
Reference NG	Scenario 1	Scenario 2	Scenario 3
2020 NG shock	Scenario 4	Scenario 5	Scenario 6

The second step is to run AURORAxmp in long-term capacity expansion mode under the baseline conditions over the study period of 2013-2035. These conditions include Henry Hub natural gas prices matching the forecast in EIA's Annual Energy Outlook 2013 Early Release, and no carbon tax.[58] Based on these price and tax levels and other default inputs, and using AURORAxmp's Eastern Interconnect project file, I run the model once in long-term mode. The run produces a year-by-year list of generating resources, complete with operating characteristics for each. The list is a forecast of how each region would meet its electricity demand every year if the aforementioned baseline inputs are the expected future conditions. The model bases decisions to retire or add generating units on economic viability, which

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[58] As public statements from some utility executives and public integrated resource plans from some utilities are incorporating some form of a carbon price in their internal modeling, I considered using the "low carbon tax" conditions in the baseline for long-term portfolio optimization. However, since any such pricing is purely speculative and hypothetical at this time, I opted instead for a "business-as-usual" condition of no carbon tax throughout the study period.

itself is based on unit revenues and costs. In regions where capacity markets exist, revenues include both energy[59] and capacity revenues.[60]

The third step is to read this list of generating resources into one economic dispatch model run for each scenario in the analysis. An economic dispatch run calls upon the lowest-cost suite of generating resources in order to meet forecasted demand for each hour in the study period. The economic dispatch run does not, however, have the power to change the list of available generating resources; it must select only from the resources made available in the list produced by the long-term run. Combining the two run types allows me to observe how a region with a portfolio crafted for the baseline conditions adjusts its dispatch to meet load under alternate sets of conditions, and how that adjustment affects electricity prices.

In assessing the output from the economic dispatch runs, I focus on the ten-year period following the imposition of unexpected natural gas prices or carbon taxes to observe (1) how each region adjusts its dispatch (generation output) to respond to these changes, and (2) the effect of that adjustment on wholesale electricity prices. My assumption is that beyond the ten-year timeframe, a utility or region would have had time to invest in significant new generating infrastructure better tailored to the alternate version of fuel and tax conditions.

In the following section, I analyze three output metrics. The first is nameplate generation capacity from the long-term capacity expansion model run. This represents the total generating capacity, in megawatts (MW), that can be called upon to meet electricity load at a given time. This result establishes the "world" in which the economic dispatch runs must operate.

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[59] Revenues from the sale of electricity generation from the unit.

[60] Revenues from capacity payments to the unit's owner. Capacity payments come from competitive capacity markets, which are a method of "provid[ing] forward pricing signals to encourage retention of existing resources and development of new resources" in a region. (PJM Reliability Pricing Model (RPM)/Capacity Market. (PJM.com))

The second metric is generation output from the economic dispatch runs. This is the actual electrical output produced by each resource for each year in the simulations. Since dispatch decisions are based on economics, least-cost resources will be called first and the generation output will adjust quickly to factors that impact resource costs, like fuel prices and emissions taxes. In scenarios with higher natural gas prices, we expect to see more output from other generation types, which may be limited by the portfolio changes derived from the long-term capacity expansion run. This limitation is what regions may face in the future should portfolios shift heavily to natural gas and natural gas prices then move counter to expectations. Generation output changes under the two non-zero carbon tax conditions are less obvious because natural gas-fired generation produces fewer emissions than coal-fired generation but more than nuclear, hydropower, or other renewable generation sources. Observing dispatch decisions under the low and high carbon tax conditions is important to assessing how each region may adapt to a federal carbon pricing mechanism.

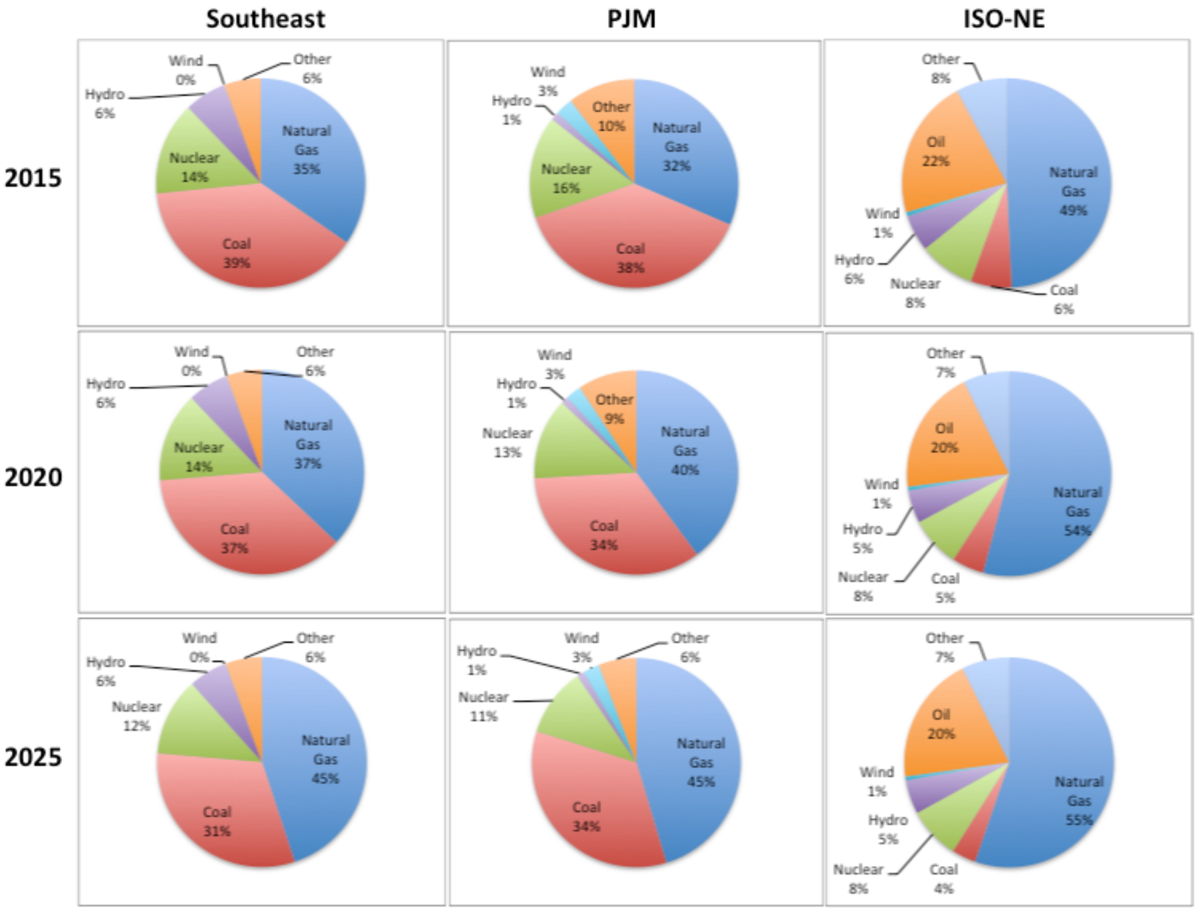
The third metric is wholesale prices from the economic dispatch runs. Wholesale prices serve as a proxy for the price impacts borne by ratepayers as conditions change. As I will describe in the following section, wholesale prices produced by the model will not be a perfect correlation with retail prices because the model does not account for fuel price-hedging strategies. Nonetheless, they provide an indication of retail price impacts and allow us to compare likely price impacts across the three regions under each scenario.

SECTION V: ANALYSIS OF RESULTS

Generation Capacity from Long-Term Resource Optimization Model Run

The highlight of the portfolio changes in the long-term optimization run is a dramatic build-out of natural gas-fired generating capacity.[61] Clearly driven by the stable, low natural gas prices of the reference case, this new gas generation comes, over time, at the expense of coal and nuclear in the Southeast and PJM regions, and of oil, nuclear, and coal in the ISO New England region. Gas capacity reaches a plurality of total capacity in all regions by 2020, and constitutes the majority of total generation in all regions by 2035. The full portfolio changes in five-year increments are shown in Figure 20.

Figure 20: Generation Nameplate Capacity Under Reference Case Conditions



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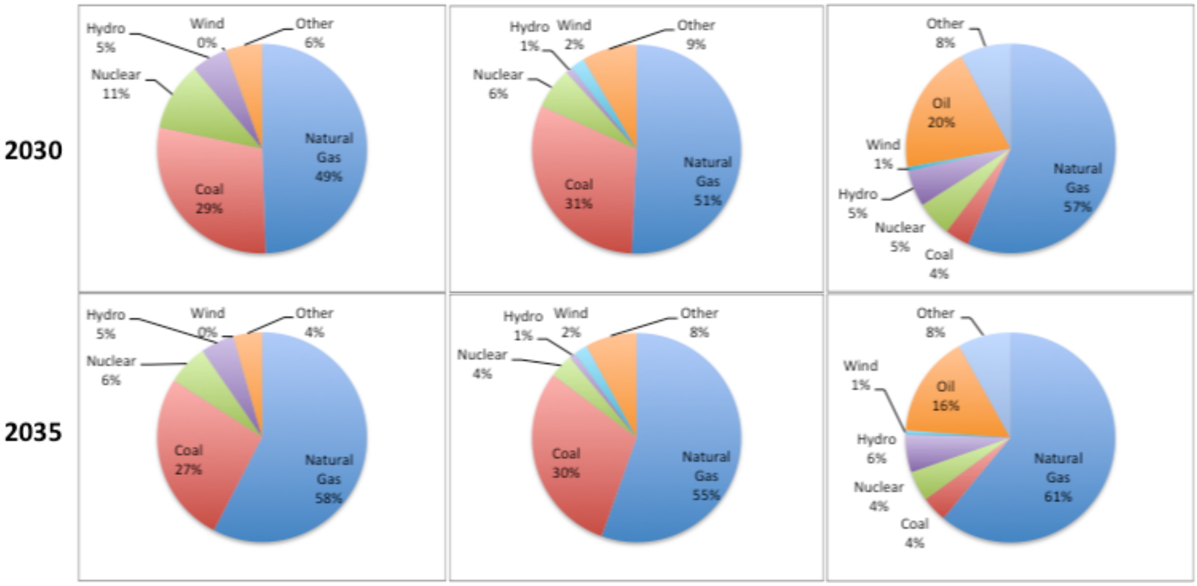
[61] Throughout this section, the term "capacity" is defined as nameplate capacity as measured in megawatts.



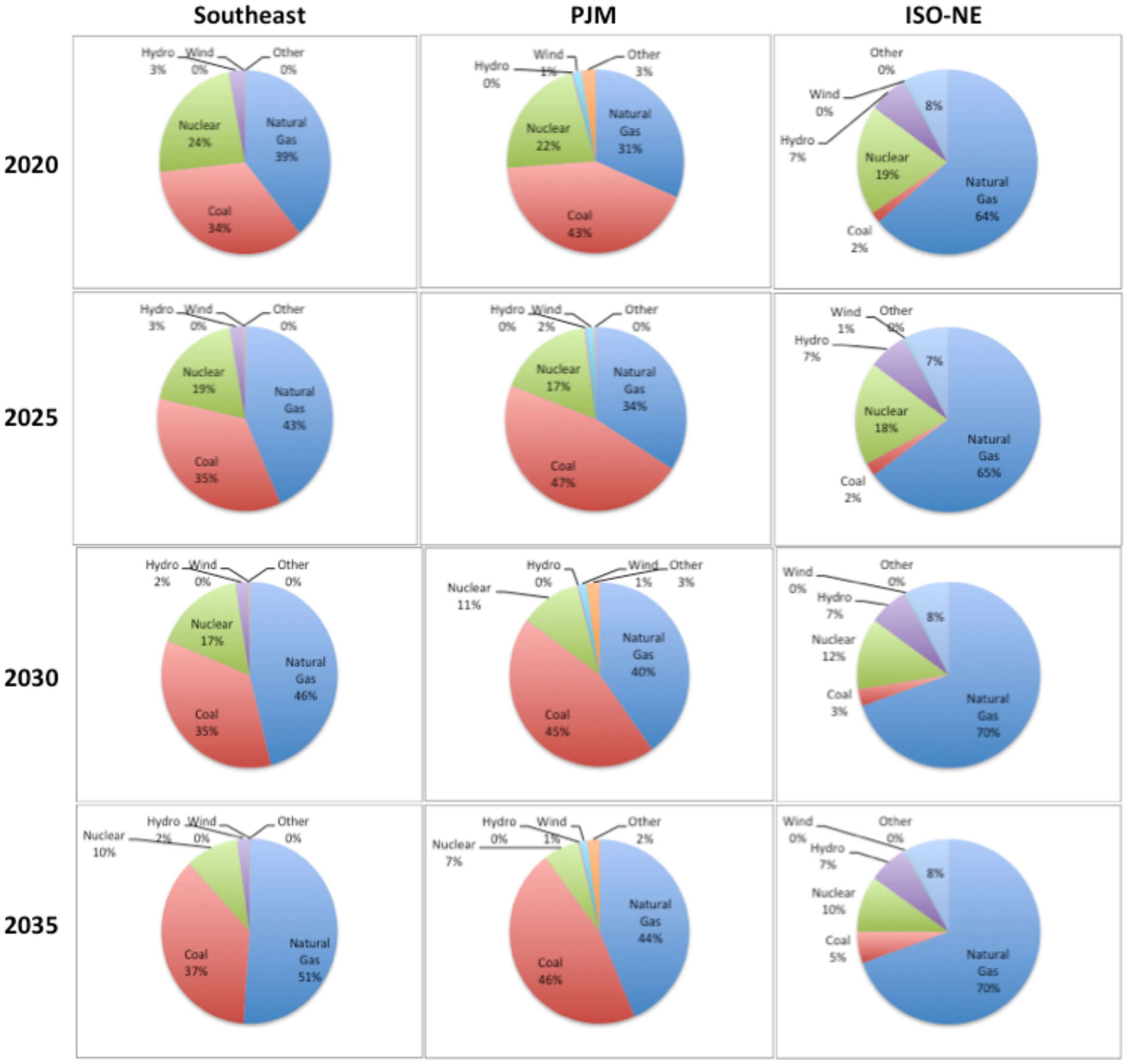
Even the ISO New England region, which begins with 49 percent natural gas-fired capacity in 2015, sees an increase to 55 percent by 2025, and 61 percent by 2035. More striking is that the Southeast and PJM begin to more closely resemble ISO New England as new gas capacity replaces coal. The Southeast and PJM retain perhaps greater flexibility with upwards of 25 percent still in coal capacity, but the marked shift to natural gas is clear.

For the successive economic dispatch model runs, these capacity levels represent the available generating capacity of each resource type that a utility or system operator can call upon to produce electricity to meet load. Individual resource characteristics – such as ability or inability to operate at partial output and fast or slow ramp rates – continue to influence dispatch choices, but the decrease in overall diversification of generating capacity reduces dispatch flexibility in all three regions. This change allows us to now assess the impact on wholesale electricity prices of unanticipated natural gas prices and carbon tax levels over the same study period.

Generation Output from Economic Dispatch Model Runs

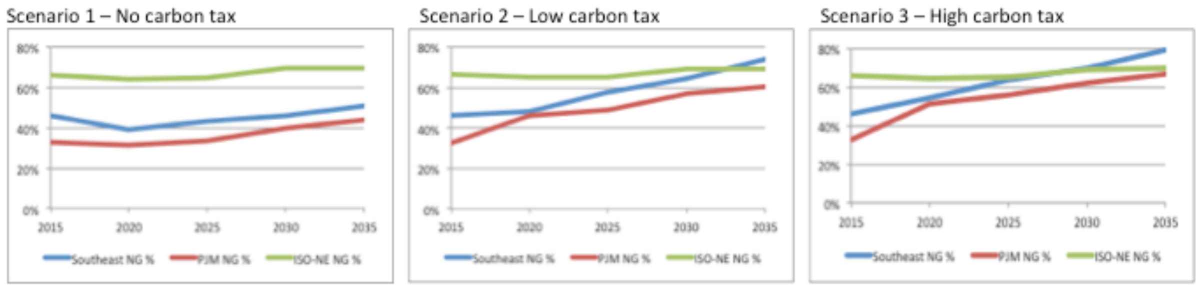
To compare outcomes under alternate natural gas price and carbon tax conditions, we first look to the outcome in the reference case, represented by Scenario 1. In the previous set of results, we saw a dramatic turn to natural gas generation as a proportion of total capacity. We see a more modest shift to gas generation as a proportion of output, particularly in the PJM region, where natural gas and coal output remain balanced all the way out to 2035. The shift to gas for output in the Southeast region is slightly less pronounced than the shift to gas for capacity in that region, with coal remaining over a third of total output from 2020-2035. ISO New England shows a shift to gas for output that is more pronounced than that for capacity. Natural gas represents 64-70 percent of total output throughout the period from 2020-2035. The full output changes in five-year increments are shown in Figure 21.

Figure 21: Generation Output Under Reference Case Conditions



Another visualization of the comparative role of natural gas generation is shown in Figure 22, which displays the percentage of total output from natural gas in each region. In the reference case, natural gas plays an increasing role in all regions, but the increase is only gradual in the Southeast and PJM and tops out at 45-50 percent. Compare this to the two carbon tax scenarios, Scenario 2 and Scenario 3, where natural gas output in the Southeast and PJM increases sharply upon the imposition of either tax in 2020. Under the low carbon tax, natural gas output increases from 43 to 57 percent in the Southeast, and from 34 to 49 percent in PJM. Under the high carbon tax, the same increases are from 43 to 64 percent and from 34 to 56 percent, respectively. The upward trend continues through 2030 for both regions.

Figure 22: Percentage Output from Natural Gas with Baseline Natural Gas Prices

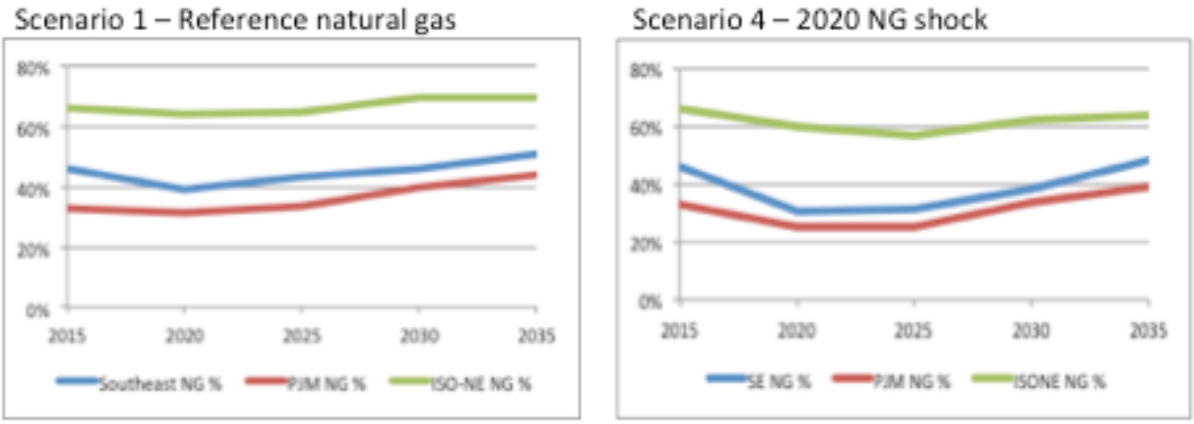


Both regions are adapting to a carbon tax by dispatching their natural gas generation in place of coal generation as the latter becomes more expensive due to the tax. Also notable is the nearly-nonexistent impact of either carbon tax level on ISO New England's natural gas dispatch. This is due both to ISO New England's limited capacity in lower-emitting resources, as well as to the minimal additional emissions cost of its gas generation, which we will see evidence of in the following section.

In Scenario 4, the 2020 NG Shock condition with no carbon tax, dispatch in the Southeast and PJM shows a sharper turn away from natural gas in 2020-2025 compared with the baseline scenario than does ISO New England (see Figure 23). They capitalize on their substantial coal capacity to dispatch coal generation instead of the increasingly expensive natural gas generation. Here is one example of the outsized influence fuel prices have over dispatch decisions compared with other generation resource costs, like operations and maintenance. Coal peaks as a proportion of output in the Southeast and PJM around 2025, reaching 47 percent and 54 percent, respectively. It then pulls back slightly by 2030 as coal capacity decreases from 2025-2030. ISO New England reacts similarly but again shows limited flexibility in adjusting to the increased natural gas prices, reducing gas output from 65 percent to 57 percent in 2025. Coal output picks up the slack, jumping from 2 percent of total output in the reference case to 9 percent.

The takeaway here is that all three regions deal with higher natural gas prices in the short term by ramping up output from coal generation. After about five years, however, the lack of new coal capacity begins to limit the regions' ability to offset the higher gas prices, and gas output increases despite the higher-than-expected fuel costs.

Figure 23: Percentage Output from Natural Gas Under 2020 NG Shock and No Tax



In Scenarios 5 and 6, where the natural gas price disruption is combined with a carbon tax, the tax initially causes higher dispatch of natural gas generation in the Southeast and PJM than in Scenario 4. In the initial years after the 2020 imposition of the tax, natural gas prices, while higher than anticipated, are not so high as to outweigh the cost implications of the tax. By 2025, gas prices reach a level high enough to override the tax effects and impact dispatch choices. Coal output is resurgent as gas output decreases substantially. The seesaw natural gas output levels are shown in Figure 24, and the gas-to-coal output ratio changes for the Southeast and PJM under the high tax conditions of Scenario 6 are shown in Figure 25 (Scenario 5 results exhibit similar behavior but with more coal output as the low tax does less to discourage coal generation). Natural gas output in ISO New England is virtually unchanged from the NG Shock –no carbon tax scenario.

Figure 24: Percentage Output from NG Under 2020 NG Shock and Carbon Tax

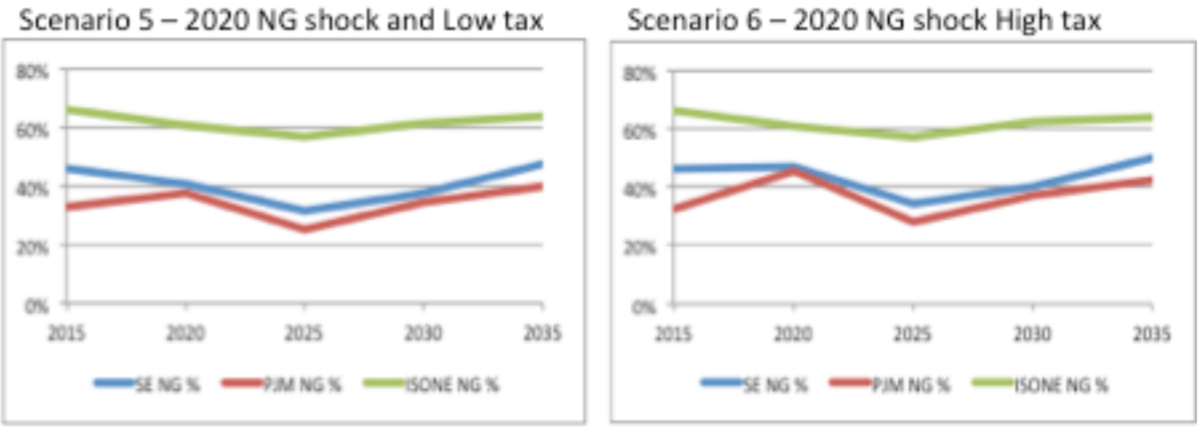
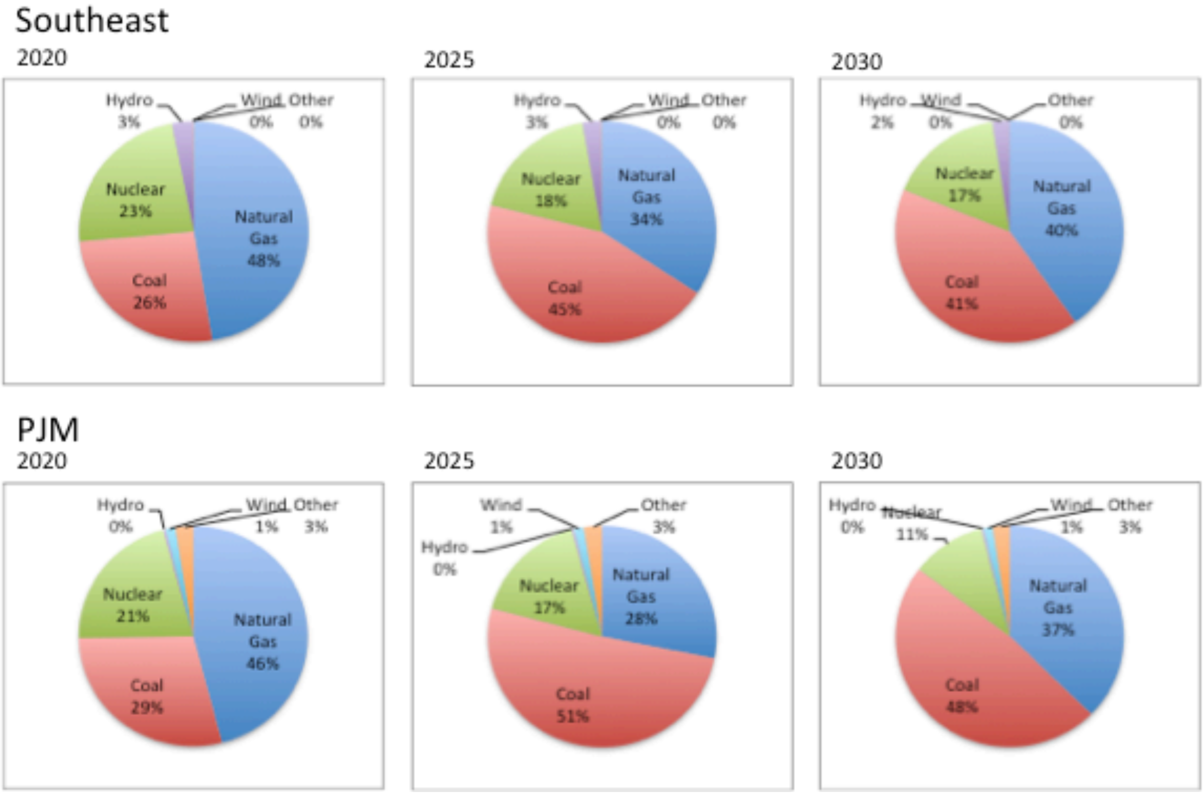


Figure 25: Generation Output Under 2020 NG Shock and High Carbon Tax



Of particular note here is the dramatic shift away from gas output in response to the higher natural gas prices even in the presence of a carbon tax. With gas prices low and stable, the Southeast and PJM regions shift rapidly to more resemble ISO New England with proportions of gas generation over 50 percent. However, when gas price increases reminiscent of the past decade are introduced to the forecast, the two regions' dispatch diverges sharply from that of gas-dependent ISO New England. As the Scenario 6 output demonstrates, this divergence occurs despite a high carbon tax dissuading coal generation. Even with that high carbon tax in place, gas output still shrinks to 34 percent in the Southeast and 28 percent in PJM by 2025.

Wholesale Electricity Prices from Economic Dispatch Model Runs

An important point to note before analyzing the wholesale electricity prices reported by AURORAxmp is that these results are independent of fuel price-hedging strategies. In reality, electricity price changes do not hew so closely to changes in natural gas prices because of hedging strategies employed by utility companies and generation owners. Thus, ratepayers are not vulnerable to fuel price swings to anything near the extent seen in the model's results. As described earlier, electricity prices display a lagging and moderated impact from fuel prices due to the purchase of futures contracts for various fuels. Nonetheless, fuel input prices represent a large share of power generation costs, and hedging strategies can offset fuel price increases for only so long.

Due to the difficulty in translating wholesale electricity prices from the model to electricity prices in the real world, I focus here on a comparison of prices produced by the model across the three regions to assess the *relative* ability of each to cushion ratepayers from the effects of fuel price fluctuations and the carbon tax.

In analyzing AURORAxmp's wholesale electricity price output, I focus on the period 2019-2030 because this captures electricity prices prior to alternate natural gas price and tax conditions (2019) through a point ten years after the onset of those alternate conditions (2030). As discussed above, the ten-year window following the onset of unexpected conditions is when the electric system is most vulnerable due to an inability to quickly shift infrastructure. Whereas I reported generation capacity and output throughout the study period to explain long-term changes, this shorter ten-year period provides the most meaningful results from a price standpoint. To analyze price output beyond that period would be misleading, as utilities and regions would have adequate time to make large-scale generation investment changes to adapt to alternate gas price and carbon tax conditions.

I report electricity price results in the form of a compound average growth rate (CAGR) seen in the regions for the 2019-2030 period. This metric allows for an effective comparison of electricity price results across regions and serves as a reasonable, if imperfect, proxy for price effects ultimately borne by ratepayers under conditions that persistently deviate from those in the reference case.

The electricity prices across the three regions show a high correlation in the reference case, as expected. With reference case natural gas prices and no carbon tax throughout the study period, the Southeast, PJM, and ISO New England show wholesale price increases between 2019 and 2030 of 1.8 percent, 1.9 percent, and 2.4 percent, respectively. These minimal growth rates reflect the benefit of perfect foresight of fuel prices and the lack of additional carbon pricing beyond regional schemes already in place.

The imposition of the two carbon tax scenarios, however, has varying impacts on the three regions' prices. While ISO New England sees a minimal jump in growth rate with the tax – 2.7 percent with a low tax and 2.9 percent with a high tax – the Southeast and PJM experience far greater impacts, seeing growth rates jump to 5-6 percent with a low tax and 8-9 percent with a high tax (see Table 4).

Table 4: Compound Annual Growth Rates Under Carbon Tax Conditions

	Scenario 1: Reference NG No carbon tax	**Scenario 2: Reference NG Low carbon tax**	**Scenario 3: Reference NG High carbon tax**
Southeast	1.8%	5.9%	9.2%
PJM	1.9%	5.3%	8.2%
ISO New England	2.4%	2.7%	2.9%

With a carbon tax level in place and continued low natural gas prices, ISO New England has a clear advantage over the more coal-heavy regions. The Southeast and PJM have limited options for reducing carbon emissions beyond shifting dispatch to natural gas to the extent possible. Beyond that, they must pay the tax on coal emissions and see electricity prices rise.

Also of note is that neither tax condition substantially alters ISO New England's electricity prices, suggesting that a gas-heavy region can comfortably adapt to even a $40 per ton tax. This may explain a lack of hesitation about shifting substantially to more gas generation in regions with historically diversified portfolios. Gas-heavy regions with minimal coal generation appear adaptable to a future with carbon pricing and low, stable gas prices, the outcome anticipated by forecasts like EIA's. The data here supports a rapid effort to replace coal capacity with gas capacity to meet this version of the future.

This advantage is erased when natural gas prices rise and no carbon tax is imposed (see Table 5). All three regions experience a substantial rise in electricity prices, with the steepest increase occurring in ISO New England and PJM. Here we see the pitfall of investing heavily in gas capacity based on forecasted low gas prices. With reference case assumptions, gas capacity reaches 45 percent of total capacity in both the Southeast and PJM by 2025. While still less than ISO New England's 55 percent at the same year, the shift nonetheless means the regions have little recourse in adapting to sustained higher-than-expected gas prices.

Table 5: Compound Annual Growth Rates Under 2020 NG Shock Condition

	Scenario 1: Reference NG No carbon tax	**Scenario 4: 2020 NG Shock No carbon tax**
Southeast	1.8%	8.8%
PJM	1.9%	9.2%
ISO New England	2.4%	9.2%

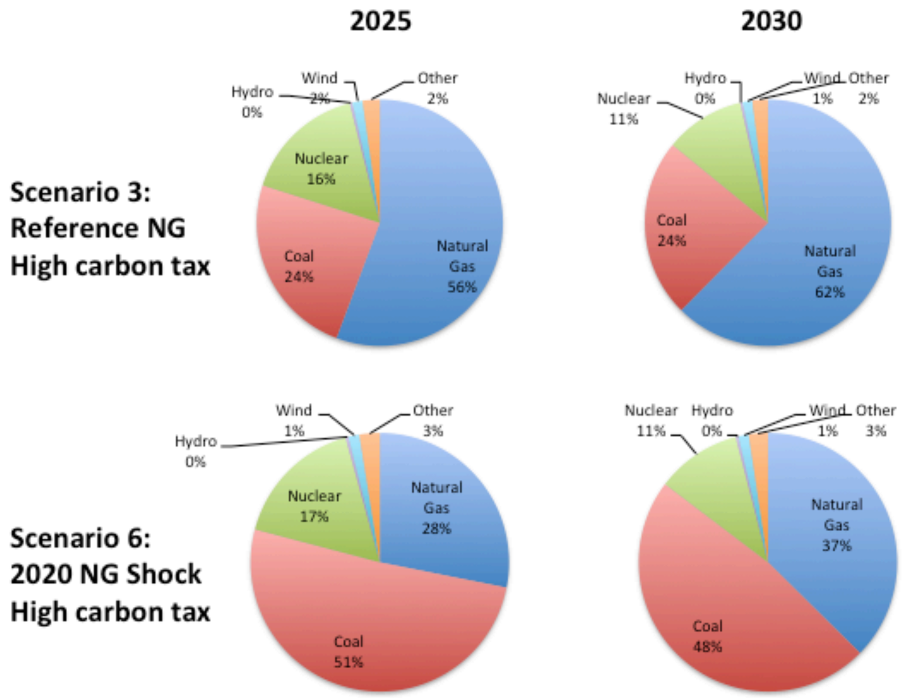
When the higher natural price and carbon tax conditions are combined, ISO New England's advantage reemerges, though to a far lesser degree than in the tax-only scenarios (see Table 6). The advantage grows with the higher tax level, as ISO New England's prices grow by 9.7 percent compared with the other regions' 11.6 percent. This again reflects ISO New England's ability to absorb the added expense of the carbon tax with little additional impact on electricity prices. The Southeast and PJM, on the other hand, now experience the compound effect of the higher fuel price and carbon tax on emissions.

Table 6: Compound Annual Growth Rates Under 2020 NG Shock & Carbon Tax

	Scenario 1: Reference NG No carbon tax	Scenario 5: 2020 NG Shock Low carbon tax	Scenario 6: 2020 NG Shock High carbon tax
Southeast	1.8%	10.2%	11.6%
PJM	1.9%	10.4%	11.6%
ISO New England	2.4%	9.5%	9.7%

The higher gas price prevents these two regions from switching dispatch largely to gas generation similar to in Scenarios 2 and 3. Compare, for instance, the large difference in PJM's coal and gas output in the two high carbon tax scenarios in Figure 26. The effect of the rising gas prices outweighs that of the carbon tax, and both PJM and the Southeast opt for substantial coal dispatch while absorbing the carbon tax cost for the additional emissions from coal generation.

Figure 26: PJM Generation Output Comparison in Two High Carbon Tax Scenarios



SECTION VI: CONCLUSION AND AREAS FOR FUTURE RESEARCH

The AURORAxmp results predict that current conditions and assumptions will lead to continued disproportionate natural gas capacity additions. If these additions do occur, the model results also suggest that higher-than-expected gas prices could mean markedly higher wholesale electricity prices. This holds true regardless of whether a region retains substantial coal capacity to which dispatch can shift during high gas price times.

From 2002 to 2008, the average retail electricity price in the ISO New England states rose by 23.7 percent in real terms. Contrast this with the national average of 13 percent over that same time.[62] Based on average US household electricity usage, a 23.7 percent increase in rates would equate to $352 in extra energy costs over a year. If regions like the Southeast and PJM shift their capacity sharply to natural gas, they will become vulnerable to similar increases. The comparable annual growth rates of nearly 9 percent seen in the model results across all three regions for Scenario 4 bear this out.

On the other hand, the results suggest that regions with a higher proportion of natural gas generation will exhibit lower electricity prices if gas prices remain low, even in the presence of a carbon tax. In the results, ISO New England was able to absorb the effects of the carbon tax with minimal effect on wholesale prices. In a world of low gas prices, the Southeast and PJM would quickly replace retiring coal with gas generation and see no ill effects, holding other factors constant.

The results show no major benefit to the restructured market design. ISO New England is largely cushioned from the electricity price impacts of a carbon tax in Scenarios 2 and 3, but this appears solely due to its higher proportion of gas generation, since PJM does not show a similar outcome. Additionally, both PJM and ISO New England face electricity

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[62] Based on U.S. Energy Information Administration data on historical average annual retail electricity rates.

price increases on par with the Southeast under higher gas price conditions, both with and without a carbon tax. However, AURORAxmp can forecast neither competitive market behavior nor state utility commission decisions with perfect accuracy, so it remains possible that ratepayers in restructured markets would fare better under the higher gas price scenarios, as investors would bear the brunt of idled gas plants. These results do not provide a definitive answer to that question though.

The chief finding in this study is that policymakers should strongly consider the uncertainty of future natural gas prices when assessing plans to meet future electricity demands. The large-scale shift to gas generation now being driven by market forces will diminish portfolio diversification and potentially leave ratepayers vulnerable to substantial rate hikes. A rise in gas prices similar to the one in the early 2000s would likely have an even greater impact on a heavily gas-reliant region than was seen then. Generation from coal and nuclear is on the decline because new units cannot be permitted or financed. The Southeast has been the recent exception to this trend, with plants in Georgia and South Carolina receiving permits, but both are several years away from coming online and more widespread deployment of nuclear appears doubtful. Wind generation is growing rapidly in certain midwest and western regions, but onshore wind potential along the eastern seaboard is limited and offshore wind remains expensive. With no emerging alternatives, retiring coal and nuclear generation will be replaced almost entirely by natural gas in the eastern US.

An increased rate of coal retirement from EPA rules will exacerbate the loss of portfolio diversification, particularly in the Southeast and PJM. According to a Brattle Group report, as of October 2012, there were 15 gigawatts of coal capacity announced for retirement in PJM, representing over 19 percent of that region’s coal capacity. The report predicted another 14-21 gigawatts (18-27 percent) – depending on the outcome of pending EPA rules –

would be retired in coming years.[63] The same report found 7 gigawatts of announced retirements in the SERC region, with another 27-30 gigawatts at risk of retirement.[64] These figures do not include any national carbon emissions-reduction policy.

Assessing risks in the electric power sector is a complicated task. While the results described above indicate substantial risk of higher electricity prices under certain future conditions, more research is needed on this topic, particularly in order to offer recommendations for maintaining portfolio diversification. One obvious area for further research is assessing how other, more diversified portfolios might perform under these scenarios. Among these alternative portfolios in the Southeast and PJM should be some that assume more coal retirement than appears in this iteration of AURORAxmp's long-term capacity expansion run, as this outcome appears increasingly likely.

Another area of related research would be to assess what increase in baseline electricity prices would be necessary to diversify these portfolios enough to reduce the risk of sharper price increases. If little or no new coal and nuclear generation is added, diversification will require alternative generation sources, and these are likely to raise electricity prices overall. Research assessing risk probabilities might offer policymakers a more concrete sense of what the cost of the price "insurance" would be to electricity customers in each region.

The role of demand side management and renewable energy generation may also be understated in my long-term results. Demand response resources have begun playing an increasing role in PJM's recent forward capacity markets, for instance. Might this participation provide meaningful risk mitigation? Likewise, will steep cost reductions in solar generation equipment and new, creative financing structures for distributed solar generation

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[63] Celebi, Metin, Frank Graves, and Charles Russell. "Potential Coal Plant Retirements: 2012 Update," Oct 2012, at 7 Available at: www.brattle.com/_documents/UploadLibrary/Upload1082.pdf

[64] Id. at 6.

allow this energy source to play a more meaningful role in the eastern U.S. within the next decade or two? Reduced costs of undersea transmission lines may also open up offshore wind resources along the eastern seaboard. And both of these sources could proliferate broadly with a breakthrough in energy storage technology. Solar and wind generation are both free of fuel price risk, so their large-scale deployment would drastically reduce overall price risk in any portfolio. Future research might assess the necessary market penetration of these alternate resources to offset the price risk of an increase in gas generation.

If the electricity price risks demonstrated by the findings here are substantiated by future research, policymakers may want to consider additional policy support for alternate generation types. This support could take many forms, but two possibilities are expanded and strengthened RPS mandates, and financing support for nuclear power.

Low natural gas prices are causing some states to reconsider their RPS goals, but these policies do drive demand for generation that – at least minimally – diversifies portfolios. All PJM and ISO New England states currently have some form of RPS mandate or goal in place. In the Southeast, however, only North Carolina currently has a RPS policy. Further proliferation of RPS goals throughout the Southeast, or implementation of a federal RPS or clean energy standard, would add more diversification to new capacity additions in the eastern US. In fact, the diversification benefit may provide an economic argument for stronger RPS goals, rather than the traditional environmental argument.

Another option is to support new nuclear generation. Lengthy permitting, inability to obtain financing, and ambivalent public sentiment toward nuclear power are obstacles that cannot be overcome without new policy or, perhaps, reduced size (and thus cost) of new nuclear-generating units. Since Fukushima, federal support for nuclear has disappeared, and cash-strapped states are unlikely to fill the void. In this challenging environment, smaller, modular nuclear reactors may stand the best chance of reaching deployment, but none has ever been permitted by the Nuclear Regulatory Commission. Renewed federal policy support might spur utility companies to invest in this new form of nuclear power.

APPENDIX A

Natural gas price conditions

All prices are in 2010$/mmBtu

Year	Reference Case NG	2020 NG Shock
2013	3.15	3.15
2014	3.03	3.03
2015	3.02	3.02
2016	3.46	3.46
2017	3.58	3.58
2018	3.84	3.84
2019	3.92	3.92
2020	4.01	5.09
2021	4.13	9.32
2022	4.34	8.36
2023	4.53	6.98
2024	4.64	11.14
2025	4.72	11.67
2026	4.87	16.80
2027	4.94	12.51
2028	5.06	12.57
2029	5.14	12.85
2030	5.23	13.23
2031	5.37	13.63
2032	5.46	14.04
2033	5.60	14.46
2034	5.85	14.90
2035	6.13	15.34

Carbon tax conditions

All prices are in 2010$/ton

Year	No carbon tax	Low carbon tax	High carbon tax
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	20.00	40.00
2021	0.00	21.00	42.00
2022	0.00	22.05	44.10
2023	0.00	23.15	46.31
2024	0.00	24.31	48.62
2025	0.00	25.53	51.05
2026	0.00	26.80	53.60
2027	0.00	28.14	56.28
2028	0.00	29.55	59.10
2029	0.00	31.03	62.05
2030	0.00	32.58	65.16
2031	0.00	34.21	68.41
2032	0.00	35.92	71.83
2033	0.00	37.71	75.43
2034	0.00	39.60	79.20
2035	0.00	41.58	83.16