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Evaluating the CO_2 emissions reduction potential and cost of power sector re-dispatch

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ABSTRACT

Prior studies of the U.S. electricity sector have recognized the potential to reduce carbon dioxide (CO_2) emissions by substituting generation from coal-fired units with generation from under-utilized and lower-emitting natural gas-fired units; in fact, this type of "re-dispatch" was invoked as one of the three building blocks used to set the emissions targets under the Environmental Protection Agency's Clean Power Plan. Despite the existence of surplus natural gas capacity in the U.S., power system operational constraints not often considered in power sector policy analyses, such as transmission congestion, generator ramping constraints, minimum generation constraints, planned and unplanned generator outages, and ancillary service requirements, could limit the potential and increase the cost of coal-to-gas re-dispatch. Using a highly detailed power system unit commitment and dispatch model, we estimate the maximum potential for re-dispatch in the Eastern Interconnection, which accounts for the majority of coal capacity and generation in the U.S. Under our reference assumptions, we find that maximizing coal-to-gas re-dispatch yields emissions reductions of 230 million metric tons (Mt), or 13% of power sector emissions in the Eastern Interconnection, with a corresponding average abatement cost of \$15–\$44 per metric ton of CO_2, depending on the assumed supply elasticity of natural gas.

1. Introduction

In the first decade of the 21st century, the U.S. power system experienced unprecedented growth in the installed capacity of natural gas combined cycle (NGCC) units. From 2000–2005 net additions of NGCC capacity totaled 138 gigawatts (GW), representing approximately a 270% increase in the installed capacity of NGCC units.[1] Over that same time period, growth in electricity consumption was relatively modest, increasing by only 7% (1.2% per year), and natural gas fuel prices for the electricity sector climbed from \$4.25 per MMBtu in 2000 to \$8.25 per MMBtu in 2005.[2] As a result, by the mid- to late-2000s, the boom in the installation of new NGCC units combined with limited growth in electricity demand and high natural gas prices resulted in a significant amount of under-utilized NGCC capacity - the average capacity factor for the NGCC fleet in 2005 was 35%.

More recently, advances in shale gas production have created an abundance of low-cost natural gas, which in turn has led to an associated increase in the utilization of NGCC plants. From 2005–2016 the average electricity sector price for natural gas fell from \$8.21 per MMBtu to \$2.99 per MMBtu, while the national average capacity factor for NGCCs increased from 35% to approximately 56% (ABB Velocity Suite).[3] Despite this increase in the utilization of NGCC plants, as of the end of 2016, there still remains a significant amount of unused NGCC capacity. The generation weighted average annual capacity factor of the 255 GW of existing NGCC capacity in 2015 and 2016 was 56% – well below the theoretical maximum. Except for required down time for maintenance, combined cycle units can be run at full capacity almost continuously, achieving annual capacity factors above 90% (Usune et al., 2011).[4] Thus, the potential exists in the U.S. to dramatically increase generation output from the existing NGCC fleet to displace generation from coal units. Given that coal-fired power plants, which historically account for the largest share of generation in the U.S.

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[1] ABB Velocity Suite, accessed 3/9/2016.
[2] Energy Information Administration (EIA) Electric Power Monthly, accessed May 2017.
[3] Historically, average capacity factors for NGCC plants have been highly correlated with natural gas prices — from 2005 to 2016 the simple correlation coefficient between the national average electric sector delivered natural gas price and the average NGCC capacity factor was 0.72.
[4] In the years 2014, 2015, and 2016 at least 46 NGCC (23 if excluding co-generation units) units operated at annual capacity factors above 80% and 14 (5 if excluding co-generation units) at above 90%, demonstrating the ability of NGCC plants to operate at very high capacity factors given appropriate conditions.

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(approximately 40% in 2014 and 33% in 2015), typically emit 2–2.5 times more CO_2 per megawatt-hour (MWh) than NGCC units,[5] re-dispatch from coal to NGCC units represents a substantial opportunity to reduce power sector CO_2 emissions.

Indeed, a number of analyses exploring the impacts of CO_2 emissions mitigation policies on the U.S. power sector find that coal-to-gas re-dispatch (sometimes referred to as fuel-switching) typically accounts for a substantial portion, if not the largest share, of the CO_2 abatement necessary to comply with the policies (Newell and Raimi, 2014; Paltsev et al., 2011; Ross and Murray, 2016; Logan et al., 2013; Bielen, 2015; Holladay and LaRiviere, 2015). Furthermore, the potential for abatement through re-dispatch has been considered in the determination of the stringency of CO_2 emission reduction policies. For example, in the development of the emissions reduction targets under the Clean Power Plan, the Environmental Protection Agency (EPA) carried out an analysis to assess the potential for abatement through alternative abatement measures. For coal-to-gas re-dispatch the EPA assumed that NGCC units could increase generation (to offset coal generation) up to the point where the NGCC units achieved a fleet-wide annual capacity factor of 70%.[6] However, the feasibility of achieving that level of utilization was questioned by some stakeholders, citing concerns about fuel and power transmission constraints, system reliability, and potential limitations due to existing emissions regulations.[7] Burtraw et al. (2014), although they do not explicitly challenge the feasibility of achieving a fleet-wide capacity factor of 70%, suggest that doing so could be relatively costly given the low efficiency of older NGCC plants.

The analysis presented here estimates the technical potential and associated cost for reducing power sector CO_2 emissions by substituting generation from *existing* coal units with generation from *existing* NGCC units in the Eastern Interconnection (EI).[8] We obtain our estimates by implementing PLEXOS, a commercially available bottom-up simulation model of generation and transmission operation. To the best of our knowledge, this is the first study to estimate the total CO_2 mitigation potential and cost of re-dispatch from coal to NGCC units in the U.S. using a security constrained unit commitment and economic dispatch (or production-cost) model. Use of a production-cost model allows for the consideration of power system constraints, such as transmission congestion and the availability of specific generating units, that may ultimately limit the potential for re-dispatch from coal to NGCC units. Furthermore, the model is generator-specific, allowing for the estimation of aggregated CO_2 mitigation potentials for any desired regionality, including states, balancing authorities, or utility service areas.

Our analysis is built around a base case, which simulates operation of the existing EI power system on a pure least-cost basis, and a maximum re-dispatch case, under which NGCC units are dispatched ahead of coal units. Our conclusions are based on direct comparison of the outcomes from the two cases, most notably emissions and cost. As a sensitivity analysis, we make our comparisons under different assumptions about the price of natural gas and the elasticity of supply for natural gas. This approach allows us to explore the *maximum* potential for re-dispatch between existing plants that could be achieved under a range of potential price and policy conditions. However, we do not estimate the expected level of re-dispatch under any particular policy nor do we consider the potential for new capacity or future retired capacity to alter the potential. Instead, our focus is on characterizing the full extent to which fuel-switching in the power sector can serve as a vehicle for short-run emissions reductions.[9]

Our results suggest that, even when accounting for key power system constraints, there is significant potential within the EI to displace generation from existing coal units with generation from existing NGCC units. We find that the fleet-wide NGCC capacity factor in the EI increases from 51% to 80% under our baseline reference and re-dispatch scenarios, respectively. This results in emissions reductions of 230 million metric tons (Mt), or 13%, with the largest reductions concentrated in the midwest, mid-atlantic, and southeast regions of the U.S. The corresponding average abatement cost ranges from \$15–\$44 per metric ton of CO_2 (tCO_2), depending on the assumed supply elasticity of natural gas. Furthermore we find that detailed power system operational constraints, including transmission congestion, ramp rate limits, minimum run times, and minimum stable generation levels, among other constraints, limit the potential for re-dispatch at large scales (over multi-state or market regions), but are secondary to capacity availability at the more local level.

Our paper is related to a number of prior studies that estimate the total potential for coal-to-gas re-dispatch (Gelman et al., 2014; Kaplan, 2010; Lafrancois, 2012). However, these prior analyses all use simple accounting frameworks to assess the potential amount of historical coal generation and associated CO_2 emissions that could have been offset by increasing generation from available NGCC capacity. As a result, none of these analyses estimate the cost of achieving the potential, nor do they fully address the technical feasibility, as they do not account for the suite of power system constraints and grid operation requirements that could limit the potential for re-dispatch, including transmission constraints, generator ramping constraints, peak load requirements, planned and unplanned generator outages, and ancillary service requirements. These constraints may prevent generation from seamlessly shifting from coal to NGCC units, even if excess NGCC capacity exists.[10] Of the three related studies, only Gelman et al. (2014) reports results at the sub-national level and therefore is the only study with which we can directly compare our results. Our estimated emissions reductions are between the values the authors estimate for scenarios in which re-dispatch is allowed between units falling within the same (1) independent system operator (ISO) region, and (2) interconnection region.

The remainder of the paper is structured as follows: Section 2 describes our model, analytic approach, and scenarios, Section 3 presents and discusses our results, and Section 4 synthesizes conclusions.

[5] This emissions rate comparison only includes burner-tip emissions - that is, the emissions resulting from the combustion of fuel. It is not a comparison of the life-cycle emissions associated with electricity generation from coal and NGCC units, and as a result, does not include emissions associated with upstream leakage from natural gas infrastructure. See Alvarez et al. (2012) and Brandt et al. (2014) for information on methane leakage from natural gas infrastructure.

[6] In order to set the targets, the EPA considered three “Building Blocks” that together comprise the “Best System of Emissions Reduction (BSER)”: increasing the operational efficiency of coal- or oil-fired steam units, shifting generation from coal units to lower-emitting gas units, and increased generation from renewable sources.

[7] See Comments of the Mississippi Public Service Commission, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Docket No. EPA-HQ-OAR-2013-0602 79 Fed. Reg. 34,830 (June 18, 2014), as well as Federal Register, Vol. 80, No. 205, p. 64728.

[8] We only consider re-dispatch to NGCCs, as opposed to natural gas combustion turbines (NGCTs), because the former represents a much more cost-effective abatement option. For example, using average heat rate data (from 2013), fuel prices (also from 2013), and fuel emissions factors from EIA, we calculate that the average abatement cost of re-dispatch from a coal plant to an NGCC plant is more than four times lower than re-dispatch from a coal plant to an NGCT plant (EIA, 2016, 2017b). Additionally, the mitigation potential for coal to NGCT re-dispatch will be limited by operational constraints, as NGCTs are able to provide quick-start capabilities that coal plants cannot. Therefore, the system operator may prefer to hold NGCT capacity in reserve, even if NGCTs are lower on the dispatch stack than coal.

[9] Over the long-run, the ability to add new NGCC capacity could further increase the potential (and lower the marginal cost) for coal-to-gas re-dispatch, while plant retirements (of either existing coal or NGCC capacity) could decrease the potential; our study does not consider these long-run opportunities or constraints.

[10] Lafrancois (2012) attempts to control for peak load requirements and generator outages using historical trends in plant operation, while both Gelman et al. (2014) and Kaplan (2010) attempt to control for transmission related constraints by limiting re-dispatch potential to coal and NGCC units within a specified maximum proximity of one another. Kaplan (2010) also provides an overview of the power system and natural gas supply system constraints that could potentially limit the mitigation potential, but does not provide an estimate of how these constraints could impact mitigation potential. None of these studies attempt to integrate the full suite of power system constraints into the analyses. Furthermore, Gelman et al. (2014) notes that additional research using generator dispatch models is necessary to refine and validate these more aggregated estimates.