Implications of changing natural gas prices in the United States electricity sector for SO$_2$, NO$_X$ and life cycle GHG emissions

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Abstract

Projections of increased domestic natural gas supply and low prices have encouraged increased natural gas utilization in the United States electricity sector. Natural gas can offset coal, likely decreasing overall greenhouse gas (GHG) emissions and other air emissions such as SO$_2$ and NO$_X$. Previous life cycle assessment (LCA) studies using limited system boundaries have attempted to quantify the benefit of offsetting coal use. However, these studies do not consider that relative regional fuel prices may contribute most to the choice of coal over natural gas. External incentives such as low natural gas prices compared to coal are required if natural gas is to displace coal. In this study, simplified economic dispatch models are used to determine how natural gas utilization will increase in the short-term in response to changes in natural gas prices in three US grid regions—ERCOT, MISO and PJM. The results indicate that the change in air emissions is lower than suggested by LCAs, since LCAs generally do not include the complexity of regional electricity grids. For instance, this study estimates that life cycle GHG emissions may, at best, decrease by 7–15% due to low natural gas prices, compared to almost 50% reductions estimated by previous LCAs.

Keywords: natural gas, coal, electricity, emissions, dispatch model

Online supplementary data available from stacks.iop.org/ERL/7/034018/mmedia

1. Introduction

The electricity sector accounted for 40% of the total energy-related carbon dioxide emissions in the US in 2009, of which almost 80% was due to coal use [1]. Natural gas has recently been considered a near- and medium-term lower carbon alternative to coal in the electricity sector [2, 3], especially due to projections of low natural gas prices and increased supply. The trend of increasing natural gas use in the electricity sector is already evident. According to the US Energy Information Administration (EIA), efficient combined cycle natural gas plants that were previously used to meet peaking or intermediate loads contributed more to baseload
power between 2005 and 2010, with a 6–10% point increase in their capacity factors (from 26 to 32% between 10:00 p.m. and 6:00 a.m., and from 40% to 50% between 6:00 a.m. to 10:00 p.m.) [4].

Various recent studies have estimated the comparative greenhouse gas (GHG) emissions of using natural gas over coal for electricity generation, considering not just emissions from fuel combustion, but the entire life cycle of the two pathways (including upstream effects such as GHG emissions from coal mining, natural gas production and processing and transport). These life cycle assessment (LCA) studies have generally concluded that GHG emissions of coal-fired electricity are higher than natural gas by up to 50% on a kWh basis [5–10]. Other studies [7, 11–13] suggest that ignoring uncertainty in life cycle GHG emissions of different fuel technology options in climate policies can increase the risk of policy failure (i.e., of not meeting emissions reduction goals). In addition, most LCA studies make the assumption that 1 kWh of natural gas-fired electricity generation can replace 1 kWh of coal-fired electricity generation. This study attempts to overcome these two limitations, outlined as follows.

Power plants are dispatched (i.e., put into operation) to meet electricity demand in different areas based on the marginal costs of generating 1 kWh of electricity, where plants with lower marginal costs are dispatched first, provided operational constraints are met. Coal has predominantly been cheaper than natural gas and has been used preferentially over natural gas to meet baseload power [14]. Natural gas can be used to displace coal only if external incentives to do so are available. For example, Newcomer et al [14] studied the effects of a carbon price that would penalize the emissions from coal-fired plants, resulting in the increased use of natural gas and other low carbon electricity sources and consequently reduced emissions. At a carbon price of $30 per metric ton, they estimated that GHG emissions would decrease by 2%, assuming that the price elasticity of electricity demand is zero. As another example, decommissioning coal plants due to policy mandates before building new capacity would also result in increased natural gas use—an issue addressed in a parallel study by Venkatesh et al [15]. Expecting to achieve up to 50% reductions in GHG emissions by offsetting all coal use with natural gas, as suggested by previous LCAs, is likely to be an overestimate. It is therefore critical to expand the life cycle system boundary to include all existing plants in a power grid, examine ways that could incentivize increased natural gas use, and estimate the corresponding decrease in carbon and other air emissions in order to calibrate potential reductions. This study examines how low natural gas prices could incentivize increased natural gas use in the electricity sector in the short-term.

Low natural gas prices in the short-term will reduce generation costs, making natural gas generation cost-competitive with other types of electricity generation, and likely displacing some coal-based electricity. This concept has been modeled in two other recent studies. The US EIA estimated the change in fuel mix due to low natural gas prices in the Southeast US through the development of regional supply curves [2]; this study, however, did not analyze the changes in air emissions. Lu et al [16] developed an econometric model and determined that half of the total reduction in US power sector GHG emissions in 2009 (about 4%) is attributable to a shift of electricity generation from coal to natural gas, especially due to reduced natural gas prices.

Between 1990 and 2007, nearly 170 GW of natural gas combined cycle capacity and 90 GW of peaking turbines were built in the US [3]. Due to high natural gas prices in the 2000s, much of the natural gas plant capacity remained underutilized. While sustained low natural gas prices and enforced environmental regulations on air quality could see the construction of new natural gas capacity in the medium-to-long term, in the short-term utilities are likely to be wary of building new capacity that may once again be underutilized if gas prices increase [17]. Therefore, this analysis assumes that no sudden increase in natural gas-based electricity infrastructure development occurs in the short-term.

This study quantifies the increased utilization of existing natural gas capacity in the electricity sector and the corresponding reductions in air emissions due to natural gas price variation. These issues are explored through the development of simplified economic dispatch models for three US electricity grid regions: the Electric Reliability Council of Texas (ERCOT), the Midwest Independent System Operator (MISO) and PJM Interconnection (including Pennsylvania, Ohio, New Jersey and surrounding states), in conjunction with historic load data. Fuel life cycle GHG emissions factors (including uncertainty ranges) are obtained from previous studies. The implications of the consequent changes in fuel use and air emissions are discussed.

2. Methods

2.1. Grid selection

Capacity and generation data from the 2007 Emissions and Generation Resource Integrated Database (eGRID) released by the Environmental Protection Agency (EPA) [18] indicate that a significant fraction of electricity in the MISO, PJM and ERCOT areas was generated by coal plants (70% in MISO, 60% in PJM, and 35% in ERCOT) in 2007. While these areas had substantial natural gas capacity in 2007 (25% of all capacity in MISO and PJM, 40% in ERCOT), much of this capacity was underutilized, as indicated by their average capacity factors (10% in MISO and PJM, 30% in ERCOT). This suggests that there are short-term opportunities in these areas to move away from coal-fired generation by using existing natural gas capacity, which can result in lowering air emissions. The three areas were selected for this analysis based on these factors, and since they are some of the largest in the US (above 70 GW) in generating capacity [19].

2.2. Base case

For the base case, simplified economic dispatch models were developed to simulate the order in which power plants are dispatched to meet electricity load, following methods in
Newcomer et al [14, 20] and Blumsack et al [21]. It was assumed that the order of dispatch is based on short-run marginal costs of generation, with the cheapest plants being dispatched first. Consistent with these previous studies, and as a result of insufficient data, no transmission constraints were modeled in this work. Since marginal cost data for individual plants are not publicly available, heat rates from eGRID [18] and regionally applicable fuel costs were used to estimate marginal costs, and hence dispatch order. Recent (from 2011) and regionally appropriate fuel costs reported by the US Energy Information Administration (EIA) [22], and marginal prices of electricity production from Newcomer et al [14] were used to estimate supply curves of electricity generation (the order in which power plants are dispatched to meet load). The values used are shown in the supporting information (SI) (available at stacks.iop.org/ERL/7/034018/mmedia).

A few modifications to the methods used in Newcomer et al [14, 20] and Blumsack et al [21] were made. First, given that the most recent eGRID data provides information about plants existing in 2007 only, it was updated with data for planned–committed units scheduled to come online between 2007 and 2011, obtained from the National Electric Energy Data System [23] used by the EPA. Second, generating units cannot operate for all hours in a year due to planned maintenance and forced outages. The time for which these units are available to generate electricity is represented by an availability factor, as a percentage of nameplate capacity. The availability of the individual power plants were taken from data used to develop the US EPA's Integrated Planning Model (IPM) [24] and are accounted for in the supply curve. For hydroelectric and wind power plants in the model, individual plant capacity factors were used instead of availability factors, since they better identify the upper bound on electricity generation from these plants. This is consistent with the assumptions in developing the EPA's IPM. In addition, turndown constraints to prevent coal steam units from being operated to strictly provide peak load were modeled as a 50% minimum-operating limit on these plants, as suggested in EPA's IPM. In a sensitivity scenario this minimum-operating limit was reduced to 30%. A similar turndown constraint of 25% minimum-operating limit on oil/gas steam units was modeled, also based on EPA's IPM. Gas units above 800 MW in PJM were also constrained to have a 25% minimum-operating limit, to ensure that the percentage of electricity generated by natural gas in PJM matched closely with industry reported data. A turndown constraint of 30% minimum-operating limit on nuclear units was also modeled, as reported by Pouret et al [25]. Resulting short-run marginal cost curve (supply curve) developed for PJM is presented in the SI (available at stacks.iop.org/ERL/7/034018/mmedia).

The 2010 hourly load data for the three areas under consideration were available [26–28], and used as a proxy for future electricity demand in the short-term. To meet a given hourly value of load or demand, all plants below this value on the supply curve are dispatched/operated, constrained mainly by their availability factors and minimum-operating limits. This ensures that the least expensive plants are dispatched first, since the supply curve follows a ranking algorithm, with the cheapest plants at the bottom of the curve. Thus, when annual hourly load were used along with the supply curve, electricity generated by each unit annually was estimated. Corresponding fuel use was also estimated, based on power plant efficiency. Average emission factors from the eGRID database for individual power plants were then used to estimate annual SO2 and NOX emissions. Life cycle greenhouse gas (GHG) emissions of natural gas, coal and fuel oil were also considered in this study. Average GHG emissions from individual power plants were obtained using plant-specific eGRID emission factors, while upstream emissions for coal, natural gas and fuel oil reported in Venkatesh et al [7, 12, 29] are used in this study. CO2 emissions per MWh from all coal, natural gas and oil plants in ERCOT, MISO and PJM are represented using boxplots in figure S3 in the SI (available at stacks.iop.org/ERL/7/034018/mmedia). It is important to note that uncertainty estimates are included for the upstream stages of coal, natural gas and fuel oil, which determine the uncertainty in life cycle GHG emissions reductions reported in section 3. Mean upstream emissions were 16 g CO2e/MJ (90% confidence interval: 11–22 g CO2e/MJ) for natural gas, 5 g CO2e/MJ (90% confidence interval: 1–13 g CO2e/MJ) for coal and 19 g CO2e/MJ (90% confidence interval: 11–31 g CO2e/MJ) for fuel oil. For this analysis, it is assumed that there are no changes in the production and processing of fuels before they reach the power plants. With changes to the power plant fleet, and with significant increases/decreases in the quantities of fossil fuels used nationally, it likely that upstream processes will be affected more significantly, causing a change in operational parameters and consequent environmental impacts. However, it is suggested that in the short-term (within the scope of this analysis), no significant changes will occur in the upstream life cycle stages of coal or natural gas, i.e., in the production, processing and transport of the fossil fuels. Emissions from ‘average’ upstream processes have therefore been used in this analysis.

It is difficult to validate supply curve models since they do not incorporate many elements that affect real-time power plant dispatch. As previously stated, the supply curve model does not include transmission constraints. In addition, fuel prices are assumed to be constant for all generators using the same fuel type. In reality, some generators may rely on long-term purchase agreements and have lower fuel prices. This would affect their bid into the market and the dispatch orders. These limitations notwithstanding, a rough model validation was performed by comparing the percentages of electricity generated from different energy sources obtained from the model and actual data for 2010 [30–32] (presented in the SI available at stacks.iop.org/ERL/7/034018/mmedia). These percentage values were found to be comparable. Since the goal of the study is to compare different scenarios using the same method for developing the supply curve models, it is proposed that matching modeled electricity prices to observed prices is not of critical importance.
2.3. Natural gas price variation scenario

Natural gas prices have varied significantly over the last two decades, between $3 and $12 per MMBtu [33]. This variation can affect the ratio of electricity produced from coal and natural gas plants, in turn impacting total air emissions. The model developed in the study was used to quantify upper and lower bounds on resulting changes in GHG and air emissions associated with changes in natural gas prices. In scenario 1, the US average delivered price of natural gas to the electric sector was varied between $1.5 per MMBtu and $5.5 per MMBtu, while the marginal costs of the other types of electricity generation were kept constant. Relationships between the US average electric sector delivered natural gas prices and regional electric sector delivered natural gas prices were estimated though simple linear regression models, to find regionally appropriate natural gas prices for each case in the scenario. For example, using data between 2002 and 2010, electric sector delivered natural gas price in ERCOT was found to be 94% of US average electric sector delivered natural gas price. Therefore, a US average electric sector delivered natural gas price of $3.5 per MMBtu was approximately equal to $3.3 per MMBtu in ERCOT. Similarly, natural gas prices in MISO and PJM were found to be 96% and 114% of US average electric sector delivered natural gas price, respectively. Regression results for all areas are presented in the SI (available at stacks.iop.org/ERL/7/034018/mmedia). For all cases in scenario 1, fuel use and air emissions were estimated, using methods followed in the base case.

3. Results

3.1. Base case

In the base case, life cycle GHG emissions were estimated to be 250 million tons CO₂ (90% confidence interval: 240–270 million tons CO₂) in ERCOT, 550 million tons CO₂ in MISO and 460 million tons CO₂ in PJM. SO₂ emissions at the power plants were estimated to be 0.7, 2.6 and 2.8 million tons in ERCOT, MISO and PJM respectively. NOₓ emissions at the power plants were estimated to be 180, 760 and 710 thousand tons in ERCOT, MISO and PJM respectively.

3.2. Natural gas price variation scenario

In scenario 1, natural gas prices were varied above and below the base case price of $4.5 per MMBtu, and the corresponding changes in fuel use, GHG, NOₓ, and SO₂ emissions were estimated. Increasing natural gas prices above the base case results in increased short-run marginal costs of electricity generation at natural gas plants. Therefore, a few coal plants that were originally more expensive to operate than some natural gas plants are now cheaper and are thus preferentially dispatched. Conversely, when natural gas prices are lower compared to the base case, more natural gas plants are now less expensive to operate than some coal and nuclear plants. This shift in the supply curve is graphically presented in the SI (available at stacks.iop.org/ERL/7/034018/mmedia) for PJM.

When natural gas prices are higher than in the base case, coal use increases marginally from the base case and offsets some natural gas use, as indicated in figures 1(A)–(B) by the stacked bars for average delivered prices between $4.5–5.5 per MMBtu. Note that these are US average electric sector delivered natural gas prices, which are modified to regionally specific prices using regressions presented in the SI (available at stacks.iop.org/ERL/7/034018/mmedia). Life cycle GHG emissions consequently increase by roughly 2% when the average delivered natural gas price increases above $4.5 per MMBtu, as shown in figures 2 (A)–(C). Beyond an average delivered price of $5.5 per MMBtu, emissions remained nearly unchanged up to a price of $12 per MMBtu (the highest observed price in the last decade [33]). At these high prices, all the coal plants are dispatched first and there is not any change in the dispatch order of natural gas plants.

When natural gas prices fall to $3.5 and $2.5 per MMBtu, more natural gas is used than in the base case, as shown in figures 1(A)–(C), offsetting coal use. The amount of electricity generated by sources other than coal and natural gas does not change from the base case in any of the areas examined. Offsetting coal use with natural gas consequently reduces life cycle GHG emissions by 1–10% on average, as shown in figures 2(a)–(c). For these cases, if only plant combustion emissions were considered, emissions reductions could be overestimated considerably. For example, at a natural gas price of $2.5 per MMBtu, average emissions reductions of 10% (90% confidence interval: 8–13%) could be expected in ERCOT when life cycle GHG emissions reductions are considered, while 15% reductions are expected if only plant combustion emissions are considered as shown by the circular markers in figure 2(a). This is because the upstream emissions from natural gas are higher than upstream emissions from coal, and offset some of the benefit that natural gas plants provide in having lower combustion emissions than coal plants do.

In the absence of operational constraints on nuclear plants, when the US average delivered natural gas price falls to $1.5 per MMBtu, generation from natural gas plants begins to displace generation from both coal and nuclear plants. While the pure economic supply curve indicates this trend, in reality, it is highly unlikely that nuclear plants will be underutilized. Unlike other types of power generation facilities, nuclear power plants have to maintain significant insurance coverage and NRC regulatory fees [34]. In addition, minimum personnel requirements exist for nuclear power plants [35]. These costs are independent of the capacity factors at which the plants are operated so the plants have an incentive to operate at its full capacity. Finally, since these plants are older and have already recovered their capital costs, they may have flexibility on the bids they submit for dispatch purposes. Unless the plants are retired, they will likely operate as must-run. Therefore, an additional constraint was included in the scenario where natural gas falls to $1.5 per MMBtu, in order to maintain nuclear power as a
Figure 1. Per cent electricity generation by energy source for the base case, compared to cases of varying natural gas price in scenarios 1 and 2. Dotted lines indicate percentage electricity generation by energy source for the base case (represented by heights of stacked bar to the farthest left in each panel). Panels (A)–(C) represent results for scenario 1 where minimum-operating limit of coal steam plants is 50%.

Panels (D)–(F) represent results for scenario 2 where minimum-operating limit of coal steam plants is lowered to 30%. Total electricity generated in ERCOT: 320 quadrillion Wh, MISO: 590 quadrillion Wh, PJM: 710 quadrillion Wh. For a detailed explanation on how to read this figure, refer to figure S6 in the SI (available at stacks.iop.org/ERL/7/034018/mmedia).

must-run. For this scenario, nuclear plants were assumed to have short-run marginal costs equal to hydroelectric plants ($10 per MWh)—lower than in the base case ($16.5 per MWh)—and the US average delivered natural gas was at $1.5 per MMBtu. With these constraints, nuclear utilization is nearly unchanged from the base case in all areas, as shown in figures 1(A)–(C) by the bars marked ‘1.5 + nuclear as must-run’. The extent of natural gas utilization differs by region. In ERCOT, there appears to be sufficient natural gas capacity to reduce coal generation by half, while nuclear plant...
utilization remains unaffected. Life cycle GHG emissions would decrease by 13% on average, as shown in figure 2 by the case marked ‘1.5 + nuclear as must-run’. In MISO and PJM, GHG emissions reduce by less than 10% on average.

Reductions in plant level SO$_2$ and NO$_X$ emissions are higher than reductions in life cycle GHG emissions, as presented in the SI (available at stacks.iop.org/ERL/7/034018/mmedia). At a natural gas price of $2.5 per MMBtu, SO$_2$ and NO$_X$ emissions decrease by 20–30% from the base case in all three regions. SO$_2$ emissions reductions can be as high as 50% in ERCOT at a natural gas price of $1.5 per MMBtu. Natural gas use, coal use, and average natural gas plant capacity factors for the base case and scenario 1 are summarized in the SI (available at stacks.iop.org/ERL/7/034018/mmedia). The highest quantity of natural gas is used in the case where average delivered natural gas price falls to $1.5 per MMBtu. While natural gas use increases by 70% in ERCOT, it increases by a factor of three in PJM, and by a factor of 12 in MISO.

Upon further analysis, it was evident that the minimum-generation constraint on coal plants limited the displacement of coal-based power in scenario 1. As part of a sensitivity analysis, the minimum-operating limit on coal steam plants was lowered from the base case value of 50% to 30% (scenario 2). A lower bound of 30% was chosen to model a case in which coal plants have more flexibility in their operations. The 30% limit was also chosen because operating below this limit is known to reduce power plant efficiency considerably [36]; hence they are not likely to be operated below this limit for extended periods of time. At this lower bound, more natural gas is utilized than in the base case (see figures 1(D)–(F)) at prices between $1.5–2.5 per MMBtu. Consequent reductions in GHG emissions are also higher than in the base case (see figures (D)–(F))—at a natural gas price of $2.5 per MMBtu, emissions reductions range between 10–15%. At most, GHG emissions decrease by about 20%, at a natural gas price of $1.5 per MMBtu and must-run nuclear in ERCOT. This trend is observed in SO$_2$ and NO$_X$ emissions as well—decreasing by up to 50–70% when natural gas price is $1.5 per MMBtu. Results for a scenario where the minimum-operating limit on coal plants is further relaxed to zero are presented in the SI (figures S7 and S8 available at stacks.iop.org/ERL/7/034018/mmedia). Emissions reductions of up to 30% are seen in ERCOT, with all coal generation being displaced by natural gas. In this scenario, however, there are significant violations of the operational limits on coal plants. It is thus presented as a bounding analysis but the results are not robust enough to be used as a basis of any conclusions.

4. Discussion

At an average delivered natural gas price of $1.5 per MMBtu, approximately 600–1500 Bcf of additional natural gas is used in each of the three areas. This translates to an increase of 8–20% of the total natural gas used in the US power sector and about 3–6% of total US natural gas consumption [37]. At this price, life cycle GHG emissions would be reduced by 8–13%, and up to 20% with low generation limits on coal plants. The
studies have compared the emissions from using natural gas. Many previous life cycle assessment (LCA) studies 

have been used in each of the regions studied, the equivalent of 2–3% of natural gas currently consumed in the US. At this price, which the US EIA’s Short-Term Energy Outlook considers very likely, life cycle GHG emissions would be reduced by 7–10% in each of the three areas. In the most optimistic fuel-switching scenario in which coal plants have more flexibility, emission reductions could increase to 15% at a gas price of $2.5 per MMBtu. Although this is a significant reduction in itself, it is still lower than the benefits reported in life cycle comparisons of coal and natural gas-based power (close to 50%). Note that in the near-term, before any new generation capacity is built, natural gas prices could remain low, consistent with the lower bounds modeled in this study. In the long run, when additional gas-fired generation capacity is added to the fleet and new markets for natural gas are opened, the prices will likely rise due to increased demand. This long-term scenario is not, however, the context for this study.

These results are obtained using simplified dispatch models that have been developed and used in a number of earlier studies [14, 20, 21] and have limitations as previously noted. Improved modeling of the electricity sector that includes start-up, shut-down, ramping and transmission constraints requires the use of a more complex unit-commitment dispatch model. It is acknowledged that these results are limited, but given that the main purpose of the work was to highlight the importance of evaluating system operations when using LCA results, the model is believed to be justifiable and adequate.

When natural gas prices were low ($2.4–4.6 per MMBtu) [33] in the late 1990s and early 2000s, US natural gas capacity tripled from 60 to 200 GW [5]. But as prices rose above $5 per MMBtu (and eventually reached $12 per MMBtu), these plants proved expensive to operate and were used only as peaker plants, remaining idle for much of the time. Given that natural gas prices have been volatile in the recent past, utilities (that are likely to be risk averse) may not choose to invest in new natural gas power plants immediately, despite predictions of low natural gas prices and increased supply. While there is significant underutilized natural gas capacity that can be used to immediately displace coal, the results show that the GHG emissions reductions could be significant (7–15%), but much smaller than the 50% reductions suggested by life cycle studies. As a comparison of related work, Newcomer et al [14] estimate about 2% reductions in CO₂ emissions with a carbon price of $30 per metric ton (at a price elasticity of electricity demand assumed to be zero, consistent with this study).

Increasing projections of domestic shale gas production and lower gas prices [39] have recently caused much debate in academia, industry and the government, especially concerning the life cycle GHG emissions associated with natural gas. Many previous life cycle assessment (LCA) studies have compared the emissions from using natural gas and coal to produce electricity, for example see [5, 6, 8–10, 40]. Howarth et al [40] report that the GHG emissions from using conventional and unconventional natural gas are higher than emissions from using coal. Other studies, including some of the authors’ previous work [6] suggest otherwise, estimating 50% lower emissions from using natural gas instead of coal for every kWh generated. Overall emission reductions can be expected to approach the values suggested by the LCA studies as natural gas displaces increasing amounts of coal in the electricity sector. However, these reductions will likely be less than suggested since these studies do not include the complexity of the power system, but rather compare coal and natural gas plants on a per kWh basis. The results of this study provide a reasonable estimate (7–15%) of potential GHG emissions reductions from using natural gas instead of coal in the electricity sector in the short-term, and provide a framework for evaluating greater reduction in the future.

Comparatively, SO₂ and NOₓ emissions were found to decline by a greater amount with increased natural gas utilization in the electricity sector resulting from lower natural gas prices. When considering alternatives to incumbent fuels with a focus on reducing environmental impacts, multi-objective decision-making approaches should be used to obtain a more comprehensive sense of the potential benefits. Further research is required to develop this area.

While this analysis focuses on specific sub-systems of electricity generation in the US and estimates potential reductions in GHG emissions through the substitution of coal with natural gas, the consequent leakage/substitution effect of reduced coal consumption in the US is an important element that remains to be analyzed. The low natural gas price scenarios modeled in this study lead to the reduced demand for coal in US electricity grid regions. It has been hypothesized that as a result of reduced coal demand, domestic coal is likely to be exported to Asia, especially China [41]. If the some fraction or all of the coal displaced in the US is likely to be used in developing economies in Asia as argued by Power [41], there will be less/no reduction in global GHG levels, despite reductions within the US. The mechanisms and magnitude of this leakage/substitution effect have not been addressed in this study, but future work will attempt to address these concerns.

This paper focuses on consumption of natural gas by the electricity sector and suggests that such consumption could increase by 25% at most for the three control areas, if natural gas prices remain low enough in the short-term (at $2.5 per MMBtu). These control areas are likely to be most impacted by low natural gas prices, as explained previously, and increased consumption here can be scaled to total increase in natural gas consumption by the US power sector. Assuming this to be the case, this translates to an increase of 8% of total US natural gas consumption. Projections for increases of domestic natural gas production are much larger, however. EIA projects that by 2015 dry production of natural gas will be 15% higher than it was in 2009 [39]. It therefore seems unlikely that the power generation sector will absorb all of the new natural gas supply. Understanding the disposition of new
sources of natural gas will thus be important to evaluate the impacts that these sources will have on the total emissions of air pollutants and greenhouse gases that contribute to climate change.

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