2.1 Modeling of Distributed Generated Market Penetration

The following key inputs are used by the DISPERSE model:

1. **Technology price and performance parameters**. The model requires price and performance data on the mix of technologies that are being analyzed. Data for each type of DG technology includes installed cost, fuel type, heat rate, electrical efficiency, usable thermal output for CHP units, and fixed and variable operating and maintenance costs. Current data for DG technologies is collected from EPRI's request for information process for a 2014 national assessment (EPRI, 2014) and are shown in Table S2 (cost parameters in Table S2 are in 2014 dollars). The price and performance parameters do not change over time in a given scenario but they change between the low DG penetration scenario and the medium/high DG penetration scenarios. The justification for keeping cost and performance parameters (in each scenario) fixed is twofold. First, a study of projected changes in capital costs of generating technologies including CHP indicated that no increase in costs were projected over the 2014-2034 timeframe (Energy and Environmental Economics, 2014). Second, the medium and high DG penetration scenarios explore how higher electric efficiencies at lower installed costs (i.e., improved price and performance characteristics based on possible future improvements in DG technologies) could affect the potential future penetration of the DG technologies considered in this study. These changes in price and performance parameters for DG units are 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). Typical part-load performance data for DG units is obtained from manufacturer's literature and incorporated into the model when the systems are operating at partial capacity.

2. **Building characteristics.** Load profiles, including electricity and fuel use by square foot for each building type used in the analysis, are generated using DOE2 building models and average weather data (J. J Hirsch 2014). Buildings are scaled to different square footage sizes. Industrial load profiles are generated from data collected by the contractor and simplified 24-hour load profiles that can be adjusted for different facility sizes based on the number of employees.

3. **Database of natural gas and electricity prices**. Commercial and industrial electricity rate schedules are identified and modeled for all utilities analyzed, including standby service rates and options for time-of-use and demand-based rate schedules. Natural gas prices are taken from 2013 monthly state average prices reported by the Energy Information Administration (EIA). For high load factor sites (industrial facilities, universities, hospitals and hotels) the lesser of the average industrial price and the average city gate price plus $1/MMBtu is used. For other commercial facilities, the lesser of the average commercial price and the average city gate price plus $2/MMBtu is used. Escalation rates for both electricity and natural gas are taken from the 2014 EIA Annual Energy Outlook (National escalation estimates applied to all projects).

4. **Financial parameter assumptions.** A project life of 10 years is assumed, reflecting the anticipated life of smaller DG projects and conservative financial planning from customers. Most of the DG units do have longer lifespans when properly maintained, but since payback periods of over 10 years were not incorporated into the analysis, the 10-year life is not seen as a constraint. The installed cost of the system, maintenance costs, and fuel costs are the primary variables, along with the calculated electricity bills for the building before and after DG is installed. A discount rate of 7 percent is used when calculating the net present value of the investment.

The DISPERSE model analysis determines the sites where the adoption of DG is economical for each of the three scenarios described in the main manuscript, using a payback period of 10 years or less. These sites therefore represent the total economic potential (in MW). The economic potential values are held static throughout the analysis period, with no growth in number of sites nor change in DG technology price or performance, essentially assuming that the potential remains until year 2030.

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 DG adoption rates based on payback periods[1], the pool of potential sites was evaluated based on their payback period, and the percent that adopt DG is based on the DG adoption rates shown in Table S1. This process was repeated every five years from 2015 to 2030, for each of the three scenarios, to develop the total MW adopted. As sites adopt DG, they are then removed from the pool of potential sites evaluated for subsequent adoption. Those with payback periods of 7-10 years are unlikely to move forward with a DG project, but as the payback period is decreased, facility owners would be more likely to consider the investment. The analysis assumes that CHP from reciprocating engines, combustion turbines and microturbines are established technologies, and that owners of large facilities with high electric and thermal demands are aware of CHP as an option. These are known as “soft” prospects, while “strong” prospects are those who are actively evaluating CHP systems. This is the convention that was used in the market study on DG adoption[1], which continues to be used as a standard guideline for evaluating DG market adoption scenarios. For this analysis, we use the survey results for soft prospects to estimate the percentage of customers that would adopt power-only DG or CHP systems. One adjustment is made, however, to reflect that a 6-7 year payback period, where a customer could see a positive NPV on their investment with a 7% discount rate, is more attractive than a 7-10 year payback period. The DG adoption percentages used are shown in Table S1.

[1] *Converting Distributed Energy Prospects into Customers*, December 2003 (EPRI Number 1010294) http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001010294

Table S1: DG adoption percentages by payback period range for soft prospects used in the DISPERSE model analysis.

Payback Period	Likelihood of Adoption
0-1 year	100%
1-2 years	67%
2-3 years	60%
3-4 years	37%
4-5 years	37%
5-6 years	18%
6-7 years	10%
7-10 years	5%

These percentages represent the likelihood of a customer to adopt DG at a moment in time, but this decision is not continuously being made. To estimate the effects over time, the assumption is made that on average, businesses would seriously evaluate these types of decisions once every five years, as facility requirements, market conditions, and economics change. This process is simulated using the results for each state that shows economic potential, applying the adoption percentages to the total pool of economic DG applications.

The steps through which the DISPERSE model analysis proceeds can be summarized as follows:

1. The process starts with the total economic potential, which is determined by comparing the cost to obtain, operate, and maintain the DG system to the cost of traditional utility-purchased heat and power. The total economic potential (in MW) represents all possible customers for DG/CHP units that could achieve payback in 10 years or less, based on the DISPERSE model inputs listed above, for each of the three scenarios described in the main manuscript.
2. The total economic potential results are then sorted by payback period.
3. Using the sorted results, the likelihood of adoption percentages are applied to the economic potential in each payback period range. This determines the “new” MW of DG adopted in a given year (e.g., 2015). The customers who adopted DG at this moment in time are removed from the remaining pool of economic potential.
4. The decision to adopt DG is then re-evaluated five years later (e.g., in 2020) for those customers who showed economic potential but have not yet adopted DG (since only a percentage of customers adopted previously – e.g., in 2015). When the decision to adopt DG is re-evaluated, the economic potential does not change other than removing any sites that have adopted DG. However, the payback periods for remaining customers change based on escalated electricity and natural gas prices. Using the new payback periods, the remaining customers (i.e., the economic potential not yet adopted) are evaluated for adoption by applying the likelihood of adoption percentages. This determines the “new” DG adopted at this moment in time (e.g., in 2020), while the cumulative adoption at this moment in time would be the sum of the adoption in 2015 plus the “new” adoption in 2020. The cumulative adoption over time is what is shown in

Figure S8, and the cumulative DG adoption for the year 2030 is that used in the spatial allocation of DG units and environmental analysis (Figure 3).

5. The steps above are repeated every five years through 2030. Adoption increases over time since only a portion of the potential customers adopt DG at a moment in time (e.g., in 2015, 2020, 2025, etc.), and the remaining customers who did not yet adopt DG reconsider the decision 5 years later using new payback periods from escalated gas and electricity prices.

For the DISPERSE model analysis, no market growth is assumed (i.e., the total economic potential remains fixed throughout the analysis period), and potential DG installations are grouped into three size categories:

1. Small (<1 MW) DG systems: Microturbines provided the most favorable economics in the DISPERSE modeling, but small engines were nearly identical, with the difference in estimated payback periods typically limited to less than one year. Small engines are used for both power-only DG and CHP applications in this size category due to their superior electric and total CHP efficiencies (Table S2).
2. Medium (1-5 MW) DG systems: Reciprocating engines are easily the most favorable technology in this size category, whether for power-only DG or CHP applications.
3. Large (>5 MW) DG systems: Large engines and combustion turbines both produce favorable economics, although the large engine proved to be the most beneficial in the analysis. For industrial facilities, large combustion turbines provided close competition, and they are generally preferred for CHP applications because of higher-volume, higher-quality steam production. All power-only DG potential in this size category comes from large engines, due to their superior electric efficiencies.

Table S2: Price ($2014) and performance parameters for the low, medium, and high DG penetration scenarios used in the DISPERSE model analysis.

		100-1,000 kW		1 - 5 MW		>5 MW	
		Engine	Microturbine	Engine	Turbine	Engine	Turbine
Low DG	CHP Installed Cost ($/kW)	2,700	2,500	1,800	2,000	1,100	1,250
	Power-only Installed Cost ($/kW)	2,400	2,200	1,600	1,800	950	1,100
	Electric Efficiency	29%	27%	37%	34%	41%	32%
	Total CHP Efficiency	79%	65%	82%	68%	77%	74%
Med and High DG	CHP Installed Cost ($/kW)	2,220	2,060	1,480	1,640	910	1,030
	Power-only Installed Cost ($/kW)	1,920	1,760	1,280	1,440	760	880
	Electric Efficiency	32%	30%	41%	37%	45%	35%
	Total CHP Efficiency	75%	62%	78%	65%	73%	70%

2.2 Modeling of Central Power Generation System Using the US-REGEN Model

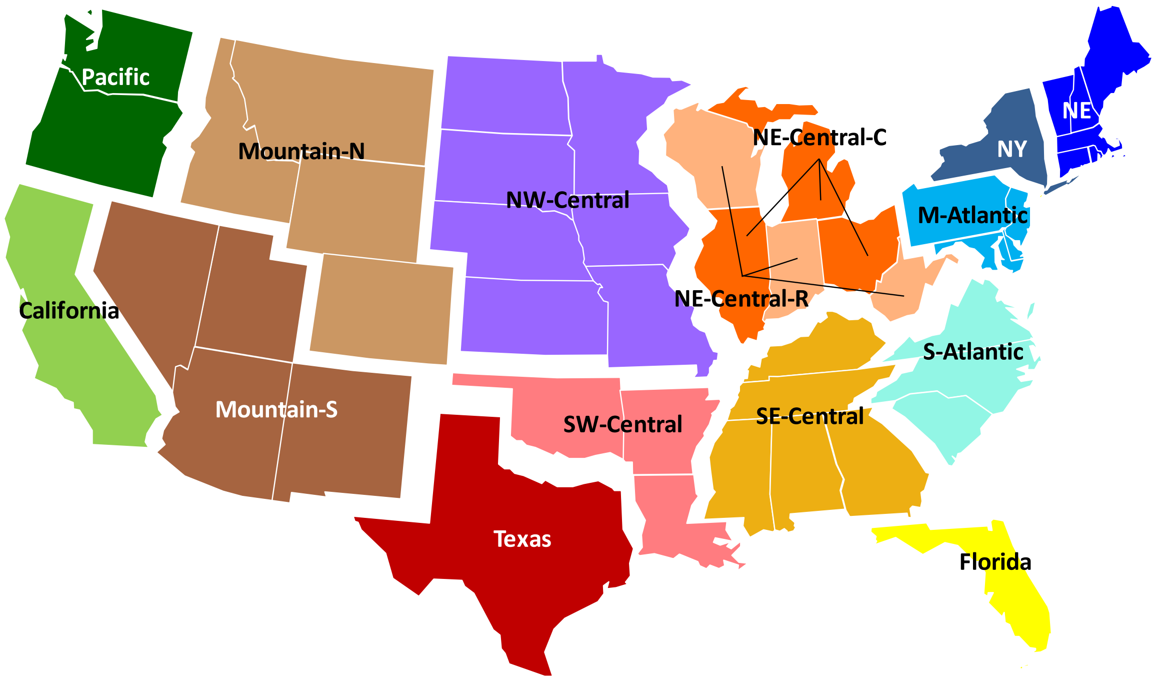

Figure S1: Regional aggregation used in the US-REGEN analysis

The emissions processing steps for the preparation of US-REGEN EGU emissions for CAMx air quality modeling can be summarized as follows. The US-REGEN model estimates hourly emissions using a bottom-up inventory approach. The model simulates temporal variation in load and emissions based on temperatures for a historical year (2007). Hourly emissions are estimated for NO_X and SO_X; other criteria pollutant emissions were scaled with NO_X. Hourly emissions from US-REGEN are converted into SMOKE input format. Because US-REGEN emissions are provided hourly, SMOKE can utilize this information directly without using temporal profiles. Next, each US-REGEN unit is assigned Source Classification Code (SCC) based on fuel type and matched to a stack in the PM NAAQS 2007 point inventory based on the Office of Regulatory Information System (ORIS) code to obtain stack location. The ORIS code is a number assigned by the Energy Information Agency (EIA) to power plants owned by utility companies. Stack parameters are assigned to each unit based on SCC. As a result, co-located stacks with different SCC (for example, co-located stacks using distillate oil and coal) were treated differently in the CAMx model. For new EGUs added to the future years, US-REGEN only tracks gross energy at regional level for the regions shown in Figure S1. Emissions related to these new units are calculated based on the following energy-emission assumptions developed in the EPRI-ET study (EPRI, 2015; Nopmongcol et al., 2017), which is described in section 2.4:

- PM: 0.09 lb/MWh (gross energy)
- SO_2: 1.0 lb/MWh (gross energy)
- NO_X: 0.47 lb/MWh (gross energy)

The resulting emissions from new EGUs were spatially distributed to sources within the corresponding region.

2.3 Modeling of Spatially Resolved Emissions for DG Units

To illustrate how DG units are spatially allocated following the methodology described in section 2.3 of the main manuscript, consider a sample state "X" with the following projected DG penetration for the commercial sector:

- Size: <1 MW Penetration: 2 MW
- Size: 1-5 MW Penetration: 8 MW
- Size: >5 MW Penetration: 20 MW

If state X spans throughout 5 grid cells, with the commercial sector area distribution between those cells depicted below, then DG units are discretely distributed to the grid cells as shown in Figure S2.

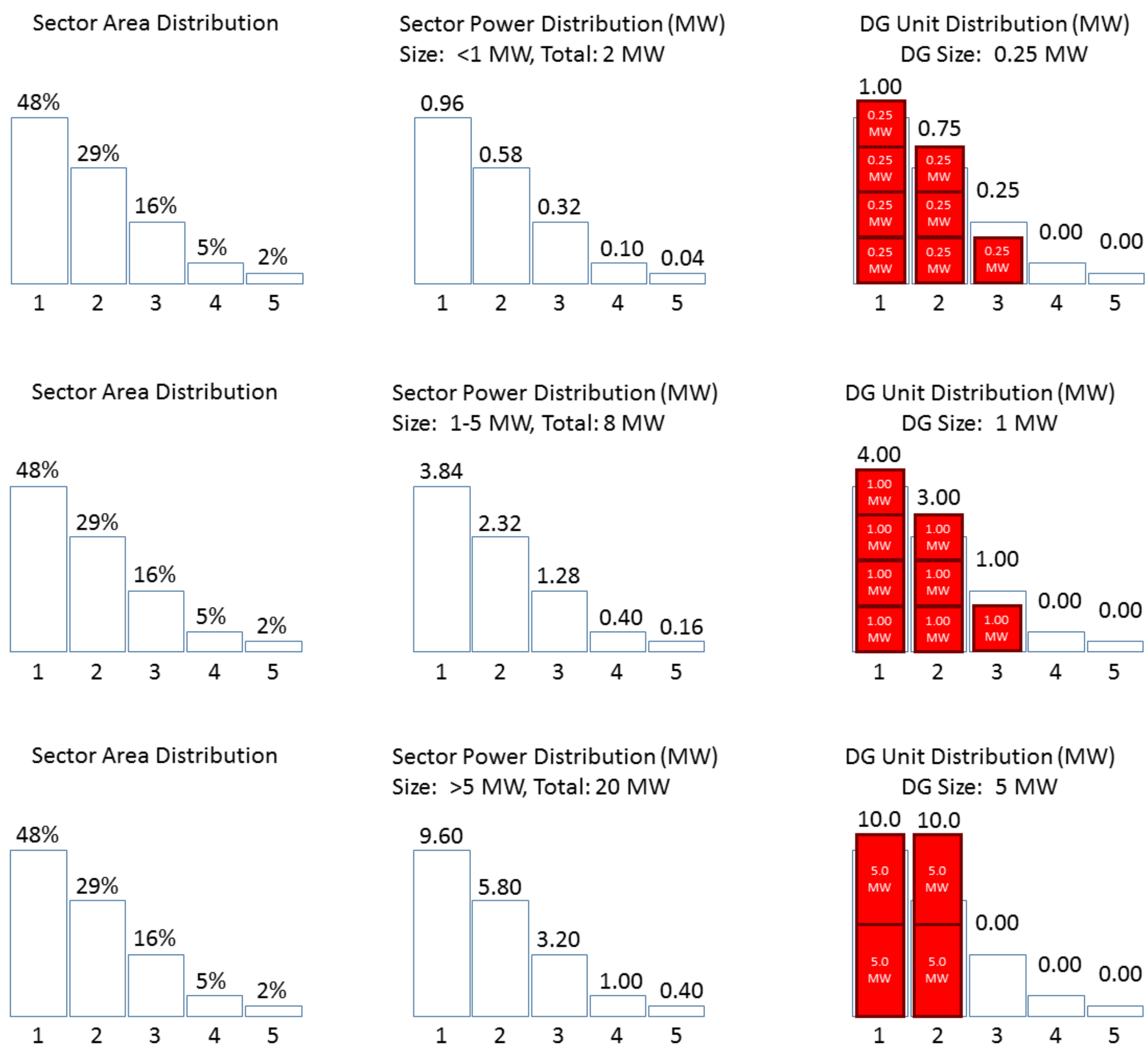

Figure S2: Example illustrating the spatial allocation DG units into rectangular grid cells following the methodology described in section 2.3 of the main manuscript.

Table S3: Land use categories and corresponding activity sectors used in the spatial allocation of DG units. All categories listed exhibit DG penetration.

Abbreviation	Activity Sector	Land Use Category
Coll	Colleges and Universities	EDU2
Elec	Electronics	IND5
Food	Food and Chemicals	IND3
Hosp	Hospitals	COM6
Hote	Hotels	COM8
Indu	All Industrial	IND1+IND2
Meta	Metals and Mineral Products	IND4
Nurs	Nursing Homes	COM7
Offi	Office Buildings	COM4
Rest	Restaurants	COM8
Reta	Retail Stores	COM1
Scho	School K-12	EDU1
Ware	Warehouses	COM2

2.3.1 Emissions Factors for DG Units

PM emissions from DG units are assumed to be all $PM_{2.5}$. Emission speciation of PM follows generic speciation profiles based on standard classification codes (SCC) extracted from the SMOKE model. The SCC codes assumed in this study are the following:

- Natural gas engines: 20100202 for sub-categories internal combustion engines; electric generation; Natural gas; reciprocating engines
- Natural gas turbines: 20100201 for sub-categories internal combustion engines; electric generation; Natural gas; turbines
- Natural gas boilers: 10100600 for sub-categories external combustion boilers; electric generation; Natural gas

For these SCC codes, PM speciation profiles are the same, with the following breakdown of species: 9% sulfate particles, 2% nitrate particles, 25% organic carbon, 38% elemental carbon and 26% unresolved inorganic particles. VOC speciation also uses the generic profiles for the three SCC codes associated with DG units and boilers. Note that for natural gas-fired turbines, U.S. EPA profile 0007 from the SPECIATE repository indicates that VOC (NMHC) emissions are speciated as 100% formaldehyde (https://cfpub.epa.gov/speciate/ehpa_speciate_browse_details.cfm?ptype=G&pnumber=0007). The speciation profiles for NO_X, SO_X, VOCs, and $PM_{2.5}$ are shown in Table S4.

Table S4: Speciation profiles for boilers, engines, and turbines used in this study.

		Boilers	**Engines**	**Turbines**
	SCC	10100600	20100202	20100201
NO_X	NO	0.90	0.90	0.90
	NO2	0.10	0.10	0.10
SO_X	SO2	0.90	0.90	0.90
	SULF	0.10	0.10	0.10
VOCs	OLE (Alkenes)		0.06	
	PAR (Alkanes)	0.74	0.21	
	TOL (Toluene)	0.05		
	FORM (Formaldehyde)	0.21	0.04	1.00
	ETH (Ethene)		0.03	
	ETHA (Ethane)		0.66	
$PM_{2.5}$	PSO4 (Sulfate Particles)	0.09	0.09	0.09
	PNO3 (Nitrate Particles)	0.02	0.02	0.02
	POA (Organic Carbon Particles)	0.25	0.25	0.25
	PEC (Elemental Carbon Particles)	0.38	0.38	0.38
	Unresolved Inorganic Particles	0.26	0.26	0.26

Using the f_{CHP} values shown in Table 4 of the main manuscript, the methodology to account for emissions displacement by CHP is described below.

1. Evaluate the total amount of thermal heat recovered in each hour, Q_{HR}, taking into account the electric energy produced by the CHP unit, Q_{elec}, the electrical and total efficiencies of each fuel-driven DG technology, $\eta_{elec,i}$ and $\eta_{total,i}$, respectively, and the particular mix of DG, $f_{DG,i}$, which can vary hour by hour due to possible differences in duty cycle for each technology.

$$Q_{HR} = Q_{elec} \sum_{i}^{n} \left(f_{DG_i} \frac{\left(\eta_{total_i} - \eta_{elec\,i}\right)}{\eta_{elec_i}} \right) \cdot f_{CHP} \quad (1)$$

2. Evaluate the total amount of offset fuel that would otherwise be burnt in the boilers to produce the same quantity of thermal energy delivered by the CHP units considering boilers efficiencies (e.g., $\eta_{boiler} = 0.8$).

$$Q_{fuel} = \frac{Q_{HR}}{\eta_{boiler}} \quad (2)$$

3. Use emissions factors for boilers (ef_{boiler}) and calculate the avoided emissions in each grid cell. As an example, the expression for displaced boiler CO emissions is presented below:

$$M_{CO,off} = Q_{fuel} ef_{boiler,CO} \quad (3)$$

   The emission factors for boilers used to calculate emissions displacement due to CHP are presented in Table S5. Emission factors obtained from the AP-42 database are applied throughout the United States, except for California. The factors for California are based on the South Coast Air Quality Management District Rule 1146.1, which limits boiler NO_X emissions to 12 ppm.

Table S5: Emission factors for boilers used for the calculation of emissions displacement by CHP

	AP-42* **lbs/MMBtu**	**CA BACT**** **lbs/MMBtu**
NO_X	0.0490	0.0150
CO	0.0824	0.0824
SO_X	0.0006	0.0006
VOC	0.0054	0.0054
$PM_{2.5}$	0.0075	0.0075

*AP-42 - Controlled - Low NO_X burners, small Boilers < 100 MMBtu/hr Heat Input
**Based on Rule 1146.1 of the South Coast Air Quality Management District, for a limit of 12 ppm NO_X

4. Determine the net flux of emissions for each pollutant in a grid cell due to CHP by subtracting the displaced boiler emissions from the total CHP emissions contribution in that cell. For example, in the case of CO, the net CHP emissions can be written as follows:

$$M_{CO,DGnet} = M_{CO,DGtot} - M_{CO,off} \quad (4)$$

2.4 Air quality modeling

Meteorological fields for the year 2007 are generated by the US EPA using the Advanced Research Weather Research and Forecasting Model (version 3.1), WRF-ARW (Skamarock et al., 2005). The WRF model is initialized using the 12 NAM analysis product provided by NCDC (http://nomads.ncdc.noaa.gov/data.php?name=access#hires_weather_dataset) and backfilled with 36 km AWIP/EDAS analysis (ds609.2) from NCAR (http://www.mmm.ucar.edu/mm5/mm5v3/data/free_data.html) where 12NAM is not available. The meteorological model was evaluated by the U.S. EPA and achieved acceptable performance (EPA, 2011). Conversion of WRF output to CAMx-ready inputs are prepared using WRFCAMx version 3.4 (Skamarock, 2008). The US EPA simulated the entire year 2007, and for this study two time periods from the full-year simulation are extracted and used in the air quality simulations: the winter episode extends from January 1st to February 28th, whereas the summer episode extends from July 1st to August 31st.

Baseline emissions for the year 2030 are based on a national modeling study that evaluated the air quality impacts of on-road vehicle and off-road equipment electrification for the lower-48 states in 2030 (EPRI, 2015; Nopmongcol et al., 2017), referred to as the "EPRI-ET" study. The EPRI-ET study considered two scenarios: a base case with no electrification and an electrification case with a significant penetration of electric technology. Our study implements revised DG and EGU emissions for the three scenarios varying in assumptions of DG penetration described in section 2.2 of the main manuscript. Emissions from all other sectors remain unchanged from the EPRI-ET's 2030 base case. Thus, 2030 baseline emissions used in the reference case, which assumes no additional DG penetration beyond the amount assumed in the EPRI-ET base case, are obtained directly from the EPRI-ET study 2030 base case. For scenarios that assume DG penetration, revised DG emissions are determined following the methodology described the main manuscript while revised EGU emissions from the US-REGEN model were processed through the SMOKE modeling system as described in section 2.2 above. SMOKE requires emissions inventory files and ancillary data files as input data that are obtained from EPA's 2007 National Emissions Inventory (NEI) PMNAAQS platform (ftp://ftp.epa.gov/EmisInventory/2007v5/). This study generates spatially resolved EGU emissions using the same SMOKE setup used in the EPRI-ET study. For additional details on the EPRI-ET study, the reader is referred to *Environmental Assessment of a Full Electric Transportation Portfolio, Volume 3: Air Quality Impacts* (EPRI, 2015) and Nopmongcol et al. (2017).

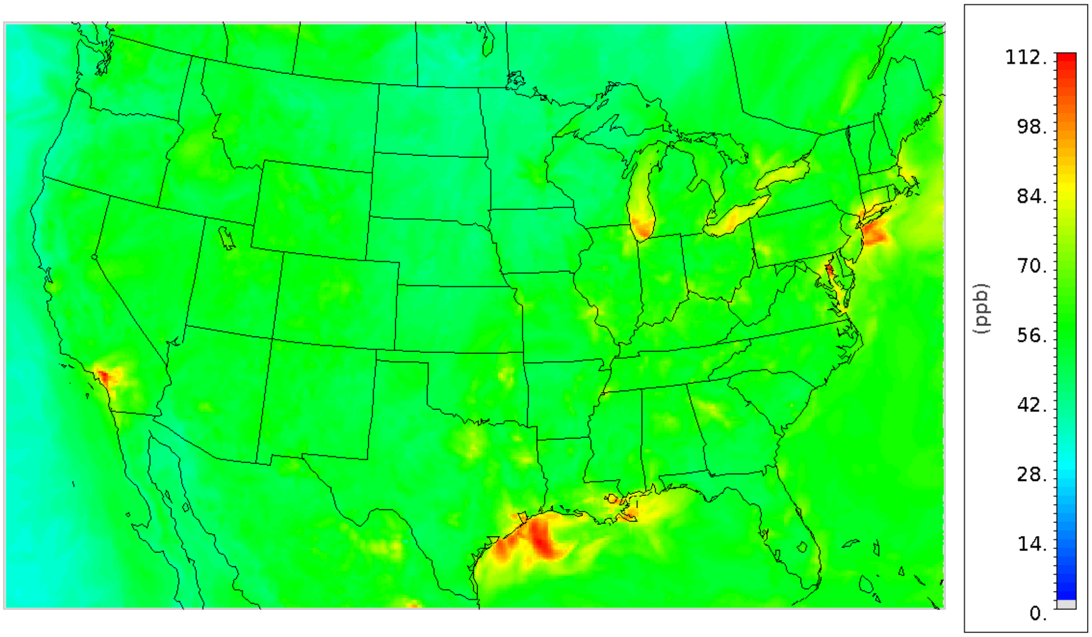

Figure S3: Peak of the maximum daily 8-hour average ozone concentration (ppb) during the period July 8 to August 31: reference case.

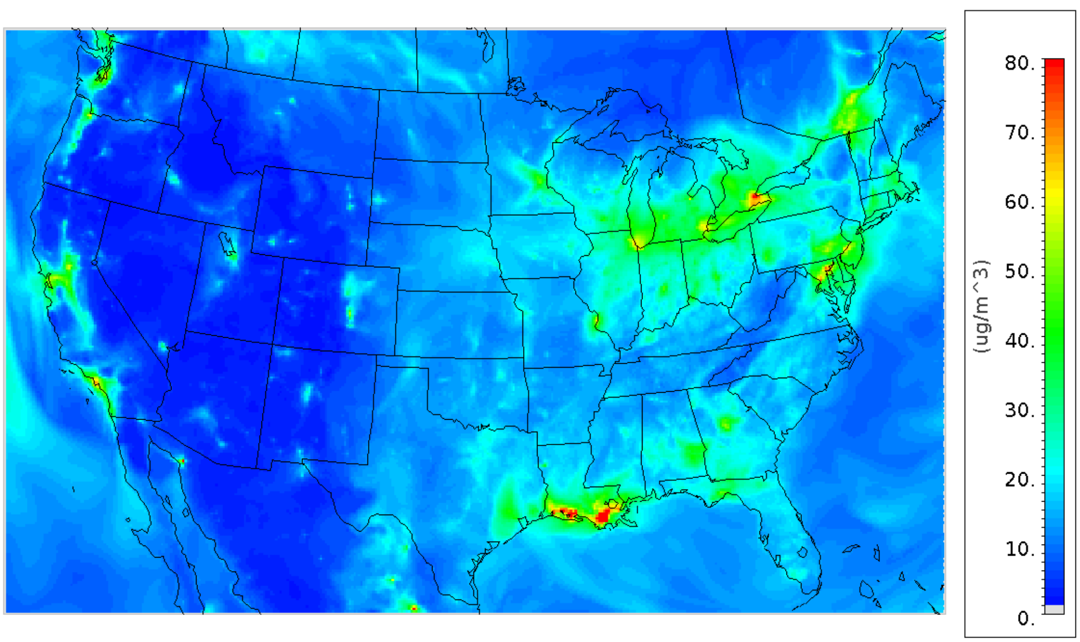

Figure S4: Peak of daily 24-hour average $PM_{2.5}$ concentrations ($\mu g/m^3$) during the period January 8 to February 28: reference case.

3.1 DG Market Penetration

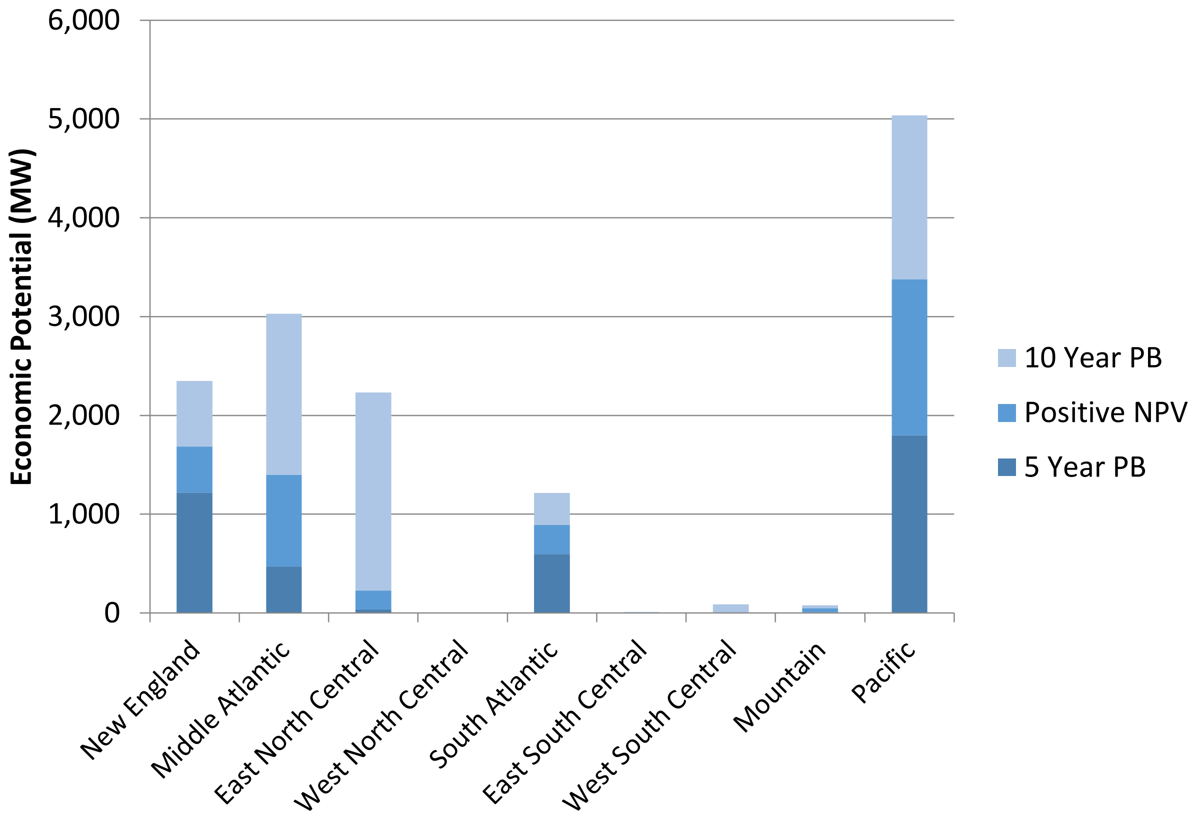

Figure S5: Total economic potential for DG by census region in the low DG penetration scenario

The total economic potential for all three scenarios is shown in Figure S6. The potential for commercial and institutional facilities (office buildings, retail stores, hotels, hospitals, colleges, etc.) is grouped in the "Commercial" category, while the potential for industrial manufacturing facilities is labeled as "Industrial". The medium and high DG penetration scenarios show an increase in economic potential for all DG size ranges, but the increase is by far the most prominent for small (<1 MW) units, primarily at commercial facilities like office buildings and retail stores. Microturbines and small engines provided nearly identical economics in this size range, with the difference in estimated payback periods typically limited to less than one year. Small engines are used for both power-only DG and CHP applications in this size category due to their superior electric and total CHP efficiencies. For larger size ranges, engines or combustion turbines provide the most attractive economics. Based on the characteristics that are evaluated, large engines tend to be preferred for commercial and power-only DG applications, while combustion turbines are more ideal for industrial CHP applications, especially over 5 MW in size, where large amounts of steam from CHP heat recovery can be utilized. Figure S8 shows the total estimated adoption over time, after applying the adoption percentages to the total pool of economic DG applications as described in section 2.1.

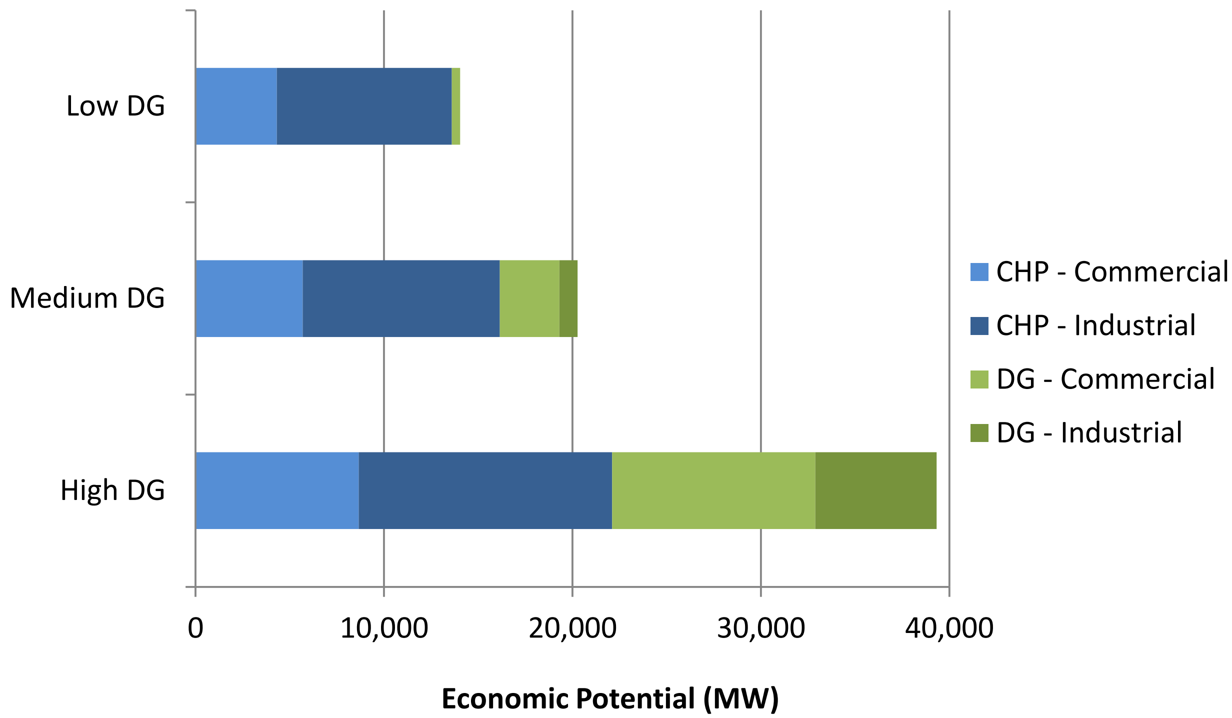

Figure S6: Total economic potential for DG for all three scenarios considered in the DISPERSE model analysis.

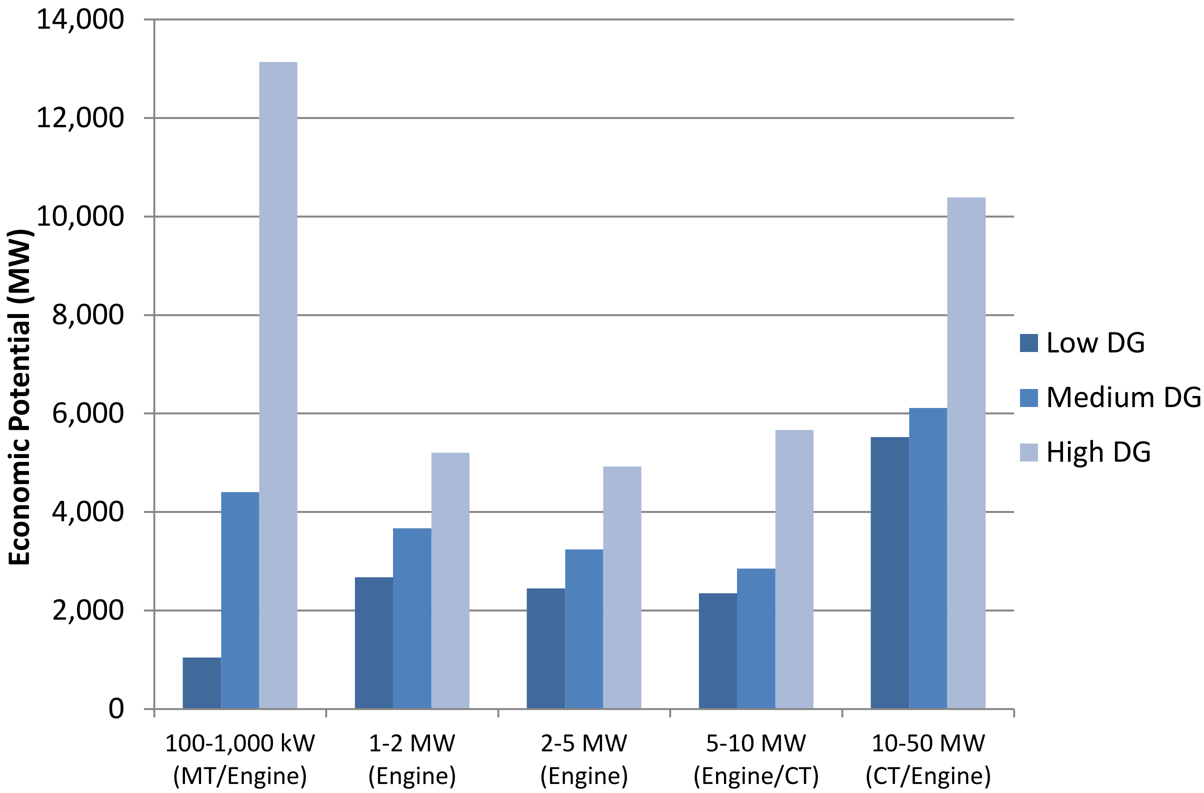

Figure S7: Total economic potential for DG for all three scenarios considered in the DISPERSE model analysis, by size range and preferred prime mover.

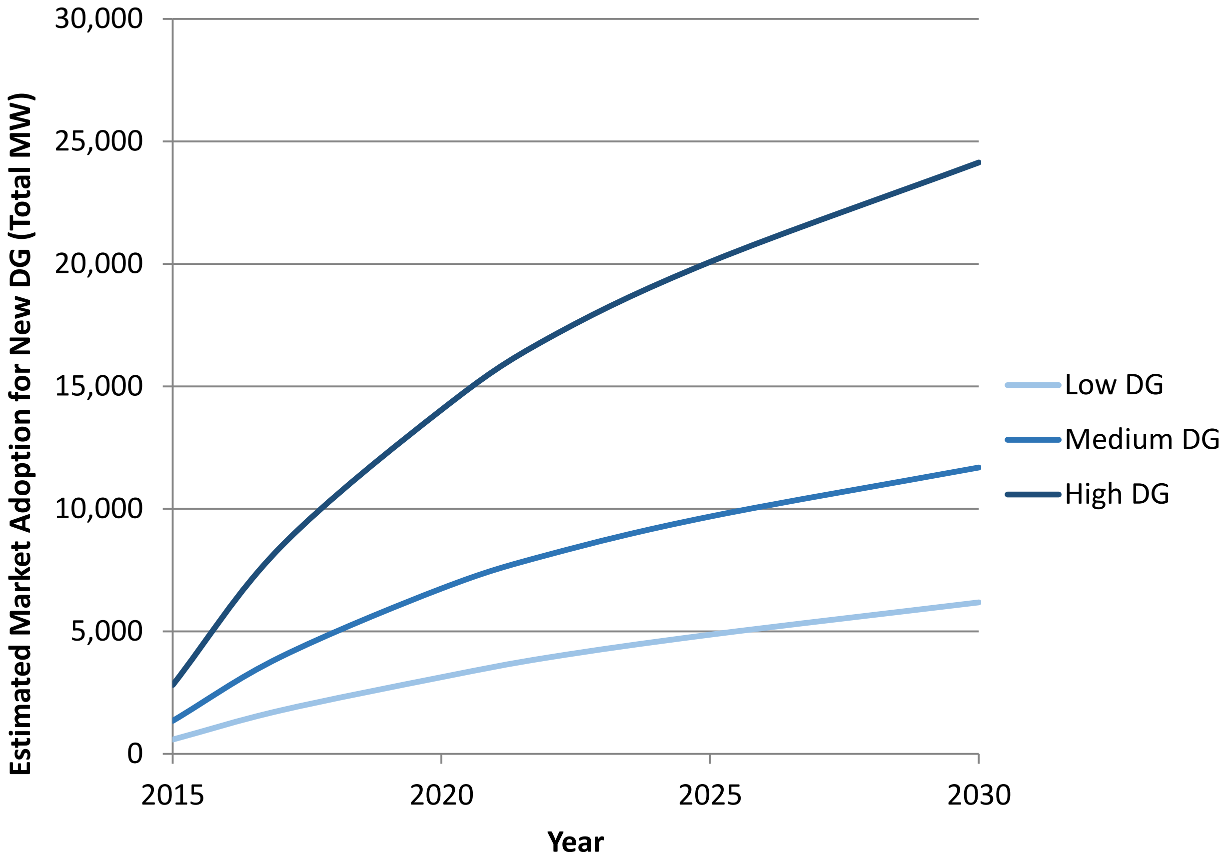

Figure S8: Estimated DG market adoption through 2030 for the three scenarios considered in the DISPERSE model analysis.

3.2 Changes in Electric Power Sector

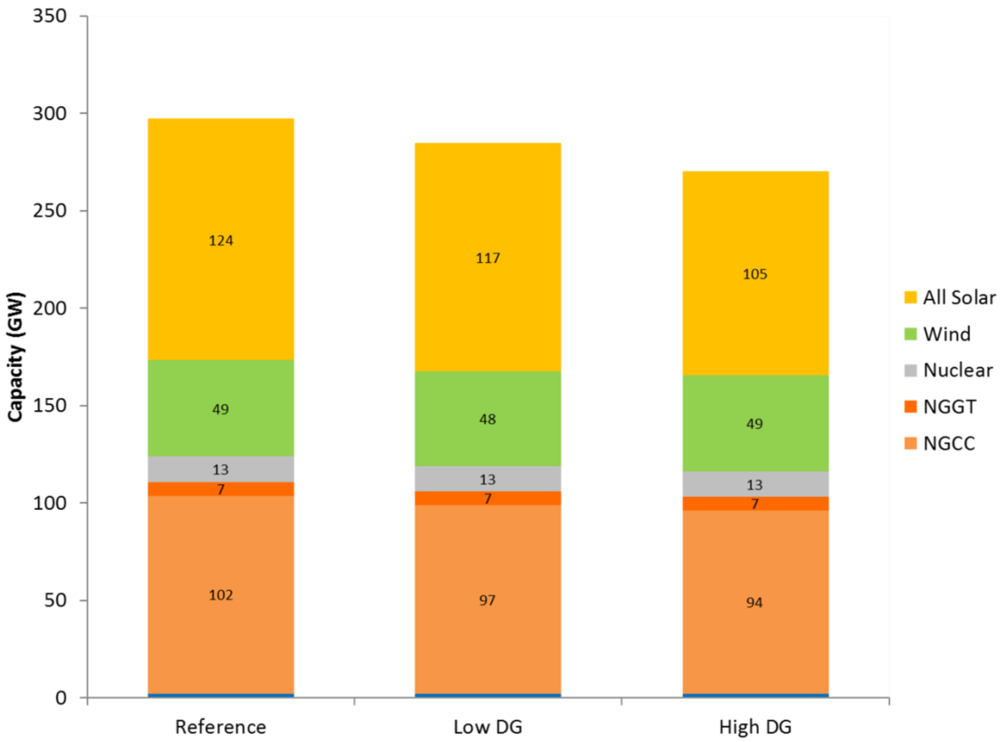

Figure S9: Projected capacity additions through 2030 in the contiguous United States for the three scenarios considered in the US-REGEN analysis. The blue color not shown in the legend corresponds to hydro and geothermal.

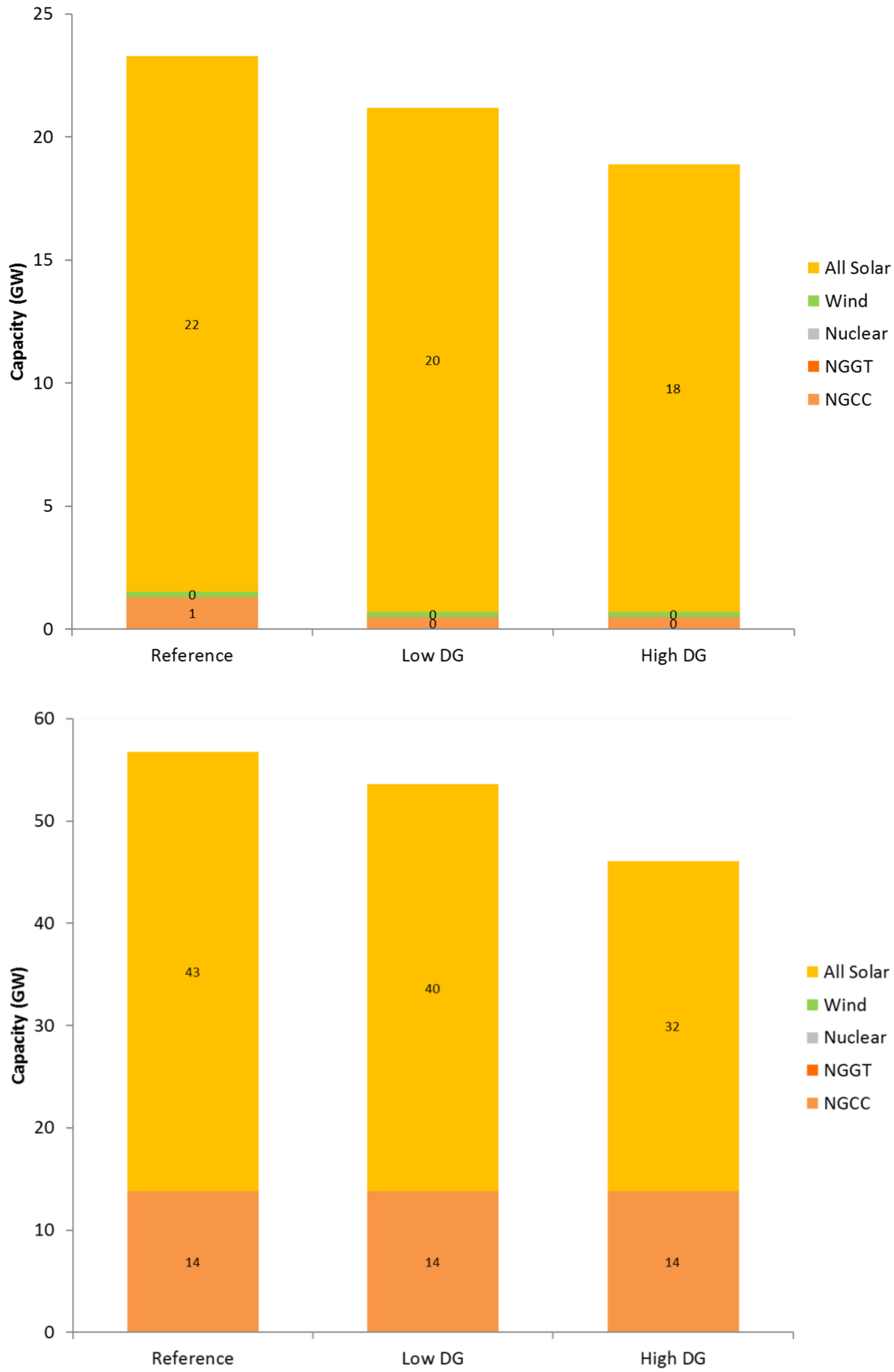

Figure S10: Projected capacity additions through 2030 in New England (top) and California (bottom) for the three scenarios considered in the US-REGEN analysis.

3.3.1 Impacts on Emissions

Average emissions of NO_X, VOC, $PM_{2.5}$, CO, and SO_X for all lower 48 states during the summer episode are shown in Table S6 through Table S10. Table S6 through Table S10 present emissions in 2030 from area and point sources in the reference case (by state), 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). Note that 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.

Table S6: Average summertime NO_X emissions (tons/day) by state in the reference case for 2030, and the change in NO_X emissions in the low DG penetration scenario and the high DG penetration scenario. 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).

	Reference Case			Low DG Penetration Scenario			High DG Penetration Scenario		
State	**AREA**	**POINT**	**TOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**
AL	196.87	44.66	241.53	0.00	1.96	1.96	0.35	2.33	2.68
AR	156.02	80.16	236.18	0.00	-1.34	-1.34	0.00	-0.90	-0.90
AZ	244.45	6.11	250.56	0.00	-0.27	-0.27	0.28	-0.48	-0.19
CA	724.19	6.05	730.24	8.33	0.12	8.45	39.43	-0.10	39.33
CO	208.18	49.42	257.60	0.00	-0.01	-0.01	0.02	-0.09	-0.07
CT	46.99	12.63	59.62	0.00	-0.25	-0.25	0.65	-0.20	0.45
DC	20.31	0.00	20.31	0.00	0.00	0.00	0.40	0.00	0.40
DE	35.28	7.07	42.35	0.00	0.05	0.05	0.25	0.01	0.26
FL	423.37	17.12	440.50	3.48	-2.16	1.33	11.61	-2.18	9.44
GA	267.72	65.19	332.91	0.00	-0.02	-0.02	0.03	0.02	0.04
IA	295.54	42.74	338.28	0.00	0.67	0.67	0.03	-0.01	0.02
ID	285.16	5.43	290.59	0.00	0.00	0.00	0.00	0.00	0.00
IL	492.29	104.86	597.16	0.00	0.02	0.02	1.83	0.00	1.83
IN	360.19	117.47	477.66	0.00	-0.25	-0.25	0.13	-1.77	-1.65
KS	333.94	12.28	346.22	0.00	2.88	2.88	0.00	-0.05	-0.05
KY	184.20	71.65	255.85	0.00	0.16	0.16	0.00	0.22	0.22
LA	320.98	19.95	340.93	0.00	-0.36	-0.36	0.00	0.15	0.15
MA	89.60	2.20	91.80	0.24	-0.07	0.17	3.95	-0.23	3.71
MD	88.54	8.74	97.28	0.00	0.05	0.05	0.83	0.03	0.87
ME	42.34	0.40	42.74	0.27	-0.08	0.19	4.20	-0.22	3.99
MI	318.48	95.02	413.51	0.30	0.02	0.31	13.04	-0.11	12.93
MN	241.68	11.37	253.05	0.00	0.22	0.22	0.50	0.04	0.54
MO	358.27	109.65	467.92	0.00	2.88	2.88	0.00	0.21	0.21
MS	161.99	25.85	187.84	0.00	-0.90	-0.90	0.00	0.14	0.14
MT	341.44	19.01	360.45	0.00	0.00	0.00	0.00	0.00	0.00
NC	233.67	27.76	261.43	0.30	-0.09	0.21	1.79	1.10	2.89
ND	107.06	29.85	136.91	0.00	0.00	0.00	0.00	0.00	0.00

NE	264.63	20.95	285.58	0.00	-0.07	-0.07	0.00	-0.27	-0.27
NH	22.59	2.40	24.99	1.09	0.14	1.23	9.86	0.05	9.91
NJ	107.63	27.37	135.00	0.00	0.02	0.02	2.91	0.08	2.99
NM	233.72	30.46	264.18	0.06	0.30	0.37	0.33	0.12	0.45
NV	107.61	1.56	109.16	0.00	-0.58	-0.58	0.03	-0.59	-0.56
NY	323.99	37.61	361.60	0.00	2.45	2.45	1.20	1.16	2.36
OH	356.50	98.58	455.08	1.04	0.41	1.45	3.24	1.85	5.09
OK	369.67	13.20	382.87	0.00	-0.50	-0.50	0.00	0.10	0.10
OR	172.04	0.79	172.82	0.00	0.01	0.01	0.48	0.00	0.48
PA	311.13	171.89	483.02	0.00	0.27	0.27	8.50	0.82	9.32
RI	15.03	1.58	16.61	0.83	-0.05	0.78	3.48	-0.20	3.29
SC	130.63	41.17	171.80	3.02	-1.15	1.87	9.02	-1.01	8.01
SD	199.02	22.77	221.79	0.00	0.00	0.00	0.00	0.00	0.00
TN	218.47	31.67	250.14	0.00	-0.01	-0.01	0.06	0.05	0.11
TX	1584.85	137.99	1722.84	0.00	-1.22	-1.22	0.00	0.37	0.37
UT	107.52	52.50	160.02	0.00	-0.35	-0.35	0.00	-0.67	-0.67
VA	190.31	34.66	224.96	0.00	0.01	0.01	0.01	0.60	0.61
VT	13.22	0.00	13.22	0.00	0.00	0.00	0.11	0.00	0.11
WA	221.53	20.25	241.79	0.00	-0.01	-0.01	0.18	-0.02	0.16
WI	218.58	47.71	266.29	0.13	1.10	1.23	2.53	-0.81	1.72
WV	67.36	51.08	118.44	0.00	-0.04	-0.04	0.00	-0.07	-0.07
WY	180.91	39.12	220.03	0.00	0.00	0.00	0.00	0.00	0.00

Table S7: Average summertime VOC emissions (tons/day) by state in the reference case for 2030, and the change in VOC emissions in the low DG penetration scenario and the high DG penetration scenario. 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).

	Reference Case			Low DG Penetration Scenario			High DG Penetration Scenario		
State	**AREA**	**POINT**	**TOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**
AL	20354.19	1.67	20355.84	0.00	0.12	0.12	0.04	0.14	0.18
AR	17350.55	2.47	17353.08	0.00	-0.09	-0.09	0.00	-0.06	-0.06
AZ	4623.76	0.36	4624.12	0.00	-0.02	-0.02	0.01	-0.03	-0.02
CA	9795.88	0.40	9796.28	1.51	0.01	1.52	8.58	-0.01	8.58
CO	2865.72	1.37	2867.09	0.00	0.00	0.00	0.00	-0.01	0.00
CT	873.09	0.68	873.77	0.00	-0.02	-0.02	1.39	-0.01	1.38
DC	127.68	0.00	127.68	0.00	0.00	0.00	0.88	0.00	0.88
DE	388.57	0.33	388.91	0.00	0.00	0.00	0.01	0.00	0.01
FL	11494.93	0.71	11495.59	0.37	-0.14	0.22	1.43	-0.14	1.28
GA	21453.96	2.35	21456.28	0.00	-0.02	-0.02	0.00	-0.03	-0.03
IA	3900.93	1.17	3902.10	0.00	0.04	0.04	0.00	0.00	0.00
ID	8380.15	0.15	8380.31	0.00	0.00	0.00	0.00	0.00	0.00
IL	5572.39	2.84	5575.23	0.00	0.00	0.00	0.09	0.00	0.09

IN	4828.24	3.76	4831.99	0.00	-0.01	-0.01	0.00	-0.09	-0.09
KS	4880.98	0.40	4881.39	0.00	0.19	0.19	0.00	0.00	0.00
KY	9213.16	2.24	9215.41	0.00	0.00	0.00	0.00	-0.01	-0.01
LA	11860.24	0.79	11861.01	0.00	-0.02	-0.02	0.00	0.01	0.01
MA	970.60	0.11	970.71	0.03	-0.01	0.02	5.48	-0.01	5.46
MD	1813.95	0.32	1814.27	0.00	0.00	0.00	0.86	0.00	0.87
ME	1368.35	0.03	1368.37	0.02	-0.01	0.01	0.51	-0.01	0.50
MI	6330.22	2.78	6333.00	0.01	0.00	0.02	0.79	0.00	0.79
MN	5628.16	0.35	5628.51	0.00	0.01	0.01	0.02	0.00	0.03
MO	20431.61	3.41	20435.02	0.00	0.19	0.19	0.00	0.01	0.01
MS	15667.62	1.18	15668.83	0.00	-0.06	-0.06	0.00	0.01	0.01
MT	8064.28	0.51	8064.80	0.00	0.00	0.00	0.00	0.00	0.00
NC	15142.73	1.59	15144.38	0.03	-0.01	0.02	0.18	0.06	0.24
ND	1122.81	0.81	1123.61	0.00	0.00	0.00	0.00	0.00	0.00
NE	2541.69	0.68	2542.37	0.00	0.00	0.00	0.00	-0.02	-0.02
NH	495.73	0.16	495.89	0.08	0.01	0.09	1.64	0.00	1.65
NJ	1072.26	1.04	1073.30	0.00	0.00	0.00	5.67	0.01	5.68
NM	4895.15	0.89	4896.05	0.00	0.02	0.02	0.02	0.01	0.03
NV	2696.53	0.10	2696.63	0.00	-0.04	-0.04	0.00	-0.04	-0.04
NY	4702.32	1.40	4703.72	0.00	0.16	0.16	3.11	0.08	3.19
OH	5115.46	3.65	5119.12	0.05	0.03	0.08	0.23	0.12	0.35
OK	10510.29	0.65	10510.94	0.00	-0.03	-0.03	0.00	0.01	0.01
OR	4174.26	0.05	4174.31	0.00	0.00	0.00	0.02	0.00	0.02
PA	6140.62	5.82	6146.44	0.00	0.03	0.03	0.73	0.07	0.81
RI	127.20	0.11	127.32	0.08	0.00	0.08	0.42	-0.01	0.42
SC	9452.28	1.33	9453.61	0.26	-0.08	0.18	0.99	-0.07	0.92
SD	2318.22	0.62	2318.83	0.00	0.00	0.00	0.00	0.00	0.00
TN	13030.40	1.04	13031.50	0.00	0.00	0.00	0.00	0.00	0.00
TX	33793.17	4.72	33797.91	0.00	-0.08	-0.08	0.00	0.03	0.03
UT	2672.47	1.51	2673.98	0.00	-0.02	-0.02	0.00	-0.04	-0.04
VA	10867.40	1.69	10869.09	0.00	0.00	0.00	0.00	0.02	0.02
VT	505.98	0.00	505.98	0.00	0.00	0.00	0.06	0.00	0.06
WA	4226.15	0.67	4226.82	0.00	0.00	0.00	0.01	0.00	0.01
WI	5246.96	1.54	5248.50	0.00	0.07	0.08	0.10	-0.02	0.08
WV	5546.77	1.47	5548.24	0.00	0.00	0.00	0.00	-0.01	-0.01
WY	2960.84	1.06	2961.89	0.00	0.00	0.00	0.00	0.00	0.00

Table S8: Average summertime $PM_{2.5}$ emissions (tons/day) by state in the reference case for 2030, and the change in $PM_{2.5}$ emissions in the low DG penetration scenario and the high DG penetration scenario. 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).

	Reference Case			Low DG Penetration Scenario			High DG Penetration Scenario		
State	**AREA**	**POINT**	**TOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**
AL	268.22	1.56	269.78	0.00	0.01	0.01	0.01	0.00	0.01
AR	609.14	2.74	611.88	0.00	-0.01	-0.01	0.00	-0.01	-0.01
AZ	518.40	0.07	518.47	0.00	0.00	0.00	0.03	0.00	0.03
CA	2793.80	0.04	2793.83	0.81	0.00	0.81	2.72	0.00	2.72
CO	461.19	1.80	463.00	0.00	0.00	0.00	0.00	0.00	0.00
CT	19.66	0.28	19.94	0.00	0.00	0.00	0.12	0.00	0.12
DC	6.56	0.00	6.56	0.00	0.00	0.00	0.07	0.00	0.07
DE	11.83	0.20	12.03	0.00	0.00	0.00	0.03	0.00	0.02
FL	288.22	0.44	288.66	0.12	-0.01	0.11	0.21	-0.01	0.20
GA	386.92	2.46	389.39	0.00	-0.01	-0.01	0.00	-0.02	-0.01
IA	469.98	1.57	471.55	0.00	0.00	0.00	0.00	0.00	0.00
ID	3339.45	0.20	3339.66	0.00	0.00	0.00	0.00	0.00	0.00
IL	808.46	3.88	812.34	0.00	0.00	0.00	0.16	0.00	0.16
IN	400.10	4.20	404.30	0.00	0.00	0.00	0.01	-0.01	0.01
KS	1430.98	0.40	1431.38	0.00	0.02	0.02	0.00	0.00	0.00
KY	229.51	2.73	232.24	0.00	0.00	0.00	0.00	-0.01	-0.01
LA	219.81	0.54	220.35	0.00	0.00	0.00	0.00	0.00	0.00
MA	110.71	0.06	110.77	0.01	0.00	0.01	0.54	0.00	0.54
MD	50.16	0.27	50.44	0.00	0.00	0.00	0.08	0.00	0.08
ME	36.61	0.00	36.62	0.02	0.00	0.02	0.08	0.00	0.08
MI	476.29	3.36	479.65	0.03	0.00	0.03	1.01	0.00	1.00
MN	1043.08	0.39	1043.47	0.00	0.00	0.00	0.04	0.00	0.05
MO	723.52	3.72	727.23	0.00	0.02	0.02	0.00	0.00	0.00
MS	300.59	0.58	301.17	0.00	-0.01	-0.01	0.00	0.00	0.00
MT	2907.98	0.70	2908.69	0.00	0.00	0.00	0.00	0.00	0.00
NC	257.96	1.04	259.00	0.01	0.00	0.01	0.07	0.02	0.09
ND	857.71	1.11	858.82	0.00	0.00	0.00	0.00	0.00	0.00
NE	698.58	0.70	699.28	0.00	0.00	0.00	0.00	0.00	0.00
NH	12.25	0.02	12.27	0.07	0.00	0.07	0.24	0.00	0.24
NJ	40.78	1.07	41.85	0.00	0.00	0.00	0.51	0.00	0.51
NM	851.99	1.08	853.06	0.01	0.00	0.01	0.02	0.00	0.02
NV	957.13	0.01	957.14	0.00	0.00	0.00	0.00	0.00	0.00
NY	216.61	1.34	217.95	0.00	0.01	0.01	0.25	0.00	0.26
OH	156.52	3.50	160.02	0.09	0.00	0.10	0.22	0.02	0.23
OK	1381.83	0.26	1382.08	0.00	0.00	0.00	0.00	0.00	0.00
OR	990.91	0.00	990.91	0.00	0.00	0.00	0.05	0.00	0.05

PA	132.88	6.66	139.53	0.00	0.01	0.01	0.53	0.03	0.56
RI	10.82	0.02	10.84	0.03	0.00	0.03	0.07	0.00	0.07
SC	173.56	1.46	175.02	0.16	-0.01	0.15	0.28	-0.01	0.28
SD	492.58	0.85	493.42	0.00	0.00	0.00	0.00	0.00	0.00
TN	281.76	1.07	282.83	0.00	0.00	0.00	0.01	0.00	0.01
TX	4094.57	4.34	4098.90	0.00	-0.01	-0.01	0.00	0.00	0.00
UT	366.06	1.87	367.93	0.00	0.00	0.00	0.00	0.00	0.00
VA	140.11	1.44	141.55	0.00	0.00	0.00	0.00	0.01	0.01
VT	12.00	0.00	12.00	0.00	0.00	0.00	0.01	0.00	0.01
WA	1259.49	0.65	1260.15	0.00	0.00	0.00	0.01	0.00	0.01
WI	266.55	1.57	268.12	0.01	0.01	0.02	0.25	-0.03	0.21
WV	52.32	1.87	54.20	0.00	0.00	0.00	0.00	0.00	0.00
WY	1288.89	1.45	1290.34	0.00	0.00	0.00	0.00	0.00	0.00

Table S9: Average summertime CO emissions (tons/day) by state in the reference case for 2030, and the change in CO emissions in the low DG penetration scenario and the high DG penetration scenario. 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).

	Reference Case			**Low DG Penetration Scenario**			**High DG Penetration Scenario**		
State	**AREA**	**POINT**	**TOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**
AL	3339.46	36.36	3375.83	0.00	5.63	5.63	1.26	6.52	7.78
AR	2848.36	41.56	2889.92	0.00	-3.98	-3.98	0.00	-2.65	-2.65
AZ	3192.67	15.11	3207.76	0.00	-0.81	-0.81	0.22	-1.43	-1.21
CA	19086.12	18.14	19104.19	22.59	0.37	22.95	147.71	-0.29	147.43
CO	2298.19	15.18	2313.37	0.00	-0.04	-0.04	0.07	-0.28	-0.21
CT	882.42	24.89	907.31	0.00	-0.74	-0.74	5.98	-0.60	5.37
DC	368.54	0.00	368.54	0.00	0.00	0.00	3.80	0.00	3.80
DE	398.36	10.38	408.74	0.00	0.15	0.15	0.20	0.01	0.21
FL	7553.48	21.97	7575.46	10.15	-6.47	3.68	40.73	-6.52	34.21
GA	4613.43	44.25	4657.68	0.00	-0.59	-0.59	0.03	-1.03	-1.00
IA	1628.99	12.17	1641.16	0.00	2.02	2.02	0.02	-0.04	-0.02
ID	31289.43	1.41	31290.86	0.00	0.00	0.00	0.00	0.00	0.00
IL	4330.97	27.48	4358.45	0.00	0.06	0.06	2.10	0.02	2.12
IN	2973.56	62.93	3036.49	0.00	-0.42	-0.42	0.10	-4.26	-4.16
KS	2539.60	8.08	2547.68	0.00	8.62	8.62	0.00	-0.14	-0.14
KY	2143.08	31.30	2174.38	0.00	0.06	0.06	0.00	-0.14	-0.14
LA	2627.15	22.98	2650.13	0.00	-1.07	-1.07	0.00	0.46	0.46
MA	1720.24	3.36	1723.60	0.69	-0.23	0.46	26.90	-0.67	26.22
MD	1696.61	7.82	1704.43	0.00	0.14	0.14	5.10	0.10	5.19
ME	638.86	1.21	640.07	0.43	-0.23	0.20	14.67	-0.65	14.03
MI	4883.94	38.86	4922.80	0.35	0.09	0.43	19.78	0.01	19.80
MN	4434.97	5.60	4440.57	0.00	0.66	0.66	0.56	0.12	0.69

MO	3692.87	59.02	3751.89	0.00	8.63	8.63	0.00	0.64	0.64
MS	2452.53	40.21	2492.74	0.00	-2.69	-2.69	0.00	0.42	0.42
MT	25869.38	4.94	25874.34	0.00	0.00	0.00	0.00	0.00	0.00
NC	4497.41	47.60	4545.01	0.74	-0.27	0.47	5.10	2.13	7.23
ND	778.17	7.75	785.93	0.00	0.00	0.00	0.00	0.00	0.00
NE	1497.67	13.09	1510.76	0.00	-0.22	-0.22	0.00	-0.81	-0.81
NH	436.84	7.18	444.02	2.16	0.41	2.57	35.26	0.15	35.40
NJ	2126.98	20.31	2147.30	0.00	0.11	0.11	25.81	0.28	26.09
NM	1492.97	12.44	1505.42	0.05	0.91	0.96	0.64	0.37	1.01
NV	3662.63	4.67	3667.30	0.00	-1.74	-1.74	0.03	-1.78	-1.75
NY	5314.83	30.02	5344.86	0.00	7.49	7.49	13.34	3.76	17.10
OH	4138.93	77.60	4216.53	1.18	1.14	2.32	5.98	5.49	11.47
OK	2938.43	23.81	2962.24	0.00	-1.50	-1.50	0.00	0.30	0.30
OR	8680.65	2.36	8683.01	0.00	0.02	0.02	0.38	0.01	0.39
PA	4246.96	93.69	4340.64	0.00	0.96	0.96	17.43	2.90	20.33
RI	295.09	4.88	299.98	2.30	-0.14	2.16	12.06	-0.50	11.56
SC	2157.62	23.03	2180.65	7.03	-3.51	3.51	27.63	-3.24	24.39
SD	1379.70	6.11	1385.81	0.00	0.00	0.00	0.00	0.01	0.01
TN	3077.27	19.77	3097.04	0.00	-0.08	-0.08	0.05	0.04	0.09
TX	10955.85	104.49	11060.35	0.00	-3.55	-3.55	0.00	1.20	1.20
UT	1580.19	20.15	1600.33	0.00	-1.03	-1.03	0.00	-2.00	-2.00
VA	3269.99	41.11	3311.10	0.00	0.00	0.00	0.04	0.80	0.83
VT	234.14	0.00	234.14	0.00	0.00	0.00	0.52	0.00	0.52
WA	11016.85	13.94	11030.84	0.00	-0.03	-0.03	0.28	-0.05	0.23
WI	2590.01	29.82	2619.83	0.10	3.28	3.38	2.07	0.19	2.26
WV	1122.20	18.25	1140.45	0.00	-0.19	-0.19	0.00	-0.34	-0.34
WY	5818.40	10.16	5828.56	0.00	0.00	0.00	0.00	0.00	0.00

Table S10: Average summertime SO_X emissions (tons/day) by state in the reference case for 2030, and the change in SO_X emissions in the low DG penetration scenario and the high DG penetration scenario. 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).

	Reference Case			Low DG Penetration Scenario			High DG Penetration Scenario		
State	**AREA**	**POINT**	**TOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**	**ΔAREA**	**ΔPOINT**	**ΔTOTAL**
AL	10.54	60.42	70.97	0.00	0.10	0.10	0.00	0.11	0.12
AR	17.23	122.19	139.42	0.00	-0.06	-0.06	0.00	-0.06	-0.06
AZ	20.53	2.02	22.56	0.00	-0.01	-0.01	0.00	-0.02	-0.02
CA	135.94	0.35	136.28	0.19	0.00	0.19	0.78	-0.01	0.77
CO	9.10	77.62	86.72	0.00	0.00	0.00	0.00	0.01	0.01
CT	2.94	8.64	11.59	0.00	-0.01	-0.01	0.06	0.00	0.07
DC	1.88	0.00	1.88	0.00	0.00	0.00	0.04	0.00	0.04
DE	3.70	6.83	10.53	0.00	0.01	0.01	0.00	0.00	0.01

FL	19.46	17.71	37.17	0.03	-0.06	-0.04	0.06	-0.09	-0.03
GA	9.18	94.96	104.13	0.00	-0.02	-0.02	0.00	-0.05	-0.05
IA	5.94	71.19	77.14	0.00	0.05	0.05	0.00	0.05	0.05
ID	210.16	8.11	218.28	0.00	0.00	0.00	0.00	0.00	0.00
IL	26.95	171.81	198.76	0.00	0.09	0.09	0.03	0.08	0.10
IN	47.43	180.51	227.94	0.00	-0.25	-0.25	0.00	-0.71	-0.71
KS	48.18	17.32	65.51	0.00	0.00	0.00	0.00	0.00	0.00
KY	6.82	113.17	119.98	0.00	-0.01	-0.01	0.00	-0.02	-0.02
LA	13.31	22.49	35.80	0.00	0.00	0.00	0.00	0.00	0.00
MA	6.73	2.04	8.77	0.00	-0.02	-0.01	0.25	-0.02	0.23
MD	5.34	10.99	16.32	0.00	0.00	0.00	0.04	0.00	0.04
ME	3.58	0.01	3.59	0.00	0.00	0.00	0.02	0.00	0.02
MI	57.33	149.65	206.97	0.00	-0.04	-0.03	0.16	-0.33	-0.17
MN	32.23	17.05	49.28	0.00	0.02	0.02	0.01	0.02	0.03
MO	99.28	163.13	262.42	0.00	0.04	0.04	0.00	0.07	0.07
MS	4.46	21.88	26.34	0.00	-0.01	-0.01	0.00	0.00	0.00
MT	176.70	30.84	207.54	0.00	0.00	0.00	0.00	0.00	0.00
NC	27.09	26.18	53.27	0.00	0.00	0.00	0.01	0.69	0.71
ND	3.42	48.21	51.63	0.00	0.05	0.05	0.00	0.05	0.05
NE	7.63	29.74	37.37	0.00	-0.01	-0.01	0.00	-0.01	-0.01
NH	4.32	0.07	4.39	0.01	0.01	0.02	0.08	0.00	0.08
NJ	4.48	39.30	43.78	0.00	0.00	0.00	0.27	0.00	0.27
NM	4.11	44.18	48.29	0.00	0.02	0.02	0.00	0.01	0.02
NV	30.96	0.06	31.03	0.00	-0.03	-0.03	0.00	-0.02	-0.02
NY	43.69	60.89	104.58	0.00	-0.02	-0.02	0.14	-0.18	-0.04
OH	37.60	136.15	173.75	0.01	-0.02	0.00	0.04	-0.08	-0.04
OK	20.58	9.71	30.30	0.00	-0.01	-0.01	0.00	0.00	0.00
OR	48.56	0.05	48.61	0.00	0.00	0.00	0.01	0.00	0.01
PA	139.07	263.42	402.49	0.00	0.00	0.00	0.09	0.00	0.10
RI	1.65	0.07	1.72	0.01	0.00	0.01	0.02	0.00	0.02
SC	10.80	60.40	71.21	0.03	-0.08	-0.05	0.06	-0.02	0.04
SD	4.91	37.61	42.53	0.00	0.00	0.00	0.00	0.00	0.00
TN	19.07	44.99	64.06	0.00	0.00	0.00	0.00	0.01	0.01
TX	51.60	188.40	240.00	0.00	-0.06	-0.06	0.00	-0.06	-0.06
UT	7.85	78.32	86.18	0.00	-0.01	-0.01	0.00	-0.02	-0.02
VA	42.20	42.70	84.90	0.00	-0.01	-0.01	0.00	0.46	0.46
VT	3.34	0.00	3.34	0.00	0.00	0.00	0.00	0.00	0.00
WA	66.14	23.63	89.76	0.00	0.00	0.00	0.00	0.01	0.02
WI	13.28	69.53	82.81	0.00	0.04	0.04	0.04	-0.81	-0.78
WV	11.11	82.70	93.82	0.00	-0.01	-0.01	0.00	-0.01	-0.01
WY	54.15	63.90	118.05	0.00	0.00	0.00	0.00	0.00	0.00

3.3.2 Impacts on Air Quality

In the low DG penetration winter episode, DG emissions cause ozone concentrations to decrease by about 0.5 ppb in some areas of California due to titration effects. Changes in EGU emissions cause slight reductions in ozone concentrations for isolated locations in Pennsylvania, and both increases and decreases in ozone concentrations in Florida. However, the impact on ozone concentrations in Florida (±1-2 ppb) is much lower in the winter episode than in the summer episode. Figure S11 shows that peak decreases in maximum daily 8-hour average ozone concentrations are less than 1 ppb in California and 2 ppb Florida. There is little to no change in winter ozone concentrations for the remainder of the United States.

In the winter episode with high DG penetration, ozone concentrations decrease in many of the areas that experienced the largest ozone increases during the summer episode, as shown in Figure S13. In southern California and the San Francisco Bay area, 8-hour average ozone concentrations decrease by up to 3 ppb in areas with a high density of DG penetration (see Figure 2 in main manuscript for map of DG penetration). Michigan, New Hampshire, Maine, Rhode Island, Massachusetts, and surrounding areas in the far northeastern U.S. also experience decreases in ozone concentrations of 1-2 ppb due to DG emissions. Areas that are near strong NO emissions sources experience ozone titration throughout the winter episode, causing maximum daily 8-hour average ozone concentrations to decrease by up to 3 ppb. Both increases and decreases in ozone concentrations occur in Florida in response to changes in EGU emissions, but they are typically less than 1 ppb during the winter episode. As is the case in the low DG penetration scenario, any significant changes in ozone concentrations that occur during the winter episode in response to DG emissions occur in areas with the highest density of DG penetration. The central United States again remains unaffected, with no change in ozone concentrations during both the summer and winter episodes.

Figure S15 through Figure S20 show the relative contributions of different PM components to the change in total $PM_{2.5}$ concentrations in the high DG penetration scenario on February 8, the day with the highest $PM_{2.5}$ concentrations in the reference case. Together, changes in the concentration of these five species account for essentially all of the change in total $PM_{2.5}$ concentrations seen in Figure S15. In most of California, nitrate aerosol accounts for half of the change in total $PM_{2.5}$ concentrations, but shows only small changes in concentration outside of California. 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 most of California, increases in $PM_{2.5}$ 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. Increases in primary elemental carbon and primary organic carbon concentrations are due to direct emissions and are mostly isolated to the northeastern U.S. and one area in southern California and around the San Francisco Bay. Sulfate aerosol concentrations increase slightly in Florida, the San Francisco Bay area, and southern California due to localized increases in SO_X emissions and direct emissions of PSO_4. However, increases in sulfate aerosol concentrations contribute only marginally to the overall increase in total $PM_{2.5}$ concentrations in most areas. Direct particulate emissions and increased formation of ammonium nitrate both contribute to increased $PM_{2.5}$ concentrations in the northeastern United States.

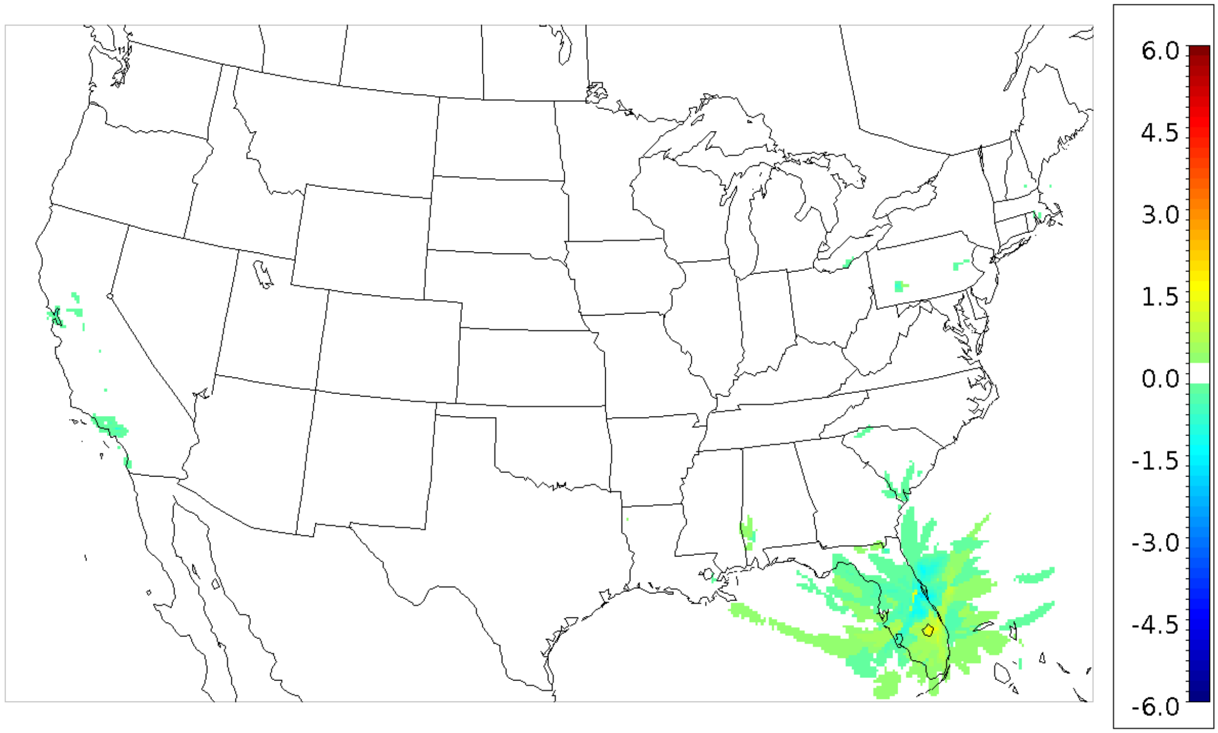

Figure S11: Peak delta in maximum daily 8-hour average ozone concentration (ppb) during the period January 8 to February 28: Low DG Penetration minus Baseline.

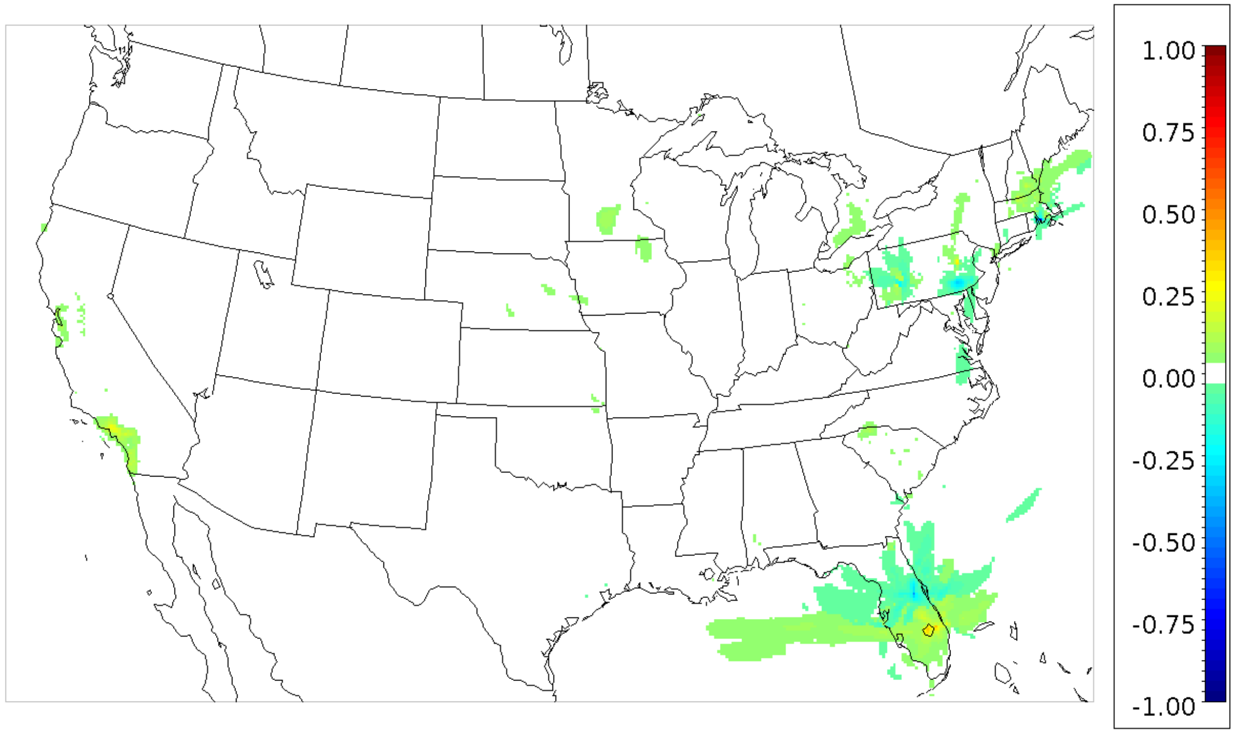

Figure S12: Peak delta in daily 24-hour average $PM_{2.5}$ concentration ($\mu g/m^3$) during the period July 8 to August 31: Low DG Penetration minus Baseline.

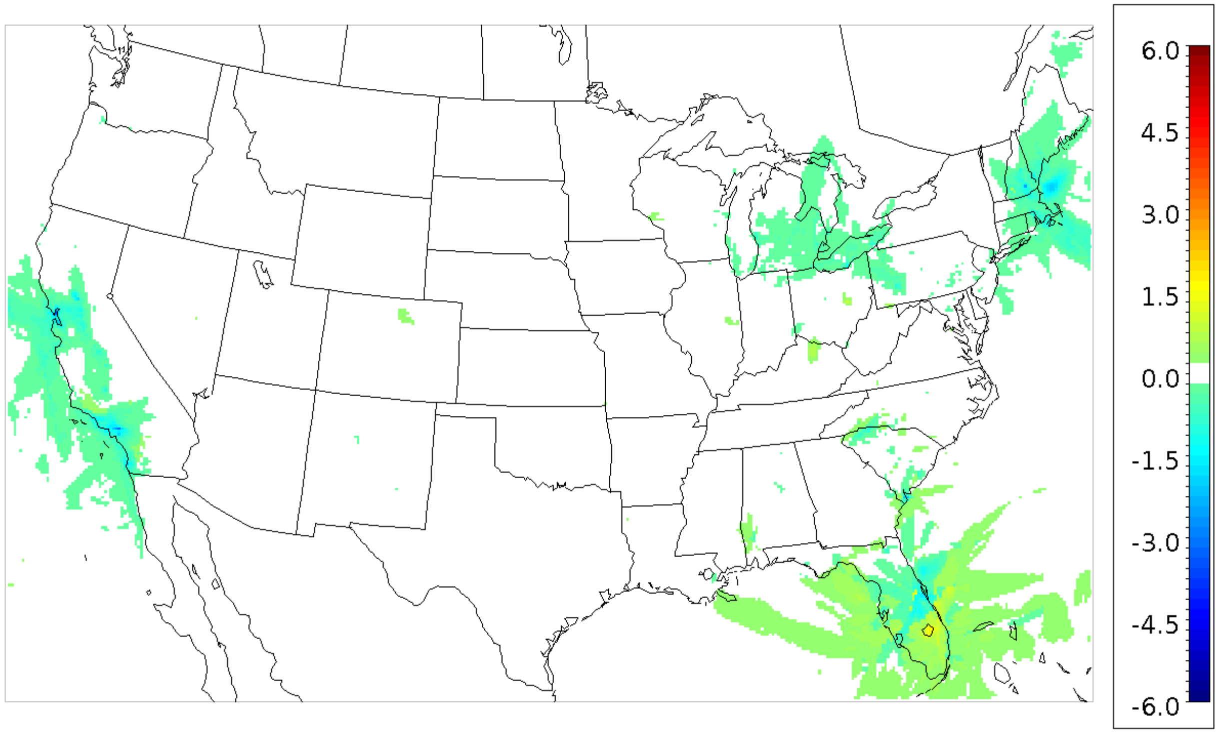

Figure S13: Peak delta in maximum daily 8-hour average ozone concentration (ppb) during the period January 8 to February 28: High DG Penetration minus Baseline.

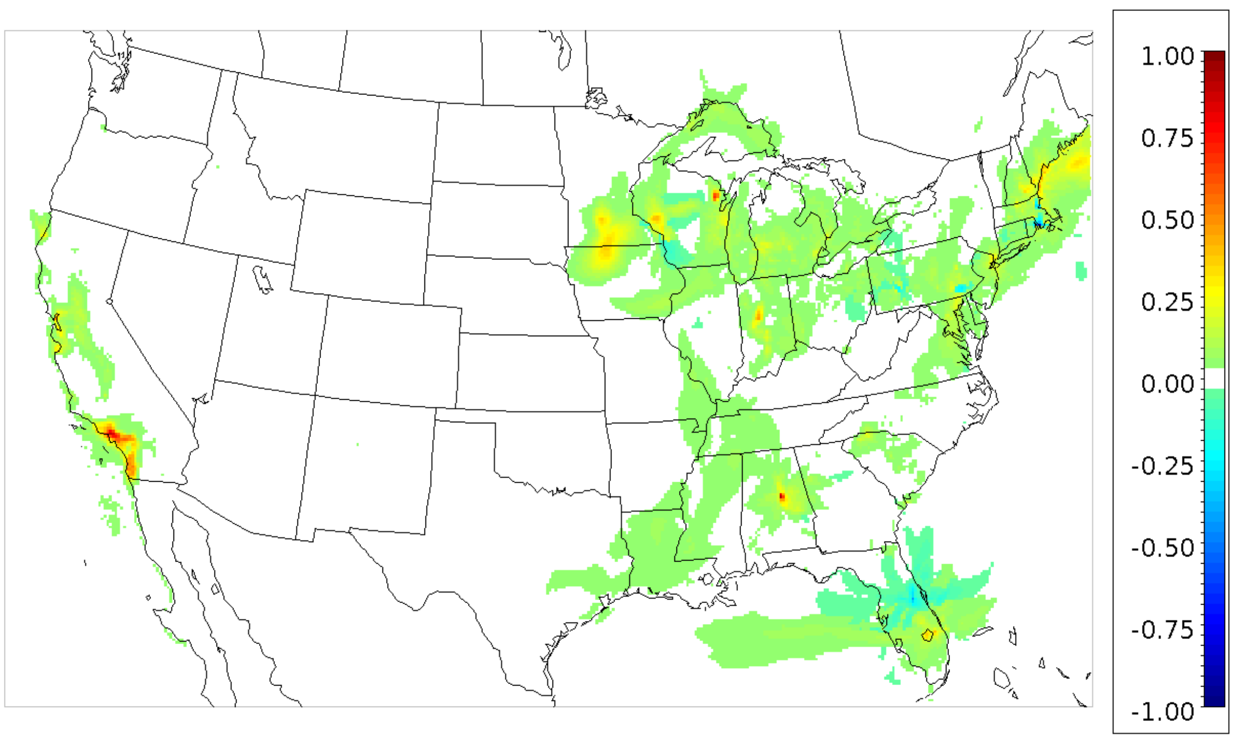

Figure S14: Peak delta in daily 24-hour average $PM_{2.5}$ concentration ($\mu g/m^3$) during the period July 8 to August 31: High DG Penetration minus Baseline.

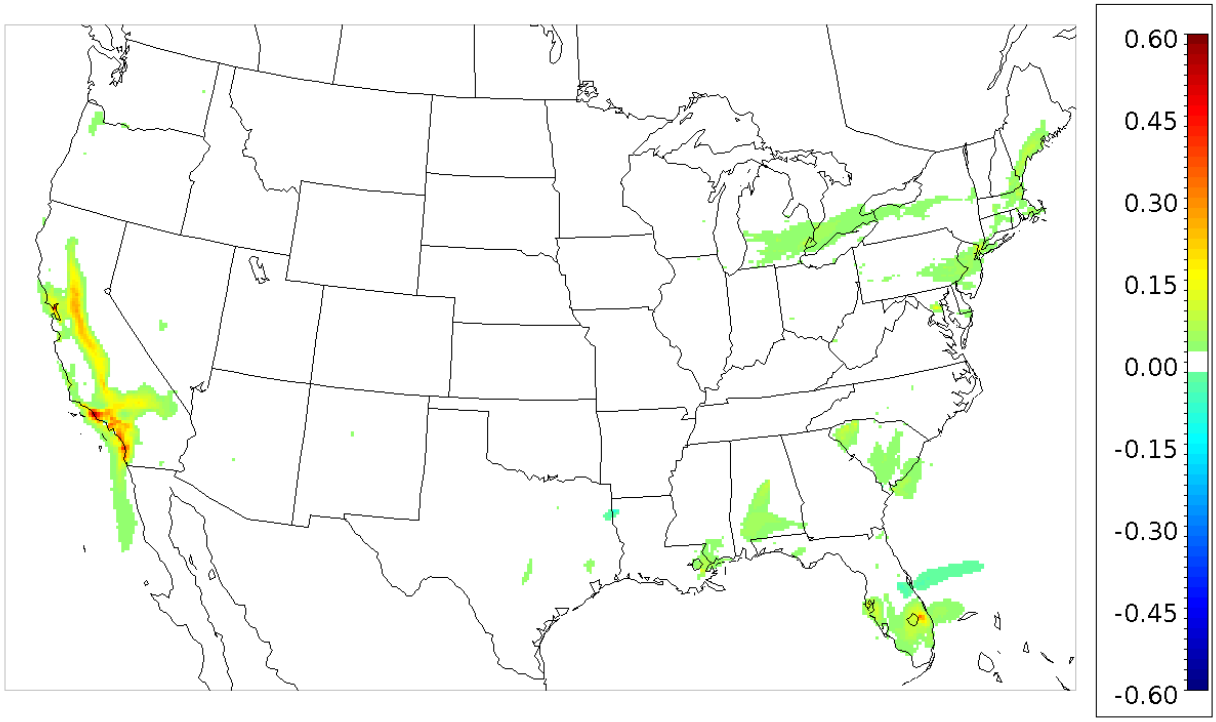

Figure S15: Delta in 24-hour average total $PM_{2.5}$ concentration (μg/m^3) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline.

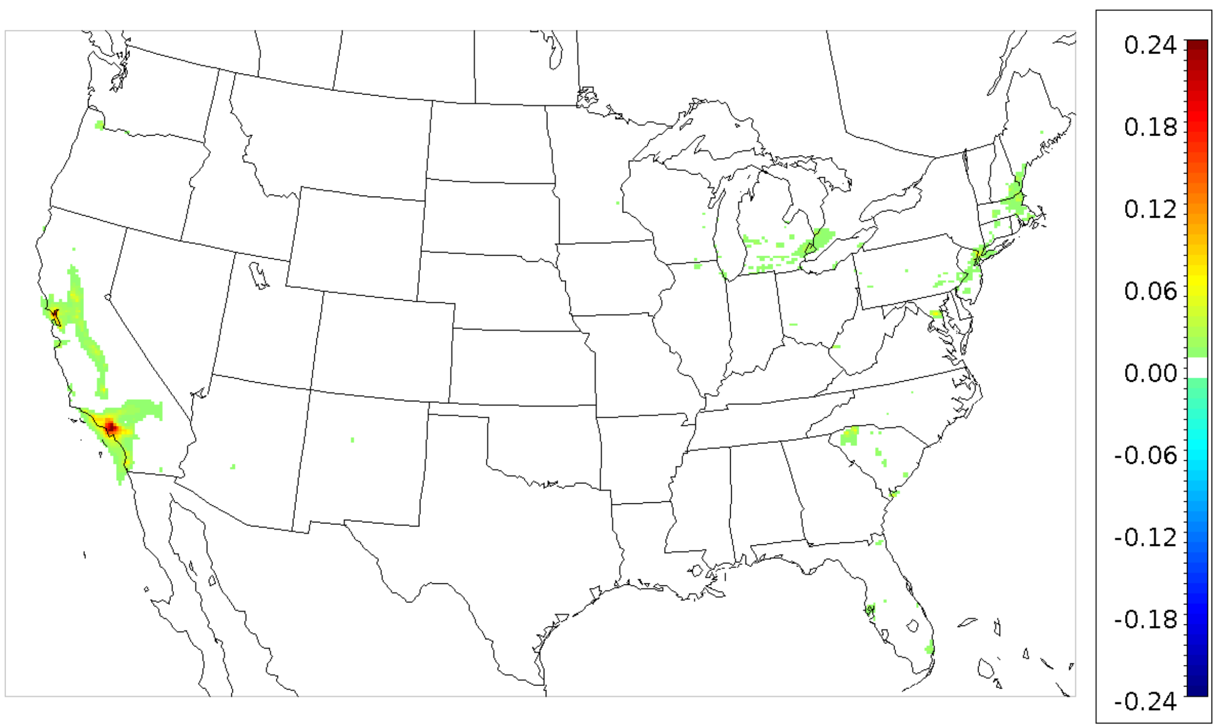

Figure S16: Delta in 24-hour average primary elemental carbon (PEC) concentration (μg/m^3) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline.

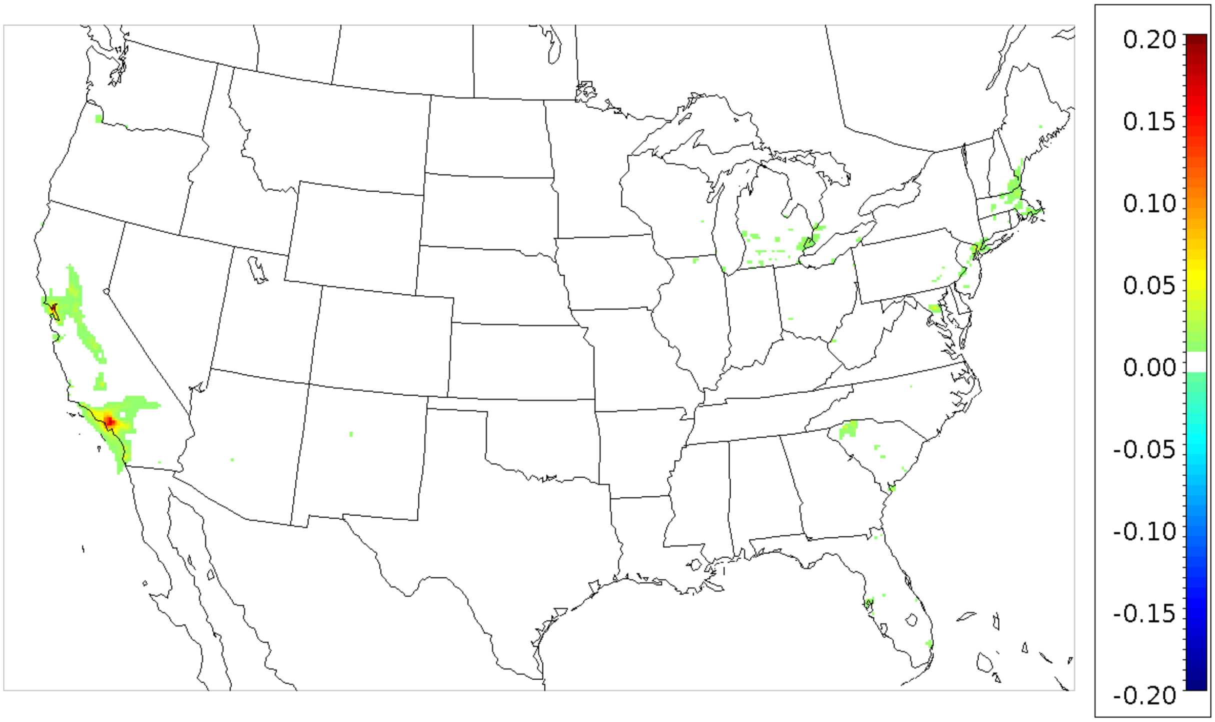

Figure S17: Delta in 24-hour average primary organic carbon (POA) concentration (μg/m^3) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline

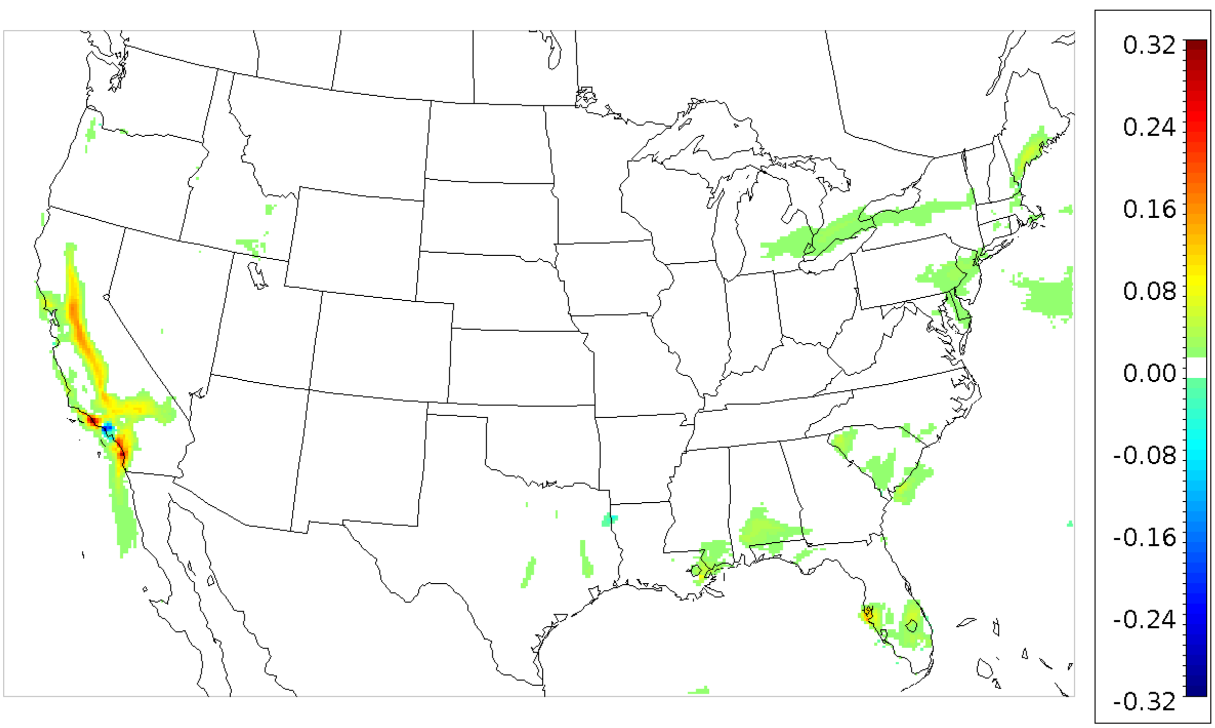

Figure S18: Delta in 24-hour average nitrate aerosol (PNO_3) concentration (μg/m^3) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline

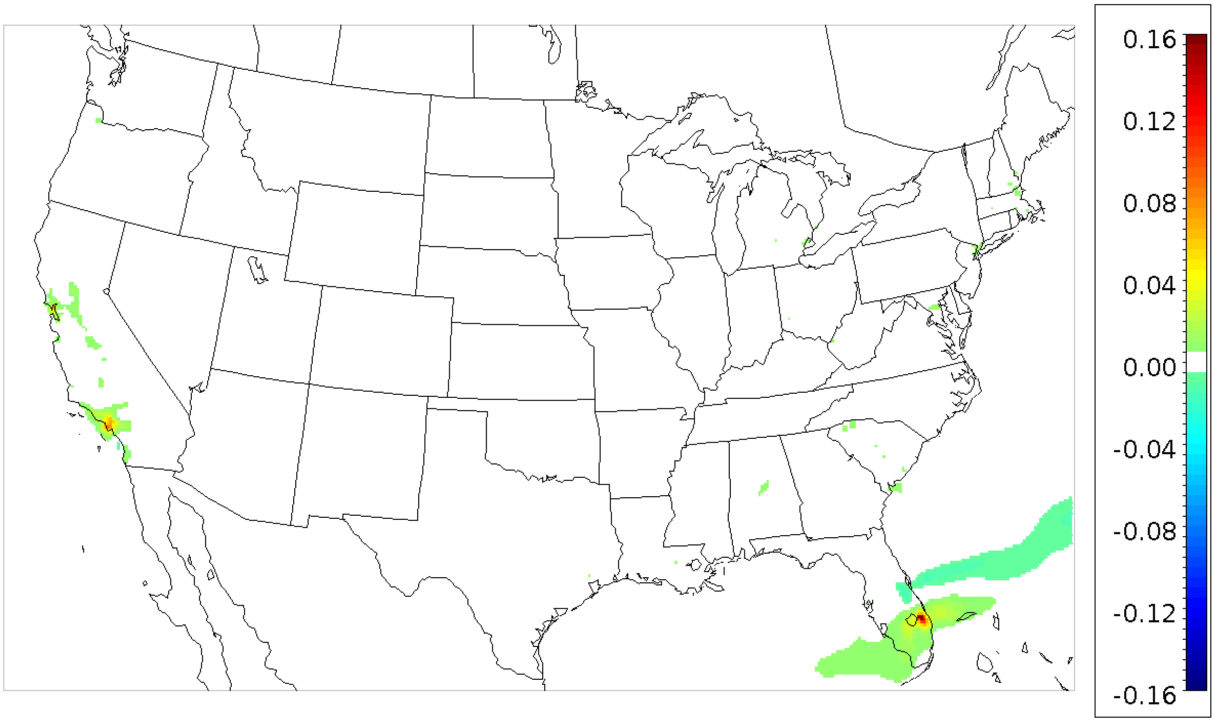

Figure S19: Delta in 24-hour average sulfate aerosol (PSO_4) concentration ($\mu g/m^3$) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline

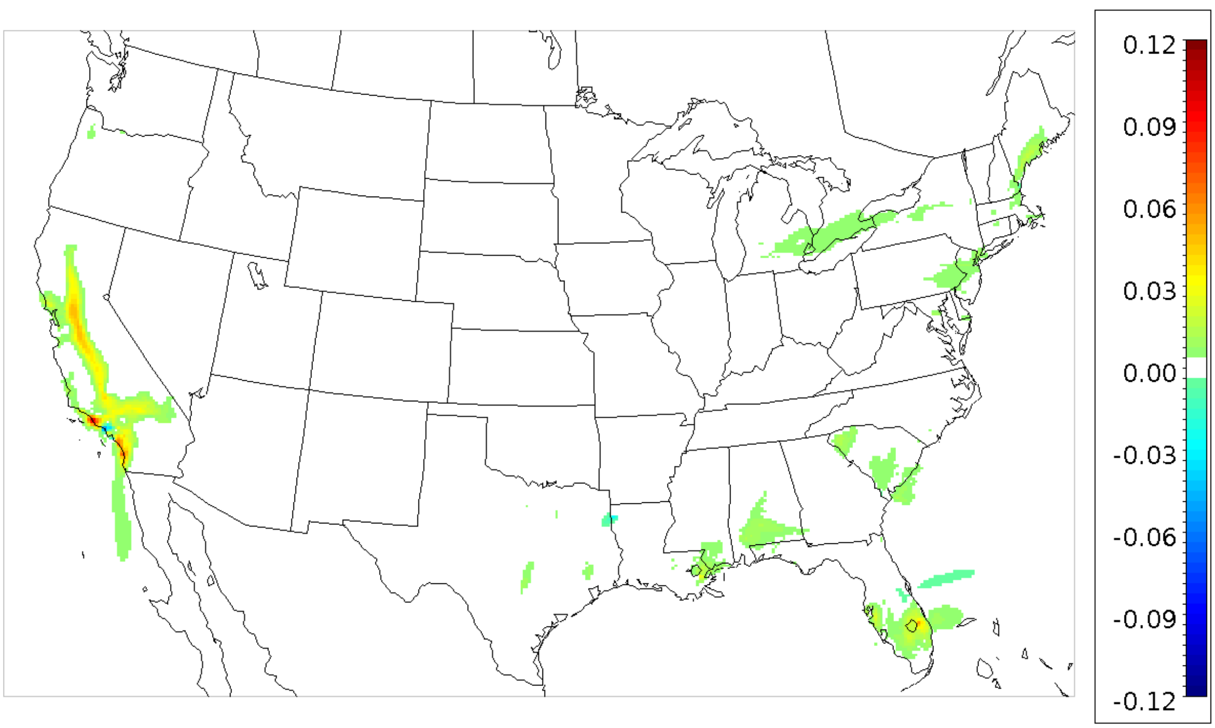

Figure S20: Delta in 24-hour average ammonium aerosol (PNH_4) concentration ($\mu g/m^3$) on February 8 (day with highest $PM_{2.5}$ concentration): High DG Penetration minus Baseline

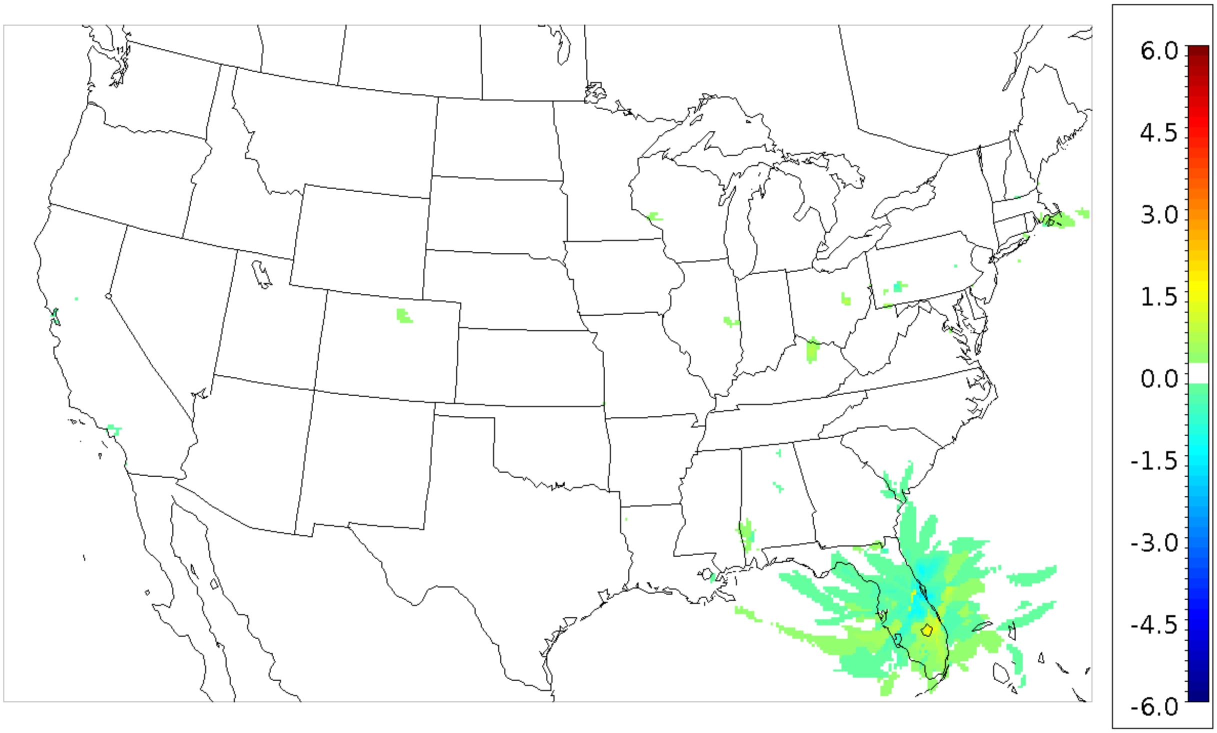

Figure S21: Peak delta in maximum daily 8-hour average ozone concentration (ppb) during the period January 8 to February 28: CARB Certification minus Baseline.

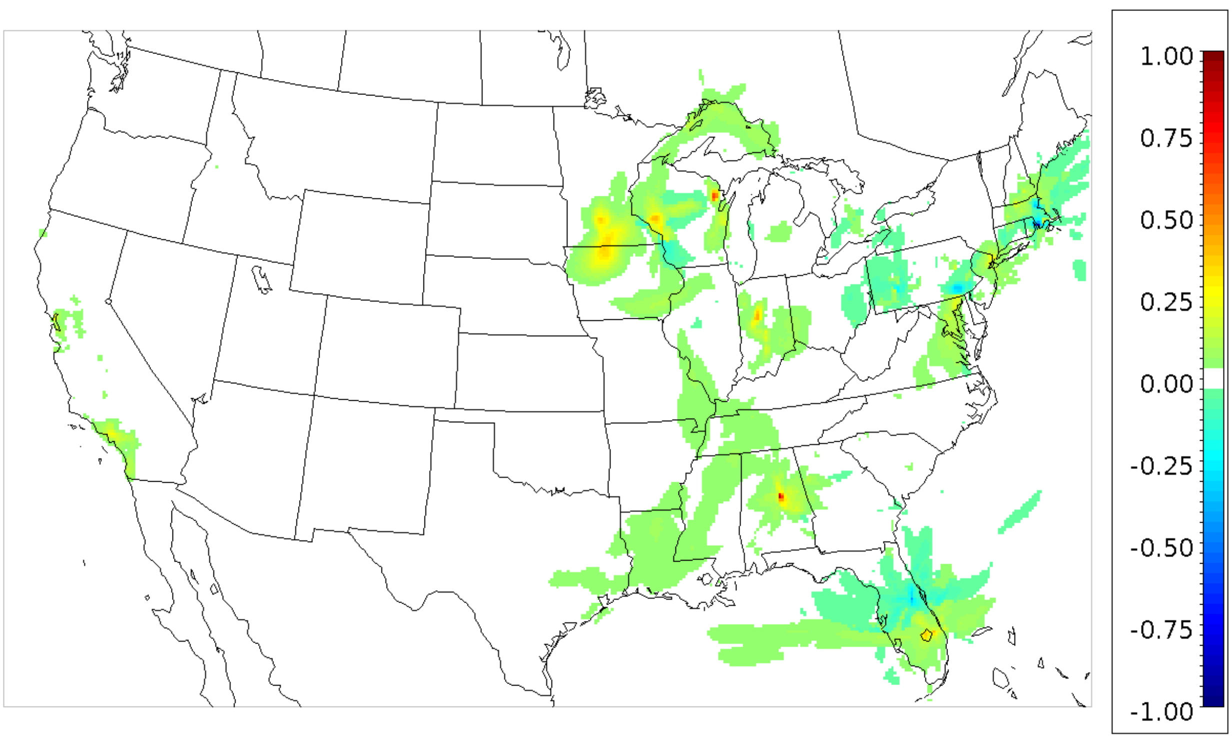

Figure S22: Peak delta in daily 24-hour average $PM_{2.5}$ concentration ($\mu g/m^3$) during the period July 8 to August 31: CARB Certification minus Baseline.

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