

Air quality impacts of projections of natural gas-fired distributed generation



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H I G H L I G H T S

- 6–24 GW of natural gas-fired DG penetration is estimated for 2030.
- Ozone levels may increase up to 6 ppb due to increased NG-fired DG penetration.
- Largest air quality impacts from NG-fired DG occur in New England and California.
- The greatest projected DG penetration occurs New England, New York, and California.
- Stricter emission limits for NG-fired DG greatly reduce air quality impacts of DG.

A R T I C L E I N F O

Article history:

Received 5 January 2017

Received in revised form

17 August 2017

Accepted 20 August 2017

Available online 23 August 2017

Keywords:

Distributed generation

Air quality modeling

Ozone

Particulate matter

A B S T R A C T

This study assesses the potential impacts on emissions and air quality from the increased adoption of natural gas-fired distributed generation of electricity (DG), including displacement of power from central power generation, in the contiguous United States. The study includes four major tasks: (1) modeling of distributed generation market penetration; (2) modeling of central power generation systems; (3) modeling of spatially and temporally resolved emissions; and (4) photochemical grid modeling to evaluate the potential air quality impacts of increased DG penetration, which includes both power-only DG and combined heat and power (CHP) units, for 2030. Low and high DG penetration scenarios estimate the largest penetration of future DG units in three regions – New England, New York, and California. Projections of DG penetration in the contiguous United States estimate 6.3 GW and 24 GW of market adoption in 2030 for the low DG penetration and high DG penetration scenarios, respectively. High DG penetration (all of which is natural gas-fired) serves to offset 8 GW of new natural gas combined cycle (NGCC) units, and 19 GW of solar photovoltaic (PV) installations by 2030. In all scenarios, air quality in the central United States and the northwest remains unaffected as there is little to no DG penetration in those states. California and several states in the northeast are the most impacted by emissions from DG units. Peak increases in maximum daily 8-h average ozone concentrations exceed 5 ppb, which may impede attainment of ambient air quality standards. Overall, air quality impacts from DG vary greatly based on meteorological conditions, proximity to emissions sources, the number and type of DG installations, and the emissions factors used for DG units.

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1. Introduction

Distributed electric power generation (DG), as a subset of

distributed energy resources (DER), entails the use of small capacity power generation technologies, such as gas turbines, internal combustion engines and fuel cells on the order of a few tens of MW or less, to produce electricity, and in some instances thermal energy, for local use. While DG also includes renewable energy technologies such as solar photovoltaic (PV) and wind turbines, the focus of the present study is an environmental analysis of the potential air quality impacts of natural gas-fired DG units. A variety of electricity industry drivers are converging to allow for a resurgence of interest in natural gas fired distributed generation. These drivers include improved DG technologies, low natural gas prices, high electric retail rates, flat load growth, and policy and incentive programs in certain areas of the country. DG technologies can fulfill the energy needs of customers. For instance, DG units can deliver critical customer loads with emergency stand-by power; support available capacity to meet peak power demands; and provide low-cost total energy in combined heat and power (CHP) applications. Typical uses of DG deployments include cogeneration, peak shaving, backup generation, and on-site generation (EPRI, 2014). Typical customers for fossil fuel fired DG systems include commercial and industrial enterprises, which are the focus of this study. Emerging DG technologies have the potential to be an important component of future electricity infrastructure, as the traditional grid is expected to morph into a smart power system capable of supporting the needs of the digital society of the twenty-first century. Therefore, it is crucial to ensure a clear understanding of their potential environmental impacts, including air emissions and any resulting changes to air quality.

There have been a number of studies that analyzed the potential effects of DG on air quality in some areas of the United States. Some studies focused on the potential increase in emissions from natural gas-fired DG compared to central generation (Allison and Lents, 2002; Strachan and Farrell, 2006) and advocated for manufacturer-based regulations that account for total supplied energy output (heat and power) to include all major efficiency advantages of DG technologies. Others have examined the impact of a shift from centralized power plants to fuel-powered (e.g., natural gas or diesel) small-scale distributed electricity generation on population inhalation exposure of primary pollutants in California (Heath et al., 2006; Heath and Nazaroff, 2007). They found that the low stack height of DG sources and their proximity to densely populated areas dramatically increases human exposure to air pollutant emissions compared with central station power plants. Several studies analyzed the effects of natural gas-fired DG in California, using dispersion modeling (Venkatram et al., 2010; Jing and Venkatram, 2011) or photochemical grid models (Rodriguez et al., 2006; Carreras-Sospedra et al., 2010; Vutukuru et al., 2011). Those studies investigated effects of new emissions regulations, duty cycle, and the spatial distribution of DG installations and used air quality modeling to evaluate impacts of DG on ozone and particulate matter (PM) concentrations and pollutant exposure in those regions. The studies concluded that the most important parameters that define the potential air quality impacts are the total installed capacity and emission factors for DG. Various plausible spatial distributions showed little effect on overall air quality impacts. Other studies analyzed potential effects over the Eastern US caused by natural gas-fired DG (Carreras-Sospedra et al., 2008) and back-up diesel generators (Gilmore et al., 2006, 2010). The studies on diesel back-up generators determined changes in ambient concentrations of pollutants and used concentration-response functions and economic parameters to evaluate the monetary cost of health impacts. Results showed that uncontrolled diesel backup generators as peaking DG units would increase PM concentrations but would cause both increases and decreases in ozone concentrations. Increases in PM concentrations up to 5 $\mu\text{g}/$

m^3 were found in all four modeled cities and were due mostly to primary emissions. Increases in NO_x emissions caused modeled ozone concentrations to decrease in urban centers due to titration effects but increase in the surrounding areas where the NO_x/VOC ratio is lower.

In general, the modeling studies were limited to simulations that spanned only a few days, although the time periods selected for the modeling were representative of conditions that typically lead to adverse air quality. Most research has focused on California and, to a lesser extent, the northeastern United States. This study estimates the potential implementation of natural gas-fired DG in the contiguous United States, including displacement of power from central power generation, and simulates the potential impacts on emissions and air quality. The study includes four major tasks:

1. Modeling of distributed generation market penetration using the DISPERSE model
2. Modeling of central power generation systems using the US-REGEN model
3. Modeling of spatially and temporally resolved emissions
4. Photochemical grid modeling using the CAMx model

The methodology for each of the tasks is described briefly in the Methodology section, and a more exhaustive description is included in the supplementary material. This article provides an updated picture of the potential impacts of increased implementation of natural gas-fired DG in the contiguous United States by integrating a novel and comprehensive electric power sector model with a DG market study. Impacts on emissions are refined from previous studies by using up-to-date emission factors from recent technology surveys. Additionally, air quality simulations are performed for both summer and winter conditions and over time periods that span several weeks, rather than only a few days, to provide a more complete assessment of potential impacts on air quality. This paper explores a range of plausible scenarios while providing a modeling framework and methodology that can be applied in future studies to assess the potential implementation and impacts of distributed generation of electricity. The results of this analysis are not intended to be definitive predictions of future DG deployment or future air quality but rather provide insights on potential degrees of DG deployment and the resulting impacts on emissions and air pollutant concentrations. Limitations of this study and recommendations for future work are summarized in section 4.

2. Methodology

The potential air quality impacts of increased DG penetration are evaluated for a winter and summer period in 2030 using year 2007 meteorology. DG units include power-only distributed generation (power-only DG) and combined heating and power (CHP) units that are located near the place of use and are used to supply electricity and thermal energy to a specific commercial or industrial load. In this paper, “DG” will be used to refer to both power-only DG and CHP units. Projections of DG penetration throughout the contiguous United States are estimated using the DISPERSE model, which produces hourly-resolved and size-resolved electricity generation for both power-only DG and CHP applications for up to 34 states where DG penetration was projected to be cost effective. DG market penetration estimates are translated into spatially and temporally resolved emissions and combined with emissions from other sources. The US-REGEN model is used to determine the impact of additional distributed generation on the capacity and dispatch mix of the electric sector, and thus, the impact on electric sector emissions. For other source sectors, the 2030 baseline

emissions for the reference case are described in the recent national modeling study conducted by [Nopmongcol et al. \(2017\)](#). The resulting total emissions are used as input to the Comprehensive Air Quality Model with Extensions (CAMx) to conduct the air quality modeling. The various scenarios considered in this study are outlined in [Table 1](#) and described in detail in the following sections.

2.1. Modeling of distributed generation market penetration

The DG market penetration analysis is performed using the DIStributed Power Economic Rationale SElection (DISPERSE) model ([RDC, 2014](#)). DISPERSE is a spreadsheet-based model that is used to estimate the achievable economic potential for distributed generation systems by comparing the cost to obtain, operate, and maintain the DG system to the cost of traditional utility-purchased heat and power. The model determines which combination of size, rate schedule, and operating mode is the most economical for a given facility. That is, the DISPERSE model determines the sites where the adoption of DG is economical for each of the three scenarios discussed below, using a payback period of 10 years or less. The sites with successful economics (i.e., those that can support a payback period of 10 years or less) represent the total economic potential (in MW). The total economic potential values are held static throughout the analysis period (2015–2030), with no growth in number of sites nor change in DG technology price or performance characteristics over time.

For the projected DG penetration analysis (estimated market adoption through 2030), the sites with successful economics are evaluated for adoption by first grouping by payback period range. Drawing from a study that quantified the likelihood for a customer to adopt DG based on payback period ([EPRI, 2003](#)), the pool of potential sites is evaluated based on their payback period, and the percent that adopt DG is based on the DG adoption percentages for each payback period range shown in [Table S1](#). These percentages represent the likelihood of a customer to adopt DG at a moment in time, but this decision is not continuously being made. Therefore, this process is repeated every five years from 2015 to 2030, for each of the three scenarios, to determine the total MW adopted ([Fig. S8](#)). As sites adopt DG, they are then removed from the pool of potential sites evaluated for subsequent adoption. DG adoption increases in future years as only a certain percentage of customers adopt DG at a moment in time, and the remaining pool of sites is re-evaluated for adoption five years later. Hourly load impacts are estimated every five years through 2030, based on modeled load profiles and DG usage patterns. For the hourly impacts, the total capacity of DG adopted was modeled to operate by meeting the 24-h site load profiles for a typical weekday, a weekend, or a holiday. These results are provided for each state, broken down by commercial,

institutional, and industrial sectors, for three different size classifications. The economic potential for commercial and institutional facilities (e.g., office buildings, hotels, hospitals, colleges, etc.) is grouped in the “Commercial” category while the potential for industrial and manufacturing facilities is labeled as “Industrial”. The database of sites comes from publicly available data including County Business Patterns (CBP, <http://www.census.gov/econ/cbp/>) and Commercial Business Energy Consumption/Manufacturers Energy Consumption Surveys (CBECS, 2010; MECS, 2010). For the CBECS/MECS data, each building is treated as a site. The CBP data provides the number of establishments, and each industrial sector establishment is treated as a site. No residential applications were considered in this study. [Fig. 1](#) illustrates how the DISPERSE model organizes the key data inputs and generates the desired outputs. One limitation of the DISPERSE model analysis is that several of the inputs are fixed throughout the analysis period (2015–2030). These inputs include DG technology price and performance parameters and other market characteristics, such as the database of sites, building characteristics (e.g., load profiles), and financial parameter assumptions. For example, future growth in the number of potential sites for DG is not considered in the DISPERSE model analysis, nor are possible changes in financial parameter assumptions that could affect the percentage of customers who adopt DG. The assumption was made to keep these market characteristics fixed throughout the analysis period as they build upon the predecessor study ([EPRI, 2014](#)), which focused on looking at current market potential for DG based on best available information at the time of the study. The results of the DISPERSE analysis are not intended to be definitive predictions of future deployment, but rather provide insight as to potential degrees of DG market adoption under various plausible scenarios with inputs and assumptions for each described below. Note that while price and performance parameters for DG units are fixed over time, the medium and high DG penetration scenarios explore how possible future improvements in natural gas-fired DG technologies could affect the projected penetration DG. A more detailed description of the inputs, assumptions, and data sources used in the DISPERSE model analysis is included in section 2.1 of the supplementary material.

Thus, for this effort, the DISPERSE model is configured to:

- Evaluate the contiguous United States market for DG applications using natural gas as a fuel, with price and performance parameters for each scenario described below.
- Examine the potential for DG applications at a variety of commercial and industrial sites.
- Process the costs and benefits for each DG unit at each site (versus utility power) and determine the DG system with the most attractive economics for each site that is analyzed.

Table 1
Name, application, and description of all scenarios considered in this study.

Scenario	Model/ Application	Description
Reference Case	US-REGEN CAMx	The Reference Case scenario includes no additional projected DG penetration and serves as the baseline to determine changes in emissions and air quality.
Low DG Penetration	DISPERSE US-REGEN CAMx	The Low DG Penetration scenario represents the lowest projected DG penetration in this study.
High DG Penetration	DISPERSE US-REGEN CAMx	The High DG Penetration Scenario represents the greatest projected DG penetration in this study.
CARB Certification	CAMx	The CARB Certification scenario uses the same DG penetration as the High DG Penetration scenario but assumes the lowest emissions factors for all DG units, which correspond to CARB certification limits.
Medium DG Penetration	DISPERSE	The Medium DG Penetration scenario is considered only in the DISPERSE model analysis.

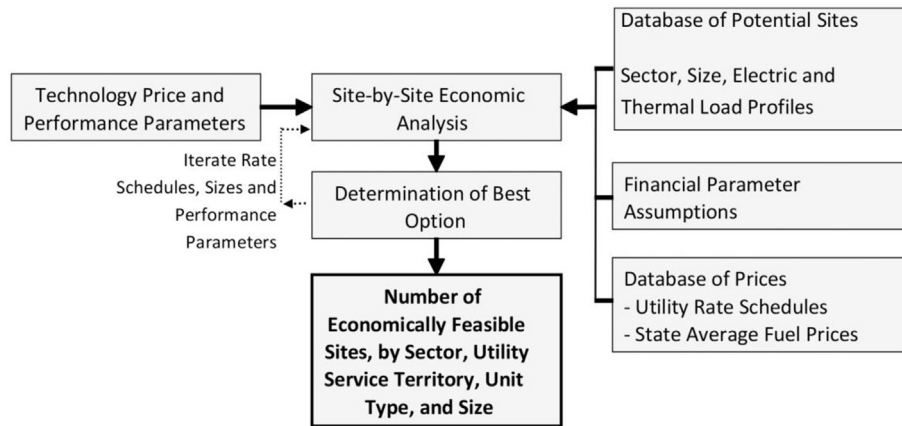


Fig. 1. Organization of key data inputs and outputs of the DISPERSE model.

The DISPERSE model performs a life-cycle cost economic analysis, based on fuel expenses, cost and performance data, electricity bill savings from modeled tariffs, and monthly state average fuel prices. The model determines whether any power-only DG or CHP technology option can achieve a 10-year payback compared to utility energy purchases. These results constitute the total economic potential, from which DG adoption is projected using the likelihood of adoption percentages shown in Table S1. The likelihood of adoption drops as low as 5 percent at payback periods of 7–10 years, and 0 percent at payback periods of over 10 years (EPRI, 2003). Thus, sites are limited to 10-year payback periods as longer periods would have no effect on DG adoption (EPRI, 2003). See section 2.1 and Table S1 of the supplementary material for additional information on DG adoption percentages by payback period. The best DG technology option is selected based on the shortest estimated payback period. This process is repeated hundreds of thousands of times, once for each group of sites within a combination of a DG unit size range/customer sector in the database of sites, to obtain the optimal configuration. Certain DG technologies meet the needs of certain applications and/or size categories more effectively than other technologies, and this is reflected in the relative economics of the various technologies. The resulting selection of DG technologies is used to model spatially resolved emissions for DG units as discussed in section 2.3. Note that while fuel cells were considered in the study from which the DG market potential results were derived (EPRI, 2014), they were not found to be economic with current price and performance data. Similarly, Stirling generators were found to not be commercially available and lacked reliable cost and performance data (EPRI, 2014). Thus, the DG technologies considered in this study are microturbines, turbines, and reciprocating internal combustion engines of various sizes (all natural gas-fired) with price and performance parameters shown in Table S2.

Three scenarios for DG market penetration are analyzed in this study:

1. Low DG Penetration scenario – this scenario assumes 2014 cost and performance specifications for power-only DG and CHP applications collected from recent technology survey (EPRI, 2015), along with load profiles of commercial and industrial facilities and market counts of these establishments. The price and performance parameters used in all three scenarios considered in the DISPERSE model analysis are provided in Table S2.
2. Medium DG Penetration scenario – the same load profiles and site data from the low DG penetration scenario are used, but the price and performance characteristics are altered to reflect a scenario where higher electric efficiencies at lower installed costs for power-only DG and CHP are prevalent. Electric efficiencies are improved by 10 percent for the medium and high DG penetration scenarios, while installed costs for DG units are lowered by 20 percent, based on reductions from a previous study that were found to have a significant impact on the market while constituting reasonable but still aggressive cost reductions from the technology manufacturer (EPRI, 2014). In both the medium and high DG penetration scenarios, the additional cost of heat recovery for CHP applications remains the same, and the 10 percent ITC credit for CHP systems is removed. The ITC for CHP systems was authorized through 2016, so an assumption was made that it would no longer be available during most of the study period. Thus, to be consistent, it was not considered at all. These adjustments create more favorable economics for power-only DG applications. However, with the improved electric efficiency and lower installed costs, many CHP applications also became more attractive, as the value of recovered thermal energy is still significant. This scenario is considered only in the DG market penetration analysis; it is not considered in the US-REGEN modeling of central power generation systems or in the air quality simulations performed using the CAMx model.
3. High DG Penetration scenario – The high DG penetration scenario explores how a natural gas cost of \$4/MMBtu would affect the potential market adoption of power-only DG and CHP units, keeping the medium DG penetration scenario price and performance parameters described above. The \$4/MMBtu price was established in the predecessor study (EPRI, 2014) and was seen as a fairly aggressive reduction in gas cost that was also being considered as a potential price with increasing gas supplies. It is not intended to be a projection of future natural gas prices, albeit actual natural gas prices have since declined further to nearly \$3/MMBtu. With the low natural gas costs, the value of recovered thermal energy from CHP units is diminished, and more power-only DG applications become attractive, especially for small commercial applications.

In the low and medium DG penetration scenarios, the 2013 Energy Information Administration (EIA) state level gas prices are used. For example, industrial gas prices ranged from \$4.1/MMBtu in Louisiana to \$8.6/MMBtu in New Hampshire for industrial, and \$5.5/MMBtu in Idaho to \$11.6/MMBtu in Delaware for large

commercial. Different gas prices and escalation rates (for both electricity and natural gas), taken from the 2014 EIA Annual Energy Outlook (AEO), are used for industrial/high load factor and commercial/low load factor applications in the economic analysis (EIA, 2014). Another limitation of the DISPERSE model analysis is that gas prices are fixed at \$4/MMBtu high DG penetration scenario, but electricity rates still escalate according to AEO forecasts. Although this may seem inconsistent given the correlation between natural gas prices and electricity rates, the degree to which changes in natural gas prices affect electricity prices in the U.S. is regionally dependent and can also depend on the degree of fuel switching (e.g., from coal-fired generation to gas-fired generation) that occurs (Linn et al., 2014). When there is more fuel switching, the reduction in electricity prices in response to decreased natural gas prices is generally smaller.

Of the three DG scenarios considered in the DISPERSE model analysis, two are chosen for the environmental analysis (which includes spatial allocation of emissions and subsequent air quality modeling). The emissions and air quality impacts of DG are analyzed for the low DG penetration scenario and the high DG penetration scenario to show the bounds in potential air quality impacts between the cases with the lowest and highest DG market adoption. Although the medium DG penetration scenario is not considered in the environmental analysis, it provides insight as to how higher electric efficiencies at lower installed costs can affect the future penetration of the DG technologies considered in this study, while electricity and natural gas prices still escalate according to the 2014 EIA AEO. The reference case described in section 2.2 is a scenario with no additional DG penetration, and serves as the baseline to determine changes in emissions and air quality.

For the market penetration analysis, sites with existing CHP applications are removed from the economic potential estimates. The sites that showed economic potential in the model are compared to a database of existing CHP installations. For each state and utility service territory, when facilities with the same principal building activity or Standard Industrial Classification/North American Industry Classification System (SIC/NAICS) code are found to have existing CHP installations of a similar size to what is found with the DISPERSE model, those installations are removed. With the current CHP installations netted out, all of the reported economic potential can be considered to be for new power-only DG and CHP installations. Existing CHP installations are obtained from ICF Combined Heat and Power Installation Database (<http://www.eea-inc.com/chpdata/>).

2.2. Modeling of central power generation system using the US-REGEN model

The U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was developed by the Electric Power Research Institute (EPRI, 2014b). The model combines detailed power sector capacity planning and dispatch for the contiguous 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the economy. For this study, the electric sector model is used by itself, as the exogenous projections of distributed generation were small relative to total load in most regions, so feedback effects from the rest of the economy were expected to be minimal. The model is run in a 15 region mode (Fig. S1) using 5-year time steps from 2010 to 2030. Additional information on the US-REGEN model is available at <http://eea.epri.com/usregen>.

The electric sector model is a detailed dispatch and capacity expansion model of the US electric system. It includes a partially disaggregated representation of both existing generation unit capacity and the hourly profile of load and variable resource availability. These details allow the model to explicitly evaluate dispatch

decisions (when and for how long installed capacity operates) as distinct from capacity decisions (new investment, retrofit, or retirement). The model can also evaluate and build new inter-region transmission if this is economic to meet load.

The model simultaneously determines a cost-minimizing solution for all regions over the entire time horizon subject to technical and policy-related constraints. This modeling structure places US-REGEN in a class of dynamic, forward-looking capacity-expansion models. Furthermore, US-REGEN's spatial and temporal detail ensure resource adequacy for each region and capture market dynamics not only for electricity but also for regulatory instruments such as RPS credits. Costs include variable costs that scale with dispatch (mainly fuel and variable operating and maintenance (VOM) costs), fixed operating and maintenance (FOM) costs that scale with installed capacity, and investment costs associated with new capacity additions (of both generating and inter-region transfer capacity). A 5% discount rate is assumed to compare costs across different time steps.

The goal of this analysis is to understand the impact of additional distributed generation on the capacity and dispatch mix of the electric sector, and thus, the impact on electric sector (e.g., EGU) emissions. To study this question, three scenarios are explored.

1. Reference Case – EPRI's Energy and Environmental Analysis (EAO2014) reference case assumptions (as described below) with no additional DG penetration. The reference case scenario serves as the baseline to determine changes in emissions and air quality.
2. Low DG Penetration scenario – Reference case assumptions combined with a conservative forecast of DG penetration. This scenario uses the DG penetration projected in the low DG penetration scenario described in section 2.1.
3. High DG Penetration scenario – Reference case assumptions combined with a more aggressive forecast of distributed generation penetration. This scenario uses the DG penetration projected in the high DG penetration scenario described in section 2.1. However, note that the natural gas prices used in the US-REGEN model analysis still escalate in this scenario, despite being fixed at \$4/MMBtu in the DISPERSE model analysis. This is a limitation of the high DG penetration scenario as changes in the price of natural gas can affect the generation mix projected by the US-REGEN model.

The emissions processing steps for the preparation of US-REGEN EGU emissions for CAMx air quality modeling is described in section 2.2 of the supplementary material. Key assumptions for the reference case are drawn from EPRI's EAO2014 reference scenario. These include:

1. Regional load growth and fuel price paths calibrated to the EAO2014 reference case.
2. Key existing environmental regulations, including the Mercury and Air Toxics Standards (MATS), State Renewable Portfolio Standards, the RGGI cap and trade market, and EPA's New Source Performance Standard for CO₂ Emissions.
3. Age limits for all units, except for existing coal. However, the model can retire a unit at any time for economic reasons.
4. Limitations on new transmission and nuclear builds per year. These include a 7 GW per decade limit for new nuclear and a limit of 20% increase in transmission (GW-miles) per decade over the base stock. More details on growth limits can be found in the US-REGEN model documentation (EPRI, 2014b).
5. Technology costs per EPRI's Generation Options Report (EPRI, 2012). The EPRI Technical Assessment Guide (TAG) program is soon to publish the 2017 Generation Options Report, which

shows little change in most technology costs except for solar and wind. While solar and wind do show cost reductions compared with the 2012 report, the subsequent drop in gas prices (also not captured in the 2012 report) essentially reverses any increased renewable penetration in the US-REGEN modeling.

The Clean Power Plan, which was not finalized at the time of this analysis, is not included in any of the scenarios. Similarly, the CSAPR Update Rule is not included in the scenarios. The two central power scenarios with additional distributed generation include all of the reference case assumptions, and in addition include penetration of DG projected in the DISPERSE market analysis. This is modeled as a reduction in load growth by state, so that the US-REGEN model solves to find the least cost capacity and dispatch mix for the residual load after the DG is subtracted. Load shapes for the different types of distributed generation are accounted for in determining the shape of the residual load. The unique integration of the US-REGEN model with the DG market penetration analysis provides an updated picture of potential impacts of widespread implementation of DG in the contiguous United States. The DISPERSE and US-REGEN modeling explore plausible scenarios of future DG deployment and the resulting impacts on the electric sector and are not intended to be definitive predictions of future generation.

2.3. Modeling of spatially resolved emissions for DG units

Projections of power generation resolved by activity sector and by state are further processed to provide the desired spatial resolution to conduct air quality modeling. To accomplish the desired resolution, land use (LU) geographical information systems (GIS) data is used. For this study, GIS data are obtained from the US EPA Emissions Modeling Clearinghouse (<http://www.epa.gov/ttn/chief/emch/index.html>). Land use GIS data are used to generate spatial surrogates that are used by the Sparse Matrix Operational Kernel Emissions (SMOKE) model to spatially resolve emissions from a county-wide resolution to a regular grid resolution, e.g. 12 km by 12 km resolution used to simulate air emissions and air quality in the contiguous United States. The land use GIS data include total surface area dedicated to specific activity sectors by census block. Activity sectors with DG penetration include colleges, hospitals, office buildings, hotels, and warehouses. A complete list of activity sectors that exhibit DG penetration and their corresponding land use categories is shown in Table S3 of the supplementary material.

Census blocks have irregular shapes and sizes, and in general, census blocks with higher population density tend to be smaller than census blocks in less populated areas. For air quality modeling, emissions need to be allocated over a regular-sized grid. Thus, the first step to use land use data for the allocation of emissions requires the processing of census-block-based spatial distribution into regular-grid-based spatial resolution. To accomplish this step, GIS spatial analysis tools are used to calculate the average square footage of a particular sector in a grid cell. Because penetration of DG in each scenario is estimated at the state level, the square footage of a particular sector is then normalized by the total area of that particular sector in each state. The resulting normalized spatial distribution is multiplied by the total state-wide power generation

for that sector to determine the spatial distribution of DG units.

The methodology to allocate DG units throughout the modeling domain takes into account the discrete size distribution of DG installations (shown in Table 2). Hence, the methodology assumes that an integer number of units of a particular size are used to meet the power demand projected by a particular scenario. For example, if a particular cell requires 1.20 MW of size category 1, a total of 5 units of 0.25 MW should be installed to meet that demand. As a result, the total installed capacity of DG units in the low and high DG penetration scenarios (Fig. 2) may be greater than the estimated market adoption projected in the DISPERSE model analysis (Fig. S8).

The following steps describe the methodology used to spatially allocate DG units into rectangular grid cells for a representative state “X”:

1. For each activity sector in state X, grid cells are ranked from the highest to the lowest land use density by dividing the square footage of each sector in that cell by the total area of that sector in state X.
2. Starting from the cell with the highest land use density, the total number of units of each size that should be installed in that cell is calculated by multiplying the land use density of each activity sector in that cell times the total power projected for that activity sector in state X.
3. DG units continue to be added into grid cells in order of decreasing land use density until the total power demand projected for each activity sector in state X is met.

The steps above are repeated for each state that exhibits DG penetration. An example illustrating how DG units are spatially allocated can be found in section 2.3 of the supplementary material (Fig. S2). The resulting spatial distribution of DG unit installations for the low DG penetration and high DG penetration scenarios is shown in Fig. 2. The total installed capacity for the contiguous United States is 7.6 GW and 25.4 GW for the low DG penetration and high DG penetration scenarios, respectively.

2.3.1. Emissions factors for DG units

Emissions factors for natural gas-fired turbines and reciprocating internal combustion engines used in previous studies vary widely, sometimes by more than an order of magnitude, depending on assumptions regarding after-treatment, unit size, operating conditions, and emissions limits application to the study region (Allison and Lents, 2002; Rodriguez et al., 2006; Strachan and Farrell, 2006; Carreras-Sospedra et al., 2008; Vutukuru et al., 2011). In general, there is a lack of current, systematic emissions test data for criteria pollutants from currently available, commercial DER technology, particularly for VOC and PM emissions (EPRI, 2015). Note also that with current commercial technology, highest efficiency and lowest NO_x emissions are not achieved simultaneously, and CO and VOC emissions are higher in engines optimized for minimum NO_x (EPRI, 2015). The emission factors used in this study are extracted from a recent DG technology survey (EPRI, 2015), which compiled and reviewed available information on measured and estimated emissions factors, air regulatory requirements for permitting DG devices, and knowledge gaps on air

Table 2
Representative unit sizes and preferred prime mover for each size category used in the spatial allocation of DG units.

Size category	Installation type	Representative size for spatial allocation
1	Small engines <1 MW	0.25 MW
2	Engines 1–5 MW	1.00 MW
3	Turbines or large engines >5 MW	5.00 MW

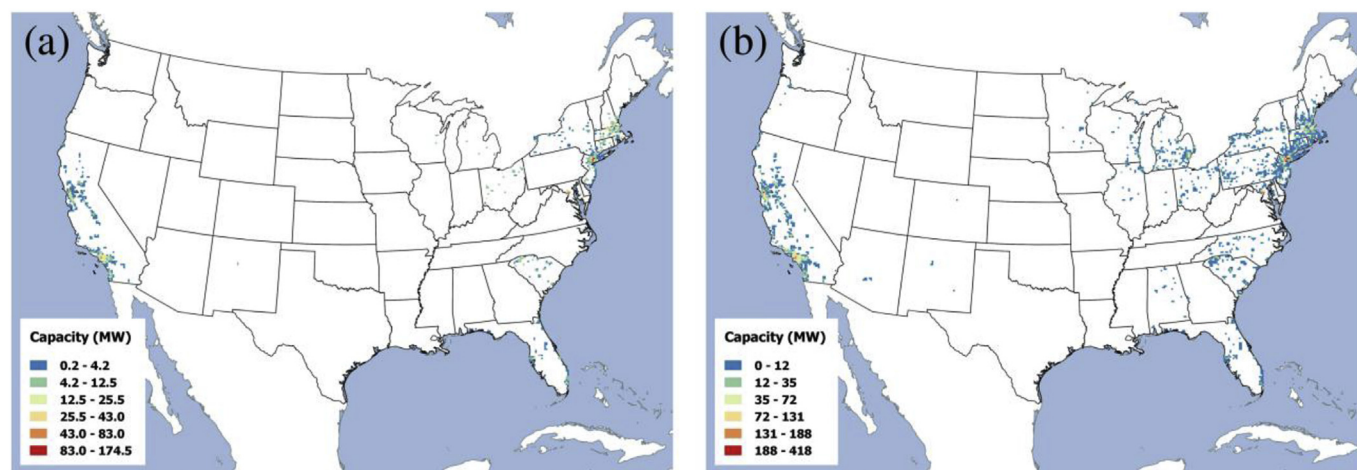


Fig. 2. Spatial distribution of DG unit installations in 2030 for (a) the low DG penetration scenario and (b) the high DG penetration scenario. Total installed capacity for the contiguous United States is 7.6 GW in the low DG penetration scenario and 25.4 GW in the high DG penetration scenario.

emissions, with a focus on natural gas-fired DG technologies. It provides information on emission factors reported by manufacturers and those obtained from emission testing data available at the time of the survey. Emissions from DG units are regulated by federal emissions standards, and some states and regional regulatory agencies establish more stringent emission limits. In particular, there are specific emission standards for the states of California, Texas, Massachusetts and Connecticut. Following the methodology of Carreras-Sospedra et al. (2008), emission regulations for New Jersey and New York are assumed to be the same as Connecticut in this study. For the rest of the states, federal emission regulations apply.

For the calculation of total emissions from DG in this study, the highest value of the emission factors reported by manufacturer and test data (i.e., with no after-treatment) is assumed as the baseline factor for each technology. However, these values are capped at the applicable emission standards. Namely, DG units are not allowed to exceed the emission limits applicable in a particular region. Some emission factors reported by manufacturers or from emission testing are lower than the emission limits applicable in various states. For these instances, the lower value is used to calculate DG emissions. The resulting emission factors used in this study are presented in Table 3. While no after-treatment is assumed when determining the baseline emissions factor for DG, the CARB certification scenario (described below) explores how implementing more stringent emissions limits for DG units, which typically reflect

emissions factors with after-treatment, can affect the emissions and air quality impacts of increased DG penetration. Details on the speciation of VOC and PM emissions are included in section 2.3.1 of the supplementary material and speciation profiles for NO_x , SO_x , VOC, and $\text{PM}_{2.5}$ are shown in Table S4.

Based on the economic analysis of this study conducted using the DISPERSE model (section 2.1), reciprocating engines will be the dominant prime mover in all power-only DG installations. Also, we find that reciprocating engines provide better economics for CHP applications that are 5 MW and smaller. Only CHP installations larger than 5 MW present economic conditions favorable for gas turbines. Consequently, emissions factors for CHP units larger than 5 MW were assumed to correspond to gas turbines, whereas the emission factors assumed for the rest of the power-only DG and CHP units correspond to reciprocating engines.

CHP applications offset the heat that would otherwise be produced by boilers, reducing the overall impact on emissions. The methodology to account for emissions displacement by CHP is described in Medrano et al. (2008), and was first used in Rodriguez et al. (2006), then Carreras-Sospedra et al. (2010) and Vutukuru et al. (2011) to determine the overall air quality impacts of CHP. The methodology can be summarized as follows. The heat utilization factors for different prime movers are taken from the 2012 Self-Generation Incentive Program Impact Evaluation and Program Outlook (http://www.cpuc.ca.gov/NR/rdonlyres/25A04DD8-56B0-40BB-8891-A3E29B790551/0/SGIP2012ImpactReport_20140206.pdf). These factors indicate the amount of heat utilized per unit of electricity generated by the CHP unit ($\text{MW}_{\text{heat}}/\text{MW}_{\text{elec}}$) and are used to determine the amount of boiler emissions that are offset through the use of CHP. The heat utilization factors used in this study

Table 3

Emission factors for engines and gas turbines (lb/MWh) used in the low DG penetration scenario and high DG penetration scenario.

	Region					
	Federal	CA	East TX	West TX	CT	MA
<i>Reciprocating Internal Combustion Engines</i>						
NO_x	1.80	0.50	0.14	1.80	0.15	0.15
CO	6.20	1.90	6.20	6.20	1.00	1.00
VOC	1.00	0.50	1.00	1.00	1.00	1.00
SO_2	0.01	0.01	0.01	0.01	0.01	0.01
PM	0.05	0.05	0.05	0.05	0.03	0.03
<i>Gas Turbines</i>						
NO_x	0.70	0.25	0.14	0.70	0.15	0.14
CO	0.70	0.20	0.70	0.70	0.70	0.09
VOC	0.08	0.04	0.08	0.08	0.08	0.08
SO_2	0.01	0.01	0.01	0.01	0.01	0.01
PM	0.09	0.09	0.09	0.09	0.03	0.09

Table 4

Efficiency parameters for CHP prime movers used in this study and the overall heat recovery utilization (f_{CHP}) calculated assuming 2012 heat utilization factors.

Prime mover	Engine	Engine	Turbine
Size Category	<1 MW	1–5 MW	>5 MW
DG Size (MW)	0.250	1.000	5.000
η_{electric}	29%	37%	32%
η_{total}	79%	82%	74%
η_{boiler}	80%	80%	80%
Displaced Boiler Size (MW)	0.539	1.520	8.203
Heat Utilization Factor	1.08	1.08	1.03
f_{CHP}	50%	71%	63%

correspond to 1.03 for gas turbines and 1.08 for engines, as shown in Table 4. To determine the overall heat recovery utilization (f_{CHP}) based on these factors, one needs the electric and overall efficiencies for the main prime movers and boilers. Based on the parameters assumed in the economic analysis described earlier, the f_{CHP} values are presented in Table 4, where η_{electric} and η_{total} are the electric and overall efficiencies of DG units and η_{boiler} is the efficiency of boilers.

The size of the boiler that can be displaced by CHP is calculated as follows:

$$\text{Displaced Boiler Size} = (\text{DG size}) \times \frac{(\eta_{\text{total}} - \eta_{\text{electric}})}{\eta_{\text{electric}} \times \eta_{\text{boiler}}}$$

The overall heat recovery utilization, f_{CHP} , can then be calculated as:

$$f_{\text{CHP}} = \frac{\text{MW}_{\text{heat}}}{\text{MW}_{\text{elec}}} \left/ \left(\frac{\text{Displaced Boiler Size}}{\text{DG Size}} \right) \right.$$

Using f_{CHP} , the amount of thermal heat recovered and thus the amount of offset fuel and emissions from boilers can be calculated following the methodology detailed in section 2.3.1 of the supplementary material. The net flux of emissions from CHP units in a grid cell is calculated by subtracting the displaced boiler emissions from the total CHP emissions in that cell.

To explore the potential air quality benefits of implementing more stringent emissions limits on all DG (including both power-only DG and CHP) units and provide a lower bound in the potential emissions and air quality impacts of the increased DG penetration projected in this study, an additional scenario is considered for air quality modeling. This scenario corresponds to the high DG penetration scenario with all DG units meeting CARB certification limits and is termed the CARB certification scenario. This sensitivity scenario uses the same DG penetration as the high DG penetration scenario, but assumes the lowest emission factors for all DG units, which correspond to the CARB certification limits of 0.07 lbs/MWh for NO_x, 0.02 lb/MWh for VOC, 0.1 lb/MWh for CO, and 0.03 lb/MWh for PM. Note that in California, only very small DG units are exempt from being regulated by air quality districts. That is, microturbines up to 250 kW, engines less than 50 HP (~37.3 kW), and fuel cells are exempt from district permits (CARB, 2006). Moderate and large DG units need to be permitted by districts, whereas the small DG units that are exempt need to be certified by the state (CARB certification). Therefore, in the low and high DG penetration scenarios, it is assumed that all DG units in California need to be permitted by districts due to their size. The CARB certification limits are tested as a separate sensitivity scenario in case the districts (along with all other areas in the contiguous U.S.) adopt the more stringent limits for all DG units. The California emissions factors listed in Table 3 correspond to DG units permitted by districts, while the CARB certification limits correspond to those certified by the state.

2.4. Air quality modeling

CAMx version 6.20 (Ramboll Environ, 2016) is used to assess the potential air quality impacts of DG deployment. The CAMx model has been used extensively in research and regulatory applications (Kemball-Cook et al., 2015; Koo et al., 2015; Heo et al., 2016; Nopmongcol et al., 2016). The CAMx model domain used in this study includes the contiguous United States at a 12 km by 12 km grid resolution. Although local air quality impacts of DG may not be captured in detail with a 12 km by 12 km resolution, the goal of the air quality modeling is to determine potential air quality impacts at

the regional level and assess their importance relative to national ambient air quality standards. The 2007 meteorology and boundary conditions used in this study are based on the EPA's 2007 modeling database for the Regulatory Impact Assessment of the 2012 Final National Ambient Air Quality Standards (NAAQS) for PM_{2.5} NAAQS modeling (EPA, 2012). CAMx model setup, including baseline emissions for the reference case, follows that of Nopmongcol et al. (2017) who used the same PM_{2.5} NAAQS modeling inputs. As described by Nopmongcol et al., the 2007 baseline simulation demonstrated acceptable ozone performance achieving the EPA's ozone performance goals for normalized error (<35%) and normalized bias (<±15%) with an over-estimation tendency in the summer and under-estimation in winter. PM performance is generally comparable to EPA's, 2007 PM_{2.5} NAAQS modeling. The CAMx model is used to simulate two time periods: the winter episode from January 1st to February 28th and the summer episode from July 1st to August 31st. Additional details on 2030 baseline emissions for the reference case and the year 2007 meteorological inputs used in the air quality simulations are provided in section 2.4 of the supplementary material.

Baseline air quality in the reference case without any additional DG penetration is shown in Fig. S3 (ozone, summer) and Fig. S4 (PM_{2.5}, winter). However, the results of the reference case are not intended to be projections of future air quality as they do not include regulations such as the Clean Power Plan and the CSAPR Update Rule. The focus of the present study is the changes in air quality due to increased DG penetration in the low DG penetration and high DG penetration scenarios. The CARB certification scenario is considered as an additional air quality modeling sensitivity scenario to investigate the potential air quality benefits of more stringent emissions limits on DG units.

To quantify changes in air quality due to increased DG penetration, results for ozone and PM_{2.5} in the low DG penetration and high DG penetration scenarios are compared to the reference case using different metrics. For ozone, the maximum delta in peak 8-h average ozone concentrations is computed for each episode (summer and winter). This metric shows the maximum difference between the peak 8-h average ozone concentration that occurs on any day during an episode and the peak 8-h average ozone concentration that occurs in the reference case on the same day. Similar to ozone, a maximum delta metric is also utilized for PM_{2.5}. However, PM_{2.5} concentrations are averaged over 24 h rather than 8 h to be consistent with the averaging time used in ambient air quality standards. This metric shows the maximum change in 24-h average PM_{2.5} concentrations that occurs on any day during each of the winter and summer episodes. A summary of the maximum increases and decreases in ozone and PM_{2.5} concentrations that occur anywhere in the domain when using the maximum delta metric is provided in Table 6.

The difference in 24-h average concentrations of various PM_{2.5} components is also computed for the high DG penetration scenario to determine the relative contributions of different compounds to the total change in PM_{2.5} concentrations. The specific PM_{2.5} components examined include primary elemental carbon (PEC), primary organic carbon (POA), nitrate aerosol (PNO₃), sulfate aerosol (PSO₄), and ammonium aerosol (PNH₄). These results are shown in Fig. S15 through Fig. S20 for the high DG penetration scenario on February 8 (the day with highest PM_{2.5} concentration in the reference case) and are discussed in the supplementary material.

3. Results and discussion

3.1. DG market penetration

Upon completion of the DISPERSE model analysis, only the most

Table 5
Total NO_x, VOC, and PM emissions (tons/day) from EGUs and new DG units in 2030 for the contiguous United States by source type for all scenarios considered in the CAMx model analysis.

	NO _x				VOC				PM			
	Winter		Summer		Winter		Summer		Winter		Summer	
	DG	EGU	DG	EGU	DG	EGU	DG	EGU	DG	EGU	DG	EGU
	DG	EGU	DG	EGU	DG	EGU	DG	EGU	DG	EGU	DG	EGU
Reference	0.0	1 639.8	0.0	1878.0	0.0	50.0	0.0	63.0	0.0	60.2	0.0	65.6
Low DG	19.2	1 638.8	19.1	1881.9	2.5	49.9	2.4	63.3	1.4	60.1	1.4	65.6
High DG	122.1	1 635.4	121.3	1877.5	33.4	49.5	33.3	63.0	7.7	60.0	7.6	65.5
CARB	7.1	1 635.4	7.2	1877.5	0.4	49.5	0.4	63.0	3.1	60.0	3.2	65.5

Table 6
Maximum changes in ozone (8-h average, ppb) and PM_{2.5} (24-h average, µg/m³) concentrations that occur in the low DG penetration scenario and the high DG penetration scenario using the maximum delta metric.

Scenario	Episode	Maximum Increase		Maximum Decrease	
		PM _{2.5}	O ₃	PM _{2.5}	O ₃
Low DG	Summer	0.39	5.16	−0.70	−5.81
Low DG	Winter	0.46	1.71	−0.33	−1.75
High DG	Summer	0.93	5.70	−0.86	−9.90
High DG	Winter	0.79	1.74	−0.32	−3.42

economical power-only DG and CHP projects, those with a payback period of 10 years or less, are selected to represent the total economic potential. The total economic potential for each scenario is shown in Fig. S6 while Fig. S7 shows the breakdown of economic potential for the three different scenarios by size range and preferred prime mover. For most states, economic potential is not achievable with the low DG penetration scenario assumptions due to low electricity prices, relatively high natural gas prices, a lack of large facilities ideal for DG applications, or a combination of these factors. However, several states do show economic potential, with the majority located in California, the Northeast, and the Midwest states. The total economic potential for the low DG penetration scenario is summarized by Census division and economic selection criteria in Fig. S5. The Pacific region, consisting entirely of potential CHP applications in California, shows the most economic potential. In the medium DG penetration scenario, the additional cost of heat recovery for CHP applications remains the same, and the 10 percent ITC credit for CHP systems is removed. These adjustments create more favorable economics for power-only DG applications. However, with the improved electric efficiency and lower installed costs, many CHP applications also become more attractive, as the value of recovered thermal energy is still significant. Overall, the effect is about a 5.4 GW increase in projected market adoption in 2030 (11.7 GW, up from 6.3 GW), mostly from new power-only DG applications. The results for the medium DG penetration scenario indicate that possible future improvements in DG technologies (i.e., improved price and performance characteristics) can significantly affect the potential adoption of DG, as the adoption projected in the medium DG penetration scenario is nearly double that in the low DG penetration scenario. In the high DG penetration scenario, many states that normally have unfavorable economics for DG applications begin to show economic potential, with 33 states and the District of Columbia being capable of supporting payback periods under 10 years. The total projected market adoption for the high DG penetration scenario is over 24 GW in 2030, double that shown in the medium DG penetration scenario and a factor of four higher than the low DG penetration scenario. The large increase in projected market adoption for the high DG penetration scenario compared with the medium DG penetration scenario highlights the importance of fuel expenses in determining DG project economics.

The total results for projected DG penetration are estimated by technology/size category and sector. Temporal profiles are resolved for each month, estimating specific DG loads for weekdays, weekends, and holidays, with hourly MWh totals. Overall, the penetration of future DG units is expected to be largest in California, followed by the Mid-Atlantic States (New York, New Jersey, and Pennsylvania) and Massachusetts as shown in Fig. S5 for the low DG penetration scenario. Several states in the Midwest including Michigan, Ohio, and South Carolina also show significant potential in the high DG penetration scenario. Fig. S8 shows the total estimated adoption over time for all three scenarios considered in the DISPERSE model analysis. In general, the total capacity in MW can be considered to be the total coincident peak hourly load, as the modeled DG applications are for power applications that tend to operate at full-load during daytime hours on weekdays. The total estimated DG market adoption in 2030 for the low DG penetration scenario and high DG penetration scenario is shown in Fig. 3, broken down by size category and power-only DG versus CHP. Recall that based on the economic analysis of this study, all power-only DG units and CHP units <5 MW correspond to engines. Only CHP installations larger than 5 MW are found to present economic conditions favorable for gas turbines.

3.2. Changes in electric power sector

The projected reference case generation mix in the contiguous United States is depicted in Fig. 4a. The AEO2014 gas price path rises steadily to ~\$8/MMBtu (\$2010), accounting for the relatively flat share of gas in the mix. Load growth thus is largely met by increasing renewable generation, both wind and solar, in the reference case. New nuclear is an economic alternative to other technologies given the assumed gas price path, but is constrained

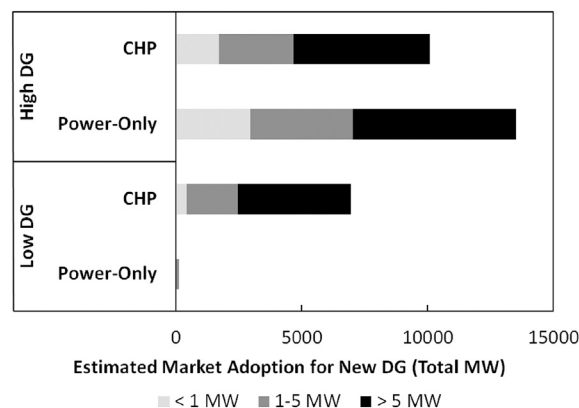


Fig. 3. Total estimated DG market adoption in 2030 projected by the DISPERSE model for the low DG penetration scenario and high DG penetration scenario. Only CHP units >5 MW correspond to gas turbines. All power-only DG units and CHP units <5 MW correspond to engines.

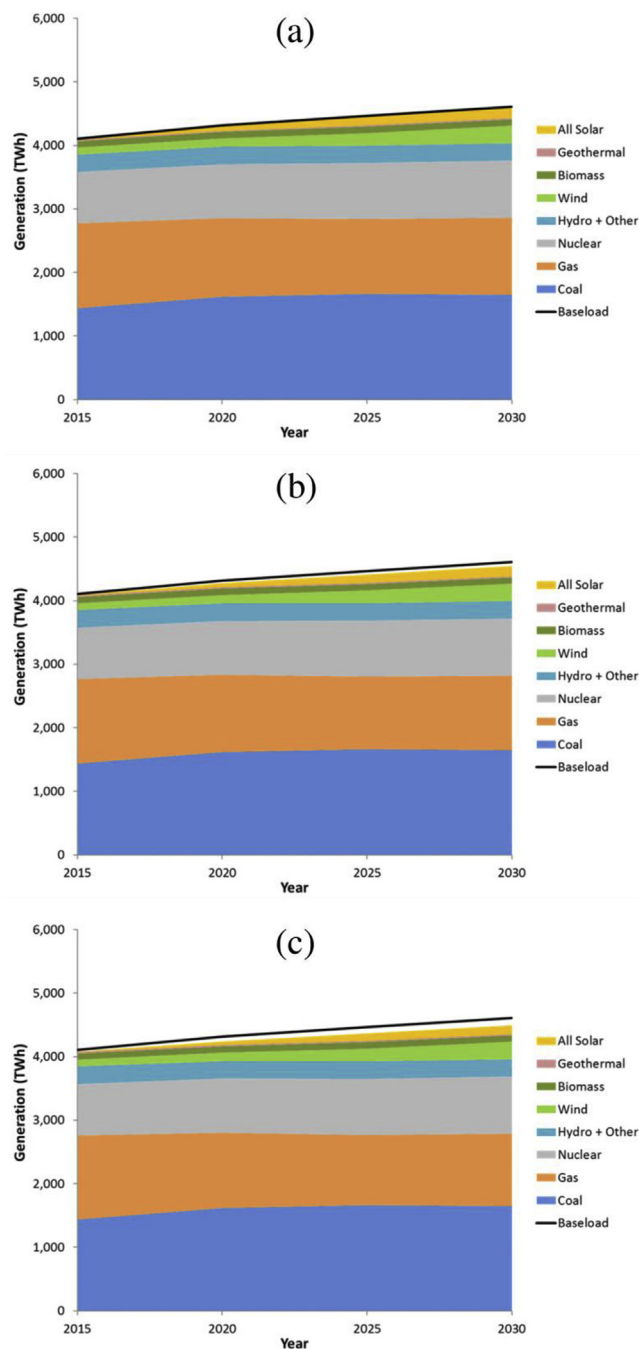


Fig. 4. US-REGEN generation mix projected for the contiguous United States in the (a) reference case, (b) low DG penetration scenario, and (c) high DG penetration scenario. Distributed generation projections are shown as the white space between the baseload and the sum of generation.

by the build limits of 7 GW per decade. Coal generation is largely flat – recall the reference case does not include any representation of the Clean Power Plan or the CSAPR Update Rule.

Fig. 4b and c show the projected generation mix in the contiguous United States for the low DG penetration scenario and high DG penetration scenario, respectively. Notice that the natural gas distributed generation projections (seen as the white space between the baseload and the sum of generation) comprise a very small share of total load in the contiguous U.S., even in the high DG penetration scenario. At the national level, the impact is largely

reflected in lower generation from gas-fired units and solar PV. Fig. S9 shows that high DG penetration (all of which is gas-fired) serves to offset 8 GW of new natural gas combined cycle (NGCC) units, and 19 GW of solar PV installations by 2030, the latter being rooftop PV as opposed to utility PV. Note that the difference between total displaced power and total projected DG deployment is due to differences in capacity factor. While DG often runs at close to 100% capacity factor, NGCC typically operates at less than 70% and solar PV around 15%. Although the impacts were minimal at the national level, reducing other capacity by no more than 3%, most of the DG projections were concentrated in the Midwest, New England, New York, and California. The impacts on New England and California, in particular, were more pronounced, as illustrated in Fig. S10 for the year 2030. Fig. S10 shows that the additional DG backed off new NGCC units and rooftop PV in New England, and rooftop PV in California. The changes in rooftop PV are due in good part to the generation profile of DG in the projections – much of it was assumed to be running during the day, and switched off at night. This coincides with the generation profile of solar PV, lowering the returns from additional PV installations. This also explains why wind, which in the U.S. is often stronger at night, was not as affected by additional DG penetration. Note that rooftop PV typically gets chosen over utility PV in the modeling because the existing electricity rate structures in the U.S. means that consumers are comparing rooftop PV against the retail price, whereas the decision to build utility PV is made by looking at the wholesale price. Therefore, when the increased DG penetration enters the generation mix, rooftop PV is the also the first to be displaced.

3.3. Impacts on emissions and air quality

3.3.1. Impacts on emissions

Average emissions of NO_x , VOC, $\text{PM}_{2.5}$, CO, and SO_x for all lower 48 states during the summer episode are shown in Table S6 through Table S10 of the supplementary material. Table S6 through Table S10 present emissions from area and point sources in the reference case for 2030, as well as the changes in emissions due to the low and high DG penetration scenarios in 2030. Changes in area sources are due to the addition of DG units, whereas changes in point sources are due to perturbation of central power plants (EGUs). While there are only increases in emissions from DG units, EGU emissions increase in some locations and decrease in others due to changes in the capacity and dispatch mix of the electric sector. More specifically, the changes in EGU emissions occur for two general reasons: (1) additional DG penetration re-distributes the use of different existing NGCC units and (2) additional DG penetration results in fewer new NGCC units being built, which leads to a higher utilization of existing, less efficient, NGCC units. For example, in some states (e.g., Florida, Alabama, and Kansas) total generation from gas-fired units decreases in response to additional DG penetration. Fewer new NGCC units are built, and there is also slightly lower generation from the existing NGCC units. However, the mix of generation within the NGCC units shifts, with less generation from the more efficient units and more generation from the less efficient units. This is due to the profile of the DG generation, which is relatively flat, meaning additional DG penetration substitutes more for highly efficient baseload units than it does for less efficient peaking units. When the (slightly) lower generation from all existing NGCC units is offset by the shift of overall generation to the less efficient NGCC units, that can lead to an increase in emissions from EGUs. Changes in EGU emissions are determined through the US-REGEN model analysis and represent only one plausible way that power plants may be deployed in response to increased DG penetration. Regarding area emissions, note that a variety of factors can influence emissions from DG units,

and the projected changes in statewide area emissions reported here reflect the spatial distribution of DG penetration shown in Fig. 2, using the emissions factors given in Table 3 and accounting for emissions displacement by CHP as described in section 2.3.1.

Table 5 shows total NO_x , VOC, and PM emissions from EGUs and new DG units in 2030 for the contiguous U.S. by source type for all scenarios considered in the CAMx model analysis, including the CARB certification scenario. Projected area emissions from new DG sources are nearly the same between the winter and summer episodes, but vary significantly between the different scenarios. In the high DG penetration scenario, NO_x and PM emissions from DG units are 5–6 times greater than in the low DG penetration scenario, and VOC emissions are more than 10 times greater. The differences in DG emissions between the low DG penetration scenario and high DG penetration scenario reflect the differences in projected DG penetration shown in Fig. 3. For example, the large increase in VOC emissions between the low and high DG penetration scenarios is due to the significant increase in projected penetration of power-only DG, for which engines are the preferred prime mover in all size categories. The VOC emissions factors used for engines in this study are much greater than those for turbines, which explains the large increase in VOC emissions from DG units in the high DG penetration scenario. In fact, the 33 tons/day increase in VOC emissions from DG units in the high DG penetration scenario is more than half of total VOC emissions from EGUs (49.5–63 tons/day), highlighting the importance of controlling VOC emissions from DG units. Implementing CARB certification limits (the lowest emissions factors for all DG units) with high DG penetration significantly reduces NO_x and VOC emissions from new DG units. Direct PM emissions are reduced simultaneously, although to a lesser extent. The greatest reduction occurs for VOC emissions, which are less than 0.5 ton/day in the CARB certification scenario compared with more than 30 tons/day in the high DG penetration scenario. In the CARB certification scenario, both NO_x and VOC emissions from DG units are lower than in the low DG penetration scenario, despite having the same DG penetration as the high DG penetration scenario. The changes in DG emissions in the CARB certification scenario indicate that most DG units in the United States emit at relatively high levels, and significant emissions reductions can be achieved through the implementation of stricter emissions limits such as those required for CARB certification. Note that total EGU emissions in the contiguous U.S. change only slightly in response to increased DG penetration since emissions from power plants increase in some locations and decrease in others as discussed previously. To understand how these changes in emissions affect the concentration of criteria pollutants such as ozone

and $\text{PM}_{2.5}$, the CAMx model is used to simulate air quality for both summer and winter episodes. The resulting changes in air quality are discussed in the following section.

3.3.2. Impacts on air quality

The highest ozone concentrations in the reference case occur during the summer episode in southern California and the north-eastern states, particularly around New York and New Jersey (Fig. S3). These are the same areas that show the greatest DG penetration in both the low DG penetration scenario and the high DG penetration scenario (see Fig. 2 for map of projected DG unit installations). Several different regions across the United States show wintertime maximum 24-h average $\text{PM}_{2.5}$ concentrations over $35 \mu\text{g}/\text{m}^3$ in the reference case, including California, the Midwest, and several states in the Northeast (Fig. S4). High $\text{PM}_{2.5}$ concentrations in Louisiana during the winter episode are due to a wildfire in the area. The results of the reference case are provided for context and are not intended to be projections of future air quality as they do not include regulations such as the Clean Power Plan and the CSAPR Update Rule. The focus of the present study is the changes in air quality due to increased DG penetration and the importance of these changes relative to ambient air quality standards. Therefore, changes in ozone concentrations that occur during the winter episode are discussed in the supplementary material.

A summary of the maximum increases and maximum decreases in ozone and $\text{PM}_{2.5}$ concentrations that occur anywhere in the domain when using the maximum delta metric are provided in Table 6. Fig. 5a shows that the largest ozone increases in the low DG penetration scenario summer episode occur in Florida, Kansas, Pennsylvania, and Alabama. Peak increases in ozone concentrations reach 5 ppb but are isolated to areas near strong emissions sources. In the surrounding areas, ozone concentrations increase by only 1–2 ppb. Similarly, ozone concentrations increase by only about 1 ppb in California, South Carolina, and the northeastern United States. Ozone increases in Kansas, Pennsylvania, Alabama and Florida are due primarily to increases in EGU emissions, whereas increases in California, South Carolina, and the northeastern U.S. are due to DG emissions. Thus, DG emissions in the low DG penetration scenario cause ozone concentrations to increase by only about 1 ppb, and the largest ozone increases occur in response to increases in EGU emissions. While the majority of the United States exhibits little to no change in ozone concentrations, increases of 3–5 ppb may impede attainment of ambient air quality standards for ozone in highly impacted areas. Reductions in EGU emissions cause ozone concentrations to decrease in some areas during the

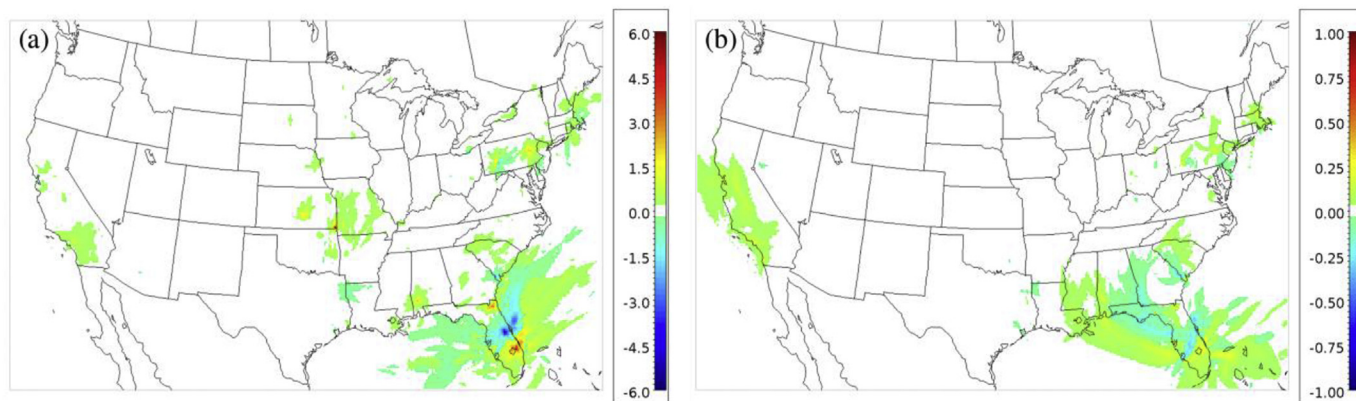


Fig. 5. Low DG penetration scenario minus baseline: (a) Peak delta in maximum daily 8-h average ozone concentration (ppb) during the period July 8 to August 31 and (b) Peak delta in daily 24-h average $\text{PM}_{2.5}$ concentration ($\mu\text{g}/\text{m}^3$) during the period January 8 to February 28.

summer episode, although the decreases are typically less than 1 ppb and only occur in isolated locations. One exception is Florida, where summertime ozone concentrations decrease by 3–5 ppb over a large area due to reductions in EGU emissions. While modeling the future capacity and dispatch mix of the electric sector is a highly uncertain issue, the results from the low and high DG penetration scenarios indicate that the operation of large EGUs can be affected by increased DG penetration, thereby impacting emissions and air quality. Results shown here represent one plausible way that power plants may be deployed under scenarios of increased DG penetration and are not intended to be definitive predictions of future deployment.

The peak changes in 24-h average $PM_{2.5}$ concentrations during the low DG penetration scenario summer episode are $+0.4 \mu\text{g}/\text{m}^3$ and $-0.7 \mu\text{g}/\text{m}^3$ in Florida and Rhode Island, respectively (Fig. S12). Decreases in $PM_{2.5}$ concentrations up to $0.4 \mu\text{g}/\text{m}^3$ also occur in Florida and Pennsylvania, while increases of about $0.25 \mu\text{g}/\text{m}^3$ occur in southern California. Fig. 5b shows that the maximum impacts on $PM_{2.5}$ concentrations in the low DG penetration scenario are similar in magnitude for both the summer and winter episodes. However, increases are more widespread during the winter episode than the summer episode due in general to more stagnant conditions and increased formation of ammonium nitrate during the wintertime. Changes in EGU emissions are responsible for the isolated decrease that occurs in Rhode Island during the summer episode as well as the impacts seen in Pennsylvania and in the southeastern U.S., while DG emissions cause the increases in $PM_{2.5}$ concentrations seen in California, South Carolina, and the Northeast. The vast majority of the United States experiences no change in $PM_{2.5}$ concentrations in this scenario during both the winter and summer episodes. Because the maximum increases in $PM_{2.5}$ concentrations are less than $0.4 \mu\text{g}/\text{m}^3$, the DG penetration projected in the low DG penetration scenario is unlikely to affect attainment of ambient air quality standards for fine particulate matter.

Although the maximum increases in ozone concentrations shown in Table 6 are similar in magnitude for the low and high DG penetration scenarios, the increases in ozone that result from DG emissions are about 3–4 times greater and more widespread in the high DG penetration scenario summer episode (Fig. 6a). In southern California and several states in the Northeast, 8-h average ozone concentrations increase by 3–6 ppb due to increased NO_x , VOC, and CO emissions from DG units. Increases in these precursor emissions tend to increase ozone concentrations, particularly during the summer months. Fig. 6a shows that increases in ozone concentrations of about 1 ppb can extend hundreds of kilometers from

emissions sources during the summer episode, covering a significant portion of the western and eastern United States. Increases of this magnitude and spatial extent may result in noncompliance of ambient air quality standards for ozone, particularly for highly impacted urban areas that are already burdened with poor air quality. In particular, the largest ozone increases that occur in California occur in designated nonattainment areas for the 2008 8-Hour ozone standard (EPA, 2017). Note that the magnitude of the impact on ozone concentrations depends on the density of DG installations in a given area. For example, although significant DG penetration exists in Michigan and South Carolina, installations are distributed throughout the state (Fig. 2) and thus cause relatively small increases in ozone, but over a large area (Fig. 5a). In contrast, a high density of DG penetration in southern California causes large increases in ozone, despite lower emissions factors for DG units in California. California, New Hampshire, Maine, Massachusetts, Rhode Island, and South Carolina show the largest increases in 8-h average ozone concentrations in response to DG emissions. Increases of 1–2 ppb in Tennessee, Kentucky, and Missouri and 2–4 ppb in Florida, Alabama, and northern Wisconsin are due to increases in EGU emissions. Decreases in ozone concentrations due to changes in EGU emissions do occur during the summer episode, but are mostly isolated to specific locations in Florida and Indiana.

The magnitude of the impact on $PM_{2.5}$ concentrations is about 3–4 times greater for the high DG penetration scenario (Fig. 6b) compared with the low DG penetration scenario (Fig. 5b) in California, the northeastern U.S., and other areas affected by DG emissions. The spatial extent of the impact of $PM_{2.5}$ concentrations is also much greater in the high DG penetration scenario compared with the low DG penetration scenario. Although the increases are relatively small in magnitude ($<0.5 \mu\text{g}/\text{m}^3$), high DG penetration causes $PM_{2.5}$ concentrations to increase over much of the eastern seaboard and over most of Michigan and the surrounding Great Lakes region during the winter episode. The largest increases in $PM_{2.5}$ concentrations due to DG emissions are isolated to the same general areas as in the low DG penetration scenario, mostly in California and the northeastern U.S., while the majority of the United States remains generally unaffected. The primary difference between the summer (Fig. S14) and winter (Fig. 6b) episodes is more widespread increases in $PM_{2.5}$ concentrations in central California and along the Pacific coast during the winter episode. Another notable difference is that changes in EGU emissions cause $PM_{2.5}$ concentrations to increase by about $0.5 \mu\text{g}/\text{m}^3$ in Minnesota, Iowa, Wisconsin, and Indiana, but only during the summer episode. Increases of $0.5\text{--}1 \mu\text{g}/\text{m}^3$ in Alabama and changes of $0.5 \mu\text{g}/\text{m}^3$ in Florida occur during both the winter and summer episodes due to

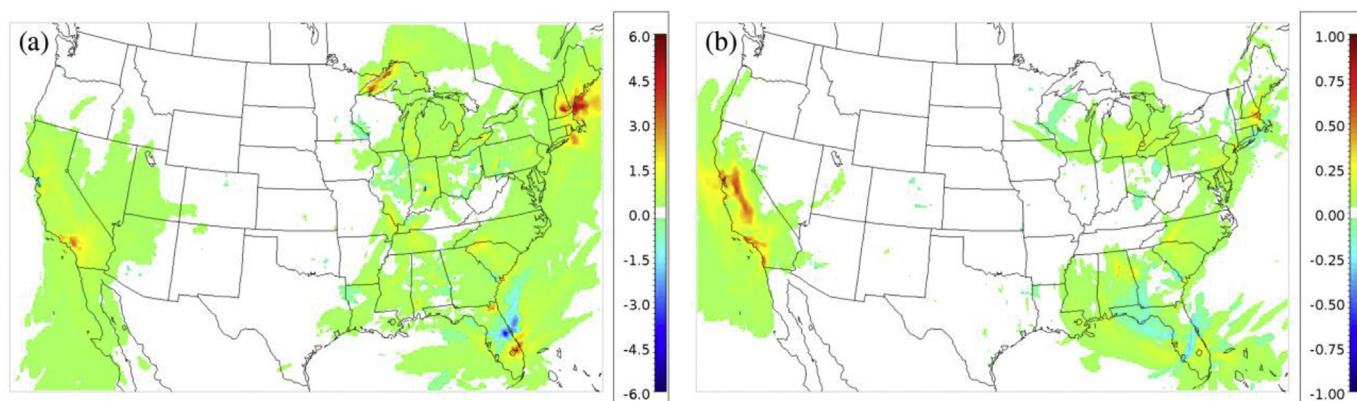


Fig. 6. High DG penetration scenario minus baseline: (a) Peak delta in maximum daily 8-h average ozone concentration (ppb) during the period July 8 to August 31 and (b) Peak delta in daily 24-h average $PM_{2.5}$ concentration ($\mu\text{g}/\text{m}^3$) during the period January 8 to February 28.

changes in EGU emissions. Despite relatively small effects on $\text{PM}_{2.5}$ concentrations, increases in concentration typically affect zones where air quality is already poor and even a slight increase PM may hinder attainment of air quality standards, particularly under stagnant conditions during the wintertime. For example, some of the largest increases occur in designated $\text{PM}_{2.5}$ nonattainment areas in California (EPA, 2017). Fig. S15 through Fig. S20 show the relative contributions of different compounds to the total change in $\text{PM}_{2.5}$ concentrations. Increases in $\text{PM}_{2.5}$ concentrations are due to a combination of increased precursor emissions as well as direct particulate emissions. In most of California, nitrate aerosol alone accounts for half of the change in total $\text{PM}_{2.5}$ concentrations. The spatial distribution of changes in ammonium aerosol concentrations closely follow that of nitrate aerosol as expected from the formation of ammonium nitrate in the particles. Thus, in central California and the coastal areas of southern California, increases in $\text{PM}_{2.5}$ concentrations are due mostly to increases in the concentration of ammonium and nitrate aerosol that result from increased NO_x emissions in areas with sufficient gas-phase ammonia to form ammonium nitrate. Direct particulate emissions and increased formation of ammonium nitrate contribute about equally to increased $\text{PM}_{2.5}$ concentrations in the northeastern United States.

Fig. 7a shows that using CARB certification emissions factors with high DG penetration nearly eliminates the increases in ozone concentrations that occur in response to DG emissions. In California for example, peak changes in 8-h average ozone concentrations during the summer episode are less than 0.5 ppb in the CARB certification scenario and occur only over a small area of southern California. On the other hand, ozone concentrations increase by 2–4 ppb in southern California in the high DG penetration scenario (Fig. 6a), and increases of about a ppb extend hundreds of kilometres from emissions sources and cover most of the state. The reduced impact on ozone concentrations is due to significantly lower NO_x , VOC, and CO emissions from DG units in the CARB certification scenario, reflecting the use of the lowest emissions factors for all DG units. Nearly all impacts on ozone in South Carolina and the northeastern United States are mitigated when using CARB certification limits, suggesting that the penalty to air quality from increased natural-gas fired DG penetration can be significantly reduced by implementing more stringent emissions limits for DG units, such as those required for CARB certification. In fact, the increases in ozone concentrations that occur in response to DG emissions are actually lower in the CARB certification scenario than in the low DG penetration scenario, despite having the same DG

penetration as the high DG penetration scenario. The air quality benefit is greatest in the northeastern United States, where the maximum increase in summertime 8-h average ozone concentrations is reduced from nearly 6 ppb in the high DG penetration scenario to less than 0.5 ppb in the CARB certification scenario. Note that the changes in ozone concentrations in Florida, Alabama, Indiana, northern Wisconsin, and other areas impacted by EGU emissions are essentially the same as those seen in the high DG penetration scenario. Aside from small changes in Florida, there is almost zero change in ozone concentrations anywhere in the United States for the CARB certification scenario winter episode (Fig. S21).

The impact on $\text{PM}_{2.5}$ concentrations during the winter episode in South Carolina, North Carolina, Virginia, and along the eastern seaboard is significantly reduced in the CARB certification scenario (Fig. 7b) compared with the high DG penetration scenario (Fig. 6b). In California, the changes in $\text{PM}_{2.5}$ concentrations in the CARB certification scenario are similar to those seen in the low DG penetration scenario, where $\text{PM}_{2.5}$ concentrations increase by about $0.25 \mu\text{g}/\text{m}^3$ in response to increased DG emissions. Similarly, using CARB certification limits for all DG units essentially eliminates the increases in $\text{PM}_{2.5}$ concentrations that occurred in Michigan and over the Great Lakes region in the high DG penetration scenario. Changes in summer and winter $\text{PM}_{2.5}$ concentrations in the CARB certification scenario, shown in Fig. S22 and Fig. 7b, indicate that California and New Jersey experience the largest increases in $\text{PM}_{2.5}$ concentrations in response to increased DG emissions. The impact on $\text{PM}_{2.5}$ concentrations in areas affected by changes in EGU emissions remains mostly unchanged from that seen in the high DG penetration scenario. One exception is that $\text{PM}_{2.5}$ concentrations decrease slightly ($<0.25 \mu\text{g}/\text{m}^3$) in South Carolina and some areas of the northeastern U.S. in response to decreases in EGU emissions when emissions from new DG units are reduced in the CARB certification scenario. Overall, the CARB certification scenario shows that conforming to low emissions factor requirements for DG units can significantly mitigate some of the negative impacts of increased DG penetration on air quality, even with high DG penetration. The impact of increased DG penetration on ozone concentrations is nearly eliminated, while the impact on particulate air quality is reduced simultaneously, although to a lesser extent. These results indicate that attainment of air quality standards for both ozone and $\text{PM}_{2.5}$ are unlikely to be affected by increased natural gas-fired DG penetration if CARB certification limits are adhered to for new DG units.

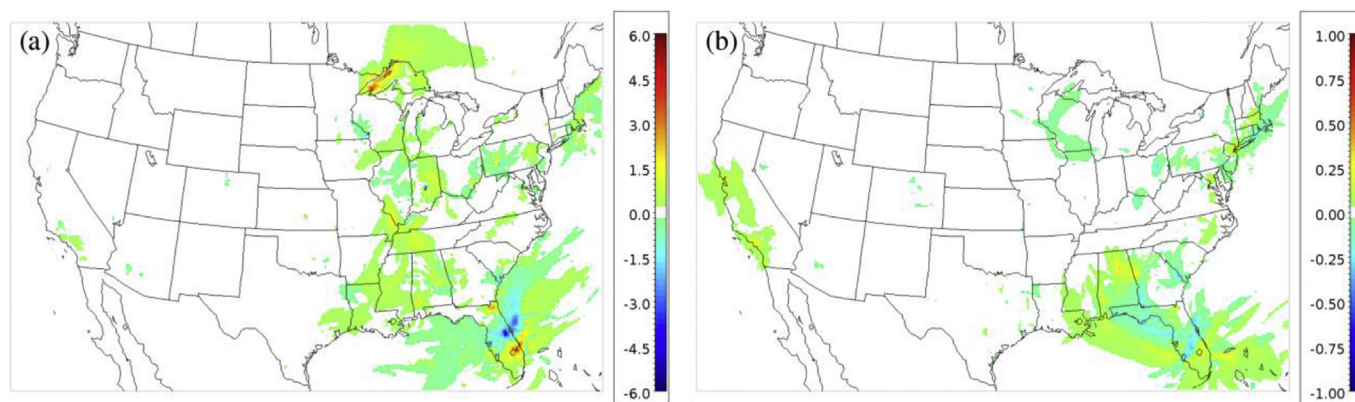


Fig. 7. CARB certification scenario minus baseline: (a) Peak delta in maximum daily 8-h average ozone concentration (ppb) during the period July 8 to August 31 and (b) Peak delta in daily 24-h average $\text{PM}_{2.5}$ concentration ($\mu\text{g}/\text{m}^3$) during the period January 8 to February 28.

4. Summary and conclusions

This study assesses the potential implementation of natural gas-fired distributed generation of electricity in the contiguous United States, including displacement of power from central power generation, and determines the potential impacts on emissions and air quality. Projections of DG penetration estimated using the DISPERSE model show 6.3 GW and 24 GW of market adoption in 2030 for the low DG penetration and high DG penetration scenarios, respectively. Both low and high DG penetration scenarios estimate the largest penetration of future DG units in three regions – New England, New York, and California. DG market penetration estimates are translated into spatially and temporally resolved emissions, which are then added to the rest of the emissions, including estimates of changes to emissions from central power generation units based on the US-REGEN modeling. High DG penetration (all of which is gas-fired) serves to offset 8 GW of new NGCC units and 19 GW of solar PV installations by 2030. The changes in rooftop solar are due mostly to the generation profile of DG in the projections – much of it was assumed to be running during the day and switched off at night, which coincides with the generation profile of solar PV, lowering the returns from additional PV installations. While there are only increases in emissions from DG (area sources), EGU emissions (point sources) increase in some locations and decrease in others due to changes in the capacity and dispatch mix of the electric sector. The changes in DG emissions for the CARB certification scenario indicate that most DG units in the United States emit at relatively high levels and significant emissions reductions can be achieved through the implementation of stricter emissions limits for natural gas-fired DG units, such as those required for CARB certification.

The greatest changes in ozone and PM_{2.5} concentrations in response to increased DG emissions occur in California and several states in the northeastern U.S. that show the greatest DG penetration. On the other hand, changes in ozone concentrations in Florida, Alabama, and Kansas are due to the changes in EGU emissions, which reflect the nature of the dispatch modeling used in this analysis. While modeling the future capacity and dispatch mix of the electric sector is a highly uncertain issue, the results of this study indicate that the operation of large EGUs can be affected by increased DG penetration, thereby impacting emissions and air quality. In California and the northeastern states, the largest increases in summer ozone concentrations typically occur in the same areas that have high ozone concentrations in the reference case. Increases in ozone concentrations of 3–6 ppb relative to a 70 ppb standard indicate a significant penalty to air quality in the high DG penetration scenario. Thus, high DG penetration may cause exceedance of applicable federal and state ozone standards in highly impacted areas during the summer months. Although peak increases in PM_{2.5} concentrations are less than 1 µg/m³ in all scenarios, some of the largest increases occur in designated PM_{2.5} nonattainment areas such as California (EPA, 2017). The CARB certification scenario indicates that conforming to low emissions factor requirements for DG units can mitigate most of the negative impacts of increased DG penetration on air quality, particularly for ozone, although there are still tangible impacts on PM_{2.5} concentrations in areas with significant DG penetration. In all scenarios, air quality in the central United States and the northwest remains unaffected as there is little to no DG penetration projected for those states. Overall, air quality impacts from distributed generation vary greatly based on meteorological conditions, proximity to emissions sources, the number and type of DG installations, and the emissions factors used for DG units.

This paper explores a range of plausible scenarios while providing a modeling framework and methodology that can be

applied and refined in future studies to assess the potential implementation and impacts of distributed generation of electricity. The results of this analysis are not intended to be definitive predictions of future DG deployment or future air quality but rather provide insights using information available at the time of the study. For example, the projected changes in the electric sector represent only one plausible scenario of how power plant may be deployed in response to increased DG penetration. Additionally, changes in electricity and natural gas prices, updated price and performance data for both fossil-based and renewable DG technologies, and an evolving regulatory environment are just some of the factors that may alter projections of DG deployment and the resulting impacts on emissions and air quality. However, the overall change in results using updated information is expected to be minimal. For example, although the cost of solar and wind technologies has dropped in the past few years, the simultaneous reduction in natural gas prices essentially reverses any increase in projected solar and wind deployment. Thus, while future studies may refine projections as new information becomes available, the methodology and conclusions of this analysis provide valuable insight that can be used in subsequent analyses.

Acknowledgments

This work was supported by the Electric Power Research Institute (EPRI) [agreement number 00-10002255].

Appendix A. Supplementary data

Supplementary data related to this article can be found at <http://dx.doi.org/10.1016/j.atmosenv.2017.08.046>.

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