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Cumulative environmental and employment impacts of the shale gas boom

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Abstract

Natural gas has become the largest fuel source for electricity generation in the United States and accounts for a third of energy production and consumption. However, the environmental and socioeconomic impacts across the supply chain and over the boom-and-bust cycle have not been comprehensively characterized. To provide insight for long-term decision making for energy transitions, we estimate the cumulative impacts of the shale gas boom in the Appalachian basin from 2004 to 2016 on air quality, climate change, and employment. We find that air quality impacts (1200 to 4600 deaths; \$23B +99%/-164%) and employment impacts (469,000 job-years $\pm$ 30%; \$21B $\pm$ 30%) follow the boom-and-bust cycle, while climate impacts (\$12B to \$94B)

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Author contributions

A.L.R. secured project funding. E.N.M., J.L.C., and A.L.R. designed the study. E.N.M. acquired and analyzed the data and modeled impacts. E.N.M., J.L.C., A.L.R., and N.Z.M. interpreted the results. E.N.M. drafted the manuscript. E.N.M., J.L.C., A.L.R., N.Z.M., and I.M.L.A. revised the manuscript.

Competing interests

J.L.C. serves as the Chair of the Board of Directors of the Center for Responsible Shale Development. The authors declare no other competing interests.

persist for generations well beyond the period of natural gas activity. Employment effects concentrate in rural areas where production occurs. However, almost half of cumulative premature mortality due to air pollution is downwind of these areas, occurring in urban regions of the Northeast. The cumulative temperature impacts of methane and carbon dioxide over a 30-year time horizon are nearly equivalent, but over the long term, the cumulative climate impact is largely due to carbon dioxide. We estimate that a tax on production of \$2 per thousand cubic foot (+172%/−76%) would compensate for cumulative climate and air quality externalities across the supply chain.

Introduction

Rapid increases in U.S. natural gas production, resulting from advancements in horizontal drilling and hydraulic fracturing, have dramatically altered world energy markets and the domestic energy outlook. The U.S. has been the largest natural gas consumer and producer over the past decade, comprising 20% of the world market, and the domestic shale gas market has contributed to price volatility and a shift in global flows of natural gas.¹ Increases in domestic supply and reserves have contributed to the displacement of coal², but have also potentially delayed investment, development and deployment of renewables and other low carbon alternatives.³

The rapidly evolving energy landscape has presented new engineering and regulatory challenges.⁴ There is an expanding literature on the impacts of natural gas development on water quality^{5–8}, air quality^{9–11}, ecosystems^{12–14}, climate^{15–17}, labor markets^{18–20}, public health^{21–23}, and several other environmental and socioeconomic factors. However, the cumulative impacts over the boom-and-bust cycle and across the natural gas supply chain, as well as the spatial and temporal distribution of and tradeoffs between impacts, are still largely unexplored and unaccounted for in public and private decision making. More broadly, the literature on modeling cumulative impacts of energy systems is sparse.

The purpose of this study is to apply a data-driven, systems-level framework for evaluating cumulative and disparate impacts of current energy systems to inform policy and decision making. This approach seeks to comprehensively assess and represent the spatial and temporal distribution of impacts, the attribution of impacts across supply chains, and the tradeoffs across multiple impact areas. Here, we analyze of the shale gas boom (and decline) in the Appalachian basin, the largest natural gas basin in the U.S. with respect to both reserves and production.²⁴ We model impacts across the regional supply chain from preproduction to end use, as well as over the development cycle beginning in 2004, the year in which the first unconventional shale gas well was drilled in the Marcellus play, to 2016. Over the period of analysis, regional shale production volumes increased annually, while drilling peaked in 2013 [see Supplementary Figures 5 and 7]. Regional natural gas consumption for electric power (8X increase) and processing volumes (18X increase) also increased (Supplementary Figure 8). Shale gas production (7.7 tcf in 2016) exceeded regional end use demand (2.1 tcf in 2016) in recent years, leading to substantial exports to other parts of the United States (Supplementary Figures 2 and 8).

We model a subset of impacts: 1) premature mortality from primary fine particulate matter (PM_{2.5}) and secondary PM_{2.5} formed from the atmospheric oxidation of nitrogen oxides (NO_x) and volatile organic compound (VOC) emissions, 2) global mean temperature change from carbon dioxide (CO₂) and methane (CH₄) emissions, and 3) employment effects associated with natural gas development. We consider these impacts because they each have differing cumulative spatial and temporal attributes, and they are often the subject of public discourse and concern. We use multiple datasets and an integrated set of models, including process-level emissions inventories, reduced complexity source-receptor air quality and climate change models, and empirical, regression-based employment models. In addition to computing spatially- and temporally-explicit estimates in physical units, we monetize impacts, which provides differential insight for decision making and policy evaluation. We focus on a single fuel source in a specific region to demonstrate the insight that can be drawn from detailed and expansive modeling of multiple cumulative impacts, rather than marginal and intermediate effects of a single impact area. Given that this methodology is very data and modeling intensive, we did not model substitutes (e.g., coal, solar, wind), but provide comparisons throughout the paper. In the following sections, we present cumulative impact estimates, comparisons across impact areas, and policies to correct for environmental externalities.

Air quality impacts

We estimate the mortality and monetized damages from air pollution. Figures 1a–b show estimates of annual emissions and the spatial distribution of emissions. VOC emissions are largely associated with upstream processes (61%) and spatially concentrated in counties with the highest cumulative production (Supplementary Figures 14 and 16). End use processes contribute a majority of NO_x (67%) and PM_{2.5} (73%) emissions across the natural gas supply chain, and NO_x and PM_{2.5} emissions are relatively evenly distributed across counties (Supplementary Figures 14, 15, and 17). Trends in emissions over time are associated with changing natural gas activity across the supply chain, as well as evolving regulations and increasing technological and operational efficiencies.

Compared to total emissions within Pennsylvania, Ohio, and West Virginia in 2014 from all industries reporting in the National Emissions Inventory (NEI), shale gas activity accounted for approximately 10% of NO_x emissions, while the contributions to total PM_{2.5} and VOC emissions were marginal (<2%). As noted in other studies, many counties within and adjacent to Appalachia are designated nonattainment or maintenance areas under the Clean Air Act National Ambient Air Quality Standards (NAAQS), and increasing emissions from shale activity contribute to and are projected to continue to contribute to regional noncompliance.^{11,25} In isolation, most shale gas activities across the supply chain, including some natural gas electric generating units, do not constitute *major sources* under federal regulations, but in aggregate at the county-level may exceed thresholds.

We estimate 1200 to 4600 premature mortalities are associated with air pollutant emissions from shale gas activity over the period 2004 to 2016; the range reflects uncertainty in the model functional form through the use of three different reduced complexity models (RCM) (factor of up to 1.6X) and uncertainty in the concentration-response relationship (factor of

up to 2.6X). As depicted in Figure 1c, more than half of the cumulative premature mortality is within source counties (54%), while transboundary impacts are concentrated in downwind populous coastal regions in the Northeast and extend to the continental divide (Supplementary Figure 18). While the majority of the premature mortality is associated with residential, industrial, commercial, and electricity generation end uses (57 to 67%), upstream (16 to 21%) and midstream (17 to 22%) segments also contribute substantial cumulative air quality impacts (Supplementary Figure 19 and Table 6). There is also an urban and rural divide, with 76% of premature mortalities occurring in urban areas. Mean cumulative damages, based on mean mortality across six model specifications, amount to \$23B (in 2017 USD), with a 95% confidence interval spanning two orders of magnitude (\$2.3B to \$61B) reflecting different VSL assumptions. Annual mortalities (439) and damages (\$3.7B) peaked in 2014, the year after peak drilling activity. The deployment of lower emitting equipment helped reduced impacts over time. To contextualize the estimated mortality, a study by Fann et al. (2018) projected PM_{2.5}-related premature mortalities attributable to emissions from the oil and gas (O&G) sector in Pennsylvania and Ohio in 2025 to be 150 (95% CI 91 to 196). Analogous systems-level analyses of cumulative air quality emissions and impacts for natural gas substitutes, such as coal, are sparse. However, marginal air pollution damages from natural gas electricity generation are on the order of 5% that of coal.^{26,27}

Climate change impacts

We estimate global mean temperature change and monetized damages from CO₂ and CH₄ emissions. As shown in Figure 2a, CH₄ emissions are largely associated with production (63%) and gathering segments (15%), while processing, transmission, and distribution collectively account for the remaining emissions (Supplementary Table 10). With respect to the distribution of CH₄ emissions across the supply chain, our findings, which leverage recently collected emissions data, are consistent with other recent estimates of CH₄ emissions across the O&G sector (Supplementary Table 11).²⁸ As compared to national O&G sector estimates (13 MMT in 2015)²⁹, CH₄ emissions from natural gas-related sources within Pennsylvania, Ohio, and West Virginia (1.25 MMT in 2015) account for 10% of U.S. emissions.

End use processes contribute a majority of CO₂ (85%) emissions across the supply chain, with remaining emissions attributable to well development (2%) and fuel consumption for production, processing, transmission, and distribution (13%). Natural gas-related sources in Pennsylvania, Ohio, and West Virginia (134 MMT in 2016) account for 9% of the CO₂ emissions across the entire U.S. natural gas sector (1502 MMT in 2016).³⁰

Comparing natural gas to its substitutes, several life cycle assessments (LCA) show that greenhouse gas (GHG) emissions from domestic natural gas use are lower than coal.^{15–17,31–34} There is also systems level evidence of the comparative climate benefit of natural gas, as the CO₂ intensity of U.S. electricity generation decreased between 2001 and 2017 by 30%, a trend reflective of declining coal and increasing natural gas and wind.²

We translate emissions into impacts, including global temperature change and monetized damages. Impacts from climatically-relevant emissions are often described by the following

impact chain: emissions → atmospheric concentrations → radiative forcing → climate change → societal and ecosystem impacts → monetized damages.^{35–38} Stepping through the chain, there is cascading uncertainty and (arguably) increasing societal relevance.^{36,39,40}

Using the social costs of carbon and methane, consistent with traditional benefit-cost analyses, we develop estimates of monetized damages from natural gas activity (Figure 2d). Cumulative climate damages from natural gas activity over the period 2004 to 2016 range from \$12B to \$94B, depending on assumptions regarding social costs. Although the use of physical metrics has been subject to criticism within the economics literature^{41–43}, metrics related to climate change phenomena, e.g., temperature, precipitation, and sea level rise, provide additional information (e.g., temporal trace of climate impacts) and apply a different set of assumptions than monetization.

Translating emissions into global temperature change, Figure 2b indicates the climate response persists well beyond the period of shale gas activity (Supplementary Figures 23–24). Short- and long-lived species have different effects on the trajectory of the climate response. CH₄ has an atmospheric lifetime of 12 years, whereas CO₂ has multiple lifetimes, with 20% remaining for tens of thousands of years.^{44,45} The magnitude of CH₄ emissions across the supply chain produces cumulative temperature impacts nearly equivalent to that of CO₂ over a 30-year time horizon from the year of first production, 2004. Over longer time periods (e.g., 100 years), the cumulative warming impact from CO₂ (77%) dominates that of CH₄ (Figure 2b). More than 65% of temperature impacts integrated over a 100-year period are associated with end use, namely CO₂ emissions from natural gas combustion.

Employment impacts

Countervailing the environmental and public health impacts are the contributions of the natural gas sector on local economic conditions, including labor markets. Several empirical studies demonstrate that natural gas activity may impact local labor demand; have spillover effects on the non-resource economy^{18,20}; and alter the distribution of income⁴⁶, poverty rates^{20,47}, and educational attainment⁴⁸. Here, we focus on employment effects, including the marginal effect as it relates to upstream activity and the aggregate effect in producing counties over time.

We observe a positive and statistically significant employment effect from natural gas activity, a finding that is robust across multiple model specifications (Supplementary Tables 14–23). A model specification that includes both spud and producing wells as predictor variables, provides an intuitive result, differentiating the jobs directly or indirectly associated with drilling activities (16 jobs per spud well) and ongoing production operations (4 jobs per producing well). In an alternative model specification, we find a mean effect size of 5 job-years per billion cubic feet (bcf) of natural gas production. Other empirical labor market studies for the U.S. natural gas sector estimate slightly higher effects (6 to 16 job-years per producing well, 7 to 19 job-years per bcf), which potentially can be explained by the differing geographic scope and expanded number of years of data incorporated in this study.^{18–20,49} We additionally observe decreasing marginal employment effects from natural gas activity over time, with 75% fewer job-years supported per bcf of production after 2012; the

intuition is that learning occurs and the industry becomes more efficient and automated over time

Employment effects are inclusive of not only those within the natural gas sector, but also spillover into other sectors, which can both positively and negatively impact local economies. We estimate that each natural gas industry job is associated with 1.9 jobs outside of the resource sector, consistent with other studies that similarly observe relatively minor multiplier effects at the county level (1 to 1.4).^{18,20} A possible explanation for the low multiplier effect is that jobs associated with extractive industries, such as drilling crews, are often held by transient workers because long-term residents in rural communities may not have the requisite skills and training. In addition, production firms are largely based outside of the county of production and as such may source supplies and equipment elsewhere.

We simulate aggregate employment over time, combining natural gas activity data with marginal employment effects. We use the metric job-year, which is a full- or part-time job over a single year, not a sustained job over multiple years or a career. We use a time-weighted metric that is contextually useful because of the transiency of natural gas-related employment. We find that the direct and induced job-years supported by the shale gas sector over the period 2004 to 2016 was 469,000 (95% CI $\pm 30\%$). As shown in Figure 3a, changes in employment over time largely mimic the transiency of jobs and the boom-and-bust cycles of other extractive resources, with the annual number of job-years peaking in 2014 at 76,000 (95% CI $\pm 30\%$), reflecting both increasing production and rapid growth and subsequent decline in drilling activity. As highlighted in Figures 3c–d, the spatial distribution of jobs largely aligns with the intensity of drilling and production, with most jobs concentrated in rural (54%) and mixed rural-urban (31%) areas. The employment associated with shale gas activity comprised less than 1% of total employment in urban or low producing counties to over 60% of total employment in rural and high producing counties. Many jobs are in counties where there are relatively few firms and workers. We also estimate cumulative earnings of \$21B (\$8B to \$33B), based on aggregate employment effects and annual average per capita earnings by county (see Figure 3b).

These employment estimates only account for direct and spillover jobs associated with upstream activities and potentially co-located midstream and end use segments. A recent study of electricity generation related employment effects estimates 0.11 job-years are supported per Gigawatt hour (GWh), which includes direct natural gas generation-related employment associated with construction, installation, manufacturing, operating, maintenance, and fuel processing⁵⁰; this suggests an additional 46,000 job-years may be associated with electricity generation using shale gas as a feedstock in the Appalachian basin. For comparison, generation-related employment of coal (0.11 job-years/GWh) is equivalent to that of natural gas, whereas it is somewhat higher for wind (0.17 job-years/GWh) and solar photovoltaics (0.87 job-years/GWh).⁵⁰

Tradeoffs between air, climate, and employment impacts

A goal of this work is to assess tradeoffs between different impacts. Comparisons of physical impacts reveal the implied tradeoffs from natural gas development decisions. As

shown in Figure 4a, we observe that after drilling peaked in 2013, air quality and employment impacts began to decline, whereas climate impacts continue to increase for another decade, all else being equal, and persist over time horizons greatly exceeding the period of natural gas activity. Based on mid-range cumulative estimates of premature mortality from air pollution and employment, the implied tradeoff is 217 job-years per premature mortality at a systems level, or equivalently, 3 job-years per life-year lost.

Weighting between these impacts is (in part) normative, and monetization is a common weighting approach. We monetize impacts to translate physical impacts to a traditional benefit-cost analysis framing. Figure 4b showed a variable relationship between monetized impacts from 2004 to 2016. As drilling activity declined after 2014, climate damages began exceeding air quality damages; although integrated climate damages obscure when impacts are realized. Based on mid-range estimates, cumulative employment impacts (\$21B) are less than air quality (\$23B) and climate change damages (\$34B); however, no impact area dominates another across the modeled sensitivities, namely due to the vast range of VSL and social costs of methane and carbon that are considered. The breakeven VSL at which mean monetized employment equates to cumulative air quality damages over the development horizon is \$7.7M. Similarly, the breakeven social cost of carbon at which mean monetized employment equates to cumulative climate damages over the development horizon is \$25 per metric ton.

Figure 4c depicts the spatial tradeoffs between near-term air quality and employment impacts. While employment benefits accrue in rural communities, damages manifest in exposed cities. The net monetized employment minus air quality impacts varies spatially among counties, ranging from $-\$1.6\text{M}$ to $\$2.3\text{M}$. In physical units, this tradeoff ranges from 1 to 16,000 job-years per premature mortality among producing counties. We further estimate the number of life-years lost minus the number of job-years created by county, which ranges from $-1,100$ to $4,400$.

Correcting for air quality and climate externalities

Estimates of cumulative air, climate, and employment impacts and interdependencies have implications for decision making and policy evaluation. Here, we focus on policies to address air quality and climate externalities. Absent comprehensive policy, private firms across the supply chain have not faced the full costs of natural gas development, and the public has effectively subsidized pollutant emissions. Thus, production and activity across the supply chain have been greater than they would have been had producers and consumers internalized environmental costs.

We find that a supply chain tax on production of \$2 per thousand cubic feet (mcf) (+172%/−76%) should be levied to account for air quality and climate externalities, as shown in Figure 5. The proposed Pigouvian tax is derived based on historical cumulative damages across the supply chain and production rates in the Appalachian basin. A similar approach can be used to derive appropriate tax rates in other producing regions in the U.S., such as the Permian basin, Anadarko basin, Eagle Ford play, and Barnett play. The trajectory of production, changing system efficiencies, and other environmental policies are also relevant

considerations in setting a future tax rate. With additional modeling of cumulative impacts for natural gas substitutes (e.g., coal, wind, solar), analogous supply chain tax rates can be derived to account for the externalities of other energy sources. A supply chain tax on renewables is expected to be much lower than that for natural gas, whereas a tax on coal would be higher. Although there is regional variation in prices, supply chain taxes would generally make renewables more and coal less economically competitive with natural gas.

To contextualize the supply chain tax on natural gas, we compare it to wellhead prices, as reported by the top producing and publicly traded firms operating in the Appalachian basin. Wellhead prices have been volatile (e.g., approximately \$4 per mcf in 2014 and \$2 per mcf in 2016), but they are similar in magnitude as the proposed tax rate. In addition, there is a large disparity between the proposed tax rate and the existing taxes and fees (\$0.08 per mcf), which we estimate based on past severance tax or impact fee revenue in Pennsylvania, Ohio, and West Virginia and production rates from 2004 to 2016. This low value indicates that climate and air quality damages are not currently accounted for in existing state severance tax and impact fee structures.

With respect to tax policy design, to optimally correct for air pollution externalities, a tax should be set according to marginal damages, which spatially vary given the emissions, dispersion, exposure, and resultant health effects of natural gas activity. As shown in Figure 1f, the majority of adverse health effects occur in downwind urban counties, and correspondingly, tax rates will be higher near more densely-populated counties, such as those around Pittsburgh, Philadelphia, New Jersey and southern New York. While a tax that incorporates spatial variation may be optimal, the complexity of implementing such a policy may be prohibitive. Another policy design consideration is the distribution of revenue generated by taxes. One approach is to compensate communities for incurred harm. Figure 1c displays the incidence of premature mortality risk across the northeastern U.S. and how revenue could be distributed. Urban areas would receive relatively greater ex poste compensation than more rural areas. A final policy design consideration is jurisdiction. Externalities cross state borders, with roughly half of premature deaths in regions not producing shale gas, as shown in Figure 1f. Thus, an optimal corrective tax, if calibrated to damages, and subsequent distribution of revenue should be administered by a federal authority. Whereas, source regions may administer a tax that captures only part of the health impacts, which would be less efficient.

Discussion

This study provides insight on the cumulative socioeconomic and environmental impacts of natural gas systems. While this study focuses on air, climate, and employment impacts, there are other important outcomes and impact areas such as water quality and ecological health. Furthermore, an analogous approach that captures cumulative and disparate impacts can be applied to and comparisons can be made with other energy sources and technologies. The coal boom-and-bust cycle is a useful analogue, and a prevailing comparison is the relative climate and air quality advantage of natural gas over coal. Even without accounting for environmental externalities, there is an economic comparative advantage of natural gas as indicated by the shifting supply and demand from coal to natural gas in recent years.

Arguably more relevant comparisons, both currently and prospectively, are between natural gas and low carbon substitutes. In the case of a decarbonizing energy system, natural gas will continue to play a role (although potentially declining), given current technical constraints such as the intermittency of renewables, the availability of storage and transmission, and the pace of innovation, as well as social and political bottlenecks. Displacing natural gas (at least in part) with low carbon substitutes would seemingly reduce or eliminate air quality and climate impacts, while potentially increasing employment; however, additional modeling is needed to explore the effects of efficiencies resulting from learning and automation. The argument that natural gas may serve as a bridge fuel is in part premised on its comparative climate advantage over coal and cost advantage over renewables and other energy technologies. However, this is unsupported if natural gas prices do not reflect the actual economics for producing firms or of climate and air quality damages.

This study illustrates the need for multivalent policies that consider interdependencies and cumulative impacts over boom-and-bust cycles and across supply chains. This includes cross-media policies that account for processes that emit chemical species that may lead to air quality and climate impacts at varying spatial and temporal scales. This also includes both environmental and economic policy which may realign incentives to produce and develop the broader energy system in a way that considers longer time horizons and disparate impacts.

Methods

Scope of Analysis

The analysis focuses on the geologically-defined Appalachian basin consisting of the Marcellus and Utica, natural gas plays with combined 2016 proved reserves of 100 trillion cubic feet (see Supplementary Figure 1).²⁴ We further focus on impacts associated with shale gas, a type of unconventional gas in low permeability shale. Unconventional refers to both the resource (i.e., shale gas) and extraction technologies (e.g., hydraulic fracturing, horizontal drilling) used to facilitate production.

We model impacts that directly stem from natural gas activity from preproduction to end use within Pennsylvania, Ohio, and West Virginia. For example, we model emissions from activity within the tristate region and associated mortality risks, which extend beyond tristate boundaries, but exclude emissions from gas exported to interstate and international markets and end use outside of the region.

We leverage and cite many natural gas LCAs^{15–17,31–34,51}; however, the scope of our approach and LCAs are both overlapping and distinct, each providing different and complementary insight. Our approach is more expansive than most LCAs in that we model multiple impact areas, consider both intermediate (e.g., emissions) and outcome (temperature change, deaths, jobs) metrics, model all regionally-relevant supply chain end points, and account for the spatial and temporal distribution of impacts.

Magnitude, timing, and geographic location of natural gas activity

Inputs required to estimate all impacts include the magnitude, timing, and geographic location of shale gas activity across the supply chain.

We compile operator-reported shale well drilling and extraction data from the PA Department of Environmental Protection, Ohio Department of Natural Resources, and West Virginia Department of Environmental Protection, including production, coordinate location, and other attributes (e.g., producing formation, well direction, spud date, operator, etc.) for each shale well.^{52–54} Given the substantial variation and inconsistencies across states and years with respect to reporting requirements and data quality, we perform significant data cleaning and simulate missing data.

Gas consumption and county location information from processing, transmission, and distribution activities, as well as, residential, industrial, and commercial end uses are based on publicly available data reported by the U.S. Energy Information Administration (EIA)^{55–60} and U.S. EPA NEI⁶¹. We also compile point location data for processing, transmission, and distribution compressor stations as reported by the U.S. EPA NEI⁶², and distribution service line and main length data from the Pipeline and Hazardous Materials Safety Administration.⁶³ For electric generation, gas consumption volumes and county location information are derived from the U.S. EPA Continuous Emissions Monitoring System (CEMS)⁶⁴, U.S. EPA NEI⁶¹, and the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID)⁶⁵. We simulate natural gas activity data for non-reporting years.

Air pollution impact modeling

We first estimate spatially- and temporally-explicit NO_x, PM_{2.5}, and VOC emissions. The inclusion of and detail in which we model each emissions source varies based on the availability and quality of data, and the relative emissions contribution of each source. We use probabilistic methods to model and characterize uncertainty for nine upstream emission processes (i.e., drilling, hydraulic fracturing, well completion, trucking, wellhead compressors, condensate tanks, production fugitives, etc.), leveraging multiple measurement and modeling studies.^{7,10,16,17,66–80} Upstream emission modeling accounts for time-varying parameters, where practicable, such as changing regulation [e.g., Tier 2 and Tier 4 non-road diesel engine standards, New Source Performance Standards (NSPS) for stationary spark ignition internal combustion engines, and NSPS for new, reconstructed, and modified oil and natural gas sector sources], water management practices (e.g., increasing water reuse), and other efficiencies (e.g., drilling rig and hydraulic fracturing pump engine fleet turnover). We estimate emissions from midstream segments (i.e., processing, transmission, distribution) using facility-level emissions reported by the U.S. EPA NEI; emissions include compressor stations, but exclude transmission pipelines, service lines, and distribution mains.^{61,62} We also derive estimates for residential, industrial, and commercial end use based on county-level emissions reported by the U.S. EPA NEI. Industrial and commercial emissions include gas combusted by industrial and commercial (and institutional) boilers and internal combustion engines, respectively.⁶² Residential emissions include gas combusted for residential household heating, grills, hot water heating, and dryers. Electricity generation

emissions are derived based on reported plant-level NO_x emissions from U.S. EPA CEMS⁶⁴ and plant-level PM_{2.5} and VOC emissions from U.S. EPA NEI⁶¹. For midstream and end use segments, we linearly interpolate or extrapolate to derive emissions for non-reporting years. For spatial compatibility with the health impact models described in the subsequent paragraph, we aggregate emissions by county, as well as at a 36 × 36 km grid cell resolution. [Refer to Supplementary Methods for additional details regarding the air pollutant emissions modeling formulation and data inputs].

We estimate premature mortalities by combining the emissions inventory with three source-receptor reduced complexity models: Air Pollution Emission Experiments and Policy model (Version 3) (AP3)^{81,82}, the Air Pollution Social Cost Accounting tool (APSCA)⁸³, and Intervention Model for Air Pollution (InMAP)⁸⁴, which are functionally different but provide complementary insight. We use three different models because each employs a distinct approach to represent pollutant fate and transport, and thus, provide a representation of exposure uncertainty. Both AP3 and APSCA generate estimates of pollution-induced premature mortalities in downwind receptors associated with emissions from source locations. We use the version of InMAP whereby pollution-induced mortality risk is attributed to source location. Premature mortality estimates are sensitive to the relationship between pollutant concentration and health response; therefore, we perform a sensitivity analysis whereby we vary the concentration-response (C-R) relationship based on the American Cancer Society (ACS) and Harvard Six Cities (H6C) studies.^{85,86}

To develop monetized impact estimates, we use the value of a statistical life (VSL), a commonly used measure of the willingness-to-pay for small changes in mortality risk. We use a probabilistic VSL with a mean (and standard deviation) of \$8.5M (±\$5.7M) (in 2017 USD), and we assume the VSL follows a Weibull distribution, following the approach used by the U.S. Environmental Protection Agency.⁸⁷

There are additional scope limitations. Mortality and monetized air pollution impact estimates are not inclusive of all impacts associated with air pollution; specifically, out-of-state consumption of the Appalachian natural gas feedstock is not included and the set of processes, species, and health and environmental endpoints other than premature mortality is limited. Health impacts from natural gas extend beyond those associated with air pollution, such as health benefits associated with increased access to healthcare or costs associated with increased traffic accidents, are not considered here.

Climate change impact modeling

We first model GHG emissions, including CO₂ and CH₄. The inclusion of and detail in which we model each emissions source is based on the availability and quality of data, and the relative contribution of each source, as indicated by national inventories and LCA studies.^{17,30,31} The GHG emissions modeling approach differs from that used for air pollutants because of differences in the underlying data and model choice. Emissions modeling accounts for time-varying parameters, where practicable, such as changing regulation (e.g., NSPS) and operational efficiencies (e.g., drilling time). We develop process-level models for the following fifteen emission sources across the upstream and midstream segments of the supply chain: 1) preproduction combustion and CH₄ losses from well pad

preparation, drilling, hydraulic fracturing, and completion, 2) lease fuel combustion and CH₄ losses at production sites, 3) CH₄ losses at gathering facilities, 4) fugitive and vented CH₄ and plant fuel combustion at processing plants, 5) fuel combustion and CH₄ losses at transmission and storage facilities, and 6) CH₄ losses from distribution service lines and mains emissions. We use deterministic, parametric, and probabilistic methods to model upstream and midstream emissions and characterize uncertainty (where possible), and we employ a variety of data sources, such as methane measurement studies conducted from 2013 to 2016^{28,77,78,88–90}, the LCA literature on natural gas^{16,17,76}, and the U.S. EIA^{59,60,91–94}. We derive deterministic, state-level emissions for electric power generation, industrial, commercial, and residential end uses based on natural gas volumes and combustion efficiencies reported by the U.S. EIA.^{55–58} [Refer to Supplementary Methods for additional details regarding the emissions modeling formulations and data inputs].

We estimate climate impacts in terms of global average temperature change, which is well-suited for assessing the cumulative climate impact of long-lived greenhouse gases emitted from natural gas activity. We use absolute rather than relative metrics such as global warming potential and global temperature potential because relative metrics do not facilitate an understanding of the temporal trace of impacts over time. We only account for climate impacts of CH₄ and CO₂ and not other climate forcers, including short-lived chemically reactive gases (NO_x, CO, and VOCs) and particles. Recent work has shown that in most scenarios, emissions from the natural gas system other than CO₂ and CH₄ have relatively little climate impact.⁵¹ Our analytical framework can be expanded to include additional species and effects at other spatial scales.

Global temperature change is estimated using a convolution of the emissions model and the average global temperature potential (AGTP), which we formulate and parameterize based on several studies.^{37,39,45,95–101} AGTP is the temperature change at a given time in the future due to a marginal pulse of emission. It is a function of the radiative forcing due to a pulse emission and the temperature response to a unit of forcing, both of which are parameterized based on more complex models that explicitly include physical and chemical processes.⁹⁶ We use a Monte Carlo simulation approach to reflect uncertainty in the AGTP values. [Refer to Supplementary Methods for additional details regarding the selection of the global temperature change metric, as well as the modeling formulation and data inputs].

To generate monetized estimates of climate damages, we employ the social cost of carbon (SCC) and social cost of methane (SCCH₄), which represent the present value of the anticipated future damages that would arise from an incremental unit of emissions in a given year. We assume values ranging from \$10 to \$126 per metric ton of CO₂ and \$319 to \$2773 per metric ton of CH₄, as reported in U.S. EPA publications.^{102,103} A recent study by Ricke et al. (2018) estimates a SCC (\$177–805 per metric ton for 2020 emissions) much greater than the highest estimate in this study, suggesting our monetized damage estimates may be conservative.¹⁰⁴ These metrics account for climate change impacts, such as changes in agricultural productivity and human health, property damage from increased flood risk, and changes in heating and cooling costs.

Employment impact modeling

We first use an empirical approach to develop marginal employment factors for initial natural gas well development (e.g., job-years per drilled well) and ongoing production (e.g., job-years per producing well). We compile a panel dataset comprised of annual, county-level employment, earnings, population, natural gas activity, and other data over the period 2005 to 2015. The dataset consists of all 272 counties within Pennsylvania, Ohio, West Virginia, and New York, of which 93 counties produced unconventional natural gas and 195 counties are within (or partially within) the Marcellus and/or Utica shale plays. The full dataset includes 2972 observations, accounting for observations that were removed due to missing data. Employment and earnings data, reported by the U.S. Bureau of Economic Analysis (BEA), are based on administrative records of government social insurance programs and tax codes, and originate from the recipients of the income or from the payer of the income.

¹⁰⁵ We use estimates of total wage and salary employment [mean (m) = 101,979 jobs, standard deviation (sd) = 244,794 jobs], defined as the average annual number of full- and part-time jobs in each area by place of work. We also estimate the share of total earnings from different sectors - farm (m = 0.01, sd = 0.02), construction (m = 0.07, sd = 0.03), manufacturing (m = 0.16, sd = 0.11), and retail (m = 0.07, sd = 0.02) – based on total and sector-level earnings. We use the U.S. Bureau of Economic Analysis (BEA) estimates of county-level population¹⁰⁵, and combining those data with county-level land area values from the U.S. Census Bureau¹⁰⁶, we estimate population density (m = 971, sd = 5,584 persons per square mile). We classify and subset nonmetropolitan counties – the top 10 percentile of counties based on population. Including only nonmetropolitan counties creates a more homogenous sample, precluding counties with large cities from excessively influencing estimates from a linear model.¹⁹

To isolate employment effects from historical shale gas activity, we use an approach similar to that of Paredes et al. (2015).¹⁸ We specify empirical models in which we regress employment (and variants of the dependent variable) on various population, economic, and natural gas development explanatory variables and interaction terms. We include county fixed effects that control for observable and unobservable differences across counties and time fixed effects that control for common changes across counties that vary over time. To estimate the models, we use ordinary least squares (OLS) regression, and to control for serial correlation, we estimate robust standard errors by clustering by county. We test the effect of lag and lead variables to capture the dynamic effect of natural gas development, temporal variables to capture technological and operational learning, natural gas activity variables, natural gas development and time interactions, and alternative rate-based employment dependent variables. We additionally perform bootstrapping to capture the uncertainty around the employment effects of natural gas activity. [Refer to Supplementary Methods for details regarding the model specification and data inputs].

We estimate aggregate county-level employment over time by combining the natural gas activity data with the marginal employment effects. To monetize employment effects, we apply the historical annual average earnings per county (m = \$42,444, sd = \$9,663), as reported by the U.S. BEA.¹⁰⁵ This method is limited because it does not segment

employment and average earnings by sector, account for executive compensation, and differentiate between full- and part-time employment.

Supply chain tax estimation

We estimate a supply chain tax that would need to be levied to account for air quality and climate externalities. The Pigouvian tax is derived based on historical cumulative climate and air pollution damages across the supply chain and production rates in the Appalachian basin.

Data availability

The datasets generated during and/or analyzed during the current study are available from the corresponding author on reasonable request.

Code availability

Sample code developed for the current study are available from the corresponding author on reasonable request.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

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Figure 1. Air quality emissions and impacts across the natural gas supply chain from 2004 to 2016.

(a) Annual NO_x , $\text{PM}_{2.5}$, and VOC emissions from sources within Pennsylvania, Ohio, and West Virginia. (b) Spatial distribution of cumulative NO_x , $\text{PM}_{2.5}$, and VOC emissions by county from 2004 to 2016. Blue lines delineate the shale gas-producing counties. (c) Spatial distribution of cumulative premature mortality from 2004 to 2016 by receptor county. Estimates based on AP3 and APSCA source-receptor RCMs using the American Cancer Society (ACS) concentration-response (C-R) relationship. Larger figures depict Northeast U.S. and the insets depict the continental U.S. Blue lines border the source emission states. (d) Annual premature mortality estimated using different RCMs and C-R relationships. Solid points represent estimates based on ACS C-R relationship, and open points represent estimates based on Harvard Six Cities (H6C) C-R relationship. Circle, triangle, and square points represent estimates based on different RCMs: AP3, APSCA, and InMAP, respectively. Black lines represent average annual mortality across all six specifications. Grey shaded regions represent range of annual estimates. (e) Annual damages associated with premature mortality from air pollution. The black line and grey shaded region represent the simulated mean and 95% confidence interval, respectively, and reflect uncertainty in the VSL. Based on average annual mortality across all six specifications, as shown in (d). (f) Attribution of cumulative mortality from 2004 to 2016 by segment of the natural gas supply chain, emission source/non-source regions, urban/mixed/rural geographic regions, and air pollutant species. Attribution is estimated using premature mortality based on AP3 and ACS C-R specification.

Figure 2. Climate change impacts across the natural gas supply chain from 2004 to 2016. (a) Annual CH₄ and CO₂ emissions from sources within Pennsylvania, Ohio, and West Virginia. Dotted black lines depict emissions under low and high emissions assumptions [See Supplementary Table 10]. (b) Annual temperature impact indicating contributions from CH₄ and CO₂ emissions. Dotted black lines depict temperature impact under low and high temperature change potential assumptions [See Supplementary Figure 29]. (c) Attribution of cumulative temperature impact over 30- and 100-year integration periods (beginning in 2004) by segment of the natural gas supply chain and GHG species. (d) Climate change damages based on different social cost of carbon (SCC) and social cost of methane (SCCH₄) values. SCC and SCCH₄ estimates vary by year, and estimates for 2004 and 2016 (in units of \$ per metric ton) are provided for reference.

Figure 3. Employment impacts across the natural gas supply chain from 2004 to 2016.

(a) Annual employment from natural gas activity, including direct effects within the natural gas sector and spillover effects into other sectors based on marginal employment effects and actual natural gas activity. Line represents mean simulated employment, and shaded regions are 95% confidence intervals (based on clustered standard errors). (b) Annual earnings from employment resulting natural gas activity, including direct and spillover effects. Based on marginal employment effects, actual natural gas activity, and reported annual earnings per capita by county. Line represents mean simulated earnings, and shaded region is 95% confidence intervals. (c) Attribution of employment from natural gas activity by sector (direct and spillover), natural gas activity (spud and producing wells), and rural-urban regions. The sector attribution is based on fixed effects model 16 fit with alternative dependent variables, total employment and mining employment (a proxy for direct jobs within the natural gas sector) [See Supplementary T able 20]. The natural gas activity attribution is based on 2004–2016 cumulative employment. The rural, mixed rural-urban, and urban regions were classified based on the 2010 U.S. Census county rurality level tertiles and based on 2004–2016 cumulative employment. (d) Spatial distribution of 2004–2016 cumulative employment by county. Color shading of counties represents cumulative employment from natural gas activity. The color of the dots at county centroids represents the average annual size of the labor market, and the size of the dots represents the percentage of employment from natural gas activity out of total employment. All results are based on mean marginal employment effects from fixed effects model specification 16. Grey line delineates the shale gas-producing counties.

Figure 4. Comparison of air, climate, and employment impacts.

(a) Impacts in physical units over time, with vertical axes standardized to range from 0 to the maximum impact value. Air quality impacts based mean annual mortality estimates across six model specifications (under different RCMs and C–R relationships) [See Supplementary Table 6]. Climate impacts under base emissions and temperature change potential assumptions [See Supplementary Table 10 and Figure 29]. Employment impacts based on marginal effects from fixed effects specification 16 [See Supplementary Table 20]. **(b)** Monetized impacts over time under mid-range VSL and SCC assumptions: mean simulated VSL of \$8.5M; SCC ranging from \$29 (2004) to \$44 (2016) per CO₂ metric ton; and SCCH₄ ranging from \$720 (2004) to \$1161 (2016) per CH₄ metric ton. **(c)** Spatial distribution of cumulative air quality and employment tradeoff in units of monetized employment minus air quality impacts. Grey line delineates the shale gas-producing counties.

Figure 5. Climate change and air quality production tax rates.

Climate change and air quality tax rates are estimated based on annual or 2004 to 2016 cumulative impacts and production. Climate change impacts are based on mid-range social cost of carbon and methane values (3% mean discount rate), and air quality impacts are based on the mean simulated VSL (\$8.8M). The wellhead prices are based on Security and Exchange Commission 10-K filings of the top nine public producing firms in the Appalachian basin (as of 2017); the triangle points represent the production-weighted average price, and the lines represent the range. The effective current “tax” is based on the aggregate annual Pennsylvania impact fee, Ohio severance tax, and West Virginia severance tax revenues divided by annual production.