Environmental Assessment of a Full Electric Transportation Portfolio

Volume 1: Background, Methodology, and Best Practices

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Product Description

Executive Summary

The *Environmental Assessment of a Full Electric Transportation Portfolio* analyzes the potential impacts of a widespread shift in transportation energy use toward electricity, anticipating that electricity will eventually replace approximately half of projected light- and medium-duty transportation-fuel use and a significant portion of non-road–fuel use. This study is a follow-up to and extension of the 2007 *Environmental Assessment of Plug-in Hybrid Electric Vehicles* performed by the Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC), which demonstrated that plug-in hybrid electric vehicles (PHEVs) could both contribute to significant reductions in national greenhouse gas emissions and also lead to improved air quality. As with the 2007 assessment, the 2015 assessment consists of two separate but related analyses of the impacts of electric transportation: an analysis of the greenhouse gas emissions from 2015 to 2050 (described in Volume 2) and an analysis of air quality impacts in 2030 (described in Volume 3).

This Volume, Volume 1, discusses the background for this analysis—including recent emissions trends, a review of related literature, and a discussion of best practices for modeling large-scale changes in electricity-sector load.

Recent Emissions Trends

It is often said that "electric vehicles are the only vehicles that get cleaner as you drive them." Figure 1 shows that over the last decade this statement has been true: between 2003 and 2013, the CO_2-emissions intensity decreased by 15%, the SO_2-emissions intensity decreased by 70%, and the NO_x-emissions intensity decreased by 50%. Reductions are occurring in every region of the country, although there is still a wide variation in emissions rates. Further reductions will be necessary to achieve societal goals for greenhouse gas and air quality impacts, but these ongoing trends provide important motivation for the current focus on beginning the transition toward electric transportation.

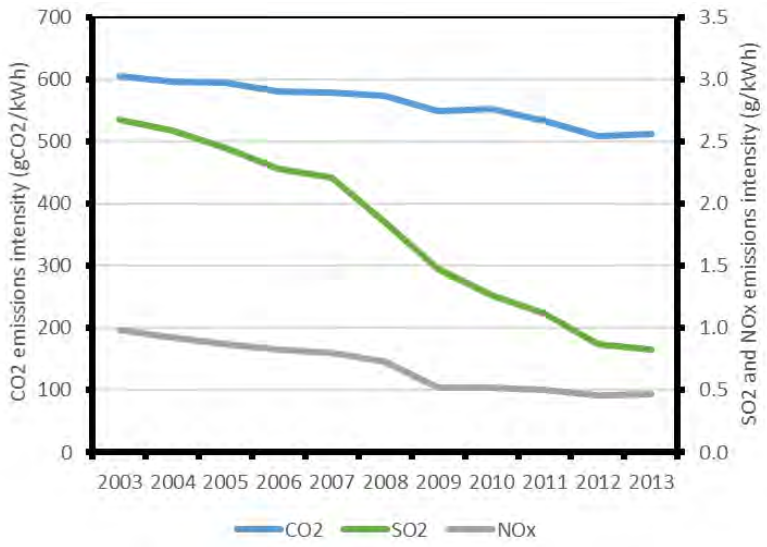

Figure 1
Historical grid emissions intensity for CO_2, SO_2, and NO_x

Review of Related Literature

Assessment of the potential benefits of electric transportation has been an area of active interest, so there have been a number of projections of the grid emissions attributable to use of electricity as a transportation fuel. Most studies have found that vehicles powered by electricity provide an emissions benefit in comparison to conventional gasoline vehicles, but the numerical results vary widely. In fact, some studies find that electric vehicles have higher emissions than conventional vehicles in some situations. The study team performed a review of the existing literature in order to understand the reasons for these variations and to determine whether or not revisions to the modeling methodology used in the 2007 assessment were necessary.

As an example of the variation in emissions estimates, Figure 2 shows each estimate for California grid emissions in the reviewed studies compared to actual average-emissions rates. There is little agreement among the projections, and all of them are higher than actual levels or trends for average emissions; some are much higher. The review indicated that variation among studies was attributable to differences in timeframe, regional resolution, and emissions scope. However, one particularly important source of variation was the grid emissions-measurement methodology. The methodologies were categorized as "historical average," "projected average," "small-scale marginal," and "large-scale marginal." Average-emissions measures do not distinguish between different sources of load, whereas marginal-emissions measures estimate the incremental emissions resulting from additional vehicle charging load. Small-scale marginal-emissions measures estimate the effects of additional load

on the usage of existing power plants, whereas large-scale marginal-emissions measures additionally consider the effects of changing load on the configuration of the generation fleet. Given the assessment's focus on large-scale changes that would occur over long time periods, the use of the large-scale methodology used in the 2007 assessment was reaffirmed. In addition, the literature review indicated the need to develop best practices for modeling the grid impacts of large-scale changes in load.

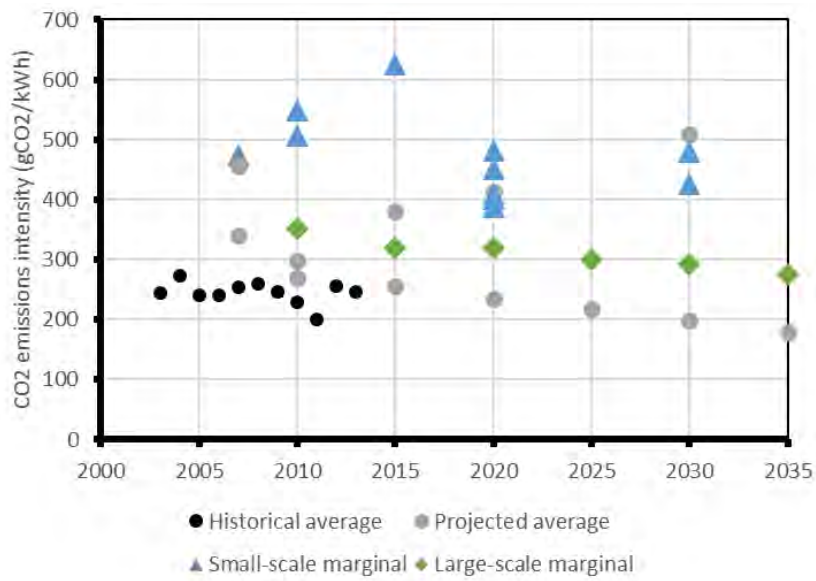

Figure 2
Estimated CO_2-emissions intensity for California from reviewed studies, separated by grid emissions-measurement methodology

Grid-Modeling Best Practices

Based on the literature review and discussions with grid-modeling experts, the study team developed a set of best practices for modeling the effects of large-scale changes in grid load. We can propose best practices in each of four important aspects of these modeling efforts:

- *Model characteristics:* Electricity emissions rates should be projected using a model with least-cost dispatch with capacity constraints; a representative regulatory framework, including constraints on emissions of criteria pollutants; and endogenous capacity expansion and retirement. These minimum characteristics ensure that the processes utilities use to make decisions about accommodating new load are represented. PEVs should be compared against an improving baseline of vehicles that meet increasingly stringent fuel-economy targets.

- *Load-modeling methodology:* If marginal emissions are estimated, a large-scale modeling methodology should be used, in which PEVs are added to the baseline grid with realistic rates and magnitudes and with a realistic load shape. This methodology allows the dynamics of generation growth and dispatch to be modeled within an economic and regulatory framework that ensures that the grid responds appropriately to the additional load.
- *Emissions reporting:* Even if marginal emissions are the focus of a study, average annual emissions rates should be calculated and presented for each study area and scenario. Average-emissions rates are more stable and general than marginal-emissions rates, and they provide useful information concerning the baseline assumptions for marginal changes.
- *Study scope:* Emissions attributable to upstream acquisition, processing, and distribution of transportation and electricity fuels such as gasoline, natural gas, and coal should be included. However, results should be presented for both life-cycle emissions and direct emissions. Upstream emissions are a significant portion of life-cycle emissions, and conventional transportation-fuel pathways differ considerably from electricity-fuel pathways. There is still a high degree of uncertainty in some upstream-pathway emissions, however, so results for direct emissions provide a useful reference point for comparisons between different studies. Vehicle-production emissions could also be a significant source of variation between PEVs and conventional vehicles.

These best practices are not a full specification for creating an electric transportation emissions model, but they ensure that grid changes are modeled realistically and allow the results to be independently analyzed.

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Section 1: Environmental Assessment Background and Outline

Transportation electrification has tremendous potential to contribute to long-term greenhouse gas reductions by replacing mobile combustion sources (whose emissions are difficult to mitigate) with central or distributed electricity generation sources (whose emissions can potentially be reduced to zero). However, because electricity is currently derived substantially from fossil-fuel sources, the pace and extent of decarbonization depend on many uncertain factors. The use of electricity in the transportation sector introduces the key question: Which generation sources will supply the additional load from new vehicles—both now and in the future? It is also important to ensure that greenhouse gas goals are not achieved at the cost of either human health impacts or environmental degradation resulting from non–greenhouse gas pollution. *The Environmental Assessment of a Full Electric Transportation Portfolio* was initiated in order to create a comprehensive analysis of the effects of a large-scale transition to electric transportation, using state-of-the-art grid and air quality models. The present assessment is a follow-up to and extension of the 2007 *Environmental Assessment of Plug-in Hybrid Electric Vehicles* performed by the Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC), which demonstrated that plug-in hybrid electric vehicles (PHEVs) could both contribute to significant reductions in national greenhouse gas emissions and also lead to improved air quality. The 2007 analysis provided a useful reference point for discussions of the potential for emissions reductions from electric vehicles. But much has changed since then in the transportation and electricity sectors, so a new analysis is warranted. The analysis described in this assessment repeats the rigorous methodology followed in the previous analysis, but it updates key assumptions to more closely match changes in the modeled sectors. The discussion of these results is also redirected in order to be more relevant to current conversations about the effects of a full electric transportation portfolio, which includes electrified light-duty vehicles, medium-duty vehicles, and non-road vehicles and devices.

Volume 1 of the present assessment discusses the background research and methodology development for the analysis. A large number of researchers have addressed the question of the potential effects of electrification, and the results of these investigations have not been homogenous. For example, Figure 1-1 shows the projected emissions intensity of electricity generation to supply plug-in

electric vehicles (PEV) in California across a range of studies.[1] The estimates vary from those that are approximately equivalent to current emissions to those that are about three times higher than current emissions. Studies of other regions and national-level results show similarly wide variations—results which can cause uncertainty about whether or not transportation electrification is actually beneficial at all.

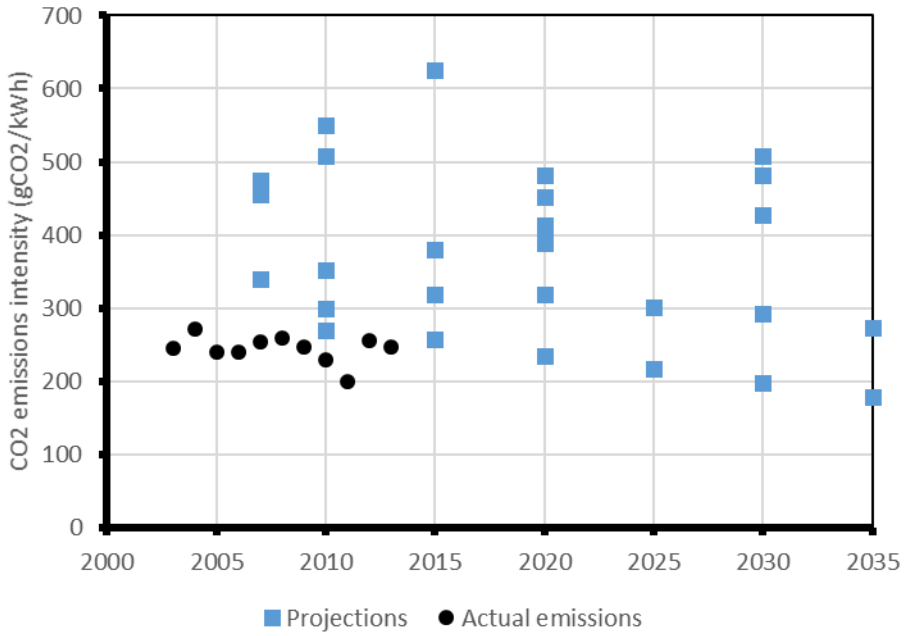

Figure 1-1
Estimated grid emissions intensity to supply PEVs in California from reviewed studies

In order to understand these variations among studies and to refine the methodology for the present analysis, the study team performed a detailed review of the differences in data sources, assumptions, and methodologies used to analyze the grid. Some variation among different studies can be expected as a result of their different assumptions about future technologies and policy. But the study team found that certain non-policy choices had particularly high impacts on the stated results for the study—including the timeframe analyzed, the emissions-measurement methodology employed, the regional aggregation scale used, and the scope of emissions included. The following sections describe the analysis of these studies and discuss the implications of different modeling choices. Based on EPRI's grid-modeling expertise, best practices for modeling the large-scale impacts of transportation electrification were developed and described.

[1] California is well-studied because of its policy focus on zero-emissions vehicles. See Section 4 for a literature review that describes each plotted study in detail.

Section 2: Recent Trends in US Grid Emissions

Electricity-grid emissions have recently been changing at an unprecedented rate as a result of a variety of economic, technological, and policy pressures. This section discusses these changes and their resulting effects on emissions as a basis for understanding projections for transportation-sector emissions.

These results indicate that

- The emissions intensity of grid electricity is decreasing for CO_2, and it is decreasing rapidly for SO_2 and NO_x.
- CO_2 emissions reductions are widespread, although there is still a very large difference between the lowest-emissions regions and the highest-emissions regions.
- In 2013, a PEV had emissions equivalent to a 61-mile-per-gallon (mpg) gasoline vehicle at the national level, with regional emissions ranging from 46 miles per gallon equivalent (MPGe) to 251 MPGe.

Current Factors Affecting Electricity-Grid Emissions

There are a great number of large-scale and local-scale factors that are driving changes in grid emissions. Factors relevant to greenhouse gas emissions and emissions of criteria pollutants are discussed in Volume 2 and Volume 3. In sum:

- Favorable natural gas prices and operational characteristics have rapidly increased the capacity of combined cycle natural gas (CCNG) generation units and increased the utilization of existing capacity at the expense of coal generation.
- Tightening restrictions on emissions of criteria pollutants, water use, waste products, and potential greenhouse gas emissions have created significant pressure to reduce the operation of coal- and petroleum-generation units. In particular, the Mercury and Air Toxics Standards (MATS) have challenged the economics of operating older and less-utilized plants by setting a rate-based cap instead of a tradable quantity–based cap. This type of cap has increased the retirement rate for these fossil fuel–fired units.
- The Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR) have increased the stringency of quantity-based caps for

sulfur dioxide (SO_2) and nitrogen oxides (NOx) for plants operating in the eastern United States.[2]

- Increasingly stringent regulations on criteria emissions and uncertainty about expected regulations on greenhouse gas emissions, water quality impacts, and coal ash disposal restricted the construction of new coal capacity.
- State-level Renewable Portfolio Standards (RPS) have created minimum standards for renewable generation deployment.
- The relative economics of solar photovoltaic systems and wind generators are becoming more favorable; therefore, these renewable-energy technologies have been installed in some locations in excess of mandated levels.
- The expectation of increasing greenhouse gas regulations has created a high degree of uncertainty about carbon-intensive generation—particularly coal. This uncertainty amplifies the perceived costs of compliance with other regulations, because it is unclear how long a given generator could be operated to repay capital expenses for upgrades.

These and other factors have driven generation trends from higher-emitting sources to lower-emitting and non-emitting sources. "Legacy" generation units have also been retrofitted with emissions-control technology in order to decrease emissions of criteria pollutants.

Recent Emissions Trends

Figure 2-1 shows the effect of the factors described above on national average electricity sector emissions: In the decade from 2003 to 2014, CO_2 emissions intensity decreased by 15%, SO_2 emissions intensity decreased by about 70%, and NO_x emissions intensity decreased by about 50%.[3] Reductions in emissions of the criteria pollutants SO_2 and NO_x have direct impact on human health, so these large reductions are very significant. (Local trends are more complex than these national trends indicate. But federal regulations like CAIR and CSAPR, as well as state and local regulations, will generally concentrate reductions in the areas in which these reductions are most beneficial.)

[2] The EPA regulates ambient levels of six pollutants (ozone, particular matter, sulfur dioxide, nitrogen dioxide, lead and carbon monoxide) through National Ambient Air Quality Standards (NAAQS). Regions that fail to meet the NAAQS are considered non-attainment areas. CAIR and later CSAPR regulate power plants in the eastern United States as programs to abate the interstate transport of pollutants from power plants contributing to fine particulate matter (i.e., SO2 and NOx) and ozone (i.e., NOx) formation.

[3] These emissions estimates were calculated using the methodology and data sources described in EPRI (2014a).

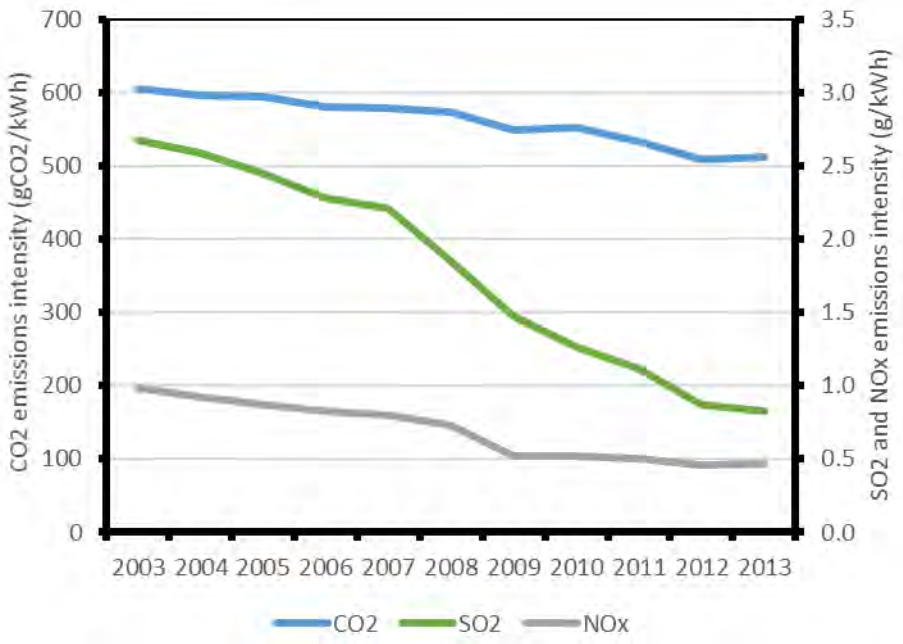

Figure 2-1
Historical national grid emissions intensity for CO_2, SO_2, and NO_x

The rapid decline in emissions of criteria pollutants is likely to continue during 2014–2016, as the MATS compliance period begins.

Recent Generation Trends

The emissions decreases shown in Figure 2-1 are attributable to both increasingly effective emissions controls and changes in generation. The generation trends over this time period are shown in Figure 2-2, and incremental generation changes are shown in Figure 2-3. Generation increases have largely been satisfied by CCNG, with significant contributions from wind power. Coal generation has decreased significantly, and petroleum generation has decreased by about 75% (but from a small baseline). (Nuclear and hydroelectric generation have varied significantly from year to year, but on average have changed little over the full time period; they have therefore been removed for the sake of clarity.) These national-level changes have resulted from a large number of small changes, which have particularly affected emissions in some regions. This regional heterogeneity is discussed in the next section.

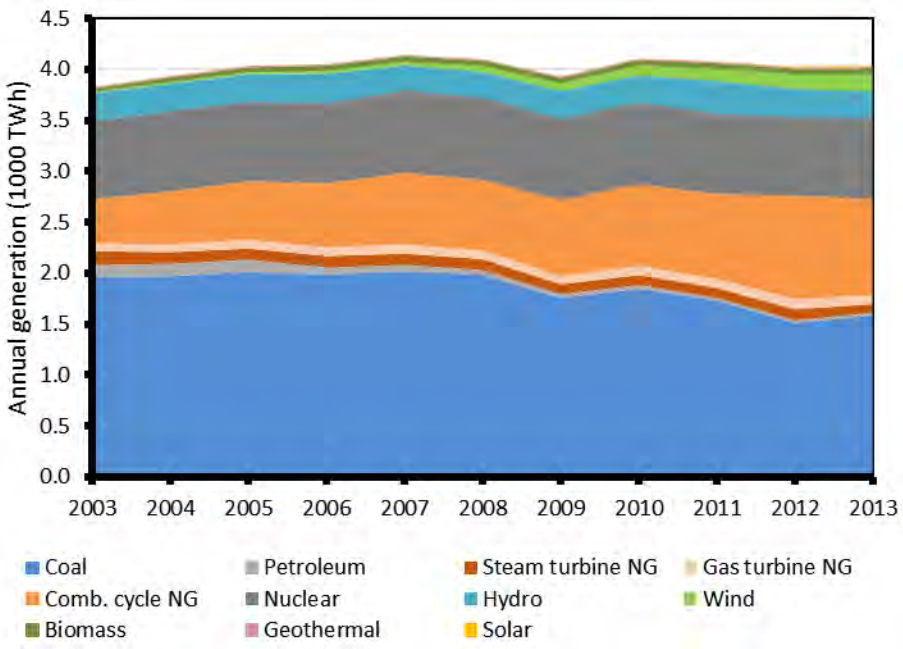

Figure 2-2
Generation trends from 2003 to 2013

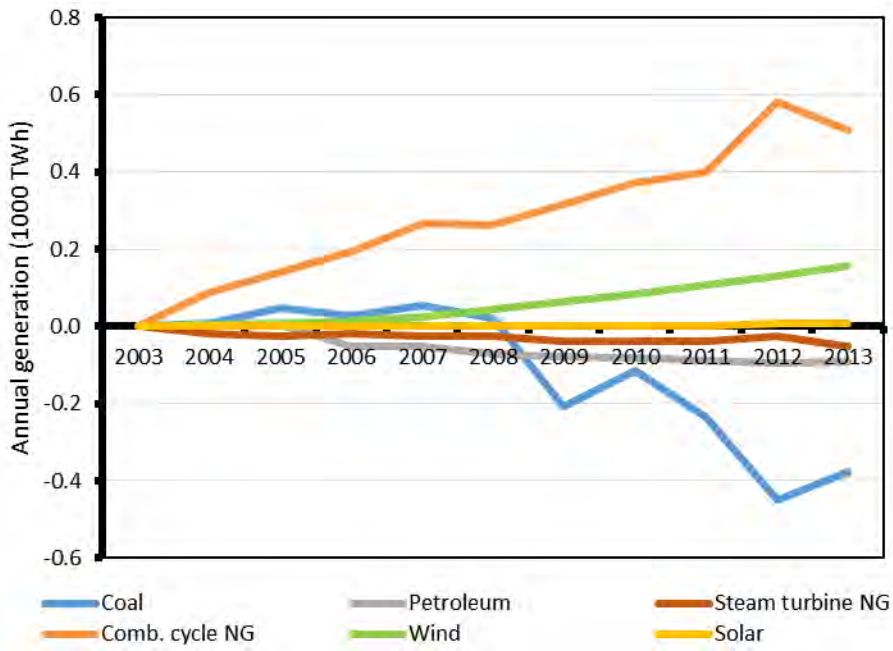

Figure 2-3
Incremental generation changes from 2003 to 2013

Regional CO_2 Emissions Trends

There are large U.S. regional variations in emissions because of the variety of resources, policies, and legacy generators present in different areas. Figure 2-4 shows the regional variation in CO_2 emissions for the historical data presented in Figure 2-1 allocated to the regions used in EPRI's United States Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. (See Appendix B and Appendix C for more information on the regional delineations.) Based on these regional boundaries, there is about a 7:1 ratio between the lowest-emitting region and the highest-emitting region. Importantly, however, all regions exhibit generally decreasing CO_2 emissions.[4] About half the regions were within +/- 100 g/kWh of the national emissions levels, and they followed similar trends. However, there were some regions with significantly higher emissions in the Upper Midwest and Mountain West. Although these two regions have generally decreasing emissions trends, they are decreases from a high baseline that stems from historically coal-intensive generation mixes. In the highest-emitting region, NW-Central, CO_2 emissions decreased by 14% between 2003 and 2013. In the next highest-emitting regions, Mountain-N and NE-Central, CO_2 emissions decreased by 14% and 9%, respectively. The regions with the greatest emissions reductions were NY and NE. These regions were already relatively clean in 2003, but their emissions decreased by about 40% by 2013.[5]

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[4] California is generally trending downwards, but emissions intensity increased by 1% between 2003 and 2013 as a result of the unexpected closure of the San Onofre Nuclear Generating Station in 2012.

[5] The United States Environmental Protection Agency (EPA) Emissions & Generation Resource Integrated Database (eGRID) estimates emissions that are about 10% higher for the NE than the estimate in this report, but the relative trends in both estimates are consistent (EPA, 2014a).

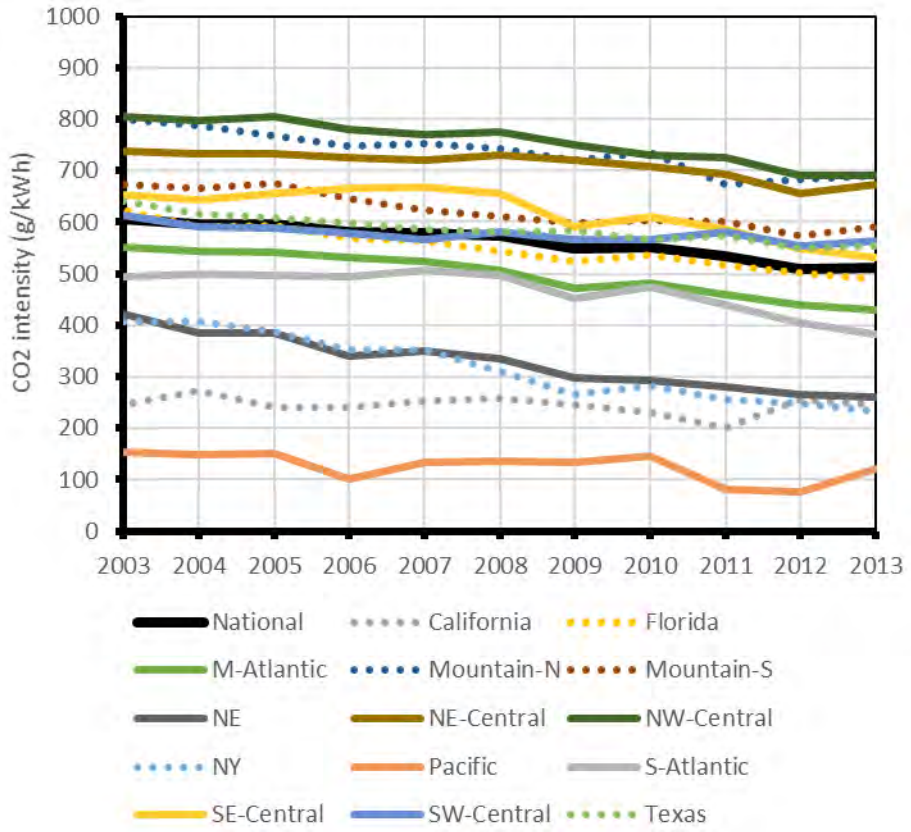

Figure 2-4
Regional variation in CO_2 emissions intensity

Another way to view grid emissions within the context of electric transportation is to convert CO_2 emissions into equivalent "gallons" of gasoline. Figure 2-5 shows the fuel economy that a gasoline vehicle would have to achieve in order to match a PEV with an electricity consumption rate equivalent to 115 mpg.[6] This comparison includes direct and upstream greenhouse gas emissions for both electricity and gasoline, and it includes transmission and distribution losses for electricity. The "Pacific" region is not shown on the chart, but it has an average emissions-equivalent fuel economy of 256 MPGe for the same time period. At the national level, a PEV running on electricity was equivalent to a gasoline vehicle with a fuel economy of 61 mpg in 2013. For the highest-emitting electricity grids, a PEV running on electricity was equivalent to a gasoline vehicle with a fuel economy of 43 mpg in 2013. Table 2-1 shows the emissions-equivalent fuel economy for each region in 2013, along with comparable fuel economies for conventional vehicles. The average fuel economy for all new vehicles in 2013 was 24.1 mpg, and the most efficient gasoline vehicle available in 2013—the Toyota Prius—achieved a fuel economy of 50 mpg.

[6] Recent PEVs achieve an energy-equivalent fuel economy of 115 MPGe (293 AC Wh/mi), as rated by the EPA.

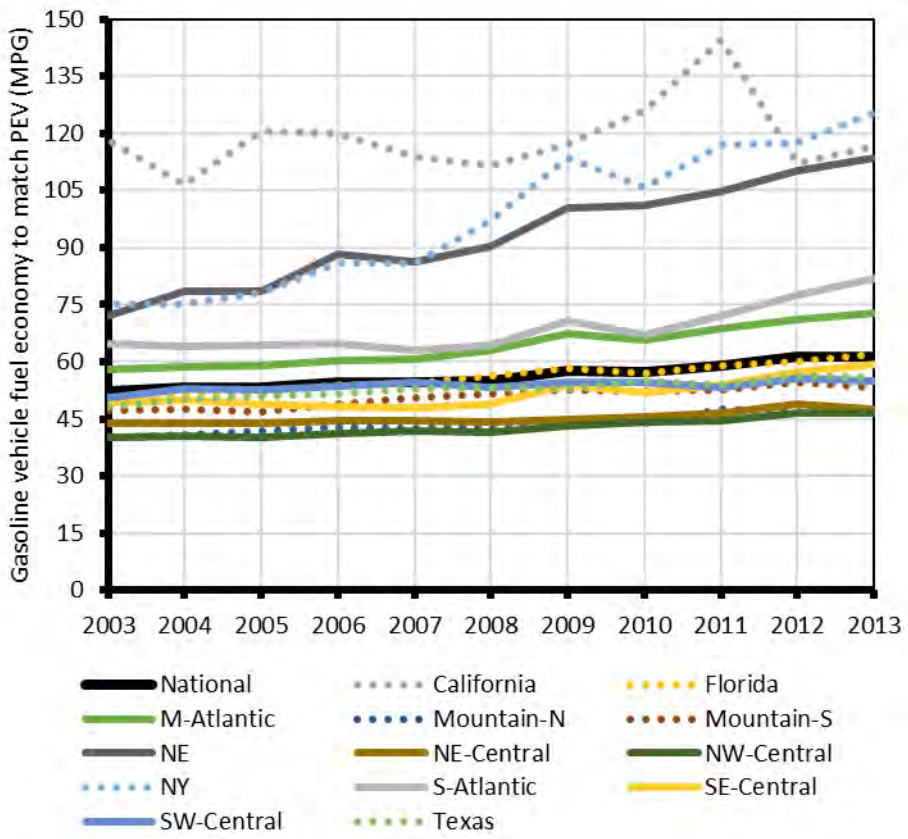

Figure 2-5
Emissions-equivalent fuel economy for electricity

Table 2-1
Regional equivalent fuel economy in 2013 and comparisons for conventional vehicles

Region / comparison	MPGe / mpg
National	61
California	116
Florida	62
M-Atlantic	73
Mountain-N	46
Mountain-S	53
NE	113
NE-Central	48
NW-Central	47
NY	125
Pacific	251
S-Atlantic	82
SE-Central	59
SW-Central	55
Texas	56
All light-duty vehicles (2012)@	20.4
New light-duty vehicles#	24.1
New cars#	27.6
*Most efficient 2013 gasoline vehicle**	50

@ Vehicle miles traveled (VMT) for light-duty cars and trucks divided by fuel use (ORNL 2014)

EPA (2014b)

* Window-sticker fuel economy for 2013 Toyota Prius (DOE 2015a)

Section 3: High-level Literature Review

The study team performed a literature review in order to understand the factors that led to variations in estimates of electric-transportation emissions. This review was used to understand whether the analysis methodology for this assessment could be refined or enhanced. This section discusses the results at a high level, and Section 5 discusses a more detailed methodological review of the studies.

The literature review found that—among the many differences in data, assumptions, and methodology among the studies—the most important sources of variation resulted from differences in timeframe, measurement methodology, regional resolution, and emissions scope.

- **Timeframe:** In addition to being published at different times, analyses also differ significantly in the timeframes considered. For example, some analyses are based on historical emissions of varying vintages, whereas other analyses use projections of future emissions. Using historical data significantly reduces the uncertainty in measurements of emissions, but care must be exercised to ensure that present and ongoing rapid changes in key characteristics of the grid are properly taken into consideration. (Section 2 discusses recent changes in grid emissions.) Using future modeled emissions recognizes that most PEVs will be sold and used in the future, when the grid will be significantly cleaner than today's grid. But using projected data introduces the uncertainty inherent in any forecast and significantly increases the modeling difficulty.
- **Measurement methodology:** There are a variety of views about how best to estimate the impacts of the incremental load from PEVs. Some analyses scale current average emissions, implicitly assuming that all current generation will scale up to meet the new load. Other analyses attempt to create "marginal" emissions measures, which recognize that some generators have fixed capacity and others are able to scale, and that incremental load will preferentially be supplied by generation that can scale. Within marginal emissions measurements, there is an additional subtlety: Some analyses consider only the effects of scaling on existing generators (an "intensive" or "dispatch" marginal), whereas others consider the additional effect of incremental load on the construction of additional generators (an "extensive" or "build" marginal). These measurements can result in divergent outcomes, because the mix of generators currently on the grid (and especially the mix of underutilized generators) is significantly different from the mix of generators that is anticipated to be built in the future, based on current policy and

market factors. These methodological differences were a key focus area for the study team. Therefore, Section 5 discusses the methodologies used in the reviewed studies in more detail after the description of these different measurement methodologies in Section 4.

- **Regional resolution:** Electricity tends to be produced by generators located relatively close to a load, with limited trade of electricity across large areas and with very little international trade in electricity. The current grid has a wide spread of emissions factors, so the characteristics of a PEV charged in one region can be significantly different from the characteristics of a PEV charged in a different region. Different analyses handle this variation in different ways—from looking at the nation as a whole to looking at state or sub-regional variations.[7]
- **Emissions scope:** All analyses include "direct" emissions from use of gasoline and fuels used to generate electricity. But analyses differ in their handling of emissions and energy use that occur in the acquisition of fuel feedstocks and the processing of these feedstocks into fuel. These emissions can be significant, as discussed in Section 5 of Volume 2 and Section 5 of Volume 3. Tools and data are now available to analyze the emissions attributable to the manufacturing of vehicles and other components necessary to create a complete fuel/vehicle system, although estimates of these emissions vary widely.

The following subsections describe the individual studies reviewed; the timeframe, measurement methodology, regional resolution, and emissions scope of each study; and the general results from the studies. Section 4 will discuss emissions-measurement methodological issues in more detail, and Section 5 will discuss the detailed results for the reviewed studies and the effects of methodology on the variation in the results.

Discussion of Individual Studies

There are a large number of studies that have addressed the question of electric-transportation emissions. The subset reviewed for this report was widely cited; made explicit claims about relative emissions; and provided sufficiently analyzable detail about the data, assumptions, and methodology used.[8] The reviewed studies (ordered alphabetically by lead author) are:

[7] Appendix B discusses the regional representations that are commonly used in emissions analyses.

[8] Appendix A describes additional prominent studies that did not contain sufficient detail for inclusion in the full review.

Bandivadekar, Anup, Kristen Bodek, Lynette Cheah, Christopher Evans, Tiffany Groode, John Heywood, Emmanuel Kasseris, Matthew Kromer, and Malcolm Weiss (2008) and Kromer, Matthew and John Heywood (2007)

These reports are from the same research group at MIT, and Bandivadekar et al. (2008) uses the grid-emissions assumptions from Kromer and Heywood (2007), but with different vehicle assumptions. Kromer and Heywood (2007) investigates the relative emissions of an array of vehicles in the year 2030 and derives the primary grid-emissions estimate for 2030 from AEO2006. Both PHEVs and battery electric vehicles (BEVs) are found to significantly decrease emissions compared to conventional vehicles, but they have mixed results compared to hybrid electric vehicles (HEVs). Compared to HEVs, BEVs are found to increase greenhouse gas emissions by about 30%, using the default national electricity mix, whereas PHEVs using the same electricity have the same per-km emissions. Bandivadekar et al. (2008) also includes vehicle-manufacturing emissions, but the study reaches similar conclusions about the comparison of PEVs, conventional vehicles, and HEVs.

Elgowainy, Amgad, Jongwoo Han, Leslie Poch, Michael Wang, Anant Vyas, Matthew Mahalik, and Aymeric Rousseau (2010)

Elgowainy et al. (2010) modeled marginal grid emissions for 2020 for three regions using three different modeling approaches: NE and NY Independent System Operators (ISOs) were modeled using an unspecified model; the Western Electricity Coordinating Council (WECC) was modeled using Generation and Transmission Maximization (GTMax); and Illinois was modeled using Electricity Market Complex Adaptive System (EMCAS). The results varied significantly by region, but PEVs were generally found to be substantially lower-emitting than conventional vehicles. PEVs charged from the average national grid were slightly higher-emitting than HEVs, but they could be significantly higher or lower in individual regions. Different charging scenarios were also modeled but were found to have relatively minor effects on the overall results.

Elgowainy, Amgad, Yan Zhou, Anant Vyas, Matthew Mahalik, Danilo Santini, and Michael Wang (2012)

Elgowainy et al. (2012) modeled marginal grid emissions in 2030 for the western United States using GTMax. The study included four different PHEV designs, with three different charging scenarios. The charging scenarios were found to result in very similar grid mixes, and the resulting emissions for PHEVs were significantly lower than for conventional vehicles and slightly lower than for HEVs. The results varied for the different PHEV designs. But in general, increased operation on electricity was associated with lower emissions than those for HEV operation.

Environmental Protection Agency (2012)

EPA (2012) uses a large-scale modeling methodology to estimate grid emissions for future electricity use for PEVs for the Agency's vehicle greenhouse gas emissions standard. The modeling is based on the Integrated Planning Model (IPM), which is frequently used for EPA analyses, and includes the effects of recent emissions regulations such as MATS and CAIR. PEVs are not compared directly to conventional vehicles and HEVs, but the results indicate that a sample PEV will have significantly lower emissions than the Agency's standard for new vehicles.

Electric Power Research Institute and Natural Resources Defense Council (2007)

This Environmental Assessment is an update to a previous Environmental Assessment performed by EPRI and NRDC in 2007. Although the present study was conducted by roughly the same project team as the 2007 study, the former study is included in the literature review in order to understand how the factors affecting the results have changed over the last seven years. The 2007 Environmental Assessment analyzed the environmental impacts of PHEVs for three levels of deployment, each of them for three grid-emissions trajectories—ranging from a relatively aggressive low-emitting grid up to a higher-emitting grid similar to typical business-as-usual projections. The grid-emissions trajectories were modeled using EPRI's National Electric System Simulation Integrated Evaluator (NESSIE) by specifying a set of technology and policy assumptions that resulted in different costs for the deployment of new generation technologies over the 40-year modeling timeframe from 2010 to 2050. Vehicle load was added to the grid in each scenario, resulting in a marginal emissions estimate that included the effects of dispatch, capacity expansion, and a full policy suite. The results indicated that PHEVs were lower-emitting than both conventional vehicles and HEVs, although regional-level results for 2010 (which were not reported) indicated that PHEVs were higher-emitting than HEVs in some regions.

Graff Zivin, Joshua, Matthew Kotchen, and Erin Mansur (2014)

Graff Zivin et al. (2014) estimates average and marginal emissions for incremental electricity use using a custom model. The model is based on historical emissions, consumption, and electricity-market data, and it estimates regional marginal emissions—including the effects of interregional transmission. (However, because of limitations in the dataset, only fossil-fuel plants can enter the marginal generation mix.) Emissions rates are estimated for each hour of the day. The study finds that there are significant differences between the marginal and average emissions rates for many regions, and that the timing of charging significantly affects emissions rates. PEVs charged with marginal electricity are found to be slightly higher-emitting than HEVs at the national level; higher-

emitting than HEVs in the majority of regions; and higher-emitting than conventional vehicles in some regions.

Hadley, Stanton, and Alexandra Tsvetkova (2008)

Hadley and Tsvetkova (2008) used Oak Ridge Competitive Electric Dispatch (ORCED) to model marginal grid emissions in 2020 and 2030, with a focus on separately investigating grid emissions in 13 different regions. The generation mix in each region is taken from AEO2007, with no capacity expansion for PEV load. The study investigates three different power levels with two charging start times. Depending on the charging scenario and timeframe, PHEVs were found to be slightly higher- or lower-emitting than HEVs, but differences could be substantial at the regional level.

Jansen, Karel, Tim Brown, and Scott Samuelsen (2010)

Jansen et al. (2010) modeled marginal grid emissions for PHEVs in California in 2007 for two different charging scenarios. (The study discusses modeling the "western grid," but validation data and presented results appear to be for California only.) The study does not compare PHEVs to conventional vehicles or HEVs, but finds that marginal CO_2 emissions are about 40% higher than average emissions, and are at levels that probably mean that PHEVs have lower emissions than HEVs using average emissions, and higher or comparable emissions with marginal generation.

Kintner-Meyer, Michael, Kevin Schneider, and Robert Pratt (2007)

Kintner-Meyer et al. (2007) analyzes regional emissions by estimating the set of power plants that is underutilized in each region and assuming that PHEV charging could be shaped to more fully utilize these plants. The emissions results are not compared with those of HEVs, but they show a significant improvement over conventional vehicles in most regions and at the national level.

Ma, Hongrui, Felix Balthasar, Nigel Tait, Xavier Ruira-Palou, and Andrew Harrison (2012)

Ma et al. (2012) analyzes average and marginal emissions in the United Kingdom and in California using a custom model. Emissions for conventional vehicles, HEVs, and BEVs are simulated for a high-load case and a low-load case. Focusing on California, the study finds that BEVs are lower-emitting than both conventional vehicles and HEVs in the low-load case for both grid-emissions scenarios. At higher load levels, however, the emissions for BEVs relative to HEVs are mixed—with BEVs being lower-emitting with average electricity but higher-emitting with marginal electricity.

McCarthy, Ryan (2009)

McCarthy (2009) develops and uses the Electricity-Dispatch model for Greenhouse Gas Emissions in California (EDGE-CA) to analyze average and marginal grid emissions for California for two main charging scenarios and a variety of system configurations. For both charging scenarios, average and marginal emissions are lower for BEVs than for both conventional vehicles and HEVs. For PHEVs, driving emissions are slightly lower than HEV emissions.

National Research Council (NRC) (2010a)

NRC (2010a) mainly focuses on fleet transition to PHEVs and comparison with other potential pathways. But it estimates future emissions for comparison purposes, using the AEO2009 Reference Case as a base case and the medium scenario from EPRI-NRDC (2007) as a low-emissions case. PHEVs are found to have significantly lower emissions than conventional vehicles for both grid scenarios, and lower emissions than HEVs in the low-emissions grid case. But they are found to have approximately equal emissions to HEVs for the base grid case.

National Research Council (2013)

NRC (2013) also focuses on transition challenges, but it analyzes the grid emissions of PEVs using the AEO2011 Reference Case and the Carbon Tax Case ($25/metric ton). PEVs were not compared to specific reference vehicles by the authors, but scenarios including PEVs improved on an "efficient vehicle" scenario that included a combination of high-efficiency conventional vehicles and HEVs.

Parks, Keith, Paul Denholm, and Tony Markel (2007)

Parks et al. (2007) analyzed the emissions of PHEVs within the Xcel service territory, using the Proprietary Hourly Power System Evaluation Model (PROSYM) in four different charging scenarios. The study finds that PHEVs have lower CO_2 emissions than conventional vehicles and HEVs under all charging scenarios. CO_2 grid emissions were generally insensitive to load shape.

Samaras, Constantine, and Kyle Miesterling (2008)

Samaras and Miesterling (2008) analyzes the lifecycle impacts of PHEVs relative to conventional vehicles and HEVs, using average grid emissions from the 2004 Annual Energy Review and two constructed scenarios that represent high- and low-emissions cases. PHEVs are found to be lower-emitting than conventional vehicles and slightly lower-emitting than HEVs, using average grid emissions. In the carbon-intensive grid scenario, PHEVs are higher-emitting than HEVs but lower-emitting than conventional vehicles; in the low-carbon grid scenario, PHEVs are significantly lower-emitting than both HEVs and conventional vehicles.

Union of Concerned Scientists (UCS) (2012)

UCS (2012) analyzed the impact of current regional grid emissions on the relative performance of BEVs. The study finds that BEVs are lower-emitting than conventional vehicles and HEVs in many regions of the United States (using Emissions & Generation Resource Integrated Database, or eGRID, subregions), but that BEVs can have emissions that are equivalent to or higher than HEVs in some regions. No regions had grid emissions that would result in BEVs having higher emissions than the average new conventional vehicle.

Main Review Findings

Table 3-1 lists the studies described in this review and summarizes the methodology and findings of each study. The studies used a wide variety of timeframes, modeling approaches, and comparison metrics, so they cannot be fully compared quantitatively. The table instead qualitatively shows how greenhouse gas emissions from PEVs compared with gasoline-powered conventional vehicles and HEVs within each study. In almost all of the studies, PEVs were lower-emitting than conventional vehicles in all cases considered within the study, and none of the studies found that PEVs were higher-emitting than conventional vehicles at the national level. The comparisons between HEVs and PEVs did display a significant amount of disagreement both among studies and within studies—mainly because of regional variations in emissions. Therefore, separate comparisons are shown for the national-level HEV/PEV comparison and the regional-level comparison. (Appendix B describes the regional definitions referred to in the table. The North American Electric Reliability Council, or NERC, no longer provides definitions for subregions, but these are nearly identical to current eGRID subregions.) The timeframe considered was important for many studies, because grid emissions have recently improved at a more rapid rate than conventional and HEV fuel economy. Studies that assumed constant emissions, or studies that relied on the Annual Energy Outlook average grid mix (which tends to forecast constant emissions rates, as discussed below), derived higher estimates for PEV emissions than studies that assumed a declining emissions intensity for grid electricity. The emissions scope was important to absolute emissions quantities, but it did not generally affect relative emissions comparisons. As discussed in Section 5 of Volume 2, upstream greenhouse gas emissions for gasoline and electricity fuels are similar as a fraction of emissions.

One particular source of variation among the studies was the methodology used for measuring or estimating grid emissions. Studies used historical data, average emissions based on well-known projections, and a wide variety of custom models that attempted to determine the marginal emissions attributable to incremental vehicle load. Because of the central importance of these methodological differences in developing best practices, the next section (Section 4) focuses on explaining the differences among the measurement methodologies, and Section 5 reviews the effects of these choices on the study results.

Table 3-1
Summary of reviewed literature

Study Citation	Study Title	Timeframe			Methodology	Regional Resolution	Scope	Results Overview		
		Near-term	Mid-term	Long-term				CV	National HEV	Regional HEV
Bandivadekar et al. (2008)[a]	On the Road in 2035: Reducing Transportation's Petroleum Consumption and GHG Emissions		*		Average (AEO) and assumed mix	National				b
Elgowainy et al. (2010)	Well-to-Wheels Analysis of Energy Use and Greenhouse Gas Emissions of Plug-in Hybrid Electric Vehicles		*		Small-scale marginal		Full fuel cycle		b	
Elgowainy et al. (2012)	Impacts of Charging Choices for Plug-in Hybrid Electric Vehicles in 2030 Scenario		*		Small-scale marginal		Full fuel cycle		b	
EPA (2012)	2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards		*		Large-scale marginal	National	Full fuel cycle	c		b
EPRI-NRDC (2007)	Environmental Assessment of Plug-in Hybrid Electric Vehicles	*	*	*	Large-scale marginal	National	Full fuel cycle			b
Graff Zivin et al.(2014)	Spatial and Temporal Heterogeneity of Marginal Emissions: Implications for Electric Cars and Other Electricity-Shifting Policies	*			Small-scale marginal	Regional (NERC)				
Hadley and Tsvetkova (2008)	Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation		*		Small-scale marginal	Regional (NERC subregion)		b		

Table 3-1 (continued)
Summary of reviewed literature

Study Citation	Study Title	Timeframe			Methodology	Regional Resolution	Scope	Results Overview		
		Near-term	Mid-term	Long-term				CV	National HEV	Regional HEV
Jansen et al. (2010)	Emissions Impacts of Plug-in Hybrid Electric Vehicle Deployment on the U.S. Western Grid	*			Small-scale marginal	Regional (NERC)		b	b	b
Kintner-Meyer et al. (2007)	Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids	*			Small-scale marginal	Regional (NERC)			b	b
Kromer and Heywood (2007)	Electric Powertrains: Opportunities and Challenges in the U.S. Light-Duty Vehicle Fleet		*		Average (AEO) and assumed mix	National				b
Ma et al. (2012)	A New Comparison Between the Life Cycle Greenhouse Gas Emissions of Battery Electric Vehicles and Internal Combustion Vehicles	*			Small-scale marginal	Regional (California only)			b	
McCarthy (2009)	Assessing Vehicle Electricity Demand Impacts on California Electricity Supply	*	d	d	Small-scale marginal	Regional (California only)			b	
NRC (2010a)	Transitions to Alternative Transportation Technologies – Plug in Hybrid Electric Vehicles	*	*	*	Average (AEO) and large-scale marginal	National				b
NRC (2013)	Transitions to Alternative Vehicles and Fuels	*	*	*	Average (AEO)	National		e		b

Table 3-1 (continued)
Summary of reviewed literature

Study Citation	Study Title	Timeframe			Methodology	Regional Resolution	Scope	Results Overview		
		Near-term	Mid-term	Long-term				CV	National HEV	Regional HEV
Parks et al. (2007)	Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory	*			Small-scale marginal	Regional (Colorado only)				b
Samaras and Miesterling (2008)	Life Cycle Assessment of Greenhouse Gas Emissions from Plug-in Hybrid Vehicles: Implications for Policy	*			Assumed mix and historical					b
Union of Concerned Scientists (2012)	State of Charge	*			Historical	State-level			f	

PEVs are lower-emitting or lower-emitting in most scenarios.

PEVs have equal emissions or have better emissions in some scenarios and worse emissions in others.

PEVs are higher-emitting or higher-emitting in most scenarios.

a: The electricity inputs from this model are derived directly from Kromer and Heywood (2007), but the vehicles are modeled separately.

b: These studies did not include comparisons for this vehicle or region.

c: The analysis in this regulatory document did not address individual vehicles, but a sample PEV had significantly lower emissions than the standard.

d: This dissertation included long-term modeling, but it was not included in this review.

e: This study included a high-efficiency comparison fleet that consisted of a mix of conventional vehicles and HEVs.

f: The study does not provide a national comparison, but it states that only 17% of the U.S. population lives in an area in which PEVs are worse than HEVs.

Section 4: Emissions-Estimation Methodologies

As discussed in Section 3, a significant source of variation among analyses of electric-transportation emissions today or in the future is the method used to estimate emissions attributable to electricity. Studies used historical data, average emissions based on well-known projections, and a wide variety of custom models that attempted to determine the marginal emissions attributable to incremental vehicle loads. This section reviews the primary methodologies for measuring grid emissions considered by this study team. These are:

- **Average historical**: Average grid emissions can be directly calculated from historical grid data by dividing total generation emissions by the quantity of electricity generated. This emissions-estimation method has the advantage of being simple, consistent, and transparent, but it is unlikely to correctly reflect future grid emissions. For example, the high rate of change of grid emissions discussed in Section 2 means that even recent historical data may not reflect current emissions—particularly for emissions of criteria pollutants.
- **Average projected**: Average emissions can also be easily calculated from projections for future generation by dividing projected emissions by projected energy generation. However, this approach assumes that all new load is treated the same as existing load and is met by the same grid mix. Therefore, it lacks the ability to represent limits in grid resources.
- **Small-scale marginal emissions**: Incremental load additions (or reductions) will likely create a grid mix that is different from the average grid mix. A variety of methods exist to estimate the incremental (or marginal) emissions that occur as a result of small changes in load—typically by identifying the generators that were dispatched last and therefore have costs and characteristics which are most sensitive to changes in load. These methods are typically only applicable to small changes in load over short timeframes, because they do not consider changes in generation capacity that may occur because of the new load.
- **Large-scale marginal emissions**: Large load changes typically occur over long time periods and impact generation capacity. Modeling the grid response to large-scale changes requires models that simulate the long-term procurement processes for generation resources. The widespread adoption of transportation electrification is likely to be such a large-scale change, so it is

important to distinguish between large-scale marginal emissions and small-scale marginal emissions.

These modeling methodologies are discussed in more detail below. The distinctions among these methodologies are important because they result in significantly different estimates of grid emissions. Figure 4-1 shows the range of grid emissions estimated for PEV charging in California in the reviewed studies. The highest estimates are almost three times higher than current average emissions, and small-scale marginal emissions estimates are consistently higher than estimates for average emissions.

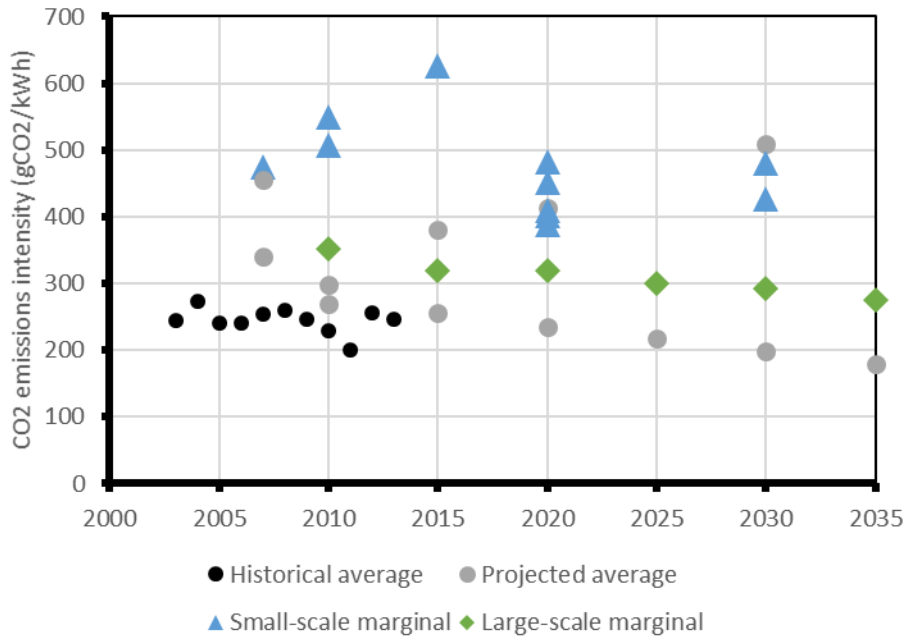

Figure 4-1
Estimated annual grid emissions intensity for PEV charging in California from reviewed studies

This section discusses the differences among these emissions-measurement methodologies. The effects of the methodological choices on study results is discussed in Section 5. As will be discussed in Section 6, the study team believes that a large-scale marginal emissions-estimation methodology best characterizes the interrelated changes in the electricity grid and the transportation fleet.

Average Measurements of Grid Emissions

Calculating average grid emissions is straightforward: total emissions are divided by total generation. There are still potential variations in results depending on timeframe, regional resolution, and emissions scope. But given similar decisions on these factors, emissions factors calculated based on historical data should be repeatable, stable, and transparent. As discussed in Section 6, these characteristics

mean that historical average-emissions calculations are widely used in regulations and for emissions reporting.

Emissions estimates based on projected average generation can be useful because projections from a wide variety of existing forecasts can be used. Once a particular projection is selected, no further analyses or assumptions are required. This simplicity is especially useful for analysts without access to specialized grid emissions-analysis techniques. However, as discussed in Section 6, the most widely used source for projections has significantly underestimated the rate of emissions reductions. Therefore, scenario selection still requires a high degree of care.

Conceptual Justification for the Use of Marginal Emissions Estimates

Using an average-emissions calculation method implicitly assumes that load increases and reductions will be met with the same resources that meet base-case grid load. However, there are well-known limits on certain generation resources that can cause incremental load to be met with significantly different resources than average load. Primarily, low-emitting plants such as nuclear plants, renewable generators, and hydroelectric generators are generally utilized to the greatest extent possible. Therefore, their usage cannot be increased. This subsection uses simplified conceptual examples to illustrate why the difference among grid resources cause marginal-emissions rates to differ from average-emissions rates, and indicate why marginal emissions are often preferred for estimating emissions attributable to *changes* in load. The next subsection relates these conceptual examples to actual grid behavior and shows how this simplified concept of "marginal" emissions differs from long-term trends.

Figure 4-2 shows a simplified dispatch curve with four generation resources: non-emitting, efficient fossil, inefficient fossil, and peak. The efficient fossil, inefficient fossil, and peak generators are assumed to use the same fuel at progressively decreasing efficiencies so that least-cost dispatch also results in an increasing emissions rate. (A case in which this assumption is not true is considered next.) The horizontal axis represents load—increasing from left to right—which causes increasing generation-fleet utilization. The vertical axis shows total CO_2 emissions for the generation fleet at a given load level. Non-emitting generators generally have very low operating costs, so they are dispatched first (starting at the lower left corner). As load increases, the generation-utilization point moves to the right, and when it reaches a sample utilization level of 40%, the non-emitting generation is fully utilized. At this point, fossil generation must be used. Generators are generally dispatched starting with the unit with the lowest operating cost first, then proceeding to progressively more expensive units. Since all generators use the same fuel in this example, the most efficient plants are dispatched first. These plants do have CO_2 emissions, but they are lower-emitting because of their high efficiency. However, at a fleet utilization level of 70%, the most efficient generators are also fully utilized, so less-efficient generators begin to be dispatched. (For clarity in the diagram, these generators have an emissions rate three times higher than the

efficient fossil-fuel generators; actual efficiencies are generally closer.) At a load level of 90%, only peak generators remain. Generation at this level only occurs for a small number of hours per year, so peak generators can generally have relatively low efficiency and therefore high emissions intensity.

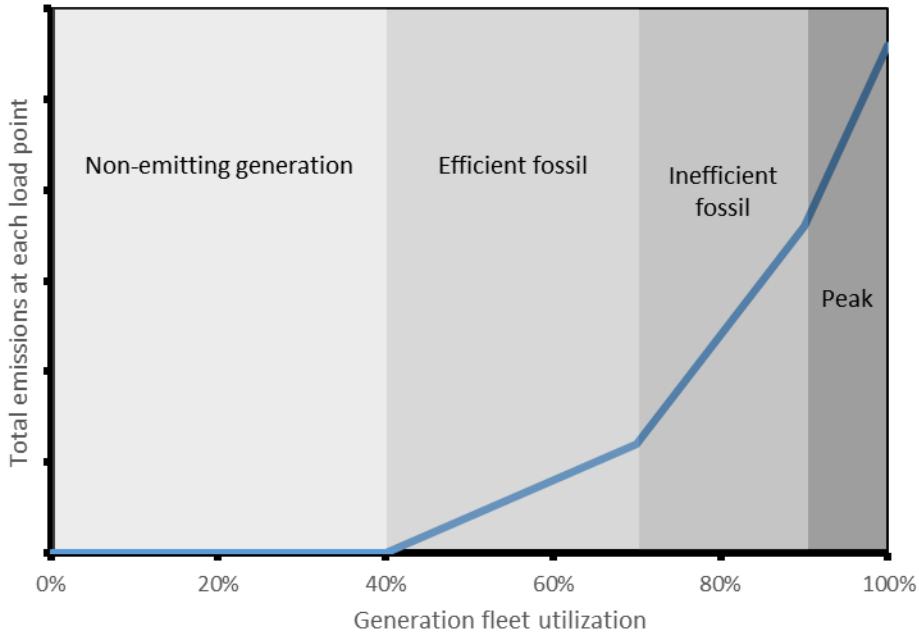

Figure 4-2
Conceptual illustration of generation fleet response to load

Figure 4-3 shows the difference between instantaneous average and instantaneous marginal emissions, assuming a baseline load that utilizes 75% of the generation fleet.[9] At this load, about half of the generation comes from non-emitting sources, and most of the rest comes from the most efficient generation. Average emissions at this point, calculated by dividing cumulative emissions by cumulative load, is mostly determined by the non-emitting and efficient generation. However, the non-emitting generation and efficient fossil generation are fully utilized, so any additional load will be served by the "inefficient fossil" generation. As illustrated, this means that the emissions of the load-following generation will be about six times higher than the average emissions of the generation fleet as a whole.

[9] These instantaneous emissions rates would only apply for one moment in time; the generation and emissions would have to be summed over time in order to calculate the emissions rate for a longer time period like a month or a year.

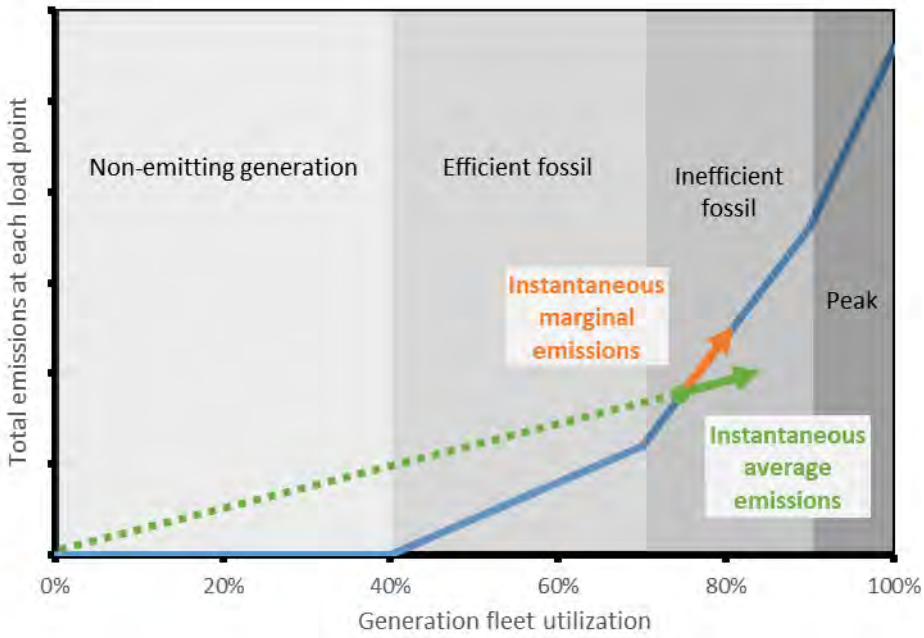

Figure 4-3
Conceptual illustration of emissions from incremental load

Although this diagram is highly stylized, it illustrates the concern about incremental generation in regions like California, the Pacific Northwest, New York, and the Northeast—all of which have high levels of non-emitting generation but supply incremental load from fossil generators.

Marginal emissions, however, can vary significantly depending on the configuration of the generation fleet. Because generation plants are dispatched based on least-cost order instead of least-emissions order, areas with generation using different fuels may behave in the opposite way. For example, Figure 4-4 shows the conceptual emissions trajectory for a grid with some non-emitting generation, a large amount of coal generation, and some efficient natural gas generation.[10] Coal generation typically has a lower incremental cost than natural gas generation because of the low relative cost of coal, so it is dispatched first. If the coal generation is fully utilized, incremental generation would come from natural gas, so the marginal emissions rate would be lower than the average emissions rate.

[10] CCNG, the most efficient natural gas generation type, has an emissions rate of about half that of typical coal, but the least-efficient natural gas plants can have an emissions rate higher than the most efficient coal plants.

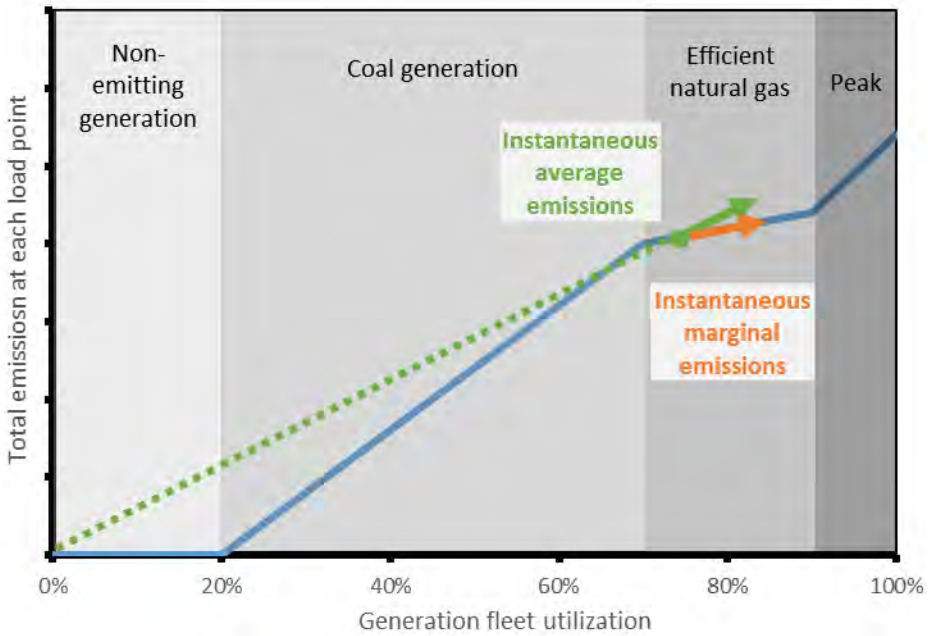

Figure 4-4
Conceptual illustration of incremental load response for a mixed-fuel generation fleet

Concerns with Intensive Marginal-Emissions Estimates for Large-scale Load Changes

The conceptual discussion in the previous subsection described the instantaneous change in generation resulting from a relatively small, unanticipated change in load. Over a short time period, these small changes in load must be met with redispatch of fixed generation assets, so existing resources are used more intensively. This is often referred to as the "intensive margin," and analysis of intensive marginal effects can be a useful tool. However, anticipated large-scale load changes like those expected for PEV charging will in the long term have different characteristics and a different response from the grid, because the mix of grid resources can respond to the changing load.[11]

Figure 4-5 shows the actual cumulative emissions for the U.S. grid as cumulative generation changed in the year 2010. In this graph, each generator is represented by a point, and the points are ordered such that non-emitting generation is summed first, then fossil generation is arranged in order of decreasing utilization level—from the highest capacity factor on the left to the lowest-capacity factor on the right.[12] This figure is conceptually similar to Figure 4-2, but it is sorted by actual annual plant-utilization level instead of potential generation-fleet

[11] In economics, this phenomenon is referred to as the "extensive" margin.

[12] Capacity factor is a dimensionless measure of utilization; the annual capacity factor is calculated using the equation: $\frac{annual\ generation\ (MWh)}{capacity\ (MW) * 1\ year * 8760\ h/year}$

utilization. In Figure 4-5, generation is roughly divided into "Non-emitting and base generation," which is essentially fully utilized within the operating constraints of the generator; "Intermediate generation," which is the generation that varies most throughout a day and between seasons; and "Peak" generation, which has high incremental costs and is used in limited circumstances, such as when a very fast response is required or the combination of seasonal and daily conditions are extreme enough that all generation sources are required, regardless of cost.

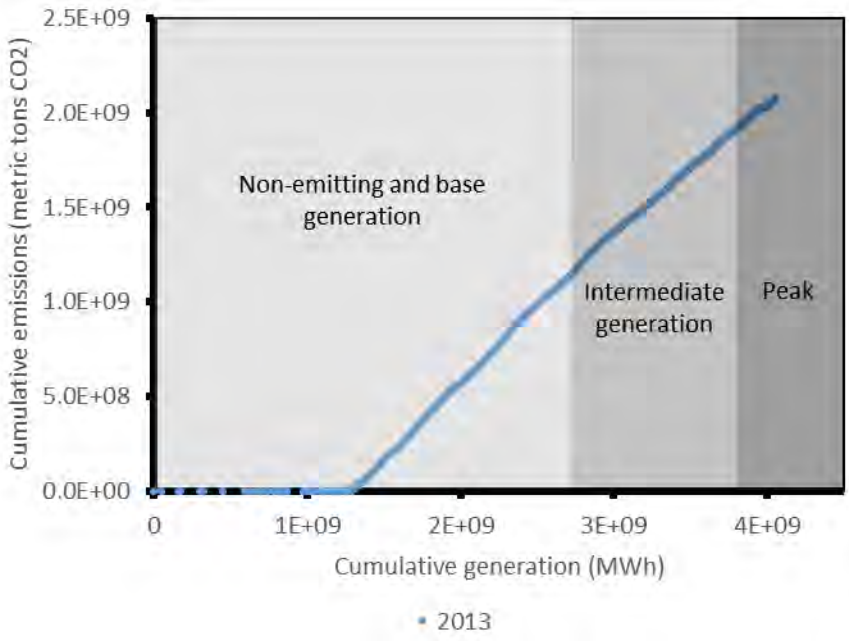

Figure 4-5
Cumulative emissions versus cumulative generation for 2013

Figure 4-6 shows the emissions/load trajectories for the decade from 2003 to 2013, arranged in the same orientation as Figure 4-5. (To enhance clarity, only odd years are shown.) Looking at the generation profiles for many years at once, it is clear that the emissions trajectories exhibit complex differences that are not driven by intensive changes alone. (If this were true, the lines would lie on top of each other except at the end.) In fact, emissions are affected by increases in non-emitting generation (which moves the starting point of the upward slope to the right) and a shift from coal generation to natural gas generation (which decreases the slope of the generation trajectory).

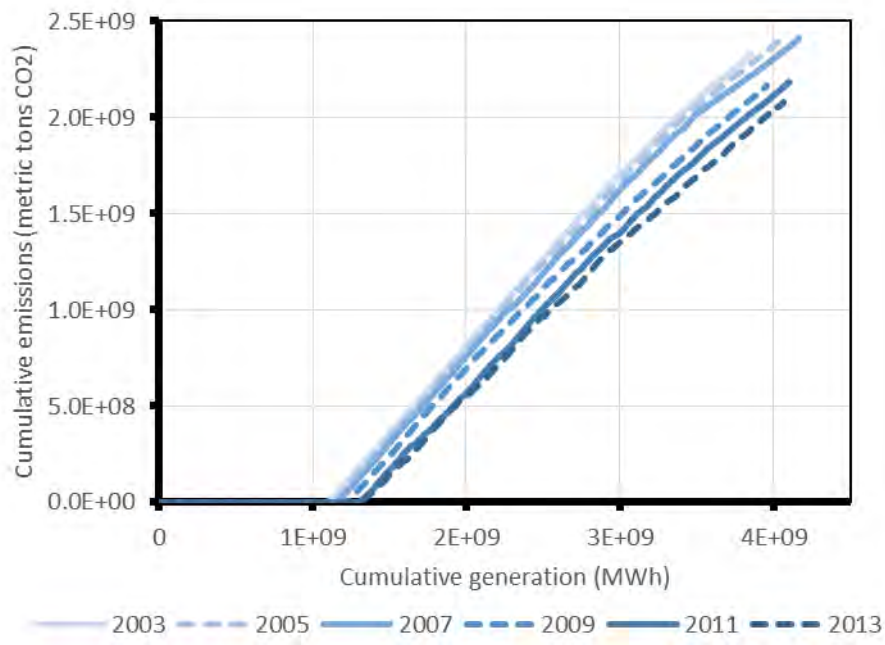

Figure 4-6
National cumulative emissions versus cumulative generation for 2003–2013

To illustrate this point further, Figure 4-7 shows the relationship between total emissions and total generation. (These are the end points of the lines in Figure 4-6.) The points are shown relative to orange arrows showing a sample national small-scale marginal-emissions rate (this rate is from Graff Zivin et al., 2014). Although short-term changes can follow this measure of marginal emissions, over longer periods of time, large-scale changes create a significantly different trajectory. Detailed analysis indicates that the deviation from linear scaling results from large-scale and permanent changes in the makeup of the generation fleet—including the increased use of non-emitting generation and a shift from coal generation to CCNG generation.

Figure 4-8 shows the growing share of energy produced by non-emitting generation over time. Although most of the non-emitting generation comes from nuclear and hydroelectric generation, most of the growth in the past decade has come primarily from wind power, as was shown in Figure 2-3. The second factor that has changed the emissions-generation trajectory is the growing use of CCNG instead of coal-steam turbine. This factor is a result of an increasing amount of CCNG capacity, a decreasing amount of coal-steam turbine capacity, and changes in the capacity utilization of both sets of assets. Figure 4-9 shows the effects of all of these changes on the utilized capacity of CCNG and coal-steam turbine for the years 2003, 2008, and 2013. Because of the widespread use of coal and gas generation sources, this shift affects the emissions of the system as a whole. (This effect can be seen in Figure 4-6 as a subtle decrease in the slope of the emissions-generation curves over time.)

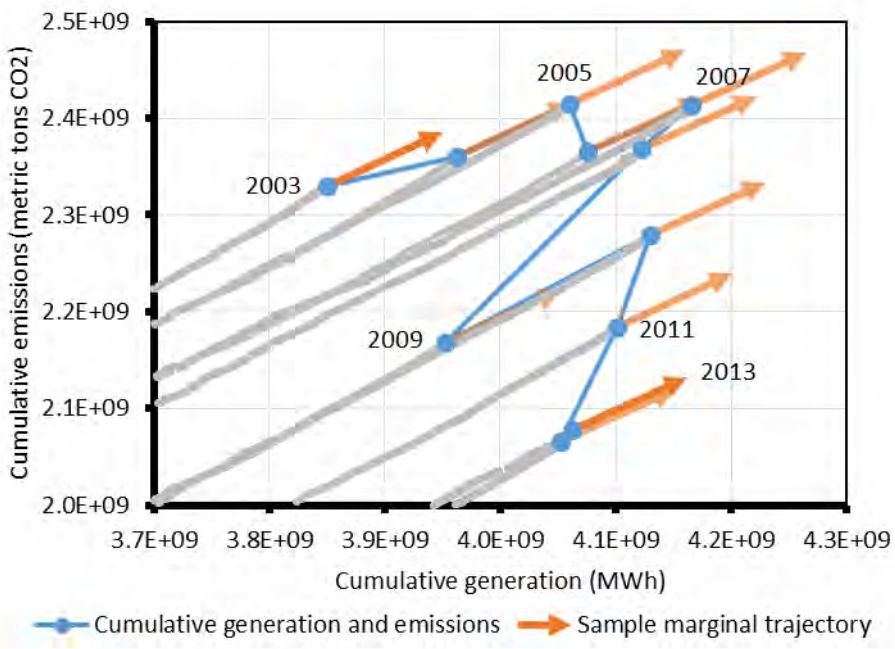

Figure 4-7
Trajectory of emissions-generation sums over time

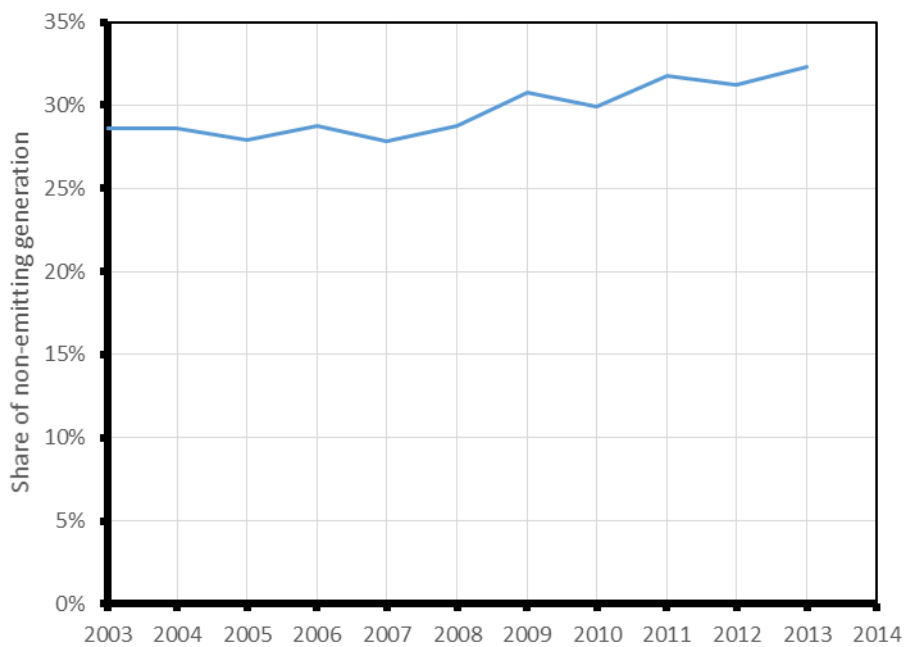

Figure 4-8
Shares of non-emitting generation over time

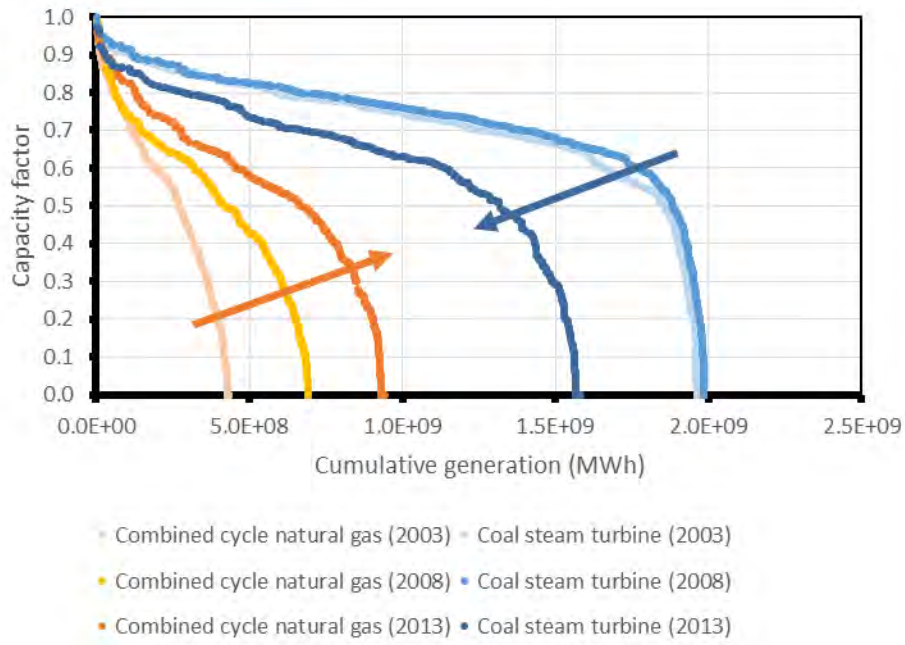

Figure 4-9
Change in utilization of CCNG and coal-steam turbine plants over time

The fact that the change in emissions over time does not track the intensive marginal emissions rate is expected. The utility grid is not a stochastic "black box"; instead, it is carefully managed to accommodate the changing demands on the system. This management allows utilities to coordinate generation capacity expansion, retirement, and redispatch to meet changing demand, evolving regulation, and varying risk-adjusted fuel prices. It is therefore important to balance the need to estimate the unique impacts of incremental load with the need to appropriately model the decision processes used by utilities to plan for generation changes. Large-scale marginal emissions estimates offer this opportunity for large-enough changes in load.

Different Measurements of Marginal Emissions

There are many ways to define "marginal" emissions-estimation methodologies. But for the purposes of this report, two main classes are considered: *small-scale* and *large-scale* methodologies. Small-scale marginal emissions-estimation methodologies are characterized by the use of methods that extrapolate the anticipated effects of small changes in load, with limited changes to the configuration of grid resources. Large-scale marginal emissions-estimation methodologies additionally consider the potential for the grid to be reconfigured to meet added load.

Small-scale Marginal-Emissions Methodologies

There are many ways to estimate the effects of *small-scale* changes to load. For this report, small-scale methodologies will be grouped into two main types: *intensive marginal* emissions estimates and *dispatch marginal* emissions estimates.

Intensive marginal methods use data on current grid operation to meet a higher level of load. So data on the use of existing resources is extrapolated assuming that they are used more intensively. In the United States, publically-available datasets from the Energy Information Agency (EIA) and the EPA provide information on the generation of every plant connected to the grid (and in some cases, for each unit within a plant for each hour of the day).[13] These datasets provide analysts with extensive information that can be used to estimate the effects of small changes in conditions. Such emissions estimates can be very useful, but they have limited scope. Historical generation data can indicate that a plant was used, but it cannot indicate why it was used or what constraints prevented it from being used further. For very small changes in load, it is reasonable to assume that these unknown constraints would not be binding or have little impact. However, for the large-scale changes in load anticipated for a widespread transition to transportation electrification, it is certain that unmodeled constraints and data would affect the results.

Dispatch marginal methods are similar to intensive marginal methods, but also redispatch generators instead of only considering variations in existing dispatch. A dispatch model is used to simulate the operation of the grid—given capacity limits, fixed and variable prices, and a subset of regulations and constraints. (The modeler must determine which aspects to model; a fully inclusive model is impossible to implement.) The modeled load is then modified to determine which generation is increased or decreased to meet the incremental change in load. Dispatch modeling is a useful tool and is a necessary part of large-scale emissions modeling. But a "dispatch" marginal-emissions estimate assumes that generation capacity is fixed, so it is still a small-scale marginal-emissions estimate. Relative to an intensive model, the added flexibility of a well-structured dispatch model is more realistic, and it can be used to model small-scale effects on future grids instead of being limited to historical data. However, the assumption that changes can only be met by using existing generators means that large-scale changes in load cannot be realistically handled.

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[13] The primary data sources typically used are Form EIA-860 data, Form EIA-923 data, and the EPA Air Markets Program data. For more information on these datasets and an example of their use to calculate historical average emissions, see: EPRI (2014a).

Large-scale Marginal-Emissions Methodologies

As defined in this document, a *"large-scale"* marginal emissions estimate is one that includes both the effects of redispatch and the effects of capacity changes.[14] Capacity changes include capacity expansion and retirement, but they also include decisions to shift planned capacity. For example, additional off-peak load may change the overall load shape, making construction of a combined-cycle intermediate unit more economical than a planned gas turbine peaking unit. In other words, the capacity technology mix may change even with no change in capacity magnitude.

The following steps are used in this analysis to analyze large-scale changes in load:

1. **Create a baseline model for the evolution of the electricity sector over time.** This assessment used a modified version of the US-REGEN baseline model used in other EPRI analyses. For more information on US-REGEN, see EPRI (2014b). Section 4 of Volume 2, and Section 4 of Volume 3 describe the modifications made for the greenhouse gas and air quality analyses.
2. **Create a baseline model for the evolution of the transportation fleet over time.** Plug-in electric vehicles (PEVs) and non-road devices will primarily replace new vehicles and devices. This means that their baseline competitors are the most-efficient vehicles and devices available, rather than the generally less-efficient existing stock. A vehicle-fleet model that simulates changes in vehicle characteristics and stock changes should be used. For example, the vehicle-fleet model used in this assessment includes the evolution of new-vehicle characteristics, the attrition of older vehicles, and changes in vehicle-usage intensity for each vehicle vintage.
3. **Implement an alternate transportation scenario with a large-scale transition to electric transportation.** The vehicle-fleet model is rerun assuming that PEVs are introduced into the new-vehicle fleet and that they represent an increasing share of new vehicles over time. Fleet turnover occurs, and PEVs become a larger share of the total vehicle fleet over time.
4. **Impose the incremental transportation load on the modeled grid.** The electricity load from these vehicles and non-road devices is added to the baseline electricity load to create a different modeled trajectory for the electricity grid. Importantly, modeling the grid through two separate runs of the full model ensures that the results include the effects of both the change in the use of existing generators and the change in the composition of the generation fleet over time in response to the new load. A variety of load shapes may be used, but the load shape should be plausible for the usage patterns of a large-scale fleet.

[14] The term "large-scale marginal" is conceptually similar to the term "build marginal" discussed in other sources. But other definitions of "build marginal" are generally restricted to capacity expansion and do not include capacity retirement or capacity shifts.

5. **Calculate the incremental changes in transportation emissions and the incremental changes in grid emissions, including life-cycle emissions from upstream fuel inputs.** Net emissions impacts are calculated from the difference in the transportation-sector changes and electricity-sector changes. For both sectors, changes in usage of upstream fuels like petroleum, coal, and natural gas can significantly affect overall emissions.

Variations on this procedure would meet the objectives for large-scale modeling. But the gradual introduction of electric-transportation load and the careful handling of the evolution of grid resources and use are necessary to ensure that the grid response is realistically modeled. This modeling methodology results in a measurement of the marginal impact of a large-scale transition to electricity as a transportation fuel.

Creating a large-scale marginal model requires extensive grid-modeling capabilities. The model must include economic dispatch, a representative policy framework (including emissions constraints), and capacity expansion and retirement or capacity shifts. Although models that meet these requirements are readily available within the utility industry, these models are extremely complex, and running them requires teams of experts. These constraints make the use of a large-scale marginal methodology difficult. But as discussed in Section 6, the study team considers the use of this methodology to be a best practice. Section 6 also discusses specific modeling best practices that are necessary to ensure that the grid response is appropriately modeled.

Section 5: Methodological Literature Review

This section continues the literature review discussed in Section 3, but focuses on analyzing the methodological modeling issues discussed in Section 4. The key question for the study team was whether or not the methodology used in the 2007 assessment could be revised to produce more representative results. No methodology will be perfect for every task. But the review indicated that for the assessment's goal of analyzing the effects of widespread transportation electrification, the large-scale marginal methodology was appropriate and produced results that match actual trends since the 2007 study was performed. Other approaches were less accurate—for specific reasons associated with modeling compromises.

Table 5-1 shows the methodologies used to determine grid emissions for electric transportation for each study discussed in Section 3. The study methodologies generally fell into four broad categories:

- Average emissions based on historical data
- Average emissions based on Annual Energy Outlook (AEO) projections
- An assumed grid mix[15]
- Small-scale marginal emissions based on a grid model

In an effort to refine the methodology used in this report, the study team formulated two research questions for a detailed review:

- Is using grid emissions from the AEO adequate?
- Which characteristics of grid models resulted in projections that were most representative of in-use emissions?

The first question was addressed by analyzing the trends in the AEO over time. The AEO is conducted annually by the Energy Information Agency (EIA), and it is the basis for many energy analyses (including, in part, analyses using US-REGEN).[16] However, the EIA is required to follow a restricted methodology in

[15] For example, assuming that future generation would be 60% CCNG and 40% renewables, but without a model-based justification.

[16] For more information on the AEO, see: http://www.eia.gov/forecasts/aeo/

performing the AEO, which may result in unrealistic projections for some sectors. The analysis discussed below indicates that the AEO significantly overestimates future grid emissions.

To address the second question, the emissions for each study that included grid modeling were compared with recent historical grid emissions. The studies addressed a wide range of regions, so quantitative comparisons were difficult. However, comparisons were possible for California for many studies, and at the national level for a limited subset of studies. These results indicate that most of the grid-based models that could be analyzed quantitatively have either overestimated actual emissions or appear to be inconsistent with current trends.

Projecting Future Grid Emissions Using the Annual Energy Outlook

The AEO from the EIA is a common source for estimates of grid emissions, fuel prices, vehicle-driving activity, and other economic and technical assumptions. The AEO is issued annually and is based on a comprehensive model (The National Energy Modeling System, or NEMS) that includes submodels for fossil-resource extraction, economic activity, electricity generation, and other energy interactions. The output data is extensive and well-described, although the detailed inputs and assumptions are difficult to determine.

The AEO includes data that can be used to estimate future grid emissions. However, the Reference Case, which is often used in PEV emissions analysis, uses a restricted methodology that only includes implemented regulations and a relatively conservative estimate of advanced generation prices. This methodology serves the primary purpose for this Reference Case of acting as a reference against which the effects of new policies can be measured. But it results in a persistent tendency to overestimate grid emissions—even over short timeframes. Figure 5-1 shows the CO_2-emissions intensity projected by various iterations of the AEO. The projections are compared to actual emissions as reported by the EIA in the agency's Monthly Energy Review (MER) (EIA 2015). The forecast has a tendency to indicate that past downward trends in grid emissions will cease, and it often indicates that future emissions intensities will be higher. This forecast partially reflects the fact that there is no national greenhouse gas emissions reduction policy. (The Clean Power Plan was finalized by the EPA in mid-2015, so it has not been included in an AEO yet.) But the forecast is also a result of mandated assumptions that regulations with "sunset" dates will not be extended and that new regulations will not increase pressure to reduce emissions. For example, Figure 5-2 shows the fraction of nonhydroelectric renewable generation in each forecast. (In historical data, hydroelectric generation varies widely because of changes in rainfall, but this variability does not reflect permanent changes to the grid.) In the AEO, nonhydroelectric renewables are generally forecasted to grow quickly in the short term, probably because of projects already under construction. But the growth rate is then forecasted to reduce sharply, stabilizing the fraction of nonhydro renewables. With each forecast, however, the point at which this stabilization occurs moves further out into the future.

Table 5-1
Methodologies used in reviewed studies

Study Citation	Emissions Methodology					Results Summary		
	Historical average	Projected average	Assumed mix	Small-scale marginal	Large-scale marginal	CV	National HEV	Regional HEV
Bandivadekar et al. (2008)[a]		*	*					b
Elgowainy et al. (2010)		*		c			b	
Elgowainy et al. (2012)				c			b	
EPA (2012)					*	d		b
EPRI-NRDC (2007)					*			b
Graff Zivin et al.(2014)				*				
Hadley and Tsvetkova (2008)				*		b		
Jansen et al. (2010)	*			*		b	b	b
Kintner-Meyer et al. (2007)				*			b	b
Kromer and Heywood (2007)		*	*					b
Ma et al. (2012)				*			b	
McCarthy (2009)				*	e		b	
NRC (2010a)[f]		*						b
NRC (2013)		*				g		b
Parks et al. (2007)				*				b

Table 5-1 (continued)
Methodologies used in reviewed studies

Study Citation	Emissions Methodology					Results Summary		
	Historical average	Projected average	Assumed mix	Small-scale marginal	Large-scale marginal	CV	National HEV	Regional HEV
Samaras and Miesterling (2008)			*					b
UCS (2012)	*						h	
PEVs are lower-emitting or lower-emitting in most scenarios.								
PEVs have equal emissions or have better emissions in some scenarios and worse emissions in others.								
PEVs are higher-emitting or higher-emitting in most scenarios.								

a: The electricity inputs from this model are derived directly from Kromer and Heywood (2007), but the vehicles are modeled separately.

b: These studies did not include comparisons for this vehicle or region.

c: Manual capacity expansion was performed if reserve margin was too low, but it was not endogenous.

d: The analysis in this regulatory document did not address individual vehicles, but a sample PEV had significantly lower emissions than the standard.

f: The main case results were used in this comparison.

e: The long-term modeling included in the dissertation did include a form of large-scale marginal modeling, but was not included in this review.

g: This study included a high-efficiency comparison fleet that consisted of a mix of conventional vehicles and HEVs.

h: The study does not provide a national comparison, but states that only 17% of the U.S. population lives in an area in which PEVs are worse than HEVs.

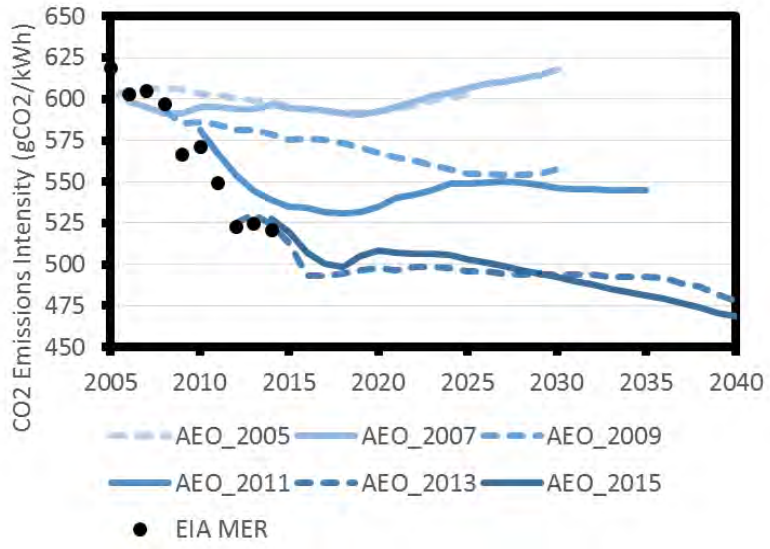

Figure 5-1
Estimates of future national grid-emissions intensity from the AEO and the Monthly Energy Review (MER).

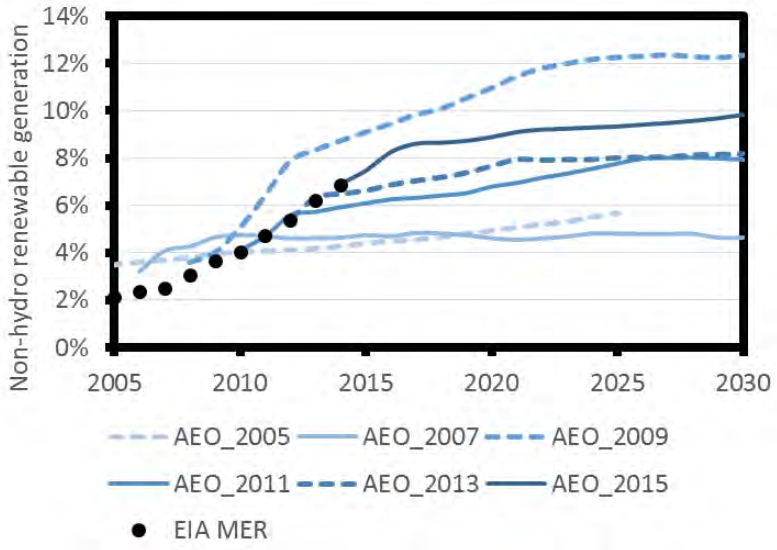

Figure 5-2
Estimates of nonhydro renewable generation from the AEO and the Monthly Energy Review (MER)[17]

[17] The comparison uses net generation for all sectors for both datasets. The AEO is derived from the same dataset as the MER so it is unclear why the estimates differ so much in 2005–2009, but comparisons between them indicate that it appears that the definition of generation from biomass and waste changed between older AEOs (which are not retrospectively adjusted) and newer AEOs and the current MER (which would be based on a newer definition). However, the rate of changes are more relevant than the absolute values.

This analysis indicates that the AEO Reference Case has generally overestimated future emissions. For example, AEO projections for 2030 CO_2-emissions intensity have decreased by approximately 25% in the last decade. This conservatism can be useful for ensuring that the actual emissions-reduction benefits of an intervention like transportation electrification will exceed projections. However, these results should be contextualized. This contextualization is especially needed for cases that assume policy pressure to rapidly decarbonize the transportation sector, because the electricity sector is generally considered to be less difficult to decarbonize than the transportation sector.

Projecting Grid Emissions Using Grid Models

This subsection describes the characteristics required for large-scale marginal-emissions modeling; lists the elements included in each reviewed model; and shows two quantitative analyses of the modeling results. The reviewed studies modeled the electricity sector using grid models of varying complexity. These models typically used readily available historical data on plant operations and costs, so results typically reflect observed behavior. However, projecting emissions requires a detailed understanding of the effects of a wide array of policies and the unusual characteristics of competitive electricity markets. Correctly incorporating these subtle effects is particularly important when modeling marginal emissions.

The modeling methodologies and results for each study that included independent grid modeling were analyzed to determine which characteristics produced the most realistic results. In many cases, the "future" time period has already occurred, so it was possible to compare the predicted emissions with actual data. This analysis revealed that many models reasonably forecasted average emissions for short timeframes, and some of the models also produced reasonable forecasts for small-scale marginal emissions. However, few studies used models and assumptions that would reasonably represent the grid response to large-scale changes in load, which at a minimum should include

- Least-cost economic dispatch modeling
- A representative regulatory framework, including constraints on emissions of criteria pollutants
- Endogenous capacity expansion and retirement
- Realistic rates and magnitudes of PEV load changes

Table 3-1 shows which of these characteristics the models in each reviewed report included. In general, most models included economic or pseudo-economic dispatch. But they did not include other important characteristics—such as modeled environmental policies, endogenous capacity expansion and retirement, or realistic introduction rates for PEVs. These excluded characteristics often meant that significant PEV load was added to a grid as a "shock," without reconfiguration of the grid or restrictions on emissions. This sudden addition of load tended to require increased energy generation by peak resources or resources that were already likely to be at their criteria pollutant–emissions limits—both of which are unlikely to occur in an actual grid.

Table 5-2
Characteristics of custom models in analyzed studies

Study Citation	Estimation Methodology			Model Characteristics			
	Projected average	Intensive marginal	Dispatch or large-scale marginal	Econ. dispatch	Emissions policy	Capacity expansion	Realistic fleet
Elgowainy et al. (2010)	*		*	*		a	
Elgowainy et al. (2012)			*	*		a	
EPRI-NRDC (2007)			*	*	*	*	*
EPA (2012)			*	*	*	*	*
Graff Zivin et al.(2014)		*					
Hadley and Tsvetkova (2008)			*	*			
Jansen et al. (2010)	*		*	c			
Kintner-Meyer et al. (2007)			*	*			
Ma et al. (2012)	*	*					
McCarthy (2009) [short-term]	*			*			
Parks et al. (2007)			*	*			

a: This study included manually specified capacity expansion to meet base load, but it did not include marginal capacity expansion.

b: The modeling methodology in this analysis was not described in detail.

c: This study used a dispatch method that was not economical but produced similar results.

Modeling Results for California

To explore this topic in more detail, a comparison was done with California emissions projections. California is a focal point for PEV policy and deployment, so many of these models included predictions for California as a separate area. The models differed slightly in scope and included plants depending on whether fixed imports were "moved into" California; whether California Independent System Operator (CalISO) boundaries or state boundaries were used; and other factors. However, there is sufficient data to correct for these variations. California is particularly interesting to analyze, because recent events allow for unusual insight into small-scale marginal-emissions rates, and the regulations concerning the procurement of new resources provide insight into probable large-scale marginal-emissions rates.

Figure 5-3 shows the estimated California CO_2-emissions intensity for each study that presents separate data for California. The "Historical average" data is for generation within the state of California only. Therefore, some of the average results were adjusted to account for differences between the CAMX eGRID subregion (which mostly matches the boundary of California, as described in Appendix B) and the state of California, based on the most recent eGRID estimate of differences between these emissions rates (EPA 2014a).[18]

Most of the studies either estimate significantly higher average emissions than actual average emissions for California, or provide estimates that are implausible given current trends. This overestimation of emissions occurs despite the fact that the closure of the San Onofre Nuclear Generating Station in 2012 was unanticipated in any of the studies—if this closure had not occurred actual emissions would be lower. There does not appear to be a consistent reason for this overestimation of emissions.

[18] This estimate primarily adjusts for emissions attributable to one out-of-state coal plant, which significantly affects overall average emissions. (The ratio between California and CAMX is 0.85.). This plant is a baseload plant, so marginal emissions are not adjusted.

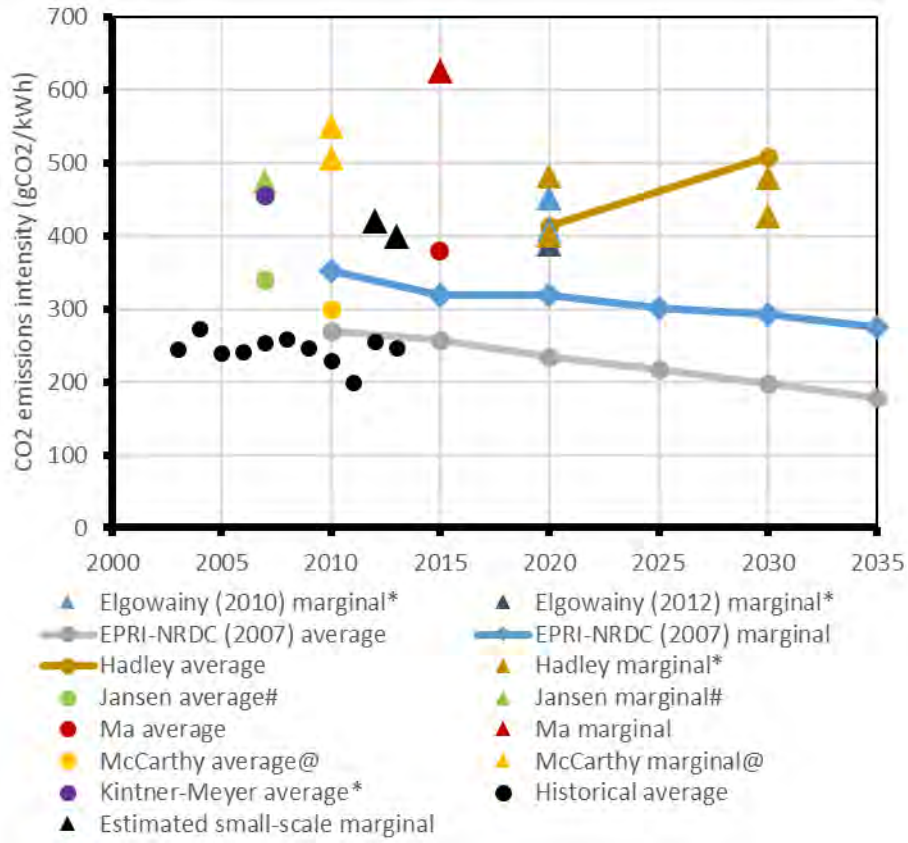

Figure 5-3
Estimated emissions intensity for California from reviewed studies

* Emissions estimated from the generation mix

$ Average emissions adjusted from CAMX to state of California

Numerical emissions not available; interpreted from plot

@ Removed upstream emissions

Many of the emissions estimates for California included estimates of both marginal and average emissions. In all cases, the estimate of marginal emissions was higher than the estimate of average emissions, which is consistent with the presence of a large amount of non-emitting generation in California that is not load-following. (This presence means that in the short term incremental load can only be met with fossil generation or imports, but non-emitting imports are also generally constrained.) However, the mix of marginal fossil generation varies significantly among studies, resulting in significantly different marginal-emissions rates. Generally, marginal-emissions estimates cannot be compared against historical data, because there is no standardized method for empirically measuring marginal emissions. However, unusual recent events in California do provide us the opportunity to calculate a high bound for marginal-emissions rates.

In general, intensive marginal emissions require extensive analysis to measure directly, because doing so requires measuring more than one load condition with the same grid; however, historical data provides only one load condition. But recent unique circumstances in California have resulted in generation changes that are very similar to the necessary load changes. First, the San Onofre Nuclear Generating Station unexpectedly shut down at the beginning of 2012, so California's nuclear generation capacity was reduced in half. Second, reduced rainfall in 2012 also resulted in considerably less hydroelectric generation availability than in 2011. As a result of the permanent shutdown of San Onofre and the continuing drought, neither generation source recovered in 2013. Therefore, the years 2012 and 2013 experienced a generation change equivalent to the instantaneous introduction of 12 million PEVs (about 45% of registered vehicles in California). Figure 5-4 shows the resulting change in generation. Total in-state energy generation remained approximately the same, and the reduction in nuclear and hydroelectric energy generation was met with CCNG and steam-turbine natural gas—with about 85% of natural gas generation coming from in-state combined-cycle in 2012. In 2013, additional renewable generation increased and replaced the steam-turbine natural gas (almost certainly because of plans that predated these unanticipated generation changes).[19] These changes imply a maximum short-term marginal-emissions rate of 400–420 g/kWh.

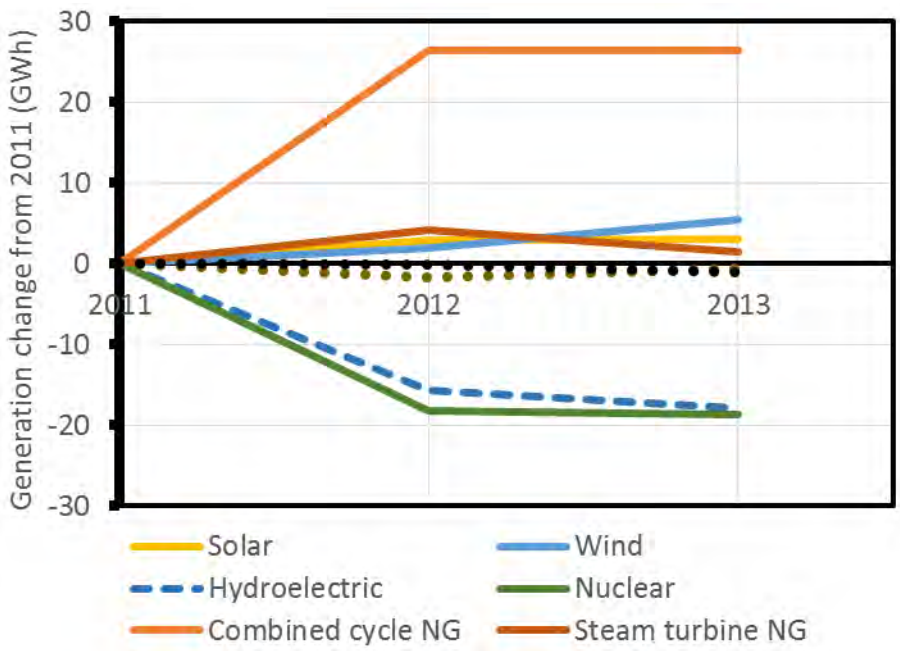

Figure 5-4
Generation shifts in California between 2011 and 2012–2013

[19] Anecdotal feedback from analysts familiar with California system operation have suggested that the steam-turbine natural gas generation was only required because of the large magnitude of the load change over such a short time. The generation changes between 2012 and 2013 are consistent with this suggestion, but more evidence would be needed to demonstrate it conclusively.

Many of the marginal-emissions estimates in Figure 5-3 are higher than 400 g/kWh, and some are considerably higher. These studies generally assumed the use of a higher level of steam-turbine natural gas. The results in Figure 5-4 indicate that these higher emissions do not occur in practice even for very large changes in load.

EPRI-NRDC (2007) was the only study that estimated significantly lower marginal emissions than this short-term rate, because of the use of a large-scale marginal-emissions estimate that includes expansion in renewable capacity (and therefore increasing renewable generation). Capacity expansion cannot occur in a one-year timeframe for changes of this magnitude, but utility regulations in California provide insight into what longer-term changes would occur from a change in load. First, increased load would require utilities to increase renewable generation to meet California's Renewable Portfolio Standard, which requires 20% of generation to come from renewable sources in 2013 and will require 25% of generation to come from renewable sources in 2016 (California Senate Bill 2, 2011). This requirement would bound the effective marginal-emissions rate at approximately 320 g/kWh in 2013 and 300 g/kWh in 2016.[20] Second, the "loading order" dictates that increased generation requirements should be met by energy efficiency, demand response, renewables, and distributed generation before construction of fossil plants. Therefore, capacity expansion will preferentially come from generation cleaner than CCNG.[21]

National Modeling Results

Out of the studies reviewed, almost all studies that had a national scope used an estimate of current emissions or projections from the AEO. Hadley and Tsvetkova (2008) provided marginal emissions for each region of the United States but did not weight them into a consolidated national estimate. Figure 5-5 shows the national emissions estimate from the EPRI-NRDC (2007) Medium case compared with historical average emissions and with average emissions from the AEO2007 and AEO2015 Reference cases. To date, EPRI-NRDC (2007) has estimated average emissions well. Unfortunately actual national marginal emissions are difficult to estimate without the occurrence of a widespread event similar to that in California.[22]

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[20] EPRI-NRDC (2007) marginal emissions are higher than this; analysis of the detailed results indicates that this overestimation occurs because the amount of PEV load in these years is small and the RPS is not exactly met for the incremental load.

[21] For example, California Public Utilities Commission (CPUC) Rulemaking 12-03-014 is the proceeding that is authorizing procurement of generation for local capacity requirements resulting from the shutdown of the San Onofre Nuclear Generating Station; similar proceedings authorize procurement of generation to meet energy requirements.

[22] The recession-induced load reduction in 2009 appears to be an interesting datapoint, but a detailed analysis of generation changes indicates that most of the emissions changes were attributable to unusually large changes in a small number of regions.

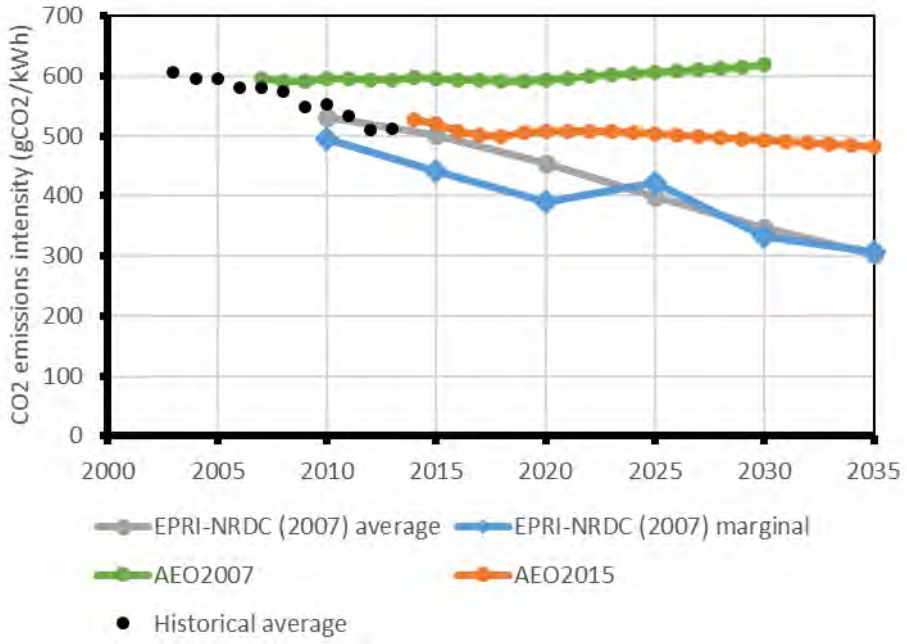

Figure 5-5
National estimated emissions intensity

Section 6: Modeling Methodology Best Practices for Large-scale Incremental Load Changes

Based on the literature review described in Section 3 and Section 5 and on consultation with grid-modeling experts, the study team developed a set of best practices for modeling the grid response to large-scale changes in load and describing the results. These best practices are not an exhaustive description of how the grid should be modeled, but they describe the minimum requirements for using a grid model to estimate the changes in dispatch and grid configuration.

The recommended best practices are:

1. Emissions rates should be projected using a model with least-cost dispatch modeling with capacity constraints; representative regulatory framework, including constraints on emissions of criteria pollutants; and endogenous capacity expansion and retirement.
2. Average emissions rates should be calculated and presented.
3. If marginal emissions are estimated, a large-scale modeling methodology should be used in which PEVs are added to the baseline grid with realistic rates and magnitudes. PEVs should be compared against an improving baseline of vehicles that meet increasingly stringent fuel-economy targets.
4. Emissions attributable to fuel acquisition and processing should be included, but results should be presented for both life-cycle emissions and direct emissions.

The subsections below describe the rationale for these best practices.

Modeling Utility-Sector Emissions

Modeling the U.S. electricity grid is extremely complex, and only a limited set of behaviors and assumptions can be included in a practical model. A model that performs well for one purpose may not be appropriate for other purposes. After a careful review of previous studies of grid emissions and general grid-modeling methodology, the study team identified grid-modeling best practices for analyzing the impacts resulting from a large-scale shift in load. A best-practices model should include

- Least-cost dispatch modeling with capacity constraints;
- A representative regulatory framework, including constraints on emissions of criteria pollutants;
- Endogenous capacity expansion and retirement; and
- Realistic rates and magnitudes of PEV load changes.

These modeling specifications apply to best practices 1 and 3, because implementing a large-scale marginal-modeling methodology first requires an appropriate grid model. The large-scale marginal-emissions methodology is described in Section 4, and the subsections below describe the rationale for each of these modeling elements.

Least-cost Dispatch Modeling with Capacity Constraints

Most reasonably representative models of the electricity grid include some version of least-cost dispatch, in which generators are deployed to meet load—starting with the lowest-cost unit, and then incrementally adding higher-cost units until the full load is met. This model represents the operational characteristics of actual grids.[23]

Correctly handling least-cost dispatch also requires accounting for capacity constraints, both for resources like renewable generation that have limited energy availability, and also for fossil-fuel plants. Although fossil-fuel plants are generally considered "dispatchable," they have operational constraints resulting from limited ramp rates, fixed periods of downtime for maintenance, and shut-down and start-up times. These constraints do not necessarily need to be modeled exactly, but the model should be tested to ensure that it does not produce results that would be impractical under these types of constraints.[24]

Credits and Limits for Emissions of Criteria Pollutants

One aspect of least-cost dispatch that is frequently neglected is accounting for the costs of credits and limits for emissions of criteria pollutants. Regulations on emissions of criteria pollutants are complex and vary widely by location, so they are difficult to model. However, all operators of fossil-fuel generation have to account for increased emissions of criteria pollutants by upgrading emissions-control equipment, limiting operation, buying emissions credits, or making operational changes that reduce emissions. These effects mean that a plant which appears to be "least-cost" if emissions of criteria pollutants are ignored may not actually be able to respond to increased demand—or it may have a higher marginal cost for increasing generation. Neglecting this complexity will be likely to cause significant errors in the estimation of increases in emissions of criteria pollutants. However, even grid analyses that do not directly concern emissions of

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[23] For example, see Stoft (2012) for an extended discussion of the operation of electricity markets.

[24] Modeling unit commitment is computationally very complex and is generally impractical for long-term models. See EPRI (2015). for more discussion of this topic.

criteria pollutants can be indirectly affected by operational constraints caused by such emissions.

Endogenous Capacity Expansion and Retirement

New plants are constantly being built and old plants are regularly being retired, so changes in capacity over time are a critical element of the evolution of the electricity grid. Capacity changes reflect the fact that utilities can respond to changing conditions by installing newer, more-efficient plants rather than paying higher costs to operate existing plants more intensively. This tradeoff is illustrated conceptually in Figure 6-1. In this case, an existing plant is compared with a more-efficient new plant that has much lower fuel and operating costs, but which would incur capital expenses for construction. At a low utilization level (illustrated here with a grey circle), the existing generator has a lower total expenditure, and a new plant would not be built. However, as usage increases, the new plant becomes more economical. Eventually, the lowest-cost decision would be to build the new plant and retire or idle the existing plant. Similarly, a retirement may cause a subsequent change in other capacity-expansion plans. For example, the retirement of a baseload plant may shift expansion plans from peaking capacity to intermediate capacity, because the retirement will increase the potential utilization level for other generators.

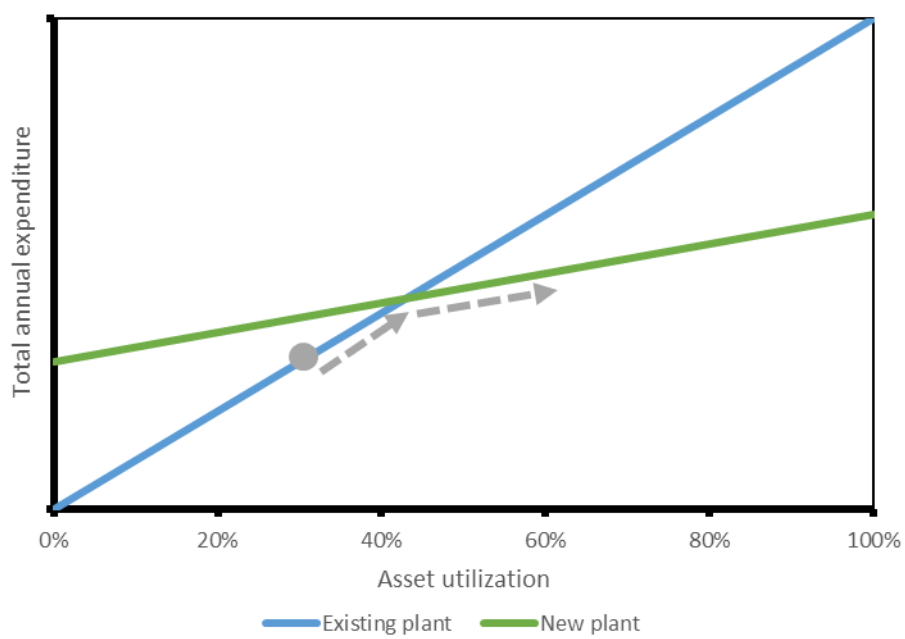

Figure 6-1
Effects of capacity expansion on more intensive use of an existing generator

Realistic Rates and Magnitudes of Load Changes

Although this study generally finds that it is beneficial to deploy PEVs and non-road devices as quickly as possible, the ability to build new vehicles and devices is

limited by production capabilities and deployment limits. Modeling load increases as instantaneous will instead "shock" the grid and cause changes that are probably unrealistic. The rate of change of load for even very optimistic deployments of electric-transportation technologies will be significantly lower than historically "normal" changes in grid load, so the load increase should not be modeled as a shock. Given realistic deployment rates, utility-system operators will have time to plan for capacity expansion; introduce programs to alter load shapes to minimize impacts; and take other measures to mitigate potential emissions increases resulting from additional load.

Reporting Direct-Emissions Rates and Average-Emissions Rates

The analysis in this assessment is focused on modeling marginal-emissions rates and comparing fuels that are based on a full-fuel cycle. However, in performing the literature review, the study team found that it is important to report both direct-emissions rates and average-emissions rates. Upstream-emissions inventories still contain a significant amount of uncertainty because of unsettled assumptions like leakage rates for natural gas and because of differences in scope, allocation method, and regional fuel-extraction-and-processing emissions rates. These differences in upstream emissions are important, but they are more likely to be revised and therefore are less stable than direct emissions.

The study team found that it is important to report average emissions for two reasons. First, even for large changes in load and large differences in marginal-emissions rates, average emissions are relatively stable and allow the general assumptions embodied in the grid model to be understood. (Primarily, this reporting can be used to assess whether the assumed changes in grid emissions are commensurate with the assumed changes in the transportation sector.)

The second rationale for presenting average emissions is that average-emissions rates are generally used in reporting protocols and regulations that could apply to the use of electricity as a transportation fuel. It is therefore important to understand how the use of average emissions instead of marginal emissions could misrepresent the actual effects of electric transportation. A review of reporting protocols and regulations is presented in the next subsection.

Use of Emissions Rates in Emissions-Reporting Protocols and Fuel Regulations

As part of the background research for this assessment, emissions-reporting protocols and fuel regulations were reviewed to search for additional best practices for modeling and reporting the impacts of electric transportation.

Two primary emissions-reporting protocols were reviewed: The Climate Registry Reporting Protocols (The Climate Registry 2015) and The Greenhouse Gas Protocol (WRI 2014). (ISO 14064 is also an important reporting protocol, but it does not make specific recommendations for calculating electricity emissions.) Both protocols suggest that entities reporting on grid emissions use average emissions for the region in which the use of electricity occurs. The Greenhouse

Gas Protocol supplement, "Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects" (WRI 2007), discusses optional methods for calculating the incremental emissions from individual projects. This supplement suggests the use of modeling techniques similar to the large-scale marginal methodology, but it mainly focuses on simplified calculation techniques that are applicable to single projects with a relatively narrow scope. When nonaverage-emissions rates are discussed, both primary protocols also indicate that organizations desire to get "credit" for the projects they develop. However, this allocation of positive benefits must be balanced with the fact that other load will be evaluated using average system emissions. If the emissions and energy generation attributable to these specially allocated emissions are not subtracted from the totals before averaging, then these benefits will be doubly counted. Providing both average-emissions rates and marginal-emissions rates can be useful for demonstrating that marginal effects are not adversely modifying average-emissions rates.[25]

The three regulatory documents that most directly address the potential use of electricity as a transportation fuel are: the model year 2017–2025 vehicle standard for greenhouse gas emissions from the EPA (2012); California's Low Carbon Fuel Standard (LCFS) (CARB 2010); and recent revisions to add electricity to the Renewable Fuel Standard (RFS) (EPA 2014c). As discussed in Section 5, the EPA's vehicle standard uses a large-scale marginal methodology to estimate electricity emissions for PEVs. However, this standard applies to the assessment of vehicle emissions at time of sale; it does not apply to use of electricity as a fuel. The LCFS regulates the emissions for vehicle fuel in California, and it applies to a variety of fuels—including electricity. Most fuels are regulated on an implicitly marginal basis, but emissions for electricity for use in charging PEVs is calculated using average historical emissions for California.[26] The RFS regulates the renewable content of vehicle fuel. Although it does not directly regulate fuel emissions, emissions are considered in the determination of which fuels are renewable and which category of "renewable" applies to each fuel. Recent revisions address the use of electricity generated from renewable sources with a method that is implicitly a small-scale marginal method. The regulation does not consider the effects of this use of electricity on other emissions regulations. (Because it is a renewable-fuels regulation, and not directly an emissions regulation, this consideration is not necessary.) It is also unclear from either the RFS or the vehicle greenhouse gas regulation how emissions attributable to electricity would be validated using measured data.

This review of protocols and regulations indicates that there is a general preference for estimating the effects of future changes using a marginal-emissions methodology, but a preference for measuring actual change using an average-

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[25] The average-emissions rates for non-electric transportation load will not be modified under the large-scale marginal methodology proposed above, because all incremental changes are assigned to the marginal rate. However, such modification could be a concern when using other methodologies.

[26] Previous versions used a marginal rate that was calculated using a specified mix, but the most recent version eliminates this option.

emissions methodology. This split creates opportunities for projections to be unrealized in actual measurements, and it also may not correctly account for the incremental effect of individual changes in load. Given this ambiguity, it will be important to have both average- and marginal-emissions estimates available so that the full effects of policy changes can be evaluated.

Improving Baseline Comparison

PEVs will be introduced to the fleet as new vehicles over an extended timeframe. This situation affects the rate-of-change of load, as noted above, but it also means that PEVs should be compared against an improving baseline of new fossil-fueled vehicles. Fossil-fueled vehicles generally do not undergo emissions reductions during their lifetimes, but new vehicles will become progressively more efficient over time in response to regulations and customer preferences. Modeling the effects of new-vehicle improvements requires a transportation model that tracks vehicle energy use by model year.

Notable Model Characteristics Not Included in Best Practices

The best practices described above are intended as a starting point for developing best practices for modeling the effects of large-scale load changes. This list is not intended to be exhaustive, but there are some model characteristics that the study team would have liked to include in the list, but which they considered to be too "unsettled" at this time. These characteristics will be the focus of future work to attempt to develop best practices:

- **Definition of a "grid" model:** The term "grid-model" is used generically in this discussion to refer to a model of the interconnected electricity system. The electricity system is quite complex, however, and there are many ways to model generation, the flow of power, and the behavior of loads. It is computationally infeasible to model every generator and every connection for long periods of time, so all available models simplify the behavior of various aspects of the grid. The study team identifies four aspects of grid modeling that are best practices. However, it does not make recommendations on many modeling elements, including the presence or representation of power flow within a region, interregional transmission, generation start-up or shut-down, unit commitment, and ancillary services. These modeling characteristics could have an effect on emissions results, but their representation will depend significantly on the research question being addressed by a particular modeling effort. For more information on the representation of these characteristics in EPRI's US-REGEN model, see EPRI (2013) and EPRI (2014b).
- **Representation of time in grid models:** As part of the simplification of the electricity system, most grid models aggregate time periods that are similar in order to reduce computational complexity. The time resolution can vary significantly among models, and blocks of time are often nonuniform. For example, US-REGEN uses 5-year timesteps, with each timestep represented by one sample year with 87 representative time periods of varying lengths

(with a minimum duration of 1 hour).[27] Models that include a detailed representation of ancillary services may require time periods as short as seconds. The study team does not make a specific recommendation on the representation of time, aside from noting that the team responsible for the model should ensure that it is appropriate for the research question being addressed.

- **Load shape for PEV charging:** The load shape for PEV charging is subject to a significant amount of uncertainty. Data is available on load shapes for current vehicles, but the PEV market is at an early stage, and it is unclear how the load shape will change in the future. The amount of energy which could be stored on a vehicle in the available charging time is often significantly larger than the amount used per trip or per day. Therefore, it is possible that management programs like time-of-use rates, demand response, and direct load management could be used to modify load on a seasonal, daily, or subhourly basis. Ultimately, PEVs may act as grid resources, so that the concept of "load shape" would no longer be applicable. This potential PEV effect is an active research topic. So it is too early to recommend a particular load shape, beyond recommending that the load shape is "reasonable," given current trends or likely future developments. For more information on the effects of different load shapes on the greenhouse gas results in this report, see Section 9 in Volume 2.

[27] As another example, the grid model used by the EIA in the AEO uses nine representative time periods per year, three representing 16.7% of the year, three representing 16.3% of the year, and three representing 0.33% of the year (EIA 2013a).

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Appendix A: Omitted Studies

A number of studies were investigated but were not included in the review because they did not contain sufficient information on quantitative results.

Many of these studies considered the effects of electric vehicles on both greenhouse gases and air quality, so they would have provided interesting contributions to the review. However, these studies generally presented monetized values that combined the effects of all impacts and did not present independent estimates of emissions or of air quality impacts. The techniques for monetizing the effects of emissions are an area of active debate and development. Therefore, unified effects measurements require a significant amount of judgment by study authors and are subject to a very large uncertainty. This means that although the results can be individually informative, they are not directly comparable. EPRI does not use monetization of health and environmental impacts to compare greenhouse gas and air quality impacts.

Tessum, Christopher, Jason Hill, and Julian Marshall (2014)

Tessum et al. (2014) compares a variety of vehicles using monetized external damages—including conventional vehicles, hybrid vehicles, and electric vehicles with a variety of grid assumptions. Monetized damages are lower than conventional vehicles for electric vehicles powered by clean electricity, but they are higher for electric vehicles powered by coal and average electricity. Information on grid emissions is not available.

Holland, Stephen, Erin Mansur, Nicholas Muller, and Andrew Yates (working paper, 2015)

The current version of Holland et al. (2015) compares the air quality and greenhouse gas impacts of conventional gasoline vehicles with those of electric vehicles, using monetized external damages. The relative monetized benefits of electric vehicles are found to vary dramatically (based on location) from significantly positive to significantly negative, with a negative average. Grid emissions are modeled using a small-scale marginal methodology, but they are not available. The grid modeling is described as a refinement of Graff Zivin et al. (2014), which is discussed above.

National Research Council (2010b)

The NRC "Hidden Costs of Energy" report (2010b) discusses external costs for a variety of energy uses, including the use of gasoline and electricity in transportation. Specific emissions rates are not available, but the study finds that electric vehicles result in significantly higher damages than conventional vehicles.

Appendix B: Regional Aggregation of Emissions

Assigning a set of generators or emissions to a given unit of consumption of electricity involves some surprisingly complicated conceptual questions. In actual operation, electricity generators and loads are pooled into clusters with limited interchange capability, but the dynamics of electricity flow are complex and generally opaque. For example, it is clear that a load in the Pacific Northwest (where hydroelectric power dominates) is likely to have cleaner electricity available than a load in the Upper Midwest (where coal power dominates). However, it is quite difficult to determine exactly where power-system boundaries should be drawn to ensure that the emissions attributable to a load are best represented. Averaging over too large an area will underestimate the variation among locations, but choosing too small an area may not properly represent the sharing of electricity—which can happen over large areas.

Weber (2010) describes a detailed attempt to determine a preferred boundary for allocating emissions for determining life-cycle emissions. The study compares the use of national boundaries, state boundaries, NERC regions, eGRID subregions, and the boundaries for Independent System Operators or Regional Transmission Organizations. The study finds that the allocation method used can have a very significant effect on the emissions assigned to a load. For example, the state of Vermont has the highest variation for CO_2 emissions, from 20 g CO_2/kWh (very low) to 720 kg CO_2/kWh (higher than the national average). Note that the generation and plant emissions are constant in all cases; only the allocation method changes. The authors do not find that one allocation method is clearly preferable to any other. Instead, they suggest that the preference should depend on the problem that is being addressed, and that guidelines should be created by standards-development organizations. Unfortunately, however, no guidelines have yet been created by such a standardization process.

This chapter describes the aggregation groupings used in the emissions estimate described in this report, US-REGEN regions, and compares them to aggregation by NERC region, eGRID subregion, and state. The US-REGEN regions group states into multistate entities that are considered one integrated grid within the model (EPRI 2013). This representation balances the need to represent the boundaries of actual power flows with the need to represent state-level economic activity and policy.

The results in this chapter show that

- The emissions rates for US-REGEN regions demonstrate similar variation among different locations because of changes in generation mixes when compared to other allocation methods.
- The US-REGEN regions demonstrate a high level of consumption and generation independence, so that generation-emissions rates can be expected to reasonably represent usage-emissions rates.
- Although no representation can be proven to be "correct," these results indicate that the US-REGEN regions provide representations of emissions for electricity use that are similar to other allocations methods.
- Additionally, these results indicate that state-level representation leads to a high emissions variability but a poor matching of generation to load, which indicates that these emissions rates are unlikely to be representative of actual emissions resulting from consumption.

Aggregation Groupings Used in Other Emissions Estimates

A number of allocation methods have been used in previous work:

National: A common allocation method used is to calculate a single value for the entire United States. This method is simple and straightforward, but it poorly represents the emissions in areas with unusually high or low emissions.

Electricity-balancing regions: One allocation method divides the United States into regions based on electricity connections, such as North American Electricity Reliability Corporation (NERC) regions. The NERC regions are also often divided into smaller regions to separate out interesting subregions to analyze in greater detail. EPRI used modified NERC regions in its previous Environmental Assessment, and a more detailed breakdown is used in eGRID and other estimates (EPRI-NRDC 2007; EPA 2014a) Electricity-balancing regions are generally more tightly connected internally than they are to each other, so this allocation method seems to match the intent of matching generation to load. Unfortunately, however, these regions are based on the system configuration and are not necessarily geographically based. So it is only possible to provide a rough approximation of region boundaries, and the boundaries may change over time. (See, for example, the discussion in EPA (2014a) for more information on the creation of the divisions for eGRID.) This type of division complicates the allocation of a given load to a specific region. A "representational" map for the NERC regions is shown in Figure B-1 and for the eGRID subregions in Figure B-2.

State: State divisions are often used to allocate emissions to loads. This approach has the advantage that the relative locations of loads and generators can be determined, and the emissions rate can generally be clearly mapped to a policy framework. However, the amount of generation within a state is often not well matched to consumption within a state, so some states import or export a significant fraction of the electricity generated. Division by state therefore has the potential to lead to emissions "leakage."

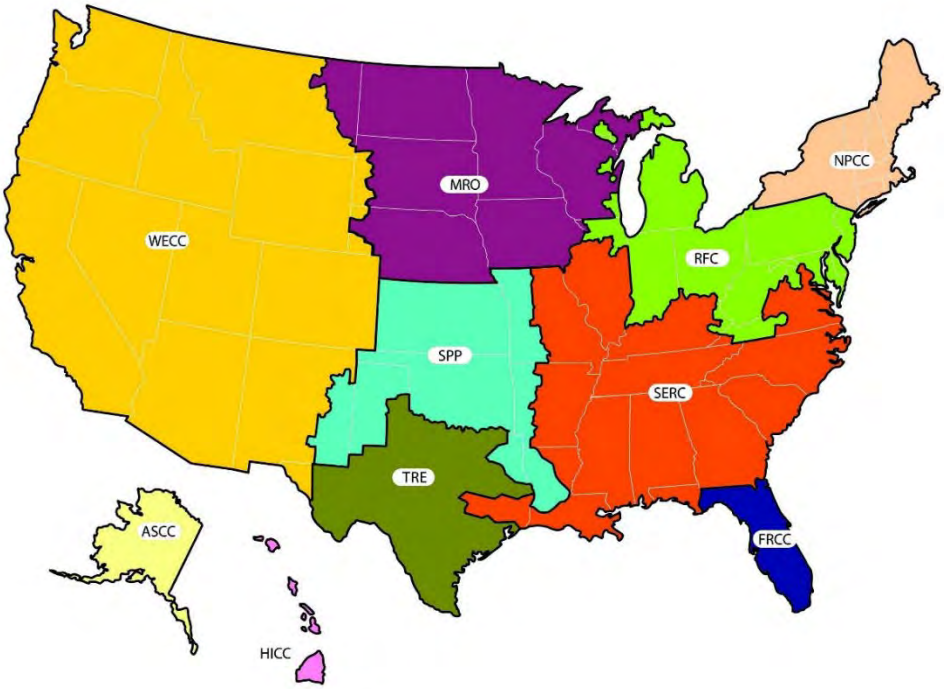

Figure B-1
NERC regions[28]

[28] This map is representational; many of the boundaries are approximate because they are based on company ownership and not geographical boundaries.

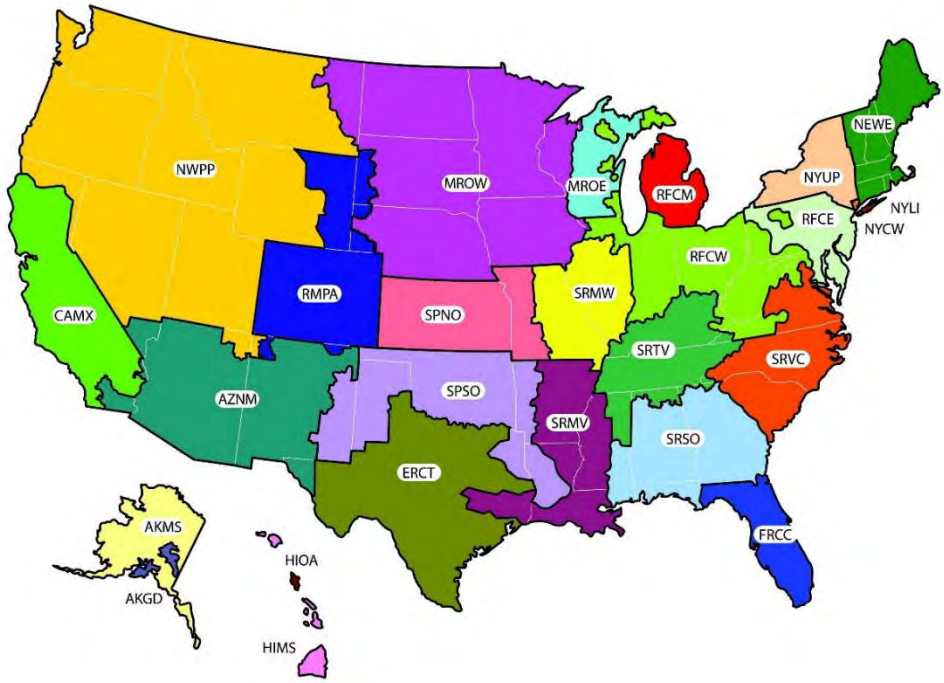

Figure B-2
eGRID subregions[29]

Aggregation Groupings Used in This Assessment

For the analysis in this assessment, results of grid analyses will be presented at two levels of aggregation, depending on the problem being addressed:

National: Much of the work in the assessment will compare a large number of characteristics or scenarios over relatively long timeframes. Presenting these results at a fine regional resolution would be difficult and would probably obscure the more important high-level effects. In these cases, the national scale is used.

US-REGEN regions: The lowest resolution presented for most results is the set of regions created by the US-REGEN modeling team for the model. These regions are groupings of states that are selected to approximately match current electricity-balancing regions while retaining separations that allow correct representation of expected policies and market behaviors. The layout of these regions means that they display most of the expected variation in emissions rates for regions that are electrically isolated (except where coupling between regions is known and important). The separation of regions by states allows the use of a wide array of databases on economic activity, and it allows simplified mapping of load and generator to regions. The US-REGEN regions are shown in Figure B-3.

[29] This map is representational; many of the boundaries are approximate because they are based on company ownership and not geographical boundaries.

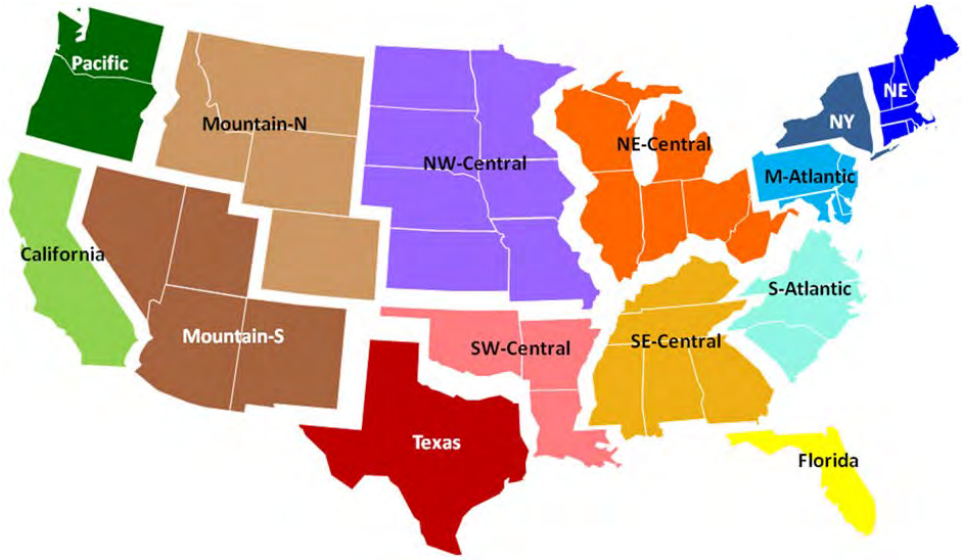

Figure B-3
US-REGEN regions

Appendix C shows the mapping among states and US-REGEN regions. Hawaii and Alaska are included in historical national results to enable comparisons with other historical datasets, but these two states are not included in US-REGEN region representations. The grids in both of these states consist of sets of unconnected or loosely connected subgrids, which are more appropriately modeled with local information and models than with large-scale models. Alaska has historically represented just under 0.2% of national generation and Hawaii has historically represented just under 0.3% of national generation.

Emissions Comparison for Different Regional Representations

In order to understand how the emissions estimates using US-REGEN regions compare to estimates using other aggregation levels, a comparison was done using data from the 9th Edition of eGRID (EPA 2014a). Because state-level data is available in eGRID, it can be used to compare emissions at the following levels: US-REGEN regions, NERC regions, eGRID subregions, and states. (Because eGRID subregion definitions are only available in eGRID, it is the only dataset that allows comparison of all levels.) Detailed emissions results are shown for CO_2, and results bands are shown for CO_2, SO_2, and NO_x. Although no regional representation is necessarily preferable, the results indicate that the US-REGEN region results have about the same variation in emissions as eGRID subregions.

Figure B-4 shows the CO_2-emissions rates aggregated at the US-REGEN region level, which shows significantly higher variation. At the US-REGEN region level, it is clear that the western coastal regions and northeastern regions—including California, Pacific, NE, and NY—have significantly lower emissions than the upper Midwest—including NE-Central and NW-Central.

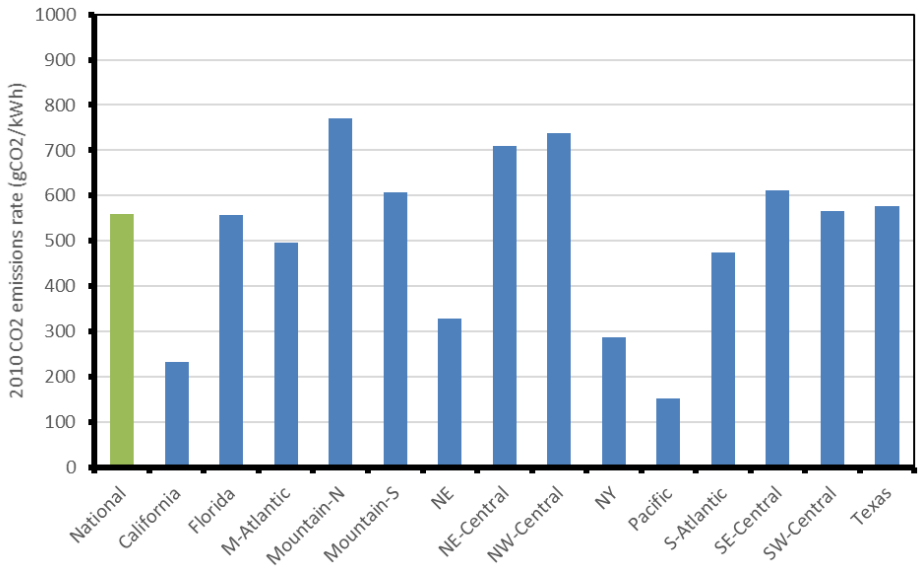

Figure B-4
CO_2 emissions rates for US-REGEN regions from eGRID for 2010

Figure B-5 shows the CO_2 emissions rates aggregated to the NERC region level. NERC regions are generally more closely electrically connected within the region, so it is likely that loads within the region are matched to generation. However, the regional breakdown is relatively coarse, so the Western Electricity Coordinating Council (WECC) contains both the relatively coal-heavy Southwest and the low-emitting Pacific Northwest, which derives most of its electricity from hydroelectric generation.

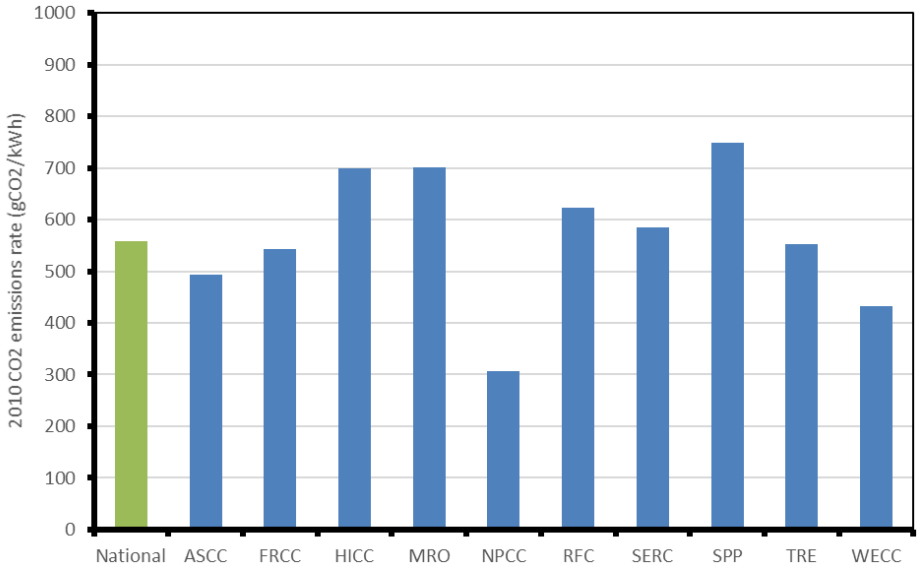

Figure B-5
CO_2 emissions rates for NERC regions from eGRID for 2010

A variety of subdivisions of NERC regions have been used to increase the resolution of results to separate regions that have interesting differences. (For example, California is usually separated from WECC.) An example of a higher-resolution aggregation is the set of subregions used in eGRID, which divide NERC regions into smaller subsets that still roughly conform to power-control areas. The emissions for these subregions have higher variation, as shown for CO_2 in Figure B-6. (The four eGRID subregions for Alaska and Hawaii are not shown, both to enhance clarity and because of the small amount of generation represented by these subregions.)

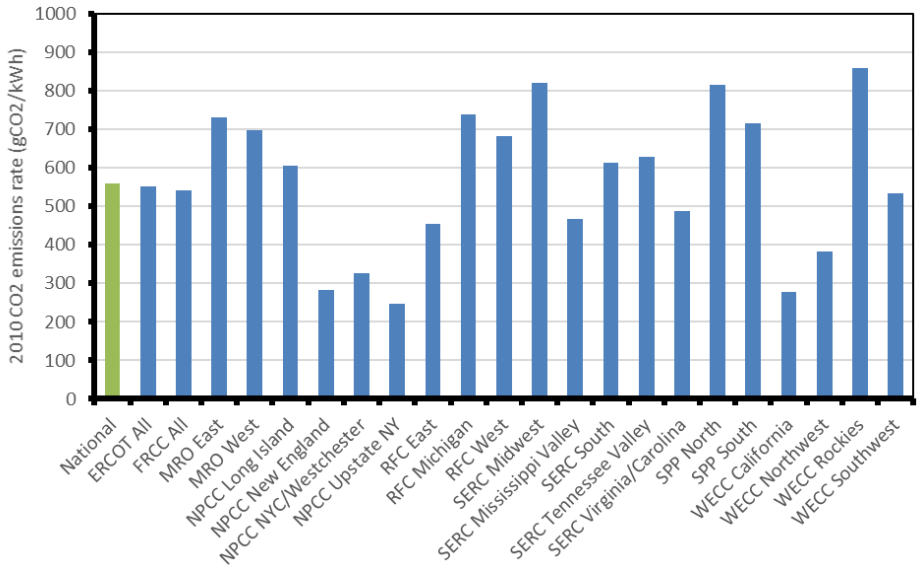

Figure B-6
CO_2 emissions rates for eGRID subregions from eGRID for 2010

State-level data allows for an even finer resolution (in most cases), which results in higher variation in emissions rates, as seen in Figure B-7. Averaging over a wider area reduces variation and may mask the effects of localized diversity. Dividing regions too narrowly, however, may decrease representativeness, which will be addressed in the next section.

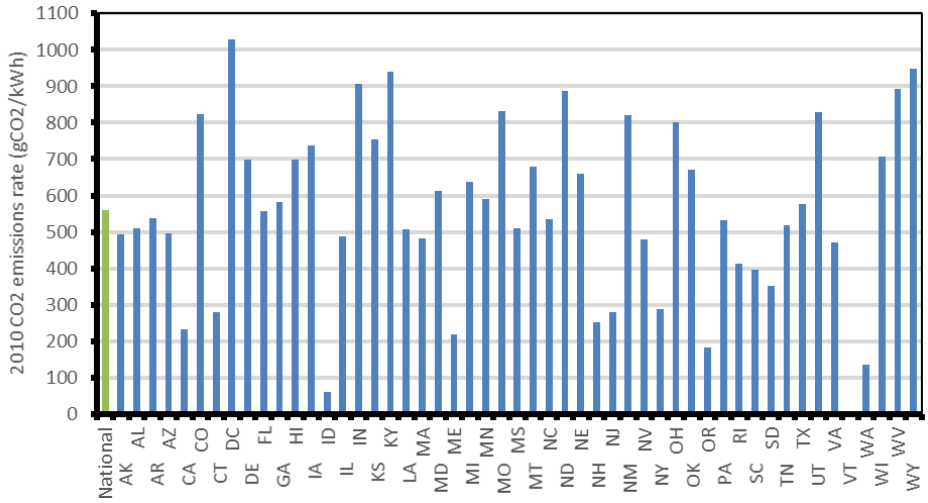

Figure B-7
CO_2 emissions rates for states from eGRID for 2010

Figure B-8, Figure B-9, and Figure B-10 summarize the range of emissions rates for each aggregation level considered in this discussion for CO_2, SO_2, and NO_x. (Alaska and Hawaii NERC regions and eGRID subregions are not included in these ranges.) US-REGEN regions provide a level of variability comparable to eGRID subregions for each of these emissions rates.

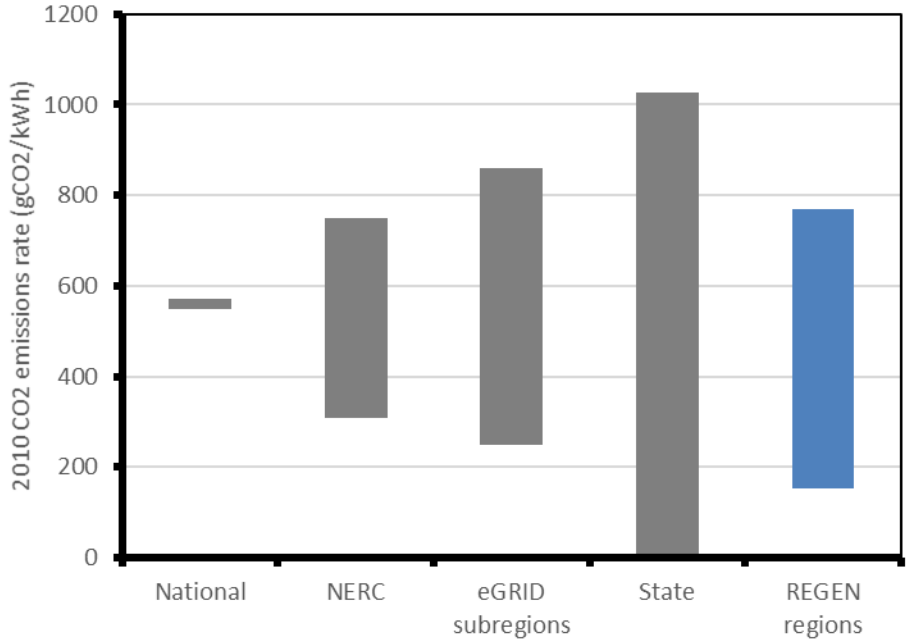

Figure B-8
Ranges of CO_2 emissions rates for different aggregation levels

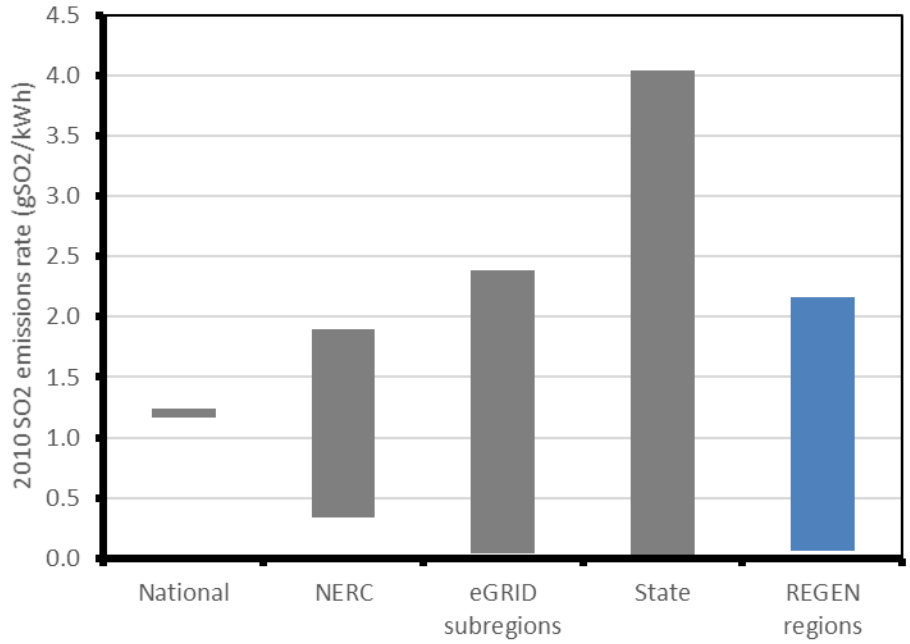

Figure B-9
Ranges of SO_2 emissions rates for different aggregation levels

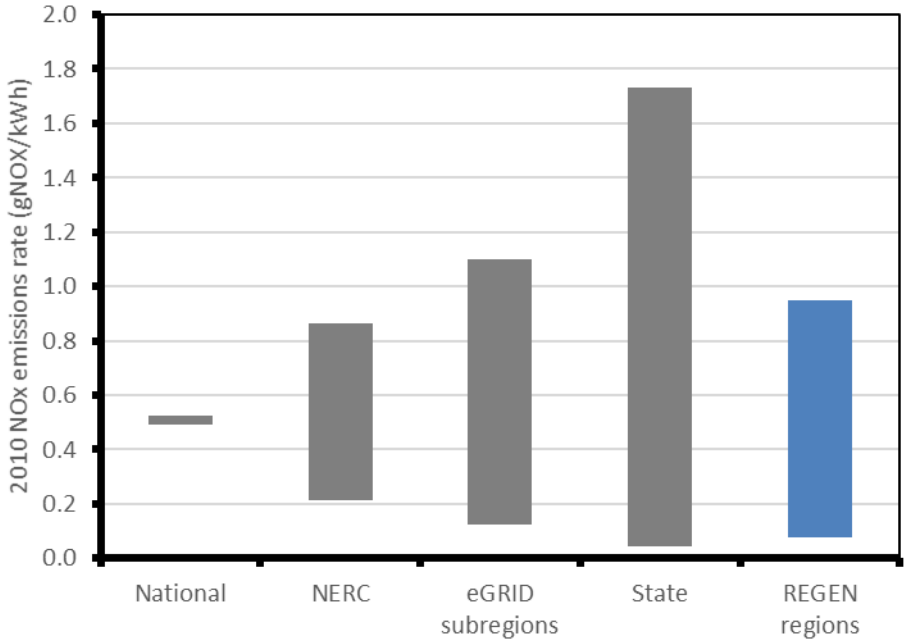

Figure B-10
Ranges of NO_x emissions rates for different aggregation levels

Matching of Load to Generation

There are two main problems with dividing regions too narrowly: 1) the sizes of regions can become incompatible, so that some regions are much bigger than others, and 2) generation can become mismatched to consumption, because regions no longer contain all of the generation assets used to generate electricity for the region. The results presented in this section indicate that aggregating at the state level is probably too narrow to match generation to consumption, whereas the US-REGEN regions appear to match generation to consumption. Unfortunately, data was not available to calculate a generation/consumption ratio for NERC regions or eGRID subregions, so it is unclear how the ratios for US-REGEN regions compare with other representations.

Figure B-11 illustrates the first concern about region sizing: that the sizes of aggregated groups can become incompatible. A high degree of variation is especially present at the state level. Thirty-two states and the District of Columbia each contain less than 2% of national generation, so the majority of states have less than an "equal share" of generation. In this sample, the highest-generating state—Texas—has as much electricity generation as the smallest 18 states combined, so data displayed at the state level will over-represent these smaller states. The largest US-REGEN regions are comparable to the eGRID subregions, and the smallest US-REGEN regions are comparable to the NERC regions. Although there is no correct definition of "balance" between regions, these divisional similarities indicate that US-REGEN regions are at least similar to commonly used regions.

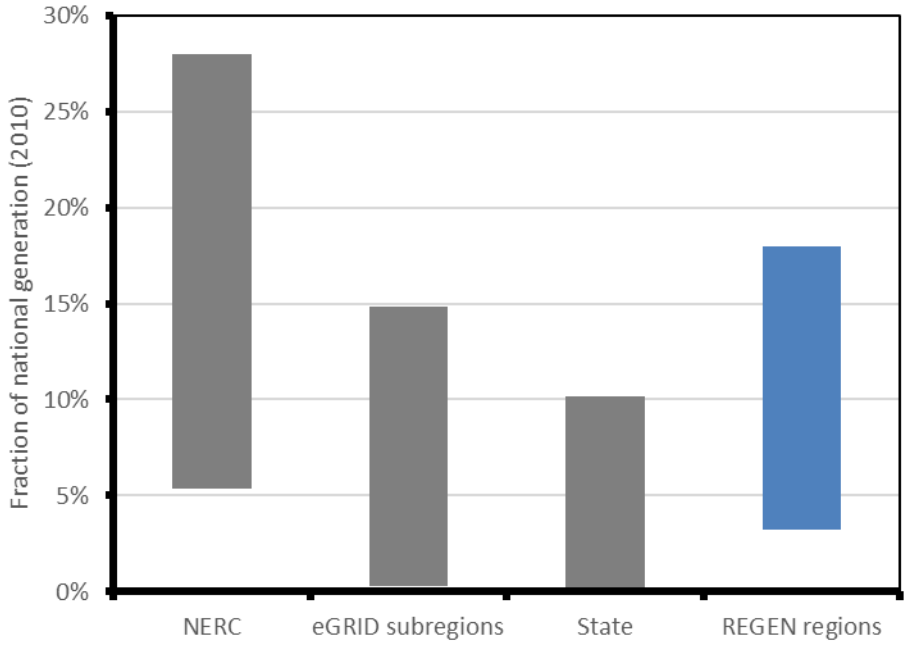

Figure B-11
Comparison of generation for different aggregation levels

The second concern is whether or not generation within an area is well-matched to consumption. To create a measure for this parameter, a generation/consumption ratio was calculated using generation data from EPA (2014a) and consumption data from EIA (2013b). Unfortunately, electricity consumption data is not available at the NERC region or eGRID subregion level, so the ability to compare generation to consumption is limited. However, the NERC regions—and to some degree the eGRID subregions—are generally grouped based on power-control areas, so the matching between generation and use should be high.

Figure B-12 shows the level of matching between generation and use at the state level, which illustrates the concern with the potential for mismatch. Some states have almost three times more generation than use, whereas some states import around half of the electricity they use. This figure indicates that using state boundaries does not closely match generation to consumption.

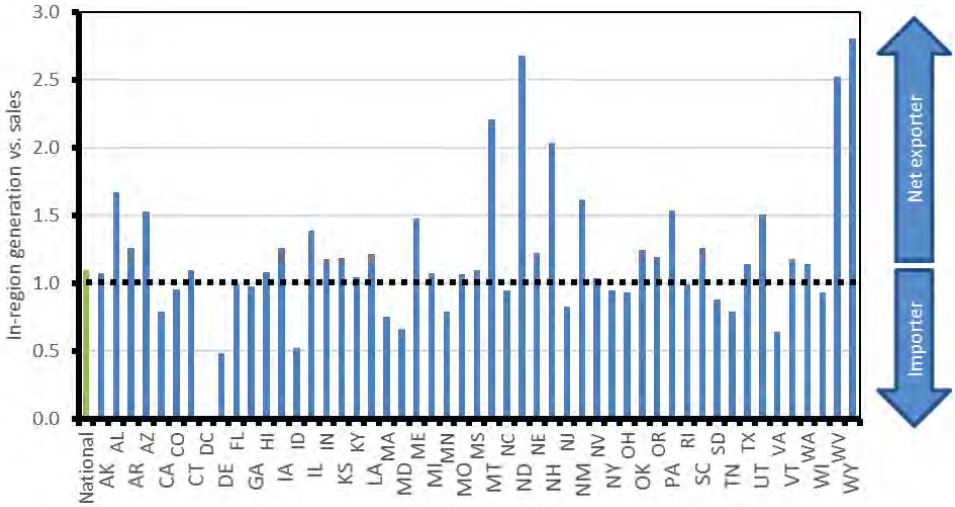

Figure B-12
Ratio of in-region generation to in-region electricity sales by state

Figure B-13 shows the level of matching between generation and use at the US-REGEN region level. Generation in US-REGEN regions is mostly well-matched to consumption, and the exceptions have important causes. California and New York are both separate regions in the US-REGEN mapping because of the unique policy characteristics of each state, but both import a significant amount of electricity from neighboring areas. For example, California draws power from Mountain-S and Pacific, which in turn draws power from Mountain-N. This behavior is an important characteristic of regional electricity trade, and it cannot be eliminated without aggregating at a higher geographic level.

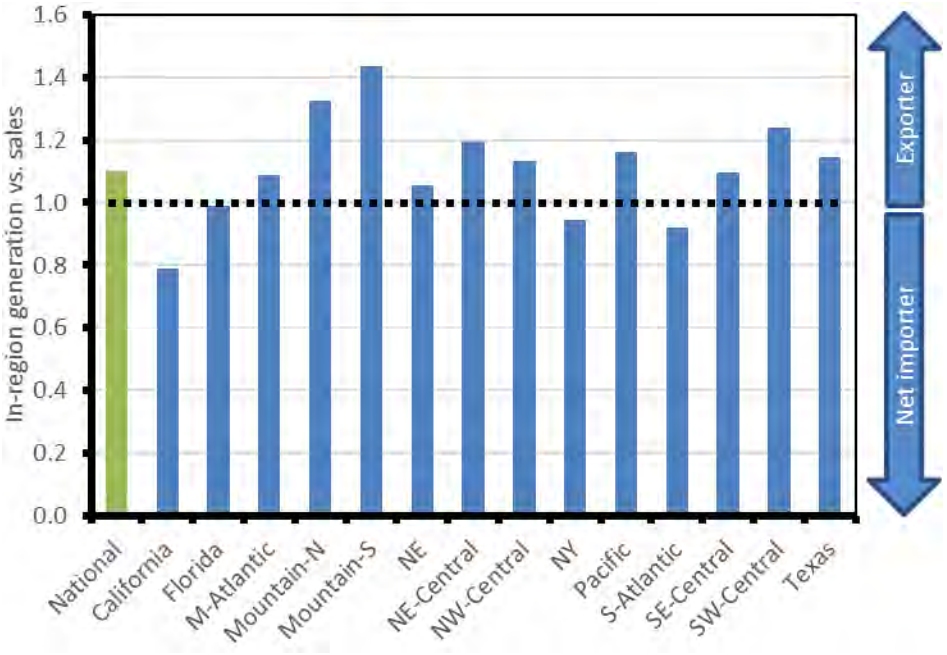

Figure B-13
Ratio of in-region generation to in-region electricity sales by US-REGEN region

Appendix C: REGEN Regions

Table C-1 shows the US-REGEN region to which each state belongs. The two right-most columns show that Alaska and Hawaii are not modeled in US-REGEN and are not included in US-REGEN national results. However, they are included in historical national results. Alaska has historically represented just under 0.2% of national generation and Hawaii has historically represented just under 0.3% of national generation, so the results for these two different views of national emissions should be similar.

Table C-1
Allocation of states to US-REGEN regions

State	US-REGEN region	US-REGEN National	Historical National
Delaware	M-Atlantic	National	National
District of Columbia			
Maryland			
New Jersey			
Pennsylvania			
Connecticut	NE		
Maine			
Massachusetts			
New Hampshire			
Rhode Island			
Vermont			
Illinois	NE-Central		
Michigan			
Ohio			
Indiana			
West Virginia			
Wisconsin			
New York	NY		
Iowa	NW-Central		
Kansas			
Minnesota			
Missouri			
Nebraska			
North Dakota			
South Dakota			
Arkansas	SW-Central		
Louisiana			
Oklahoma			
Texas	Texas		

Table C-1 (continued)
Allocation of states to US-REGEN regions

State	US-REGEN region	US-REGEN National	Historical National
Florida	Florida	National	National
North Carolina	S-Atlantic		
South Carolina			
Virginia			
Alabama	SE-Central		
Georgia			
Kentucky			
Mississippi			
Tennessee			
California	California		
Colorado	Mountain-N		
Idaho			
Montana			
Wyoming			
Arizona	Mountain-S		
Nevada			
New Mexico			
Utah			
Oregon	Pacific		
Washington			
Alaska			
Hawaii			

Environmental Assessment of a Full Electric Transportation Portfolio

Volume 2: Greenhouse Gas Emissions

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ELECTRIC POWER RESEARCH INSTITUTE

NRDC

Environmental Assessment of a Full Electric Transportation Portfolio: Executive Summary

The Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC) produced the Environmental Assessment of a Full Electric Transportation Portfolio to provide in-depth analysis of the environmental impact of electrifying a range of vehicles, including U.S. light-duty and medium-duty transportation and industrial equipment such as forklifts.

The study simulates emissions and air quality impacts of a significant shift from internal combustion engines to electric vehicles and equipment.

Findings

The study bases its analysis on projections that the electric grid will rely significantly more on renewable energy and non-emitting power generation. It corroborates earlier findings that a decarbonizing grid accommodating a fleet of electric vehicles would reduce emissions relative to scenarios in which transportation, industrial and other fleets continue to rely primarily on petroleum fuels. With the widespread adoption of plug-in electric vehicles (PEVs), greenhouse gas emissions would be reduced, even when compared with efficient conventional vehicles. Electrifying vehicles and non-road equipment will lead to better air quality.

- The study estimates that, by 2050, the electricity sector could reduce annual greenhouse gas (GHG) emissions by 1700 million metric tons relative to 2015 levels.
- The analysis concludes that combining a cleaner grid with the widespread electrification of light-duty vehicles, medium-duty vehicles and non-road equipment could reduce greenhouse gas emissions by 540 million metric tons annually in 2050—equivalent to removing 100 million passenger cars from the road.
- The U.S. market share for electric vehicles projected by the analysis in 2050 would consume 13% of grid-supplied electricity.

Report Overview

The report examines the potential impact on greenhouse gas emissions and air quality of the widespread adoption of electricity in transportation energy use. It is based on a projection that by 2050 electricity replaces traditional fuels for approximately half of light- and medium-duty transportation and a significant portion of non-road equipment. This study builds on the 2007 Environmental Assessment of Plug-in Hybrid Electric Vehicles by EPRI and NRDC, which showed that plug-in hybrid electric vehicles could contribute to significant reductions in national greenhouse gas emissions, while also leading to improved air quality. As with the earlier assessment, this study consists of two separate, but related, analyses: greenhouse gas emissions from 2015-2050, and air quality impacts in 2030.

Volume 1: Background, Methodology and Best Practices

Background information includes recent emissions trends, a literature review, and a discussion of best practices for modeling large-scale changes in electricity sector load. Among the trends cited are those showing that U.S. grid emissions per kilowatt-hour are already declining. From 2003 to 2013, CO_2 emissions intensity decreased by 15%, SO_2 emissions intensity decreased by 70%, and NO_X emissions intensity decreased by 50%. Greenhouse gas emissions reductions are occurring in every U.S. region, although regional emissions rates vary widely.

Volume 2: Greenhouse Gas Emissions

Volume 2 describes modeling and results for greenhouse gas emissions. It examines the potential for electrification to reduce transportation greenhouse gas emissions, accounting for the emissions of petroleum fuels and electric power as transportation fuels. The analysis considers the potential for clean generation sources to achieve deep reductions in overall electric sector emissions.

The analysis assumes that electric transportation technologies are widely adopted. For example, the electric vehicle market share grows from approximately 1% today, to a substantial share of total sales, such that by 2050 electricity is powering 53% of personal vehicle miles traveled. As transportation is electrified, a comprehensive grid model uses the incremental load growth to estimate power sector emissions. The analysis compares resulting grid emissions with emissions from conventional petroleum fuels, using a full-fuel-cycle method that accounts for the production, delivery and use of fuels in the transportation and electricity sectors. It estimates emissions for two generation scenarios, the Base Greenhouse Gas Scenario and the Lower Greenhouse Gas Scenario.

Without electrification, the results point to a 24% reduction in GHG emissions relative to 2015 levels, based on current policies that require greater efficiency for new vehicles, along with additional, assumed improvements. The importance of electrifying transportation is emphasized by this analysis, which finds that GHG emissions can be reduced 52% in the "Base" scenario, and reduced 60% in the "Lower" scenario.

Volume 3: Air Quality

Volume 3 evaluates air quality impacts of electric transportation by simulating air quality in 2030 with and without electrification. The electrification case assumes that the overall fraction of vehicle miles traveled by the U.S. vehicle fleet using electricity stored in batteries is 17% for light-duty vehicles and 8% for medium-duty vehicles. For non-road equipment, the fraction in 2030 varies for electrified equipment types depending upon their characteristic applications and uses. Emissions from transportation and power sectors were calculated and subsequent effects on air quality were modeled in the continental United States, using a comprehensive three-dimensional atmospheric model.

Considering the electric power sector and transportation sectors together, net emissions of pollutants leading to atmospheric ozone and fine particulate matter ($PM_{2.5}$) decrease in the electrification scenario. Modeling simulations indicate that even considering recent Tier 3 vehicle emission standards, electrifying on-road vehicles can result in modest, yet widespread reductions in ozone and $PM_{2.5}$ levels throughout the United States. Electrifying non-road equipment provides significant air quality benefits, in some cases greater than those of on-road electrification, particularly in urban areas. The electrification scenario also showed reductions in the deposition of acids and nutrients that can damage ecosystems.

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Executive Summary

The electrification of transportation vehicles and equipment has tremendous potential to reduce greenhouse gas (GHG) emissions in the transportation sector. Vehicles powered by electric motors are much more efficient than those that rely solely on petroleum-fueled internal-combustion engines. When calculating the GHG emissions associated with a plug-in electric vehicle (PEV), including the emissions resulting from the production and delivery of electricity for the vehicle, we find that PEVs pollute less than today's conventional petroleum-fueled vehicles in the United States. And in the future, PEVs will continue to be cleaner. The result will be lower GHG emissions as electrification expands in the transportation sector.

Volume 2 of the *Environmental Assessment* describes the modeling and results for greenhouse gas emissions from the widespread adoption of electric vehicles and non-road equipment. We assume that electric-transportation technologies available today will be broadly adopted in the market. For example, our model predicts that by 2050, 53% of U.S. personal-vehicle miles traveled will be powered by grid electricity.

We recognize that only certain portions of the transportation sector can be transitioned from petroleum fuel to grid electricity. Vehicles that we assume can be electrified include light-duty personal vehicles and heavy-duty commercial vehicles with limited driving requirements. Our "electrifiable transportation" also includes industrial non-road equipment such as forklifts and lawn and garden equipment. The portions of the traditional transportation sector that we exclude from electrification are heavy long-haul trucks, rail, aviation, and marine vessels.

As the transportation fleet transitions toward electricity, the incremental load for PEV charging is imposed on a comprehensive grid model to estimate the changes attributable to increasing electrification. The resulting grid emissions are compared with emissions from the use of conventional fuels. We use a "full-fuel-cycle" emissions analysis, which includes both emissions created during the upstream production and delivery of fuel sources for electricity and petroleum and the emissions resulting from the combustion of these fuels.

Electricity-Sector Modeling Results

The overall modeling approach used in this analysis is described in Volume 1. This large-scale marginal approach involved modeling the evolution of the electricity and transportation sectors 1) without transportation electrification and 2) with transportation electrification, in order to allow analysis of incremental emissions in both sectors. This modeling approach applies the incremental load resulting from vehicle use to the electricity system at a realistic rate, while insuring that existing regulations—including renewable portfolio standards and regulations on emissions of criteria pollutants—are met. (The focus of this volume is on greenhouse gas emissions. However, regulations on emissions of criteria pollutants are also important to model, because they can restrict the use of existing capacity.) The large-scale marginal approach allows additional load to be met with a combination of the redispatch of existing generation resources and expansion in generation capacity.

The electricity sector was modeled using EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. Emissions were estimated for two future grid scenarios from 2015 to 2050: a Base Greenhouse Gas Scenario and a Lower Greenhouse Gas Scenario. Both scenarios project grid emissions as decreasing over time, in part because of existing and expected regulations and of plausible economic conditions. As implied by its name, the Lower GHG Scenario achieves deeper grid emissions reductions as a result of increased low- and zero-emitting generation sources.

The incremental transportation load is applied to these future grids, reaching an additional 5% in 2030 and 13% in 2050 relative to the non-electrification load. As shown in Figure 1, this modeling found that the additional generation required to satisfy the incremental transportation load comes primarily from combined-cycle natural gas, with additional contributions from wind and solar. In the 2040–2050 time period, coal with carbon capture and storage (CCS) is also a major contributor.

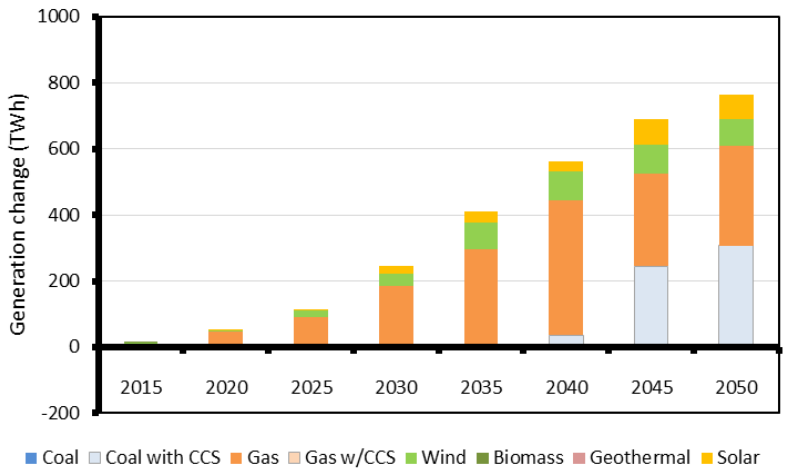

Figure 1
Energy-generation changes in the Base GHG Scenario resulting from transportation electrification

Overall Modeling Results

Table 1 summarizes the reductions in total emissions from 2015 to 2050 for transportation without electrification and for transportation with electrification. In both electrification scenarios, the electric-vehicle adoption is the same. Emissions associated with the generation and delivery of electricity to power PEVs is assigned to the transportation sector.

Table 1
Summarized reductions from 2015 to 2050
(Negative reductions indicate an increase in emissions over this time period.)

	Transportation Without Electrification	Base GHG Scenario	Lower GHG Scenario
Electricity		45%	77%
Transportation	24%	52%	60%
Personal Vehicles	32%	57%	64%
Commercial Vehicles	23%	53%	60%
Non-road Equipment	-84%	-19%	0%

Figure 2 shows the combined emissions for the modeled electricity and transportation sectors. We include the Base GHG Scenario without any transportation electrification, which shows the effects of a grid that is evolving toward cleaner generation and a transportation fleet that has improving fuel economy. When the transportation sector is electrified in the Base GHG Scenario, 2050 emissions are

reduced by 48% from 2015 levels. In the Lower GHG Scenario, total emissions are reduced by 50% from the Non-Electrification Base GHG Case and by 70% from 2015 levels.

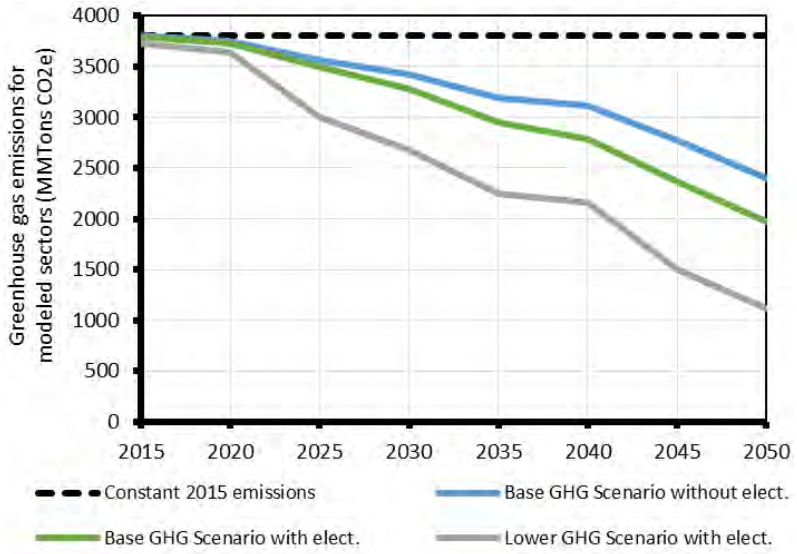

Figure 2
Greenhouse gas emissions for the modeled electricity and transportation sectors

Applying the national-level grid scenarios to an average personal vehicle also demonstrates the GHG-reduction potential of electrification. Figure 3 compares a conventional gasoline-powered passenger car (CV) with a comparable PEV, both today and in 2050. For ease of comparison, emissions are presented in grams CO_2-equivalent per mile (gCO_2e/mi), averaged over the lifetime of the vehicle. Compared with a petroleum-powered vehicle, only the PEV can get cleaner as it runs over its lifetime—because it is being powered by a grid that is continuously evolving toward cleaner sources.

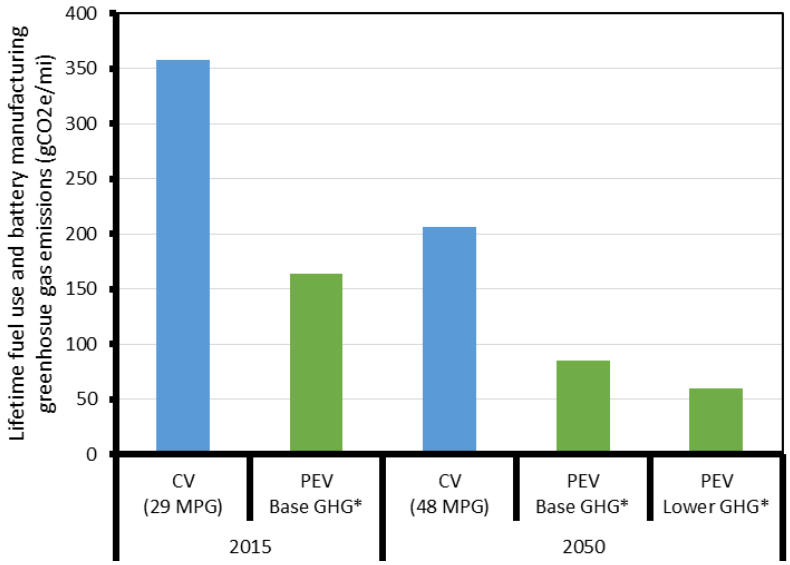

Figure 3
Relative vehicle emissions for the passenger car class for 2015 and 2050

* PEV emissions include battery-manufacturing emissions and full-fuel-cycle emissions for electricity and gasoline, averaged over a 150,000-mile vehicle lifetime. The utility factor for the PEV is 87%.

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Section 1: Introduction

This volume presents analyses of the effects of transportation electrification on greenhouse gas (GHG) emissions. Increased concentrations of GHG emissions in the atmosphere are the primary contributor to increased earth surface temperatures and climate change. To avoid the worst consequences of climate change, fueled by more than a 2°C increase in temperature, the International Panel on Climate Change finds that developed economies like that of the United States need to reduce GHG emissions to 80% below 2005 levels by 2050.[1] Such large emissions reductions require a dramatic shift to low-carbon technologies in the electricity generation and transportation sectors, because these two sectors are responsible for approximately 60% of today's emissions.[2]

Transportation electrification is an essential strategy for achieving deep GHG-emission reductions in the transportation sector. Many studies have found that switching from petroleum to a near-zero transportation-fuel source is ultimately necessary to cut transportation emissions by 80%, and they have identified the direct use of electricity as a replacement fuel as a critical strategy.[3] Because electric vehicles are more efficient at converting input energy into motion than their combustion-engine counterparts,[4] electrifying vehicles can reduce GHG emissions even with today's grid scenario (as described in Volume 1).

When the supplied electricity comes from very low and non-emitting sources (as required to reduce electric-sector emissions), the GHG footprint of electric vehicles is substantially reduced. In this volume, we quantify potential GHG

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[1] Gupta, S., D. A. Tirpak, N. Burger, J. Gupta, N. Höhne, A. I. Boncheva, G. M. Kanoan, C. Kolstad, J. A. Kruger, A. Michaelowa, S. Murase, J. Pershing, T. Saijo, A. Sari, 2007: *Policies, Instruments and Co-operative Arrangements. In Climate Change 2007: Mitigation*. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer, eds.), Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[2] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013* (April 2015).

[3] See Williams et al., "The Technology Path to Deep Greenhouse Gas Emission Cuts by 2050: The Pivotal Role of Electricity," *Science*, January 2012; Yang, C., McCollum D., McCarthy, R., and Leighty, W., "Meeting an 80% reduction in greenhouse gas emissions from transportation by 2050: a case study in California," *Transportation Research Part D: Transport and Environment 14*, 2009; International Energy Agency, *World Energy Outlook 2012*, OECD/IEA, 2012; Melaina, M., and Webster, K., "Role of fuel carbon intensity in achieving 2050 greenhouse gas reductions within the light-duty vehicle sector," *Environmental Science and Technology 45 (9),* 2011; "Pathways to Deep Decarbonization, Interim 2014 Report," Sustainable Development Solutions Network and Institute for Sustainable Development and International Relations, July 2014.

[4] DOE, EPA, http://www.fueleconomy.gov/feg/evtech.shtml

emissions reductions in the transportation sector resulting from electrifying vehicles under two grid scenarios. In the first scenario—called the Base Greenhouse Gas Scenario—power-generation profiles evolve gradually according to currently expected policies and utility planning, resulting in a grid carbon intensity (GHG emissions per unit of energy delivered) that declines by about 60% between 2015 and 2050. The second scenario—called the Lower Greenhouse Gas Scenario—has a more rapid transition to clean energy in the power sector, in which carbon intensity decreases by over 80% over the same time period. Under this more climate-protective scenario, total electric-sector emissions are reduced by 77% between 2015 and 2050.[5]

A High-Level View of Carbon Dioxide Emissions

To illustrate an alternative emissions future, Figure 1-1 shows the carbon dioxide (CO_2) emissions by sector for the Annual Energy Outlook (AEO) 2014 Reference Case (EIA, 2014).[6,7] The AEO generally projects that although emissions intensity decreases in each sector, activity levels—such as miles traveled, increased production, and increased population—increase quickly enough that these gains in efficiency do not result in lower overall emissions. In this emissions projection, total emissions increase slightly despite small decreases in the residential and non-electrifiable transportation categories. This emission trajectory falls well short of meeting an 80% GHG-reduction target by 2050.

This study discusses an alternative scenario for electricity and transportation emissions that results in significantly greater emissions reductions.

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[5] Emissions due to the production of electricity to power electric vehicles is ascribed to the transportation sector in this report.

[6] Most of the discussion in this report includes CO_2, the principal greenhouse gas, and weighted contributions from CH_4, N_2O, and SF_6. The Annual Energy Outlook does not report emissions for secondary greenhouse gases for these categories, so the illustrations in this section include CO_2 only.

[7] The presentation of results in this study uses different boundaries: Sector-based emissions are presented for all GHGs, including upstream emissions; non-road emissions are allocated differently. (See Section 3 for more discussion.) Additionally, the emissions reductions from existing policy are projected to have a higher impact in this study than in the AEO. In this discussion, the AEO transportation-sector emissions are divided into "electrifiable" and "non-electrifiable" groups by transportation mode. However, the boundaries within each mode are slightly different. So the trends are illustrative, and absolute values should not be compared with the results below.

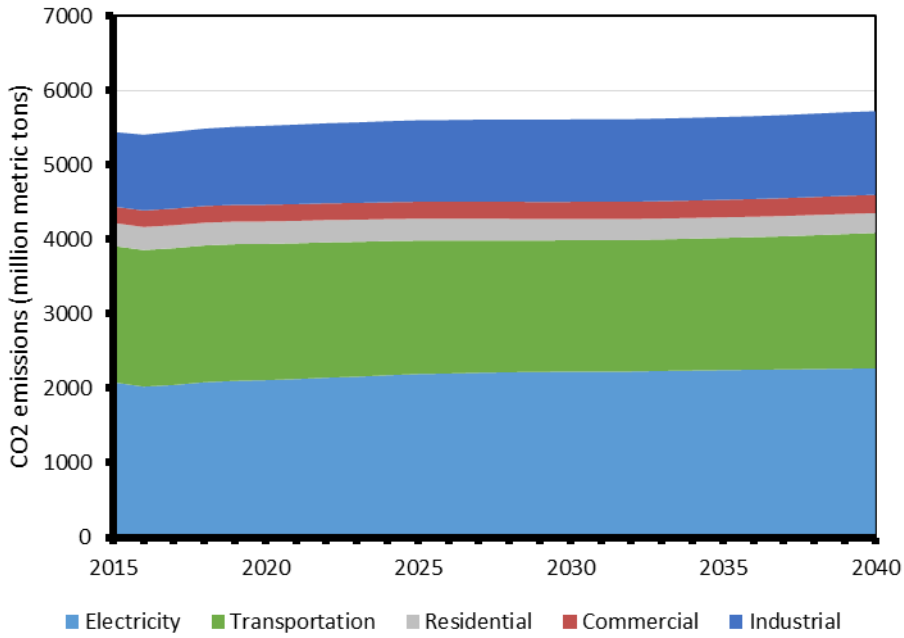

Figure 1-1
CO_2 emissions by sector in the AEO2014 Reference Case

Study Scope

The analysis in this study discusses a view of future GHG emissions that results in significantly lower emissions than those shown in Figure 1-1. It focuses on opportunities for emissions reduction through 1) improvements in the electricity grid and 2) the application of electrification to the transportation sector. The scenarios for both sectors are aggressive, but they are limited to technologies and policies that are either currently observed or that are probable given current trends. This study scope excludes developments such as breakthroughs in battery costs, which would immediately transform transportation markets or lead to policies that would mandate reductions in vehicle or generation emissions (beyond policies already in place). Based on these limits, electrification is only applied to transportation-energy use that can be shifted from petroleum-derived fuels to electricity using available technologies (and without a major redesign of transportation infrastructure). This scenario excludes shipping, air travel, rail, and long-distance freight movement. Figure 1-2 shows the emissions for electrifiable transportation (solid) versus non-electrifiable transportation (crosshatched).[8]

Figure 1-3 compares emissions for the two sectors considered within the study scope to total emissions—with electrifiable transportation separated from transportation that is considered non-electrifiable. These two sectors are highlighted as solid areas, and they account for approximately 60% of the total emissions. The remaining 40% of emissions are from sources that are out of

[8] In this figure, the AEO "Freight" category is divided into electrifiable and non-electrifiable categories to match the description of electrifiable transportation in Section 2 and the results discussed. Given the differences in vehicle categorization between the AEO and this study, the division of freight is approximate and is intended for illustration only.

scope—including emissions in the residential, commercial, and industrial sectors and the portion of transportation-sector emissions that are not considered to be electrifiable within the scope of this study.[9]

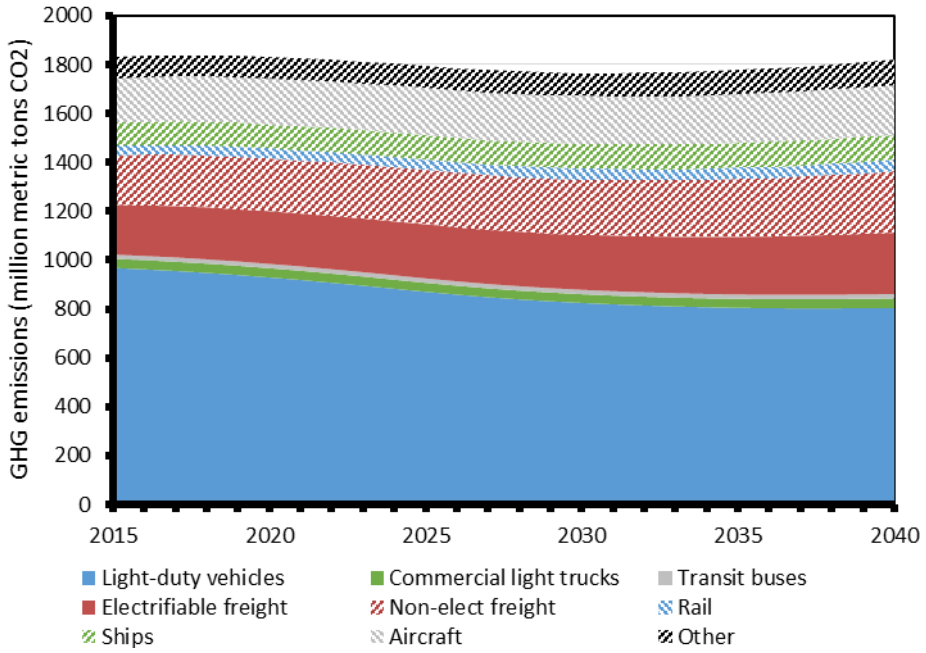

Figure 1-2
Included transportation-sector CO_2 emissions from the AEO2014 Reference Case

[9] This study considers the potential electrification of non-road transportation equipment, which is categorized in the commercial and industrial sectors in AEO2014. The covered emissions are a small fraction of the total emissions within these sectors.

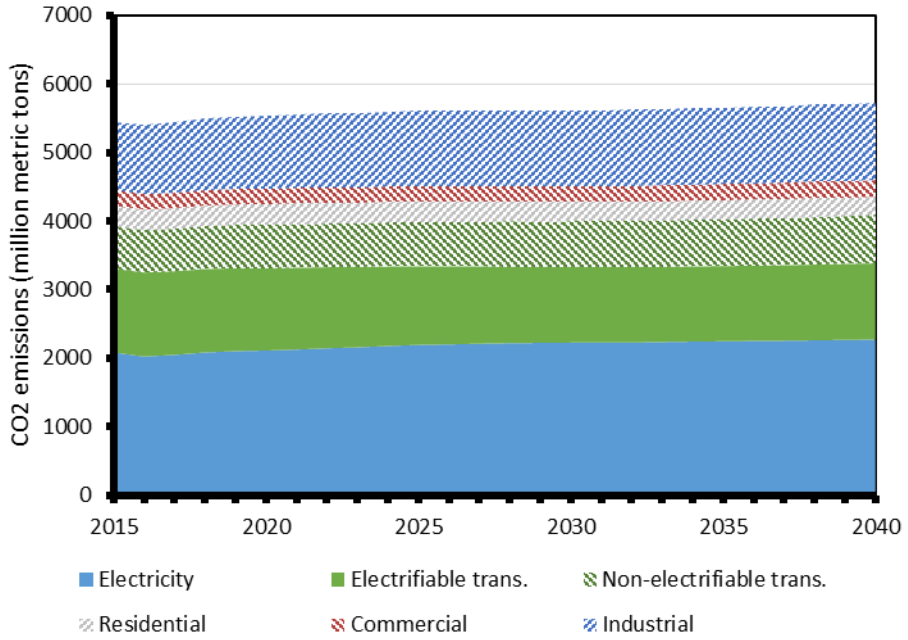

Figure 1-3
Included CO_2 emissions relative to the AEO2014 Reference Case

Models Used in This Analysis

No single analysis tool was available to evaluate the GHG emissions of on-road transportation according to the requirements of this study, so a composite model was created based on a number of well-established transportation models. GHG emissions of the on-road vehicle fleet were built up from the bottom by calculating how the individual markets for different types of vehicles evolve over time; applying energy-consumption assumptions at the per-mile-traveled level; and then applying GHG emissions factors for the fuels that were consumed. The models used in this analysis include the following:

- Market Analysis Tool. This EPRI software projects the evolution of PEVs within the on-road vehicle market over time and calculates the fuel and electricity consumption of the total combined population of vehicles.[10]
- PEV Utility Factor. This EPRI tool evaluates the portion of a PEV's annual operation that can be fueled by electricity versus other fuels, using a national database of daily driving patterns and the characteristics of the various PEV types.[11]
- The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET), a detailed model created by the Argonne

[10] This tool is described in Section 2 and in Appendix A.

[11] The results of this model are discussed in EPRI (2011)

National Laboratory to assess the full life-cycle impacts of transportation fuels and light-duty on-road vehicles.[12]

- U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN), an EPRI tool that combines a detailed electricity-sector model with a high-level model of the U.S. economy.[13]

Figure 1-4 illustrates how the various models and tools are linked together.

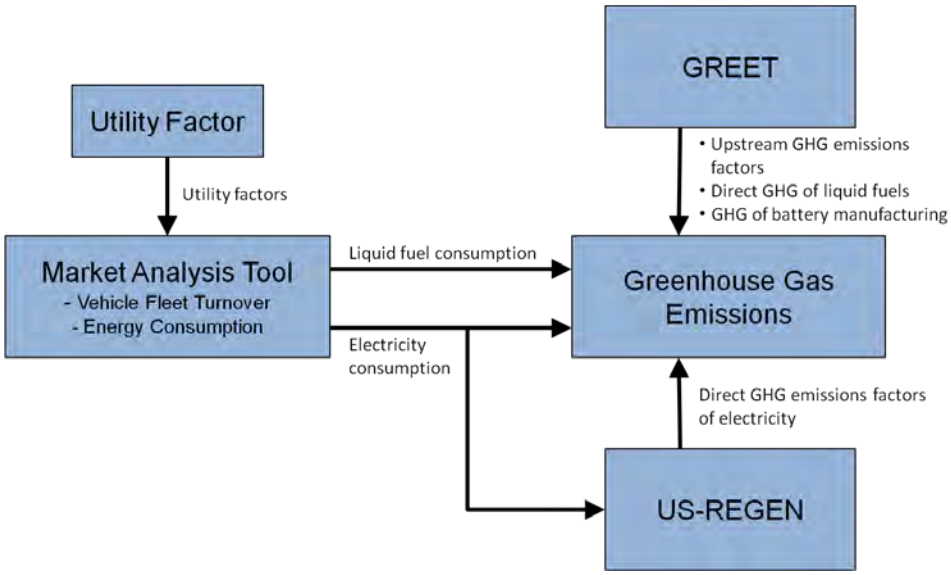

Figure 1-4
On-road transportation models

The basic procedure for the modeling in this analysis is:

- The transportation sector and electricity sector are modeled for a baseline case with no electrification.
- Transportation electrification is applied to the transportation sector, resulting in reduced petroleum usage and increased electricity usage.
- The incremental electricity usage is applied to the electricity-sector model, which projects the additional capacity and generation required to meet the additional load. This projection is done for two different grid scenarios.
- The total greenhouse gas emissions are summed in both cases for both scenarios, including upstream emissions required for producing fuel for transportation and electricity uses and incremental manufacturing emissions for batteries for PEVs.

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[12] The 2014 Version of GREET 1 was used for upstream fuel emissions, and the 2014 Version of GREET 2 was used for battery-manufacturing emissions. For more information, see: https://greet.es.anl.gov/

[13] US-REGEN is described in EPRI (2014)

This modeling procedure shows the long-term effects of a significant shift toward electric transportation with 1) a grid that improves at the expected rate and 2) a grid that improves at a faster-than-expected rate.[14]

The models used in this analysis are described in more detail in the sections below, followed by discussions of the results for each sector and the overall multisector results.

Report Outline

The following sections describe the assumptions and models used to model greenhouse gas emissions from these two sectors:

- Section 2 and Section 3 describe the assumptions and modeling for on-road and non-road transportation.
- Section 4 describes the electricity-sector model used to project future electricity-sector emissions and the policy and technology assumptions for the two electricity-system scenarios used in this analysis.
- Section 5 discusses the factors used to account for upstream emissions for transportation fuels and fuels used for electricity generation.
- Section 6 presents the electricity-sector emissions results, including the incremental effects of additional load for transportation electrification.
- Section 7 presents the transportation-sector emission results.
- Section 8 presents the combined multisector emissions.
- Section 9 presents sensitivity results for alternative assumptions.

[14] This methodology results in an estimate of the *large-scale marginal* effects of transportation electrification, as defined in Volume 1.

Section 2: On-road Transportation Sector Model and Scenarios

This section describes the models, data sources, and assumptions used to model the GHG emissions of on-road vehicles over the study period of 2015 through 2050. The characterization of on-road vehicles includes all categories of vehicles that operate on highways and roads—from motorcycles and passenger cars up to long-haul heavy-duty combination trucks. Two main cases were considered: a base case with no vehicle electrification, and an electrification case.

The base case uses a combination of assumptions from the U.S. Environmental Protection Agency's (EPA's) Motor Vehicle Emission Simulator (MOVES)[15] model, the Energy Information Administration's (EIA's) Annual Energy Outlook (AEO), and studies by the National Academy of Sciences. The electrification case applies an optimistic, yet plausible, scenario for PEV adoption.

An existing EPRI PEV market-adoption tool was used to evaluate the impact of the introduction and market growth of new PEVs on the existing vehicle fleet. This tool calculates the market shares of different vehicle types within the overall on-road vehicle fleet over time. The tool also determines the amounts of liquid petroleum fuel and electricity consumed by each vehicle type and category, which are used to calculate the GHG impact.

This section

- Describes the model used to estimate baseline transportation-sector emissions for on-road vehicles and the effects of transportation electrification.
- Describes the datasets used to create the modeling assumptions.

Appendix A presents additional detail for some assumptions, and Section 9 presents an alternative transportation scenario where conventional vehicle fuel economy increases at a faster rate than in these primary scenarios.

[15] U.S. Environmental Protection Agency, Motor Vehicle Emission Simulator model, version 2010a. For more information, see: http://www.epa.gov/otaq/models/moves/moves-archive.htm

Market-Adoption Model

This analysis uses an existing EPRI market-adoption model to estimate transportation-sector emissions with and without transportation electrification. The model uses data and assumptions for vehicle miles traveled (VMT), vehicle survivability and retirement, new-vehicle market shares, and vehicle performance to simulate the evolution of the vehicle fleet over time. Including these factors recognizes that in order to transform the fuels market, PEVs must first become part of the overall vehicle fleet via sales of new vehicles. Additionally, improvements from PEVs are measured against a rapidly improving fleet of new conventional vehicles, so PEVs and the grid must continually improve if they are to provide emissions reductions in the future.

The vehicle-turnover model used in this study is based on the vehicle population and VMT growth calculations described in the EPA's MOVES 2009 Software Design and Reference Manual (EPA, 2009a). The model tracks vehicle cohorts over time so that vehicles "age" as the model progresses. This cohort tracking accounts for changes in vehicle usage and performance as the market evolves.

The fleet model uses external assumptions for the sales rates of different powertrain types, along with other necessary parameters to calculate the population and VMT of the various types and categories of vehicles. The parameters required by the turnover model include the initial vehicle population by vehicle category, vehicle age, and type; vehicle population growth over time; changes in VMT over time, both at the fleet level and per-vehicle level; vehicle survival rates (that is, the inverse of what portion of the existing fleet is retired each year); and other data. Appendix A provides additional details.

Vehicle Energy Consumption

The market-analysis tool generates a variety of results—including the vehicle population, VMT, amount of electrified VMT, liquid-fuel consumption (gasoline and diesel), and electricity consumption. Each of these results is available by vehicle type, category, and age. For this analysis, the most important output was fleet fuel usage. The fuel- and electricity-consumption results were used in conjunction with the GHG intensities (emissions per unit of fuel or electricity) to calculate the GHG emissions of the overall vehicle fleet. In addition, the amount of electricity consumed was used to create the incremental load for the modeling of the overall electricity grid, as discussed in Section 4.

Assumptions and Data Used in this Analysis

The rest of this section describes the assumptions and data used in the market-analysis tool to perform the simulations for this report.

Vehicle Categorization

Different kinds of on-road vehicles have very different operating characteristics and energy consumption. For example, the energy-use characteristics of an all-

electric passenger car are quite different from a light-duty pickup truck with a gasoline engine that uses no grid electricity and refuels at a typical gas station. Furthermore, the energy consumption of these vehicles has no correlation to that of a plug-in hybrid heavy-duty worksite truck or a diesel-fueled long-haul combination truck.

To adequately estimate the GHG impact of the broad spectrum of on-road vehicles, different kinds of vehicles are split into categories and modeled separately. This study uses the following terminology to classify vehicles:

- Vehicle "type" refers to broad categories of vehicle-powertrain technology, such as conventional vehicles with gasoline or diesel engines, hybrid electric vehicles, battery-electric vehicles, and plug-in hybrid electric vehicles.
- Vehicle "class" distinguishes vehicles according to broad groupings of typical daily operating patterns, such as passenger cars, school buses, and long-haul trucks.
- Vehicle "age" separates vehicles by model year in order to differentiate the energy-consumption performance of new vehicles from that of older vehicles.

Vehicle Types

The electrification case includes a number of different electric-vehicle types. A battery electric vehicle (BEV) relies solely on an on-board battery for stored energy; once the battery has been depleted, the vehicle cannot drive further until the battery is recharged. A plug-in hybrid electric vehicle (PHEV) utilizes both grid electricity and another fuel (typically gasoline or diesel) as energy sources; a PHEV can continue operating with a depleted battery, but in general it is beneficial to recharge the battery as frequently as possible.[16] BEVs and PHEVs taken together are designated as plug-in electric vehicles (PEVs), because both PEV types draw electricity from the grid.

This study further classified the PEVs into sub-types according to all-electric range (AER), which is the distance an individual vehicle can travel on electricity after a full recharge. Some PHEV designs use a "blended" mode, in which the vehicle consumes battery energy while also using the engine to power the vehicle at certain times. For these vehicle types, the AER is the equivalent distance that a nonblended PHEV could drive solely on electric power. This report identifies the AER of PHEVs and BEVs by appending the AER in miles to the "PHEV" or "BEV" descriptor. For example, a PHEV20 is a plug-in hybrid with 20 miles of electric range. The study team chose to consider PHEV20, PHEV40, and PHEV60 configurations and a single BEV type that has a range of 100 miles or greater (BEV100+). They developed a projection of the distribution of various PEV subtypes, which is illustrated in Figure 2-1. Through 2013 the ratios are based on actual data. Over the later course of the study timeframe, the allocation shifts toward PEVs with greater AER—based on the assumption that as battery costs decrease, the PEV market will shift toward vehicles with greater electric

[16] The definition of PHEV used in this study includes so-called extended-range electric vehicles.

capability. By 2030, the allocation of new PEV sales is 25% PHEV40, 25% PHEV60, and 50% BEV100+; in 2050, the distribution is 25% PHEV60 and 75% BEV100+. This allocation applies equally to all vehicle classes that are considered to have PEV sales, as described below in Table 2-1.

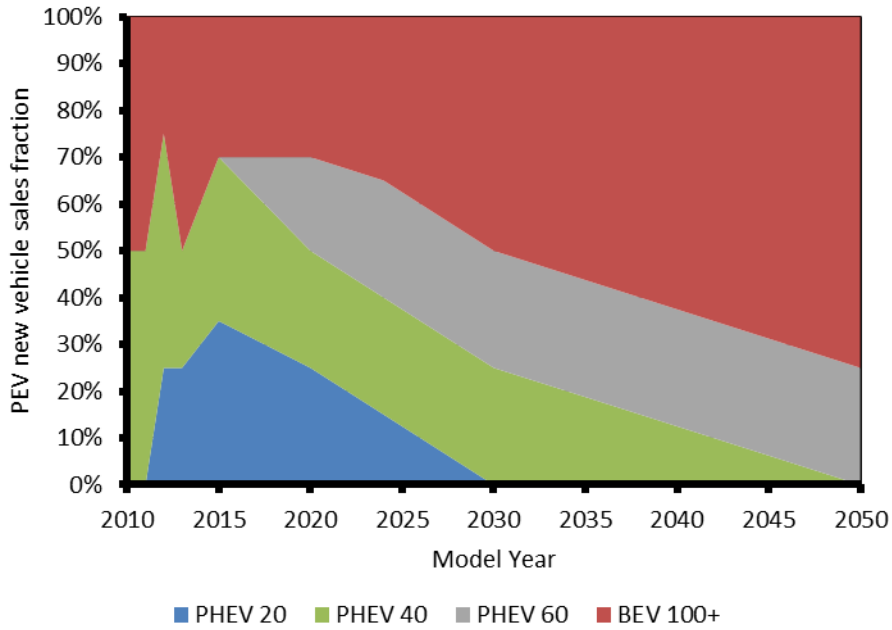

Figure 2-1
Distribution of new PEV sales among various PEV types

Hybrid electric vehicles (HEVs) are sometimes designated as "electrified" vehicles, but HEVs do not recharge from the grid. Instead, they rely on regenerative braking and generation provided by the engine to charge the battery. Because of increasing pressure to improve fuel economy, automakers are including increasing levels of "hybrid" technologies into conventional vehicles. So the line between HEVs and conventional vehicles is getting blurry, and it is likely to become more so over time. The objective of this study is to investigate the impact of grid electrification on the transportation sector, so no distinction is made between conventional vehicles and the different HEV types. However, it assumes that the composite non-PEV fleet improves through the use of varying levels of hybrid and nonhybrid technologies. The remainder of this report refers to the composite fleet of conventional and hybrid vehicles as "conventional vehicles."

Vehicle Classes

In order to categorize the various classes of on-road vehicles by their typical daily activity patterns, this study adopted the 13 categories used by the EPA MOVES software, as shown in Table 2-1. In later discussions, the 13 categories are grouped into "personal" vehicle categories, which primarily satisfy the requirements for personal transportation by drivers, and "commercial" vehicle categories, which primarily satisfy the requirements for passenger and goods movements by commercial and government entities.

Most vehicle classes that travel less than 200 miles per day are assumed to be electrified, but intercity buses, motor homes, short-haul combination trucks and long-haul combination trucks are not assumed to be electrified.[17] Although it is possible that these vehicle categories will also eventually be electrified to some degree, it is likely that the energy-intensive operational requirements and limited market size of these categories will constitute significant challenges to shifting extensive numbers of these vehicles to grid electricity.

The classifications used in MOVES, and adopted for this study, group vehicles by use rather than by the weight classes used in other classifications (such as "light-duty," "medium-duty," and "heavy-duty." As noted in Table 2-1, the "Light Commercial Truck" and "Passenger Truck" categories contain a small but significant share of non–light-duty trucks. The vehicle counts and fuel economies for these classes reflect this mixture of vehicle attributes. Appendix A provides additional detail on the makeup of these classes, and EPA (2010b) describes the MOVES classes in detail.

[17] "Combination" trucks are trucks that primarily tow trailers, and they are mostly heavy-duty "semi" trucks. For more information, see EPA (2010b). Electrification of short-range combination trucks is possible by various means, but it was considered out-of-scope for this analysis.

Table 2-1
Electrification of vehicle categories

	Vehicle Class	PEVs Allowed	Conventional Vehicles Only	Vehicle Class Description
Personal	Motorcycle	X		Motorcycle
Personal	Passenger Car	X		Passenger Car
Personal	Passenger Truck	X		Minivans, pickups, SUVs, and other 2-axle / 4-tire trucks used primarily for personal transportation This category is approximately 93% light-duty and 7% heavy-duty (on a VMT basis).
Commercial	Light Commercial Truck	X		Minivans, pickups, SUVs, and other 2-axle / 4-tire trucks used primarily for commercial applications This category is approximately 83% light-duty and 17% heavy-duty (on a VMT basis).
Commercial	Intercity Bus		X	Buses that are not transit buses or school buses (e.g., those used primarily by commercial carriers for city-to-city transport)
Commercial	Transit Bus	X		Buses used for public transit
Commercial	School Bus	X		School and church buses
Commercial	Refuse Truck	X		Garbage and recycling trucks
Commercial	Single-unit Short-haul Truck	X		Single-unit trucks with majority of operation within 200 miles of home base
Commercial	Single-unit Long-haul Truck		X	Single-unit trucks with majority of operation outside of 200 miles of home base
P	Motor Home*		X	Motor Home
Comm.	Combination Short-haul Truck		X	Combination trucks with majority of operation within 200 miles of home base
Comm.	Combination Long-haul Truck		X	Combination trucks with majority of operation outside of 200 miles of home base

* Motor homes span a wide range of sizes. By size and fuel consumption, they are generally in the middle-range of commercial vehicles, but by usage they are considered personal vehicles in the analysis in Section 7. They represent a small fraction of transportation emissions, so the effect of either categorization is negligible.

It is assumed that the vehicle types with internal-combustion engines (all types except BEVs) are fueled by either gasoline or diesel fuel. Although the analysis considers that the use of biofuels will partially displace gasoline and diesel, other alternative fuels such as natural gas or hydrogen are not considered for on-road vehicles. Section 5 discusses the fuel options used in this study in more detail.

New-Vehicle Market Shares

As mentioned previously, this study uses two cases of PEV market shares: a base case and an electrification case.

Base Case

The *base case* assumes that there are no PEV sales in any of the vehicle categories in the future. This trajectory suggests the presence of fewer PEVs than are likely given current trends, but it allows the study to focus on the marginal effects of transportation electrification. As described above, this study considers HEVs together with conventional vehicles as a composite fleet that meets regulated fuel economy and emissions standards, but with an unspecified mix of technologies. The base case implicitly assumes an increasing degree of hybridization for personal vehicles and a limited hybrid-vehicle penetration among commercial vehicles.

Electrification Case

The *electrification case* assumes an aggressive, but plausible, trajectory for on-road transportation electrification, which is derived from the high-electrification scenario in the National Academy of Sciences *Transitions to Alternative Fuels* study (National Research Council, 2013). This projection assumes that the PEV market grows at a rate of about 1% per year from 2015 through 2020, then rapidly accelerates to exceed 50% of sales just beyond the year 2030, and levels off in 2045 at 67% of new-vehicle sales. These total PEV sales projections are distributed into PEV subtypes, using the shares in Figure 2-1 to obtain the overall sales mix shown in Figure 2-2.

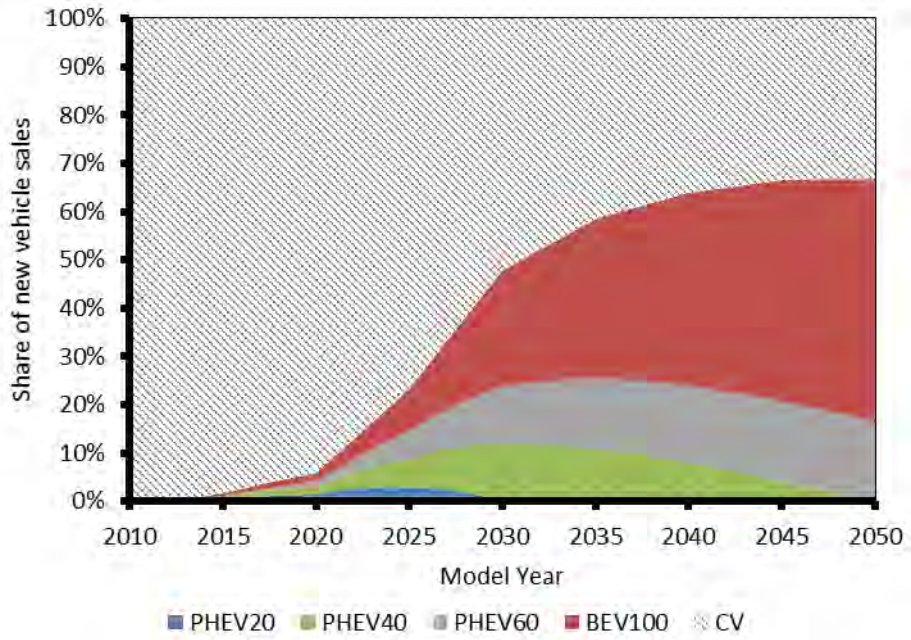

Figure 2-2
Distribution of new-vehicle sales among various types, for vehicle categories that include PEV sales

The market-share projection illustrated in Figure 2-2 was used to model the expansion of the PEV fleet within each of the vehicle classes listed as having PEV sales in Table 2-1. The other vehicle classes are assumed to have zero PEV sales. As a result, when considering the entire on-road vehicle fleet (including all categories listed in Table 2-1), the overall fraction of new-vehicle sales that are PEVs is less than the levels indicated in Figure 2-2.

It should be noted that the PEV projection was sourced from a study that focused on light-duty vehicles only. However, the study team decided to apply the same market share to all electrifiable vehicle classes; current trends indicate that shorter-range vehicles in larger-size classes such as delivery vans and buses will be electrifiable, and that payback times will become relatively short as battery costs decrease. The study does not consider very-heavy-duty vehicles, such as combination trucks, to be electrifiable.

Vehicle-Population and Miles-Traveled Data

Section 2 of Volume 3 describes how the VMT data was developed for the Air Quality Analysis component of this study. The VMT data used for the GHG analysis is similar, but it has been updated with more-recent data. As in the air quality analysis, the base source of VMT data is EPA's National Mobile Inventory Model (NMIM)[18] database, which provides the VMT by vehicle class for calendar year 2008 (version NCD20101201). The vehicle-population data

[18] U.S. Environmental Protection Agency, Assessment and Standards Division, Office of Transportation and Air Quality. http://www.epa.gov/otaq/nmim.htm

was developed for 2008 using EPA MOVES (2010a version)[19] and NMIM data. For the GHG analysis, the same vehicle-turnover model was used, but the VMT forecast was set to the VMT trajectory from the AEO (EIA, 2014).[20] The new-vehicle population was adjusted so that the VMT per vehicle assumptions remained the same as those used in the air quality analysis.

The vehicle-turnover model requires additional data on vehicle activity and vehicle lifetimes to project the evolution of the fleet. This data was derived from the MOVES model (2010a version); Appendix A provides additional detail.

Vehicle-Energy Economy of Individual Vehicles

This section describes the energy consumption of the different vehicle types.

Vehicle Fuel Economy

The primary assumptions behind the fuel-economy trajectory in this study are driven by the need to comply with the aggressive standards in recent regulations. In 2012, the United States enacted a major change to light-duty vehicle fuel-economy standards that requires significant increases in fuel efficiency by 2025, starting with 2017 vehicle models.[21] These changes expanded on a previous requirement for 2016 model-year vehicles, announced in 2009.[22] Although the updated 2025 standards were widely described in the media as requiring a dramatic increase in average fuel economy to 54.5 miles per gallon (mpg) by 2025, the regulation (known as the "National Program") is actually a dual standard: equivalent to 163 grams per mile of CO_2 and a fuel-economy standard of 49.6 to 49.7 mpg (unadjusted).[23] Additionally, the program provides compliance flexibility as well as credits to incentivize advanced technologies—including plug-in vehicles.[24] Furthermore, the fuel-economy and CO_2 requirements apply to EPA certification test-cycle results, whereas actual on-road fuel economy is expected to be about 20% lower.[25] As a result (based on Department of Energy data in AEO2013), new light-duty passenger cars are required to achieve an average fuel economy of about 42 mpg by 2025, and new

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[19] U.S. Environmental Protection Agency, Motor Vehicle Emission Simulator model, Version 2010a. http://www.epa.gov/otaq/models/moves/moves-archive.htm

[20] Because AEO datasets contain 3 years of history and approximately 25 years of future projection, the VMT and vehicle-population projections were calibrated to AEO2011 for 2008 through 2010 and then calibrated to AEO2014 from 2011 through 2040. The projections were then extended to 2050 by using 5-year rolling averages of the growth rates.

[21] The U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) jointly developed the new rules. http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE_2017-25_Fact_Sheet.pdf

[22] http://www.whitehouse.gov/the_press_office/President-Obama-Announces-National-Fuel-Efficiency-Policy/ (May 19, 2009)

[23] http://www.epa.gov/otaq/climate/regs-light-duty.htm#new1

[24] http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/CAFE_2017-25_Fact_Sheet.pdf

[25] U.S. Energy Information Administration Annual Energy Outlook, 2013, page 80.

light trucks are required to meet an average fuel economy of 32 mpg.[26] The fuel-economy and electricity-consumption values below are "adjusted" to reflect on-road performance; therefore, they achieve these lower targets.

This study assumes that the baseline light-duty vehicle fuel economy of new vehicles follows the projections in AEO2013 through 2025, and then continues to improve at 0.5% per year beyond 2025.[27] AEO2013 does include estimates for fuel economy from 2025 to 2040, but it does not consider policies to drive additional fuel-economy improvements beyond the current 2025 standards. The assumed improvement after 2025 reflects the potential for further fuel-use reductions resulting from future policy and technical developments. (Assuming that conventional vehicles continue to improve ensures that the potential benefits of electrification are not overestimated.) The available data in AEO2013 are estimates of fuel economy on the EPA test cycles, which represent higher fuel efficiency than is typically seen in actual vehicle operation. Therefore, the figures have been adjusted downward, using the "degradation factors" available in AEO2013, in order to arrive at on-road fuel-economy estimates.[28]

Figure 2-3 illustrates the projections of new-vehicle fuel economy for the two light-duty categories with the greatest annual fuel consumption: gasoline-fueled passenger cars and passenger trucks.[29] The "Light Commercial Truck" category is also responsible for a significant portion of the fuel use for light-duty vehicles; its fuel economy is roughly 2% lower on an mpg basis (that is, greater fuel consumption per mile) than the "Passenger Truck" category. The "CV" fuel economy is a composite of both hybrid and conventional vehicles (CVs). PHEVs are assumed to have the fuel economy of a "full" HEV when traveling beyond their all-electric range; these projections are denoted as "PHEV" in Figure 2-3.

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[26] U.S. Energy Information Administration Annual Energy Outlook, 2013, Tables 41 and 43.

[27] The study team evaluated the vehicle fuel–economy data presented by the more-recent AEO2014 and found inconsistencies in the projections of energy consumption (per mile) for electric vehicles. Although the fuel-economy estimates in AEO2014 appear reasonable for conventional and hybrid vehicles, in light of the discrepancies in the electric-vehicle data, the team opted to use AEO2013 data as the basis for the vehicle energy economy assumptions for this project.

[28] U.S. Energy Information Administration Annual Energy Outlook, 2013, Table 43.

[29] These categories are a weighted average of all cars and light-duty trucks, as defined in the MOVES database, and as modified based on AEO2013 fuel-economy trajectories.

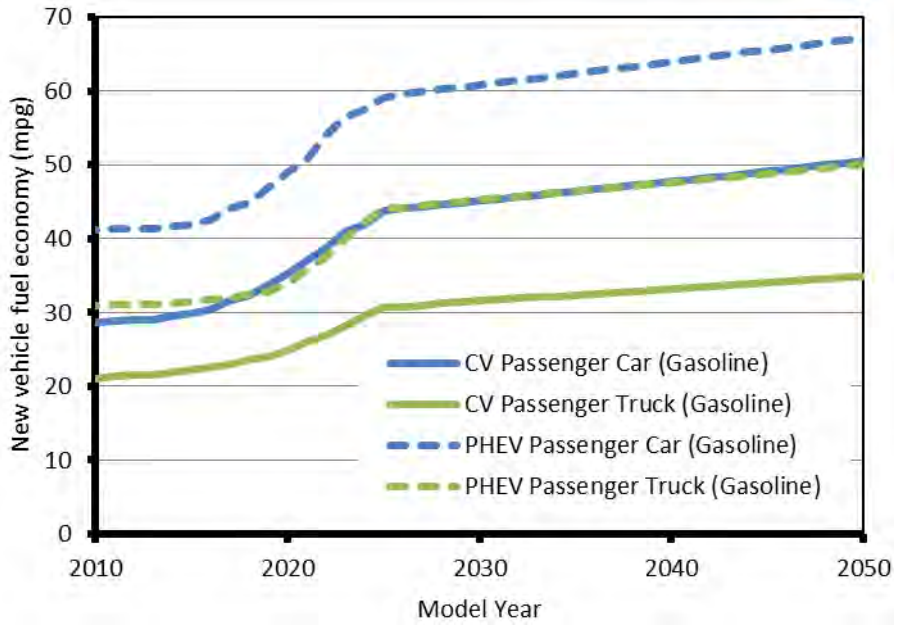

Figure 2-3
Fuel economy of selected light-duty vehicle categories (new vehicles)

The data presented in this section are the assumed fuel economies of new vehicles. The average fuel economy of *all* vehicles in operation within a particular vehicle category is lower (less efficient), because older, existing vehicles with lower fuel economy are already on the road. The fuel economy of the existing vehicle fleet in 2010 was calibrated in the vehicle-turnover model to align with data available in AEO2013.

In addition to the regulatory changes to the fuel economy of light-duty vehicles, in 2011 the United States announced first-ever fuel-efficiency standards for heavy-duty[30] vehicles (HDVs), to be phased in over model years 2014 through 2018. These regulations require improvements ranging from 10 to 20%.[31] This study's fuel-economy assumptions for heavy-duty conventional vehicles follow the default values in the EPA MOVES model for model-year 2010. Beyond 2010, the fuel economies track the rates of improvement projected by AEO2013 for heavy-duty vehicles through 2019, and they are then assumed to improve at 0.5% per year beyond 2019. This assumption for continued improvement is similar to that used for light-duty vehicles: there is potential for further policy advancements and technical improvements beyond the phase-in period of the regulations that are currently in place. Indeed, the EPA recently proposed "Phase 2" HDV fuel-economy regulations for model-years 2018 through 2027.[32] For

[30] The term "heavy-duty" as used in this discussion of fuel economy includes vehicles sometimes referred to as "medium-duty" vehicles. The delineation of "medium-duty" vehicles is inconsistent among different databases and standards. So in this document, all non–light-duty vehicles are referred to as "heavy-duty."

[31] http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/Factsheet.08092011.pdf

[32] http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/hd-ghg-fr-notice.pdf

PHEVs operating beyond their all-electric range, the study team adjusted the fuel-economy numbers for the corresponding nonhybrid CV in the same vehicle class, based on the available estimates for hybrid-vehicle fuel-consumption improvement reported by the National Academy of Sciences (NAS).[33] As shown on Table 2-1, both of the "mixed" (partially HDV) categories—"Passenger Truck" and "Light Commercial Truck"—are assumed to be electrified. Among the remaining heavy-duty categories, only certain bus and short-haul truck categories are electrified. Although the "mixed" classes are composed mostly of light-duty vehicles, the heavy-duty segments of these classes are responsible for a significant portion of the fuel consumption of the combined set of electrified HDV categories. In fact, the heavy-duty segment of gasoline-fueled passenger trucks is the second-highest fuel consumer among the electrified HDVs. The "Single-unit Short-haul Truck" category has the greatest annual fuel use among the electrified heavy-duty categories. Figure 2-4 shows the new-vehicle fuel economy for two selected HDV classes. As with the light-duty vehicle categories, the fuel economy for the overall HDV fleet (including both existing and new vehicles) in 2010 was calibrated to AEO2013 data.

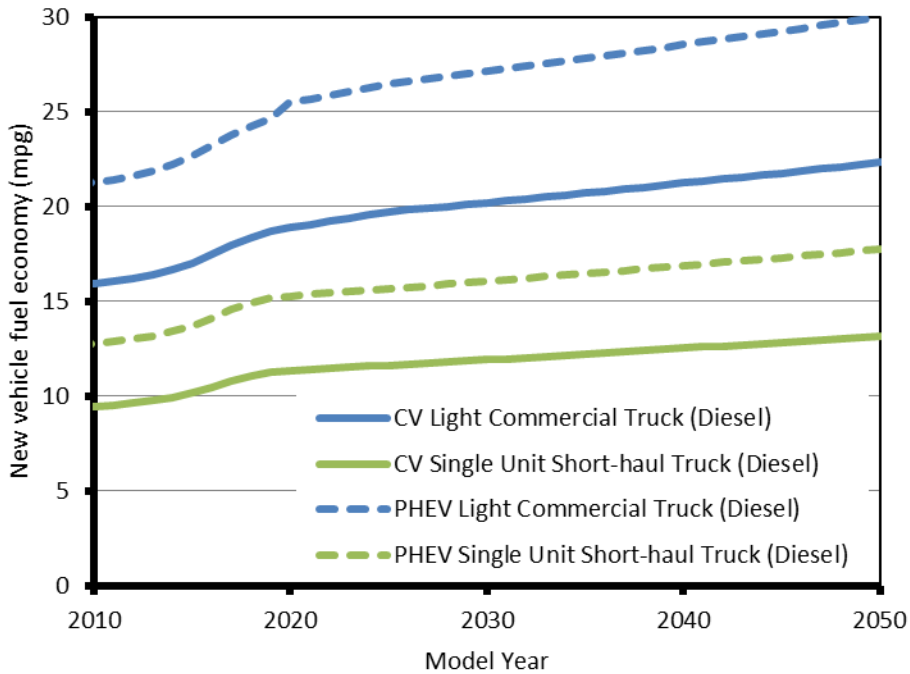

Figure 2-4
Fuel economy of selected heavy-duty vehicle categories (new vehicles)

[33] The study team made assumptions to map the vehicle categories presented by the NAS report to the vehicle classes used in this project. Source: National Academies Press, *Technologies and Approaches to Reducing the Fuel Consumption of Medium- and Heavy-Duty Vehicles,* 2010. Downloaded from www.nap.edu , Table 6-18.

Vehicle Electricity Consumption in Electric Mode

The revised fuel-economy regulations are also expected to indirectly lead to improvements in the energy efficiency of plug-in vehicles, because components and techniques developed for improving conventional-vehicle fuel economy can also be applied to PEVs. For example, efforts to reduce the vehicle structural mass of conventional vehicles will probably benefit PEVs, and improvements in CV engine efficiency may be applied to PHEVs. For some manufacturers, the plug-in vehicle products are showcases of advanced fuel-efficient technologies, and some of these developments may be applicable to CVs. In such cases, the PEV may lead technology to the CV.

Figure 2-5 shows the modeled electricity consumption per mile of selected light-duty PEVs during the time frame of this study. The PEV energy-economy assumptions are based on the projections in AEO2013 for various light-duty electric-vehicle types through 2025, and they assume continued improvement at 0.5% per year beyond 2025. The various PEV types (BEVs and PHEVs of different electric ranges) are assumed to have the same electricity consumption per mile, consistent with current performance data indicating that electricity consumption is similar for different types of PEVs in the same class.[34]

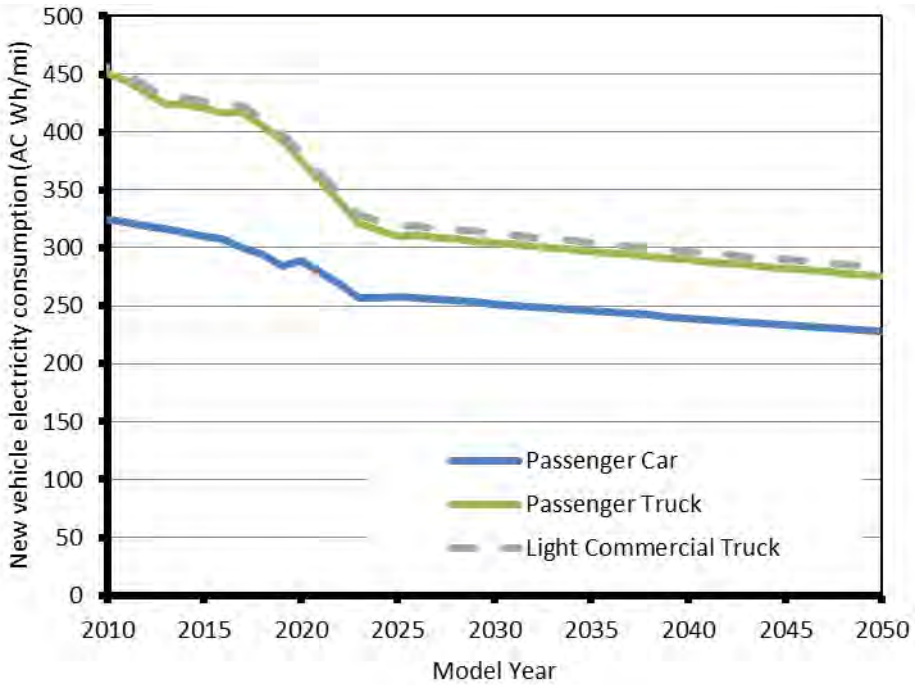

Figure 2-5
Electric-energy economy of selected light-duty vehicle categories (new vehicles)

[34] It is assumed that diesel-fueled PHEVs have slightly higher electricity consumption than gasoline PHEVs when operating as electric vehicles, because a diesel-hybrid powertrain would generally weigh more than a gasoline powertrain. However, these vehicles are rare in light-duty classes.

The trajectories of PEV energy consumption are slightly different from the efficiency improvements for conventional vehicles because of the technology-specific assumptions in AEO2013. Conventional passenger cars improve at a faster rate than other vehicles, presumably because of opportunities for powertrain improvements that do not apply to other classes or types. These differences result in a reduction of the efficiency advantage of PEVs from approximately 3.5:1 to approximately 3:1, as shown in Figure 2-6. For the time period after 2025, when fixed improvement rates are assumed by this study, the ratios between conventional vehicles and PEVs remain constant.

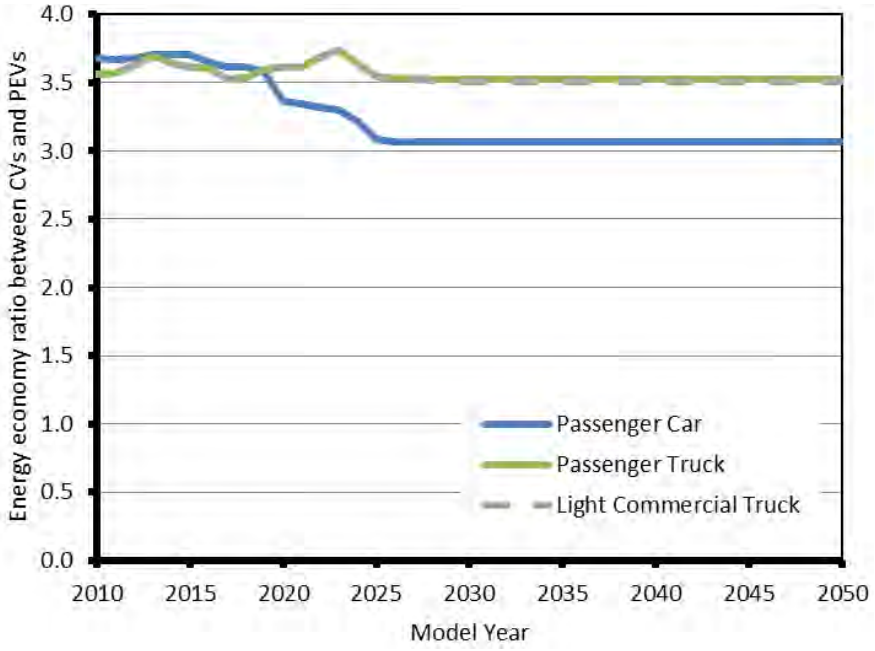

Figure 2-6
Ratio of conventional-vehicle fuel consumption and PEV electricity consumption

There are very limited data available on the electricity consumption of heavy-duty PEVs. The study team developed an approach in which the HEV fuel economy (mpg) for the corresponding vehicle category is multiplied by an appropriate energy-efficiency ratio, and the resulting "MPGe" (miles per gallon equivalent) quantities were then converted to electricity consumption in watt-hours per mile. Figure 2-7 shows the resulting projections for two of the primary heavy-duty PEV categories. As stated earlier, the "Passenger Truck" and "Light Commercial Truck" categories contribute significantly to the energy use of the heavy-duty vehicles; Figure 2-5 shows the electricity consumption for the gasoline-fueled PHEV variants of these categories.[35]

[35] By comparing Figure 2-5 and Figure 2-7, it can be seen that the per-mile electricity consumption of diesel "Light Commercial Truck" PHEVs is assumed to be significantly higher than that of gasoline-fueled "Light Commercial Truck" PHEVs. The modeling assumption is that diesel engines would probably be selected for heavy-duty applications, and these heavier-duty vehicles would have greater vehicle mass than their light-duty counterparts.

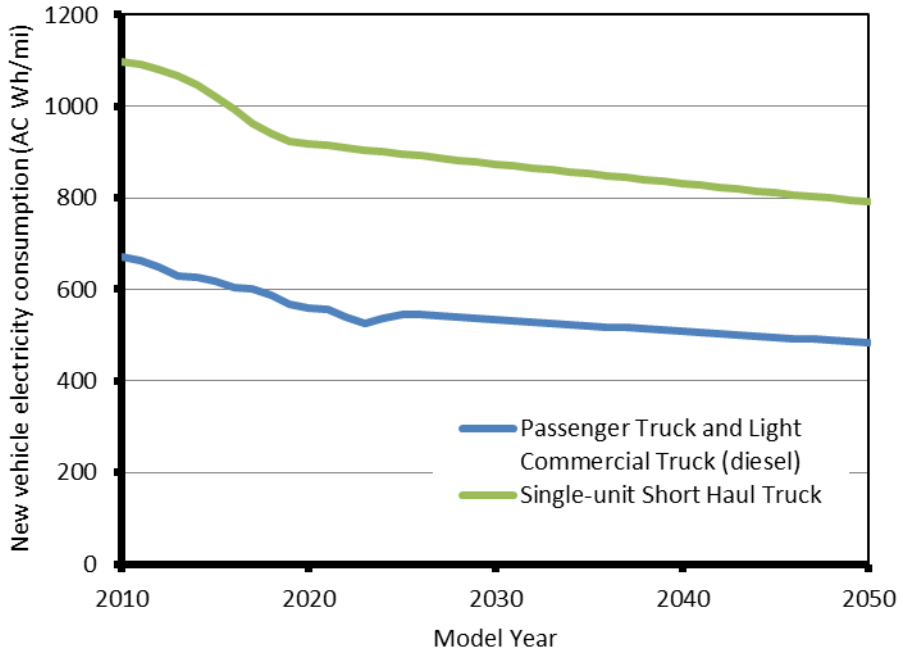

Figure 2-7
Electric-energy economy of selected heavy-duty vehicle categories

All PEV electricity-consumption data presented in this section represent electric-energy use at the point of the wall outlet or end-use circuit, which is designated as "AC" (alternating current) on the electricity-consumption charts. Vehicle battery-charging losses are included in these estimates. Additional electrical transmission and distribution losses are considered separately in the calculations for grid-electricity use and GHG emissions.

PEV Utility Factor

PHEVs are able to drive beyond their all-electric range by incorporating an on-board range-extending engine. This means that over the vehicle's lifetime, some portion of the vehicle's miles will be fueled by electricity from the utility grid, and the remaining miles will be provided by another fuel. In the majority of present-day PHEVs, the fuel used by the range-extender is gasoline, but this study assumes that PHEV technologies will be deployed in heavier-duty classes using diesel engines in the future.

A PEV's u*tility factor* is the fraction of operation that uses electricity as the energy source. Utility factors vary based on the usage pattern of each individual vehicle and are affected by how often the vehicle battery is recharged. In general, PHEVs that are driven very long distances between recharging events will have a low utility factor, whereas PHEVs that perform many short trips without fully depleting the battery will have a very high utility factor. Because BEVs typically have longer "refueling" (charging) times than many other vehicle types, a BEV driver may choose to use a substitute vehicle over other travel options when faced with a very long trip. In most cases, the alternate vehicle would be a gasoline- or

diesel-fueled vehicle, so the concept of utility factor may be extended to BEVs as well.

The Society of Automotive Engineers J2841 standard,[36] an update of the former J1711 standard, sets guidelines for calculating the utility factor of PHEVs. The J2841 standard assumes that PHEVs only have one opportunity to recharge per day (in the evening). EPRI has developed a more sophisticated calculation of utility factor that accounts for details such as diverse driving patterns and daytime charging.[37] Table 2-2 shows the utility-factor values used in this study. These values were determined by the EPRI utility-factor model, using assumptions that charging is available at the driver's home and work locations (but not at other stops such as shopping), and that the charge rate is 6.6 kW. The evaluation of BEV utility factors is more complex than that for PHEVs,[38] and a consensus has not been reached on how to calculate the utility factor for BEVs. This study makes a simplifying assumption: that the BEV utility factor is equal to that of a PHEV100. This utility factor would be relatively high for a BEV with 100 miles of range, but the modeled BEV is assumed to represent a variety of BEVs with a range of 100 miles or greater. High-mileage BEV trips are assumed to be driven using a substitute conventional vehicle. Because of the efficiency differences between conventional vehicles and the PHEV powertrain in range-extended mode, the BEV100+ uses approximately the same amount of gasoline as the PHEV60. Therefore, the analysis is relatively insensitive to the split between these two powertrain types.

Table 2-2
PEV utility factor

Vehicle Type	PHEV20	PHEV40	PHEV60	BEV100+
Utility Factor	56%	73%	80%	87%

Electricity Consumption for On-Road Vehicles

Figure 2-8 shows the electricity consumption for all on-road vehicles based on the assumed VMT, efficiency, and utility factors described above. In 2050, the total electricity consumption for on-road vehicles is 536 TWh, which is an increase of about 9% compared to baseline electricity consumption in 2050.

[36] Society of Automotive Engineers. "Utility Factor Definitions for Plug-In Hybrid Electric Vehicles Using 2001 U.S. DOT National Household Travel Survey Data," Hybrid Committee, J2841; March 2009.

[37] Transportation Statistics Analysis for Electric Transportation. EPRI, Palo Alto, CA: 2011. 1021848.

[38] Transportation Statistics Analysis for Electric Transportation. EPRI, Palo Alto, CA: 2011. 1021848, p. 3-1.

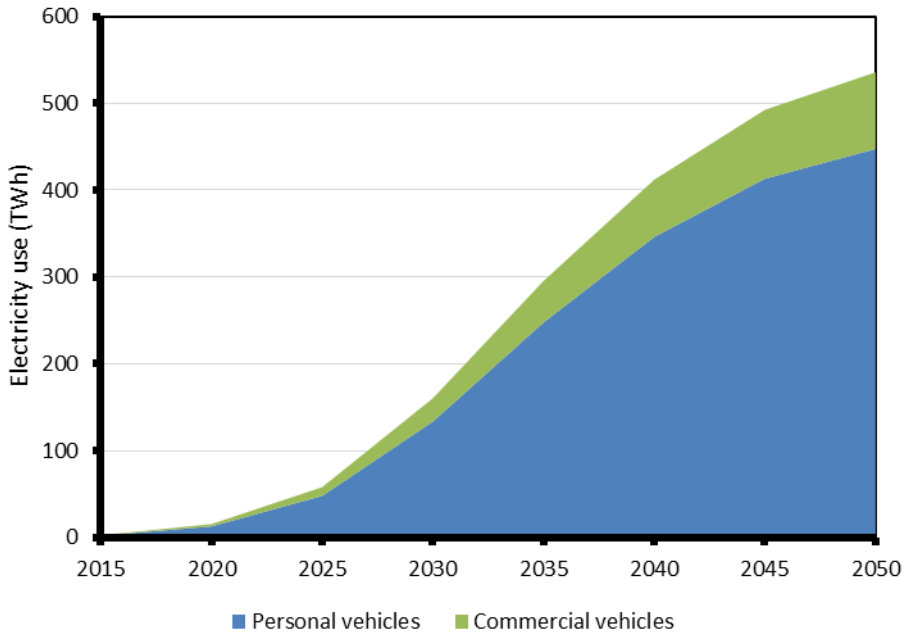

Figure 2-8
Electricity consumption for on-road vehicles

Section 3: Non-road Transportation-Sector Technology Penetration, Emissions Displacement, and Electric Load

In addition to the more typical on-road transportation applications, the study scope included non-road transportation applications. Non-road equipment that can be electrified contributes only about 5% percent of the total emissions from electrifiable transportation sources, so non-road transportation electrification makes a relatively small contribution to reducing total GHG emissions. However, electrification of these sources provides a significant reduction in emissions of criteria pollutants. Because the primary effects of electrification of non-road equipment is on air quality, the discussion of non-road transportation in Section 3 of Volume 3 provides a complete discussion of the development of the non-road vehicle emissions inventory. This section includes a more limited discussion that focuses on GHG impacts. The GHG inventory was developed using the same tools as those used for the air quality analysis, but it used a much lower spatial resolution and focused only on the changes in "electrifiable" non-road equipment.

The main data source for fleet counts and activity levels is the EPA's NONROAD model (EPA, 2009b).

This section

- Describes which non-road subcategories were considered to be "electrifiable" and which were considered to be "non-electrifiable."
- Describes electrifiable and non-electrifiable non-road transportation and delineates the electrification assumptions for each non-road category.
- Describes the assumptions for market share within each electrifiable subcategory.
- Presents the total electrical load resulting from non-road transportation.

Electrifiable Non-road Transportation

Determining the degree of electrification for non-road equipment involved a two-step process: First, it was determined whether or not a given category was *electrifiable*, and then it was determined how much of each electrifiable category was actually *electrified*. This subsection discusses the determination of electrification potential, and the next subsection discusses the market share for electricity within the electrifiable categories. The GHG results described below consider only "electrifiable" non-road equipment. This distinction is necessary in order to align both the marginal effects and the absolute effects of non-road electrification with the study scope. It also helps to provide a closer match to other inventories, which generally report non-road emissions in the "commercial" or "industrial" sectors instead of in the transportation sector.[39]

Figure 3-1 shows the fraction of estimated 2015 GHG emissions from each category that is considered to be electrifiable in this analysis.[40] Electrifiable emissions account for 21% of total non-road transportation- emissions inventory in 2015—falling to 13% in 2050. This level of electrification is relatively conservative; much higher levels of electrification could be possible in many source categories. For this analysis, however, only equipment that had current electrification options, or was determined to be relatively straightforward to electrify, was included. The subsections below describe which modes within each category were electrified. (Categories not described had no electrifiable equipment.) The next section discusses how much of each "electrifiable" mode was actually electrified.

[39] To align these results with other inventories, the initial non-road transportation emissions should be subtracted from the commercial and industrial sectors of the other inventory (unless the inventory specifically includes similar non-road equipment).

[40] Note that aircraft emissions (except for auxiliary power unit operations), rail emissions (except for switchyard operations), ocean-going vessel emissions (except for in-port emissions), and almost all military transportation emissions are excluded from this inventory.

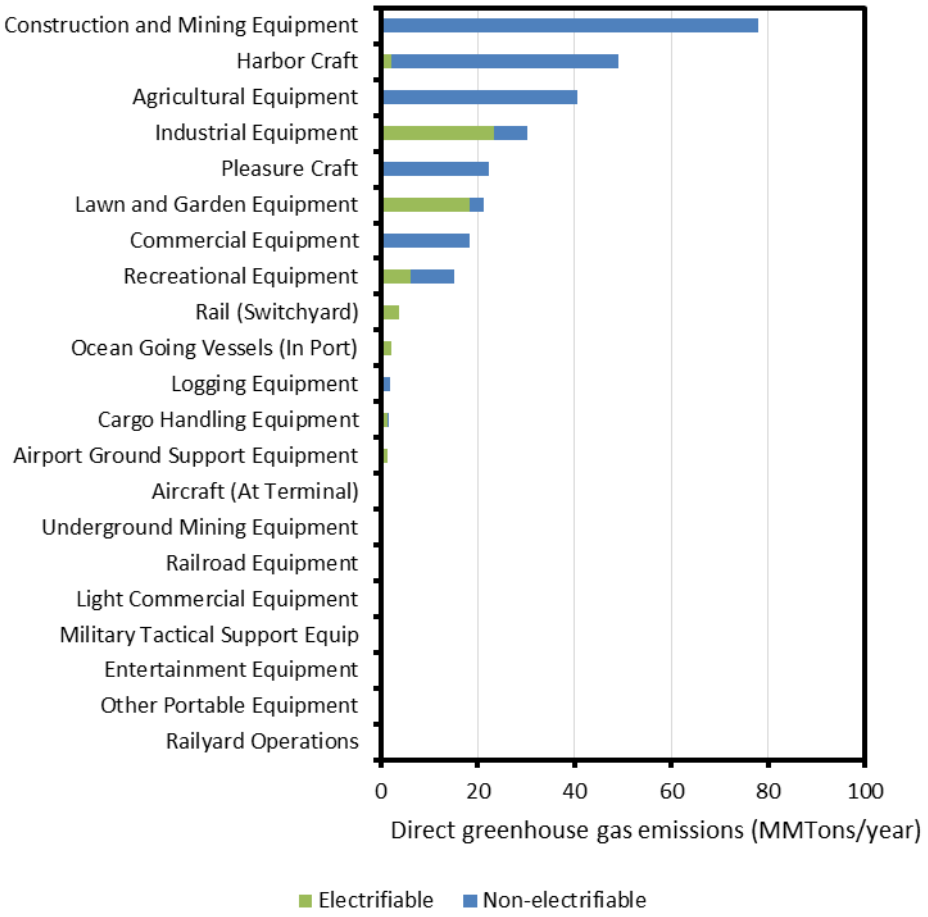

Figure 3-1
Direct greenhouse gas emissions from non-road equipment considered in this report for 2015

Aircraft (Terminal Operations), Rail (Switchyard Operations), and Ocean- Going Vessels (Port Operations)

Emissions from aircraft, rail engines, and ocean-going vessels were separated into "in-port" emissions that occur at an airport, rail switchyard, or seaport and that could be powered by an external power source, and "in-route" emissions, which include emissions that occur during transit between ports. In-route emissions were excluded from this analysis (and are not shown in Figure 3-1), but 100% of in-port emissions were considered to be electrifiable.

Aircraft Ground-Support Equipment and Cargo-Handling Equipment

Aircraft ground-support equipment and cargo-handling equipment operate within confined utilities, and most equipment has relatively low energy use or is in a limited set of locations during operation. Therefore, equipment with low weight requirements was considered to be electrifiable. Cargo-handling

equipment modes, representing 86% of 2015 GHG emissions and 100% of aircraft ground-support equipment, were considered to be electrifiable.

Harbor Craft

Harbor craft are specialized vessels used within and around seaports. A small fraction of harbor craft was considered to be electrifiable—equivalent to 4% of 2015 harbor-craft emissions.

Industrial Equipment

Within the "Industrial Equipment" category, the majority of emissions are attributable to forklifts and refrigeration units, which have a high potential for electrification. As seen in Figure 3-2, even with some remaining non-electrifiable modes, those that are electrifiable represent 77% of 2015 GHG emissions.

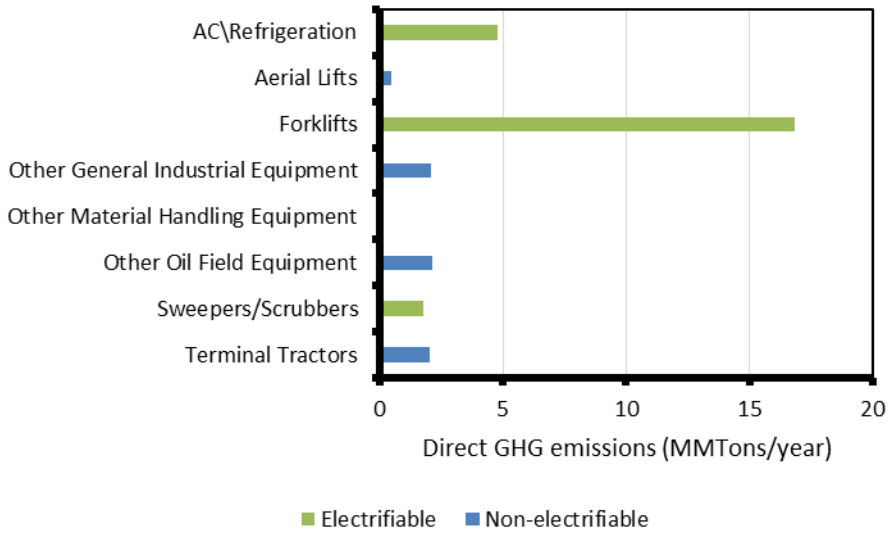

Figure 3-2
Electrifiable modes for the "Industrial Equipment" category with 2015 emissions

Lawn and Garden Equipment

"Lawn and Garden Equipment" is a relatively small source category, but it has a large number of modes that can be electrified because of the relatively low energy demand of the equipment and the proximity to electricity service. As shown in Figure 3-3, 86% of 2015 emissions come from modes that are electrifiable.

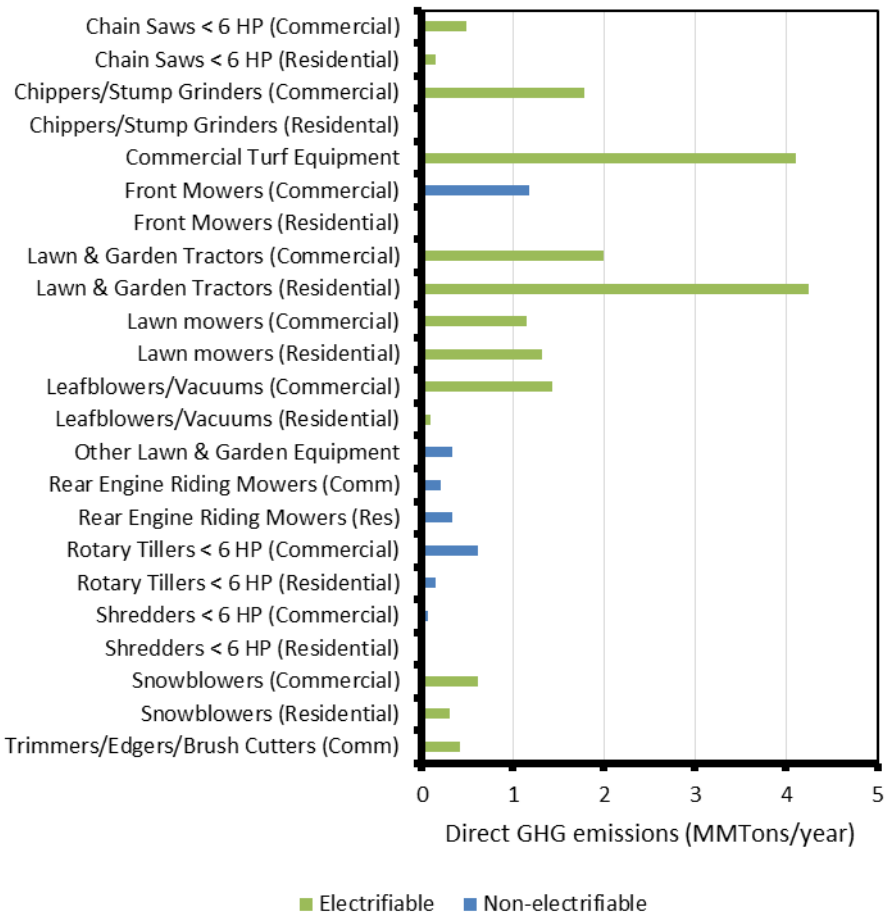

Figure 3-3
Electrifiable modes for the Lawn and Garden category with 2015 emissions

Recreational Equipment

"Recreational Equipment" with low energy requirements is considered to be electrifiable, as shown in Figure 3-4. Forty percent of 2015 GHG emissions came from electrifiable categories, because the highest-emitting category—snowmobiles—will be difficult to electrify given the energy and temperature performance of current batteries.

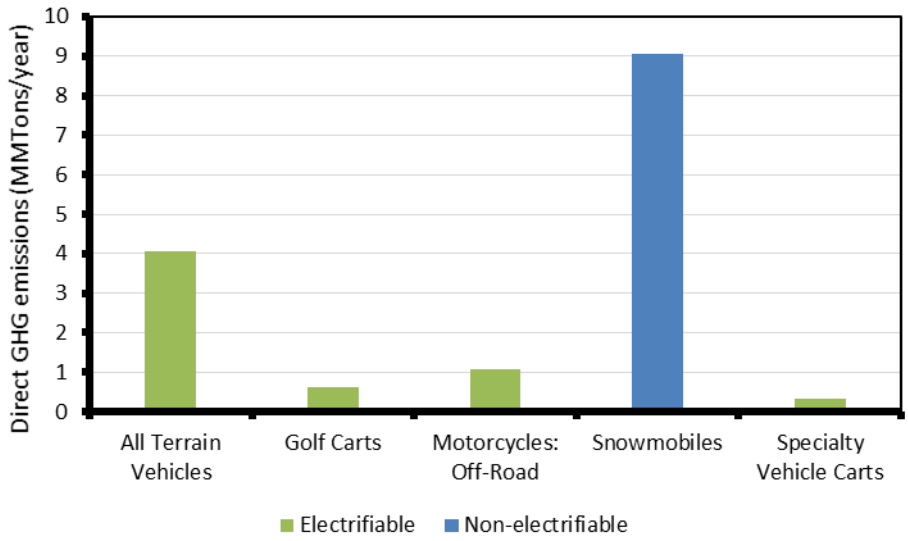

Figure 3-4
Electrifiable modes for the "Recreational Equipment" category with 2015 emissions

Electrification Potential

Within each electrifiable mode, only a fraction of the equipment was electrified. Estimates of electrification potential were developed for each electrifiable mode.

A key element of electrification potential for non-road applications is the way in which electric energy is stored for usage in electrically powered equipment once it has been transferred from the electric grid. Battery storage is the most ubiquitous and tested storage option, and it is likely to remain in widespread usage for the foreseeable future. Whereas lead-acid and other lower-energy density batteries will remain in use, it is expected that in the future advanced lithium-ion batteries or other advanced batteries will become economical for use in non-road applications. High-energy batteries will allow for increasing electrification of non-road applications that are sensitive to battery weight, such as hand-held lawn and garden equipment. This increased electrification potential is reflected in the electric-equipment market-penetration estimates presented below.

We assume that lead-acid and lower-energy lithium-ion battery technology constitute the primary electric-storage devices up to 2020. From 2020 to 2050, we assume that increases in electric-equipment market share would result from the introduction of progressively better batteries with more favorable energy storage per unit weight.

We assume that the highest electric market share for new equipment sales in 2050 would be 90%, and that this share level would only be achieved by equipment that was either already subject to widespread electrification or for which there are very few impediments to electrification. For equipment with few impediments to electrification, but with lesser current electrification, we assume that 70% of equipment sales would be electric by 2050. For equipment with

significant impediments to electrification, electric sales would be less than 70% in 2050. All-terrain vehicles (ATVs), off-road motorcycles, and switching locomotives have electrical sales fractions of less than 70%. For ATVs and off-road motorcycles, we assume that the lack of charging availability during remote use would slow adoption of electric units. For electric switching locomotives, there have been challenges in initial deployments—including fires in early hybrid models and a high sensitivity to the increased cost of electric models versus diesel-fueled models (Wong, 2009). Therefore, a lower electric penetration is assumed.

Figure 3-5 and Figure 3-6 show electric sales fractions for lawn and garden (L&G) and recreational equipment, and Figure 3-7 shows electric sales fractions for industrial equipment. ("C" denotes commercial-use equipment and "R" denotes residential-use equipment.)

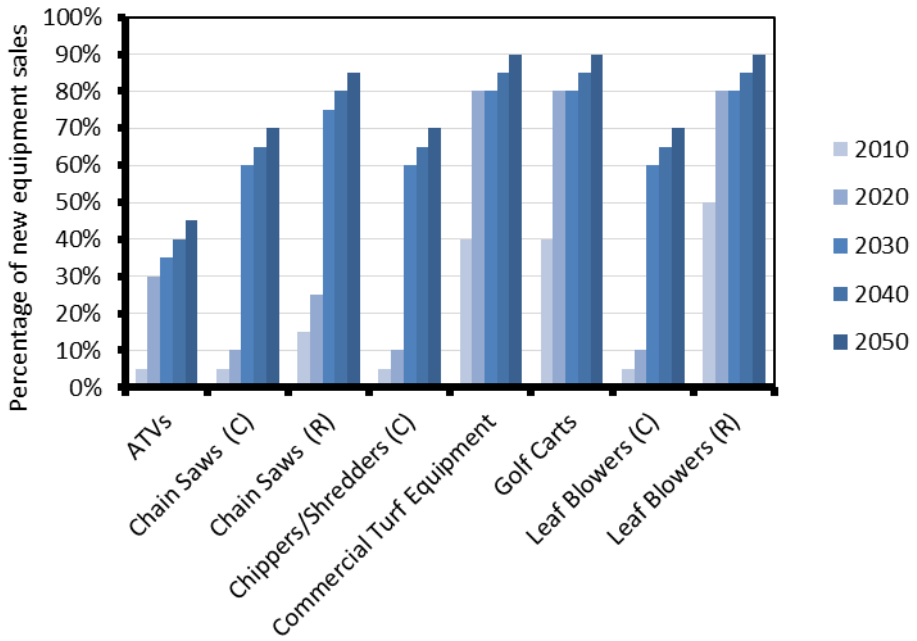

Figure 3-5
Lawn and garden (L&G) and recreational equipment; new-unit electrical sales fractions (1/2)

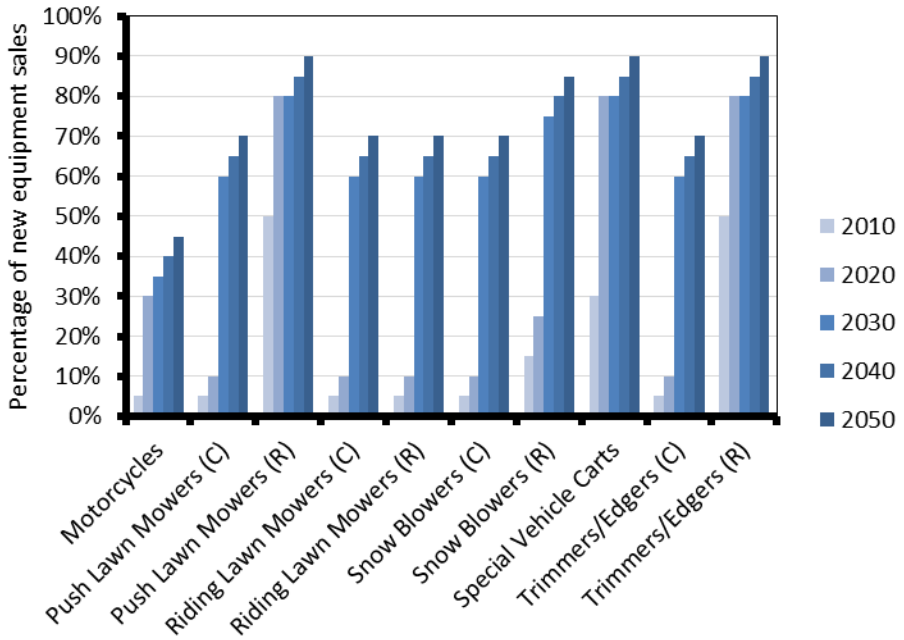

Figure 3-6
Lawn and garden (L&G) and recreational equipment; new-unit electrical sales fractions (2/2)

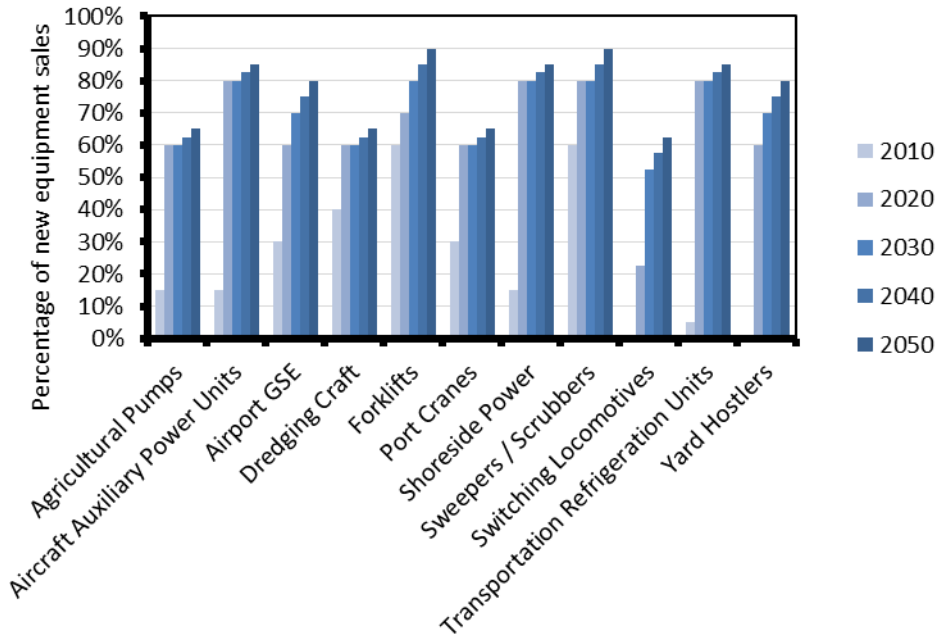

Figure 3-7
Industrial equipment; new-unit electrical sales fractions

Electrification Estimates

Estimates of fleet-wide electrification are based on retirement of older models in each year and phase-in of new equipment over time. Electric-equipment sales by year are incorporated into a fleet-turnover model to estimate fleet-wide electrification estimates.

Sample results are presented below for airport ground-support equipment (Figure 3-8) and commercial-use leaf blowers (Figure 3-9). For airport ground-support equipment, it is estimated that in 2010 the fleet-wide electric population fraction is 20%, and that in 2010, 30% of all airport ground-support equipment sold is electric-powered. The share of new airport ground-support equipment sold that is electric is estimated to increase to 60% in 2020, 70% in 2030, 75% in 2040, and 80% in 2050; the fleet-wide share of equipment that is electric is estimated to increase to 38% in 2020, 58% in 2030, 68% in 2040, and 74% in 2050. For commercial-use leaf blowers, we estimate that in 2010, the fleet-wide electric population fraction is 3%, and that in 2010, 5% of all commercial-use leaf blowers sold are electric-powered. The share of new commercial-use leaf blowers sold that are electric is estimated to increase to 10% in 2020, 60% in 2030, 65% in 2040, and 70%, in 2050; the fleet-wide share of equipment that is electric is estimated to increase to 8% in 2020, 54% in 2030, 64% in 2040, and 69% in 2050.

GHG emissions are estimated using the procedure described in Section 3 of Volume 3, which assumes that new fossil-fueled equipment reflects the newest equipment in the inventory and that electrically powered equipment has no direct emissions. Electricity use for non-road equipment is calculated using the procedure described in the next section.

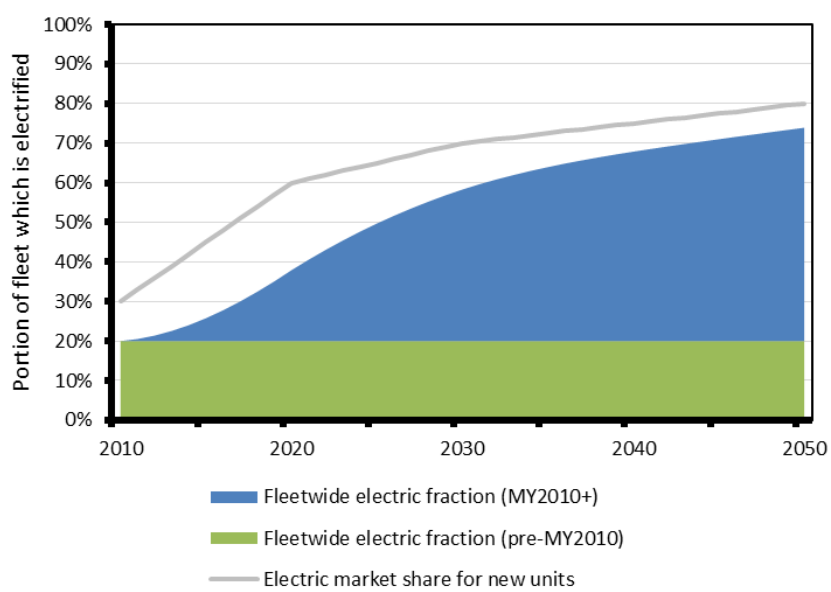

Figure 3-8
Electrification example: Airport ground-support equipment

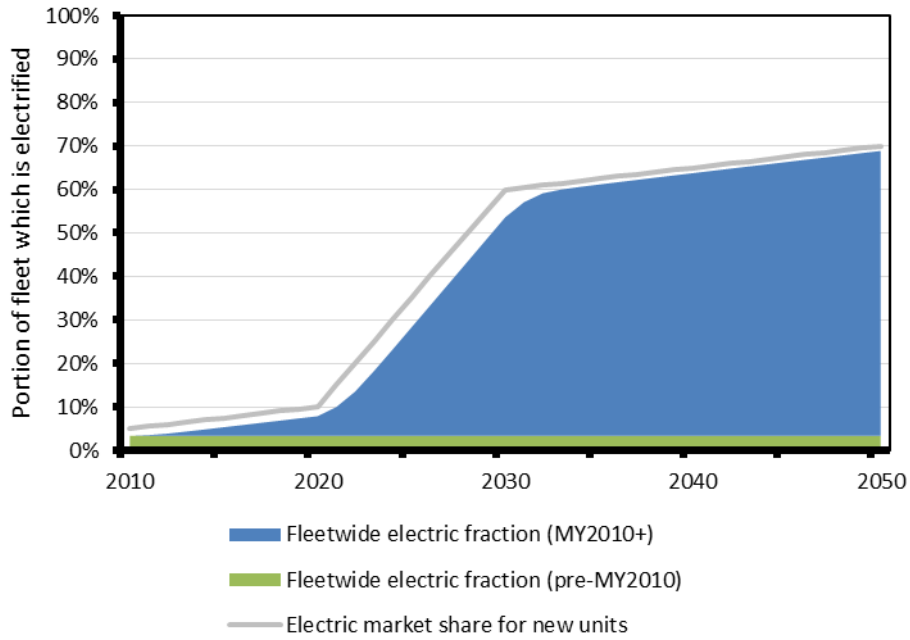

Figure 3-9
Electrification example: Commercial leaf blowers

Non-road Equipment Electricity Consumption

The power usage for non-road equipment is estimated by combining its rated horsepower, load factor, and average annual hours of use. For the electrified-equipment types, the electrified population of each equipment type was multiplied by its corresponding power usage per piece of equipment. It was assumed that electrified non-road equipment would have the same output power as the fossil-fueled equipment being replaced. Figure 3-10 presents the electricity consumption for each equipment category. In 2050, the total additional electricity consumption by non-road equipment is 74.2 TWh, which is an increase of about 1% compared to baseline electricity consumption in 2050.

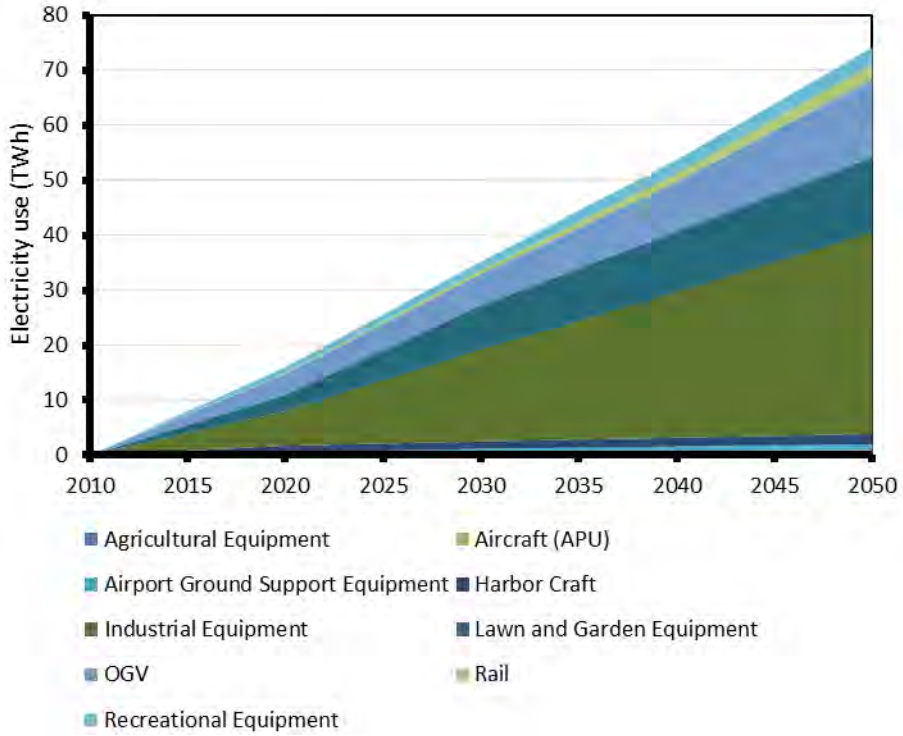

Figure 3-10
Electricity consumption for non-road equipment

Section 4: Electricity-Generation Modeling and Scenarios

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was used to simulate the electricity grid for the analysis presented in this report. US-REGEN uses state-of-the-art grid-modeling techniques and EPRI's detailed estimates of the performance and cost of generation technologies to create long-term forecasts of changes in the electricity sector. Using this model enables the results to capture the marginal effects of electric transportation on both dispatch and capacity expansion and retirement, while ensuring that a comprehensive suite of environmental policies are met.

This section

- Briefly discusses US-REGEN, the model used to simulate the electricity sector in this study.
- Describes the data inputs and assumptions for the scenarios in the GHG analysis.
- Discusses the cases used to impose the incremental load resulting from electric-transportation load and to calculate the marginal grid emissions.

Detailed information on the US-REGEN model is available in the US-REGEN Model Documentation 2014 (EPRI, 2014a). The modeling in this report uses a "large-scale marginal" methodology to estimate the incremental effects of transportation electrification. Volume 1 provides more information on this methodology in comparison to alternatives.

US-REGEN Model Background

The US-REGEN is a model developed by the Electric Power Research Institute (EPRI). It combines a detailed dispatch and capacity-expansion model of the U.S. electric sector with a high-level dynamic computable general equilibrium (CGE) model of the U.S. economy. The two models are solved iteratively to convergence, allowing analysis of policy impacts on the electric sector while taking into account economy-level responses. This convergence makes US-REGEN capable of modeling a wide range of environmental and energy policies in both the electric and non-electric sectors.

US-REGEN is a regional model of the United States. It considers 15 sub-regions of the continental United States to account for differences in resource endowments, energy demand, costs, policies, and policy impacts. Figure 4-1 shows a map of the regions in the model.[41,42] US-REGEN is an intertemporal optimization model, which solves in five-year time steps through 2050.

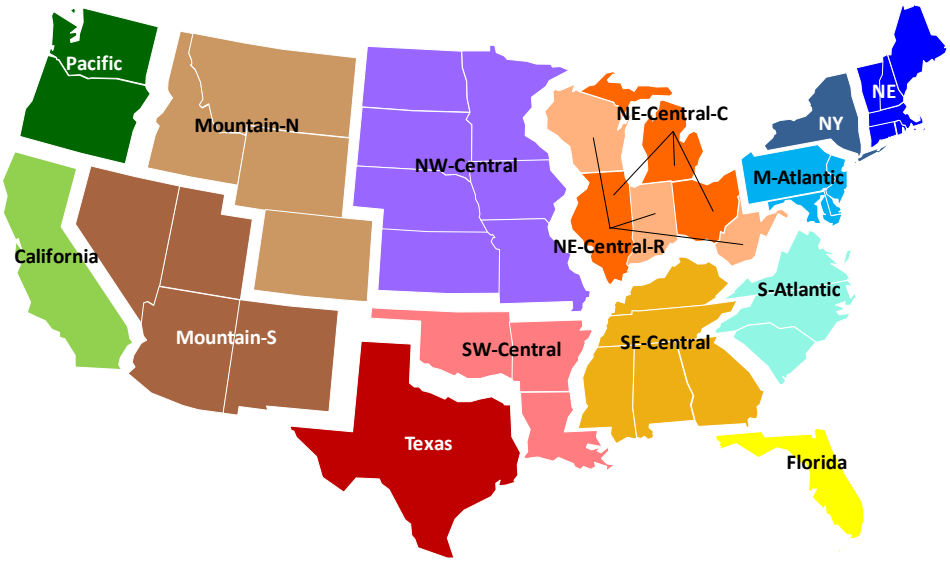

Figure 4-1
Regional structure of US-REGEN model

The electric-sector component of US-REGEN is a detailed generation-planning model. In each time step, the model makes decisions about capacity (for example, new investment, retrofit, or retire) and dispatch to meet energy demand for both generation and inter-regional transmission. It uses a bottom-up representation of power-generation capacity and dispatch across a range of intra-annual load segments. It models transmission capacity between regions, and it requires that generation and load, plus net exports and line losses, balance in each load segment and for each region.

The macroeconomic component of US-REGEN is a CGE model applied to the United States. This model uses a classical Arrow-Debreu general-equilibrium framework to describe the entire economy over time, calibrated to observed U.S. economic data covering all transactions amongst firms and households and forecasted economic growth into the future. Production in each sector is described by a constant-elasticity-of-substitution (CES) production function.

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[41] In defining the regions of the integrated model, there is necessarily a trade-off between optimally representing the economy (in which data is typically available along state lines) and optimally representing the U.S. electricity sector (the internal boundaries of which frequently cross state boundaries).

[42] US-REGEN models NE-Central as two tightly connected subregions—one which represents competitive electricity markets (C), and one which represents regulated electricity markets (R). Emissions and generation from these subregions are combined and reported as one region in the remainder of this report.

Firms are assumed to maximize profits, and households to maximize utility—the latter assumed to be a function of consumption across the timespan of the model. The model is designed to show how changes in policy impact economic activities relative to a baseline case.

The two models comprising US-REGEN are built on economic data sourced from the Impact Analysis for Planning (IMPLAN) database; energy data from the Energy Information Administration (EIA) of the U.S. Department of Energy; U.S. generation fleet data from Ventyx (Ventyx Velocity Suite); and a variety of other sources providing economic growth, wind, solar, and biomass data.

Overview of Assumptions

For this analysis, the model is calibrated to the AEO2011 Reference Case for key "external" variables, including Gross Domestic Product (GDP), electricity demand, industrial growth, and most fuel prices. Natural gas price trends are updated to those in the AEO2013 Reference Case because of their rapid and significant change from the fuel prices in AEO2011. US-REGEN is focused on the electricity sector, and it maintains an independent set of assumptions on electric-sector technologies (which may differ significantly from the AEO).

In designing the scenarios for this analysis, assumptions on the technology options in the future were set as follows:

- Nuclear-generation capacity is assumed to be at similar levels in 2050 as it is today. Within the model, this assumption is implemented by allowing existing nuclear units to receive license extensions to 60 years, and then allowing 80% of those units to receive a further license extension to 80 years. Also, some new nuclear units are permitted, but they were limited on the basis of the trajectory shown in Figure 4-2.[43]
- Carbon capture and storage (CCS) technology is available after 2020 for new and existing coal plants and new natural gas plants.
- Renewable capital costs decline along a pathway defined in the EPRI Generation Options Report (EPRI, 2012) and by recommendations from EPRI's Renewables staff.
- Biomass supply curves were generated from the Forest and Agricultural Sector Optimization Model (FASOM) by US-REGEN region, as described in Appendix D of the US-REGEN Documentation (EPRI, 2014a).
- New biofueled units are possible, and existing coal units have the option of either converting to biomass or co-firing up to 10% biomass.
- Existing coal units can also convert to gas, retrofit with CCS technology, or retrofit with non–CO_2 pollutant controls, as described below.

[43] Limits for 2010–2020 reflect current plans; limits for 2020–2040 are 3.5 GW per time step; and limits for 2040–2050 match additions to retirements.

- New inter-regional transmission is permitted at a cost of $3.84 million per mile, constructed for a high-voltage line capable of carrying 7.2GW.
- Existing coal units are retired at 70 years of age. (All generation types may also retire early if the economics of operation are unfavorable.)

Capital and operating costs for new generation are detailed in the next section. Note that the US-REGEN model incorporates data on the complete generating fleet in the lower-48 states as of 2010—as supplied by Ventyx (now ABB Enterprise Software). For the purposes of running the model, these units are aggregated into "representative" plants by region and by operating characteristics.

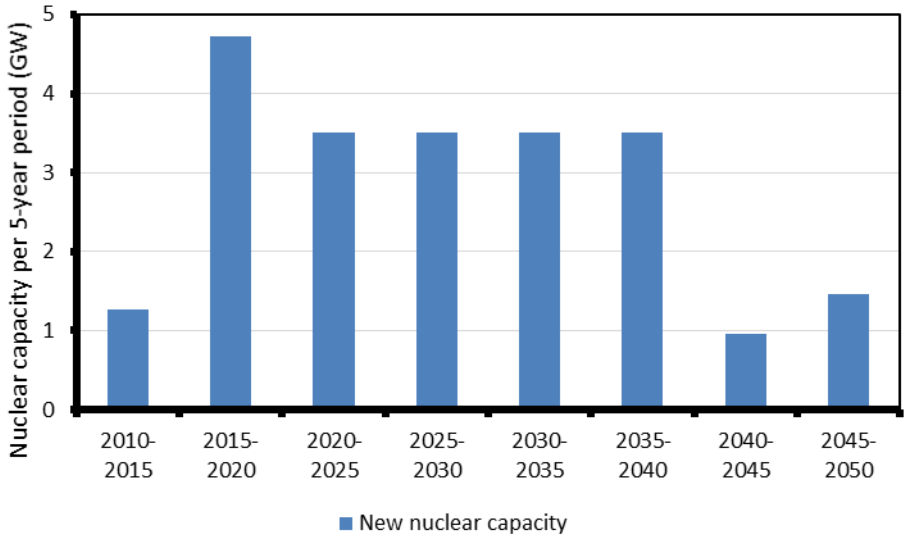

Figure 4-2
Limits on new nuclear capacity for each 5-year time step

New-Generation Cost and Characteristics

US-REGEN considers all major generating technologies in its assessment of potential electric-sector capacity expansion. The costs for these technologies are sourced largely from the EPRI Generation Options Report (EPRI, 2012), supplemented by the expert opinions of EPRI's Generation and Nuclear staff. Table 4-1 presents capital costs and heat rates for new generation by installation year and type.

Table 4-1
Time-varying new technology parameters

Technology	Installation Year	Capital Cost ($/kW)*	Heat Rate (mmBTU / MWh)
Supercritical Pulverized Coal (with full environmental controls and without CCS)	2015 2030 2050+	2590 2590 2590	8.749 7.935 7.582
Integrated Gasification Combined-Cycle (IGCC) Coal (with full environmental controls and without CCS)	2015 2030 2050+	3490 3050 2870	8.932 7.582 6.963
IGCC Coal (with CCS) *(Not available until 2020)*	2020 2030 2050+	4380 4040 3800	10.006 8.726 7.667
IGCC Coal (with partial CCS) *(Not available until 2020)*	2020 2030 2050+	4100 3780 3560	9.749 8.492 7.520
Natural Gas Combined-Cycle (NGCC) (without CCS)	2015 2030 2050+	1160 1160 1160	6.893 6.319 6.319
NGCC (with CCS) (Not available until 2020)	2020 2030 2050+	2280 2180 2050	7.403 7.01 6.89
Natural Gas Turbine (without CCS)	2015 2030 2050+	820 820 820	11.01 10.19 9.75
Dedicated Biomass (based on a 50-MW direct-fire plant)	2015 2030 2050+	4610 4410 4150	12.875 11.371 10.662
Nuclear	2015 2030 2050+	5620 5360 5050	10 10 10
Hydroelectric	2015 2030 2050+	2000 2000 2000	N/A
Geothermal	2015 2030 2050+	5560 5310 5000	N/A
Wind Power Onshore, *More Optimistic*	2015 2030 2050+	2090 1510 1510	N/A

Table 4-1 (continued)
Time-varying new technology parameters

Technology	Installation Year	Capital Cost ($/kW)*	Heat Rate (mmBTU / MWh)
Wind Power Onshore, *Reference*	2015 2030 2050+	2270 1770 1770	N/A
Wind Power Onshore, *Less Optimistic*	2015 2030 2050+	2440 2030 2030	N/A
Wind Power Offshore, *More Optimistic*	2015 2030 2050+	3140 2270 2010	N/A
Wind Power Offshore, *Reference*	2015 2030 2050+	3140 2460 2180	N/A
Wind Power Offshore, *Less Optimistic*	2015 2030 2050+	3140 2610 2310	N/A
Solar Photovoltaic (Central Station) *More Optimistic*	2015 2030 2050+	1830 1160 1010	N/A
Solar Photovoltaic (Rooftop) *Reference*	2015 2030 2050+	3350 2290 2050	N/A
Solar Photovoltaic (Rooftop) *Less Optimistic*	2015 2030 2050+	3950 2840 2590	N/A
Concentrating Solar Power, *More Optimistic*	2015 2030 2050+	6480 4550 3340	N/A
Concentrating Solar Power, *Reference*	2015 2030 2050+	6480 5440 4660	N/A
Concentrating Solar Power, *Less Optimistic*	2015 2030 2050+	6480 5840 5340	N/A

* All costs are in constant 2009 dollars.

Table 4-2 lists fixed and variable (non-fuel) operating and maintenance costs and plant lifetimes of new generation. Operating costs are held constant over time and are assumed not to increase as a plant ages.

Table 4-2
Non–time-varying new technology parameters

Technology	Fixed O&M Costs ($/kW-year)*	Variable O&M Costs ($/MWh)*	Plant Lifetime
Supercritical Pulverized Coal (with full environmental controls and without CCS)	58	2.5	70
Integrated Gasification Combined-Cycle (IGCC) Coal (with full environmental controls and without CCS)	105	2	60
IGCC Coal (with CCS)	134	3.4	60
IGCC Coal (with partial CCS)	119	3.1	60
Natural Gas Combined-Cycle (NGCC) (without CCS)	14	2.4	60
NGCC (with CCS)	26	5	60
Natural Gas Turbine (without CCS)	14	4.5	60
Dedicated Biomass (based on a 50-MW direct-fire plant)	62	5	60
Nuclear	105	1.7	80
Hydroelectric	67	0	100
Geothermal	67	9.6	30
Wind Power Onshore	37	0	25
Wind Power Offshore	98	0	25
Solar Photovoltaic (Central Station)	21	0	30
Solar Photovoltaic (Rooftop)	21	0	30
Concentrated Solar Power (CSP), or Solar Thermal	72	0	60

*All costs are in constant 2009 dollars.

Fuel Prices

US-REGEN calibrates wholesale gas prices in the REGEN baseline to match the AEO2013 Lower-48 Wellhead Price. Crude-oil prices are calibrated to the AEO2011 Imported Crude Price. Coal prices are calibrated to the AEO2011 Average Minemouth Price. A retail margin, also obtained from the AEO, is added by sector to obtain retail prices. Note that the US-REGEN model

incorporates price response to changes in demand for fuels through the CGE component of the model; thus fuel prices in the policy scenarios will deviate from the AEO projections over time. The policy scenarios considered in this analysis did not result in any significant change to fuel prices from the baseline. The national-average delivered fuel prices to the electric sector for coal, gas, and refined petroleum are depicted in Figure 4-3.

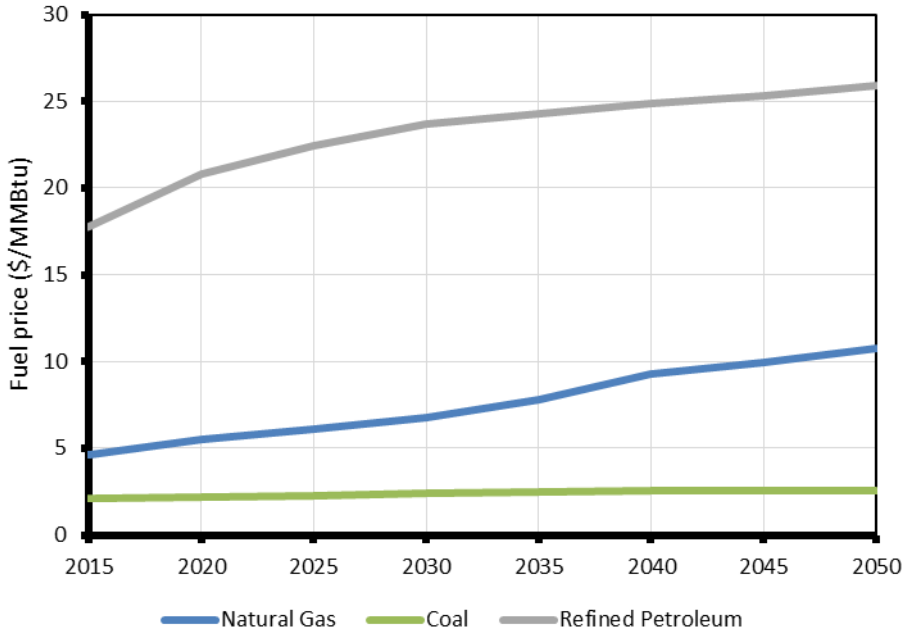

Figure 4-3
National-average delivered fuel prices to the electric sector

Electricity-Demand Growth

Demand growth in the Base Case is calibrated to the AEO2011 Reference Case, starting at 4200 TWh per year in 2010 and rising to 5790 TWh per year by 2050.

Pollution-Control Equipment Costs and Characteristics

US-REGEN includes several retrofit options for existing coal capacity in response to environmental policy. The retrofits enable reductions in emissions of SO_2 or NO_x, which may be motivated by market-based caps or technology-forcing policies that require environmental retrofits as a condition of continued operation. The model can also convert existing coal units to biofuel or to natural gas, and it may add the capability to co-fire biomass at 10%. These transformations incur a one-time capital cost, and can result in capacity degradation and changes in operating parameters—including variable costs, heat rates, and emission rates (described below).

Table 4-3 outlines the assumed costs of retrofitting an existing coal plant and the assumptions on the resulting changes in the plant's performance.

Table 4-3
Cost and performance assumptions for coal retrofits

	Capital Cost ($/kW)	Change Relative to Base Coal Plant			
		Capacity Penalty	Heat Rate	Non-CO_2 Emissions Rates (SO_2/NO_x)	Variable O&M
Enable 10% Biomass Co-Fire	$20 (i.e., $200/kW of biomass capacity)	1.2	1.2	0.0/0.8	1.0
Convert to Gas	$150	1.0	0.96	0.0/0.05	0.5
Convert to 100% Biomass	$1,000	1.44	1.2	0.0/0.05	0.9
Convert to CCS (90% capture)	$1,500 for non-compliant classes; $750 or more for compliant classes / environmental retrofit*	1.5	1.5	0.15/0.05	2.0
Environmental Retrofit	Varies by class up to $6,000 (see Table 4-4 below)	1.05	1.05	0.15/0.05	$4/MWh

* "Second-stage" CCS retrofit of capacity that has already undertaken an environmental retrofit is adjusted in some cases to ensure that the total cost of both retrofits is greater than $1,500 (the cost of a "single-stage" CCS retrofit). Additionally, the cost of the single-stage retrofit declines slightly over time.

The capital cost of an environmental retrofit was estimated separately, as described in Appendix C of the US-REGEN Documentation (EPRI, 2014a). The methodology employed estimated the total cost required for each unit individually to comply with all pending and proposed environmental regulations by 2015. A range of retrofit cost estimates was calculated for every unit in the database through the use of EPRI's analysis system, the Integrated Emissions Control Cost Estimating Workbook, known as IECCost. The IECCost model generated unit-specific estimates of capital costs, operating costs, maintenance costs, and consumable quantities for NO_X, SO_2, and mercury emissions–control systems. The distribution of these costs in depicted in Figure 4-4.

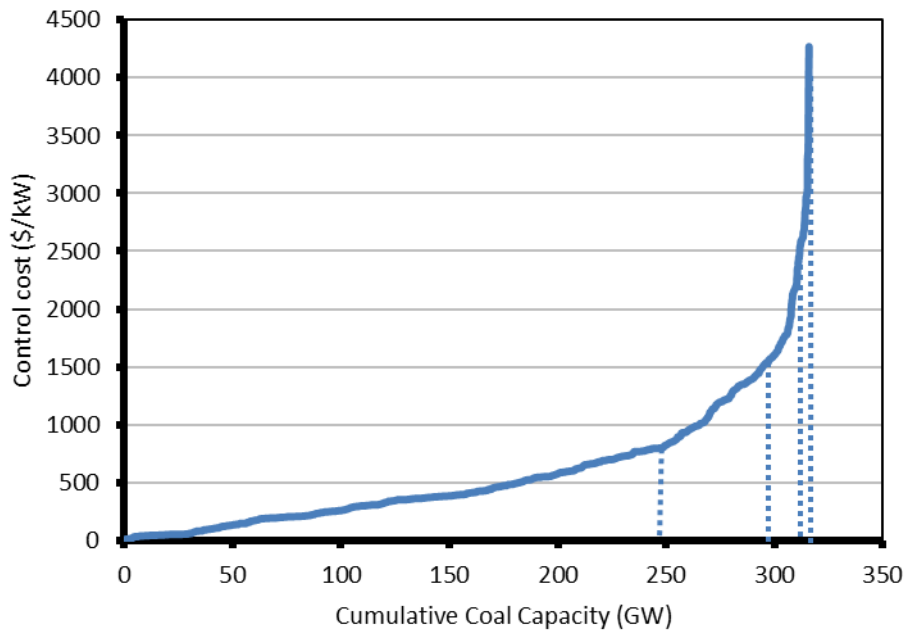

Figure 4-4
Distribution of environmental-control costs by bins defined by breakpoints at $800, $1,600, $2,400, and $4,000 per kW of control cost

The distribution was broken into five intervals by selecting breakpoints at $800/kW, $1,600/kW, $2,400/kW, and $4,000/kW. The average retrofit cost for each bin is listed in Table 4-4.

Table 4-4
Average retrofit costs and existing capacity for the five retrofit cost bins

Retrofit Cost Bin ($/kW)	GW	Avg. Retrofit Cost ($/kW)
<$800	222	367
$800-$1,600	66	1,104
$1,600-$2,400	20	1,850
$2,400-$4,000	7	3,158
>$4,000	1	4,373

Environmental Regulations

The scenarios were constructed to incorporate pending EPA regulations and other restrictions on pollutants. These included

- Existing State Renewable Portfolio Standards as of 2012, including separate requirements for solar where applicable

- A full suite of non-GHG environmental-control regulations, pending or expected to be implemented by model-year 2015. These regulations cover the following five environmental pathways:
    1. New requirements and emissions limits for sulfur oxide pollutants (SO_x), under the Hazardous Air Pollutants Maximum Achievable Control Technology (HAPs MACT) regulations[44]
    2. New requirements and emissions limits for nitrogen oxide pollutants (NO_x), again under HAPs MACT
    3. New requirements for the control of mercury and related heavy-metal pollutants in stack emissions, also under HAPs MACT
    4. New protections for aquatic species impacted by cooling-water intake structures, potentially leading to far more closed-loop cooling systems, as a part of Section 316 (b) of the Clean Water Act
    5. New, more restrictive classification of coal ash solid waste (coal combustion residuals, or CCRs) under relatively more elaborate and expensive disposal requirements across the fleet, through Subtitle D of the Resource Conservation and Recovery Act
- An implementation of the Cross-State Air Pollution Rule.
- The EPA proposed New Source Performance Standards for new Fossil-Fueled Generation. Specifically, these standards are assumed to prohibit the construction of new coal units without CCS technology.

Note that the version of the model used in this analysis did not have an implementation of the California Cap-and-Trade scheme authorized under AB32, nor did it include the Northeast and Mid-Atlantic states Regional Greenhouse Gas Initiative (RGGI) cap-and-trade market. Additionally, the EPA's Clean Power Plan was not finalized at the time modeling was performed, and it is not explicitly modeled.

Scenarios Used to Model Greenhouse Gas Emissions

The greenhouse gas analysis used two primary scenarios: the "Base Greenhouse Gas Scenario" (Base GHG Scenario) and the "Lower Greenhouse Gas Scenario" (Lower GHG Scenario). Each of these scenarios were run for two cases: one case with no transportation-electrification load ("non-electrification" case) and one case with the additional electricity load required to supply the vehicles described in Section 2 and Section 3 ("electrification" case). This section describes the differences between the two scenarios and the additional load used in the electrification cases.

[44] At the time of the release of this study, the HAPs MACT (which is part of the Mercury and Air Toxics Standard) has been remanded to the D.C. District Court by the Supreme Court. Many of the changes required by the policy have already occurred, and the policy is still in effect at this time. However, the policy may be changed in unknown ways from its current implementation.

Scenario Assumptions

The Base GHG Scenario uses the assumptions described above without modification. In the Lower GHG Scenario, it is assumed that in addition to the policies and constraints described above, electricity generators also incur a cost for carbon emissions. This cost is not intended to model any specific policy. The carbon cost is a gradually increasing "ramp" that begins at $20/ton in 2016 and increases at an annual rate of 5% per year (modeled as a 28% increase per 5-year time step).

These scenarios are slightly different from the scenario used in the Air Quality analysis, but they are consistent with the 2030 model year used in that analysis. Appendix A in Volume 3 discusses these differences in more detail.

Electricity Demand for the Non-electrification and Electrification Cases for Each Scenario

Each scenario was run for two cases: one case with no transportation electrification and one case with the additional transportation-electrification load described in Section 2 and Section 3. Figure 4-5 shows both load trajectories. The modeled transportation electrification increases load by 5% in 2030 and 13% in 2050. This increase in load occurs relative to a baseline increase to accommodate additional load from non-transportation sources. Transportation electrification increases the baseline load growth rate by 30–40% in the 2030–2050 time frame.

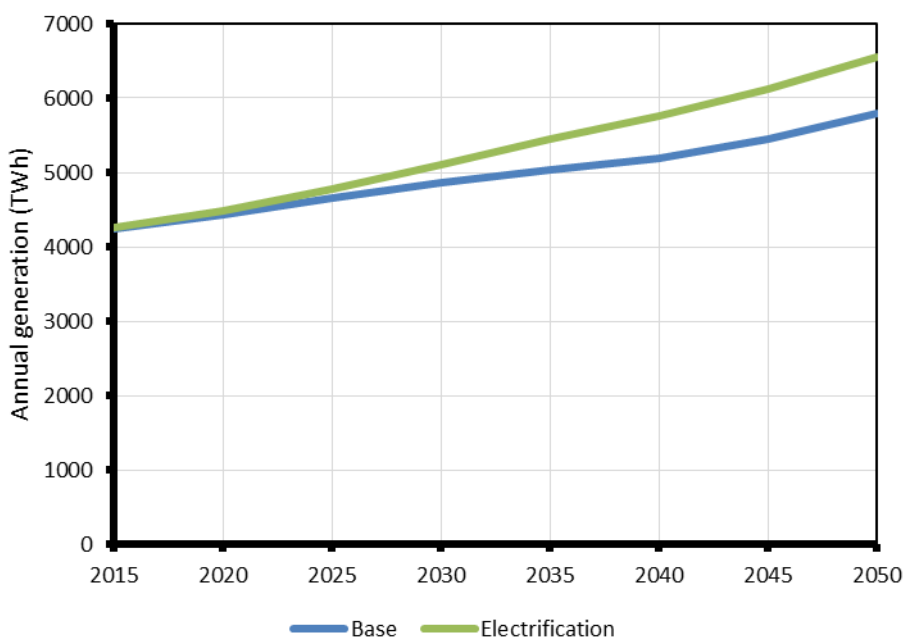

Figure 4-5
Annual generation with and without transportation electrification

Transportation-Electrification Load Shape

There is a significant amount of uncertainty about when load from electrified vehicles will occur. Battery charging has a high degree of time-flexibility relative to most other loads because of the low average daily utilization of batteries and the extended charging periods available.[45] It is probable that charge management could lead to decreased emissions. For example, region-specific load shapes could be implemented that matched load to the mix of renewable generation available within each region. However, optimizing the load shape was outside of the scope of this analysis, so a fixed load shape was selected. Section 9 reviews a variety of potential fixed load shapes, but it finds that the variation in GHG emissions among different load-shape scenarios is low. For this analysis, the "scaled" load shape was selected, which scales the default US-REGEN load shape and therefore proportionally distributes electrification load onto existing load. This load varies among regions and throughout the year, but it has the average hourly load shape shown in Figure 4-6.

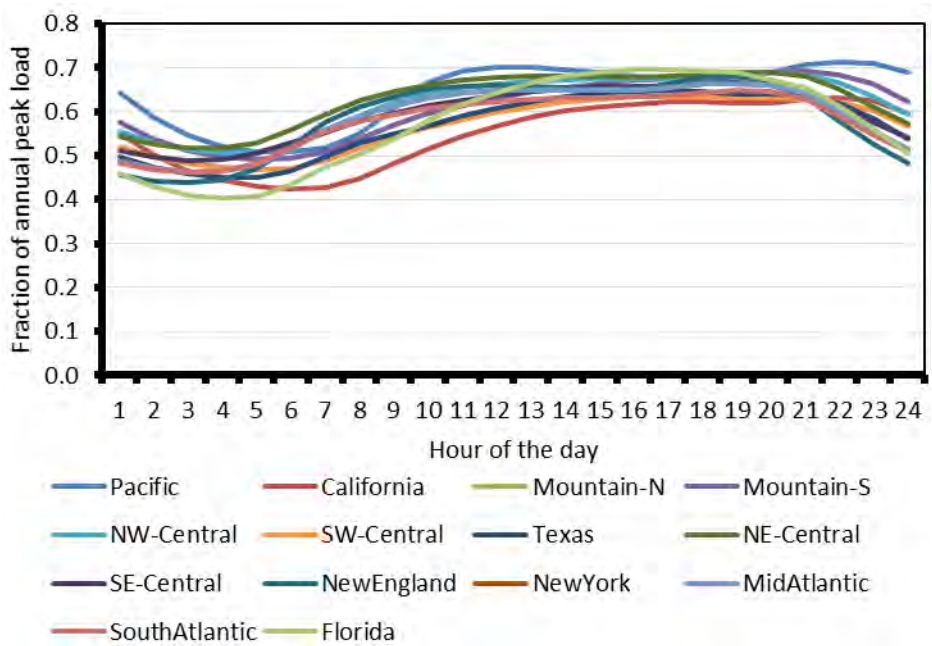

Figure 4-6
Average daily load shape by region

Estimation of Direct Non-CO_2 Greenhouse Gas Electricity-Sector Emissions

The version of US-REGEN used in this analysis only models CO_2 emissions from power plants; it does not model other GHG pollutants emitted directly from electricity-sector sources. Source- and species-specific emissions factors

[45] Although there is grid-connected non-road equipment in the total electrification demand, almost all of the increased load is a result of battery charging.

were developed for nitrous oxide (N_2O)[46], methane (CH_4), and sulfur hexafluoride (SF_6), which represent almost all non-CO_2 GHG emissions from the utility sector. The procedure to develop these emissions factors is described in Appendix A. It is assumed that per-kWh emissions remain fixed over the study time frame, but total emissions will decrease because of changes in the generation mix. Non-CO_2 GHG emissions constitute 1.1% of total electricity-sector GHG emissions. "Upstream" GHG emissions emitted indirectly via fuel use are additive to these direct emissions, and they are discussed in the next section.

[46] Nitrous oxide is a nitrogen oxide (NO_x), but it has low reactivity and is primarily regulated as a GHG.

Section 5: Upstream Emissions

Direct, or "downstream," emissions from vehicle tailpipes and power plants constitute the majority of life-cycle GHG emissions in the transportation sector. But non-direct, "upstream" emissions resulting from the extraction and processing of input fuels are an important secondary source of emissions. Emissions related to vehicle manufacture may also be an additional source of incremental emissions from electrified vehicles. These manufacturing emissions are generally projected to be small relative to other emission categories. But there are concerns about emissions from battery manufacturing, so incremental manufacturing emissions for batteries are estimated and included.

This section

- Discusses the development of the estimates for upstream GHG emissions to supply fuels for use in vehicles and in power plants. These emissions occur during feedstock extraction, processing to final fuels, and transportation of feedstocks and fuels.
- Discusses the vehicle-cycle emissions analyzed in this report. Because of high uncertainty concerning models and data sources for manufacturing emissions, vehicle-cycle emissions are limited to emissions required for battery manufacturing.

Gasoline and Diesel Fuel-Cycle Emissions Factors

The GREET 1 model (2014 version) was used to obtain the upstream GHG emissions factors of the fuels consumed by electricity generation and the total (direct and upstream) emissions of other fuels. For all fuels CO_2, CH_4, and N_2O were weighted to create a CO_2 equivalent, "CO_2e" which included all greenhouse gas emissions. This study primarily used the default assumptions in GREET 1, but made modifications to the estimates for biofuels content. The study investigates the GHG emissions through the year 2050, whereas GREET only extends to 2020. It was assumed that the GHG emissions of the various fuels contributing to the supplies of gasoline and diesel remain constant beyond the year 2020. This is a conservative assumption, because the petroleum fuel supply has the potential to become increasingly carbon-intensive from the greater use of tight and tar-sands oil resources (Gordon et al, 2015).

Biofuel and Renewable Content of Liquid Fuels

The only on-road transportation fuels considered in this study are gasoline, diesel, and grid electricity. However, it was assumed that biofuels would continue to be used in "pump" gasoline and diesel. The biofuel and renewable-fuel content in gasoline and diesel was modified using the mix of fuels in AEO2014. Appendix A describes additional assumptions and data.

Gasoline and Diesel

The GHG data provided by GREET for the various component fuels was used in conjunction with the biofuel assumptions to obtain weighted-average GHG factors for the gasoline and diesel supplies. Table 5-1 presents the upstream and direct GHG-emissions factors for these two fuels. Whereas the emissions factors for petroleum fuels and biofuels are fixed after 2020, the factors for the blended fuels change over time because of the varying portions of biofuel and renewable fuel in the blends. The biofuel content in gasoline increases in the future, which causes blended gasoline to become lower-emitting over time. However, the biofuel and renewable-fuel content of diesel is assumed to decrease after 2015 (according to AEO2014 data), which causes the diesel blend to become slightly higher-emitting. Approximately 20% of gasoline and 17% of diesel fuel-cycle emissions result from upstream emissions.

Table 5-1
Greenhouse gas emissions factors for gasoline and diesel, including biofuels

	Gasoline (kg/gal)			Diesel (kg/gal)		
	Upstream	**Direct**	**Total**	**Upstream**	**Direct**	**Total**
2015	2.2	8.6	10.8	1.9	10.2	12.1
2020	2.2	8.6	10.7	2.0	10.3	12.3
2025	2.1	8.5	10.6	2.0	10.3	12.3
2030	2.0	8.5	10.5	2.0	10.3	12.3
2035	2.0	8.5	10.5	2.0	10.3	12.3
2040	2.0	8.4	10.4	2.1	10.3	12.3
2045	2.0	8.4	10.4	2.1	10.3	12.3
2050	2.0	8.4	10.4	2.1	10.3	12.3

Non-road Fuels

Non-road equipment utilizes a variety of fuels—including gasoline, diesel, jet fuel, liquid petroleum gas (LPG), and compressed natural gas (CNG). Gasoline and diesel emissions were calculated using the factors in Table 5-1, and the emissions for additional non-road fuels were calculated using the emission factors in Table 5-2. The fuel mixes for jet fuel, LPG, and CNG were not assumed to include biofuels, so the emissions factors were fixed for the entire study period.

Table 5-2
Greenhouse gas emissions factors for non-road fuels (kg/gal)

	Upstream	Direct	Total
Jet Fuel	1.7	9.6	11.3
LPG	1.4	5.8	7.2
CNG (kg/gge)	2.6	7.8	10.4

Fuels for Electricity Generation

US-REGEN was used to calculate the direct emissions resulting from electricity generation, but the model does not include indirect emissions resulting from the extraction and processing of fuels for electricity generation. GREET 1 was used to obtain the upstream-emissions factors, which were applied to the US-REGEN results for the quantities of each fuel consumed to obtain the upstream GHG intensity of electricity. The emissions factors for each electricity-generation fuel are listed in Table 5-3. Emissions for 2015 were calculated as the average of the GREET results for 2010 and 2020, and all subsequent years used the GREET results for 2020. The chemical energy in uranium for nuclear generation is not a meaningful representation of the amount of fuel used; so instead, upstream emissions attributable to generation from nuclear plants are measured per million BTUs (MMBtu) of electricity generated.

Table 5-3
Greenhouse gas emissions factors for fuels for electricity production (kg/MMBtu)

	2015	2020–2050
Natural Gas	10.1	10.1
Coal	5.8	5.8
Petroleum	13.3	13.8
Biomass	2.5	2.5
Nuclear (kg/MMBtu of electricity)	3.0	2.0

Battery-Manufacturing Emissions

PEVs and conventional vehicles use very different powertrain components, so it is possible that vehicle-cycle emissions could change significantly as PEVs become more prevalent. These potential effects are important to consider, but a literature review by the study team found that the models for analyzing vehicle-cycle emissions are still relatively new. There is significant disagreement among different estimates of the manufacturing emissions for PEVs and conventional vehicles. However, the analysis also indicated that manufacturing emissions for battery production accounted for most of the differences between PEVs and conventional vehicles, and that recent work has clarified the reasons for disagreement among many of the conflicting emissions estimates (Dunn, 2015).

Dunn (2015) demonstrates that the primary source of the large differences in results were attributable to whether the study was assuming a "pilot," small-scale plant or a mature, large-scale facility. In the interest of representing the incremental emissions attributable to PEVs, battery-manufacturing emissions were included in "upstream" emissions to create a semi–life-cycle emissions measurement that includes the full fuel-cycle and partial vehicle-cycle emissions.

The 2014 version of GREET 2 was used to analyze the energy and GHG-emissions impacts of battery manufacturing because it assumes mature, large-scale production (consistent with this study's electrification scenario). A small portion of the default assumptions was modified, as detailed in Appendix A. GREET 2 provides emissions results in terms of the mass of GHG over an individual vehicle's lifetime. For this study, the intermediate results within GREET for the life-cycle emissions of battery systems were used to create a measurement of emissions per kWh of battery capacity. These energy-specific emissions were then scaled to match the variety of vehicle types and categories considered in this analysis. The energy-specific emissions factors also improved over time because of improving grid emissions, as described below.

To create baseline battery-manufacturing emissions factors, two reference battery packs were created in GREET. These reference battery packs used the 2012 calendar year GREET 2 battery-manufacturing emissions for the lithium-manganese-oxide (LMO) chemistry and the "Conventional Material" passenger-car vehicle class.[47] The version of GREET 2 that was used is capable of modeling a variety of chemistries, but the LMO system was selected because it is used in the majority of today's PEVs. Separate factors were calculated for PHEV and BEV battery packs: specifically, the 18-kWh lithium-ion pack for a PHEV with 40 miles of electric range, and the 28-kWh lithium-ion pack for a BEV car with approximately 100 miles of range. These emissions factors were used to represent the emissions per kWh for PHEVs and BEVs generally, with the capacities scaled up or down to match the diverse set of vehicle types and classes modeled in this report. The scaling was based on electrical-energy use for each vehicle configuration, so total battery requirements were lower for more-efficient vehicles, and the battery requirements decreased over time as vehicles became more efficient.

Because GREET 2 does not provide assumptions for other years, time-dependent assumptions were developed for some of the model-input values in order to more accurately model the manufacturing emissions in future years. Some information is known about the upcoming battery technology that will be put into production in the near term. However, beyond 2020 there is high uncertainty surrounding further improvements in electric-vehicle battery chemistry, design, and manufacturing. The EPRI Energy Storage research team expects that battery manufacturers will work to reduce cost by developing a reduced number of cell designs that can be shared across a variety of electric-vehicle and stationary-storage applications, and that those designs will favor

[47] Burnham, A., 2012, Updated Vehicle Specifications in the GREET Vehicle-Cycle Model Center for Transportation Research, Argonne National Laboratory, Argonne, Ill.

improvements in specific energy over power density. From the perspective of electric-vehicle performance, this means that for a given battery size and weight, the focus will be on extending the vehicle's range (energy-storage capacity) rather than on improving top speed and acceleration (maximum power). For these reasons, this study maintains GREET's assumptions for two separate electric-vehicle batteries (PHEV and BEV) only until 2020; beyond 2020, it uses GREET's BEV battery as the "average" electric-vehicle battery.[48] It is very uncertain which specific lithium-ion system will be used in future batteries, so the lithium-manganese-oxide (LMO) system is used to represent the active materials in all future batteries.

Appendix A presents additional detailed assumptions regarding the life-cycle emissions of PEV batteries—including the specific energy of modeled batteries, projected over the study period; battery-material assumptions across the study period; and the direct and upstream emissions of the electricity used to manufacture batteries.

[48] Through 2020, the GREET PHEV battery results were applied to this study's PHEV20 and PHEV40 vehicle types, and the GREET BEV battery was used for the PHEV60 and BEV types. Beyond 2020, the GREET BEV battery was used for all vehicle types.

Section 6: Electricity-Sector Results

The effects of transportation electrification on the electricity system were modeled by applying the vehicle loads described in Section 2 and Section 3 to the electricity-system scenarios described in Section 4. US-REGEN forecasts the changes in the use of generation resources that exist in the non-electrification base cases as a result of the new load, and it also forecasts changes in expansion and retirement of capacity.[49] The electricity system is modeled for two scenarios: the Base Greenhouse Gas Scenario (Base GHG Scenario) and the Lower Greenhouse Gas Scenario (Lower GHG Scenario). Each scenario is modeled for two cases: a Non-electrification case that does not include any transportation electrification and an Electrification Case that includes the on-road and non-road transportation load.

This section

- Describes the trajectory of generation changes over time for each non-electrification case and the marginal effects of transportation electrification.
- Discusses changes in average and marginal grid emissions over the study time frame.

Section 7 will describe the effects of these grid emissions on transportation-sector emissions, and Section 8 will discuss the multisector effects of transportation electrification.

Base GHG Scenario Modeling Results

Non-electrification Case Generation and Capacity

Figure 6-1 shows the evolution of energy generation over the model time frame in the Base GHG Non-electrification Case. Most incremental generation comes from wind power, with additional contributions from solar power in later years. Nuclear and hydroelectric generation are relatively constant throughout the full model time frame. Existing capacity for both resource types is very economically competitive and plants are long-lived, but addition of new capacity is difficult. Coal generation remains roughly flat until 2030, when retirements begin to reduce coal capacity. In the 2040–2050 time period, coal with CCS becomes competitive, and it provides a significant amount of generation as conventional

[49] Additional load from PEVs is unlikely to result in increased power-plant retirements, but it could cause changes in the mix of plants retired.

coal retirements accelerate. Natural gas generation—primarily combined-cycle—acts as the "swing" dispatchable resource, increasing as coal decreases and decreasing as coal with CCS and renewables increase in the 2040–2050 time frame.

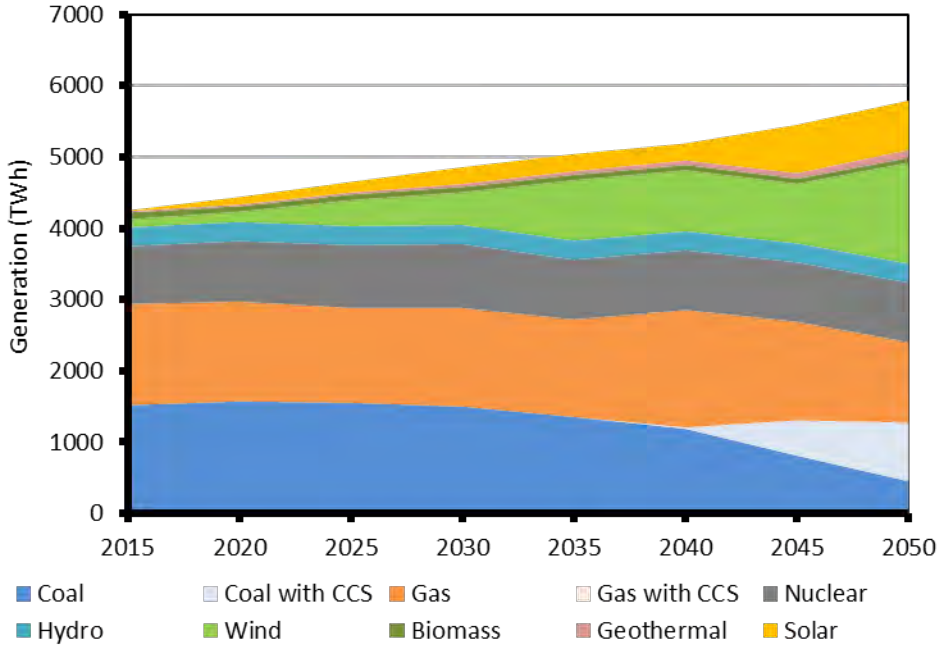

Figure 6-1
Energy Generation in the Base GHG Non-electrification Case

Figure 6-2 shows the related evolution of generation capacity in the Base GHG Non-electrification Case. Because of the relatively low capacity utilizations for solar and wind generation, the capacity for these resources is a significantly higher fraction of the total than for energy generation. By 2050, the capacity for these two generation resources is about half of the total, whereas energy generation is approximately 35%.

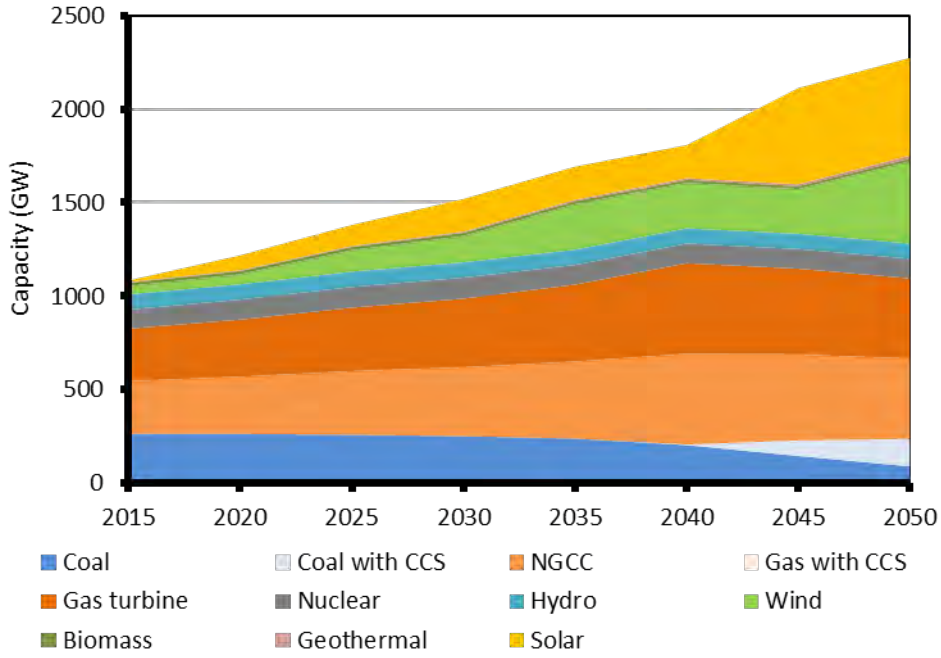

Figure 6-2
Generation capacity in the Base GHG Non-electrification Case

Base GHG Scenario with Transportation Electrification

Figure 6-3 shows the trajectory of energy generation with the additional load from transportation electrification. The changes resulting from the additional load are difficult to distinguish, so Figure 6-4 shows just the changes for each generation type. (Generation types that are not shown had negligible changes for all scenarios.) The highest share of marginal generation comes from natural gas, which is almost all combined-cycle, with additional contributions from wind and solar. In the 2040–2050 time period, coal with CCS is also a major contributor.

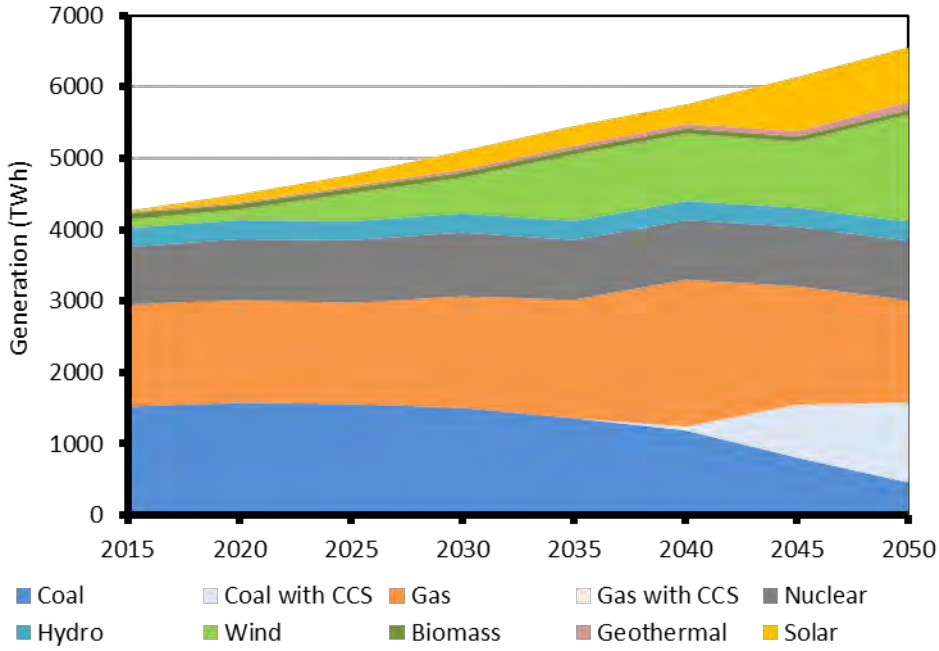

Figure 6-3
Energy generation Base GHG Electrification Case

The capacity changes resulting from electrification, shown in Figure 6-5, largely mirror the generation changes. The lower capacity factor for renewable generation means that renewable capacity is "over-represented" in capacity, whereas the high capacity factor for coal with CCS means that less capacity is required relative to natural gas.

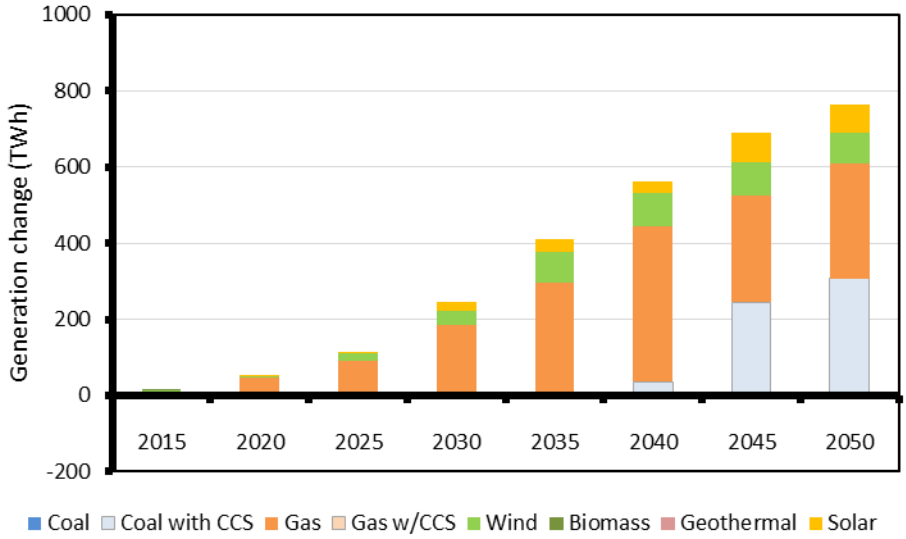

Figure 6-4
Energy generation changes in the Base GHG Scenario resulting from transportation electrification

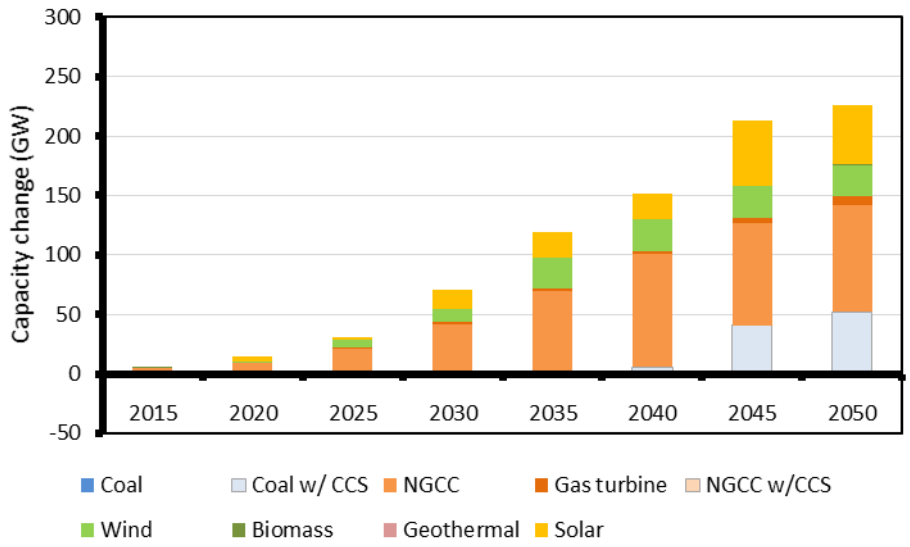

Figure 6-5
Capacity changes in the Base GHG Scenario resulting from transportation electrification

Lower GHG Scenario Modeling Results

Non-electrification Case Generation and Capacity

Figure 6-6 shows the trajectory for energy generation in the Lower GHG Non-electrification Case. Compared to the Base GHG Non-electrification Case, total generation is the same, but generation from coal decreases earlier and faster; generation from natural gas decreases significantly; and generation from renewables increases rapidly. These changes are a result of the additional carbon cost described in Section 4, and they significantly decrease GHG emissions from the grid (as will be discussed below).

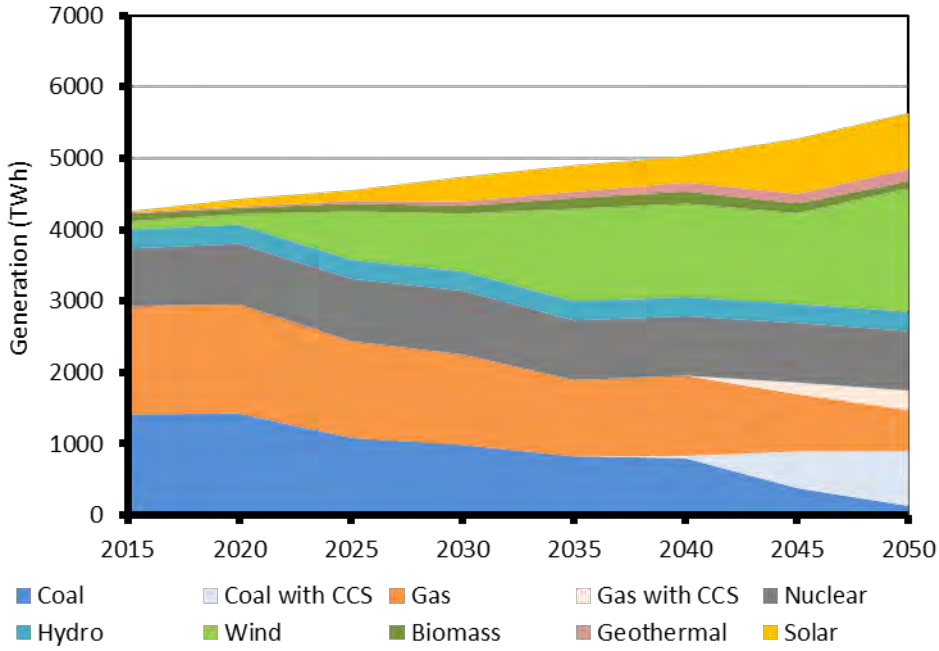

Figure 6-6
Energy generation in the Lower GHG Non-electrification Case

The trajectory for generation capacity for the Lower GHG Non-electrification Case is shown in Figure 6-7. Because of the increased demand for renewable generation, wind and solar capacity is significantly higher than in the Base GHG Non-electrification Case. By 2050, 58% of capacity is non-hydro renewable generation. Fewer coal and NGCC units are required compared to the Base GHG Non-electrification Case, but approximately the same amount of gas-turbine capacity is required because of the need to maintain capacity reserves amidst high levels of intermittent renewable generation.[50]

[50] Grid energy storage could also provide this service, but it is out of scope for the grid modeling because of the difficulty of accurately capturing hourly chronology in the annual dispatch model.

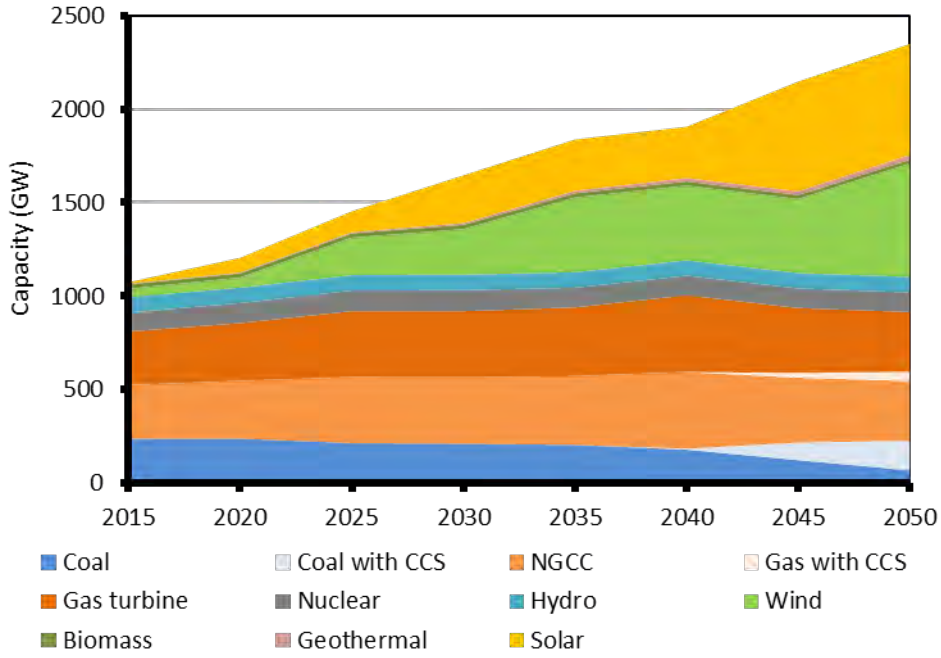

Figure 6-7
Generation capacity in the Lower GHG Non-electrification Case

Lower GHG Scenario with Transportation Electrification

As in the Base GHG Scenario, the additional generation required to satisfy transportation load is indistinguishable in the full generation trajectory. Figure 6-8 shows the incremental generation. The additional load is primarily met with natural gas and renewable generation. In the 2040–2050 time period, coal with CCS becomes economical and satisfies most of the load not met by renewable generation. For the load shape and fuel prices used in this analysis, coal with CCS is more economically competitive than gas with CCS on a marginal basis—causing a shift away from gas with CCS in the non-electrification load. Gas with CCS still increases in the total generation scenario, but by less than it would without transportation electrification.

Figure 6-9 shows the incremental changes in generation capacity resulting from transportation electrification. These changes largely track the changes in energy generation, but the lower capacity factor for renewable generation means that more capacity is required for these resources relative to other generation types.

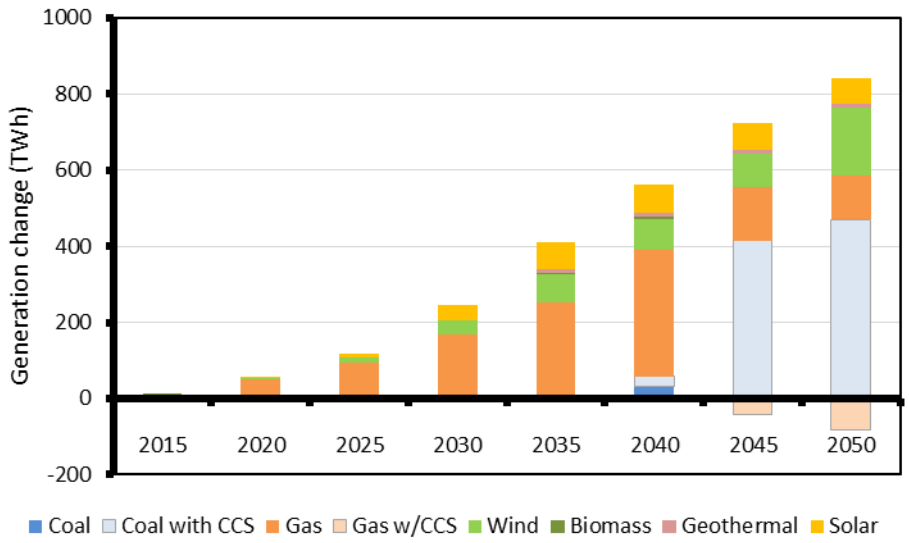

Figure 6-8
Energy-generation changes in the Lower GHG Scenario resulting from transportation electrification

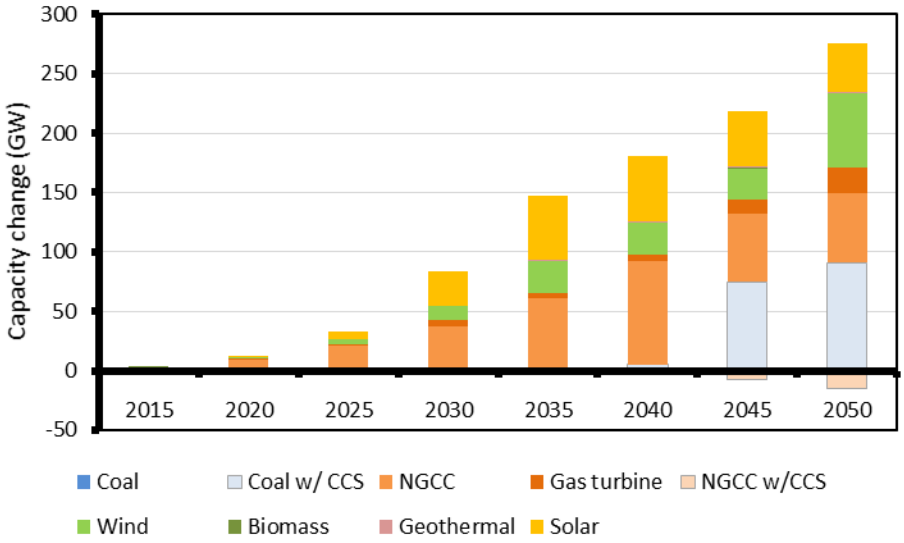

Figure 6-9
Generation-capacity changes in the Lower GHG Scenario resulting from transportation electrification

Electricity-Sector Greenhouse Gas Emissions

This subsection presents emissions results for both scenarios. Emissions results for both scenarios are presented first as "direct" GHG emissions—which include only generation emissions—and then as "consumption" emissions—which include upstream emissions and transmissions and distribution losses.

Base GHG Scenario

The generation changes described above lead to significant reductions in electricity-sector emissions. Figure 6-10 shows the GHG-emissions rate for direct utility-sector emissions for the Base GHG Non-electrification Case; the average Electrification Case emissions; and the large-scale marginal emissions resulting from transportation electrification. The large-scale marginal emissions are calculated by dividing the incremental emissions by the incremental load for each time period.[51] The incremental electrification load is relatively small, and the average generation resources are similar to marginal resources. Therefore, the total of the average emissions in the electrification case is almost identical to the average emissions in the base case. Marginal electrification emissions are significantly lower than average emissions in the 2020–2035 time frame. But as the grid gets cleaner, average emissions narrow the gap and eventually overtake marginal emissions.[52]

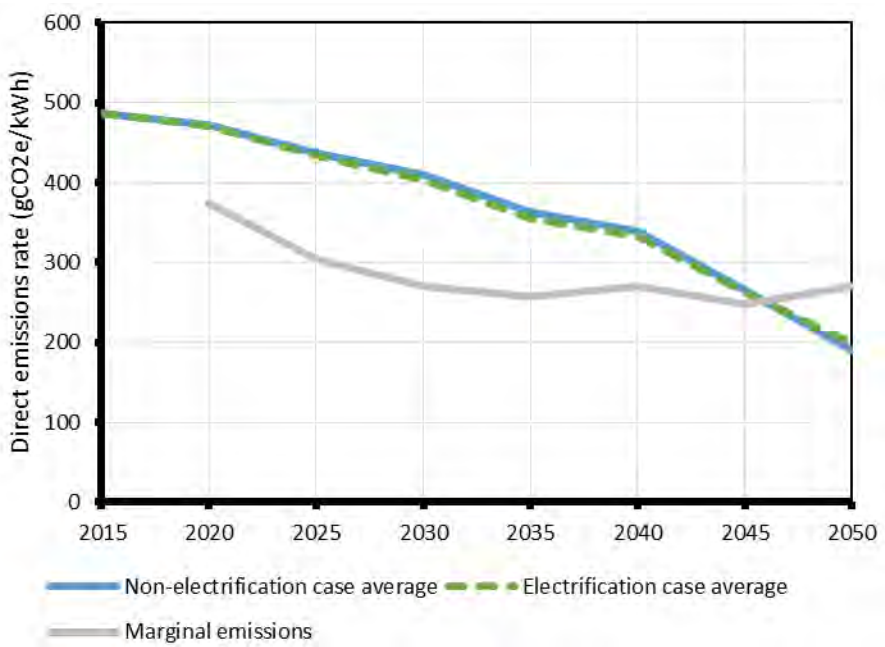

Figure 6-10
Direct electricity-sector GHG emissions rate for the Base GHG Scenario

[51] In the 2015–2020 time frame, the incremental electrification load is very small, so the average emissions rate would be a better representation of electrification than the large-scale marginal rate.

[52] Throughout the model time frame, marginal emissions are set largely by CCNG generation. Average emissions are largely driven by coal emissions. But as time progresses, coal declines and is replaced by low-CO_2 alternatives that are lower-emitting than CCNG after 2045.

Lower GHG Scenario

Figure 6-11 shows the CO_2 emissions rate for direct utility-sector GHG emissions for the Lower GHG Non-electrification Case; the average Electrification Case emissions; and the calculated marginal emissions resulting from transportation electrification. As before, the relatively small load and similar resource mix for marginal generation results in an average emissions rate that is almost the same as that for the base case.

Marginal emissions are generally lower in the Lower GHG Scenario than in the Base GHG Scenario, but the average emissions decrease significantly more quickly and overtake the marginal emissions rate earlier. The reduction in emissions in the Lower GHG Scenario is primarily attributable to reduced coal generation because of the additional cost of carbon.

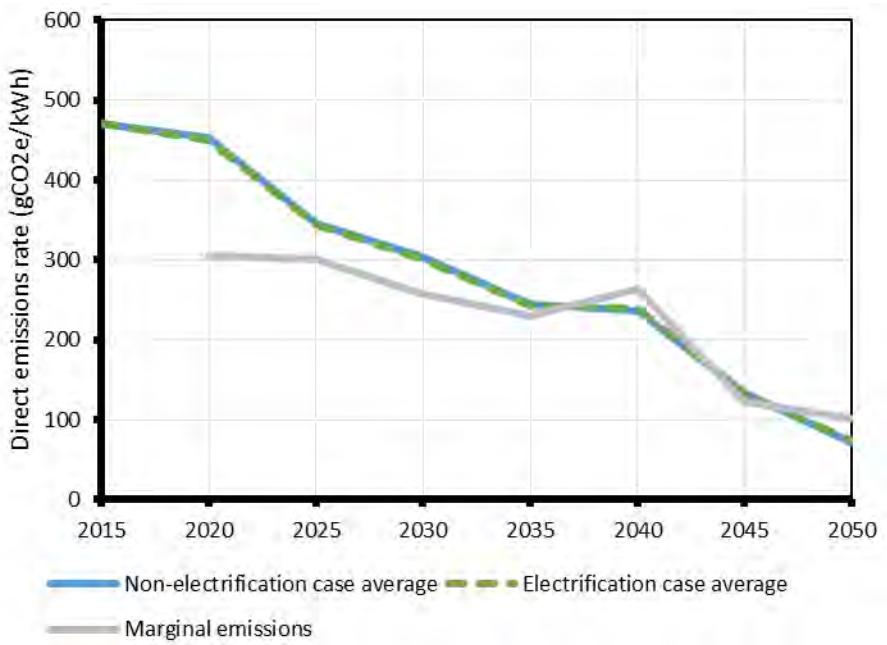

Figure 6-11
Direct electricity-sector GHG emissions rate for the Lower GHG Scenario

Electricity-Sector Emissions Including Upstream Emissions and T&D Losses

The results in the previous subsections were for direct emissions only. These results are useful for comparisons to other modeling results, because there is generally a higher agreement in direct emissions than in upstream emissions in different studies. However, calculating the full impact of charging requires a "consumption"-emissions rate that includes all factors which affect emissions at the point of use. In order to create a consumption-emissions measurement, upstream emissions resulting from input fuels for generation and transmission and distribution (T&D) losses must also be considered. Figure 6-12 shows the consumption-emissions rates that include these factors for marginal and average

emissions for both grid scenarios. From 2015 to 2050 the average emissions rate decreases 45% in the Base GHG Scenario and 77% in the Lower GHG Scenario.

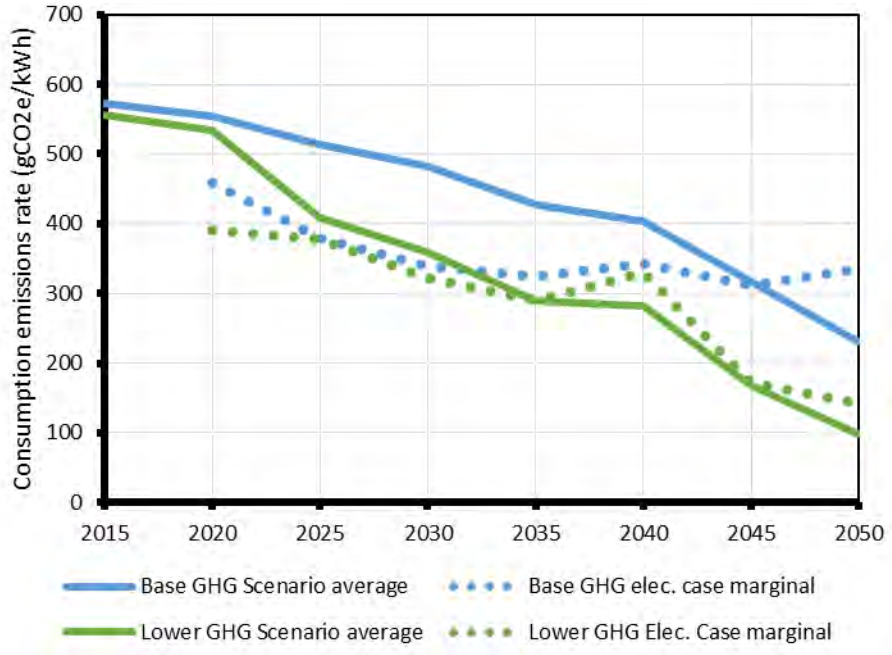

Figure 6-12
Emissions rates "at the wall plug" for both scenarios

Figure 6-13 shows the fraction of total consumption emissions attributable to upstream emissions and T&D losses.[53] The marginal-emissions estimates tend to have a higher percentage of upstream emissions than average-emissions estimates because of a greater reliance on natural gas generation (which has a higher fraction of upstream emissions than coal generation). The upstream fraction also increases in the post-2040 time frame because of the increased share of generation with carbon capture and sequestration. This technology decreases direct emissions, but it does not affect upstream emissions. It is likely that in a full policy scenario in which direct emissions are aggressively decreased, upstream emissions would also be targeted. However, this factor is not modeled in this analysis. (See Section 5 for more information.)

[53] Upstream emissions are discussed in Section 5. Transmission and distribution (T&D) losses, which are 6.3% in all scenarios and for the full timeframe, are discussed in EPRI (2014b).

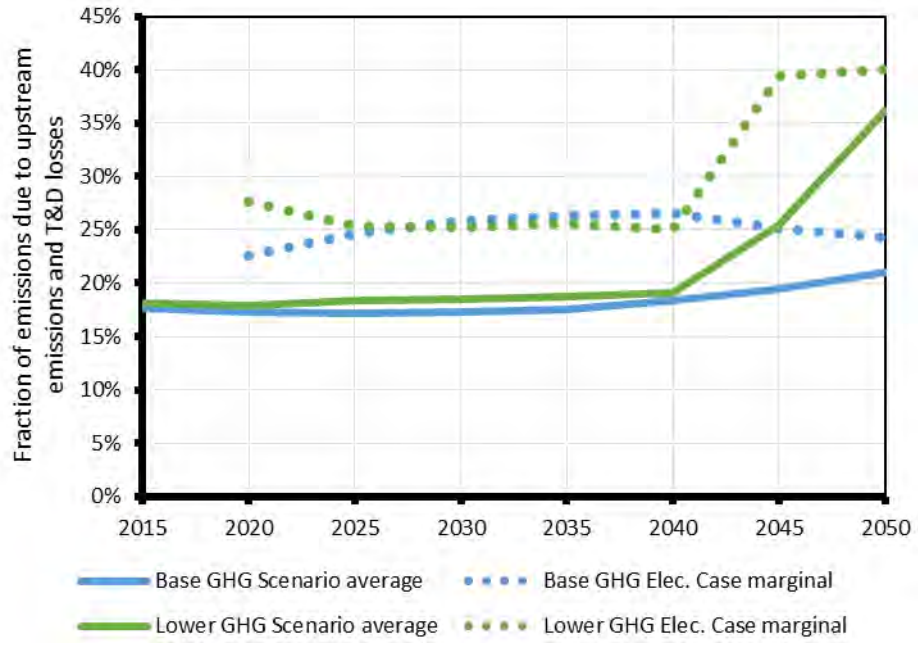

Figure 6-13
Fraction of emissions resulting from upstream emissions and T&D losses

Section 7: Transportation-Sector Results

This section presents the effects of transportation electrification on transportation-sector GHG emissions. This analysis combines the fuel-related emissions from Section 5 with the emissions from marginal electricity use in Section 6. In this section, the transportation sector is divided into *personal*, *commercial*, and *non-road* categories. Personal vehicles generally correspond to "light-duty" vehicles, but they include an increasing share of heavy-duty pickups. Commercial vehicles primarily include medium- and heavy-duty vehicles, but they also include some light-duty vehicles. These categories are derived from the "vocational" categories used in the EPA's MOVES model, as defined in Table 2-1 and discussed in Section 2. Non-road equipment is discussed in Section 3.

This section

- Presents results for transportation emissions in the non-electrification scenario; emissions with transportation electrification and the Base GHG Scenario grid; and emissions with transportation electrification and the Lower GHG Scenario grid.
- Results include upstream emissions for all energy pathways and battery-manufacturing emissions for PEVs.

Vehicle-Emissions Comparison

Most of the emissions results in this section are aggregated to the national level. But Figure 7-1 shows the differences between different vehicle types for the "passenger car" class in 2015 and in 2050. The PEV option has 54% lower lifetime emissions than the conventional vehicle in 2015 because of the shift from petroleum fuel to electricity.[54] (At this electricity-utilization level, the PEV is equivalent to a BEV100+.) In 2050, the improvement increases to 59% with the Base GHG grid and 71% with the Lower GHG grid.

[54] Electricity emissions use "consumption" rates for national marginal electricity from the two scenarios described in Section 4 and Section 6.

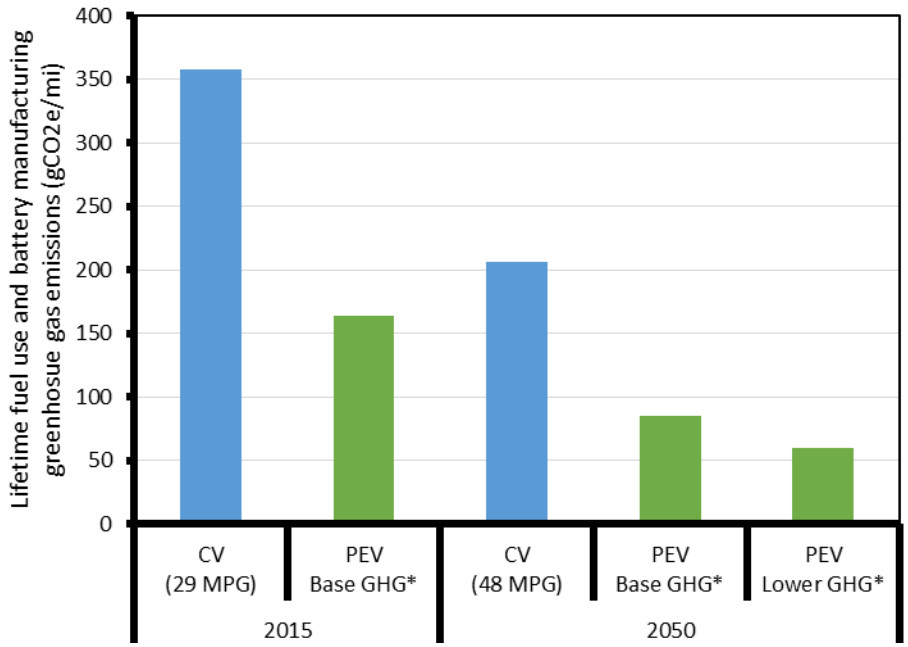

Figure 7-1
Relative vehicle emissions for the passenger car class for 2015 and 2050

** PEV emissions include battery-manufacturing emissions and full-fuel-cycle emissions for electricity and gasoline, averaged over a 150,000 mile vehicle lifetime. Utility factor for the PEV is 87%.*

Baseline Transportation Emissions

As discussed in Section 2 and Section 3, current policies and trends will generally lead to reductions in transportation-sector emissions intensity even without electrification, as vehicles in the current fleet are replaced with newer, more-efficient vehicles. However, increases in activity levels will offset these improvements in emissions rates, so total emissions will decrease at a lower rate. This subsection discusses the balance of these effects for the case without transportation electrification. The analysis in this report is focused on the effects of transportation electrification on *electrifiable* vehicles and non-road equipment, as defined in Section 2 and Section 3. To provide additional context, this subsection also discusses emissions for *non-electrifiable* equipment. Achieving very low transportation emissions will require an expansion in the definition of what is "electrifiable" or the use of other alternative fuels.

Baseline Personal Vehicle Emissions

Figure 7-2 shows the trajectory for personal vehicle emissions in the base case. Existing standards for light-duty vehicles are expected to lead to significant decreases in personal vehicle emissions, even without electrification or other fuel-switching options. As discussed in Section 5, about 20% of fuel-cycle emissions for gasoline (the primary personal vehicle fuel) are attributable to upstream extraction and processing. There is a very small amount of non-electrifiable personal vehicle emissions that are attributable to motor homes.

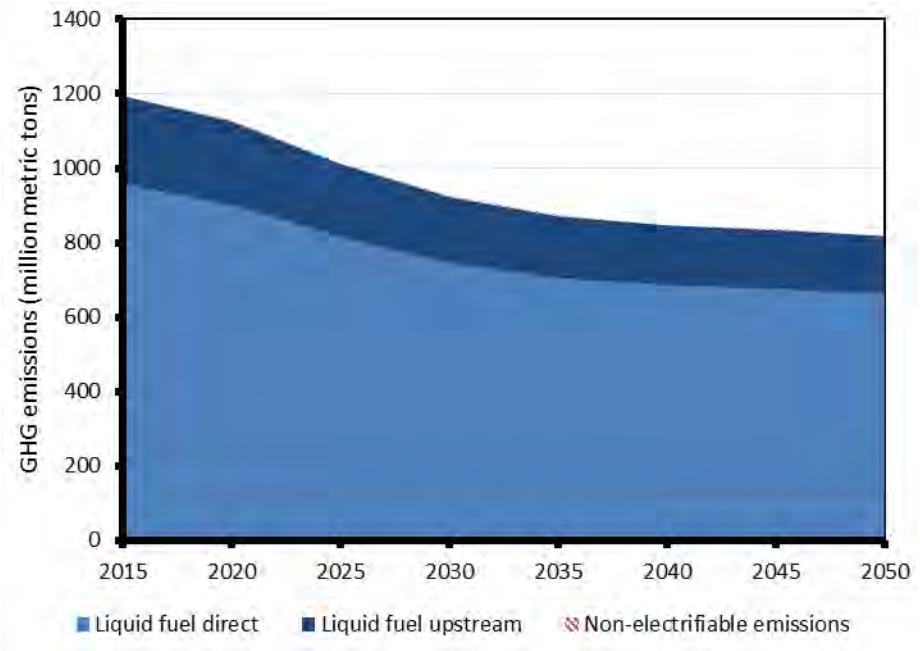

Figure 7-2
Baseline emissions for personal vehicles

Baseline Commercial Vehicle Emissions

Figure 7-3 shows the emissions trajectory for commercial vehicles. The electrifiable fraction of the commercial vehicle fleet has a large fraction of medium-duty vehicles, and modeled regulations are leading to a decrease in emissions for these categories. The majority of commercial emissions are attributable to long-distance heavy-duty trucking, which were not considered to be electrifiable in this analysis. As discussed in Section 2, the EPA's proposed post-2018 regulation for heavy-duty vehicles was not modeled for this analysis, but it would reduce non-electrifiable emissions from the levels shown in Figure 7-3.

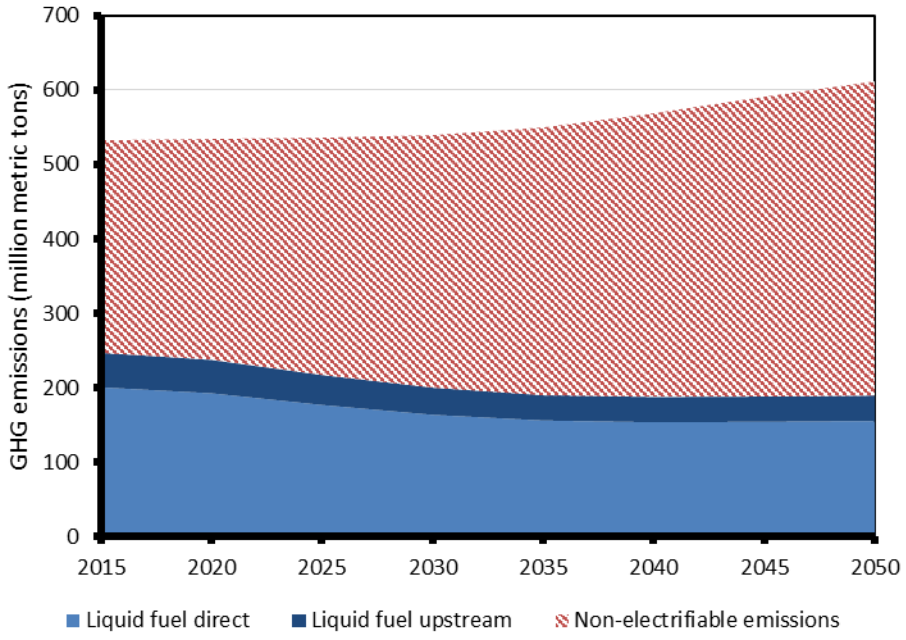

Figure 7-3
Baseline emissions for commercial vehicles

Baseline Emissions for Non-road Equipment

Figure 7-4 shows the emissions trajectory for non-road equipment. As discussed in Section 3, in the non-road category a large fraction of GHG was from equipment that was considered to be non-electrifiable in this analysis. Further electrification of non-road equipment is probably feasible and economical, but this analysis was limited to equipment that already had some electrification or that was amenable to electrification.

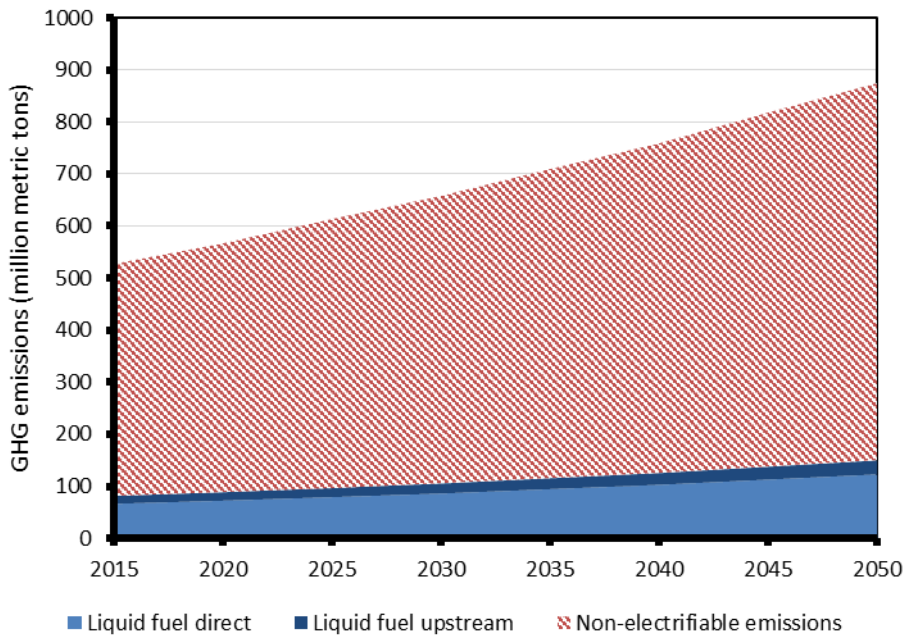

Figure 7-4
Baseline emissions for non-road equipment

Total Baseline Emissions

Figure 7-5 summarizes baseline emissions for all categories. Existing policies—particularly regulations on light-duty vehicle emissions—are projected to significantly decrease transportation-sector emissions. These decreases make further reductions resulting from electrification more difficult. But as the next sections show, projected electricity-sector emissions are low enough to allow it to be a low-emissions alternative fuel.

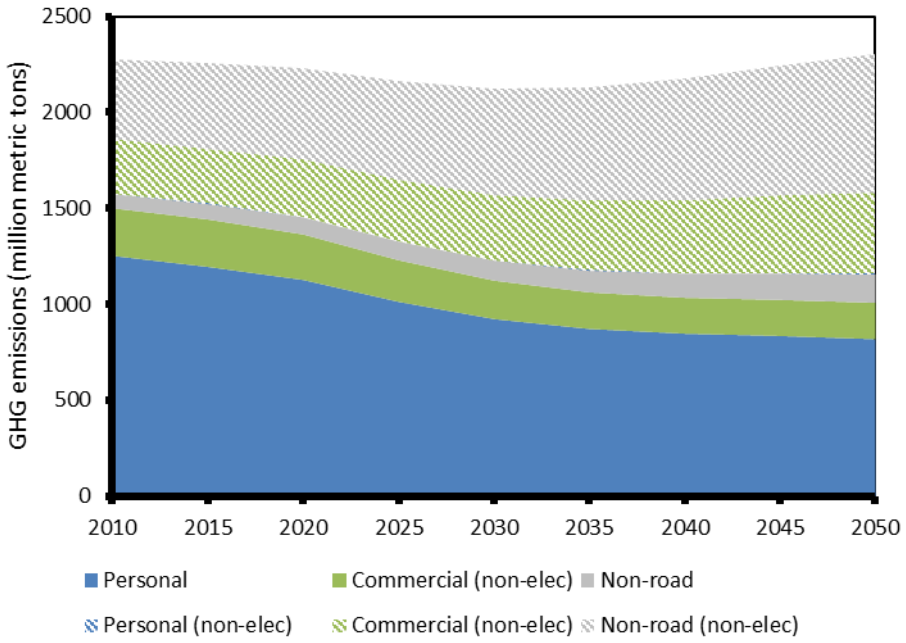

Figure 7-5
*Baseline emissions for all vehicle categories**

*"Non-elec" shows the portion of each category that is considered to be not electrifiable within the scope of this study.

Effects of Electrification on the Transportation Sector

The modeling assumptions discussed in Section 2 and Section 3 result in significant electrification of each category. This subsection discusses these effects on the electrifiable portion of each category.

Effects of Electrification on Personal Vehicles and Commercial Vehicles

Figure 7-6 shows the transition of the modeled personal-vehicle fleet resulting from the assumptions discussed in Section 2 and the effects of this transition on electrified vehicle miles traveled (VMT). By 2050, over 50% of VMT are electrified.

Figure 7-7 shows the same transition for commercial vehicles. Because only electrifiable commercial vehicles are included in this analysis, and the assumptions are for the fraction of the fleet that is electrified, the results are almost the same as those for personal vehicles. (Variances are attributable to differences in vehicle turnover and per-vehicle-VMT.)

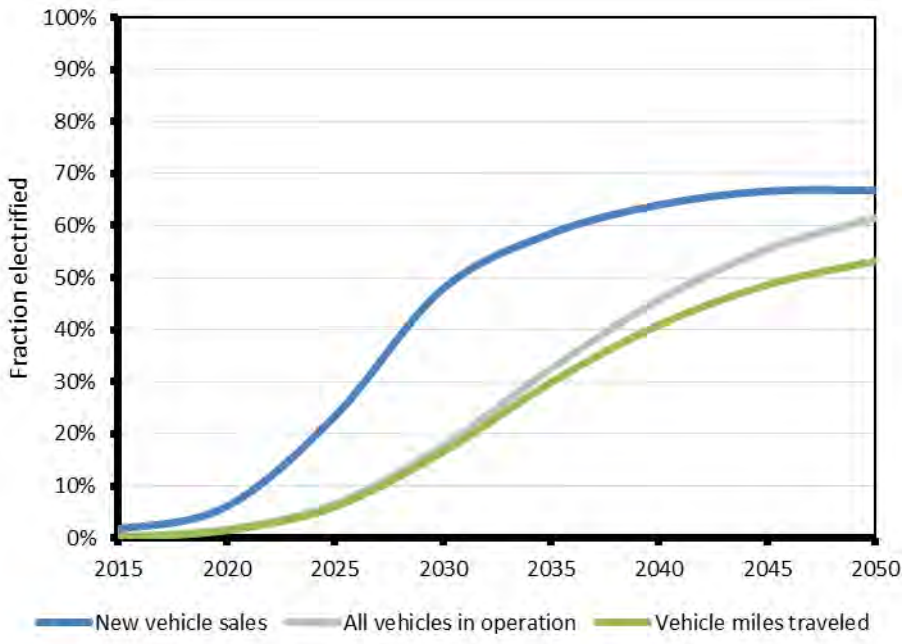

Figure 7-6
Effects of electrification on personal vehicles

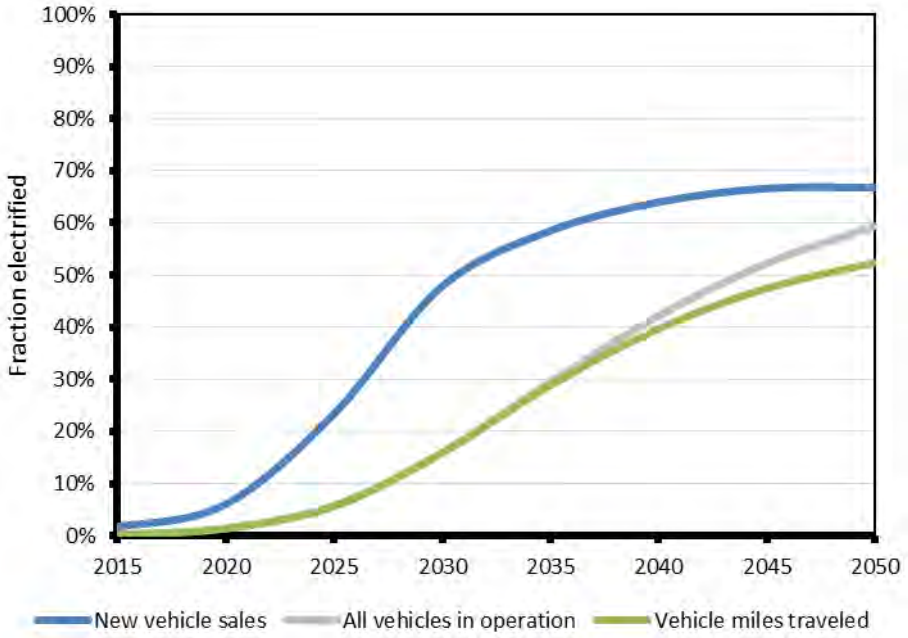

Figure 7-7
Effects of electrification on commercial vehicles

Effects of Electrification on Non-road Equipment

Figure 7-8 shows the effects of electrification on the energy use of non-road equipment. Because of the very wide variation in non-road equipment, sales rates and activity levels cannot be meaningfully summarized. (For example, such an analysis would require homogenizing the number of lawnmowers sold with the fraction of in-port ships that were "cold-ironed".)

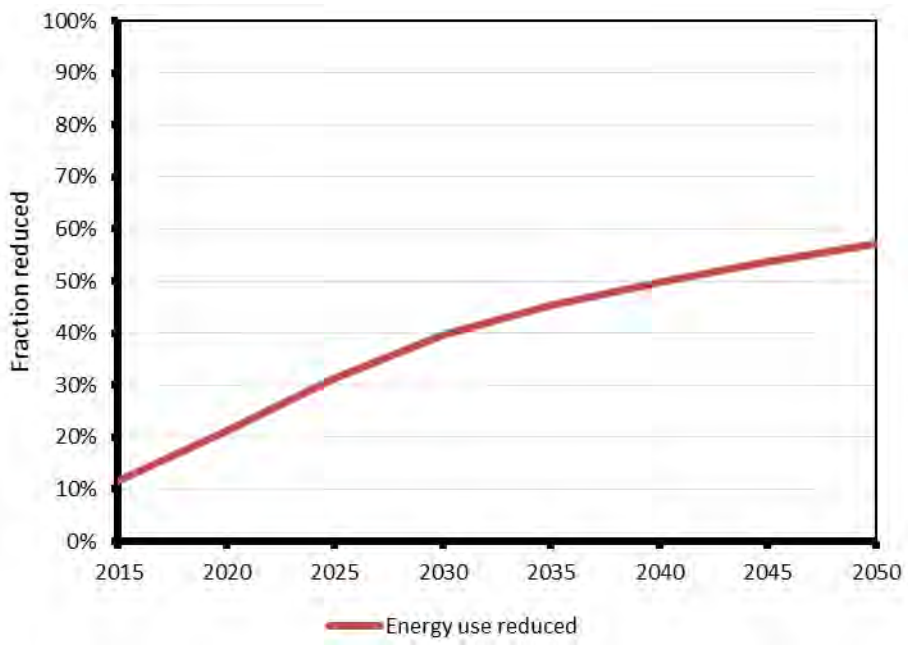

Figure 7-8
Effects of electrification on non-road equipment

Transportation Emissions for the Base GHG Scenario

This subsection discusses the effects of transportation electrification in the Base GHG Scenario (discussed in Section 4). In this scenario, the grid undergoes significant reductions in average GHG emissions, and the marginal emissions attributable to additional load from transportation electrification are lower for most of the study timeframe. The emissions results for each transportation category are discussed, and the total emissions are then summarized.

Base GHG Scenario Emissions for Personal Vehicles

Figure 7-9 shows the reduction in emissions resulting from electrification for personal vehicles in the Base GHG Scenario. As noted in Figure 7-6, electric miles represent an increasing fraction of total miles over the study time frame, until they exceed 50% in approximately 2042. This increase results in a substantial decrease in emissions attributable to liquid fuels (shown in blue in the figure, relative to the top of the dotted black area for non-electrification emissions). Although generating electricity and manufacturing batteries result in incremental emissions, total personal-vehicle emissions are reduced by 37% in 2050.

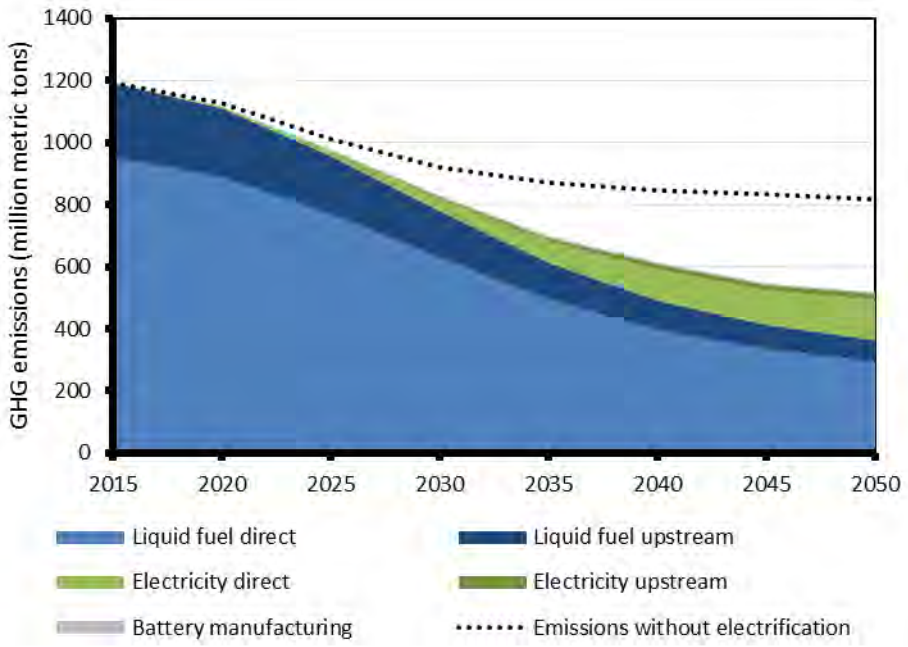

Figure 7-9
Base GHG Scenario emissions for personal vehicles with electrification

Base GHG Scenario Emissions for Commercial Vehicles

Figure 7-10 shows the reduction in emissions resulting from electrification for commercial vehicles in the Base GHG Scenario. Including both the reduction in emissions attributable to gasoline and diesel and the increase in electricity emissions and battery manufacture, net emissions decrease by 39% in 2050.

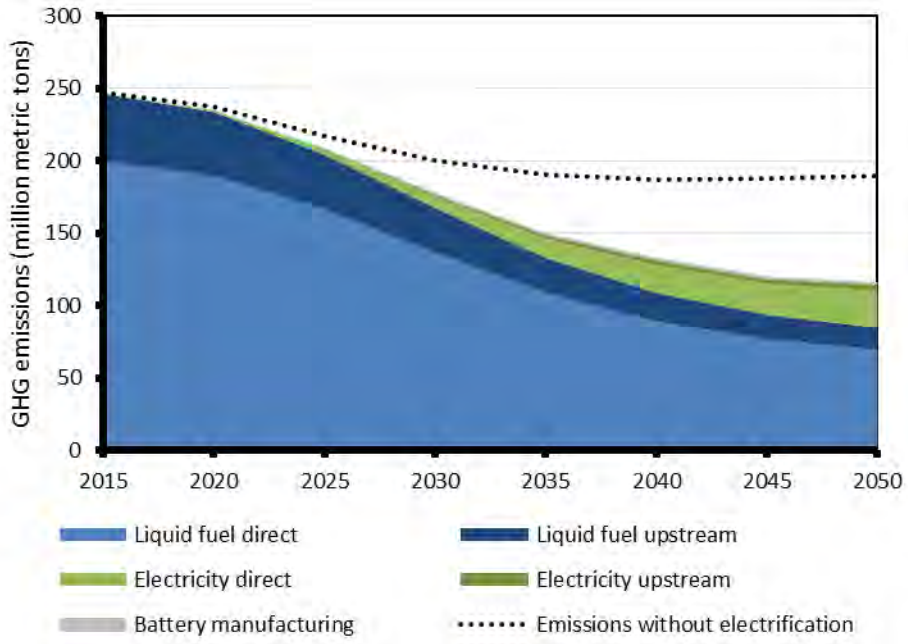

Figure 7-10
Base GHG Scenario emissions for commercial vehicles with electrification

Base GHG Scenario Emissions for Non-road Equipment

Figure 7-11 shows the reduction in emissions resulting from electrification for non-road equipment in the Base GHG Scenario. Net emissions are reduced by 39% by 2050.

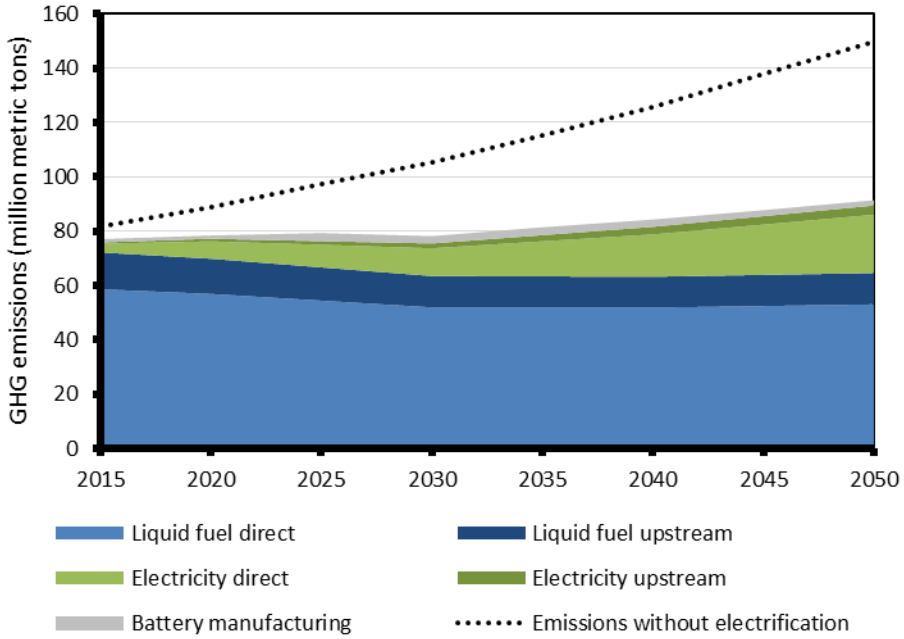

Figure 7-11
Base GHG Scenario emissions for non-road equipment with electrification

Total Transportation Emissions in the Base GHG Scenario

Figure 7-12 shows total emissions for the electrifiable transportation sector for the Base GHG Scenario. "Conventional" areas include emissions resulting from conventional fuels and upstream emissions, and "electrification emissions" include direct electricity-sector emissions, upstream emissions for fuels for electricity generation, and battery manufacturing. Net emissions—including the reductions in the use of conventional fuels and the increase in electricity generation—result in a 37% reduction in emissions in 2050.

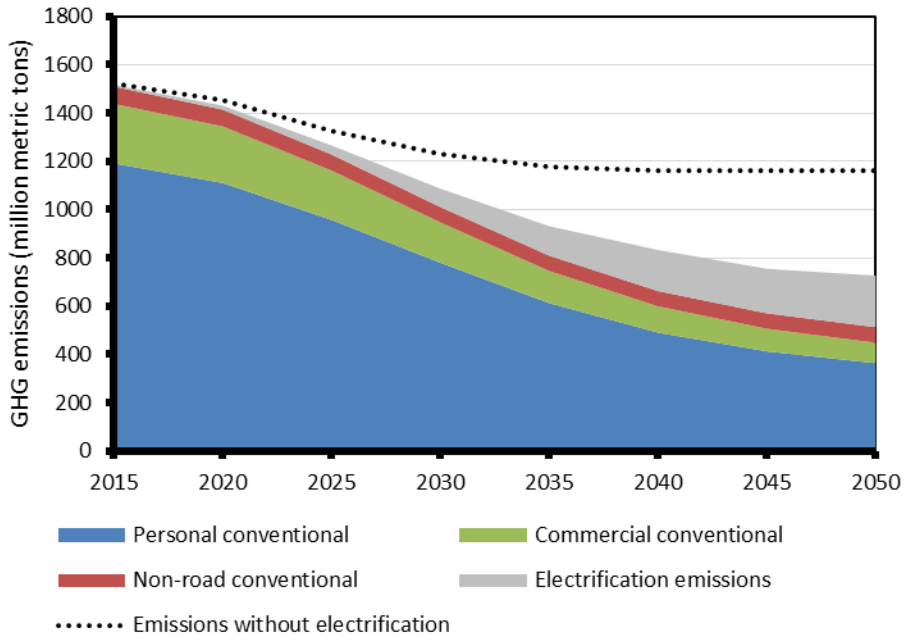

Figure 7-12
Base GHG Scenario emissions for the electrifiable transportation sector

The next subsection discusses emissions in the Lower GHG Scenario, which results in additional decreases in electricity-sector emissions. (All other factors stay the same.)

Transportation Emissions for the Lower GHG Scenario

This subsection discusses the effects of transportation electrification in the Lower GHG Scenario (discussed in Section 4). This scenario includes an additional cost of carbon emissions for the utility sector, which causes reductions in emissions relative to the Base GHG Scenario. Only electricity-sector emissions change between the two cases, so the discussion of results is reduced to personal vehicle emissions and total emissions.

Lower GHG Scenario Emissions for Personal Vehicles

Personal vehicles represent the largest share of transportation-sector emissions, so they are shown as a sample of the effects of reduced emissions in the electricity sector. Figure 7-13 shows the emissions for personal vehicles in the Lower GHG Scenario. Because of the reduction in electricity-sector emissions, total emissions in this case are 47% lower in 2050 compared to baseline emissions.[55]

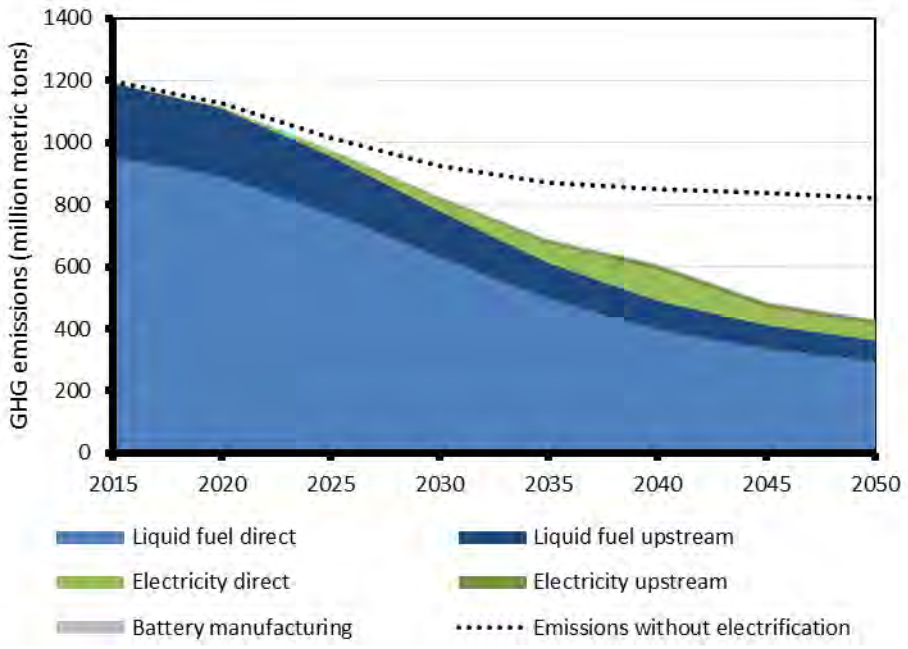

Figure 7-13
Lower GHG Scenario emissions for personal vehicles

Lower GHG Scenario Emissions for Commercial Vehicles and Non-road Equipment

Non-electrified emissions are the same in the Base GHG and the Lower GHG Scenarios, and electrification emissions follow similar trends in other transportation categories. In the Lower GHG Scenario, emissions for commercial vehicles decrease by 48% by 2050, and emissions for non-road equipment decrease by 49% by 2050.

[55] The apparent increase in emissions in 2040 is attributable to slightly higher marginal emissions in 2040 in this case and to the more significant decreases in emissions in the 2045–2050 time frame (which make the 2040 emissions appear larger in comparison). See Section 4 for more information on electricity-sector emissions in this scenario.

Total Transportation Emissions in the Lower GHG Scenario

Figure 7-14 shows total emissions for the electrifiable transportation sector in the Lower GHG Scenario. Total emissions are decreased by 48% relative to the baseline case without transportation electrification.

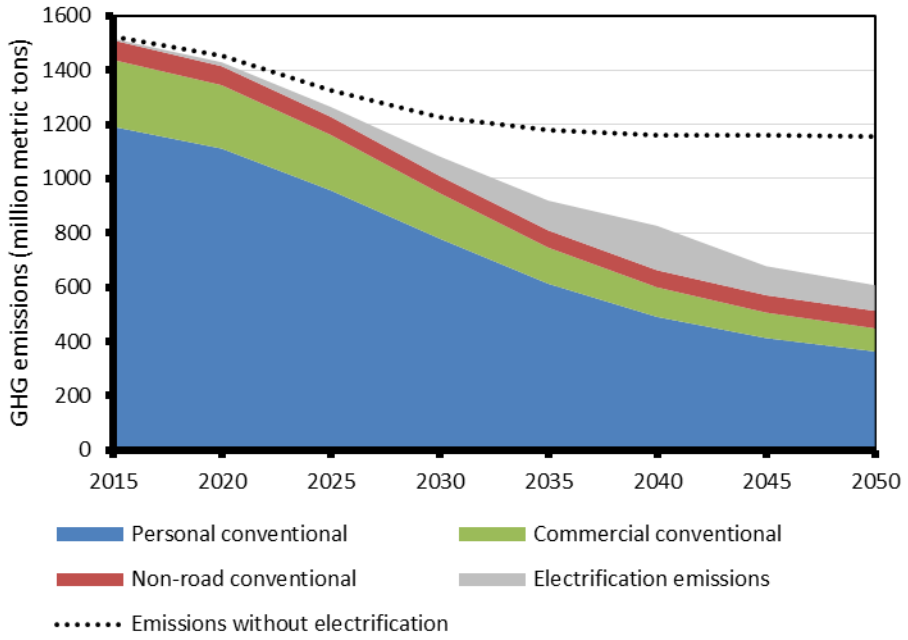

Figure 7-14
Lower GHG Scenario emissions for the electrifiable transportation sector

Summary of Transportation-Sector Emissions Changes

Table 7-1 summarizes the emissions reductions relative to the non-electrification case in 2050 for personal vehicles, commercial vehicles, all on-road vehicles, and non-road equipment. The percentage reduction achieved for commercial vehicles and for all on-road vehicles depends on whether or not out-of-scope non-electrifiable heavy-duty vehicles are included.[56] These vehicles (particularly long-distance trucks) have high emissions levels, so including them reduces the fraction of emissions reduction. (The emissions reductions in terms of MMTons remain the same.)

[56] As described in Section 1 and Section 3, GHG emissions from non-road equipment logically reside in the commercial and industrial sectors, rather than in the transportation or electricity sectors. Therefore, the large amount of non-electrified activity in these classes is not included in Table 7-1. Additionally, emissions attributable to aircraft, rail, and shipping transportation are not included in the "All" categories in the table.

Table 7-1
Summarized results for 2050 emissions reduction due to electrifications by vehicle class

		Base GHG Scenario	Lower GHG Scenario
Personal vehicles	Electrifiable	37%	47%
	All	37%	47%
Commercial vehicles	Electrifiable	39%	48%
	All	12%	15%
On-road vehicles	Electrifiable	37%	47%
	All	26%	33%
Non-road equipment	Electrifiable	39%	49%
Transportation	Electrifiable	37%	48%
	All	27%	24%

Table 7-1 summarizes the emissions reductions from 2015 to 2050 for each category, both for electrifiable vehicles only in each category and for all vehicles in the category. Emissions in some categories increased, resulting in negative reductions over this time period.

Table 7-2
Summarized reductions from 2015 to 2050 (negative reductions indicate an increase in emissions over this time period)

		Without electrification	Base GHG Scenario	Lower GHG Scenario
Personal vehicles	Electrifiable	32%	57%	64%
	All	31%	56%	64%
Commercial vehicles	Electrifiable	23%	53%	60%
	All	-15%	-1%	2%
On-road vehicles	Electrifiable	30%	56%	63%
	All	17%	39%	45%
Non-road equipment	Electrifiable	-84%	-19%	0%
Transportation	Electrifiable	24%	52%	60%
	All	-2%	36%	43%

Section 8: Multi-sector Results

This section synthesizes the electricity-sector results from Section 6 with the transportation-sector results from Section 7 to show the total effects of transportation electrification and improvements in grid emissions.

Base GHG Scenario Results

Multisector Emissions Without Transportation Electrification

Figure 8-1 shows the evolution of transportation- and electricity-sector emissions as modeled in this analysis with the Base GHG Scenario grid assumptions and no transportation electrification. (Emissions for both sectors include upstream emissions.) Emissions for both sectors decrease as a result of current trends and policies, and by 2050 multisector emissions are 37% lower than today's emissions. In the near term, electricity-sector emissions are approximately 50% higher than emissions for electrifiable transportation. But electricity-sector emissions decrease more quickly than transportation-sector emissions, and by 2050 they are approximately equivalent.

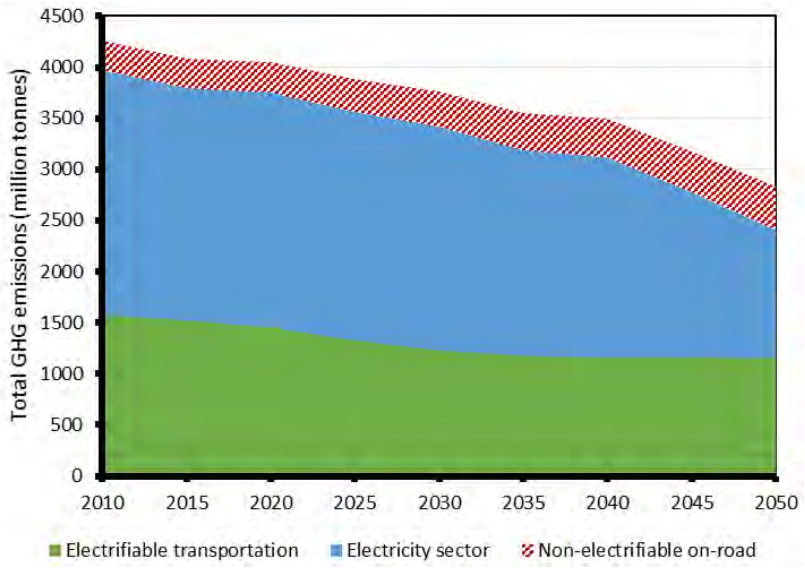

Figure 8-1
Multisector emissions without transportation electrification in the Base GHG Scenario

Multisector Emissions with Transportation Electrification

Figure 8-2 shows the effects of transportation electrification on the multisector results, with emissions attributable to electric transportation separated from emissions attributable to other fuels. Non-transportation electricity-sector emissions (in blue) do not change, but total electricity-sector emissions increase as a result of additional generation to supply electric vehicles (blue plus grey). Transportation-sector emissions attributable to conventional fuels decrease dramatically, however, so total multisector emissions decrease by 48% between 2015 and 2050.

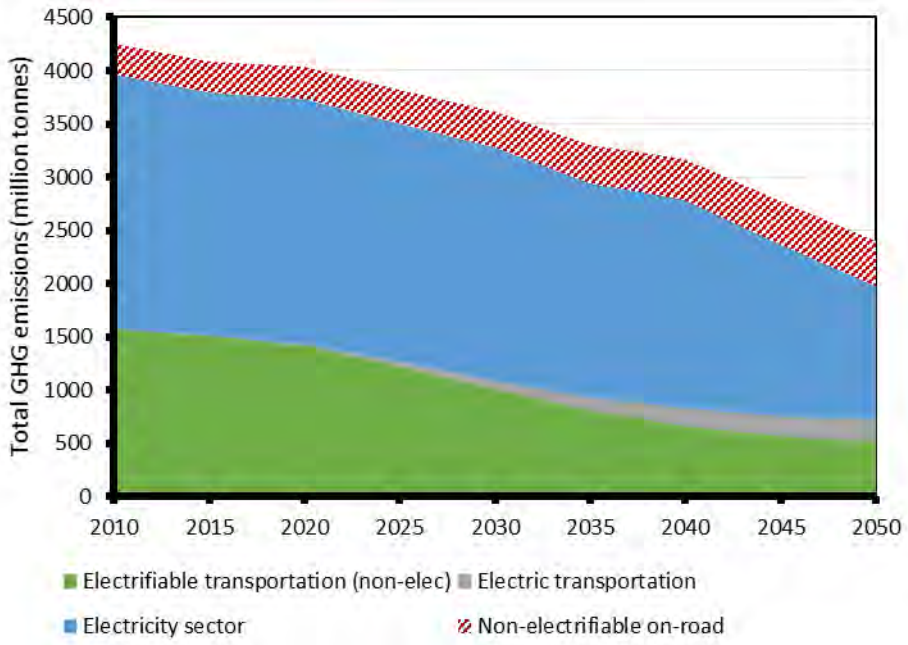

Figure 8-2
Multisector emissions with electrification in the Base GHG Scenario

Lower GHG Scenario Results

Baseline Multisector Emissions

Figure 8-3 shows the multisector emissions for the Lower GHG Scenario. Compared to the baseline results in Figure 8-1, transportation-sector emissions are the same, but electricity-sector emissions are reduced. Electricity-sector emissions decline by approximately 80%, and multisector emissions decline by 55%, relative to 2015 levels.

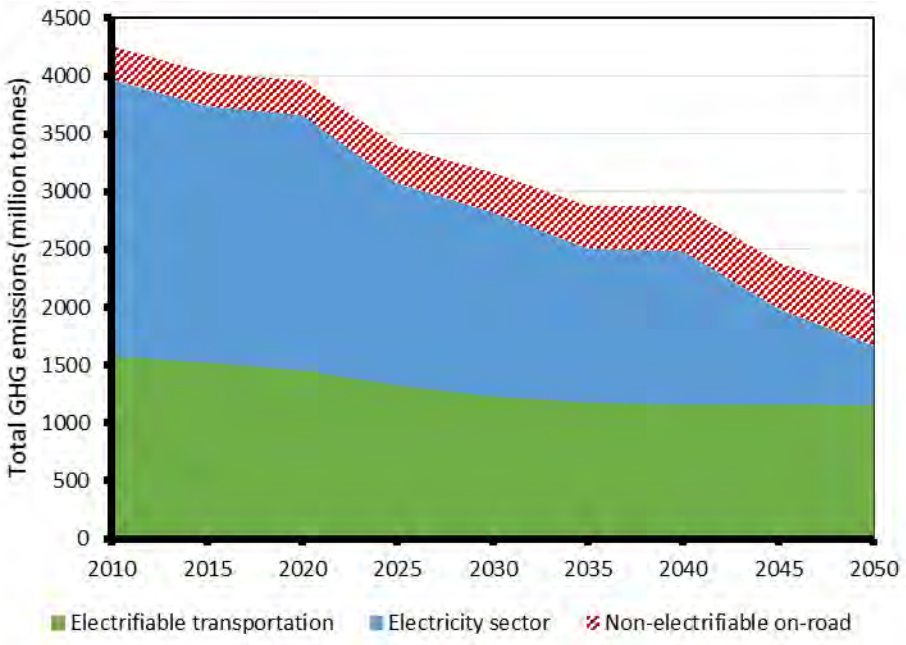

Figure 8-3
Multisector emissions without electrification in the Lower GHG Scenario

Multisector Emissions with Transportation Electrification

The results of the previous two subsections indicate that multisector emissions can be reduced by about half with the modeled changes to either the electricity sector or the transportation sector. Figure 8-4 shows the effects of changing both sectors: Multisector emissions are decreased by 70%.

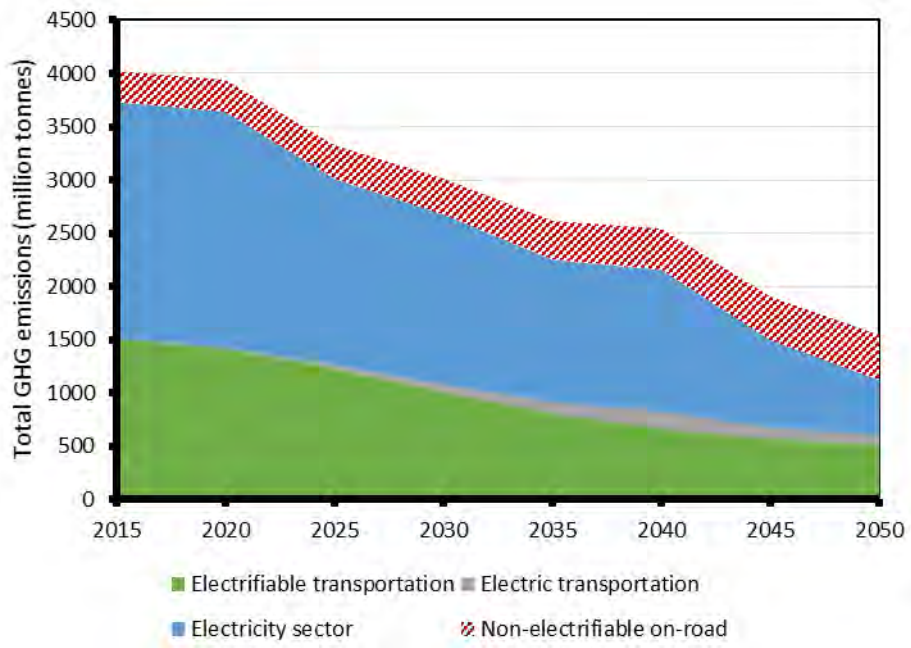

Figure 8-4
Multisector emissions with electrification in the Lower GHG Scenario

Section 9: Alternative Sensitivity Cases

The analysis results described in the preceding sections include a number of assumptions that are uncertain. This section explores the potential effects of a limited set of alternative assumptions or views of the data—including alternative load shapes, regional variations in emissions, and a more rapidly improving conventional-transportation fleet after 2025.

Effects of Alternative Load Shapes

As discussed in Section 6, the analyses in this report use the default US-REGEN load shape for charging load. However, the load shape for charging batteries is highly flexible, and automakers and utilities are collaborating to develop the capability to robustly manage this load. A number of studies have determined that the timing of charging load can have a significant effect on grid emissions; for example, see (Elgowainy, et al. 2012). However, as discussed in Volume 1, most other studies of transportation-grid emissions have used average or small-scale marginal emissions, which have a different response to incremental load than the large-scale marginal approach used in this analysis. Optimizing the load-shape management strategy was not an objective of this paper. However, in order to understand the potential effects of other load shapes on the emissions results described above, an analysis was done using three other fixed load shapes. These three load shapes and the default load shape are compared for the Base GHG Scenario and the Lower GHG Scenario. The results indicate that the grid modeling in this study is relatively insensitive to variations in load shape resulting from the effects of policy and economics on capacity expansion (which is important in the large-scale marginal approach but is unavailable in the small-scale marginal- or average-emission estimation approaches. (See Volume 1 for more information on these different approaches.)

Alternate Sensitivity Load Shapes

The analysis of the sensitivity to load-shape variation used three alternative load shapes: the "Departure and Opportunity" shape and the "End-of-Day" load shape from (Elgowainy, et al., 2012), and the load shape from the previous EPRI-NRDC environmental assessment, labeled as the "nighttime" shape. All three load shapes are shown in Figure 9-1.

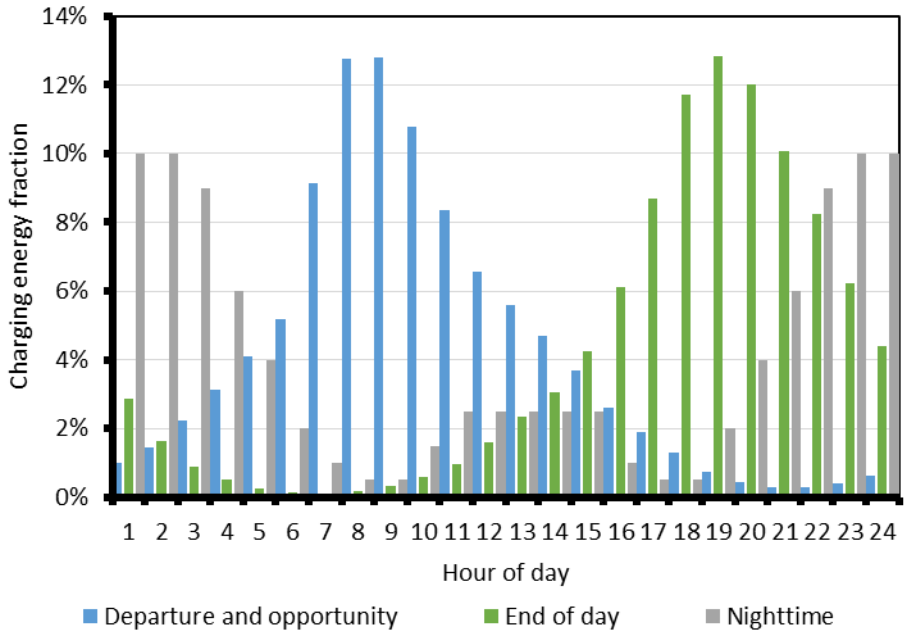

Figure 9-1
Load shapes for sensitivity runs

The "End-of-Day" load shape represents a scenario in which vehicle drivers plug in their vehicles when they arrive home, and charging begins immediately with no delay or control. The mix of vehicle ranges and charging levels has an effect on the charge shape, and the mix in Elgowainy, et al. (2012) is different from the mix used in this study. But as discussed in EPRI (2011), previous EPRI work has found that the sensitivity to differences is relatively low except in cases of very short vehicle range or very high power—neither of which occur in Elgowainy, et al. (2012) or this study. The "Departure and Opportunity" load shape assumes that vehicles are carefully controlled to begin home charging as late as possible so that they are fully charged before leaving home and are then charged when parked under specific conditions. See Elgowainy, et al. (2012) for more detail. This load shape was selected because it effectively "mirrors" the "End-of-Day" load shape, with the maximum load occurring in the morning instead of in the evening. The "Nighttime" load shape allows for a comparison between the modeling in the present Environmental Assessment and that is the 2007 version.

Emissions for Alternative Load Shapes in the Base GHG Scenario

Each of the sensitivity load shapes was used to apply the incremental transportation-electrification load to the Base GHG Scenario grid. The resulting "wall plug" marginal emissions, including upstream emissions and transmission and distribution losses, are shown in Figure 9-2. The US-REGEN result is the same as the result shown in Figure 6-12. (See the surrounding discussion for more information on the upstream emissions calculations.) The results in Figure

9-2 indicate that marginal emissions were similar for all load shapes. However, the generation that leads to these results is somewhat different in each case.

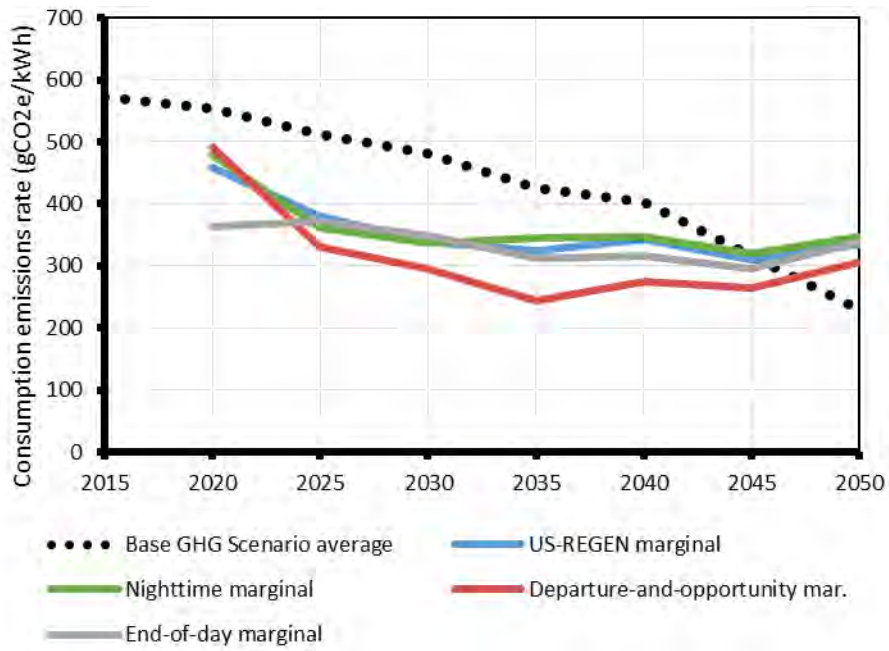

Figure 9-2
Marginal grid emissions for sensitivity load shapes in the Base GHG Scenario

Figure 9-3 shows the marginal generation for each load shape in 2035. (This year was chosen as a sample because it has the largest divergence between the lowest and highest emissions for large load levels, as seen in Figure 9-2.) The "End-of-Day" and US-REGEN load shapes are broadly similar in shape, so they induce generation from similar resources. The "Nighttime" load shape has similar emissions to these two load shapes, but it has a significantly different mix of resources. Because most of the load for this load shape occurs at night, solar generation is not available; however, wind generation is more abundant. (In the United States, the wind tends to occur night; this phenomenon is not true worldwide.)[57] The lowest emissions occurred for the "Departure and Opportunity" load shape. And the incremental generation shows that this result occurs because the load is a good match for wind generation. Therefore, a high fraction of incremental load is met by wind generation.

[57] The "Nighttime" load shape shows "negative" marginal generation, which means that this case has lower solar generation than the baseline. Although it is difficult to determine exact causes at this low level of generation, it is probably attributable to the particular load shape, which improves the economics of wind power in a region in which a Renewable Portfolio Standard is binding.

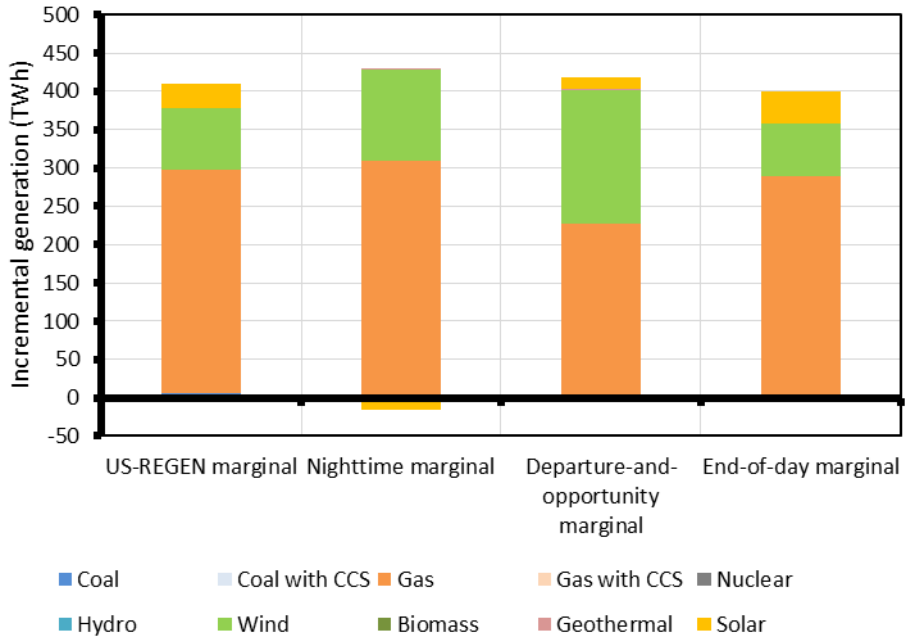

Figure 9-3
Marginal generation in 2035 for each load shape in the Base GHG Scenario

Emissions for Alternative Load Shapes in the Lower GHG Scenario

Figure 9-4 shows the marginal-emissions results for the alternative load shapes in the Lower GHG Scenario. Similar to the Base GHG Scenario, most of the emissions results followed a similar trajectory. Unlike in the Base GHG Scenario, the "Departure and Opportunity" load shape did not have lower emissions than the other load shapes, and the "Nighttime" load shape had significantly higher emissions than other load shapes. In fact, the marginal emissions for the "Nighttime" load shape were higher than the average emissions.

Figure 9-5 shows the marginal generation for each load shape in 2035 for the Lower GHG Scenario. As in the Base GHG Scenario, the "Departure and Opportunity" load shape is a good match for wind generation and improves its relative economics. In this case, however, the increased pressure to reduce CO_2 results in increased solar generation in the US-REGEN and "End-of-Day" load shapes. Therefore, the emissions are similar for all three load shapes. (A small amount of coal generation in the "Departure and Opportunity" load shape negates the higher share of renewable generation.) The marginal emissions for the "Nighttime" load shape are significantly higher than those for the other load shapes, as a result of an increase in the share of natural gas generation and a small increase in coal generation. This shift in emissions is not seen in the Base GHG Scenario, and it is caused by "decreasing returns to scale" for renewable generation in this case. The higher renewable builds in the Reduced GHG Scenario mean that integration of additional renewable generation is more difficult, because of the most favorable resources already being built out and the

additional backup support needed for the higher renewable penetration. Furthermore, the low correlation between the "Nighttime" load shape and solar availability significantly decreases the amount of solar generation. This effect is small, but given the low level of electrification load and the low emissions levels being targeted, it causes a significant increase in relative emissions. Nighttime charging has been suggested as a method for increasing asset utilization and decreasing the cost of charging, but these results indicate that increased emissions may be an unintended side effect. In a scenario with increased pressure to reduce GHG emissions, it is unlikely that a charge-control program would be implemented that would increase the emissions rate. It is likely that a charge-control program could be implemented that would co-optimize reduced emissions and reduced capacity investment. However, implementing such a program was outside the scope of this analysis.

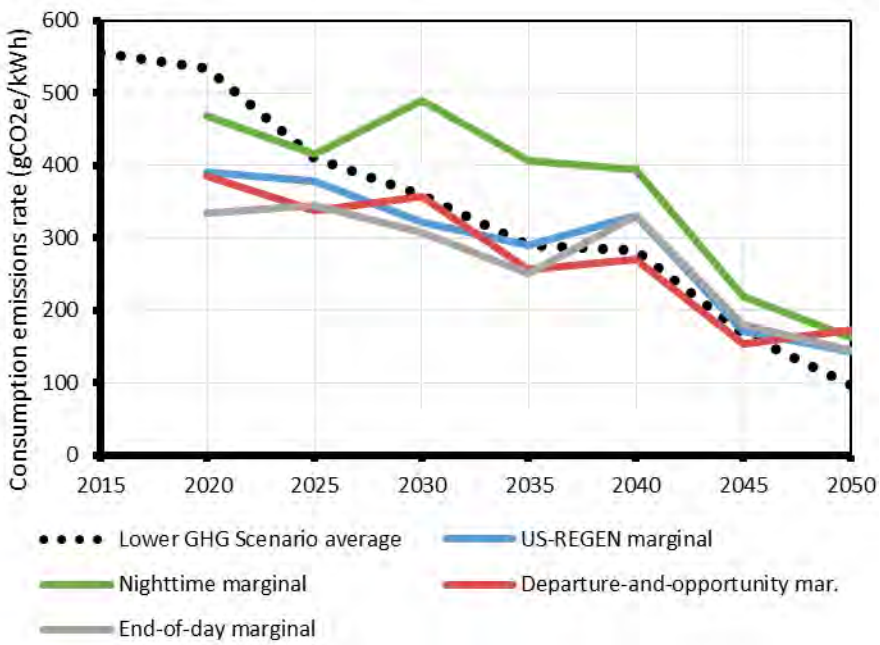

Figure 9-4
Marginal grid emissions for sensitivity load shapes in the Lower GHG Scenario

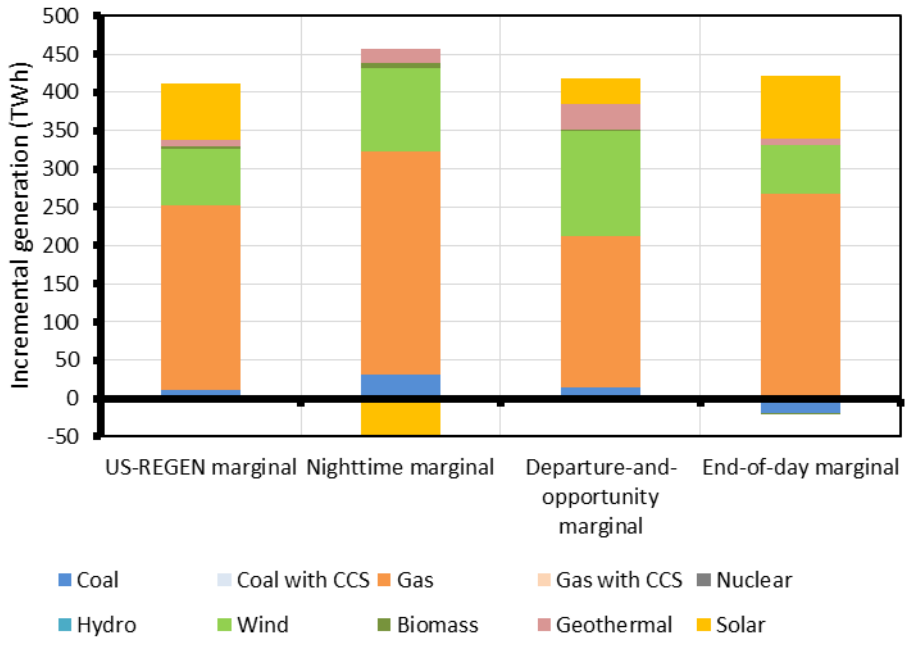

Figure 9-5
Marginal generation in 2035 for each load shape in the Lower GHG Scenario

Regional Variation in Emissions

The different regions of the United States have significantly different levels of natural resources and historical installed generation. For example, the Pacific Northwest has heavy annual rainfall that results in a high fraction of low-emitting hydroelectric generation; the upper Midwest has a high historical fraction of coal generation with higher emissions; and the Great Plains region has the potential to significantly increase the fraction of low-emitting wind generation. These differences are likely to cause significant variations in grid emissions, which can increase or decrease the benefits of transportation electrification. The analysis in this report focuses on national effects, but this subsection explores the differences among regions. These results show that emissions do vary significantly, but that the calculation of marginal-emissions rates is confounded by model-boundary issues which would make these rates difficult to apply in practice.

Regional Variation in Average Emissions

Figure 9-6 shows the regional average CO_2 emissions rate for the Base GHG Scenario without transportation electrification. (The emissions results in this section do not include non-CO_2 direct emissions or upstream emissions, because fuel-use data was not generated at the regional level.) The national trendline seen in Figure 6-10 is present, but it can now be seen that this composite is made up of a wide range of regions that have emissions rates almost 60% higher and almost 70% lower than national emissions. The regions with lower emissions rates tend to be those with higher historical levels of hydroelectric generation and

those with regulatory environments that have encouraged emissions reductions; regions with higher emissions rates tend to be those with historically high levels of coal generation.

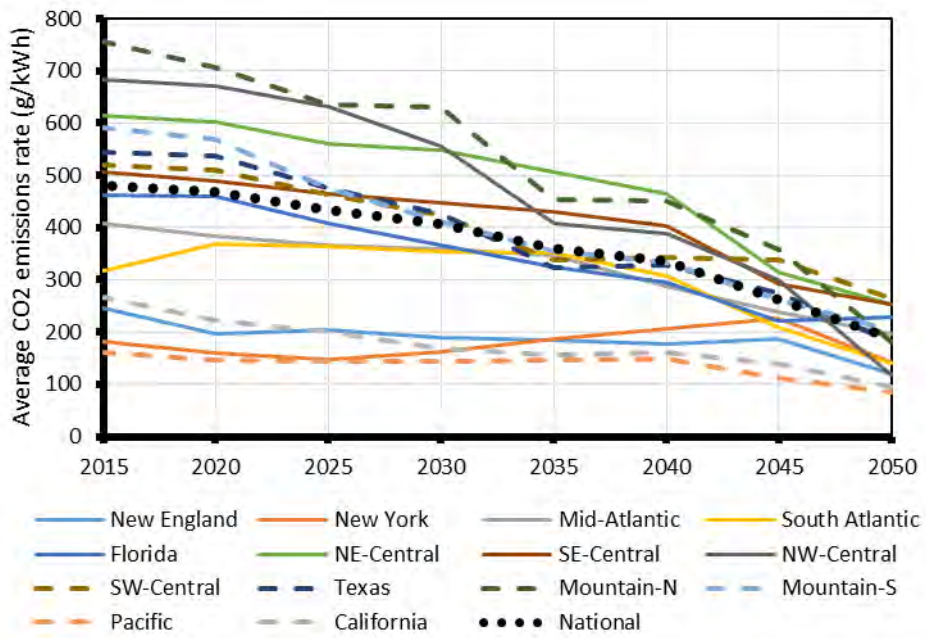

Figure 9-6
Regional variation in average CO_2 emissions rate for the Base GHG Scenario

Regional Variation in Marginal Emissions

It is intuitive that the resource and generation variations which caused average-emissions rates to vary would also affect marginal-emissions rates. Analysis of the regional marginal-emissions rates in this analysis indicates that this intuition is generally true. However, the precise results are difficult to determine because of the close connections among many regions. The marginal generator for a region in an individual time step is often located in an adjacent region. And it is impossible to distinguish which portion of incremental generation in the adjacent region serves the first region's load, and which portion serves its own load. This effect occurs in the average-emissions estimate as well. However, because total load is much larger than the transmission capacity, and most existing load is served by existing generators, the degree of variation is small. Because marginal load often requires capacity expansion, and the marginal load is small relative both to total load and to interregional transmission capacity, marginal emissions are especially sensitive to small differences in regional economics. This sensitivity is not as significant in national-level results, because only the overall changes in generation are important (and not where that generation occurs).

Effects of More Rapid Improvement in Conventional Vehicles after 2025

In the primary transportation scenario discussed in this report, efficiency for light-duty vehicles increases rapidly between 2015 and 2025 in response to the light-duty Corporate Average Fuel Economy (CAFE) and GHG standards. After 2025, however, fuel economy increases at a lower rate (0.5%). Heavy-duty conventional vehicles also increase in efficiency at a rate of 0.5% per year after 2020. These assumptions are based on historical trends. But they may be too pessimistic, given consumer interest in improved fuel efficiency, increased pressure to reduce GHG emissions and the increasing rate of technological progress. Furthermore, this technological progress may come primarily from developments in engines and transmissions, which will have limited applicability to PEV powertrains. A more rapid development of conventional vehicles relative to PEVs would erode the benefits of electrification. This sensitivity analysis investigates the effects of more rapid improvements in conventional vehicles after 2025 on the emissions reductions described in the main report. These results indicate that these rapid improvements would reduce the emissions benefits from electrification, but that electrification nevertheless remains highly beneficial.

Historical and Recent Trends

Fuel-economy improvements for new light-duty vehicles are driven by improving technology, increased customer demand for fuel efficiency, and regulations. Prior to 2012, the primary fuel-efficiency standard was the federal CAFE standard, established by the National Highway Traffic Safety Administration (NHTSA) within the U.S. Department of Transportation (DOT) This standard mandated a minimum fuel economy for new vehicles, but the car standard was fixed at 27.5 mpg from 1990–2010, so it did not mandate increasing levels of fuel economy (DOT/NHTSA 2014). Car fuel economy increased by an average rate of 0.4% per year during this time period, even though regulations did not require it (EPA 2014). Fuel economy for new light-duty trucks was regulated under a different CAFE standard, which did increase over time. But fuel economy for trucks increased at a slightly lower rate (0.3%) from 1990–2010 (DOT/NHTSA 2014, EPA 2014). In 2011, NHTSA raised the CAFE standard for cars. And in 2012, NHTSA and EPA created a joint "National Program" for automotive fuel economy and GHG regulations that required significantly higher improvement rates than had occurred previously. From 2012 to 2025, this program will require new-vehicle fuel economy to improve at approximately 4% per year.[58]

Limited data are available on historical trends for the fuel economy of heavy-duty vehicles, partially because of the complexity of defining "fuel economy" for a wide

[58] The improvement rate is based on projections for the combined car and light truck standards by NHTSA and EPA for model years 2012-2016 (EPA, DOT/NHTSA 2010) and 2017-2025 (EPA, DOT/NHTSA 2012). The achieved automobile fleet fuel efficiency will be determined by the technology improvements within each vehicle size and the mix of vehicle types and size sold.

array of different vehicle types.[59] However, improving the fuel economy of heavy-duty trucks has been an important area of regulatory activity in recent years, and it will provide guidance on future improvements. In 2011, NHTSA and EPA announced the first standard for GHG emissions for medium- and heavy-duty trucks, which set standards for model-years 2014–2018 vehicles (EPA, 2011). In 2015, NHTSA and EPA expanded this program in order to cover more vehicle types and to extend the standards through 2027 (EPA, 2015a). Meeting these standards will require an efficiency-improvement rate of approximately 2–3% per year.

Forecasts Beyond Current Policy in the Assessment's Default Transportation Scenario

As described in detail in Section 2, the default transportation scenario in this study used AEO2013 fuel-economy forecasts through the end of the current standards. The 2015 revision to the heavy-duty standard was not included in this forecast—so, as modeled, the heavy-duty standard reached full effect in 2018. After the end of these standards, AEO2013 forecasted that fuel-economy levels would effectively be constant for both light-duty and heavy-duty vehicles. For this assessment, the study team instead used a fuel-economy improvement rate of 0.5% per year for all vehicle types following the end of the regulated standards in AEO2013. This change assumed that, although standards might not mandate improved fuel economy, customer demand and technical progress would lead to fuel-economy improvement rates similar to historical trends.

Assumption Changes for This Sensitivity Case

It was assumed that fuel economy would continue to improve past the end of current regulations. However, it is not clear how quickly fuel economy will continue to increase after the rapid increases required to meet current regulations. From one viewpoint, the regulations have initiated a change in focus. So GHG emissions will be one of the primary performance criteria for future vehicles, and it will be subject to intense research and development activity by automakers. This focus could allow rapid improvement rates to continue for an extended time frame. From another viewpoint, many of the technologies being applied to achieve rapid improvements in the near term had been "on the shelf"—but they had not been applied to previous vehicles because of insufficient policy or market barriers. As these technologies are applied over the next decade, there will be diminishing returns for additional improvements. Eventually, therefore, the cost to achieve additional improvements will increase rapidly. For example, 3–5 speed automatic transmissions have historically been relatively standard. But in the past few years, 6-speed transmissions have become commonly available, and 9-, 10-, and 11-speed transmissions have been announced or proposed. Increasing the number of gears increases the opportunity for efficient engine operation, but it also increases mass and complexity. At some point, it allows such limited

[59] EIA tracks heavy truck fuel economy in its Monthly Energy Review. Over the years 2007 to 2013, the average annual change in fuel economy was 0%. (EIA, 2015)

opportunity for improvements in engine efficiency that further overall reductions are not possible (Autoweek, 2012). Therefore, although increasing the number of transmission gears may be an enabling technology for rapid improvement in the near term, it may not be available for the same level of improvements in the post-2025 time frame. The study team's selection of a 0.5% improvement rate was not intended to suggest a limit to potential improvements for vehicle fuel efficiency; instead, it was intended to suggest a potential for improvements beyond AEO2013 forecast in the absence of significantly stronger standards. The sensitivity case in this subsection presents an alternative case that shows the effects of more-rapid improvement rates. Additionally, many of the current fuel-economy improvements result from the application of engine and transmission technologies that will not be applicable to electrified vehicles. It is not clear what portion of future improvements would occur because of improvements in these areas, and what portion would occur as a result of light-weighting, drag reduction, and aerodynamic improvements. Therefore, it is possible that conventional vehicles will improve at a much faster rate than electric vehicles—thereby diminishing the emissions advantage of PEVs.

To analyze the effects of more rapid fuel-economy improvement rates and the potential for conventional vehicles to improve at a more rapid rate than plug-in vehicles, the following alternative assumptions were used for the fuel-economy improvement rates of on-road vehicles:

- Current standards are followed until the end of the implementation period, based on AEO2013.
- For new light-duty vehicles, conventional-vehicle fuel economy is assumed to improve at a rate of 2.0%/year for 2027–2050. (Although the current light-duty standard applies through 2025, AEO2013 shows continued improvement in 2026.) The fuel-economy rate for PHEVs running on gasoline or diesel (but not electricity) is assumed to increase at this more rapid rate.
- For new heavy-duty vehicles, conventional-vehicle fuel economy improves at a rate of 3.0% per year from 2020–2035—to represent the improvements required by the 2015 standard and improvements beyond the standard's full implementation in 2027. For 2036–2050, heavy-duty fuel economy is assumed to increase at a rate of 0.5% per year.
- As before, the electricity consumptions of PEVs are assumed to improve at a similar rate to those of conventional vehicles during the scopes of current regulations. But they are assumed to improve at a rate of 0.5% after the standards reach full implementation. (As before, the 2015 heavy-duty standard is not modeled, so the 0.5% rate begins in 2020 for heavy-duty PEVs.) The different improvement rates for conventional vehicles and PEVs implicitly assume that 75% of the improvement in conventional vehicles comes from factors that do not apply to PEVs.

The next subsections discuss the effects of these assumptions on new-vehicle fuel-economy and transportation-sector results. Because the electricity consumption of PEVs is not changed, the electricity-sector results and the

marginal effects of PEVs are the same as in the analysis presented in Sections 6 through 8.

New-Vehicle Fuel Economy in the Transportation-Sensitivity Case

Based on the revised assumptions discussed above, new-vehicle fuel economy improves to levels significantly higher than in the default- transportation case. Figure 9-7 shows the fuel economy for new conventional personal vehicles in the sensitivity case compared with the fuel economy for the "default case" vehicles described in Figure 2-3. Fuel economy for PHEVs while running on gasoline or diesel is shown in Figure 9-8. Based on the rates in the sensitivity case, fuel economy for new personal cars in 2050 is projected to be 72 mpg for conventional vehicles and 96 mpg for PHEVs. Fuel economy for new personal trucks in 2050 is projected to be 49 mpg for conventional vehicles and 70 mpg for PHEVs. All fuel-economy figures are approximately 40% higher than the fuel economy for similar vehicles in 2050 used in the default case.

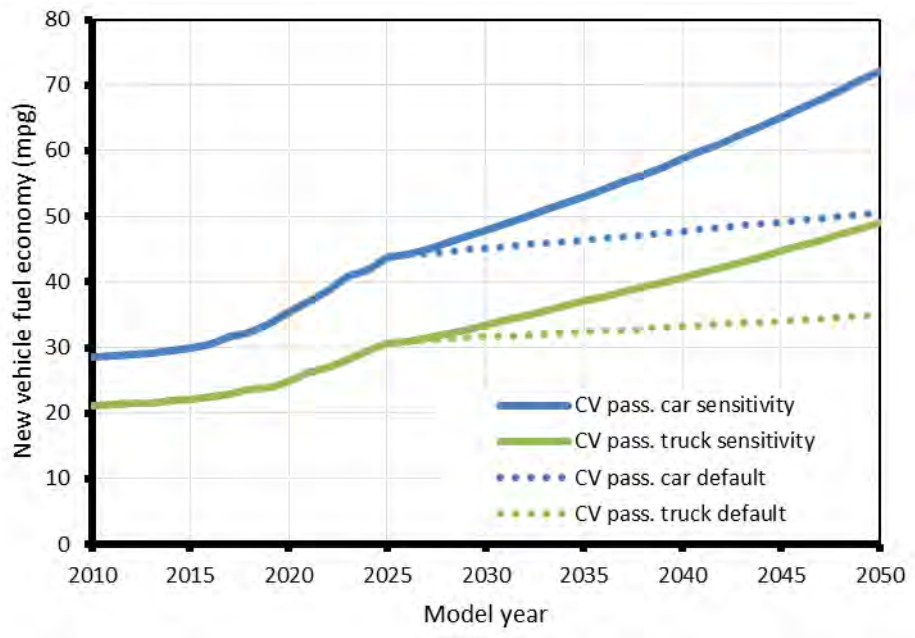

Figure 9-7
New-vehicle fuel economy for personal conventional vehicles in the sensitivity and default cases

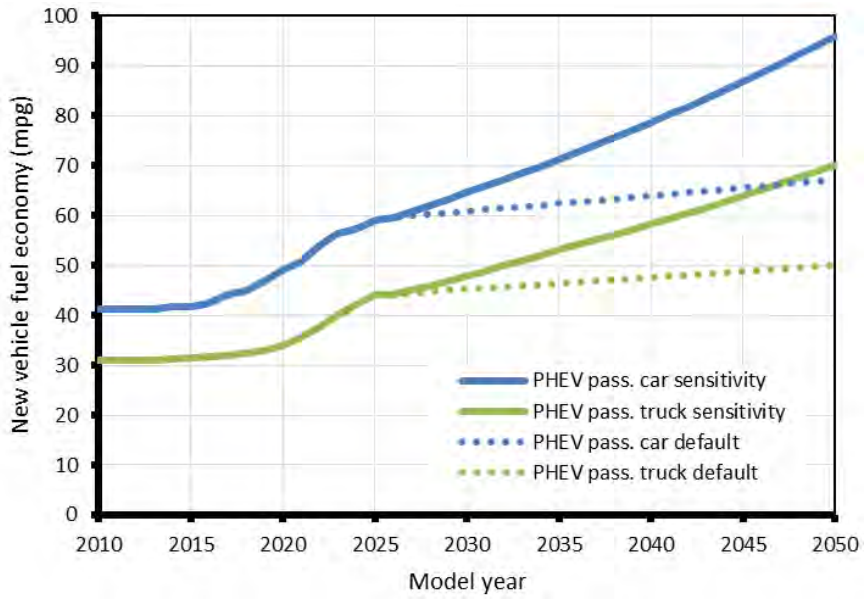

Figure 9-8
New-vehicle fuel economy for personal PHEVs in the sensitivity and default cases

Figure 9-8 and Figure 9-9 show the sensitivity-case fuel-economy improvements for conventional and plug-in hybrid commercial vehicles, respectively. As a result of the rapid improvement rate from 2020 to 2035, new-vehicle fuel economies for commercial vehicles are 45% higher in the sensitivity case than in the default case.

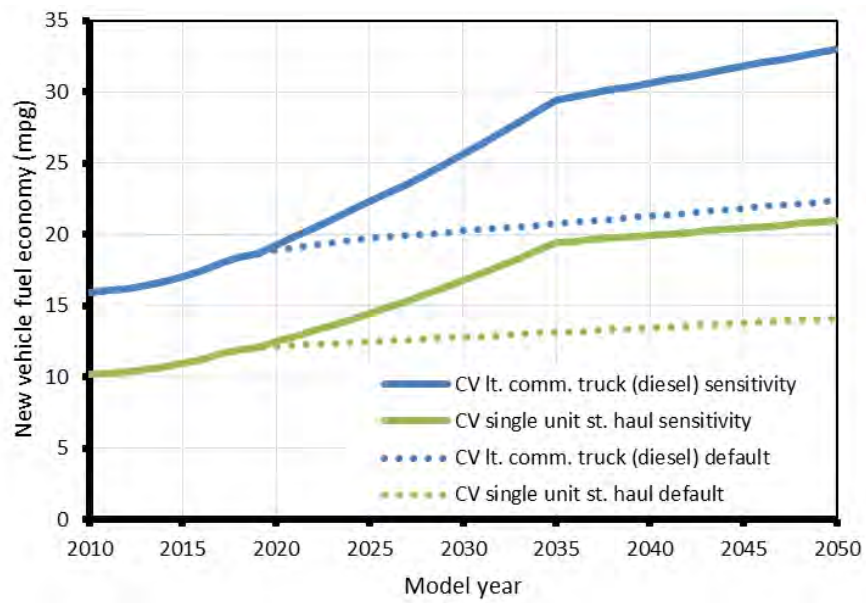

Figure 9-9
New-vehicle fuel economy for commercial conventional vehicles in the sensitivity and default cases

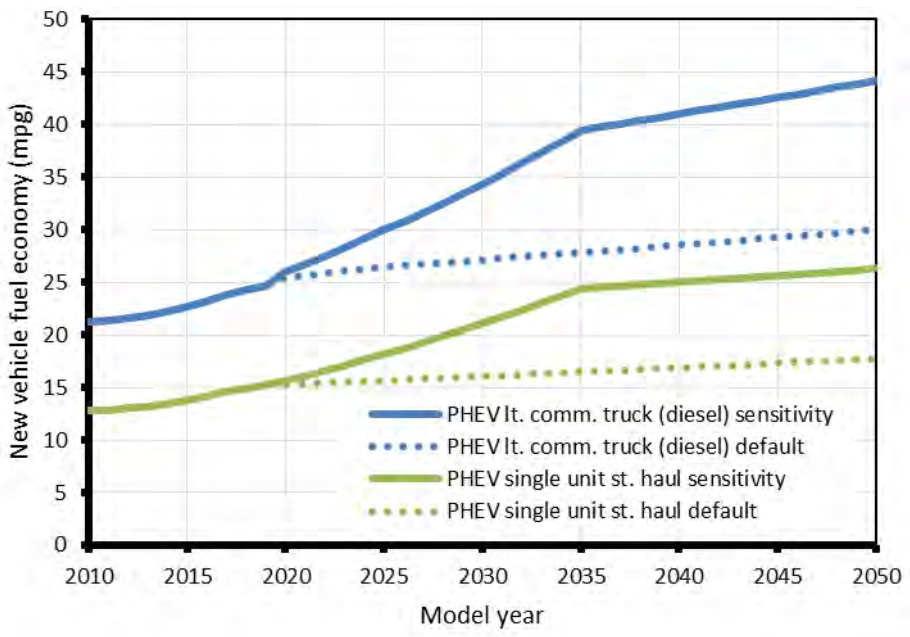

Figure 9-10
New-vehicle fuel economy for commercial PHEVs in the sensitivity and default cases

As a result of the higher improvement rates for conventional-vehicle fuel efficiency relative to the electricity consumption of PEVs, the efficiency gap between the vehicle types decreases. Figure 9-11 shows the ratio of the efficiency of conventional vehicles to PEVs. The efficiency ratio in 2050 declines by about 40% relative to today's levels and 30% relative to the default-case transportation assumptions. However, PEV passenger cars remain 2.1 times more efficient in converting input fuel to miles than the improved conventional-vehicle baseline, and PEV passenger trucks and light commercial trucks remain 2.5 times more efficient than this baseline.

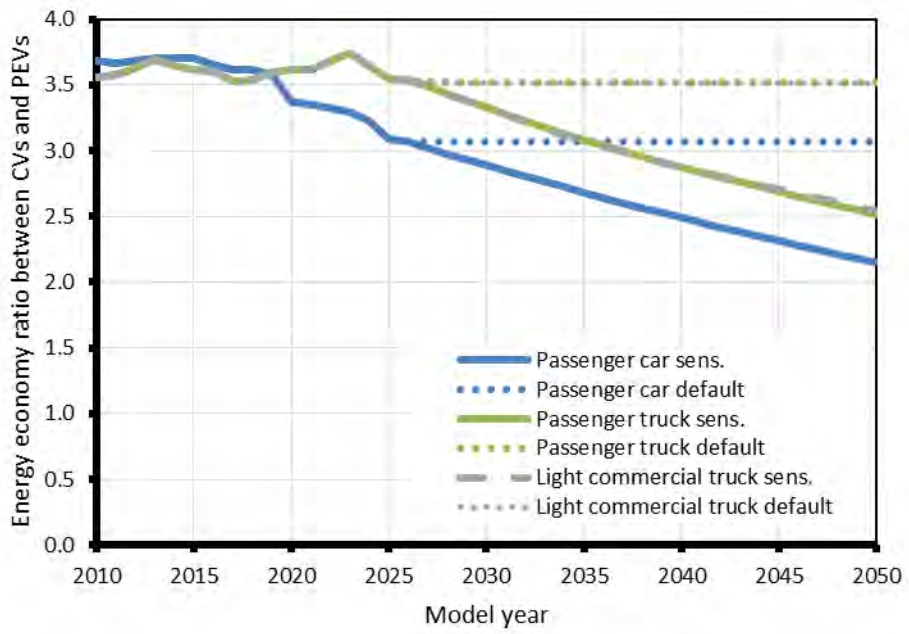

Figure 9-11
Ratio of conventional-vehicle fuel consumption and PEV electricity consumption

Transportation-Sector Emissions Results in the Sensitivity Case

The more rapid increase in conventional-vehicle fuel economy in the transportation-sensitivity case results in greater reductions in overall emissions. But it also results in a decrease in the advantages of electrification. The overall results in the transportation-sensitivity case are similar to those in the default case, so the charts of these results are similar to those shown in the main document. Instead of presenting full results, three representative charts are shown—and then numerical results are shown that allow for detailed comparison.

Figure 9-12 shows the emissions trajectory for personal vehicles for the revised transportation assumptions for the Base GHG Scenario. Compared with Figure 7-9, emissions both with and without electrification are lower. However, the emissions trends are similar, indicating that transportation electrification is still providing a benefit—even with a significantly improved conventional-vehicle baseline.

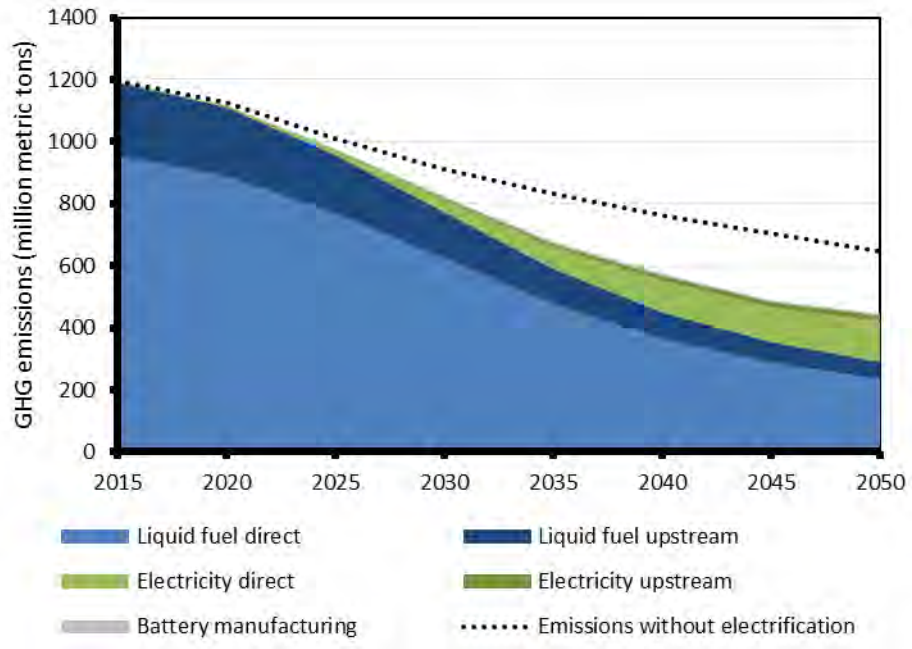

Figure 9-12
Base GHG Scenario emissions for personal vehicles with electrification for the transportation-sensitivity case

Figure 9-13 shows the baseline emissions for commercial vehicles without electric transportation. Although non-electrification case emissions are generally not a focus of this report, Figure 9-13 shows an important difference from Figure 7-3, which affects the numerical results presented below. In the default-case transportation assumptions presented in the main report, overall commercial emissions increased—primarily because of significant increases in emissions from non-electrifiable heavy-duty vehicles. With the higher fuel-efficiency improvements in the sensitivity case, these emissions are approximately flat. (Improved efficiency is matched by increased VMT for these vehicles). This result means that overall commercial vehicle emissions are somewhat lower in 2050 than in 2015. Additionally, it means that the gap between emissions sums for "all" transportation and "electrifiable" transportation will be lower.

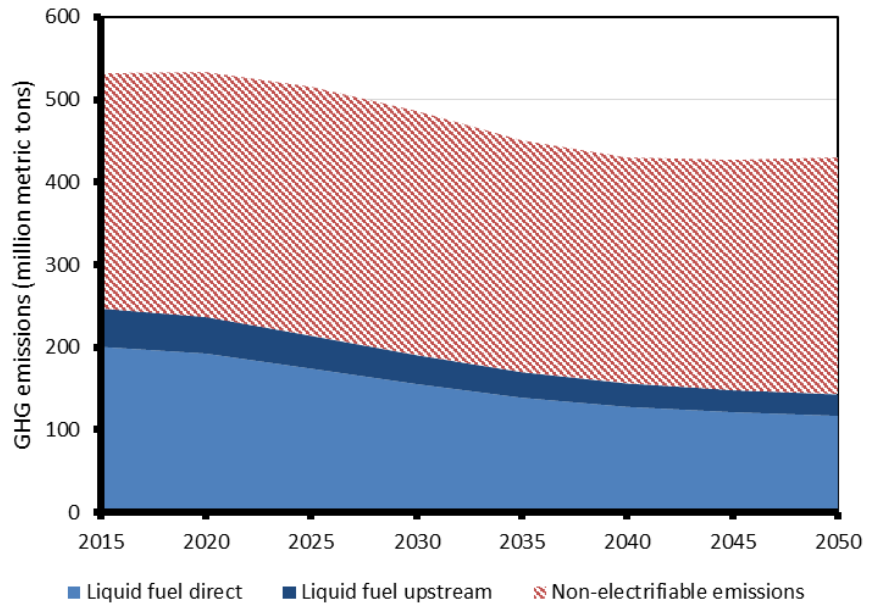

Figure 9-13
Baseline emissions for commercial vehicles in the transportation-sensitivity case

Figure 9-14 shows the trajectory for all electrifiable-transportation emissions for the Base GHG Scenario grid. Compared with Figure 7-12, the blue, green, and red bands are smaller (indicating that the residual non-electrified fuel use is lower), and the overall emissions level is decreased.

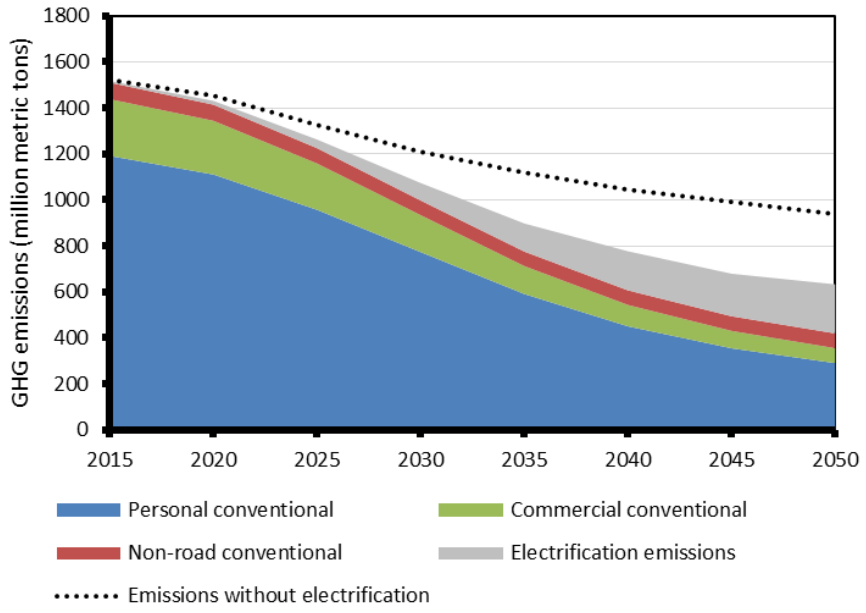

Figure 9-14
Base GHG Scenario emissions for the electrifiable transportation sector

Table 9-1 and Table 9-2 present the numerical results for the transportation-sensitivity case. (Emissions for non-road equipment are unchanged from the default-transportation case, but they are presented for completeness.) Compared with the numerical results in Table 7-1 and Table 7-2, there are a number of notable differences:

- The 2050 reductions from the non-electrification case to the two electrification cases presented in Table 9-1 are lower. Because the conventional-vehicle baseline has lower emissions, converting these vehicles to electricity has a lower benefit.
- The reductions from 2015 to 2050 presented in Table 9-2 are uniformly greater. Emissions without electrification are lower because the baseline conventional vehicles are improved, and emissions with electrification are lower because the residual fuel usage of non-electrified vehicles is lower. Overall transportation emissions are 65% lower in 2050 than in 2015 for electrifiable transportation in the Lower GHG Scenario, compared with a 60% reduction in the default-transportation case.
- The gap between emissions measures for "electrifiable" transportation and "all" transportation is lower in all cases. Most of the difference between these measures is attributable to non-electrifiable long-haul heavy-duty trucks. As a result of the improvements in these vehicles in the sensitivity case (as shown in Figure 9-13), these non-electrifiable emissions are lower, and the performance of all transportation is more similar to the performance of electrifiable transportation.[60]

Table 9-1
Summarized results for 2050 emissions reductions resulting from electrification by vehicle class

		Base GHG Scenario	**Lower GHG Scenario**
Personal Vehicles	Electrifiable	31%	44%
	All	31%	44%
Commercial Vehicles	Electrifiable	33%	45%
	All	11%	15%
On-road Vehicles	Electrifiable	31%	44%
	All	23%	32%
Non-road equipment	*Electrifiable*	*39%*	*49%*
Transportation	Electrifiable	32%	44%
	All	25%	33%

[60] As in the analysis presented in the main report, non-electrifiable non-road equipment is not included in "all" transportation, because these emissions logically reside in the commercial or industrial sectors instead of in the transportation sector.

Table 9-2
Summarized reductions from 2015 to 2050
(Negative reductions indicate an increase in emissions over this time period.)

		Without Electrification	**Base GHG Scenario**	**Lower GHG Scenario**
Personal Vehicles	Electrifiable	46%	63%	70%
	All	46%	63%	70%
Commercial Vehicles	Electrifiable	42%	61%	68%
	All	19%	28%	31%
On-road Vehicles	Electrifiable	45%	62%	70%
	All	38%	52%	58%
Non-road equipment	*Electrifiable*	*-84%*	*-19%*	*0%*
Transportation	Electrifiable	38%	58%	65%
	All	14%	49%	55%

Overall, the transportation-sensitivity case indicates that a more rapid increase in conventional-vehicle fuel economy will reduce the emissions improvements possible through electrification, but that electrification will still provide an emissions advantage. Additionally, the reduction in emissions for residual fuel use and for non-electrifiable transportation will make societal goals for emissions reductions more achievable—both for individual vehicle categories and for overall transportation emissions.

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Appendix A: Detailed On-road Vehicle-Model Assumptions

This appendix describes additional assumptions for the on-road vehicle modeling.

"Passenger Truck" and "Light Commercial Truck" Categories

The naming of the "Passenger Truck" and "Light Commercial Truck" categories in the EPA MOVES software may be misinterpreted; the names, which are based on use, imply that only light-duty vehicles are present in the category. In the EPA's categorization, these categories are partially composed of heavy-duty vehicles, which can affect the fuel economies of the categories as a whole. Table A-1 presents the division of these categories on a VMT basis for calendar year 2030, based on data in Table B-1 in Volume 3. Although only 7% of passenger-truck VMT and 17% of light-commercial-truck VMT are driven by heavy-duty vehicles, the heavy-duty segments of these categories are responsible for a significant fraction (32%) of the total heavy-duty VMT (including all HDV categories) in 2030–because heavy-duty VMT comprise only about 10% of the total on-road VMT.

Table A-1
Distribution of "Passenger Truck" and "Light Commercial Truck" VMT in 2030

		Light-duty	Heavy-duty
Passenger Truck	Gasoline	92.3%	5.4%
	Diesel	0.6%	1.6%
Light Commercial Truck	Gasoline	79.9%	9.5%
	Diesel	2.8%	7.9%

Vehicle-Activity Data

As described in Section 2, the base-year VMT and vehicle-population data was projected to 2050 using the vehicle-turnover model and aligning it to AEO VMT data. Because AEO datasets contain 3 years of history and approximately 25 years of future projection, the VMT and vehicle-population projections were calibrated to AEO2011 for 2008 through 2010, and then calibrated to AEO2014 for 2011 through 2040. The projections were then extended to 2050 using 5-year rolling averages of the growth rates. Because the AEO projection includes fewer light-duty and heavy-duty vehicle categories than the 13 categories used by the MOVES model, the VMT data was aligned to AEO using two broad categories: light-duty vehicles and heavy-duty vehicles.

The vehicle-turnover model is used to project the evolution of each vehicle class of the vehicle fleet and to track how new vehicle powertrain types impact the vehicle fleet over time. The model is based on the vehicle population and VMT growth calculations described in the United States Environmental Protection Agency's (EPA's) Motor Vehicle Emission Simulator (MOVES) 2009 Software Design and Reference Manual (EPA, 2009a). The turnover model requires a large amount of supporting data, which include

- Base-year VMT and population data, by vehicle class. The source of this data is described in Section 2.
- Projections of VMT and population by vehicle class. These projections are based on AEO data, as described in the previous paragraph.
- Initial age distribution. This data indicates how the initial vehicle population is distributed across vehicle ages (model years). There are 31 bins of vehicle age, with the 31st bin including vehicles aged 30 years or more. There are separate initial age distributions for each vehicle class. The source of this data is MOVES 2010a.
- Survival rate. This data indicates what fraction of vehicles of a particular age survive to the next calendar year (as opposed to being retired/scrapped). There are 31 age bins, with separate data for each vehicle class. The source of this data is MOVES 2010a.
- Relative mileage accumulation rate. This data (by vehicle age) is multiplied element-wise by the age distribution (by vehicle age) of a particular calendar year to determine the travel fraction for that year. The travel fraction is then used to determine the distribution of that year's VMT across vehicle ages. The relative mileage-accumulation-rate data include 31 age bins and separate data for each vehicle class. The source of this data is MOVES 2010a.

Biofuel and Renewable Content of Liquid Fuels

The assumed quantities of biofuel and renewable fuel in the gasoline and diesel supplies are based on quantities from AEO2014 and emissions from GREET. The study team made the following additional assumptions:

- The AEO2014 specifications of "ethanol from other starch" and "liquids from biomass" are assumed to be equivalent to corn ethanol.
- Cellulosic ethanol will be sourced from sugarcane for purposes of determining upstream emissions. AEO2014 does not specify a feedstock for cellulosic ethanol. Ethanol sourced from switchgrass has the potential to provide significant GHG reduction. However, given the uncertainties concerning future production using this pathway, sugarcane ethanol was used as a commercially available substitute.
- AEO2014 does not designate a feedstock for biodiesel or renewable diesel; both of these fuels are assumed to be sourced from soybeans.
- Because AEO2014 only provides data up through 2040, beyond 2040 the biofuel quantities are escalated—using an average of each quantity's growth rate over the previous 5 years.

These assumptions result in the following schedule for the content of biofuel and renewable fuel in the gasoline and diesel supplies.

Table A-2
Biofuel and renewable content of liquid fuel supplies

	Gasoline Mix			Diesel Mix		
Year	**Corn Ethanol**	**Sugarcane Ethanol**	**Petroleum-based**	**Biodiesel**	**Renewable Diesel**	**Petroleum-based**
2010	9.82%	0.00%	90.18%	0.76%	0.14%	99.10%
2015	10.65%	0.05%	89.30%	3.74%	0.04%	96.22%
2020	11.96%	0.16%	87.88%	3.39%	0.25%	96.36%
2025	13.70%	0.24%	86.06%	3.16%	0.24%	96.61%
2030	14.95%	0.26%	84.79%	3.02%	0.23%	96.75%
2035	15.48%	0.27%	84.25%	2.96%	0.22%	96.82%
2040	15.92%	0.28%	83.81%	2.91%	0.21%	96.88%
2045	15.93%	0.28%	83.79%	2.85%	0.21%	96.94%
2050	15.95%	0.28%	83.77%	2.80%	0.21%	97.00%

GREET 1 Configuration

The GHG emissions factors of the assumed biofuel levels in gasoline and diesel were calculated using weighted averages of the emissions rates of 100% gasoline (E0) and 100% ethanol (E100) for the assumed biofuel levels in gasoline, and by weighting 100% diesel (B0) with 100% biodiesel (B100) or 100% renewable diesel (RD100) for various blends of biodiesel. To obtain the emissions factors of the "pure" fuels, the following parameters were modified in GREET 1:

- By default, GREET 1 assumes that gasoline contains 10% ethanol by volume. This setting was changed to 0% to obtain the GHG emissions of gasoline without any blended ethanol (E0).
- By default, GREET 1 assumes that the ethanol content in a "dedicated" ethanol vehicle is 85% ethanol by volume. This setting was changed to 100% to obtain the GHG emissions factor of 100% ethanol (E100).
- By default, GREET 1 assumes that ethanol is sourced from 100% corn. This setting was set to 100% sugarcane to obtain the GHG factor for sugarcane ethanol.
- By default, GREET 1 assumes that the biofuel content of biodiesel is 20% by volume. This setting was changed to 100% to obtain the GHG emissions of 100% biodiesel (B100).

Detailed GREET 2 Assumptions for Battery Manufacturing

A small portion of the default assumptions in GREET 2 were modified for this study, as described below.

Battery-Specific Energy

The specific energy (amount of energy-storage capacity per unit mass) of batteries has consistently increased in past decades as technology has advanced and new battery chemistries have been discovered. Accordingly, this analysis is based on the LMO chemistry, but it assumes that the specific energy of the batteries will improve throughout the time frame of this study. It is likely that other unknown chemistries will instead replace those currently modeled. The active materials for these new chemistries may have higher or lower manufacturing energy than LMO; most other lithium-ion chemistries modeled in GREET have higher manufacturing energy on a per-battery basis than LMO, but most current chemistries are within a 20% band on a per-battery basis (Dunn, 2050). This analysis implicitly assumes that the active material in these new chemistries will produce similar manufacturing emissions on a per-kWh basis to the current LMO system.

The study team reviewed the specific energy assumptions in both the 2014 and 2013 versions of GREET 2 and decided that the data in the 2013 version is appropriate for model-year 2010 vehicles using LMO batteries. These assumptions are 74 Wh/kg for the PHEV and 102 Wh/kg for the BEV, and they apply to the total battery system—including container and battery-

monitoring systems. This study assumes that the specific energy increases by 3% per year from 2010 to 2015, and it will then reach 130 Wh/kg for an average electric-vehicle battery by 2020. Beyond 2020, it is expected that specific energy will continue to increase at 2% per year. This leads to the schedule shown in Table A-3.

Table A-3
Battery specific energy at the pack level

	Specific Energy (Wh/kg)	
Year	**PHEV**	**BEV**
2010	74	102
2015	86	118
	Converged PEV	
2020	130	
2025	144	
2030	158	
2035	175	
2040	193	
2045	213	
2050	235	

Battery Materials

GREET models the amount of energy consumed and emissions generated during the production of the various materials that comprise the battery, as well as the assembly and end-of-life disposal/recycling of the battery. GREET uses assumptions for the composition of the battery in terms of the share of each material relative to the overall battery mass. This mass distribution is then used to scale the amount of mass of each material resulting from changes in battery capacity or specific energy. This study assumes that the default mass-distribution assumptions remain constant across the study period.

This study makes some simplifying assumptions regarding how battery performance will improve over time. Specifically, it is assumed that increases in the battery specific energy (shown in Table A-3) will occur as a result of improvements focusing on the battery's active material; the shares of various materials within the battery are assumed to remain the same as the specific energy of the active material increases. It is further assumed that the energy requirements to produce the battery (per weight of each material) would also remain the same over time (except for the electrodes), despite the increases in specific energy. As a conservative assumption, the electrodes would require additional energy to produce, per weight of material, in direct proportion to the

increase in battery capacity.[61] The emissions resulting from manufacturing the active material would remain constant, per battery kWh, as battery specific energy increases; the emissions of other materials decrease, per battery kWh, because of decreases in the amount of materials required. Overall, the energy requirements and GHG emissions from manufacturing the battery would decrease per kWh of battery capacity as the specific energy increases.

Emissions Resulting from Electricity Consumption

GREET 2 models the energy consumption and emissions of a wide range of manufacturing processes. Different processes are modeled as consuming a variety of energy sources in amounts that are specific to each process. For battery manufacturing, electricity is an important source of input energy. Because GREET only includes assumptions until the year 2020, the study team altered the GREET 2 input data for electricity to use GHG-emissions results from the US-REGEN grid modeling in Section 6 in place of GREET's direct GHG emissions of electricity generation. Average electricity emissions were used, and the Base GHG Scenario and Lower GHG Scenario were both modeled. GREET's default assumptions for upstream GHG emissions of electricity (from GREET 1) were maintained because of the complexity of modifying this assumption within GREET2. This change will be conservative for all modeled years. (Emissions will be higher than if the fuel-use data from US-REGEN were used instead.)

Battery Capacity and System Efficiency

The total GHG impact of battery manufacturing was determined for each calendar year over the study time period by individually multiplying the GHG-emissions results from GREET (expressed in grams per kWh of battery capacity) by the total battery-storage capacity (kWh) by vehicle category and by vehicle type. The total battery capacity of each vehicle category and type is determined by the sales of new vehicles in each calendar year (as output by the vehicle-turnover model) and the assumed battery capacity per vehicle. The battery capacity was calculated by the assumed electric consumption (AC Wh/mi, or energy at the point of input to the vehicle charger) and the electric range (in miles) of individual vehicles—corrected by the system efficiency and the fraction of battery capacity that is usable during vehicle operation. Estimates of system efficiency (electric vehicle supply equipment, or EVSE, charger, and battery) and usable battery capacity were made based on data available on present-day passenger PEVs, and they have been projected across the study period; the tables below show these projections.

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[61] For nonactive materials like copper, aluminum, and plastic, emissions scale on a per-mass basis. For active materials like the positive and negative electrode materials, emissions scale on a per-energy basis. The mass of all materials is held constant, but the energy required to manufacture the mass of active material increases.

Table A-4
Estimated usable battery capacity

Vehicle Type	2010	2020	2030	2040	2050
PHEV20	65%	70%	75%	75%	75%
PHEV40	65%	75%	80%	80%	80%
PHEV60	75%	85%	90%	90%	90%
BEV100+	88%	90%	95%	95%	95%

Table A-5
Estimated battery system efficiency (EVSE, charger, battery)

Vehicle Type	2010	2020	2030	2040	2050
PHEV20	78%	85%	87%	87%	87%
PHEV40	84%	89%	91%	91%	91%
PHEV60	84%	89%	91%	91%	91%
BEV100+	84%	89%	91%	91%	91%

Battery Requirements for Non-road Equipment

Non-road equipment has widely varying requirements for battery energy. For example, powering ocean-going vessels while in port uses a fixed grid connection and requires no batteries, whereas forklifts are likely to be almost exclusively battery-powered. In order to calculate battery requirements for non-road equipment, the electricity use for each vehicle and device subcategory was considered separately. Within each subcategory, the number of battery cycles per day was estimated—ranging from 0 for equipment that was permanently connected to the grid, to 2 for equipment like airport ground-support equipment and forklifts, which are recharged during the day. (This estimate is typical for current applications.) This cycling data was multiplied by the amount of electricity use for each category to determine the quantity of battery energy required. Additionally, it was assumed that batteries would be replaced every 10 years in non-road applications.

Appendix B: Estimation of Non-CO_2 Greenhouse Gas Emissions for the Electricity Sector

As described in Section 2 and Section 4, transportation-sector emissions factors were derived from GREET, and they include both direct CO_2 emissions and direct non-CO_2 emissions. Electricity-sector emissions were generated using US-REGEN data, which only includes CO_2 emissions. This appendix describes the methodology for estimating non-CO_2 emissions to create a comprehensive direct GHG measurement. The analysis combines data from the "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013" (EPA, 2015b) and the *Monthly Energy Review* (EIA 2015) to create generation-specific factors in terms of emissions per kilowatt-hour of generation. Because of the importance of sulfur hexafluoride (SF_6) emissions within electricity transmission and distribution, an emissions factor for SF_6 was also developed, which is applied to all generation. Non-CO_2 GHG emissions increased 2013 electricity-sector emissions by approximately 1.0%.

Electricity-Sector Non-CO_2 Greenhouse Gas Emissions

Table B-1 shows total GHGs for the electricity sector from EPA (2015b), adjusted using the factors in Table B-2. Note that "Electricity generation" includes all generation sources listed above, which include all direct grid emissions reported in the inventory. For the 5 years from 2009 to 2013, non-CO_2 GHG emissions represented 1.0% of total emissions in the inventory.

Table B-1
Non-CO_2 greenhouse gas emissions for the electricity sector (MMTons CO_2e)

		2009	2010	2011	2012	2013
Coal	CO_2	1740.9	1827.6	1722.7	1511.2	1575.0
	CH_4	0.43	0.43	0.43	0.29	0.29
	N_2O	9.57	10.69	9.83	8.72	10.34
Natural Gas	CO_2	372.2	399.0	408.8	492.2	441.9
	CH_4	0.14	0.29	0.29	0.29	0.29
	N_2O	4.79	5.04	5.21	6.41	5.98
Fuel Oil	CO_2	32.2	31.4	25.8	18.3	22.4
	CH_4	*	*	*	*	*
	N_2O	*	*	*	*	*
Geothermal	CO_2	0.4	0.4	0.4	0.4	0.4
	CH_4	*	*	*	*	*
	N_2O	*	*	*	*	*
Wood	CO_2	*	*	*	*	*
	CH_4	*	*	*	*	*
	N_2O	*	*	*	*	*
Electricity Generation	CO_2	2145.7	2258.4	2157.7	2022.2	2039.8
	CH_4	0.57	0.71	0.57	0.57	0.57
	N_2O	14.36	15.81	15.05	15.22	16.33
Electricity T&D	SF_6	7.18	6.88	6.69	5.60	5.01

* Emissions for these species in these categories were below the reporting limit used in EPA (2015b).

The total emissions were used with historical annual generation from EIA (2015) to create the emissions factors shown in Table B-2, based on the weighted average for 2009–2013. These emissions factors are for kWh generated, so they will be applied before transmission and distribution (T&D) losses are subtracted. (A kWh of use is less than a kWh generated, so the emissions per kWh used will be higher.) Note that non-CO_2 GHG emissions for fuel oil, geothermal, and biomass generation are not zero on a per-kWh basis, but they are below the EPA's reporting threshold—given the very small amount of generation that comes from these sources.

Table B-2
Emissions factors for non-CO_2 greenhouse gas emissions (gCO_2e/kWh)

	CH_4	N_2O	SF_6	Total
Coal	0.22	5.88	0.00	6.11
Natural gas	0.27	0.07	0.00	0.33
Fuel oil	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00
Wood	0.00	0.00	0.00	0.00
Transmission and distribution	0.00	0.00	1.61	1.61

Environmental Assessment of a Full Electric Transportation Portfolio

Air Quality Impacts

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Executive Summary

In 2007, the Electric Power Research Institute (EPRI) published a state-of-the-art evaluation of the effects of plug-in electric vehicles (PEVs) on ambient air quality in the United States (EPRI-NRDC, 2007). This report is an update and expansion of the 2007 study, which includes recent changes in the expected trajectories of the electricity and transportation sectors. This new study includes both plug-in hybrid and fully electric vehicles, as well as a variety of off-road equipment. It also includes a revised projection of electricity-sector emissions. As before, the analysis uses the modeled changes in the electricity and transportation sectors as input to state-of-the-art emissions and air quality models to project the effects of electrification on air quality in the year 2030.

The assumptions that underlie the projected improvements in the electricity sector and the modeled levels of electrification are aggressive, but they are limited to technologies and policies that are either currently observed or that are probable under current trends. The scope of this study excludes developments like breakthroughs in battery costs that would immediately transform transportation markets, or policies that would mandate reductions in vehicle or generation emissions (beyond those policies already in place). On the basis of these limits, electrification is only applied to transportation energy use that can be shifted from petroleum-derived fuels to grid electricity, using available technologies and without major changes to transportation infrastructure. This scope excludes changes to shipping, air travel, rail, and long-distance truck transportation. The limited nature of this focus means that this study does not describe the maximum possible effects deriving from electrification; however, it also means that the projected improvements are both achievable and likely to be improved upon by future developments in these fast-moving sectors.

Motivation for Air Quality Analysis

Transportation electrification offers the opportunity to substantially reduce petroleum use and greenhouse gas emissions. However, it is important to ensure that these improvements do not come at the cost of air quality. Air quality problems could increase even if transportation emissions decrease as a result of increases in electricity-sector emissions and the complex spatial and temporal interactions of emissions of criteria pollutants.

The air quality analysis focuses on air quality impacts from pollutants regulated by the U.S. Environmental Protection Agency (EPA): ozone and particulate matter (PM). The EPA regulates ozone and PM and sets National Ambient Air Quality Standards (NAAQS). Primary NAAQS are established to protect human health, whereas secondary NAAQS are established to protect the public welfare (for example, vegetative health and recreational/aesthetic values). The current primary and secondary ozone standards are equivalent at 75 parts per billion (ppb). EPA is considering lowering this standard to 65–70 ppb, or even as low as 60 ppb. Figure 1 illustrates U.S. counties where measured ozone between 2011–2013 was above 65–70 ppb. Given the stringency of the proposed standards, even a 1-ppb reduction of ozone in these counties is important.

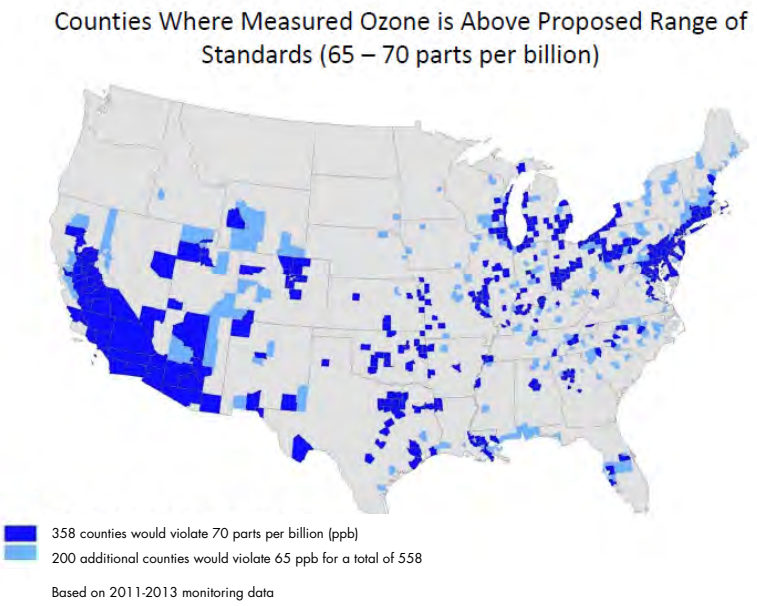


Figure 1
Counties where measured ozone is above proposed range of standards (65–70 parts per billion) (EPA, 2014)

The effect of electric vehicles and equipment on deposition of acids and nutrients is also evaluated to provide insight into changes in deposition resulting from the widespread use of electric vehicles and electric equipment, even though there are no deposition-based secondary NAAQS at present.

[1] This standard is based on a 3-year average of the annual 4th highest maximum daily 8-hour average ambient concentration of ozone.

Methodology

The air quality study evaluated two scenarios for the year 2030: 1) a Base Case with minimal electrification of on-road vehicles and non-road equipment in the United States and 2) an Electrification Case with moderate electrification of on-road vehicles and non-road vehicles and equipment by 2030. In the Electrification Case, the overall fraction of vehicle miles traveled by the U.S. vehicle fleet using electricity stored in batteries is 17% for light-duty vehicles and 8% for heavy-duty vehicles. The fraction of non-road equipment that is electric in 2030 varies from 0% to 67% for electrified vehicle and equipment types, depending upon the unique application and usage attributes of each type. Emissions from the mobile source and power sectors were modified, and subsequent effects on air quality and deposition were modeled in the lower-48 states.

Transportation-Sector Modeling

For both the Base Case and the Electrification Case, the transportation sector and its emissions were modeled for the future year 2030. Emissions offset as a result of the displacement of fossil-fueled vehicles with electric vehicles (and reductions in upstream fuel-production emissions) were calculated by the transportation models. In addition, the incremental electricity demand caused by electric vehicles was calculated for the Electrification Case. Electric vehicles include a mix of plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs). Electric vehicle penetration of the vehicle fleet for each model year (2010 to 2030) was estimated using a vehicle fleet turnover model to determine the market penetration of electric vehicles in the overall vehicle fleet over time. Figure 2 shows the fraction of new vehicle sales electrified, total fleet vehicles electrified, and vehicle miles traveled electrified for passenger vehicles. Commercial vehicles followed a similar trajectory, but with lower levels of electrification.

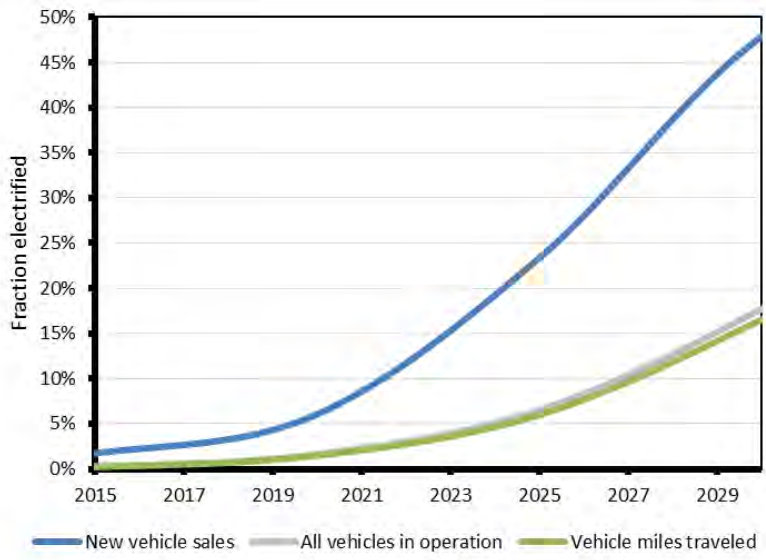


Figure 2
Percent of passenger vehicles electrified

Non-road Transportation-Sector Modeling

For both the Base Case and the Electrification Case, the non-road transportation sector and its emissions were modeled for the future year 2030. Emissions offset as a result of the displacement of fossil-fueled equipment with electric equipment (and reductions in upstream fuel-production emissions) were calculated, along with the incremental electricity demand caused by electrification.

Emissions reductions associated with electrification were estimated for the equipment types listed in Table 1. Not included in this list are equipment types that have been electrified but which are relatively small components of the non-road sector emissions inventory, such as underground mining equipment. Electrification was not considered for equipment for which energy of infrastructure requirements for electrification would require development of new technologies.

Table 1
Equipment types for which emissions reductions resulting from electrification were estimated

Industrial		Recreational and Lawn & Garden	
Agricultural Pumps	Intermodal Equipment (Port Cranes, Yard Trucks, Side/Top Picks)	All-Terrain Vehicles (ATVs)	Motorcycles
Aircraft Auxiliary Power Units	Shoreside Power for Ocean-Going Vessels	Chain Saws *(units ≤6 horsepower)*	Push Lawn Mowers
Airport Ground-Support Equipment *(units ≤175 horsepower)*	Sweepers / Scrubbers *(units ≤25 horsepower)*	Chippers/ Shredders *(units ≤6 horsepower)*	Riding Lawn Mowers *(units ≤40 horsepower)*
Dredging Craft	Switching Locomotives	Commercial Turf Equipment *(units ≤25 horsepower)*	Snow Blowers *(units ≤3 horsepower)*
Forklifts *(units ≤175 horsepower)*	Transportation Refrigeration Units	Golf Carts	Special Vehicle Carts *(units ≤25 horsepower)*
		Leaf Blowers	Trimmers/Edgers

Electric-Sector Modeling

Electric-sector capacity expansion and generation was modeled using the EPRI United States Regional Economy, Greenhouse Gas, and Energy (US-REGEN[2]) model. US-REGEN simulates new generation units, retrofits, and retirements through to the year 2050, along with demand-side responses (taking into account key policy and regulatory constraints). The model was run without and with the electrification load for on-road and non-road vehicles to determine electricity-sector emissions in both scenarios.

The Base Case and Electrification Case both exhibited significant changes in generation and capacity mix through 2030. Figure 3 depicts the generation mix in the Base Case, and Figure 4 shows the incremental generation in the Electrification Case. In the Base Case, the policies and fuel prices result in economics that favor new nuclear power plants and renewables, to the detriment of natural gas. In the Electrification Case, incremental load is met by a mix of renewable and natural gas generation.

[2] For more information on the US-REGEN model, see: http://eea.epri.com/models.html

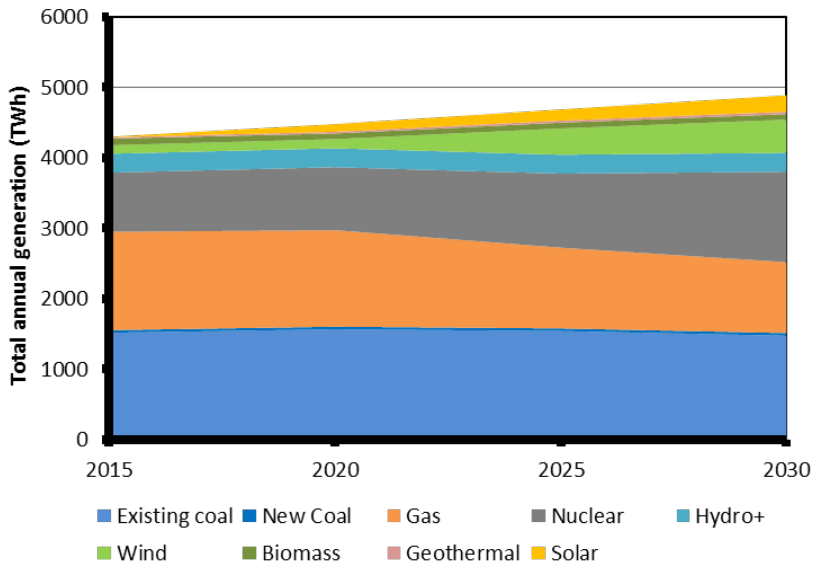


Figure 3
Generation mix in the Base Case

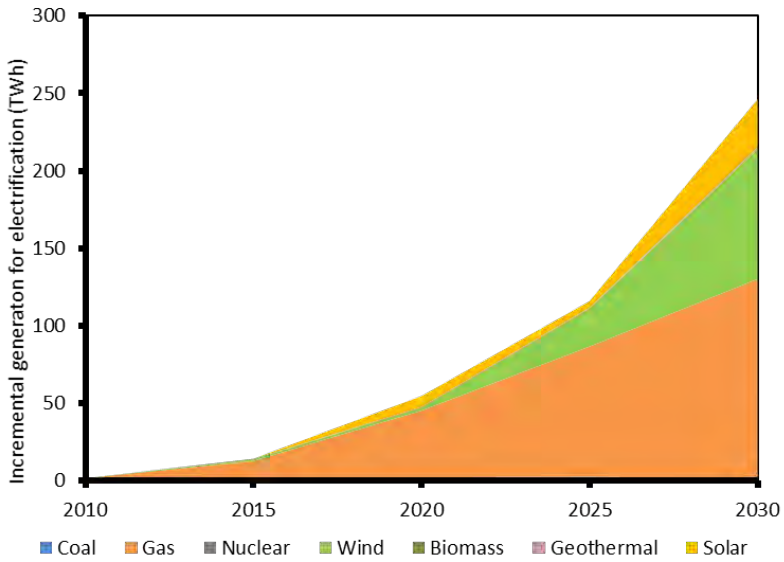


Figure 4
Incremental generation in the Electrification Case

Upstream-Sector Modeling

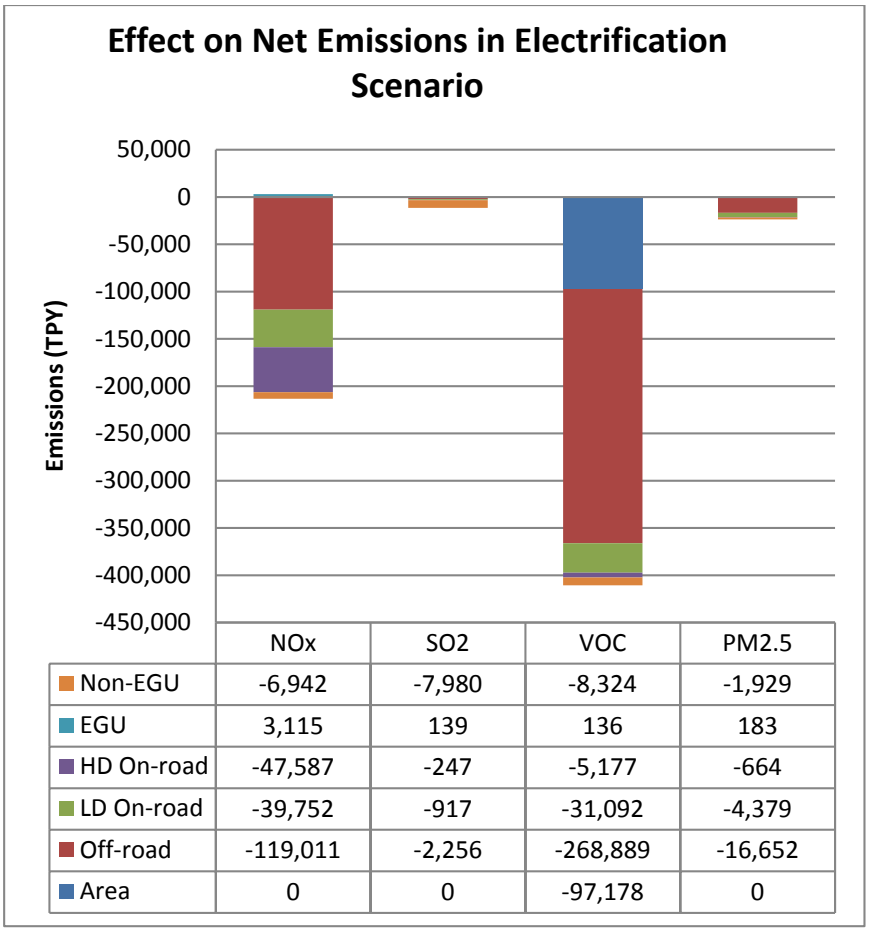
Upstream emissions are emissions that are associated with transportation-fuel production—specifically the processing, transport, and storage of crude oil, gasoline, and diesel. Upstream emissions are reduced for the Base Case to account for federal light- and heavy-duty greenhouse gas rules; they are reduced for the Electrification Case to account for decreased gasoline and diesel consumption.

Air Quality Modeling

The Comprehensive Air Quality Model with Extensions (CAMx[3]) was used with source-apportionment algorithms to evaluate overall air quality in 2030, plus the individual contributions to air quality from each sector affected by electrification (for example, on-road vehicles, non-road mobile sources, and power plants).

Summary of Results

The overall effect of electrification on emissions across all sectors was a reduction for all pollutants, as shown in Figure 5. Continental United States (CONUS) NOx emission decreases of 3% were estimated, with 57% of the reduction due to non-road sector electrification and 42% of the reduction due to on-road vehicle electrification. Emission reductions of 4% for volatile organic compounds (VOC) were estimated; 65% of the VOC reduction came from non-road sector electrification, and 24% of the VOC reduction came from the area-source sector (primarily because of reductions in upstream emissions). SOx-emission reductions of 0.5% were estimated, with 71% of the reduction coming from upstream point sources outside of the electricity sector. $PM_{2.5}$ primary emission reductions of 1.1% were estimated, with 71% of the reduction coming from non-road electrification and 22% of the reduction coming from on-road vehicle electrification.



	NOx	SO2	VOC	PM2.5
Non-EGU	-6,942	-7,980	-8,324	-1,929
EGU	3,115	139	136	183
HD On-road	-47,587	-247	-5,177	-664
LD On-road	-39,752	-917	-31,092	-4,379
Off-road	-119,011	-2,256	-268,889	-16,652
Area	0	0	-97,178	0

Figure 5
Effect of electrification on net emissions within the Continental United States

[3] For more information on the CAMx model, see: http://www.camx.com/

Air quality modeling results indicate that the air quality benefits associated with electrification, although modest, are widespread across the Continental United States. Figure 6 shows widespread ozone benefits related to electrification.[4] The current NAAQS for ozone is 75 ppb for the 4th highest 8-hour ozone concentration, averaged over three years. Most ozone reductions are modest—generally less than 1 ppb. Many urban areas, including cities that exceed the current level of the ozone standard, see larger ozone reductions (as high as 3 ppb). The largest reduction (of 4 ppb) is estimated to occur in Los Angeles. These ozone reductions result mostly from decreases in non-road sector emissions, as a result of the electrification of non-road vehicles and equipment. Ozone benefits from non-road sector electrification are widespread. In the Electrification Case, areas near the Gulf Coast and Los Angeles also receive benefits from commercial marine emissions reductions associated with reduced crude-oil imports. Ozone increases (less than 1.5 ppb) are restricted to a few grid cells in rural areas.

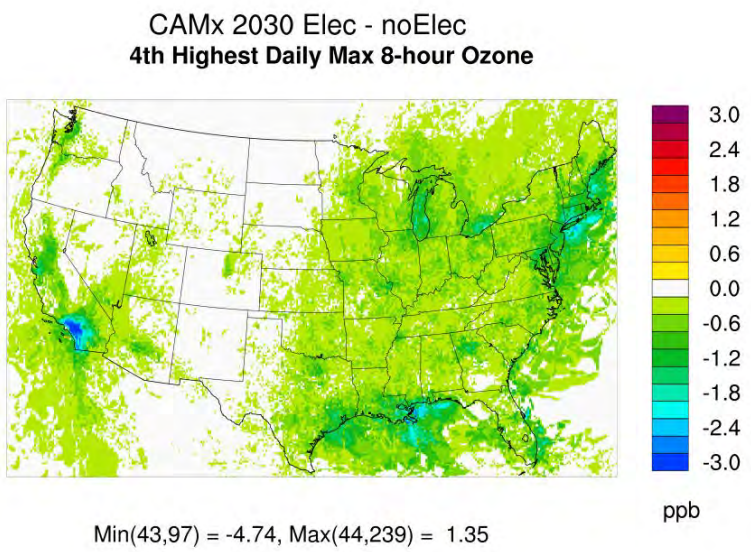


Figure 6
Annual 4th highest 8-hour-ozone (ppb) – Difference between Electrification Case and Base Case

[4] The 4th highest 8-hour ozone concentration is calculated separately for each cell; therefore, the same color represents the same concentration level, but adjacent cells may experience this maximum concentration during different days.

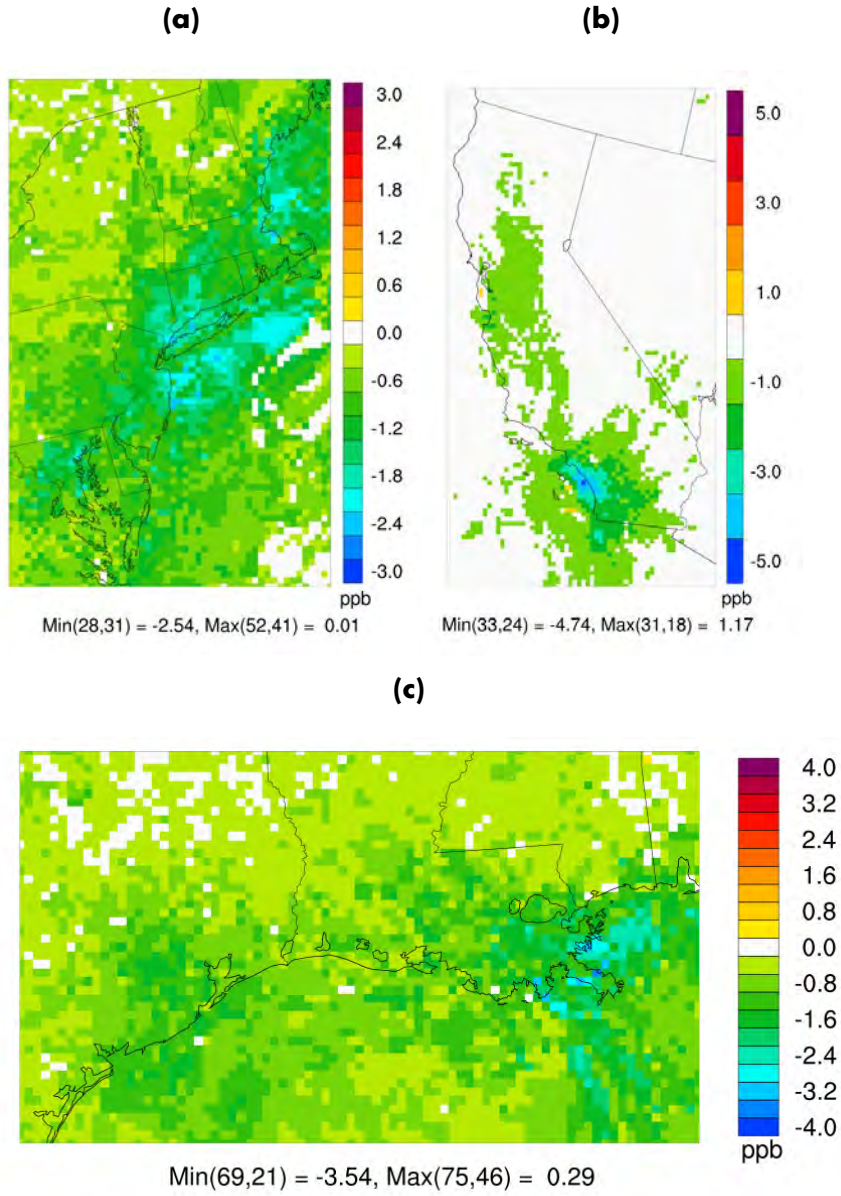


Figure 7
Annual 4th highest 8-hour-ozone (ppb) – Difference between Electrification Case and Base Case. Zoom-in maps for (a) the Northeastern Corridor, (b) California, and (c) Texas-Lousiana

A closer look at three focus areas emphasizes the larger ozone reductions that occur in urban settings. Figure 7 (a) shows widespread ozone benefits related to electrification in the Northeastern Corridor. Major cities—including Boston, New York City, Washington, D.C., and Baltimore—see about 2 ppb of ozone reduction. The ozone benefit is smaller outside of the cities; yet it is over 1 ppb along the main corridor. In southern California, the Los Angeles metropolitan area sees ozone reductions of 3 ppb, mainly as

a result of the electrification of non-road equipment (Figure 7 (b)). For activities in close proximity to major ports (the Port of Los Angeles and the Port of Long Beach), the ozone benefit increases up to 4 ppb—as a combined result of non-road equipment and commercial marine emissions reductions. Given that most areas in southern California would probably be designated as "non-attainment" under lower standards (Figure 1), the magnitude of predicted ozone benefits is considered a significant achievement. This combined benefit of non-road and commercial marine emissions reductions is also realized in New Orleans, where more than 3 ppb of ozone reduction is predicted (Figure 7 (c)). In fact, widespread areas along the Gulf Coast experience ozone reductions of over 1 ppb. It should be emphasized that even a 1-ppb reduction is important—particularly when considered as part of a comprehensive program to reduce ozone in these regions.

The results also indicated significant reductions in PM levels. PM is a mixture of particles that are directly emitted (primary particles) and particles that form in the atmosphere (secondary particles). Primary particles can be composed of a variety of inorganic and organic compounds. In general, secondary particles are composed of sulfate, nitrate, ammonium, and secondary organic aerosol that originate from emissions of precursor gases: SO_2, NOx, NH_3, and VOC. The resultant PM mixture in the atmosphere is thus made up of constituents that are of both biogenic and anthropogenic origin. Figure 8 shows reductions in fine particulate matter ($PM_{2.5}$) related to electrification, with the 8th highest 24-hour average $PM_{2.5}$ concentration lowered in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are modest (generally less than 0.5 micrograms per cubic-meter [$\mu g\ m^{-3}$]) but they are consistent. (The 24-hour NAAQS for $PM_{2.5}$ is 35 $\mu g\ m^{-3}$, based on the 98th percentile of 24-hour measurements averaged over three years.) PM benefits are mostly from electrification of non-road sources, with close to 2 $\mu g\ m^{-3}$ reductions in Los Angeles. The PM reductions result partly from decreases in primary emissions of PM, but mainly from reductions in VOC and NO_x emissions—which lead to less secondary PM formation. Annual average concentrations of $PM_{2.5}$ and PM_{10} show a similar pattern of modest reductions; these are mostly in urban areas, as a result of electrification of mobile sources.

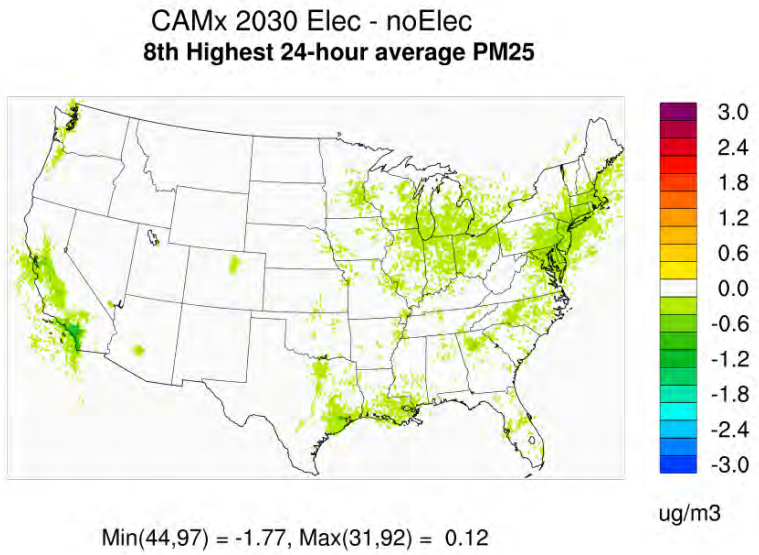


Figure 8
Annual 8th highest 24-hour average concentrations (µg m-3) of $PM_{2.5}$ – Difference between Electrification Case and Base Case

In addition to the primary air quality indicators, acid and nutrient deposition was also analyzed. Nitrogen deposition may adversely influence water quality and ecosystems. Figure 9 shows reduced total nitrogen deposition (that is, both oxidized and reduced nitrogen) as a result of electrification of mobile sources across the United States. In the Electrification Case, total nitrogen deposition is reduced throughout the Eastern United States and near major urban areas—primarily caused by lower mobile-source ammonia emissions. Multiple urban areas (including Los Angeles, Dallas, Houston, Denver, and Atlanta) and large port cities (such as Fort Lauderdale, New Orleans, and the San Francisco Bay Area) have nitrogen reductions higher than 3%.

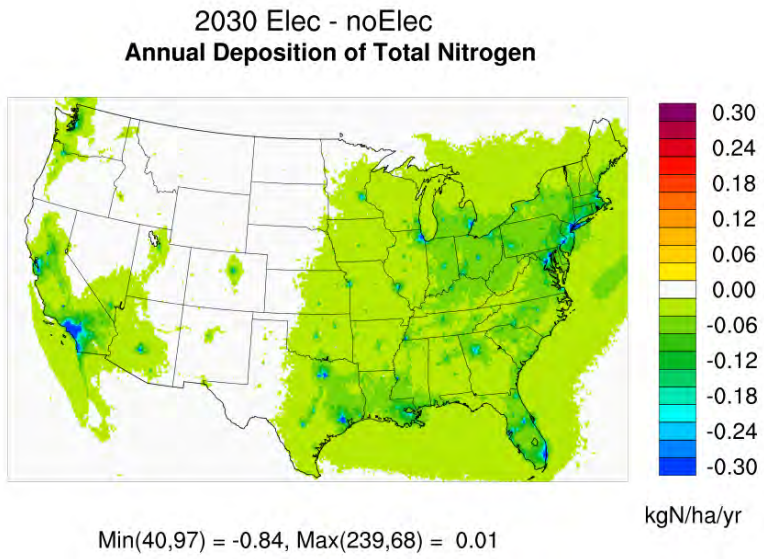


Figure 9
Annual deposition (kg Ha-1) of total nitrogen for 2030 – Difference between Electrification Case and Base Case

Key Findings

The key results of the analysis of the effects of electrification on emissions of criteria pollutants and ambient air quality can be summarized as follows:

- Considering the electric and mobile sectors together, total emissions of VOC, NO_x, SO_2, and PM decrease in the Electrification Case.
- Ozone benefits related to electrification of on-road and non-road mobile sources occur across the United States. Many urban areas—including cities with ambient air quality exceeding the current ozone standard—see reductions in the 4th highest 8-hour average ozone concentration of up to 4 ppb. The ozone decreases are mostly a result of decreases in non-road sector emissions resulting from electrification of non-road equipment.
- Electrification of mobile sources reduces the 8th highest 24-hour average PM concentrations in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are modest (generally less than 0.5 $\mu g\ m^{-3}$), but they are widespread. PM_{10} and $PM_{2.5}$ benefits derive mostly from electrification of non-road sources.
- Electrification of mobile sources reduces nitrate and total nitrogen deposition across the United States.

These findings demonstrate that even with the recently promulgated Tier 3 vehicle-emission standards, the electrification of on-road vehicles has a small but significant and widespread benefit to air quality. In addition, electrifying non-road equipment provides significant benefits that are in some cases larger than the benefits of on-road electrification—particularly in urban areas where air quality exceeds national ambient air quality standards. Few adverse effects of electrification were found, and air quality impacts related to increased power plant emissions are confined in extent and small in magnitude.

The largest sources of uncertainty for this study are in the estimation of future emissions from power plants and mobile sources. Future activity levels associated with these sources were estimated based on accepted models and methods; these activity projections are nevertheless speculative. Future regulations will affect the development of vehicle, non-road equipment, and power plant technology. Alternative assumptions of electric-unit market penetration and power-generation levels will yield different emissions scenarios. Re-evaluation of the air quality impacts may be needed as changes occur in the regulatory (for example, greenhouse gas rules), economic (for example, energy prices) and technology drivers (for example, batteries) and as other new data become available.

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Section 1: Introduction

Sales of electric vehicles and equipment have increased dramatically in recent years, piquing national interest in the societal benefits associated with electrification. An important aspect of electrification is the way in which air quality will be affected by the displacement of fossil-fueled vehicles and equipment with electric models. And although electrification of the non-road sector may not always attract the same level of public attention as that of vehicle electrification, the air quality benefits associated with non-road equipment electrification may be of equal or greater importance as those of on-road vehicle electrification.

Previous modeling studies have evaluated the ozone impacts of using plug-in electric vehicles (PEVs) (*Alhaieri et al., 2011; Thompson et al., 2011; Brinkman et al., 2010*). The findings of these studies, which employ different methodologies and assumptions, show that PEVs have the potential to either decrease or increase ozone. A regional-scale study for the Pennsylvania, New Jersey, and Maryland region found mixed impacts for PEVs—reporting decreases of 2–6 ppb in peak 8-hour ozone in urban areas and increases of up to 8 ppb in small areas (*Thompson et al., 2009*). A recent national-scale study used a life-cycle inventory, accounting for upstream processing and assuming that PEVs would constitute 10% of 2020 VMT. It found that the impacts of PEVs on ozone and particulate-matter (PM) values vary depending on how the electricity for PEVs is generated (*Tessum et al., 2014*). The Electric Power Research Institute (EPRI), in cooperation with the Natural Resources Defense Council (NRDC), previously conducted a state-of-the-art evaluation of the effect of plug-in hybrid electric vehicles (PHEVs) on air quality (EPRI-NRDC, 2007). Significant air quality–related findings of the previous study indicated that an aggressive penetration of PHEVs into the vehicle fleet has the potential to improve air quality—particularly in urban areas with high levels of vehicle-related pollution.

This study extends the 2007 analysis with an updated and more complete assessment of electrification. The effects of plug-in hybrid and fully electric vehicles on air quality are analyzed, along with the effects of the electrification of non-road mobile sources such as residential and commercial mobile equipment (for example, lawn and garden equipment), industrial equipment (for example, cargo handling equipment and forklifts), and recreational equipment (for example, all-terrain vehicles). The study uses the Comprehensive Air Quality Model with Extensions (CAMx[5]) source-apportionment algorithms to discretely

[5] For more information on CAMx, see: http://www.camx.com

evaluate the contributions to air quality from each sector affected by electrification (for example, on-road vehicles, non-road mobile sources, and power plants).

Electrification of the transportation and non-road mobile sector reduces direct emissions from these sources. Emissions associated with the processing, refining, and distribution of gasoline and diesel fuel also decline as a result of lower fuel consumption. However, greater electricity demand as a result of electric-vehicle charging requirements increases electricity generation and could also increase associated emissions.

This study calculates the magnitudes of these emission changes—including any changes in spatial and temporal patterns of emissions from electrical generating units—assuming a moderate level of electric vehicle and electric non-road equipment penetration. These emission changes are implemented in a future-year (2030) emissions inventory for the continental United States. Detailed air quality model simulations for a full calendar year are performed to evaluate the impact of these net emission changes on ozone, particulate matter, and the deposition of acids and nutrients (sulfate, nitrate, and total nitrogen).

Methodology

In order to perform this analysis, a suite of computational modeling tools is used to compare two scenarios:

- A Base Case, assuming a minimal electrification level of the vehicle and non-road equipment fleets
- An Electrification Case, assuming a moderate penetration of electric vehicles and electric non-road equipment

The air quality impacts of non-road equipment and on-road vehicle electrification are compared to a baseline scenario, using assumptions consistent with recent U.S. Environmental Protection Agency (EPA) and California Air Resources Board (ARB) rulemakings on regulation of emissions of criteria pollutants and greenhouse gas from on-road vehicles, non-road vehicles and equipment, and power plants at the time of the study. (The exceptions are noted at the end of this section.) A detailed air quality model is used to translate the changes in emissions resulting from electrification to metrics for ambient pollutant levels and deposition.

On-road Transportation Sector Modeling

Section 2 describes the development of emissions for the on-road transportation sector that were used as input for the air quality model. Vehicle emissions were modeled for calendar year 2030 for the Base Case and the Electrification Case, using a vehicle population and usage model that separately tracked each vehicle class in the on-road transportation sector.

The transportation-sector models used in this study tend to be cautious in projecting the impact of new technologies, and they therefore represent a "business-as-usual" approach to vehicle inventories. The analysis in this study includes current EPA regulations affecting the transportation sector, including the Tier III Programs, the Clean Air Highway Diesel Rule, and the Light Duty and Heavy Duty Greenhouse Gas Rules. As discussed in Section 2 future projections for the transportation sector are sensitive to many important factors. In particular, the principal factors for defining the Electrification Case include

- Plug-in hybrid and full electric vehicle market penetration
- Plug-in hybrid and full electric vehicle characteristics
- Plug-in hybrid and full electric vehicle utility factors
- Plug-in hybrid and full electric vehicle electrical consumption
- Electric charging profiles (discussed in Section 4)

Non-road Sector Modeling

Section 3 describes the development of emissions for the non-road sector that were used as input for the air quality model. The non-road sector includes the following categories of equipment:

- Aircraft
- Locomotive
- Commercial marine vessels
- Agricultural equipment (such as tractors, combines, and balers)
- Airport ground support (such as terminal tractors)
- Construction equipment (such as graders and backhoes)
- Industrial and commercial equipment (such as forklifts and sweepers)
- Residential and commercial lawn and garden equipment (such as lawnmowers, leaf blowers, and snow blowers)
- Logging equipment (such as shredders and large chain saws)
- Recreational equipment (such as off-road motorbikes and snowmobiles)
- Recreational marine vessels (such as power boats)

The principal determinants for emissions from each equipment type in the non-road sector were modeled for calendar year 2030 for the Base Case and the Electrification Case.

Similar to the transportation sector, non-road sector models used in this study tend to be cautious in projecting the impact of new technologies, and they therefore represent a "business-as-usual" approach to non-road mobile source inventories. The analysis in this study includes current EPA regulations affecting the non-road sector, including the Commercial Marine Engine Standards, Locomotive Engine Standards, and EPA's suite of rules on non-road mobile

source compression-ignition and spark-ignition engines. As discussed in Section 3 future projections for the non-road sector are sensitive to many important factors. In particular, the principal factors for defining the Electrification Case include

- Electric equipment market penetration for equipment types amenable to electrification
- Electric equipment characteristics
- Electric equipment utility factors
- Electric equipment electrical consumption
- Electric charging profiles (discussed in Section 4)

Electric-Sector Modeling

Section 4 describes the electric-sector modeling, the assumptions that underpin the results in this analysis, and the likely impacts to the electric sector resulting from an increased demand for electricity by on-road vehicles and non-road equipment. The latter include changes in generation mix; types of capacity brought online, retrofitted, or retired; and the resulting CO_2, NO_X, and SO_2 emissions from those units.

Upstream Emissions

Section 5 describes changes to emissions associated with the processing, transport, and storage of crude oil and gasoline as a result of decreased gasoline and diesel consumption by on-road vehicles and non-road equipment. Upstream emissions are reduced for the Base Case to account for federal light- and heavy-duty greenhouse gas rules; they are reduced for the Electrification Case to account for decreased gasoline and diesel consumption.

Emissions Processing

Before air quality model simulations are performed, emissions from the mobile sector and electric sector are merged with emissions from all other economic sectors and from natural sources. Section 6 describes this process in detail and summarizes national emissions for both the Base Case and the Electrification Case.

Air Quality Modeling

An air quality model was used to simulate the air quality impacts of on-road vehicle and non-road equipment electrification in 2030. The CAMx was used to simulate both scenarios; the impact of electrification was determined by comparing results from the two simulations. Air quality impacts are presented for the following air quality parameters:

- Ozone-mixing ratios
- Particulate-matter concentrations

- Acid and nutrient (sulfate, nitrate, and total nitrogen) deposition

This comparison is presented in Section 8, accompanied by an evaluation of the extent of the electrification impacts on deposition flux metrics. The final modeling results are discussed in Section 8 and summarized in Section 9. Because of the significant reduction in emissions from mobile-source fuel combustion, the study finds that in many regions deployment of moderate numbers of electric vehicles and non-road equipment would both reduce levels of ozone and particulate matter and reduce deposition rates for acids and nutrients.

Overall, the air quality benefits from electrification are attributable to a reduction of vehicle and non-road equipment emissions below levels required by current regulation (because of their nonemitting operation in electric mode). Also, electricity generation emission increases for the Electrification Case are small compared to on-road vehicle and non-road equipment emission reductions because of emissions regulations in place in the electricity sector. Any additional increase in the amount of all-electric vehicle miles traveled, or further emissions constraints on the electric sector, would tend to magnify these benefits.

Context for Air Quality Modeling Results

Because of the long development and run times for the air quality model used in this analysis, it was necessary to fix assumptions relatively early in the study process. However, there have been a number of recent changes in the transportation and electricity sector that affect key assumptions of this analysis:

- A number of renewable portfolio standards have been increased from modeled levels, and prices for renewable generation—particularly solar—have significantly decreased from the modeled levels. These changes will likely decrease average and marginal emissions of criteria pollutants.
- The Regional Greenhouse Gas Initiative in New England and the Cap-and-Trade program in California have been finalized; both policies are intended to reduce greenhouse gas emissions. Neither policy is included in the electricity-sector model. These policies are likely to reduce average and marginal emissions of criteria pollutants even further within both regions.
- The Tier 3 vehicle-emissions standard was modeled using the proposed regulation, which was subsequently finalized. The final standard closely matches the proposed standards, so the modeling is consistent with the final standard.
- The Mercury and Air Toxics Standard was remanded by the Supreme Court to the D.C. District Court. The standard remains in effect at time of publication, but it may undergo unknown changes in the future with similarly unknown effects on electricity-sector emissions.
- The Clean Power Plan has been finalized by the EPA. This plan is focused on greenhouse gas emissions, but it will probably have a significant effect on emissions of criteria pollutants as a result of reductions in coal generation and overall reductions in fossil-fuel generation. The exact effects of this

regulation on average and marginal emissions are highly dependent on the future development of State Implementation Plans.

- The outlook for future nuclear capacity expansion is now more pessimistic than the levels assumed in the U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN[6]) modeling. This factor will potentially increase average emissions, but it will have only a minor effect on marginal emissions because nuclear power is not a marginal generation resource in this analysis. This nuclear-related assumption was changed for the electricity-sector modeling in the greenhouse gas analysis in Volume 2, and the differences are described in more detail in Appendix A.[7]

Some of these changes are expected to lead to increased emissions. But the study team believes that—on balance—these changes in policy, economics, and generation prospects will lead to a reduction in average and marginal emissions.

[6] For more information on US-REGEN, see: http://eea.epri.com/models.html

[7] Absolute emissions levels are different between the two sets of assumptions, but marginal emissions in 2030 are consistent.

Section 2: On-Road Electric Vehicle Penetration, Emissions Displacement, and Electric Load

This section describes the development of emissions for the on-road vehicle sector to be used as an input to the air quality model. Age-weighted vehicle populations, vehicle miles traveled (VMT), and corresponding emissions for each vehicle class in the transportation sector were modeled for calendar year 2030 for two scenarios:

- Base Case
- Electrification Case

The starting points for developing on-road emissions for these two scenarios were 2030 emission factors from the U.S. EPA's Motor Vehicle Emissions Simulator (MOVES) model and state-supplied VMT specific to 2008. The VMT were projected to 2030 using the data on vehicle sales and activity projections from the 2011 Annual Energy Outlook (AEO). At the time when on-road vehicle emissions were prepared for this study, several rulemakings with significant emissions impacts in year 2030 were not yet included in MOVES (2010a version; EPA, 2010a). To account for these rulemakings, the emissions effects were incorporated into the Base Case by applying scaling factors to the MOVES-based inventory. The rulemakings accounted for externally to MOVES include:

- EPA's Tier 3 emission standards with lower sulfur content (10 ppm) gasoline
- Light-duty greenhouse gas (GHG) rulemaking, beginning with 2017 models
- Heavy-duty GHG rulemaking, beginning with 2014 models

In order to account for the above rulemakings, scaling factors were developed and applied to the MOVES inventory to generate the 2030 Base Case. A separate set of scaling factors specific to vehicle class were developed and multiplied with the Base Case emissions to generate the 2030 Electrification Case. Reductions in point-source and area-source upstream emissions because of reduced motor-fuel consumption as a result of electric vehicle penetration were also included in the analysis; these upstream reductions are discussed later in Section 5.

The MOVES (2010a version) model includes two vehicle classification schemes: 1) MOVES source type vehicle categories and 2) source category classification code (SCC) vehicle types, which are similar to those utilized in EPA's previous on-road vehicle emission estimation model, MOBILE6. The MOVES source type vehicle categories were used exclusively in the analysis of electric vehicle activity presented below. SCC vehicle type emissions were generated by MOVES for air quality modeling because MOVES (2010a version) emissions output by MOVES source type are not easily processed for use in air quality modeling. Emissions by SCC vehicle type are presented below. Appendix B presents crosswalk tables for the MOVES source type vehicle categories and SCC vehicle types.

2030 Base Case Emissions

This subsection describes the development of the 2030 Base Case on-road inventory. The on-road inventory for areas outside of California used MOVES emission factors and state-supplied VMT. California emissions were downloaded directly from the web, using a web-tool version of the California Air Resources Board (ARB) EMissions FACtor model (EMFAC2011; ARB, 2013).[4] Adjustments were applied to the MOVES and EMFAC inventories to account for emissions changes resulting from recent on-road rulemakings, and cold-temperature adjustments were applied to on-road PM exhaust emissions prior to air quality modeling.

2030 Emission Factors

Emission factors for counties outside of California were developed using EPA's MOVES model (EPA, 2010a). The model version *MOVES2010a* with database version *movesdb20100830* was used to generate all 2030 emissions factors. Rather than run the model for all U.S. counties, a subset of approximately 200 representative counties was selected, based on the underlying county properties within the MOVES database. In this approach, counties whose emissions-determining properties are similar are grouped, and one set of MOVES runs corresponding to the representative county are applied to the full group. Because the representative-county approach produces similar results to a full MOVES run but saves a significant amount of computing time, EPA has also used this method—for example, in the Transport Rule analysis (EPA, 2010b and 2010c) and the 2008 National Emissions Inventory (NEI; EPA, 2012a). An exception to the appropriateness of using a representative approach occurs for one emission process: extended idling (often termed "hoteling") from heavy-duty diesel vehicles (HDDV). For the extended idling emissions process only, MOVES was run at the national aggregated level for 2030 and the national results were allocated to counties using the models' allocation method of source hours of idling (SHI) fractions. The SHI fractions in MOVES are a set of county

[4] California has separate authority under the Clean Air Act to develop motor vehicle emissions regulations and uses its own model to estimate vehicle emissions.

allocation factors based on presence and utilization of truck stops by state, as well as the amount of interstate VMT in each county (EPA2010d).

The MOVES runs were performed for an average January and July day in 2030 and included the pollutants: volatile organic compounds (VOC), CO, NO_X, PM_{10}, $PM_{2.5}$, SO_2, and NH_3. PM emission factors were generated in different MOVES runs from other pollutants, with the ambient temperature set to a flat value of 72°F to prevent the cold-temperature PM adjustments that MOVES applies. Instead, more spatially detailed temperature data were used to adjust the exhaust-mode PM emissions that are sensitive to cold temperatures. This work is discussed below.

The effects of gasoline containing 10% ethanol (E10 fuel) were incorporated into those counties whose fuel properties for 2030 in MOVES specified conventional gasoline (E0). Approximately 18% of U.S. counties' emission factors were adjusted, using ratios of emissions for E10 divided by emissions for E0 to align these areas with the fuel-properties assumptions in EPA (2012c). The other 82% of counties' emission factors were already based on E10 fuel, so they did not receive any adjustment. For the counties needing the E10/E0 ratio adjustment, the average value of emission-factor changes were a 13% decrease for CO; a 4% increase for exhaust VOC; and 127%, 11%, and 8% increases in evaporative VOC from the emission processes of fuel permeation, fuel-vapor venting, and fuel leaks, respectively. The E10 effects were negligible for NO_x and nonexistent for PM exhaust.

Representative county emission factors were developed using the methods described above, for each Source Category Code (SCC) (a numeric code identifying the vehicle, fuel, and road type), pollutant, and emission process (for example, start exhaust) in units of grams per mile. The emission factors were then multiplied with each county's VMT corresponding to the representative county groups. The county-level VMT development is described next.

2030 VMT

The 2030 VMT development was based on VMT reported for the 2008 National Emissions Inventory (NEI), Version 1, contained in the national county database (NCD) maintained by the EPA. States provide VMT by SCC and county to the EPA for the NEI every three years, and the 2008 NEI was the latest available data at the time when on-road emissions estimates were prepared. The 2008 VMT in the NCD was listed for each county, 28 vehicle classes (the system used by MOBILE6), and 12 road types. VMT classified by the 28 vehicle classes were summed to the 12 MOVES-based SCC vehicle types, using a many-to-one cross reference. No changes were needed to road-type classifications. Annual VMT was apportioned to January or July, based on monthly temporal patterns from the Vehicle Travel Information System (VTRIS; ENVIRON, 2008) for those states where data existed, and on MOVES national monthly allocations elsewhere. Table 2-1 lists which states had VTRIS data by region, and Figure 2-1shows comparisons of monthly VMT allocation by region.

Table 2-1
List of states by region that have VTRIS monthly profile data

Region	Applicable States
Northeast	CT, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT, WV
Southeast	AL, DC, FL, GA, KY, LA, MS, NC, SC, TN, VA
Upper Midwest	IA, MT, ND, SD, WY
Lower Midwest	AR, CO, KS, NE, NM, OK, TX

The Upper Midwest region from the VTRIS data source shows the highest fraction of its annual VMT during the summer and a low amount of travel during winter months. Conversely, the Southeast region shows the least variation in month-by-month VMT change.

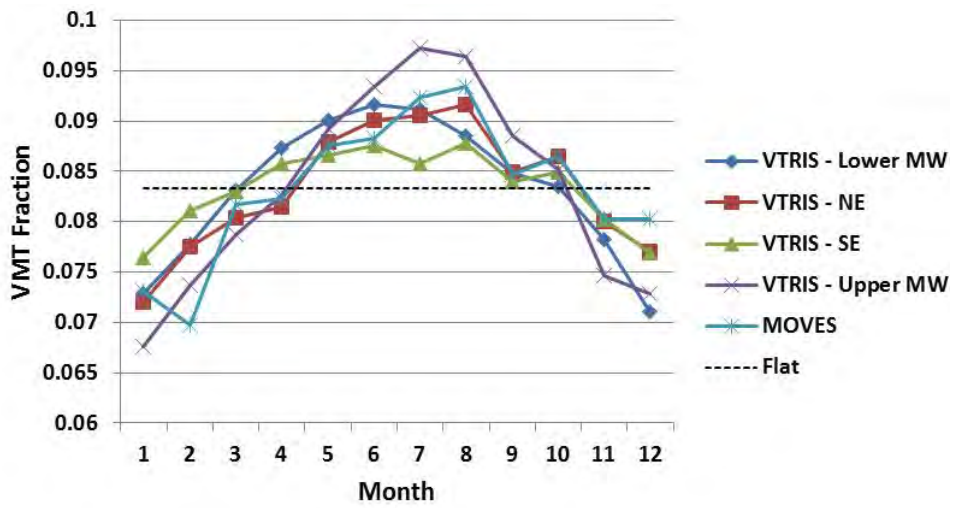

Figure 2-1
VMT monthly allocation factors in four VTRIS regions and from MOVES

Next, the January and July VMT were projected from 2008 to 2030, using growth projections that are an update to MOVES's activity growth from 2008 to 2030. MOVES projects 1999 base year VMT to future years through 2050, using growth factors primarily derived from the Energy Information Administration (EIA) 2009 Annual Energy Outlook (AEO) estimates of growth in vehicle activity (EPA, 2010d). More recent AEO 2011 data were used to update yearly growth within MOVES. Table 2-2 shows the projection as the ratio of 2030 VMT to 2008 VMT by vehicle class, comparing MOVES defaults (AEO 2009) to the updated AEO 2011 data used in this VMT development effort. Motorcycle VMT growth from 2008 to 2030 was identical between MOVES default and the 2011 AEO update, but all other vehicle types in the 2011 AEO projection case have less VMT growth by 2030.

Table 2-2
VMT projection factors for 2008 to 2030, showing MOVES default and AEO2011 updates

SCC Vehicle	SCC Vehicle Type	Fuel Type	Description	MOVES 2010a Default	2011 AEO Updated
2201001000	LDGV	Gasoline	Passenger Cars	1.576	1.390
2201020000	LDGT1	Gasoline	Light-Duty Trucks (0-6,000 lbs. GVWR)	1.045	1.017
2201040000	LDGT2	Gasoline	Light-Duty Trucks (6,001-8,500 lbs. GVWR)	1.045	1.017
2201070000	HDGV	Gasoline	Heavy-Duty Gasoline Vehicles (>8500 lbs. GVWR)	1.215	1.046
2201080000	MC	Gasoline	Motorcycles	1.211	1.211
2230001000	LDDV	Diesel	Passenger Cars	2.496	2.201
2230060000	LDDT	Diesel	Light-Duty Trucks	1.083	1.054
2230071000	HDDV2b	Diesel	Heavy-Duty Diesel Vehicles (8501-10,000 lbs. GVWR)	1.142	1.111
2230072000	HDDV345	Diesel	Heavy-Duty Diesel Vehicles (10,001-19,500 lbs. GVWR)	1.040	1.012
2230073000	HDDV67	Diesel	Heavy-Duty Diesel Vehicles (19,501-33,000 lbs. GVWR)	1.805	1.495
2230074000	HDDV8	Diesel	Heavy-Duty Diesel Vehicles (>33,000 lbs. GVWR)	1.391	1.335
2230075000	HDDB	Diesel	Heavy-Duty Diesel Buses	1.948	1.572

The smaller growth factors shown above in Table 2-2 in the 2011 AEO update for light-duty vehicles are caused by reduced VMT growth in early years closer to 2008. Figure 2-2 compares year-by-year growth factors between MOVES and the 2011 AEO update for passenger cars and light-duty trucks, showing that updated passenger car VMT growth estimates predict lower VMT growth (up to 1.5% lower) for 2009 to 2023. Beyond 2023, predictions are slightly higher (up to 1.3% higher), whereas updated light-duty trucks VMT growth factor estimates in general show less difference from the MOVES estimates than passenger cars. The discontinuity in light-duty VMT growth factors in the year 2030 is attributable to the assumption in the MOVES methodology of an increase in per-vehicle annual VMT accumulation from 0.3% annually to 1% annually, beginning in 2030.

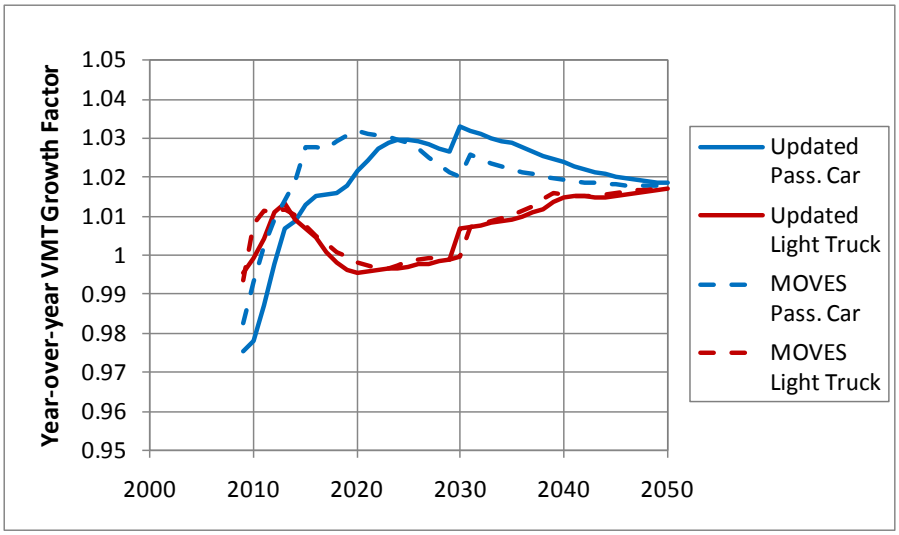

Figure 2-2
Passenger car and light truck MOVES default and AEO2011 updated year-over-year VMT growth factors

Figure 2-3 shows similar comparisons for medium-duty vehicles, buses, and heavy-duty vehicles. For medium-duty vehicles and buses, 2009 to 2011 VMT growth estimates from the 2011 AEO are higher relative to MOVES defaults, but lower thereafter. Heavy-duty vehicles show differences in AEO 2011 and MOVES default VMT growth factors of less than 2.5% from 2009 to 2013, and less than 0.8% differences thereafter. As previously mentioned, the overall effect of using 2011 AEO estimates is lower VMT growth from 2008 to 2030, compared to MOVES defaults predicted by the 2009 AEO.

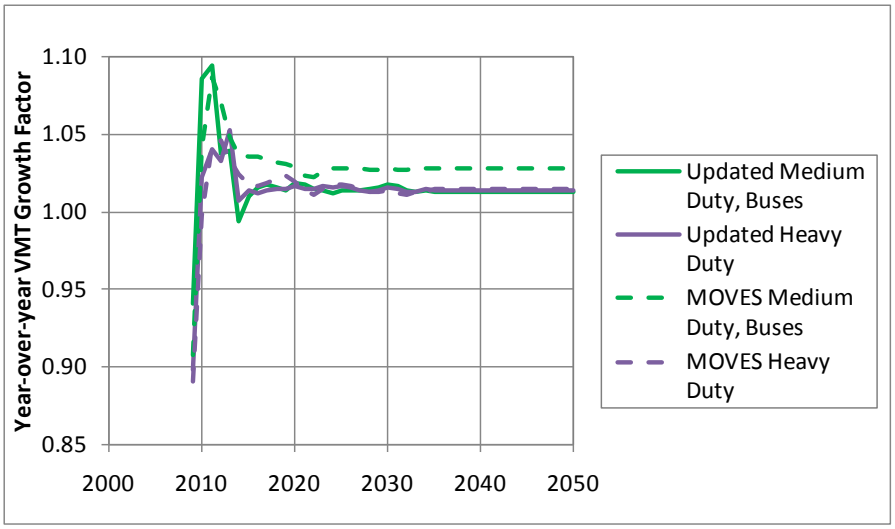

Figure 2-3
Medium-duty vehicles and buses and heavy- duty vehicle MOVES default and AEO2011 updated year-over-year VMT growth factors

In summary, because VMT is a principal determinant of on-road emissions, a number of updates were made to develop the 2030 activity data. These efforts included updated base year VMT using the 2008 NEI; updated seasonal allocation of annual VMT to summer and winter months depending upon state; and updated VMT projection factors using the latest data available from the AEO.

The 2030 VMT data within each county was multiplied by the county's corresponding representative county set of emission factors. The resulting 2030 emission inventory contained a level of detail that included emissions by pollutant, process (for example, start, exhaust), SCC, season, and county. The next section discusses further adjustments incorporated into the 2030 Base Case on-road emissions.

Adjustments to Account for On-road Rulemakings

Three important on-road rulemakings were incorporated into the MOVES-based inventory outside of California and the EMFAC2011 inventory within California. Scaling factors were developed in a separate, detailed analysis and then multiplied with the 2030 Base Case. These adjustments were done for the following on-road rulemakings:

1. EPA's Tier 3 emission standards (40 CFR Parts 79, 80, 85 et al.) with lower-sulfur-content (10 ppm) gasoline and the LEV-III standards with low-sulfur gasoline within California (already adopted by the ARB).
2. Light-duty GHG rulemaking, beginning with 2017 models (49 CFR Parts 523, 531, 533 et al.).
3. Heavy-duty GHG rulemaking, beginning with 2014 models (40 CFR Parts 85, 86, 1036 et al. and 49 CFR Parts 523 and 535).

The scaling factors were developed separately for each rulemaking, and for the first rulemaking above (Tier 3), scaling factors were developed separately inside California and the rest of the nation.

Tier 3 Rule Scaling Factors Outside of California

EPA's Tier 3 rule seeks to reduce tailpipe and evaporative emissions through more stringent emission standards and cleaner fuel, and it closely aligns with California's LEV-III emission standards. Similar to California, the Tier 3 rule will fully phase in the new emission standards by 2025; will extend durability requirements of 150,000 miles; and will propose gasoline sulfur content to be limited to 10 ppm.

The light-duty fleet emissions effects of Tier 3 standards with lower-sulfur gasoline relative to Tier 2 standards were addressed by developing scaling factors to account for the emissions decreases. The scaling factors differ by pollutant and SCC, and they were carefully developed—using the best available data sources—as of July 2013. The method of scaling VOC (exhaust and evaporative), CO, and NO_x involved a two-step adjustment of baseline emission factors:

1. Tier 2 to LEV-II, using EPA alternative emission factors (EPA, 2010e)
2. LEV-II to LEV-III (Tier 3), using California ARB tools (ARB, 2011a)

The PM exhaust emission-scaling factors were developed in one step—a single set of adjustment factors reflecting changes from Tier 2 to Tier 3.

The scaling-factor development for VOC, CO, and NO_x emissions began with running MOVES to develop emission factors for each vehicle-model year in the 2030 fleet (2000 through 2030 models) for two cases: 1) Tier 2–compliant vehicles and 2) vehicles compliant with California's LEV-II standards. The latter emission-factor set was generated in MOVES using EPA's alternative emission factors for LEV adoption in other states (EPA, 2010e). The by-model-year LEV-II emission factors were then scaled to the LEV-III standard using an ARB tool. The ARB released the Advanced Clean Cars (ACC) program LEV-III Inventory Database Tool (ARB, 2011a) that generates California statewide baseline (LEV-II) and LEV-III inventories by light-duty vehicle class and model year. The MOVES LEV-II emission factors were scaled by multiplying by the reduction factors shown in Table 2-3, produced from runs of the ARB tool—leading to final emissions factors that were significantly lower than the federal Tier 2 base.

Table 2-3
Emissions ratios of LEV-III to LEV-II by vehicle class

ARB Tool Ratios	Equivalent Federal Class	THC Exhaust		CO		NO_x	
		Run	Start	Run	Start	Run	Start
LEV III/LEV II PC (LDV)	LDGV	0.373	0.232	0.588	0.489	0.445	0.267
LEV III/LEV II LT1&2	LDGT1	0.375	0.230	0.641	0.552	0.430	0.275
LEV III/LEV II LT3	LDGT2	0.365	0.229	0.624	0.530	0.425	0.281

Similarly, LEV-II evaporative hydrocarbon (HC) emission factors by model year from MOVES were scaled using ratios of LEV-III to LEV-II from the ARB tool. Because evaporative-emission process definitions are not the same between MOVES and ARB's tool, the evaporative-emissions assignments listed in Table 2-4 were used to assign all the ARB emissions benefits into MOVES classifications. The LEV-III set of emission factors was finalized by incorporating the phase-in schedule over years 2017 to 2025.

Table 2-4
Cross-reference of evaporative-emissions processes between ARB and MOVES classifications

ARB EMFAC	MOVES
Sum of Diurnal, Running Loss, and Hot Soak	Evaporative Fuel-Vapor Venting
Resting Loss	Evaporative Permeation and Fuel Leaks

The scaling-factor development for PM emissions required a different approach because EPA alternative emission factors (LEV-II) did not include PM estimates. Instead, the PM adjustments were developed as a ratio of emissions directly from Tier 2 levels to LEV-III, based primarily on the magnitudes of the two standards. EPA is proposing to reduce the 10 milligrams per mile (mg/mi) standard to 3 mg/mi for exhaust PM over the period 2017–2020. According to MOVES modeling results, the representative Tier 2 standard emission factor for the gasoline light-duty vehicle fleet at the end of useful life is approximately 7.7 mg/mi, which is well below the 10 mg/mi standard. Because vehicles easily meet the 10 mg/mi standard and the margin of compliance with a 3 mg/mi standard may be narrower, the emissions ratio was conservatively estimated as 3 mg/mi divided by 7.7 mg/mi—or approximately 0.389 at full implementation. The phase-in years and full-implementation scaling factors are shown in the rightmost column of Table 2-5.

Table 2-5
Light-duty vehicle PM-emission standards, Tier 3 phase-in schedule, and scaling factor adjustments

Vehicle Model Year	Light Duty Standard (mg/mi)	Phase-in (%)	Scaling Factor
2016 & earlier	10	0	1
2017	3	20%	0.878
2018	3	20%	0.878
2019	3	40%	0.756
2020	3	70%	0.573
2021–2030	3	100%	0.389

Also included as part of Tier 3 is EPA's proposal to lower gasoline sulfur content to 10 ppm on an annual average basis (down from the current level of 30 ppm). This change will reduce exhaust emissions from any gasoline-fueled vehicle with a catalyst. The emissions effects of lower-sulfur gasoline were incorporated by adopting the approach developed for a study for the American Petroleum Institute (API, 2012), in which the California Predictive Model was used to estimate emissions reductions resulting from reducing sulfur content by 1/3. The reductions vary geographically and by SCC, but overall the NO_x from gasoline vehicles operating on lower sulfur fuel was reduced up to 12%, CO up to 2%, and HC exhaust up to 3%.

Accounting for all of the above effects, two sets of emission factors were created: 1) Tier 2–compliant vehicles and 2) LEV-III–compliant vehicles, which are introduced beginning in 2017 and progressively phase in until all new vehicles are compliant in 2025. The two sets of emission factors were aggregated over model years 2000 to 2030 into a single average-aged emission factor for each vehicle type, pollutant, and emission process. The aggregation was performed using travel fractions, a weighted average that reflects a relatively higher portion of activity in late model years closest to 2030. Finally, the ratio of these average-age

emission factors were calculated as emission factors at LEV-III, divided by emission factors at Tier 2. These ratios were multiplied with the 2030 MOVES-based on-road inventory to generate updated 2030 Base Case emissions reflecting EPA's Tier 3 rulemaking with 10 ppm gasoline sulfur.

The results of Tier 3 and low gasoline sulfur adjustments to the 2030 inventory compare well with EPA's Tier 3 rulemaking analysis documentation (EPA, 2013), despite different modeling approaches. Table 2-6 lists the two 2030 national emissions totals and shows excellent agreement in VOC, NO_X, and NH_3. CO and SO_2 did not match well, but have clear explanations for the discrepancies.

Table 2-6
Comparison of 2030 Tier 3–adjusted on-road inventory to EPA's Technical Support Document (EPA, 2013)

Pollutant	EPA TSD (EPA, 2013) (tons/year)	Tier 3 Emission Inventory (tons/year)	% Difference
VOC	699,592	702,803	0%
CO	11,984,061	16,174,712	35%
NOx	1,371,925	1,447,934	6%
SO_2	15,068	11,291	-25%
NH_3	90,104	86,576	-4%
$PM_{2.5}$	83,842	59,130*	N/A

* $PM_{2.5}$ reported at 72°F (without cold-temperature adjustments to gasoline-fueled vehicle emissions).

EPA's analysis shows approximately 30% lower CO emissions than EPRI's Tier 3 inventory because of their assumption of 100% E15 fuel in use by 2030. EPRI's Tier 3 on-road inventory assumed 100% use of E10, and higher ethanol is associated with reduced CO emissions. EPA's SO_2 emissions were approximately 30% higher because the analysis assumed a flat value of 10 ppm in the Tier 3 scenario case. By contrast, EPRI's on-road inventory reflects gasoline with geographically varying sulfur content below the 10 ppm sulfur standard by a margin of compliance. Tier 3 PM results are 29% lower than EPA's estimate, but these should not be directly compared because the PM exhaust has not yet been adjusted (increased) for cold-temperature effects. These temperature adjustments are discussed below.

LEV-III Rule Scaling Factors Inside California

The scaling factors to incorporate the LEV-III rule into the EMFAC2011 emission inventory were developed using methods similar to those described for the rest of the United States, in that the ARB tool was used to estimate effects of LEV-III relative to LEV-II. The resulting LEV-III–adjusted California on-road inventory was compared to ARB estimates of 2030 statewide total emissions

reported in the ARB's technical support document for LEV-III (ARB, 2011b; Figures 3.5–3.8). Table 2-7 shows that the two inventories match within 12% for all pollutants (ROG, CO, NO_X, and $PM_{2.5}$).

Table 2-7
California LEV-III 2030 statewide emissions comparisons for those vehicles affected by LEV-III (excludes motorcycles and heavy-duty diesel)

Pollutant	CA LEV-III inventory (TPD)	ARB (2011b) (TPD)	Data source in ARB, 2011b	% Difference, (CA LEVIII-ARB)/ARB
ROG	125	125	Figure 3.5	0%
NO_x	108	120	Figure 3.6	-10%
CO	1,132	1,050	Figure 3.7	8%
$PM_{2.5}$	23	26.5	Figure 3.8	-12%

Light-duty GHG Rule Scaling factors

Light-duty vehicles impacted by the GHG rule include five classes tracked in the 2030 Base Case on-road inventory: gasoline cars (LDGV), diesel cars (LDDV), gasoline-truck classes (LDGT1 and LDGT2), and diesel light-duty trucks (LDDT). EPA's Regulatory Impact Analysis (RIA) Table 5.4-1 provides estimated gasoline reduction by calendar year resulting from the GHG rule; for year 2030 the gasoline consumption was 18% lower than the reference case without the GHG rule (EPA, 2012b). Because of an absence of information on diesel consumption, the same 18% reduction was assumed for light-duty diesel fuel to reduce baseline emissions of SO_2, $PM_{10}SO_4$, and $PM_{2.5}SO_4$ in the diesel-fueled light-duty vehicles. The 18% reduction was applied only to affected model years (2017–2030). Aside from the fuel-sulfur effects, this rule only affects upstream emissions.

Heavy-duty GHG Rule Scaling Factors

Heavy-duty vehicles impacted by the GHG rule include six classes tracked in the on-road inventory: heavy-duty gasoline vehicles (HDGV) and five categories of heavy-duty diesel (HDDV): HDDV2B, HDDV345, HDDV67, HDDV8, and diesel buses (HDDB). EPA's RIA Table 5-13 lists on-road emissions in the year 2030 for a reference and control case representing the downstream heavy-duty vehicle sector emissions without and with the GHG rule (EPA, 2011a). Those emissions are transcribed below into Table 2-8, with an additional column added to show the calculated percent change in emissions by pollutant.

Table 2-8
Heavy-duty vehicle emissions in year 2030 for reference and control scenarios (EPA, 2011a) and percent change in emissions resulting from the heavy-duty GHG rule

Pollutant	Reference (tpy)	Control (tpy)	Percent Change
VOC	133,377	108,112	-18.9%
CO	2,646,583	2,594,341	-2.0%
NO_X	1,068,212	832,813	-22.0%
$PM_{2.5}$	20,743	22,503	8.5%
SO_2	4,852	4,424	-8.8%

According to Table 2-8, heavy-duty vehicle emissions of VOC, CO, NO_x and SO_2 decrease as a result of the heavy-duty GHG rule by approximately 19%, 2%, 22%, and 9%, respectively. According to EPA's analysis, however, $PM_{2.5}$ emissions are expected to increase by 8.5% as a result of an assumed increase in use of auxiliary power units (APU) during extended idling to meet future GHG standards (EPA, 2011a). The use of an APU instead of a main engine during idle reduces fuel consumption, but because PM emissions from APUs are regulated as non-road small engines for criteria (non-GHG) pollutants, these smaller engines emit higher rates of PM than main engines equipped with a diesel particulate filter (DPF). Similar to the light-duty GHG adjustment applications, the heavy-duty GHG emission changes were applied to affected model years (2014 through 2030).

The changes to the 2030 Base Case resulting from both GHG rulemakings reduced the national total Tier 3 baseline emissions inventory by 14% for NO_x and SO_2. $PM_{2.5}$ emissions increased by 3%, VOC emissions fell by 3%, and CO changes were negligible.

Adjustments to Account for Cold-temperature PM Exhaust

As previously mentioned, on-road PM-exhaust emission factors were generated in MOVES runs separately from other pollutants, with the ambient temperature set to a flat value of 72°F to prevent the cold-temperature PM adjustments that MOVES applies. The temperature adjustments were instead applied using higher-resolution meteorological data in a calculation step after the emissions processing and prior to input to the air quality model. PM emissions increase exponentially with temperatures below 72°F, and ambient temperatures specific to the modeling episode by grid cell and hour of day were used to determine the appropriate adjustment to PM exhaust from gasoline-fueled vehicles. The equations below show the MOVES2010a multiplicative adjustment factors, which were applied to start exhaust (Eq. 2-1) and running exhaust (Eq. 2-2).

For T < 72°F,

$$Adjustment_{Start\ PM} = 28.039e^{-0.0463T} \qquad \textit{Eq. 2-1}$$

$$Adjustment_{Running\ PM} = 9.871e^{-0.0318T} \qquad \textit{Eq. 2-2}$$

Where T = ambient temperature in °F.

For T ≥ 72°F,

$$Adjustment = 1$$

A script was written to compute the above adjustments for each grid cell and hour and multiply them with the appropriate unadjusted PM-exhaust emissions from gasoline-fueled vehicles in the 2030 Base Case. The net effect of PM adjustments at the nationwide total level was an increase in national total $PM_{2.5}$ from 167 tons/day to 202 tons/day.

2030 Base Case Summary

The final Base Case on-road emission inventory and VMT is summarized in Table 2-9 by state, showing year 2030 average-day emissions and activity. Appendix C provides the Base Case emissions disaggregated into light-duty and heavy-duty vehicle types.

Table 2-9
Annual average 2030 Base Case on-road criteria pollutant emissions and VMT by state, units of tons, or miles per average day

State	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3	VMT
AL	35.7	851.1	70.4	8.4	3.1	0.5	4.6	194,758,938
AR	24.0	538.7	51.2	4.6	1.8	0.3	2.5	102,342,770
AZ	42.4	714.2	82.0	10.5	4.0	0.6	5.0	203,644,015
CA	174.0	1,461.0	290.7	78.5	35.8	5.0	29.7	1,200,801,308
CO	32.3	793.7	48.8	8.2	3.1	0.4	3.8	159,331,703
CT	19.2	421.7	33.8	5.8	2.2	0.2	2.5	103,542,099
DC	2.3	56.7	3.1	0.7	0.2	0.0	0.3	11,608,727
DE	5.3	136.8	10.1	1.6	0.6	0.1	0.7	28,726,781
FL	131.8	2,438.3	183.0	31.0	10.9	1.7	15.5	645,921,819
GA	60.8	1,489.3	121.1	15.8	5.9	0.8	7.8	318,028,423
IA	19.6	613.9	38.1	5.2	2.1	0.3	2.4	101,544,084
ID	11.2	334.3	23.3	2.6	1.0	0.1	1.2	47,196,890
IL	72.5	1,940.5	145.7	21.1	8.1	0.9	8.4	334,590,513
IN	47.9	1,347.8	113.4	12.4	4.8	0.6	5.7	235,450,017
KS	18.1	504.6	33.4	4.5	1.7	0.2	2.3	96,052,580
KY	30.0	690.7	68.6	7.2	2.8	0.4	3.7	154,574,737
LA	29.9	617.6	61.8	6.3	2.4	0.4	3.6	148,988,434
MA	27.9	835.8	52.9	9.9	3.8	0.4	4.3	179,746,303
MD	33.3	856.2	54.6	9.0	3.4	0.4	4.4	181,446,613
ME	9.8	306.3	17.5	2.6	1.1	0.1	1.1	45,128,647
MI	72.3	2,173.6	118.5	19.9	7.7	0.8	7.9	321,177,548
MN	40.7	1,389.8	68.3	12.0	4.8	0.5	4.5	185,817,963
MO	49.4	1,209.3	97.8	11.4	4.4	0.6	5.4	220,166,675
MS	23.5	583.0	52.1	5.5	2.1	0.4	3.4	148,778,468
MT	6.9	209.1	16.6	1.8	0.7	0.1	0.9	35,754,966
NC	66.6	1,735.0	117.2	16.2	6.1	0.8	8.0	325,590,191

Table 2-9 (continued)
Annual average 2030 Base Case on-road criteria pollutant emissions and VMT by state, units of tons, or miles per average day

State	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3	VMT
ND	5.1	166.1	10.1	1.4	0.5	0.1	0.6	25,849,667
NE	12.0	377.6	23.9	3.4	1.4	0.2	1.5	62,808,726
NH	7.2	229.2	12.4	2.3	0.9	0.1	1.0	42,546,300
NJ	39.8	1,103.2	58.3	12.2	4.5	0.5	5.7	238,846,469
NM	19.1	378.2	39.8	4.1	1.6	0.2	2.1	86,460,162
NV	18.6	238.7	22.0	3.0	1.1	0.2	1.7	69,995,542
NY	72.2	2,287.1	120.6	22.4	8.4	0.9	10.3	430,429,180
OH	65.7	2,110.6	133.0	18.5	7.2	0.9	8.7	361,612,276
OK	32.1	734.9	58.2	7.4	2.8	0.4	3.8	159,463,696
OR	21.7	630.3	43.4	5.5	2.1	0.3	2.6	108,612,332
PA	108.1	1,991.6	119.1	18.5	7.2	0.9	8.8	358,636,848
RI	7.0	128.8	6.9	1.4	0.5	0.1	0.7	27,334,030
SC	33.0	774.9	62.0	7.3	2.7	0.4	3.8	156,373,234
SD	5.7	182.0	11.5	1.5	0.6	0.1	0.7	29,724,827
TN	45.4	1,075.9	87.9	10.9	4.2	0.6	5.4	218,137,867
TX	125.2	2,780.1	321.8	38.6	14.8	2.2	20.2	851,113,808
UT	19.2	476.9	31.8	4.7	1.8	0.2	2.0	83,117,777
VA	53.7	1,338.2	92.3	12.6	4.7	0.6	6.3	257,693,753
VT	4.5	147.3	6.3	1.1	0.4	0.1	0.6	25,129,191
WA	34.0	998.2	65.8	9.9	3.8	0.5	4.4	181,683,524
WI	39.7	1,181.9	58.9	10.3	4.1	0.4	4.4	182,342,205
WV	13.8	424.4	25.4	2.9	1.2	0.2	1.6	66,175,767
WY	6.5	193.3	15.2	1.6	0.7	0.1	0.8	31,260,223
Total	1,876.7	44,198.4	3,400.6	514.0	202.0	26.5	237.3	9,786,058,616

Electrification Case

The Electrification Case required significant analysis in order to model a future scenario of high market penetration for electric vehicles. The MOVES model (version 2010a) does not account for electric vehicles, and so the 2030 Base Case on-road inventory assumes that all vehicles operate on fossil fuels.

Several varieties of electric vehicles were included in the 2030 Electrification Case. Fully electric vehicles are those that must plug in to charge the battery (battery electric vehicle, or BEV). Plug-in hybrid electric vehicles (PHEV) operate on both electricity and fossil fuel, and may be plugged in to recharge from grid electricity.[5] BEVs and PHEVs taken together are denoted plug-in electric vehicles (PEV), and both PEV types draw electricity from the grid. Hybrid-electric vehicles (HEV) are sometimes classified as "electrified" vehicles, but HEVs do not use grid electricity, and instead rely on regenerative braking and generation supplied by the engine to charge the electric battery. The purpose of the Electrification Case is to evaluate the impact of PEVs, so this study assumes that the air quality impact of HEVs is the same in the Base Case and the Electrification Case. The subsections below discuss the methods and assumptions to estimate the market penetration of all electric vehicles included in the Electrification Case, the development of the 2030 Electrification Case on-road inventory, and the summarized on-road transportation-sector emissions for this case.

Electrification-Case Assumptions

The introduction of any kind of advanced automotive technology takes time to propagate into the fleet of vehicles in service, because only about 10% of the fleet is replaced each year with new vehicles, and those vehicles have a relatively long lifespan (usually more than 10 years). Plug-in electric vehicles, in particular, represent a paradigm shift in terms of the way vehicles are fueled, which means that it will take several years for the general public to gain an understanding of the new technology. As a result, this study assumes that the new-vehicle market share of PEVs starts at a relatively low volume that grows over time. This gradual expansion of the PEV market lengthens the amount of time required for it to reach market saturation.

The project team used a vehicle fleet–turnover model to determine the market penetration of PEVs in the overall vehicle fleet over time.[6] The fleet model uses exogenous assumptions for new-vehicle market shares of different vehicle powertrain types and other necessary parameters to determine the vehicle population and VMT of the various types and categories of vehicles. The additional parameters required by the turnover model include the initial vehicle

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[5] The definition of PHEV used in this study includes so-called extended-range electric vehicles.

[6] The vehicle-turnover model used in this study is based on the vehicle population and VMT growth calculations implemented in the United States Environmental Protection Agency's Motor Vehicle Emission Simulator (MOVES) 2009 software (EPA, 2009).

population by vehicle category, vehicle age, and vehicle type; vehicle population growth over time; changes in VMT over time, both at the fleet level and per-vehicle level; vehicle retirement rates; and other data. The next section describes the various vehicle types and categories.

Vehicle Classification

In order to categorize the various classes of on-road vehicles by their typical daily activity patterns, each of the 13 MOVES source type vehicle categories used by the EPA MOVES software were modeled. Based on EPRI's current vehicle-development projects and the vehicles available today in at least preliminary forms, most of the vehicle categories with daily travel distances of less than 200 miles per day were assumed to be electrifiable by 2030, as shown in Table 2-10. The categories assumed to have no PEV adoption are intercity buses, motor homes, short-haul combination trucks and long-haul trucks. Although it is possible that these categories will also be electrifiable in some form, limited market size or energy-intensive operational requirements make application of electric technologies within these categories challenging.

Table 2-10
Electrification of vehicle categories

Vehicle Category	PEV and Conventional Vehicles	Conventional Vehicles Only	Vehicle-Category Description
Motorcycle	X		Motorcycle
Passenger Car	X		Passenger Car
Passenger Truck	X		Minivans, pickups, SUVs, and other 2-axle / 4-tire trucks used primarily for personal transportation
Light Commercial Truck	X		Minivans, pickups, SUVs, and other 2-axle / 4-tire trucks used primarily for commercial applications
Intercity Bus		X	Buses that are not transit buses or school buses (e.g., those used primarily by commercial carriers for city-to-city transport)
Transit Bus	X		Buses used for public transit
School Bus	X		School and church buses
Refuse Truck	X		Garbage and recycling trucks
Single-Unit Short-Haul Truck	X		Single-unit trucks with majority of operation within 200 miles of home base
Single-Unit Long-Haul Truck		X	Single-unit trucks with majority of operation outside of 200 miles of home base

Table 2-10 (continued)
Electrification of vehicle categories

Vehicle Category	PEV and Conventional Vehicles	Conventional Vehicles Only	Vehicle-Category Description
Motor Home		X	Motor Home
Combination Short-Haul Truck		X	Combination trucks with majority of operation within 200 miles of home base
Combination Long-Haul Truck		X	Combination trucks with majority of operation outside of 200 miles of home base

Within each of the vehicle categories listed in Table 2-10, the analysis included several different vehicle power train types, including conventional vehicle (CV), HEV, PHEV, and BEV. With respect to HEVs (non-plug-in hybrids), the GHG rulemakings described above are likely to cause hybridization to occur in varying degrees across a wide range of vehicle types by 2030. For many vehicle categories, HEVs will essentially become "conventional" by 2030, so Table 2-10 does not distinguish HEVs separately from conventional vehicles.

The PEVs were further classified into sub-types according to all-electric range (AER)—the distance an individual vehicle can travel on electricity after a full recharge. For "blended" PHEVs, this range is the equivalent distance that a non-blended PHEV could drive on electric power. This report identifies the AER of PHEVs and BEVs by appending the AER in miles to the "PHEV" or "BEV" descriptor. For example, a PHEV 20 is a plug-in hybrid with 20 miles of electric range. The study team chose to consider PHEV 20, PHEV 40, and PHEV 60 configurations, along with a single BEV type that has a range of 100-miles or longer.

Figure 2-4 shows how the new PEV sales are distributed across the various PEV types over the study period for each category that is electrified. Through the middle of 2013, the ratios are based on actual data. Then the allocation over time shifts toward longer AERs, based on the assumption that as battery costs decrease, the PEV market will shift toward vehicles with greater electric utility. By 2030, the allocation of new PEV sales is 25% PHEV 40, 25% PHEV 60, and 50% BEV 100+. The distribution of PEV types shown by Figure 2-4applies equally to all vehicle categories in Table 2-10 that are denoted as "PEV and conventional vehicles."

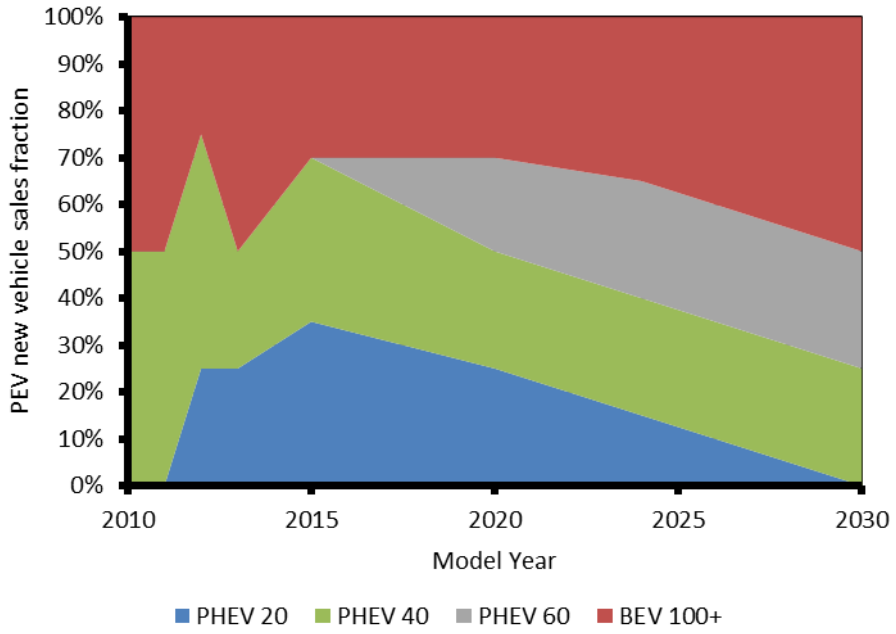

Figure 2-4
Distribution of new PEV sales among various PEV types

This study assumes that the vehicle types with internal-combustion engines (all types except BEV) are fueled by either gasoline or diesel, so this analysis does not explicitly consider alternative fuels such as biofuels, natural gas, or hydrogen.

Electric Vehicle Market Penetration

A wide range of publicly available PEV-adoption estimates were reviewed to find an optimistic, yet plausible, adoption scenario; a high-electrification scenario from the National Academy of Sciences Transitions to Alternative Fuels report was selected (National Academies Press, 2013). The PEV type split from Figure 2-4 was applied to the PEV market share in the report to create the new vehicle market share projection, shown in Figure 2-5. This projection assumes that the PEV market share grows modestly through about 2020, then accelerates rapidly to surpass 50% market share of new vehicles just beyond the year 2030.

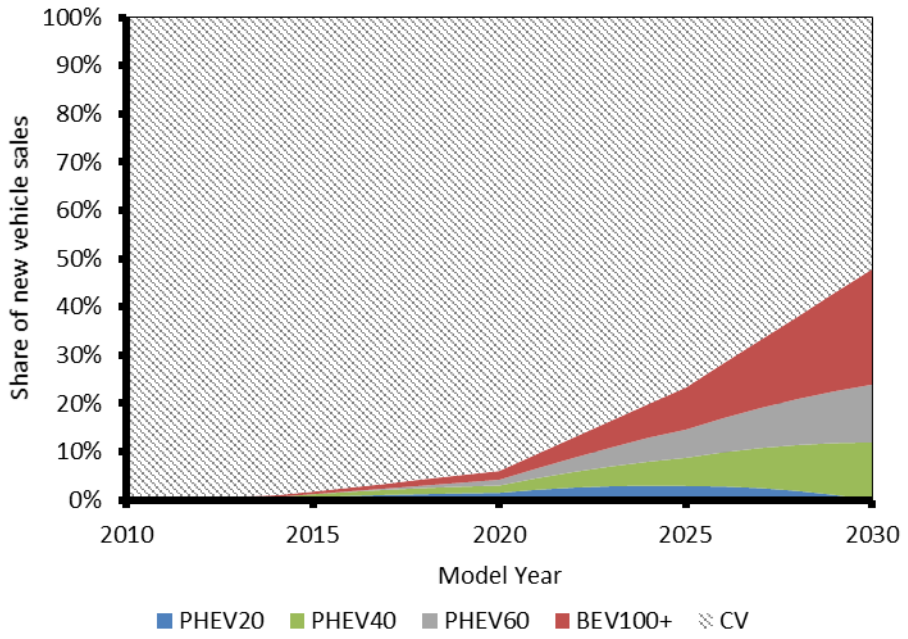

Figure 2-5
Distribution of new vehicle sales among various types, for vehicle categories that include PEV sales

The market-share projection illustrated in Figure 2-5 was applied to the vehicle categories that were considered for PEV adoption, as listed in Table 2-10. The other vehicle categories have zero PEV sales; therefore, the PEV market share for the entire on-road vehicle fleet (including all categories listed in Table 2-10) is less than the levels indicated in Figure 2-5.

Although the National Academy of Sciences study was focused on light-duty vehicles, the same market share was applied to all electrifiable vehicle categories. It is unlikely that the market for heavy-duty vehicles will exactly match the market for light-duty vehicles. However, it is likely that reductions in battery cost will be a key driver in achieving the assumed levels of light-duty PEV adoption, and these cost reductions will also create the market conditions for electrification of heavier vehicles that have usage patterns which match the benefits and limitations of PHEV and BEV configurations. There are limited data on heavy-duty usage patterns that could be used to create a separate market-share estimate, but this will be an area for future study.

Electric Vehicle Characteristics

Vehicle-Energy Economy in Electric Mode

MOVES does not include electric vehicles, so electricity consumption estimates were estimated separately. The revised fuel-economy regulations incorporated into the Base Case assumptions are expected to drive improvements in the energy efficiency of plug-in vehicles as well. For example, technologies to reduce the

vehicle mass and drag of conventional vehicles will likely be applied to plug-in vehicles.

Figure 2-6 shows the electricity consumption per mile of selected light-duty PEVs, projected over the time frame of this study. These PEV energy-economy assumptions are based upon projections in AEO2013 for various light-duty vehicle types through 2025, with continued improvement at 0.5% per year beyond 2025. For simplicity, this study assumes that various PEV types (BEVs and PHEVs of different electric ranges) have the same electricity consumption per mile. However, this analysis assumes that diesel-fueled PHEVs have slightly higher electricity consumption than gasoline PHEVs when operating as electric vehicles, because a diesel hybrid power train would typically weigh more than a gasoline power train.

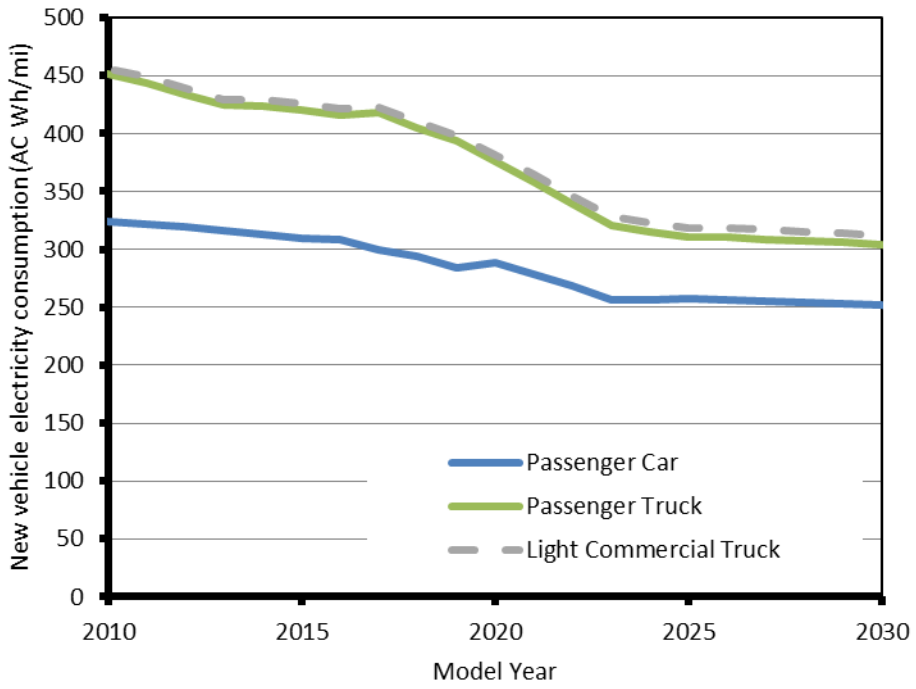

Figure 2-6
Electric-energy economy of selected passenger-vehicle categories

There are very limited data available on the electricity consumption of commercial PEVs. The study team developed a projection methodology based on the HEV fuel economy (mpg) for the corresponding vehicle category, multiplied by an appropriate energy-efficiency ratio. The resulting "mpge" (miles per gallon equivalent) quantities were then converted to electricity consumption in watt-hours per mile. Figure 2-7shows the resulting projections for the primary commercial PEV categories.

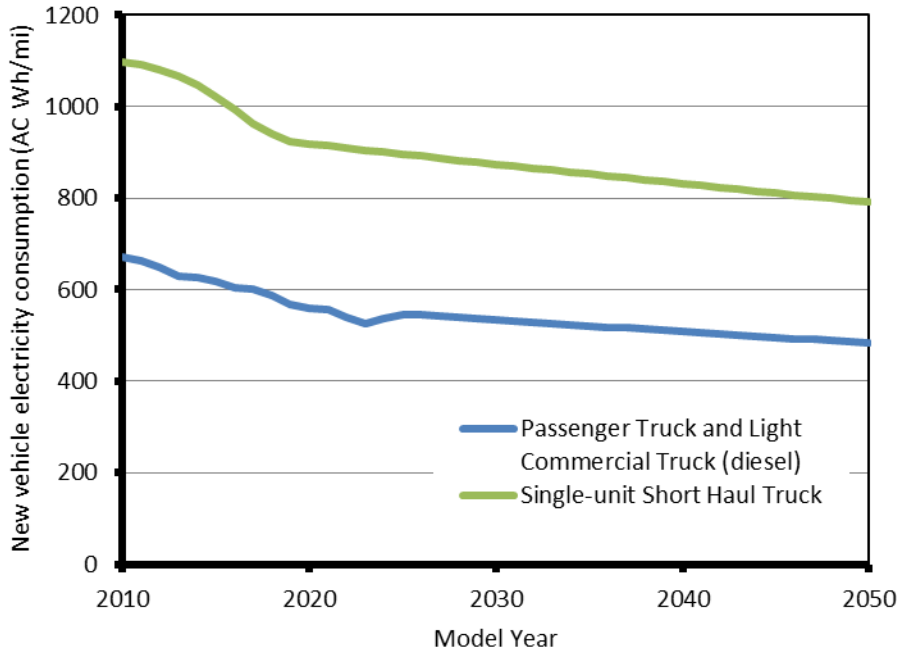

Figure 2-7
Electric- energy economy of selected commercial- vehicle categories

PEV Utility Factor

PHEVs have the ability to drive beyond their all-electric range by making use of an on-board range-extending engine. This means that over the vehicle's lifetime, some portion of the vehicle's miles will be provided by grid-sourced electricity and the remaining miles will be provided by another fuel. In the majority of present-day PHEVs, the fuel used by the range-extender is gasoline, but this study assumes that the use of diesel engines in PHEVs will expand in the future.

Utility factor is a term used to describe the fraction of PEV operation that is performed by electricity. Utility factors vary with each individual vehicle based on usage patterns and are affected by opportunities to charge the vehicle. In general, PHEVs that are driven very long distances between recharging events will have a low utility factor, whereas PHEVs that perform many short trips will have a very high utility factor. Since BEVs have longer "refueling" (charging) times than many other vehicle types, there will be certain long trips for which a BEV driver will choose to use a substitute vehicle over other travel options. In most cases, the alternate vehicle will be a vehicle type that uses a fuel other than electricity, so the concept of utility factor may be extended to BEVs as well.

Whereas many transportation analyses use the Society of Automotive Engineers J2841 standard[7] for utility factor, EPRI uses a more sophisticated calculation of

[7] Society of Automotive Engineers. "Utility Factor Definitions for Plug-In Hybrid Electric Vehicles Using 2001 U.S. DOT National Household Travel Survey Data," Hybrid Committee, J2841, March 2009.

utility factor that accounts for details such as daytime charging (EPRI 1021848). Table 2-11 shows the utility factor values used in this study. The utility factors are based on EPRI estimates, assuming that charging is available at the driver's home and work locations at a charge rate of 6.6 kW. Whereas the evaluation of BEV utility factors is more complex than that for PHEVs (EPRI 1021848), this study makes a simplifying assumption that the BEV utility factor is equal to that of a PHEV100. This simple but conservative estimate assumes that long trips that cannot be completed with a BEV are instead driven using a substitute conventional vehicle.

Table 2-11
PEV utility factor

Vehicle Type	PHEV20	PHEV40	PHEV60	BEV100+
Utility Factor	56%	73%	80%	87%

PEV Petroleum and Electricity Consumption

MOVES (version 2010a) does not have the ability to explicitly model PEVs, so an existing EPRI market-adoption tool was modified to use equivalent vehicle-usage assumptions to calculate the amount of liquid petroleum fuel and electricity consumed by PEVs. The reduction in petroleum-fuel consumption was used to create a scaling factor for the MOVES emissions results, and the electricity consumption was used to create the incremental load for the electricity modeling (described in Section 4).

The EPRI PEV market-analysis tool uses a cohort model that tracks vehicles as they age over time, which accounts for changes in vehicle performance as the market evolves. The VMT and energy-consumption assumptions—which vary by vehicle type, category, model year, and age—are based on data equivalent to that used in MOVES for the air quality modeling.[8]

Figure 2-8 presents the PEV electricity consumption over the study period. The "Other Bus and Truck" group includes three vehicle categories: Transit Bus, School Bus, and Refuse Truck. These categories, along with Motorcycles, comprise a very small portion of the overall electricity consumption. Because the Passenger Car and Passenger Truck categories account for a majority of the total VMT within the categories considered for electrification, those two categories dominate the PEV electricity use. Table 2-12 presents the consumption for each vehicle category. In 2030, the total PEV electricity use is 176 TWh. It should be noted that close to 50% of heavy-duty VMT are in vehicle categories that were not considered for electrification in this study (that is, single-unit long-haul

[8] The energy-consumption assumptions used in the EPRI tool account for the EPA GHG rulemakings discussed in Section 2.0 for light-duty and heavy-duty vehicles. The light-duty vehicle assumptions are based on data in AEO2013. For heavy-duty vehicles, the energy assumptions are based on a combination of data from AEO2013, MOVES default assumptions, and the following National Academy of Sciences report: National Academies Press, *Technologies and Approaches to Reducing the Fuel Consumption of Medium- and Heavy-Duty Vehicles*, 2010, downloaded from www.nap.edu , Table 6-18.

trucks, motor homes, intercity buses, and combination-unit trucks), so the amount of converted VMT is relatively small for heavy-duty vehicles.

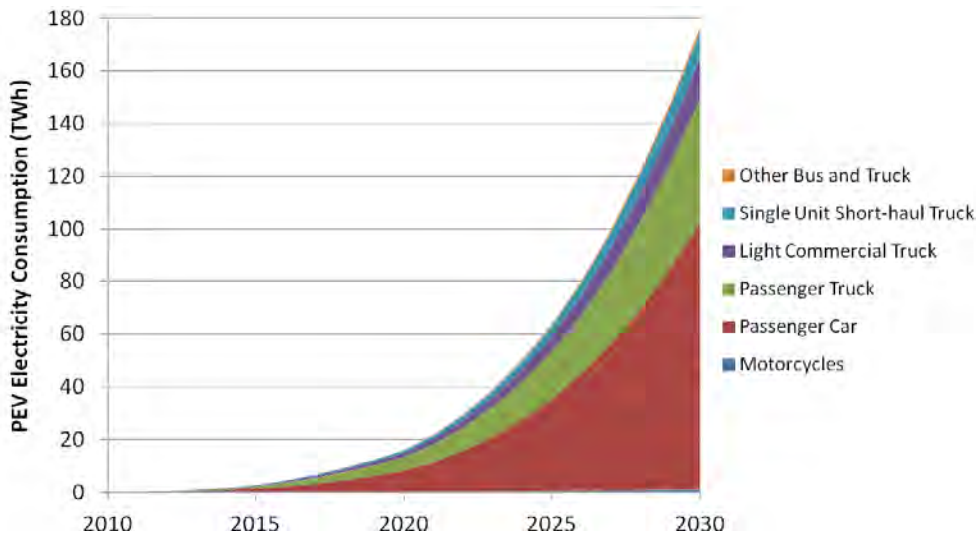

Figure 2-8
PEV electricity consumption

Table 2-12
PEV electricity consumption in 2030

Vehicle Category	Electricity Consumption (TWh)
Motorcycles	1.1
Passenger Car	101
Passenger Truck	47
Light Commercial Truck	15
Transit Bus	0.2
School Bus	0.9
Refuse Truck	0.5
Single-Unit Short-Haul Truck	10
Total	176

2030 Electrification Case Emissions

The Electrification Case for on-road vehicle emissions was developed by multiplying the 2030 Base Case by scaling factors that depend on vehicle class.

Electric vehicles in this scenario include a mix of PHEVs and BEVs. Estimates of electric-vehicle penetration of the vehicle fleet for each model year (2010 to 2030) affect the inventory vehicle classes listed in Table 2-10 according to the phase-in schedule shown in Figure 2-9. The affected vehicle classes, categorized by MOVES source types, include *passenger car*, *passenger truck*, *light commercial truck*, *motorcycle*, *refuse truck*, *single-unit short-haul truck*, *school bus*, and *transit bus*.

Single-unit long-haul trucks, motor homes, intercity buses, and combination-unit trucks (short- and long-haul) are assumed to operate entirely on conventional fuel in 2030 (no electrification). The vehicle classes that are impacted by electrification have increasing amounts of activity share (VMT and population) in the on-road fleet because of increasing new-vehicle sales. Figure 2-9 shows the electrification shares for new-vehicle sales, total vehicles, and for vehicle miles traveled for passenger vehicles (which include passenger cars, passenger trucks, motorcycles, and motor homes). Electrification shares for commercial vehicles follow similar trajectories, but with slightly lower shares.

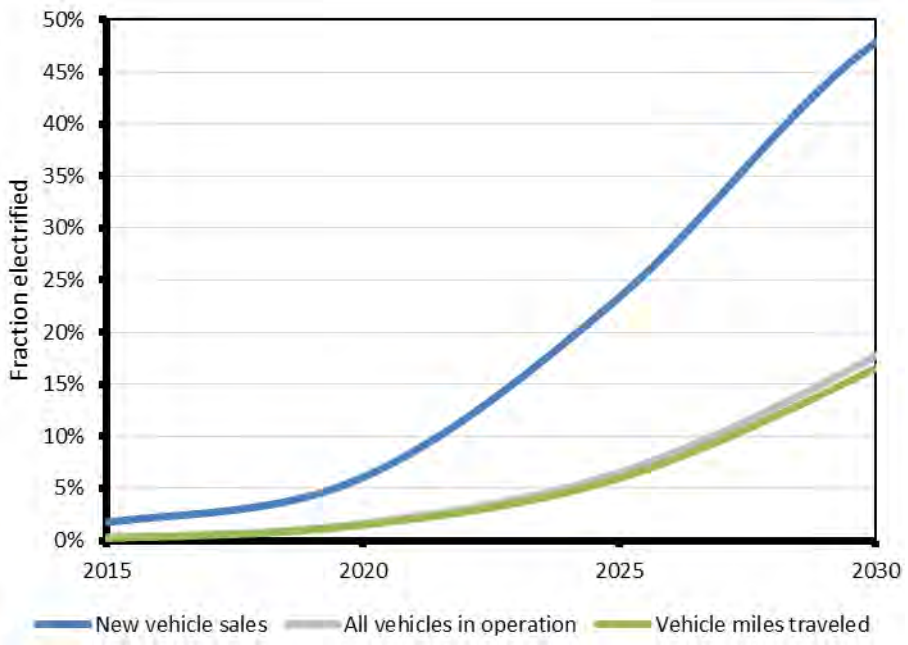

Figure 2-9
Electrification share for new-vehicle sales, total vehicles within the class, and vehicle miles traveled

Figure 2-10 shows four types of activity level by model year. Series A and B shows the penetration of electric VMT and series C and D show two different representations of the electric vehicle population. The four activity types were used to determine appropriate reductions in emissions by emission mode or process. Table 2-13 summarizes the emissions-reduction assumptions.

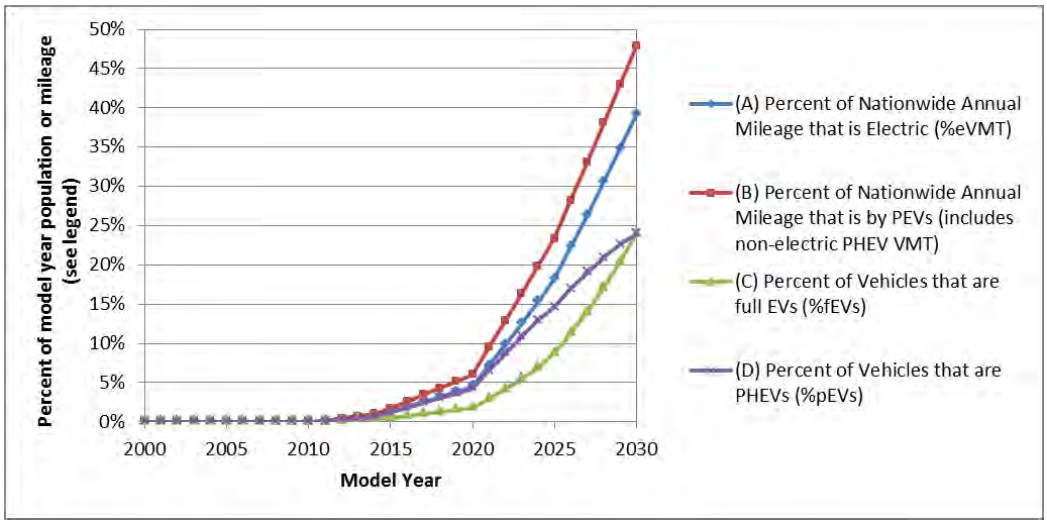

Figure 2-10
Activity levels by model year

Table 2-13
Emissions-reduction assumptions for electric vehicles

Emissions Process	Activity Source Used for Emissions Reductions	Emissions-Reduction Assumptions
Running Exhaust	(A) Percent of nationwide annual mileage that is electric (%eVMT)	Running-exhaust emission reductions equivalent to electric-vehicle mileage fraction
Start Exhaust	(C) Percent of vehicles that are BEVs (%BEVs)	No start emissions for BEVs
	(D) Percent of vehicles that are PHEVs (%PHEVs)	PHEV start emissions are reduced by 80% compared to conventional-vehicle start emissions.
Evaporative	(C) Percent of vehicles that are BEVs (%BEVs)	No evaporative emissions from BEVs. PHEV evaporative emissions are similar to conventional-vehicle evaporative emissions
Brake Wear[1]	(B) Mileage that is by plug-in electric vehicles ("Plug-in electric vehicles" includes fully electric vehicles and PHEVs.) This activity includes nonelectric PHEV VMT.	BEV and PHEV emissions are reduced by 25% because of regenerative braking.
Tire Wear	Assume no change	

[1] The magnitude of brake wear emissions reductions resulting from electrification is an area of uncertainty.

Scaling-Factor Creation

Scaling factors were developed in a detailed by-model-year analysis accounting for the following parameters:

1. Emission factors by vehicle type, pollutant, and emission process from MOVES, except in California where EMFAC2011 emission factors were used
2. Tier 3 and GHG rulemaking–associated criteria pollutant emission reductions by vehicle type and pollutant
3. Electric-activity penetration fractions and the associated emissions reductions

Two sets of emission factors by model year were developed for each vehicle class, pollutant, and emission process: a Base Case and an Electrification Case. Both the Base Case and the Electrification Case emissions factor by-model-year datasets were adjusted to account for Tier 3 and GHG rulemakings over the appropriate model year ranges.

After developing Base Case emission factors by model year, emission factors were decreased in the electrification emission-factor dataset. Running exhaust, start exhaust, evaporative emissions, and brake-wear emission factors were each reduced to account for electric vehicles according to the assumptions in Table 2-13 and the phase-in schedule illustrated in Figure 2-9.

Several examples of Base Case and Electrification Case emission factors by model year are shown in the next three figures. Figure 2-11 shows that running-exhaust NO_x emission factors by model year from gasoline light-duty vehicles (LDGV, or passenger cars) have incremental emissions benefits resulting from electrification that are not readily visible on the same plot as older model-year emission factors. LDGV emissions have historically been regulated with Tier 2 (beginning in 2004–2007) and Tier 3 (starting in 2017) emission standards. In order to show the electrification benefits, Figure 2-11 shows a zoomed-in view of the emission factors for model years 2020 to 2030. The model year 2030 Electrification Case NO_x emission factor is 39% lower than the Base Case, as is expected according to fleet penetration of electric VMT (eVMT) for 2030 (shown above in Figure 2-10).

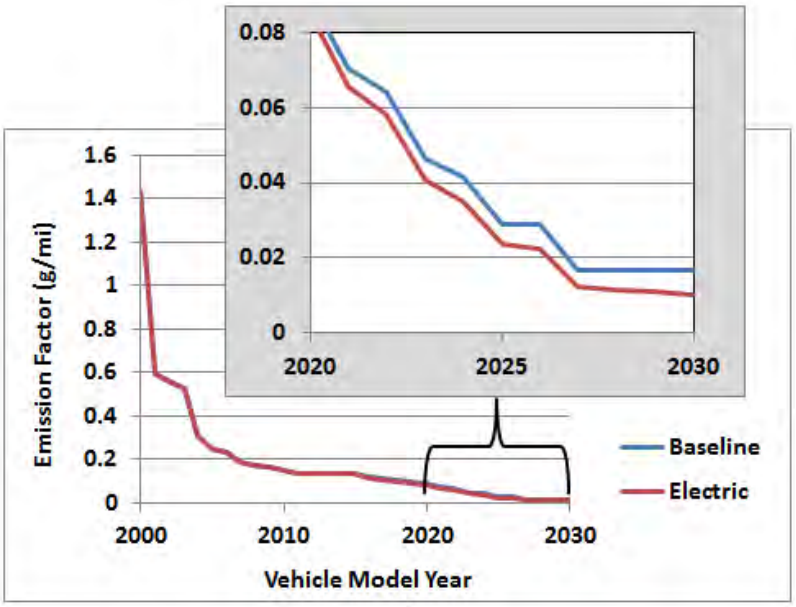

Figure 2-11
Base Case and Electrification Case LDGV NOx running- exhaust emission factors by model year, ; inset with larger view of 2020—2030 results

In contrast to passenger cars, historically the emissions from motorcycles (MC) have not been subject to increasingly stringent emission standards over time. The running-exhaust NO_x emission factors from MC shown in Figure 2-12 also achieve a 39% reduction in running-exhaust NO_x by 2030; however, the fleet-wide impact of electrification is clearly stronger for motorcycles than for passenger cars, because emissions only decreased incrementally between 2000 and 2030. (There are currently no implemented or proposed policies to decrease motorcycle emissions from current levels.)

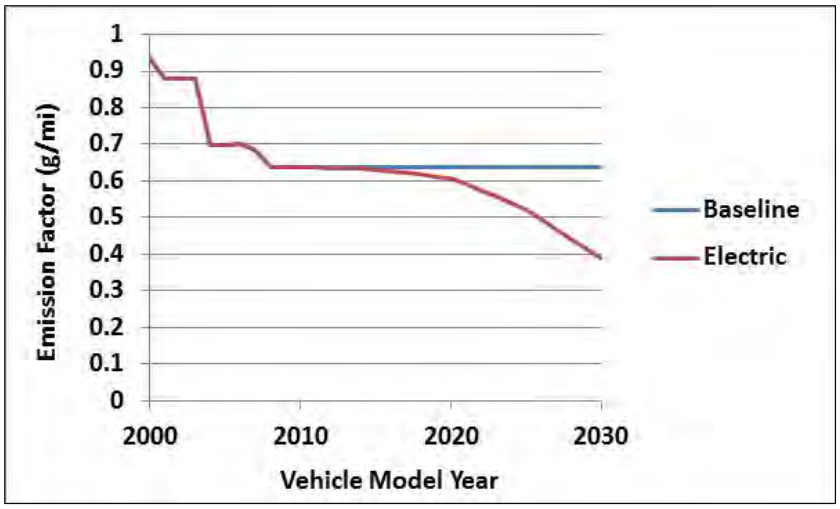

Figure 2-12
Base Case and Electrification Case motorcycle NO_x running-exhaust emission factors by model year

Similar to motorcycle NO_x emission factors, PM brake-wear emission factors change little over time. The Electrification Case results in the year 2030 presented in Figure 2-13 show a 12% reduction in the brake-wear emission factor by the 2030 model year, which is the expected reduction— given that approximately 49% of the 2030 fleet VMT is from plug-in electric vehicles (Figure 2-10), multiplied by the 25% reduction in brake-wear emissions (Table 2-13).[9]

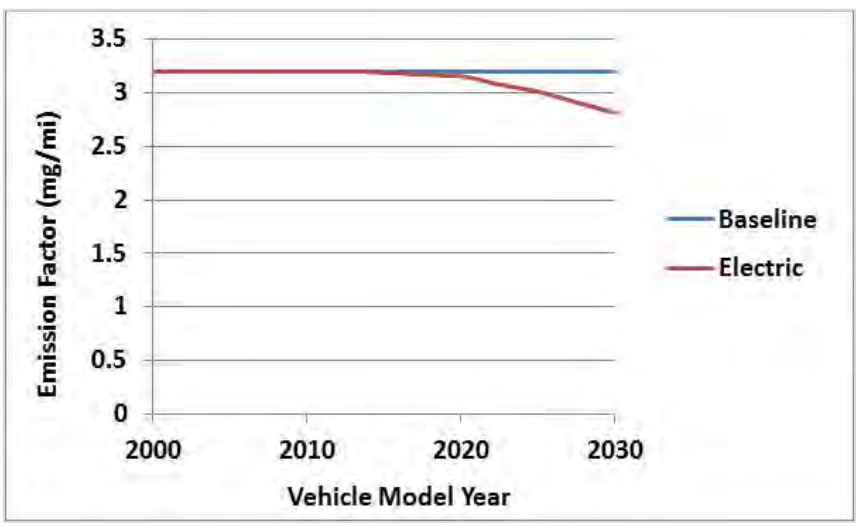

Figure 2-13
Base Case and Electrification Case passenger car $PM_{2.5}$ brake-wear emission factors by model year

[9] PEVs have regenerative braking, which reduced the use of friction brakes.

The by-model-year analysis was performed separately for the state of California and for the rest of the United States because emission factors by model year from the EMFAC model differ from MOVES model estimates.

After completing the by-model-year analysis inside and outside of California for each vehicle type, pollutant, and emission process, the Base Case and Electrification Case emission factors were aggregated over all model years to obtain average-age emission factors for each vehicle type. Similar to 2030 Base Case adjustments to account for on-road rulemakings, the aggregations were performed again using travel-fraction weighting factors. Travel fractions account for a higher population count of vehicles in the fleet from later model years and their propensity to accumulate more miles annually. Finally, the emission inventory scaling factors were calculated as the ratio of the Electrification Case aggregated emission factor to the Base Case aggregated emission factor.

These scaling factors are summarized below in Figure 2-14for the United States outside of California, and Figure 2-15 for California is presented as the scaling-factor ratio subtracted from 1. Therefore, results can be read as percent reductions to be applied to the Base Case emissions to generate the Electrification Case emissions. Evaporative emissions for diesel vehicles are assumed to be negligible.

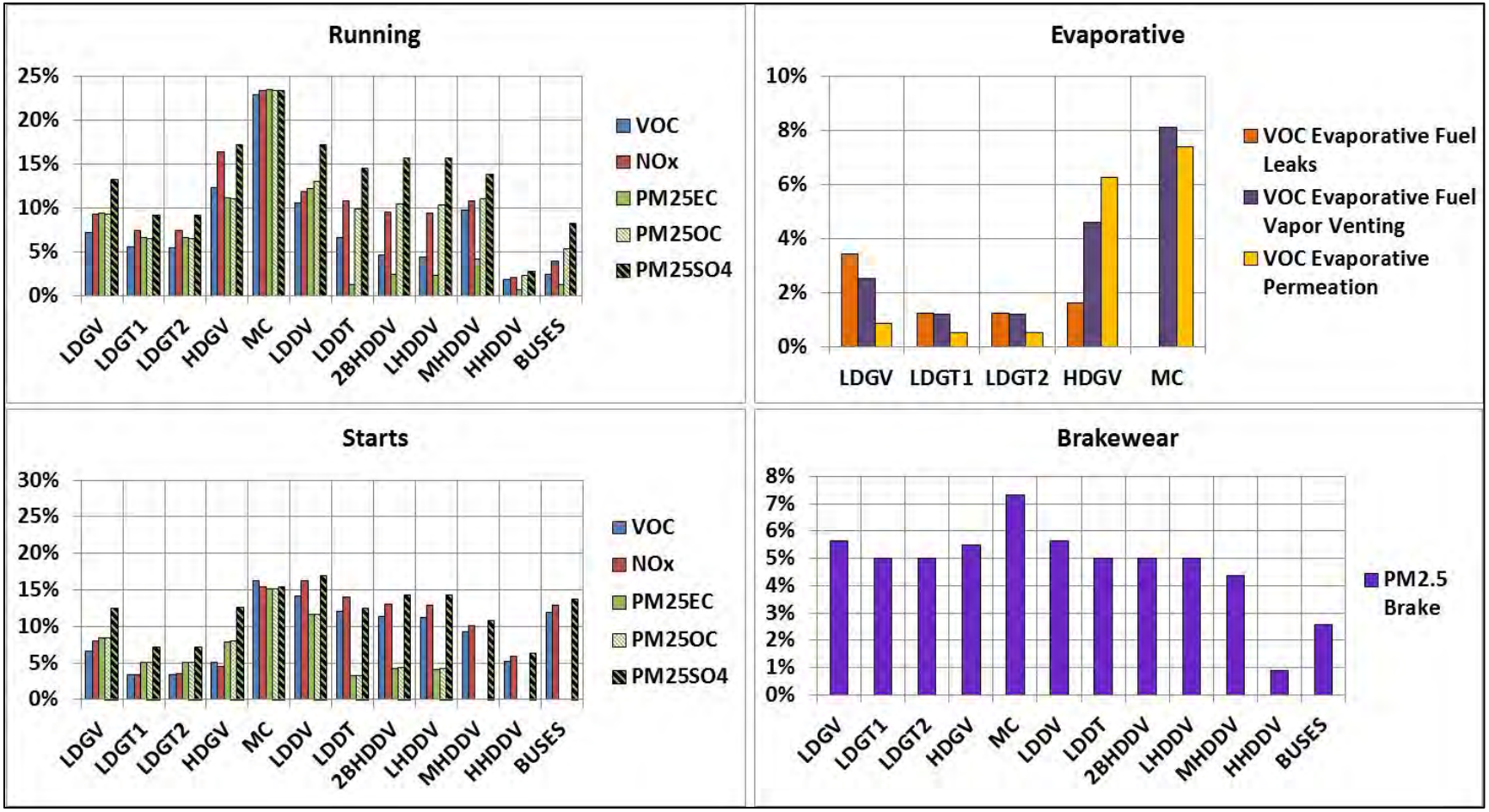

Figure 2-14
Percent reductions to running, start, evaporative, and brake-wear emissions of select pollutants resulting from electrification – United States outside of California

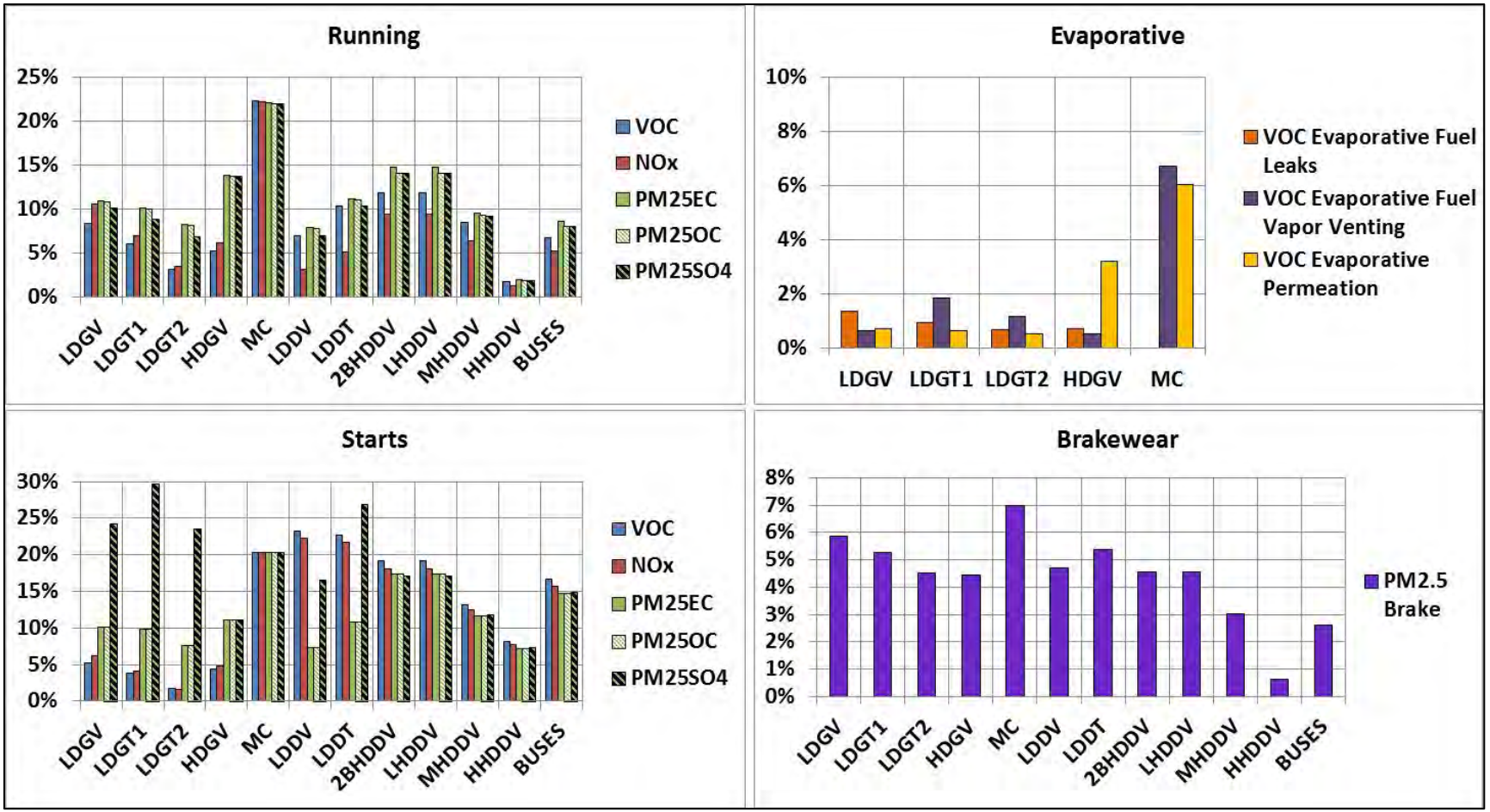

Figure 2-15
Percent reductions to running, start, evaporative, and brake-wear emissions of select pollutants resulting from electrification – Inside California

Scaling-Factor Application to Baseline

The 2030 Electrification Case was generated by multiplying the 2030 Base Case with scaling factors on the basis of SCC vehicle class, pollutant, and emission process. The resulting state-level emissions from the 2030 Electrification Case are reported in Table 2-14. Appendix C provides electrification-case emissions disaggregated into light-duty and heavy-duty vehicle types.

Table 2-14
Annual average 2030 Electrification Case on-road emissions of criteria pollutants and VMT by state, units of tons, or miles per average day

State	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3	VMT
AL	33.7	772.8	65.4	7.9	2.9	0.4	4.0	194,758,938
AR	22.6	490.4	47.6	4.3	1.6	0.2	2.2	102,342,770
AZ	40.2	649.7	76.4	9.9	3.7	0.5	4.3	203,644,015
CA	164.2	1309.7	272.7	75.3	34.1	4.3	25.4	1,200,801,308
CO	30.5	720.3	45.2	7.6	2.9	0.3	3.2	159,331,703
CT	18.2	383.0	31.4	5.4	2.1	0.2	2.1	103,542,099
DC	2.1	51.7	2.9	0.6	0.2	0.0	0.2	11,608,727
DE	5.0	124.4	9.4	1.5	0.6	0.1	0.6	28,726,781
FL	124.4	2214.2	169.9	29.4	10.3	1.4	13.2	645,921,819
GA	57.9	1359.6	112.8	14.9	5.5	0.7	6.7	318,028,423
IA	18.5	557.7	35.5	4.8	1.9	0.2	2.1	101,544,084
ID	10.6	304.2	21.3	2.4	0.9	0.1	1.0	47,196,890
IL	68.8	1769.2	135.4	19.6	7.5	0.8	7.2	334,590,513
IN	45.2	1224.7	105.7	11.6	4.5	0.5	4.9	235,450,017
KS	17.1	458.5	31.0	4.2	1.6	0.2	1.9	96,052,580
KY	28.3	627.5	63.9	6.7	2.6	0.3	3.2	154,574,737
LA	28.2	561.2	57.6	6.0	2.2	0.3	3.1	148,988,434
MA	26.5	758.8	49.1	9.2	3.5	0.4	3.7	179,746,303
MD	31.5	778.1	50.6	8.4	3.2	0.4	3.7	181,446,613
ME	9.3	279.4	16.2	2.4	1.0	0.1	0.9	45,128,647
MI	68.1	1975.0	109.8	18.6	7.2	0.7	6.7	321,177,548
MN	38.5	1264.5	63.3	11.0	4.4	0.4	3.9	185,817,963
MO	46.6	1100.4	90.8	10.7	4.1	0.5	4.7	220,166,675
MS	22.1	527.5	48.4	5.2	2.0	0.3	2.9	148,778,468
MT	6.5	190.0	15.5	1.6	0.7	0.1	0.7	35,754,966
NC	63.0	1580.3	108.7	15.2	5.7	0.7	6.9	325,590,191

Table 2-14 (continued)
Annual average 2030 Electrification Case on-road emissions of criteria pollutants and VMT by state, units of tons, or miles per average day

State	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3	VMT
ND	4.8	150.9	9.4	1.3	0.5	0.1	0.5	25,849,667
NE	11.3	342.8	22.2	3.2	1.3	0.1	1.3	62,808,726
NH	6.8	208.1	11.5	2.1	0.8	0.1	0.9	42,546,300
NJ	37.7	1003.0	53.9	11.4	4.2	0.4	4.8	238,846,469
NM	18.0	343.6	37.2	3.8	1.5	0.2	1.8	86,460,162
NV	17.4	216.1	20.3	2.8	1.0	0.1	1.4	69,995,542
NY	68.5	2079.9	111.0	20.8	7.8	0.7	8.8	430,429,180
OH	62.2	1917.2	123.6	17.3	6.6	0.7	7.4	361,612,276
OK	30.3	667.6	54.1	6.9	2.6	0.3	3.3	159,463,696
OR	20.5	573.4	40.3	5.1	2.0	0.2	2.3	108,612,332
PA	99.6	1780.3	109.3	17.1	6.6	0.7	7.5	358,636,848
RI	6.5	115.7	6.3	1.3	0.5	0.0	0.6	27,334,030
SC	31.2	704.3	57.5	6.9	2.6	0.4	3.3	156,373,234
SD	5.4	165.3	10.7	1.4	0.6	0.1	0.6	29,724,827
TN	42.9	979.5	81.8	10.3	3.9	0.5	4.6	218,137,867
TX	119.2	2531.0	301.3	36.6	13.9	1.9	17.4	851,113,808
UT	18.2	434.3	29.4	4.4	1.7	0.2	1.8	83,117,777
VA	50.9	1219.6	85.7	11.8	4.4	0.5	5.4	257,693,753
VT	4.2	132.2	5.7	1.0	0.4	0.0	0.5	25,129,191
WA	32.1	905.8	60.9	9.2	3.5	0.4	3.8	181,683,524
WI	37.5	1075.5	54.6	9.5	3.7	0.4	3.8	182,342,205
WV	13.1	385.8	23.5	2.7	1.1	0.1	1.4	66,175,767
WY	6.1	175.6	14.2	1.5	0.6	0.1	0.7	31,260,223
Total	**1,772.3**	**40140.3**	**3,160.8**	**482.7**	**188.2**	**22.6**	**202.9**	**9,786,058,616**

On-road Transportation-Sector Emissions Summary

Detailed on-road emission inventories were developed for the year 2030 representing a Base Case and an Electrification Case. The national total emissions results from each case and the on-road emissions reductions resulting from electrification are shown in Table 2-15. On-road total VOC, CO, and NO_x emissions from on-road vehicles in 2030 are expected to decrease by 6%, 9%, and 7%, respectively, because of electrification. On-road PM emissions are expected to decrease by 7%. The benefits for SO_2 and NH_3 emissions are slightly larger—at 16% and 14%, respectively.

Table 2-15
Year 2030 average-day emissions results, continental United States total

Vehicle Type	VOC	CO	NOx	SO_2	NH_3	$PM_{2.5}$
Base Case (TPD)						
Light Duty	1,632	38,436	1,397	16	204	[a]
Heavy Duty	244	5,762	2,003	11	34	[a]
Totals	**1,876**	**44,198**	**3,401**	**26**	**237**	**202**
Electrification Case (TPD)						
Light Duty	1,544	34,991	1,288	13	173	[a]
Heavy Duty	229	5,150	1,873	10	31	[a]
Totals	**1,773**	**40,140**	**3,161**	**23**	**203**	**188**
Reduction (TPD)						
Light Duty	88	3,446	109	3	31	[a]
Heavy Duty	16	612	130	1	3	[a]
Totals	**104**	**4,058**	**239**	**3**	**34**	**14**
Reduction (%)						
Light Duty	5%	9%	8%	16%	15%	[a]
Heavy Duty	6%	11%	7%	6%	9%	[a]
Totals	6%	9%	7%	12%	14%	7%

[a] Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes.

The percent reductions expected in 2030 within California are similar to those for the rest of the United States, as shown below in Figure 2-16. The largest difference, by pollutant, of the expected emissions benefit occurred for CO (9% outside of and 10.5% within California).

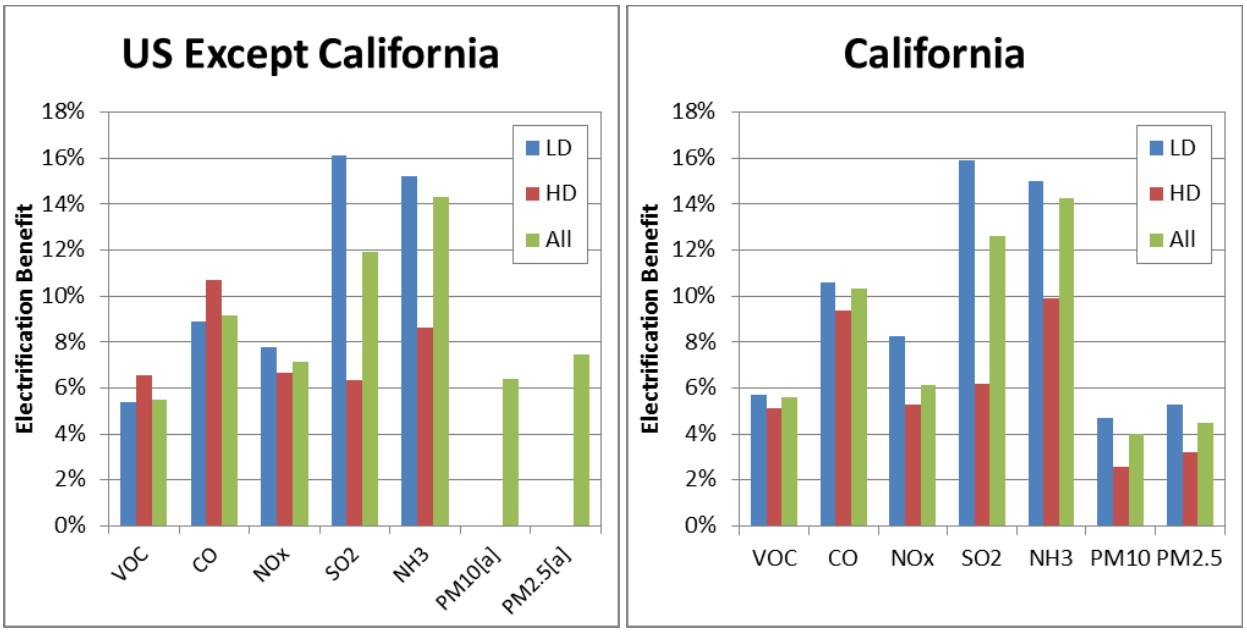

Figure 2-16
Comparison of electrification benefit on light-duty (LD), heavy-duty (HD), and all vehicle emissions (Left panel: U.S.-wide except California; right panel: California)

[a] Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes.

Electrification benefits came from a variety of vehicle classes, as shown in Table 2-16. The nationwide VOC benefit in 2030 is estimated to be 104 tons per day (TPD). Electric motorcycles are the largest source of emissions benefit, contributing over one-third of the total VOC reduction. Electric LDGVs are responsible for over 40% of the 4,058 TPD reduction in CO. Despite the assumption that only certain heavy-duty diesel vehicles are assumed to be electrified (see Table 2-10), electric heavy-duty diesel vehicles are responsible for the largest portion of the on-road NO_x reduction—responsible for removing nearly a quarter of the 239 TPD NO_x reduced nationwide. Approximately one-third of the on-road PM reduced is from gasoline-fueled vehicle exhaust during starts and running ("Adjusted PM" in Table 2-16). Vehicle-class detail is not presented for PM emissions; instead, the total is separated by whether the emissions received a cold-temperature adjustment ("Adjusted PM") or did not require temperature adjustment ("Other PM"). The adjusted PM is from starts and running exhaust from all gasoline-fueled vehicles, whereas the other PM is everything else (brake, tire, and diesel-fueled vehicle exhaust emissions).

Table 2-16
Year 2030 average-day emissions results – Continental United States totals, by vehicle class

Pollutant Vehicle Class	Base Case (TPD)	Electrification Case (TPD)	Reduction (TPD)	Reduction (%)
VOC	**1,876**	**1,773**	**104**	**-6%**
LDGV	518	491	27	-5%
LDGT1	518	503	15	-3%
LDGT2	222	216	6	-3%
HDGV	109	101	8	-7%
MC	371	332	39	-11%
LDDV	1	1	0	-14%
LDDT	2	2	0	-10%
2BHDDV	8	7	1	-9%
LHDDV	5	4	0	-9%
MHDDV	12	11	1	-10%
HHDDV	107	101	5	-5%
BUSES	4	4	0	-7%
CO	**44,198**	**40,140**	**4,058**	**-9%**
LDGV	17,274	15,544	1,730	-10%
LDGT1	14,268	13,215	1,053	-7%
LDGT2	5,636	5,234	402	-7%
HDGV	4,573	4,053	521	-11%
MC	1,183	931	252	-21%
LDDV	50	44	6	-13%
LDDT	25	23	3	-11%
2BHDDV	129	115	15	-11%
LHDDV	82	72	9	-11%
MHDDV	174	155	20	-11%
HHDDV	714	676	37	-5%
BUSES	90	79	11	-12%

Table 2-16 (continued)
Year 2030 average-day emissions results – Continental United States totals, by vehicle class

Pollutant Vehicle Class	Base Case (TPD)	Electrification Case (TPD)	Reduction (TPD)	Reduction (%)
NO_x	**3,401**	**3,161**	**239**	**-7%**
LDGV	446	406	40	-9%
LDGT1	621	582	40	-6%
LDGT2	257	241	16	-6%
HDGV	265	226	39	-15%
MC	46	35	10	-23%
LDDV	5	4	1	-14%
LDDT	22	19	3	-12%
2BHDDV	86	76	9	-11%
LHDDV	54	49	6	-11%
MHDDV	170	152	17	-10%
HHDDV	1,374	1,318	56	-4%
BUSES	55	52	3	-5%
SO_2	**26**	**23**	**3**	**-12%**
LDGV	9	7	1	-17%
LDGT1	5	4	1	-15%
LDGT2	2	2	0	-13%
HDGV	1	1	0	-15%
MC	0	0	0	-23%
LDDV	0	0	0	-17%
LDDT	0	0	0	-15%
2BHDDV	0	0	0	-16%
LHDDV	0	0	0	-16%
MHDDV	1	1	0	-13%
HHDDV	7	7	0	-3%
BUSES	0	0	0	-8%

Table 2-16 (continued)
Year 2030 average-day emissions results – Continental United States totals, by vehicle class

Pollutant Vehicle Class	Base Case (TPD)	Electrification Case (TPD)	Reduction (TPD)	Reduction (%)
NH_3	**237**	**203**	**34**	**-14%**
LDGV	119	100	19	-16%
LDGT1	57	49	8	-14%
LDGT2	24	20	3	-14%
HDGV	8	7	1	-16%
MC	3	3	1	-24%
LDDV	0	0	0	-18%
LDDT	0	0	0	-16%
2BHDDV	2	2	0	-16%
LHDDV	1	1	0	-16%
MHDDV	4	4	1	-14%
HHDDV	17	16	0	-2%
BUSES	1	1	0	-8%
PM_{10}[a]	**514**	**483**	**31**	**-6%**
Adjusted PM[b]	149	130	19	-15%
Other PM[c]	365	352	13	-4%
$PM_{2.5}$[a]	**203**	**188**	**14**	**-7%**
Adjusted PM[b]	71	62	9	-15%
Other PM[c]	131	126	5	-4%

[a] Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes.

[b] Adjusted PM emissions include starts and running-exhaust PM from gasoline-fueled vehicles from MOVES run at a flat temperature of 72°F and subsequently adjusted for cold temperatures, as described above.

[c] Other PM emissions are the rest of the PM emissions that do not require temperature adjustment; these include brake and tire wear, as well as PM exhaust from diesel-fueled vehicles.

The related emissions reductions in point-source and area-source upstream emissions because of reduced motor-fuel consumption as a result of electric vehicle penetration are discussed later, in Section 5.

Section 3: Non-Road Electric Technology Penetration, Emissions Displacement and Electric Load

This section describes the development of emissions for the non-road sector to be used as an input to the air quality model. The non-road sector consists of mobile and portable internal combustion–powered equipment not generally licensed or certified for highway use. Non-road emissions were estimated for the following categories of equipment:

- NONROAD Equipment: Emissions from many types of non-road equipment included in EPA's NONROAD model. All applicable federal non-road equipment standards are incorporated into emission estimates. Not included in emission estimates are the effects of ARB clean diesel programs such as the 1) In-Use Off-Road Diesel Vehicle Regulation (California Code of Regulations, Section 2449, Title 13), 2) Transport Refrigeration Unit Air Toxics Control Measure (California Code of Regulations, Section 2477, Title 13), and 3) In-Use Off-Road Mobile Agricultural Equipment Regulation (California Code of Regulations, Section 2428, Title 13).
- Cargo-Handling Equipment: Loosely defined as any equipment used to move freight to and from ships arriving at ports, and more specifically defined by a list of equipment types by ARB (California Code of Regulations, Section 2479, Title 13). Cargo-handling equipment emissions were estimated outside of EPA's NONROAD model for key types of equipment associated with containerized cargo: yard trucks, side picks, top picks, and rubber-tired gantry cranes (RTGs).
- Aircraft: Aircraft landing and takeoff. All applicable aviation emission standards are incorporated into emission estimates.
- Locomotive: Line-haul freight, passenger, and switching locomotives. All applicable federal locomotive engine emission standards are incorporated into emission estimates.
- Commercial Marine Vessels: Harbor craft and ocean-going vessels (OGV). All applicable federal and international OGV engine emission standards are incorporated into emission estimates.

Non-road emissions were modeled for calendar year 2030 for two scenarios:

1. Base Case: Does not account for increases in non-road electrification.
2. Electrification Case: Assumes moderate penetration of electric technology for non-road equipment types most amenable to electrification.

Reductions in point-source and area-source upstream emissions resulting from reduced non-road sector fuel consumption as a result of electric equipment use were also included in the analysis; these upstream emission reductions are discussed in Section 5.

2030 Base Case Non-road Emissions

NONROAD equipment

NONROAD equipment emissions were estimated using EPA's NONROAD 2008 model (EPA, 2009b), except in California, where emissions were estimated based on the WRAP PRP18b emission inventory (ENVIRON, 2009), which was forecasted to 2030 using the California Air Resources Board (ARB) OFFROAD model.

The EPA NONROAD2008a model estimates emissions from the following types of non-road equipment:

- Agricultural equipment (such as tractors, combines, and balers)
- Airport ground support (such as terminal tractors)
- Construction equipment (such as graders and backhoes)
- Industrial and commercial equipment (such as forklifts and sweepers)
- Residential and commercial lawn and garden equipment (such as lawnmowers, leaf blowers, and snow blowers
- Logging equipment (such as shredders and large chain saws)
- Recreational equipment (such as off-road motorbikes and snowmobiles)
- Recreational marine vessels (such as power boats)

In this study, emissions from cargo-handling equipment associated with the handling of containerized cargo at ports and rail yards were estimated outside of EPA's NONROAD model, based on existing port and rail yard emission inventories.

EPA's National Mobile Inventory 2008 Model (NMIM) (EPA, 2009d) runs the EPA NONROAD2008a model, using area-specific inputs for all U.S. counties. The NMIM-NONROAD platform was used to generate the 2030 national non-road equipment inventory. NMIM was run for each county in the United States for 2030 for both a winter (January) and a summer (July) month. NMIM outputs the pollutant results by year, month, county, SCC, and horsepower range. NMIM contains many county-specific data files supplied to EPA as part of its

national emission inventory (NEI) efforts in place of the NONROAD model default data. The version of the NONROAD county database used in this study is NCD20090531. A table within this database containing fuel formulation for gasoline fuels was updated with a more recent table procured from EPA (2010f). The updated fuels table reflects 10% ethanol in gasoline.

In California, Ramboll Environ utilized the Western Regional Air Partnership (WRAP) 2018 PRP18b emission inventory as the basis for the California criteria air-pollutant emissions and forecasted these emissions to 2030, based on ARB OFFROAD2007 model runs for 2018 and 2030. The ARB2007 model is no longer the most recent source of emissions for non-road equipment emissions in California, but it was used in this study because it was the most recent set of emissions data available at the time that emissions were developed. As of April 2014, non-road diesel equipment, cargo-handling equipment, transportation refrigeration units, and recreational vehicles are all estimated outside of the OFFROAD2007 model, according to ARB's website (ARB, 2014).

Cargo-Handling Equipment

Emissions from cargo-handling equipment are not defined separately from other industrial equipment types in EPA's NONROAD model. These emissions are included together with similar types of equipment used in different applications for forklifts, off-highway trucks, and material-handling equipment. In this study, cargo-handling equipment emissions were estimated outside of the NONROAD model 1) to understand the effects of electrification on cargo-handling equipment separately from other industrial equipment types and 2) to spatially allocate cargo-handling equipment emissions more accurately to ports and rail yards where they operate. Cargo-handling equipment emissions were estimated for the following types of equipment: yard trucks, side picks, top picks, and rubber-tired gantry cranes.

The approach taken to estimate cargo-handling equipment emissions was to develop average emission estimates on a unit-of-activity basis: twenty-foot equivalent unit (TEUs) in the case of ports, and lifts in the case of rail yards. The average emissions per unit of activity were extrapolated to the regional and national level based on publicly available datasets.

Ports

The activity metric associated with port cargo-handling equipment, TEU, is a measure of cargo capacity often used to describe the capacity of container ships and container terminals. It is based on the volume of a 20-ft-long (6.1-m) intermodal container, a standard-sized metal box which can be easily transferred between different modes of transportation—such as ships, trains, and trucks. The North American container traffic in TEUs by county were obtained from the American Association of Port Authorities website (AAPA, 2010).

Calendar year 2005 cargo-handling equipment emission inventories by equipment type available for the Port of Los Angeles (POLA, 2007) and the

Port of Long Beach (POLB, 2007) were used to estimate per-TEU emissions by equipment type for all ports. Average per-TEU emissions are shown in Table 3-1.

For each port, emissions and population by equipment type were divided by the respective port's TEUs and the average per-TEU emissions were developed. The annual 2005 NO_x, VOC, CO, SO_2 and PM_{10} emissions were estimated by multiplying average per-TEU estimates and total 2005 TEU traffic estimates obtained from AAPA (2010).

Port cargo-handling equipment emissions by equipment type were allocated to the county level in the United States based on the fraction of container traffic TEUs by port as obtained from the AAPA (2010).

Table 3-1
Year 2005 port cargo-handling equipment emissions per TEU (grams per TEU)

Type	VOC	CO	NO_x	PM_{10}	SO_x
Forklift	2.73	21.68	11.74	0.32	0.04
Rubber-Tired Gantry Crane	2.11	8.36	32.69	1.01	0.25
Side Pick	0.31	1.41	8.96	0.23	0.08
Top Pick	0.92	4.11	25.55	0.66	0.22
Yard Hostler	5.94	49.50	144.82	4.62	1.37

Rail

The activity metric associated with rail-yard cargo-handling equipment, "lift", is the movement of a container onto or off of a rail car. Total lift counts were obtained from the Association of American Railroads' U.S. rail intermodal traffic statistics (AAR, 2010). Rail intermodal is the long-haul movement of shipping containers or truck trailers by rail, combined with a (usually much shorter) truck movement at the trip origin and/or destination. The total lift counts were based on the assumption that two lift counts were required for each rail intermodal movement.

Cargo-handling equipment emissions per lift by equipment type for all U.S. rail yards were estimated using data from the Oakland (UP, 2008a), City of Industry (UP, 2008b), Los Angeles Transportation Center (UP, 2009), and Commerce (UP, 2008c) rail yards, as well as the Dolores and Intermodal Container Transfer Facility rail yards in Long Beach operated by Union Pacific (UP, 2007). Average per-lift emissions are shown in Table 3-2.

The approach to estimate 2005 base year emissions of criteria pollutants for all rail yards is the same as described above for ports, except per-lift emissions and populations were multiplied by lift counts instead of TEUs.

Rail-yard cargo-handling equipment emissions by equipment type were allocated to the county level in the United States based on GIS data obtained from the National Transportation Atlas Database (BTS, 2009). The county boundaries polygon and the intermodal facility point files (only where the "Type" field was equal to "Rail") were spatially joined to achieve a file containing attributes from both, as well as a count of facilities within each county; facility count was used to allocate emissions.

Table 3-2
Year 2005 rail-yard cargo-handling equipment emissions per lift (grams per lift)

Type	VOC	CO	NO_x	PM_{10}	SO_x
Forklift	0.15	0.62	1.36	0.09	0.01
Rubber-Tired Gantry Crane	2.42	15.03	48.36	1.96	0.37
Side Pick	0.29	2.31	5.11	0.23	0.05
Top Pick	0.69	3.84	9.98	0.52	0.06
Yard Hostler	2.62	42.70	72.67	2.74	0.92

Growth and Control

Based on EPA (2009a), it was assumed that container traffic would grow at a long-term average rate of 4.9% per year; hence the TEUs for ports and lifts for rail yards were grown at this rate.

EPA (2009c) suggested that nationwide average fuel properties were used to conduct EPA NONROAD model runs for the calendar years 2005 and 2030. The percentage changes in emissions from calendar years 2005 to 2030 were estimated by equipment type and pollutant. The results are shown in Table 3-3.

Table 3-3
Percent change in emissions by equipment type and pollutant from 2005 to 2030

Equipment Type	VOC	CO	NO_x	SO_2	PM
Cranes	-68%	-93%	-94%	-99.7%	-96%
Forklifts	-69%	-90%	-80%	-99.7%	-97%
Material Handling (Side Picks, Top Picks)	-85%	-85%	-83%	-99.6%	-90%
Terminal Tractors (Yard Trucks)	-64%	-91%	-92%	-99.7%	-97%

Reconciliation

The NONROAD model and WRAP PRP18b emission inventory also include emissions from cargo-handling equipment aggregated with applications other than cargo-handling equipment. For counties in which the cargo-handling equipment inventory emissions for a cargo-handling equipment type were smaller

than the associated emissions in the NONROAD model or the forecasted WRAP PRP18b, emissions were subtracted from the NONROAD model or forecasted WRAP PRP18b inventory. In cases in which the cargo-handling equipment inventory was larger than the NONROAD or forecasted WRAP PRP18b emissions for source categories that included cargo-handling equipment, the NONROAD or forecasted WRAP PRP18b emissions were set to zero.

Aircraft

Aircraft emissions were forecasted to 2030 from 2008 aircraft emissions developed by the EPA for the 2008 NEI (EPA 2010g). Activity data for aircraft emissions are landing-takeoff cycles (LTOs); emission factors are primarily from the Federal Aviation Administration (FAA) Emissions and Dispersion Modeling System (EDMS).

The FAA EDMS model combines specified aircraft and activity levels with emissions factors in order to estimate annual inventories for a specific airport. Aircraft-activity levels in EDMS are expressed in terms of LTOs. Each LTO can be divided into four aircraft operating modes: taxi and queue, take-off, climb-out, and landing. Default values for the amount of time a specific aircraft spends in each mode, or the time-in-modes (TIMs), are coded into EDMS. Year 2030 aircraft emissions were estimated for five aircraft categories:

- Air carriers (AC): Larger turbine-powered commercial aircraft with at least 60 seats or 18,000 lbs payload capacity;
- Air taxis (AT): Commercial turbine or piston-powered aircraft with less than 60 seats or 18,000 lbs payload capacity;
- General aviation aircraft (GA): Small piston-powered, non-commercial aircraft;
- Military aircraft (MIL); and
- Auxiliary power units (APUs): relatively smaller engines used primarily on air carriers, which power ventilation, cooling, and heating systems when an aircraft's engine is off and provide power to start the main aircraft engines.

Aircraft-emission forecasts were made based on by-state activity growth estimates taken from the FAA Terminal Area Forecast (TAF) database and control factors for applicable pollutants and aircraft types. Historic and projected LTO data are available online from the FAA TAF database for all aircraft categories for which emissions were estimated (FAA, 2010). Growth factors were calculated by state as the ratio of the sum of LTOs by aircraft type in 2030 to the sum of LTOs by aircraft type in 2008. APU activity growth by state was assumed to be equivalent to air carriers' activity growth estimates by state. The growth factors relative to 2008 are presented in Table 3-4.

Table 3-4
Years 2008 to 2030 aircraft activity growth factors by aircraft type and state

State	AC	AT	GA	MIL	State	AC	AT	GA	MIL
AK	1.73	1.57	1.65	1.69	MS	1.26	1.13	1.08	1.00
AL	1.71	1.52	1.51	1.29	MT	1.26	1.13	1.08	1.00
AR	1.71	1.52	1.47	1.25	NC	1.25	1.12	1.07	1.00
AS	1.65	1.39	1.33	1.19	ND	1.22	1.12	1.07	0.99
AZ	1.61	1.37	1.28	1.15	NE	1.20	1.12	1.07	0.99
CA	1.61	1.37	1.24	1.14	NH	1.20	1.11	1.07	0.99
CO	1.59	1.36	1.21	1.08	NJ	1.20	1.11	1.06	0.98
CT	1.58	1.34	1.20	1.07	NM	1.19	1.11	1.06	0.98
DC	1.57	1.30	1.19	1.07	NV	1.16	1.10	1.05	0.98
DE	1.57	1.29	1.18	1.07	NY	1.15	1.10	1.04	0.97
FL	1.56	1.28	1.18	1.06	OH	1.13	1.08	1.04	0.97
GA	1.55	1.26	1.17	1.06	OK	1.11	1.08	1.04	0.96
HI	1.48	1.25	1.14	1.05	OR	1.09	1.07	1.04	0.96
IA	1.48	1.25	1.13	1.05	PA	1.09	1.06	1.03	0.96
ID	1.47	1.24	1.13	1.04	PR	1.07	1.05	1.03	0.95
IL	1.46	1.22	1.12	1.03	RI	1.07	1.04	1.02	0.95
IN	1.44	1.22	1.12	1.02	SC	1.07	1.03	1.02	0.92
KS	1.44	1.20	1.12	1.02	SD	1.05	1.02	1.02	0.91
KY	1.43	1.20	1.12	1.02	TN	1.04	1.01	1.01	0.91
LA	1.42	1.20	1.11	1.02	TX	1.02	1.00	1.01	0.90
MA	1.40	1.19	1.11	1.02	UT	1.00	1.00	1.01	0.90
MD	1.40	1.18	1.10	1.01	VA	1.00	0.99	1.01	0.89
ME	1.37	1.18	1.10	1.01	VT	0.98	0.96	0.99	0.87
MH	1.35	1.17	1.09	1.01	WA	0.92	0.95	0.99	0.86
MI	1.35	1.17	1.08	1.01	WI	0.91	0.91	0.98	0.81
MN	1.34	1.17	1.08	1.01	WV	0.86	0.88	0.98	0.56
MO	1.31	1.15	1.08	1.00	WY	0.27	0.86	0.92	0.24

The International Civil Aviation Organization (ICAO) has promulgated NO_x and CO emission standards for commercial aircraft (exempting general aviation and military engines from the rule) (ICAO, 1998). EPA officially promulgated the ICAO standards for air carriers in a final rule in November 2005 (40 CFR Part 87). Winther and Rypdal (2009) suggest that NO_x may be reduced by introducing engines fitted with double annular combustion chambers, resulting in reduction of NO_x, HC, and CO emissions. Changes to VOC emissions are assumed to equal the changes in HC emissions on a percent reduction basis.

Mean 2030 control factors relative to the 2008 NEI were assumed to be equal to those projected by the *European Monitoring and Evaluation Programme (*EMEP) in 2020 and are presented in Table 3-5 for each pollutant.

Table 3-5
Control factors for aircraft emissions for 2030 in relation to 2008

Pollutant	2030 Control Factors (relative to 2008)
NO_X	0.8
VOC	0.76
CO	0.73
NH_3	1
PM_{10}	1
$PM_{2.5}$	1
SO_2	1

Locomotive

Locomotive emissions for 2030 were available on a nationwide basis in the EPA 2008 Regulatory Impact Analysis (RIA) (EPA, 2008a). The RIA-forecasted national emissions were allocated to counties using the 2005 NEI emissions as surrogates (EPA, 2008b).

Commercial Marine

EPA datasets were relied upon to generate 2030 harbor-craft emission estimates. The 2008 NEI provides emissions for harbor craft on a by-county basis for the United States (EPA, 2010g). The EPA also estimated nationwide future harbor-craft emissions within an RIA (EPA, 2008a) for calendar years 2006 to 2040. The RIA-forecasted national emissions for 2030 were allocated to counties using the 2008 NEI emissions as surrogates.

Ocean-going vessel (OGV) emission estimates were taken from the EPA PM NAAQS modeling platform. Modeling platform 2020 emissions were used to represent 2030 emissions.

To be consistent with the upstream emission-reduction estimation methodology described in Section 5, crude-oil transport was assumed to be reduced because of the EPA light-duty and heavy-duty GHG rulemakings and as a result of electrification. It was assumed that reductions in petroleum transport of 12.5% would result in reductions in OGV emissions of 2.5% for the Base Case relative to PM NAAQS modeling platform estimates.

2030 Base Case Emission Summary

Emissions by major source category are presented in Table 3-6. Appendix D shows non-road emission estimates by state.

Table 3-6
Year 2030 lower-48 state non-road emissions by major source category (tons per year)

Category	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2
Agricultural Equipment	20,714	187,113	113,962	5,354	5,175	274
Airport Ground-Support Equipment	746	15,649	2,620	66	59	9
Commercial Equipment	106,075	3,021,781	71,636	5,857	5,399	283
Construction and Mining Equipment	52,047	431,460	173,091	8,605	8,173	503
Industrial Equipment	14,420	373,817	104,402	3,259	3,203	469
Lawn and Garden Equipment	446,690	6,522,730	71,606	27,551	25,304	406
Logging Equipment	9,843	81,916	1,627	1,215	1,113	11
Pleasure Craft	245,528	2,020,082	159,889	13,807	10,924	466
Railroad Equipment	247	3,838	955	90	88	2
Recreational Equipment	544,854	2,233,635	52,320	14,757	13,507	686
Underground Mining Equipment	506	2,238	3,016	257	249	3
Aircraft	65,151	705,898	117,353	15,145	11,294	14,866
Cargo-Handling Equipment	516	1,485	4,073	65	63	1
Harbor Craft	6,696	139,314	299,005	10,006	9,705	3,471
Ocean-Going Vessels[1]	44,095	116,988	923,175	18,044	16,553	59,421
Rail	17,658	195,388	436,939	8,834	8,583	463
Totals	**1,575,786**	**16,053,332**	**2,535,669**	**132,912**	**119,392**	**81,334**

[1] Modeling domain-wide totals

Electrification Case Non-road Emissions

Emission estimates for the Electrification Case were developed based on 1) a review of the literature to identify NONROAD applications that have been or could be electrified, 2) an analysis of the electrification-potential of various non-road equipment applications, and 3) application of emissions reductions to the 2030 Base Case to develop an Electrification Case inventory.

Electric Equipment Market Penetration

Electrifiable Equipment

Based on a review of the literature, emissions reductions associated with electrification were estimated for the equipment types listed in Table 3-7. For equipment types included in Table 3-7, it was assumed that technology developments will allow for lower costs, longer run times, and lower energy-storage weights, which will lead to increasing electrification of these types of applications. Not included in this list are equipment types that have been electrified, but which are relatively small components of the U.S. NONROAD emissions inventory. (For example, underground mining equipment has been electrified at a number of locations, but it only contributes a very small fraction to overall non-road sector emissions and therefore was not included.) Equipment with high torque requirements, such as loaders and backhoes, was also not included, because future electrification of this equipment is unable to be estimated at this time. Line-haul and passenger-rail electrification was also not considered in this analysis.

Table 3-7
Equipment types for which emissions reductions resulting from electrification were estimated

Industrial		Recreational and Lawn & Garden	
Agricultural Pumps	Intermodal Equipment (Port Cranes, Yard Trucks, Side/Top Picks)	ATVs	Motorcycles
Aircraft Auxiliary Power Units (APUs)	Shoreside Power for Ocean-Going Vessels	Chain Saws *(units ≤6 horsepower)*	Push Lawn Mowers
Airport Ground-Support Equipment *(units ≤175 horsepower)*	Sweepers / Scrubbers *(units ≤25 horsepower)*	Chippers/ Shredders *(units ≤6 horsepower)*	Riding Lawn Mowers *(units ≤40 horsepower)*
Dredging Craft	Switching Locomotives	Commercial Turf Equipment *(units ≤25 horsepower)*	Snow Blowers *(units ≤3 horsepower)*
Forklifts *(units ≤175 horsepower)*	Transportation Refrigeration Units	Golf Carts	Special Vehicle Carts *(units ≤25 horsepower)*
		Leaf Blowers	Trimmers/ Edgers

Electrification Potential

A key element of electrification potential for non-road applications is how electric energy is stored for usage in electrically powered equipment once it has been transferred from the electric grid. Battery storage is the most ubiquitous and tested storage option and is likely to remain in widespread usage for the foreseeable future. Although lead-acid and other lower-energy density batteries will remain in use, it is expected that in the future advanced lithium-ion batteries or other advanced batteries will become economical for use in non-road applications. High-energy batteries will allow for increasing electrification of non-road applications that are sensitive to battery weight, such as hand-held lawn and garden equipment. This increased electrification potential is reflected in the electric equipment market-penetration estimates presented below. Although hydrogen fuel cells and other types of in-development technology (such as ultra capacitors and fly wheels) may become available in the future, additional study and real-world application is needed to determine if these technologies are commercially feasible and will be able to compete for market share with battery options.

In this analysis, up to the year 2020, it was assumed that lead-acid and lower-energy lithium-ion battery technology are the primary electric-storage devices. From 2020 to 2030, it was assumed that increases in electric equipment market share would result from the introduction of progressively better batteries with more favorable energy storage per unit weight.

It was assumed that the highest electric market share for new equipment sales in 2030 would be 80%, and that this percentage would only be achieved by equipment that was already subject to widespread electrification or for which there are very few impediments to electrification. For equipment with few impediments to electrification, but with lesser current electrification, it was generally assumed that 60% of equipment sales would be electric by 2030. For equipment with significant impediments to electrification, electric sales less than 60% in 2030 were assumed. All-terrain vehicles (ATVs), off-road motorcycles, and switching locomotives were all assumed to have electrical sales fractions less than 60%. For ATVs and off-road motorcycles, it was assumed that lack of charging availability during remote use would slow adoption of electric units. For electric switching locomotives, there have been challenges—including fires in early hybrid models and impediments associated with the higher cost of electric models versus diesel-fueled models (Wong, 2009). Therefore, lower electric penetration was assumed.

Figure 3-1 shows electric sales fractions for lawn and garden (L&G) and recreational equipment, and Figure 3-2 shows electric sales fractions for industrial equipment.

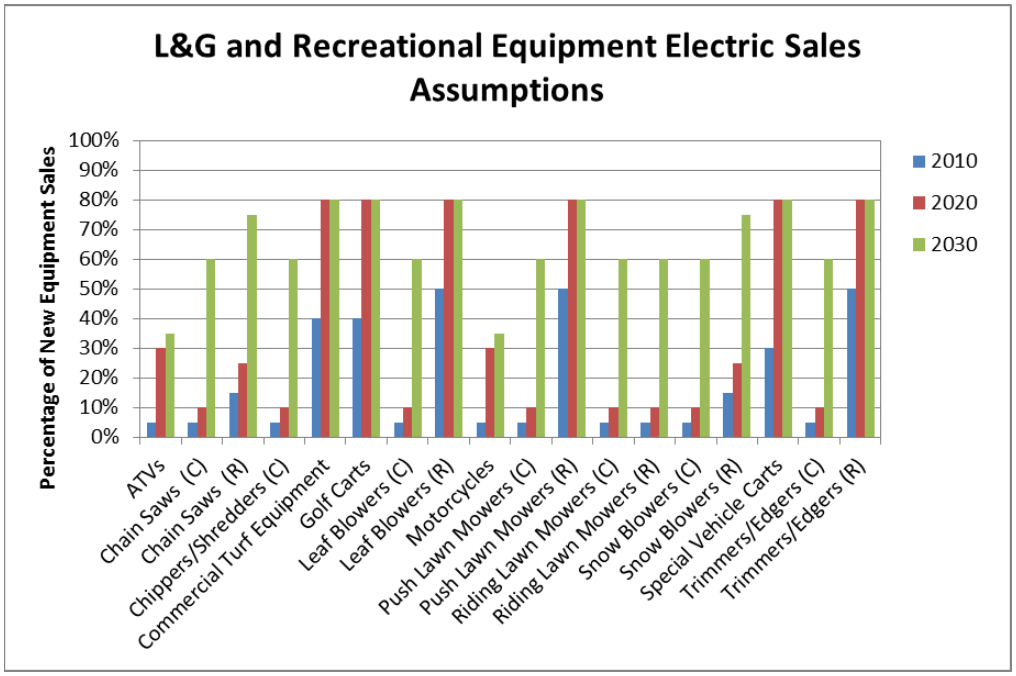

Figure 3-1
Lawn and garden (L&G) and recreational equipment new-unit electrical sales fractions for 2010, 2020, and 2030. (C) denotes commercial-use equipment and (R) denotes residential- use equipment.

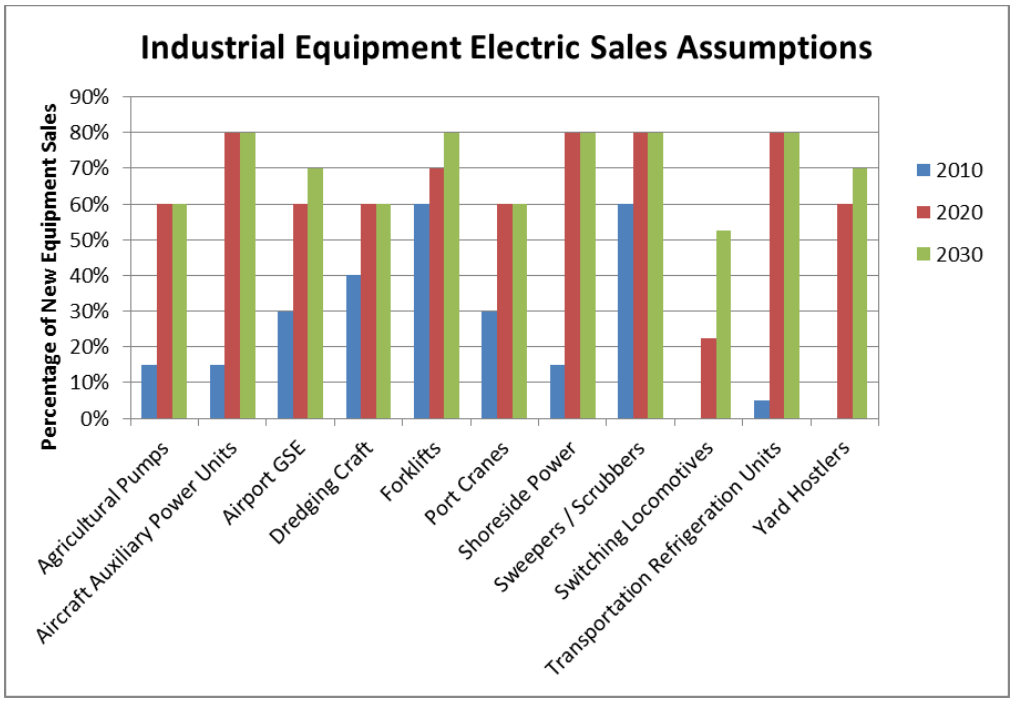

Figure 3-2
Industrial equipment new- unit electrical sales fractions for 2010, 2020, and 2030

Electrification Estimates in 2030

Estimates of fleet-wide electrification are based on retirement of older models in each year and phase-in of new equipment over time. Electric equipment sales by year were incorporated into a fleet-turnover model to estimate fleet-wide electrification estimates.

Sample results are presented below for airport ground-support equipment (Figure 3-3) and commercial-use leaf blowers (Figure 3-4). For airport ground-support equipment, it is estimated that in 2010, the fleet-wide electric population fraction is 20%, and that in 2010 30% of all airport ground-support equipment sold is electric-powered. Although the percentage of new airport ground-support equipment sold that is electric is estimated to increase to 60% in 2020 and 70% in 2030, the fleet-wide fraction of equipment that is electric is estimated to increase to 38% in 2020 and 58% in 2030. For commercial-use leaf blowers, it is estimated that in 2010, the fleet-wide electric population fraction is 3%, and that in 2010, 5% of all commercial-use leaf blowers sold are electric-powered. Although the percentage of new commercial-use leaf blowers sold that are electric is estimated to increase to 10% in 2020 and 60% in 2030, the fleet-wide fraction of equipment that is electric is estimated to increase to 8% in 2020 and 54% in 2030.

The NONROAD model does not include electric equipment; the NONROAD model only includes fossil-fueled equipment and is based on fossil-fueled, non-road equipment population estimates. The fossil-fueled, non-road equipment

population estimates in the model are based on data primarily from the 1996–2000 time period (EPA, 2010h) and growth estimates from 1989 to 1996 (EPA, 2004). It has been assumed that electric equipment added to each equipment fleet beyond pre-2010 model year electrification levels is reflective of emerging technology not accounted for in the NONROAD model. Emission reductions resulting from electrification have been estimated as:

$$EmisRed = \frac{(ElecFrac_{FW,Y} - ElecFrac_{FW,Pre2010})}{(1 - ElecFrac_{FW,Pre2010})}$$

Where:

EmisRed: Percent reduction in emissions resulting from electrification

$ElecFrac_{FW,Y}$: Percent of the total fleet population that is electric in year *Y*

$ElecFrac_{FW,Pre2010}$: Percent of the total fleet population that is electric pre-2010

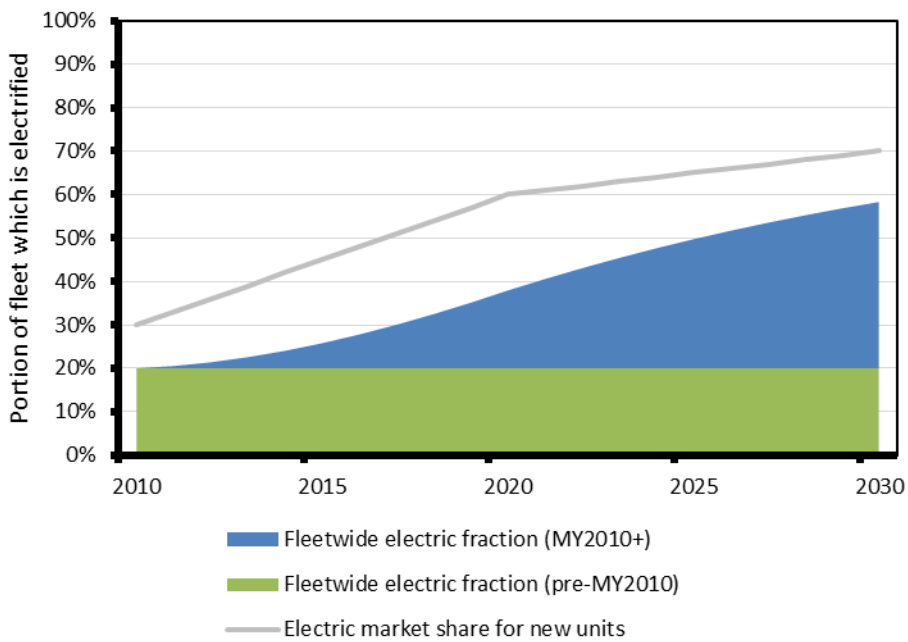

Figure 3-3
Electrification example: airport Airport ground-support equipment

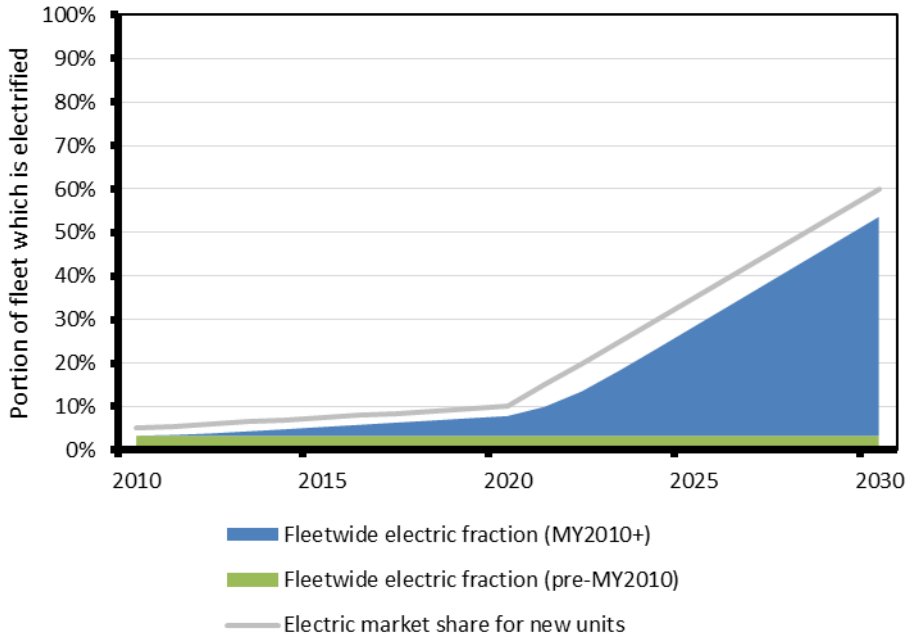

Figure 3-4
Electrification example: Commercial-use leaf blowers

Non-road Equipment Electricity Consumption

The same models and calculation methods that were used to calculate Base Case emissions were used to calculate electrified non-road equipment electricity consumption. The power usage of a piece of non-road equipment can be estimated by combining its rated horsepower, load factor, and average annual hours of use. For the electrified equipment types, the electrified population of each equipment type in 2030 was multiplied by its corresponding power usage per piece of equipment. It was assumed that electrified non-road equipment would have the same output power as the fossil-fueled equipment being replaced. Table 3-8 presents the electricity consumption for each equipment category. In 2030, the total additional non-road equipment electricity consumption is 35.2 TWh.

Table 3-8
U.S. 2030 non-road equipment electricity consumption by equipment type

Equipment Type	2030 Annual Electricity Consumption (GWh)
Commercial Lawn and Garden Equipment	
Chain Saws	333
Chippers/ Shredders	<1
Commercial Turf Equipment	2,662
Riding Mowers	954
Push Lawn mowers	488
Leaf Blowers	732
Snow Blowers	17
Trimmers/ Edgers	202
Subtotal	***5,386***
Residential Lawn and Garden Equipment	
Chain Saws	73
Riding Mowers	1,587
Push Lawn mowers	783
Leaf Blowers	68
Snow Blowers	11
Trimmers/ Edgers	114
Subtotal	***2,636***
Recreational Equipment	
All-Terrain Vehicles	732
Golf Carts	460
Motorcycles: Off-Road	337
Specialty Vehicle Carts	133
Subtotal	***1,662***

Table 3-8 (continued)
U.S. 2030 non-road equipment electricity consumption by equipment type

Equipment Type	2030 Annual Electricity Consumption (GWh)
Industrial Equipment	
Agricultural Pumps	522
Aircraft Auxiliary Power Units	104
Airport Ground-Support Equipment	547
Forklifts	11,234
Harbor Craft (Dredging)	1,350
Intermodal Cranes and Side/ Top Picks	282
Intermodal Yard Trucks	1,198
Ocean-Going Vessel s (Shoreside Power)	5,719
Sweepers / Scrubbers	15
Switching Locomotives	612
Transportation Refrigeration Units	3,977
Subtotal	***25,559***
Grand Total	**35,243**

2030 Electrification Case Emissions

Figure 3-5 shows 2010 fleet-wide electric population fractions for lawn & garden and recreational equipment, and Figure 3-6 shows the same information for industrial equipment. The fleet-wide electric population fractions are the basis of the emission-reduction estimates by equipment type shown in Table 3-9. For industrial equipment, there is a range of emission-reduction estimates from 17% to 67%, with aircraft auxiliary power units, shoreside power, and yard hostlers all estimated to have emission reductions of 60% or more. For recreational and lawn & garden equipment, there is a range of emission-reduction estimates from 26% to 67% for commercial turf equipment, golf carts, and special vehicle carts, and of 60% or more for residential-use leaf blowers, push lawn mowers, and trimmer/ edgers.

Year 2030 emission reductions by major source category are presented in Table 3-10. Total non-road sector emission reductions vary by pollutant, with the greatest reductions to VOC (17%), CO (22%), PM_{10} (14%), and $PM_{2.5}$ (14%), and lesser reductions to NO_x (5%) and SO_2 (3%) emissions. Lawn & garden emission reductions account for 70% of VOC emission reductions, and recreational equipment emission reductions account for 27% of VOC emission reductions. Lawn & garden emission reductions account for 81% of CO emission reductions, and recreational equipment emission reductions account for 15% of CO emission reductions. The largest sources of NO_x emission reductions are industrial equipment, ocean-going vessels, and lawn & garden equipment, which

account for 29%, 28%, and 21% of NO_x emission reductions, respectively. Lawn & garden equipment is the greatest source of PM_{10} (76%) and $PM_{2.5}$ (75%) emission reductions. Ocean-going vessels account for 58% of SO_2 emission reductions, and aircraft APUs account for 18% of SO_2 emission reductions.

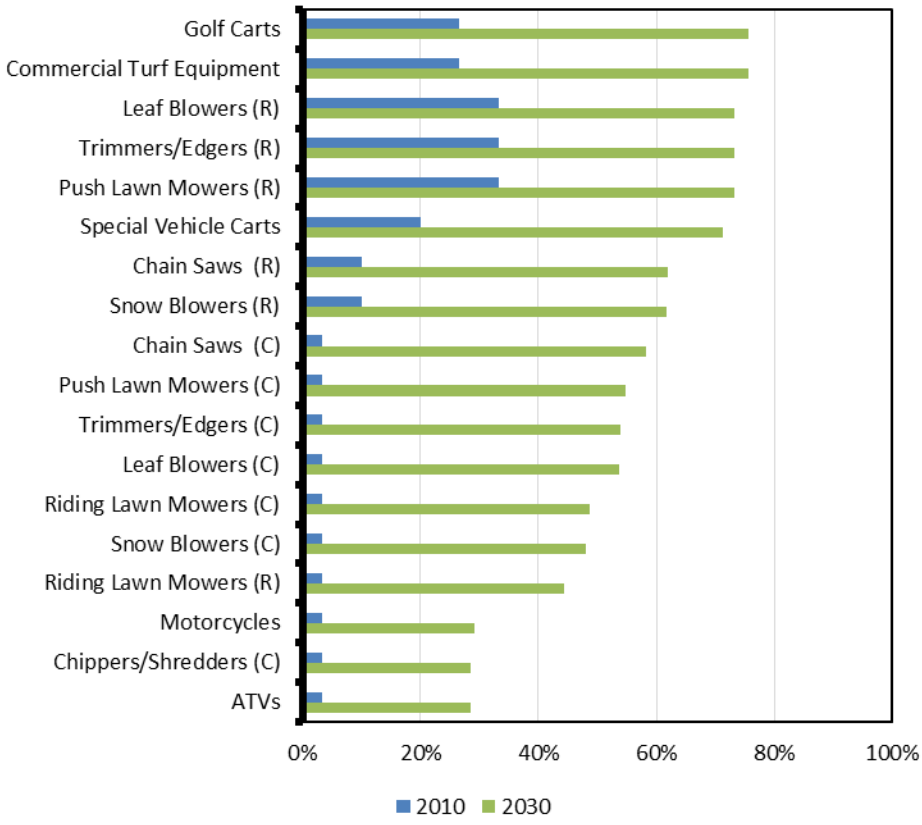

Figure 3-5
Lawn & garden and recreational equipment electric population fractions. (C) denotes commercial-use equipment and (R) denotes residential-use equipment.

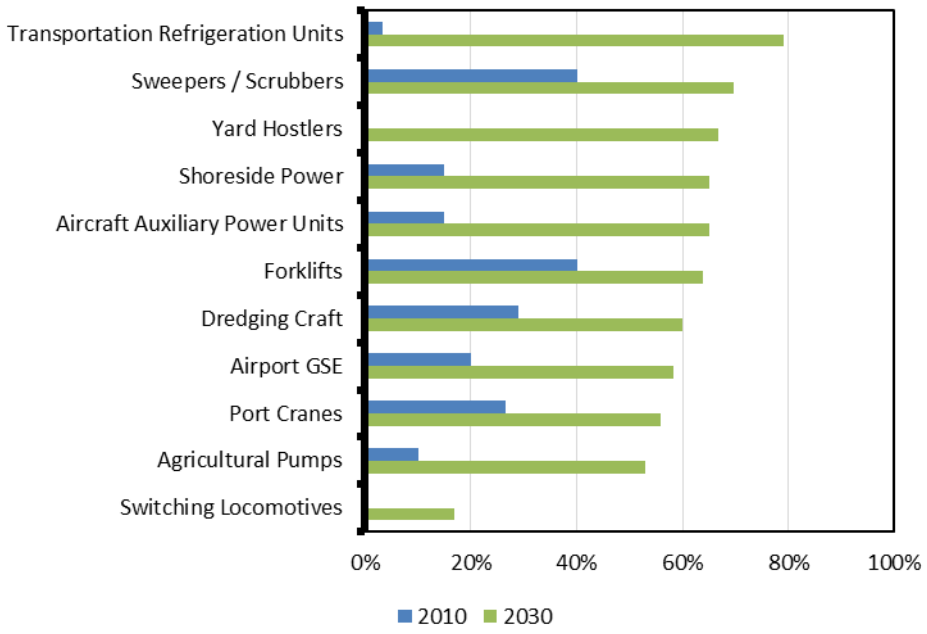

Figure 3-6
Industrial equipment electric population fractions

Table 3-9
Percent reduction in 2030 emissions resulting from electrification

Industrial		**Recreational and Lawn & Garden (continued)**	
Agricultural Pumps	48%	Chippers/ Shredders (C)	26%
Aircraft Auxiliary Power Units	65%	Commercial Turf Equipment	67%
Airport GSE	48%	Golf Carts	67%
Dredging Craft	33%	Leaf Blowers (C)	52%
Forklifts	40%	Leaf Blowers (R)	60%
Port Cranes	40%	Motorcycles	27%
Shoreside Power	65%	Push Lawn Mowers (C)	53%
Sweepers / Scrubbers	49%	Push Lawn Mowers (R)	60%
Switching Locomotives	17%	Riding Lawn Mowers (C)	47%
Transportation Refrigeration Units	39%	Riding Lawn Mowers (R)	42%
Yard Hostlers	67%	Snow Blowers (C)	46%
Recreational and Lawn & Garden		Snow Blowers (R)	58%
ATVs	26%	Special Vehicle Carts	64%
Chain Saws (C)	57%	Trimmers/ Edgers (C)	52%
Chain Saws (R)	58%	Trimmers/ Edgers (R)	60%

Table 3-10
Year 2030 U.S. lower-48 state Electrification Case emissions by source category

Major Subcategory	VOC		CO		NO_x		PM_{10}		$PM_{2.5}$		SO_2	
	tpy	(%)	tpy	(%)	tpy	(%)	tpy	(%)	tpy	(%)	tpy	(%)
Agricultural Equipment	-136	(-1%)	-1,195	(-1%)	-466	(0%)	-19	(0%)	-18	(0%)	-2	(-1%)
Airport Ground-Support Equipment	-210	(-28%)	-6,664	(-43%)	-757	(-29%)	-14	(-22%)	-12	(-20%)	-2	(-21%)
Commercial Equipment	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Construction and Mining Equipment	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Industrial Equipment	-3,749	(-26%)	-109,779	(-29%)	-34,861	(-33%)	-1,094	(-34%)	-1,079	(-34%)	-161	(-34%)
Lawn & Garden Equipment	-190,011	(-43%)	-2,926,110	(-45%)	-24,591	(-34%)	-13,588	(-49%)	-12,466	(-49%)	-174	(-43%)
Logging Equipment	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Pleasure Craft	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Railroad Equipment	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Recreational Equipment	-74,577	(-14%)	-547,155	(-24%)	-5,307	(-10%)	-1,774	(-12%)	-1,618	(-12%)	-141	(-21%)
Underground Mining Equipment	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)	0	(0%)
Aircraft Auxiliary Power Units	-283	(0%)	-3,664	(-1%)	-2,587	(-2%)	-412	(-3%)	-412	(-4%)	-401	(-3%)
Cargo-Handling Equipment	-283	(-55%)	-807	(-54%)	-1,919	(-47%)	-29	(-44%)	-28	(-44%)	-1	(-53%)
Harbor Craft	-112	(-2%)	-2,322	(-2%)	-4,983	(-2%)	-167	(-2%)	-162	(-2%)	-58	(-2%)
Ocean-Going Vessels[1,2]	-1,497	-3%	-4,652	-4%	-32,760	-4%	-655	-4%	-609	-4%	-1,310	-2%
Rail	-571	(-3%)	-2,429	(-1%)	-10,412	(-2%)	-221	(-3%)	-215	(-3%)	-6	(-1%)
Grand Total	-271,429	(-17%)	-3,604,776	(-22%)	-118,645	(-5%)	-17,974	(-14%)	-16,619	(-14%)	-2,255	(-3%)

[1] Modeling domain-wide totals

[2] Electrification Case OGV emissions incorporate reductions resulting from shoreside power and emission reductions based on reduced crude-oil shipments, as described in Section 5.

Section 4: Electricity Generation Scenarios and Emissions

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) was used to model the electricity grid for the analysis presented in this report. US-REGEN uses state-of-the-art grid-modeling techniques and EPRI's detailed estimates of the performance and cost of generation technologies to create long-term forecasts of changes in the electricity sector. Using this model enables the results to capture the marginal effects of electric transportation on both dispatch and capacity expansion and retirement, while ensuring that a comprehensive suite of environmental policies are met.

This section describes the model and assumptions used to project electricity-sector emissions of criteria pollutants and the resulting trajectories for generation and emissions.

U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) Model

The U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) is a new model developed by the Electric Power Research Institute (EPRI). It combines a detailed dispatch and capacity expansion model of the U. S. electric sector with a high-level dynamic computable general equilibrium (CGE) model of the U. S. economy. The two models are solved iteratively to convergence, allowing analysis of policy impacts on the electric sector and taking economy-level responses into account. This makes US-REGEN capable of modeling a wide range of environmental and energy policies in both the electric and non-electric sectors.

US-REGEN is a regional model of the United States. It considers 15 sub-regions of the continental United States to account for differences in resource endowments, energy demand, costs, policies, and policy impacts. Figure 4-1 shows a map of the regions in the model.[10] US-REGEN is an intertemporal optimization model, which solves in five-year time steps through 2050.

[10] In defining the regions of the integrated model, there is necessarily a tradeoff between optimally representing the economy, in which data is typically available along state lines, and optimally representing the U.S. electricity sector, the internal boundaries of which frequently cross state lines.

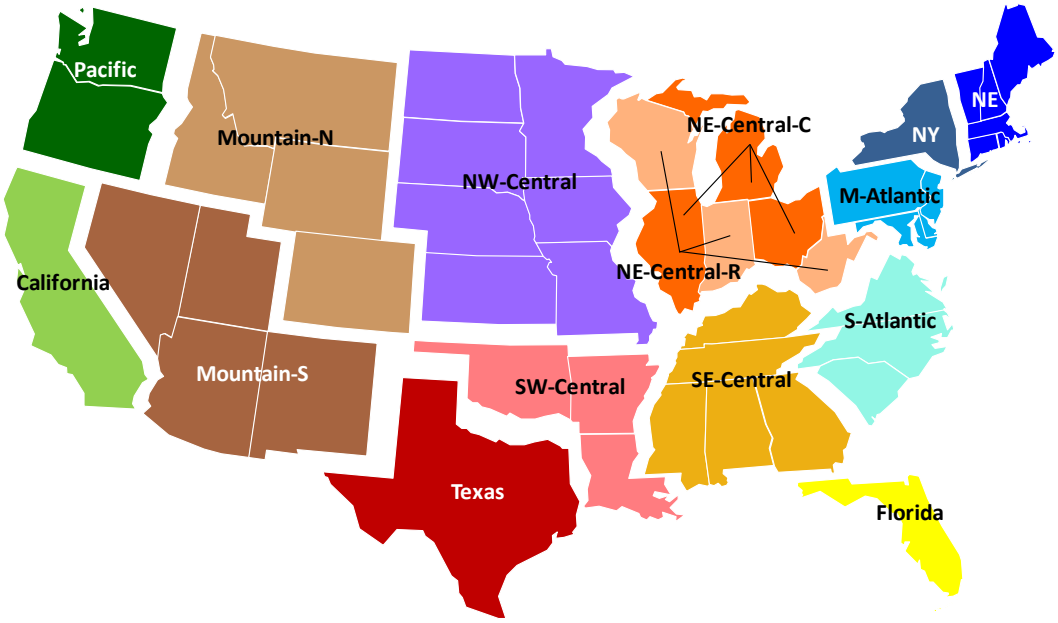

Figure 4-1
Regional structure of the US-REGEN model

The electric-sector component of US-REGEN is a detailed generation-planning model. In each time step, the model makes decisions about capacity (for example, new investment, retrofit, or retire) and dispatch to meet energy demand for both generation and inter-region transmission. It uses a bottom-up representation of power-generation capacity and dispatch across a range of intra-annual load segments. It models transmission capacity between regions, and it requires that generation and load plus net exports and line losses balance in each load segment and for each region.

The macroeconomic component of US-REGEN is a CGE model applied to the United States. This model uses a classical Arrow-Debreu general- equilibrium framework to describe the entire economy over time, calibrated to observed U.S. economic data covering all transactions amongst firms and households and to forecasted economic growth into the future. Production in each sector is described by a constant-elasticity-of-substitution (CES) production function. Firms are assumed to maximize profits, and households to maximize utility—the latter assumed to be a function of consumption across the time span of the model. The model is designed to show how changes in policy impact economic activities relative to a baseline case. For this analysis, two scenarios were defined: 1) a Base Case was constructed using the US-REGEN baseline electricity assumptions and exogenously supplied transportation assumptions and 2) an Electrification Case was constructed with increased on-road and non-road transportation electrification, which modified the transportation assumptions and added electrical load.[11]

[11] The generation-availability assumptions in the air quality modeling differed slightly from those used in the greenhouse gas modeling. See Appendix A: for more information on the difference

The two models comprising US-REGEN are built on economic data sourced from the Impact Analysis for Planning (IMPLAN) database, energy data from the Energy Information Administration (EIA) of the U.S. Department of Energy, U.S. generation fleet data from Ventyx (Ventyx Velocity Suite), and a variety of other sources providing economic growth, wind, solar, and biomass data.

Further details on the US-REGEN model can be found in the US-REGEN Documentation (US-REGEN).

Overview of Assumptions

For this analysis, the model was calibrated to the AEO2011 for key variables—including Gross Domestic Product (GDP), electricity demand, industrial growth, and most fuel prices. Gas-price trends were taken from the AEO2013. However, US-REGEN maintains an independent set of assumptions on electric-sector technologies, which may differ significantly from the AEO.

In designing the scenarios for this analysis, assumptions on the technology options in the future were set as follows:

- All existing nuclear units received a license extension to 60 years, and 80% of those received a further license extension to 80 years.
- New nuclear units are restricted to the limits shown in Figure 4-2.
- Carbon capture and storage (CCS) technology is available after 2020.
- There are declining cost pathways for renewable capital costs, per the EPRI Generation Options Report and the judgment of EPRI's renewables staff.
- Biomass supply curves were generated from the Forest and Agricultural Sector Optimization Model (FASOM) by US-REGEN region, as described in Appendix D of the US-REGEN documentation.
- New biofueled units are possible, and existing coal units have the option of converting to biomass or of co-firing up to 10% biomass.
- Existing coal units can also convert to gas, retrofit with CCS technology, and retrofit with non-CO_2 pollutant controls as described below.
- New inter-regional transmission is permitted at a cost of $3.84 million per mile, constructed for a high-voltage line capable of carrying 7.2GW.
- Existing coal units retire at 70 years of age.

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between these modeling runs. The criteria pollutant emissions in the 2030 timeframe were consistent between the two sets of assumptions.

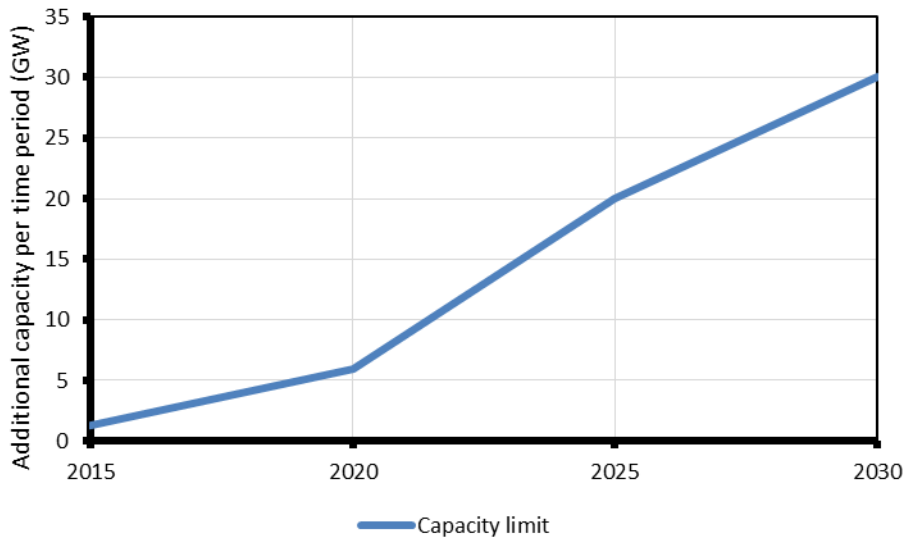


Figure 4-2
Additional nuclear capacity per 5-year timestep

Capital and operating costs for new generation are detailed in the next section. Note that the US-REGEN model incorporates data on the complete generating fleet in the lower 48 states as of 2010, as supplied by Ventyx. For the purposes of running the model, these units are aggregated into buckets by region and by operating characteristics.

US-REGEN explicitly models three types of passenger-transport vehicles: internal combustion, plug-in hybrid, and all-electric vehicles. The current formulation is a process model embedded within the CGE model. This requires an exogenously supplied trajectory for the evolution of the vehicle fleet, which for this analysis was supplied to the US-REGEN model for both the Base Case and the Electrification Case by the analysis presented in Section 2.

New Generation Cost and Characteristics

US-REGEN considers all major generating technologies in its assessment of potential electric-sector capacity expansion. The costs for these technologies are sourced largely from the EPRI Generation Options Report (2012), and are supplemented by the expert opinions of EPRI's generation and nuclear staff. Table 4-1 presents capital costs and heat rates for new generation by installation year and type.

Table 4-1
Time-varying new technology parameters

Technology	Installation Year	Capital Cost ($/kW)*	Heat Rate (mmBTU / MWh)
Supercritical Pulverized Coal (with full environmental controls and without CCS)	2015 2030	2590 2590	8.749 7.935
Integrated Gasification Combined Cycle Coal (with full environmental controls and without CCS)	2015 2030	3490 3050	8.932 7.582
IGCC Coal (with CCS) *(Not available until 2020)*	2020 2030	4380 4040	10.006 8.726
IGCC Coal (with partial CCS) *(Not available until 2020)*	2020 2030	4100 3780	9.749 8.492
Natural Gas Combined Cycle (without CCS)	2015 2030	1160 1160	6.893 6.319
Natural Gas Combined Cycle (with CCS) *(Not available until 2020)*	2020 2030	2280 2180	7.403 7.01
Natural Gas Turbine (without CCS)	2015 2030	820 820	11.01 10.19
Dedicated Biomass (based on a 50-MW direct fire plant)	2015 2030	4610 4410	12.875 11.371
Nuclear	2015 2030	5620 5360	10 10
Hydroelectric	2015 2030	2000 2000	N/A
Geothermal	2015 2030	5560 5310	N/A
Wind Power Onshore	2015 2030	2270 1770	N/A
Wind Power Offshore	2015 2030	3140 2460	N/A
Solar Photovoltaic (Rooftop)	2015 2030	3350 2290	N/A
Concentrating Solar Power	2015 2030	6480 5440	N/A

* All costs are in constant 2009 dollars.

Table 4-2 lists fixed and variable (non-fuel) operating and maintenance costs and plant lifetimes of new generation. Operating costs are held constant over time and are assumed not to increase as a plant ages.

Table 4-2
Non-time-varying new technology parameters

Technology	Fixed O&M Costs ($/kW-year)*	Variable O&M Costs ($/MWh)*	Plant Lifetime
Supercritical Pulverized Coal (with full environmental controls and without CCS)	58	2.5	70
Integrated Gasification Combined Cycle Coal (with full environmental controls and without CCS)	105	2	60
IGCC Coal (with CCS)	134	3.4	60
IGCC Coal (with partial CCS)	119	3.1	60
Natural Gas Combined Cycle (without CCS)	14	2.4	60
Natural Gas Combined Cycle (with CCS)	26	5	60
Natural Gas Turbine (without CCS)	14	4.5	60
Dedicated Biomass (based on a 50-MW direct fire plant)	62	5	60
Nuclear	105	1.7	80
Hydroelectric	67	0	100
Geothermal	67	9.6	30
Wind Power Onshore	37	0	25
Wind Power Offshore	98	0	25
Solar Photovoltaic (Central Station)	21	0	30
Solar Photovoltaic (Rooftop)	21	0	30
CSP (Solar Thermal)	72	0	60

*All costs are in constant 2009 dollars.

Fuel Prices

US-REGEN calibrates wholesale fuel prices in the US-REGEN baseline to match the AEO2013 lower-48 Wellhead Price. A retail margin, also obtained from the AEO, is added by sector to obtain retail prices. Note that the US-REGEN model incorporates price response to changes in demand for fuels through the CGE component of the model; thus fuel prices in the policy scenarios will deviate from the AEO. The policy scenarios considered in this analysis did not result in any significant change to fuel prices from the baseline. The national average delivered fuel prices to the electric sector for coal, gas, and refined petroleum are depicted in Figure 4-3.

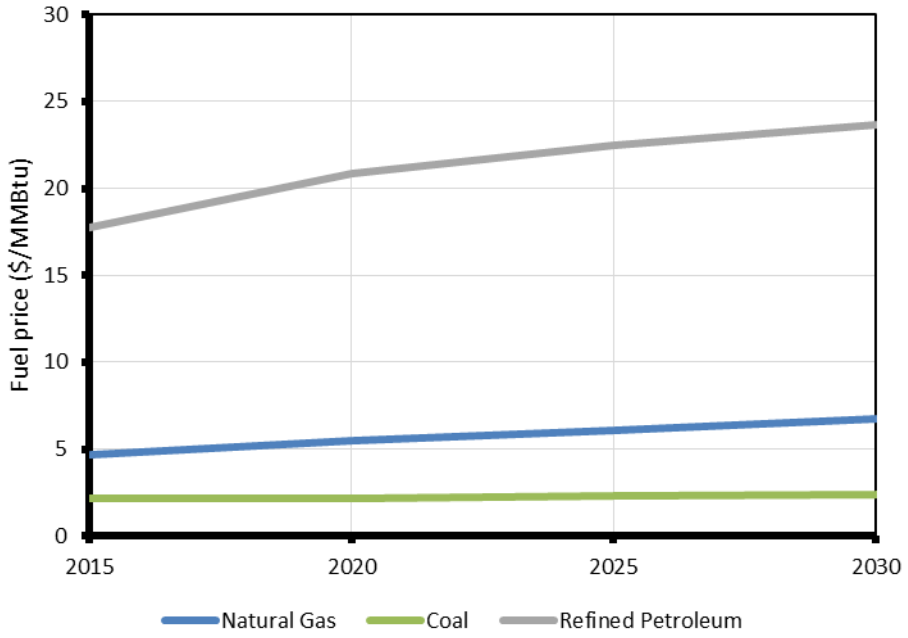


Figure 4-3
National average delivered fuel prices to the electric sector

Electricity-Demand Growth

Demand growth in the Base Case is calibrated to the AEO2011 reference case, starting at 4200 TWh per year in 2010 and rising to 4850 TWh per year by 2030.

Pollution-Control Equipment Costs and Characteristics

US-REGEN includes several retrofit options for existing coal capacity in response to environmental policy. The retrofits enable reductions in emissions of SO_2 or NOx, which may be motivated by market-based caps or technology-forcing policies that require environmental retrofits as a condition of continued operation. The model can also convert existing coal units to biofuel or to natural gas, and it may add the capability to co-fire biomass at 10%. These transformations incur a one-time capital cost, and they can result in capacity degradation and changes in operating parameters—including variable costs, heat rates, and emission rates (described below).

Table 4-3 outlines the assumed costs of retrofitting an existing coal plant and the assumptions on the resulting changes in the plant's performance.

Table 4-3
Cost and performance assumptions for coal retrofits

	Capital Cost ($/kW)	Change Relative to Base Coal Plant			
		Capacity Penalty	Heat Rate	Non-CO_2 Emissions Rates (Sox/Nox)	Variable O&M
Enable 10% Biomass Co-Fire	$20 (i.e., $200/kW of biomass capacity)	1.2	1.2	0.0/0.8	1.0
Convert to Gas	$150	1.0	0.96	0.0/0.05	0.5
Convert to 100% Biomass	$1,000	1.44	1.2	0.0/0.05	0.9
Convert to CCS (90% capture)	$1,500 for Non-Compliant classes; $750 or more for Compliant classes / Environmental Retrofit*	1.5	1.5	0.15/0.05	2.0
Environmental Retrofit	Varies by class up to $6,000 (see Table 5-4 below)	1.05	1.05	0.15/0.05	$4/MWh

* "Second-stage" CCS retrofit of capacity that has already undertaken an environmental retrofit is adjusted in some cases to ensure that the total cost of both retrofits is greater than $1,500, the cost of a "single-stage" CCS retrofit. Additionally, the cost of the single-stage retrofit declines slightly over time.

The capital cost of an environmental retrofit was estimated separately, as described in Appendix B of the US-REGEN documentation. The methodology employed was to estimate the total cost required for each unit individually to comply with all pending and proposed environmental regulations by 2015. A range of retrofit cost estimates were calculated for every unit in the database through the use of the EPRI analysis system known as the Integrated Emissions Control Cost Estimating Workbook (IECCost). This model generated unit-specific estimates of capital costs, operating costs, maintenance costs, and consumable quantities for NO_X, SO_2, and mercury emissions-control systems. The distribution of these costs in depicted in Figure 4-4.

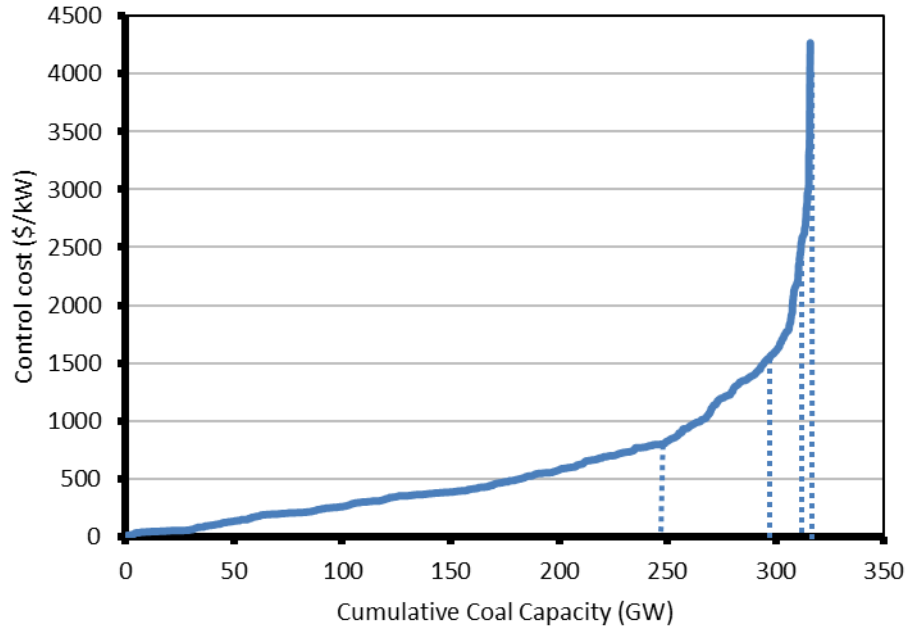


Figure 4-4
Distribution of environmental control costs by bins defined by breakpoints at $800, $1,600, $2,400, and $4,000 per kW of control cost

The distribution was broken into five intervals by selecting breakpoints at $800/kW, $1,600/kW, $2,400/kW, and $4,000/kW. The average retrofit cost for each bin is listed in Table 4-4.

Table 4-4
Average retrofit costs and existing capacity for the five retrofit cost bins

Retrofit Cost Bin ($/kW)	GW	Avg. Retrofit Cost ($/kW)
<$800	222	367
$800-$1,600	66	1,104
$1,600-$2,400	20	1,850
$2,400-$4,000	7	3,158
>$4,000	1	4,373

Environmental Regulations

The scenarios were constructed to incorporate pending EPA regulations and other restrictions on pollutants. This included:

- Existing State Renewable Portfolio Standards as of 2012, including separate requirements for solar where applicable
- A full suite of non-CO_2 environmental-control regulations, pending or expected to be implemented by model year 2015. These cover the following five environmental pathways:
    1. New requirements and emissions limits for sulfur oxide (SO_x) pollutants under the Hazardous Air Pollutants Maximum Achievable Control Technology (HAPs MACT) regulations
    2. New requirements and emissions limits for nitrogen oxide (NO_x) pollutants, again under HAPs MACT
    3. New requirements for the control of mercury and related heavy-metal pollutants in stack emissions, also under HAPs MACT
    4. New protections for aquatic species impacted by cooling-water intake structures, leading potentially to far more closed-loop cooling systems, as a part of Section 316 (b) of the Clean Water Act
    5. New, more restrictive, classifications of coal ash solid waste (coal combustion residuals, or CCRs) under relatively more elaborate and expensive disposal requirements across the fleet, through Subtitle D of the Resource Conservation and Recovery Act.
- An implementation of the Cross-State Air Pollution Rule (CSAPR[12]).
- The EPA-proposed New Source Performance Standards for new Fossil Fueled Generation. Specifically, this ruling is assumed to prohibit the construction of new coal units without CCS technology.

Note that the version of the model used in this analysis did not have an implementation of the California Cap-and-Trade scheme authorized under AB32, nor did it include the New England Regional Greenhouse Gas Initiative (RGGI) cap-and-trade market.

Calculation of Electric Generating Unit Emissions

Emissions of CO_2, SO_2, and NO_X are explicitly calculated in US-REGEN. For existing units, the model uses fully loaded emissions rates sourced from the Ventyx dataset. Emissions are then calculated annually by multiplying the rates by the unit's annual generation. Variations resulting from ramping or partial loading are not captured. For units retrofitted with environmental controls, emissions are assumed to be cut to at or under 0.15 lb/MMBtu for SO_2, and 0.10 lb/MMBtu for NO_X. New coal units (limited by the EPA New Source

[12] For more information on CSAPR, see: http://www.epa.gov/airtransport/CSAPR/

Performance Standards to only those currently in the construction process) take on the same values.

VOC, CO, PM_{10}, $PM_{2.5}$, and NH_3 Emissions

VOC, CO, PM_{10}, $PM_{2.5}$ and NH_3 emissions were estimated by scaling US-REGEN model NO_x-emission estimates by fuel type. Scalars were calculated for each US-REGEN model fuel type from the EPA PM NAAQS modeling platform, 2020 electricity-generating unit emission inventory as the ratio of total emissions for each pollutant to total NO_x emissions across all the power plants in the United States. Table 4-5 provides the scalars developed to calculate emissions of VOC, CO, PM_{10}, $PM_{2.5}$ and NH_3.

Table 4-5
VOC, CO, PM_{10}, $PM_{2.5}$, and NH_3 scalars by US-REGEN model fuel type

Fuel Type	VOC/NO_x	CO/NO_x	PM_{10}/NO_x	$PM_{2.5}$/NO_x	NH_3/NO_x
Biomass	0.0890	3.1851	0.1063	0.1050	0.0422
Coal	0.0186	0.1784	0.1715	0.1341	0.0089
Natural Gas	0.0583	2.0588	0.0083	0.0053	0.1577
Other	0.0306	3.3709	0.1760	0.1601	0.1439
Refined Petroleum	0.0004	0.0034	0.0117	0.0117	0.0486
Coal Co-fired with Biomass	0.0186	0.1784	0.1715	0.1341	0.0089
Industrial Wood	0.0890	3.1851	0.1063	0.1050	0.0422
Landfill Gas	0.0306	3.3709	0.1760	0.1601	0.1439

Electrification Case Generation Scenario

Electricity Demand

Electricity-demand forecasts in the Base Case were taken from the AEO2011. These forecasts include a modest penetration of electric vehicles in the AEO; however, for this analysis, fuel use by vehicles in the Base Case and the Electrification Case were supplied by the results of the modeling described in Section 2 and Section 3. The Electrification Case resulted in higher demand than the Base Case: around 1.2% higher in 2020 and 5.0% higher in 2030, as a result of the increased use of PHEVs, BEVs, and electric non-road vehicles and devices.

Electrification Load Shape

There is a significant amount of uncertainty about when load from electrified vehicles will occur. Although there are grid-connected non-road vehicles in the total electrification demand, most of the load comes from battery charging. Battery charging has a high degree of time-flexibility relative to most loads

because of the low average daily utilization of batteries and the extended charging periods available. Section 9 in Volume 2 reviews a variety of potential load shapes, but it finds that the variation in the generation mix between different load-shape scenarios is low. However, the timing of emissions can have an effect on air quality, even if the magnitude of emissions remains the same. For example, similar modeling in Thompson et al. (2011) indicates that shifting emissions to the night is likely to offer an ozone benefit (although the benefit is limited). Optimizing the load shape to minimize air quality impacts was outside of the scope of this analysis. For this analysis, the "Scaled" load shape was selected, which scales the default US-REGEN load shape and therefore proportionally distributes electrification load onto existing load. This load varies between regions and throughout the year, but it has the average hourly load shape shown in Figure 4-5. This load shape contains a balance of on-peak and off-peak load. It is thus less likely to cause instability in the timing of emissions, which could cause the air quality results to change because of the numerical characteristics of the model rather than because of the characteristics of the changing load.

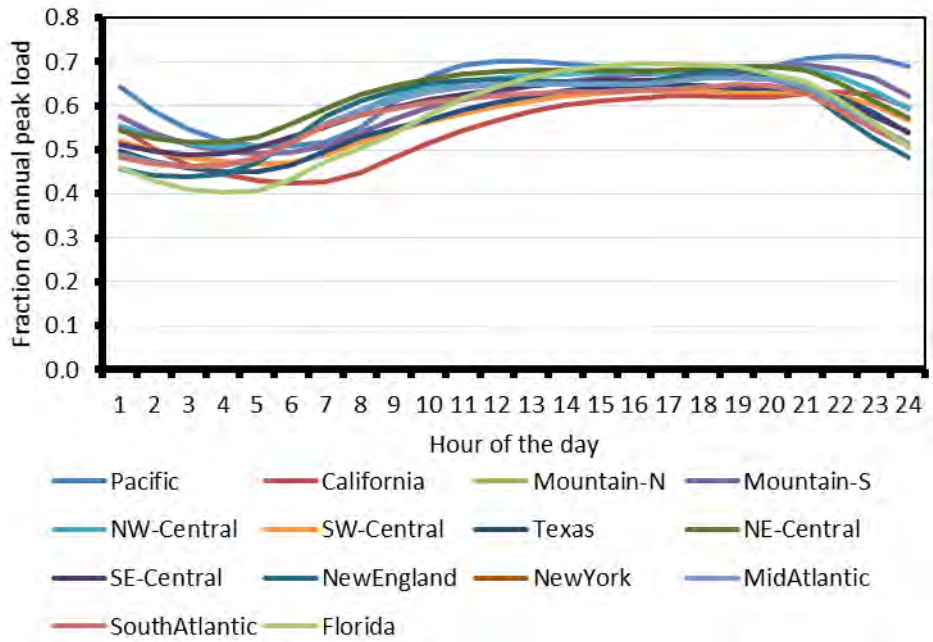


Figure 4-5
Average daily load shape by region

Electric Sector Modeling Results

Generation and Capacity Mix

The scenarios modeled had a significant impact on the generation and capacity mix of the fleet through 2030. Figure 4-6 shows the generation mix in the Base Case, and Figure 4-7 shows the generation mix for the Electrification Case.

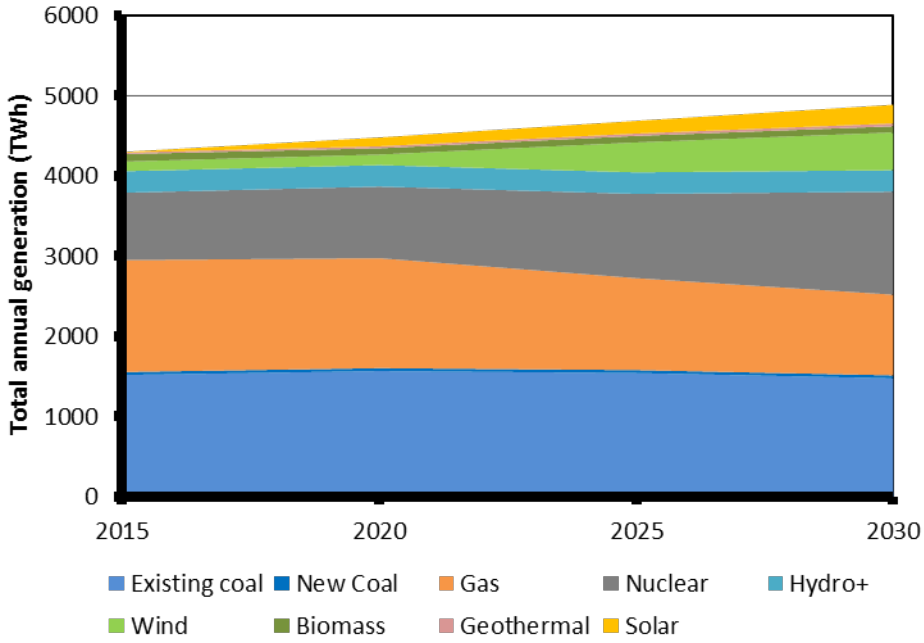


Figure 4-6
Generation mix in the Base Case

The Base Case assumes the AEO2013 gas-price path, which rises to over $6.75/mmbtu by 2030. The resulting economics favor new nuclear and renewables, to the detriment of the gas fleet. New solar is mostly rooftop photovoltaics (PV), which is assumed to take the retail price.

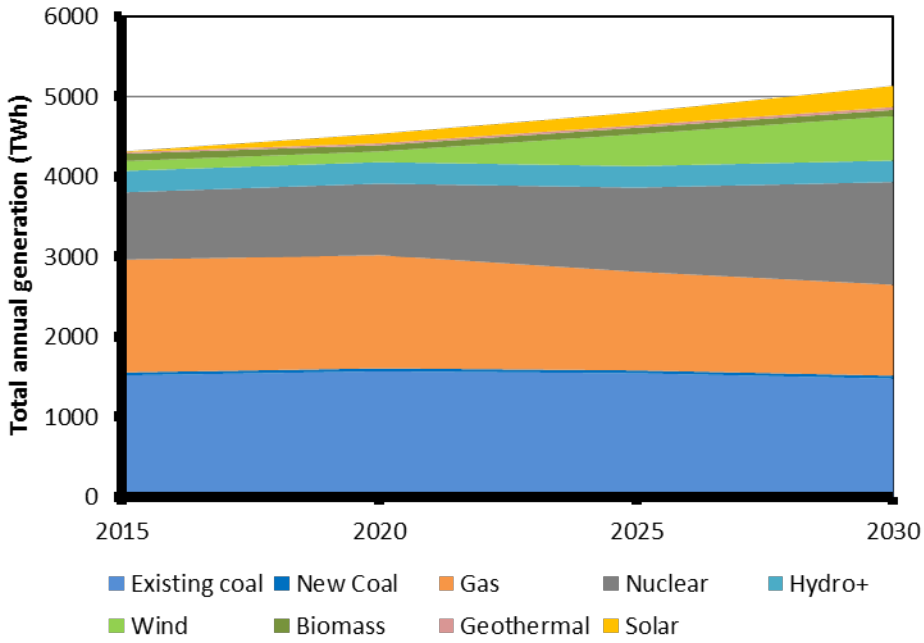


Figure 4-7
Generation mix in the Electrification Case

The additional Electrification Case envisages considerable load growth. New load is met through additional renewables and gas generation. The mix of new generation varies significantly across regions, as shown in Figure 4-9, compared to the Base Case generation, as shown in Figure 4-8. The additional load in the Electrification Case is primarily met with new gas generation, but significant amounts of wind and solar generation occur in the West and Midwest. Because nuclear is constrained nationally, additional New Nuclear in the South reduces New Nuclear in the Midwest.[13]

[13] Because of capacity-expansion limits implemented at the national level, nuclear does not enter the marginal mix at the national level. But there are differences in the marginal mixes of regions because of builds occurring in one region instead of the other.

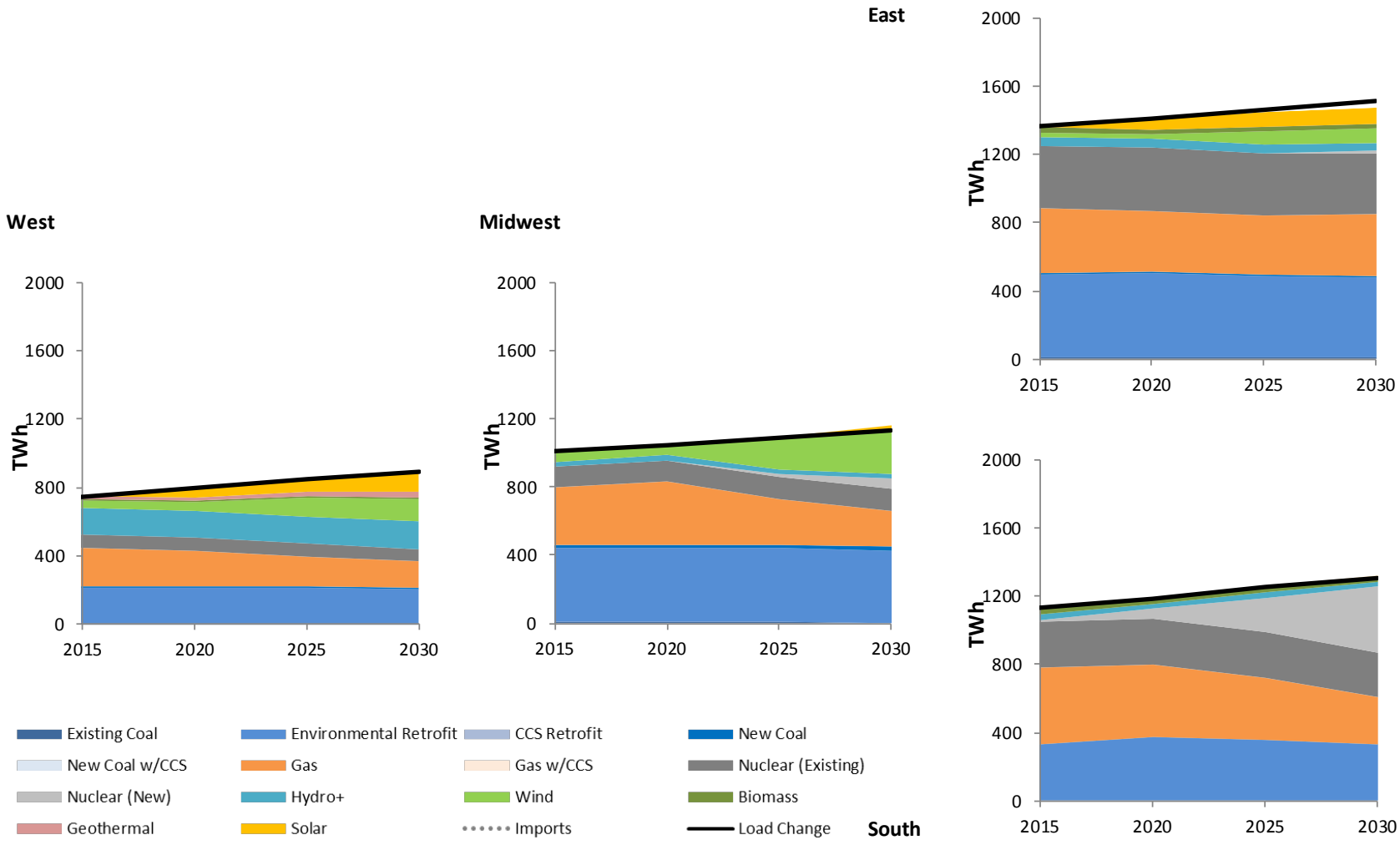


Figure 4-8
Regional generation in the Base Case

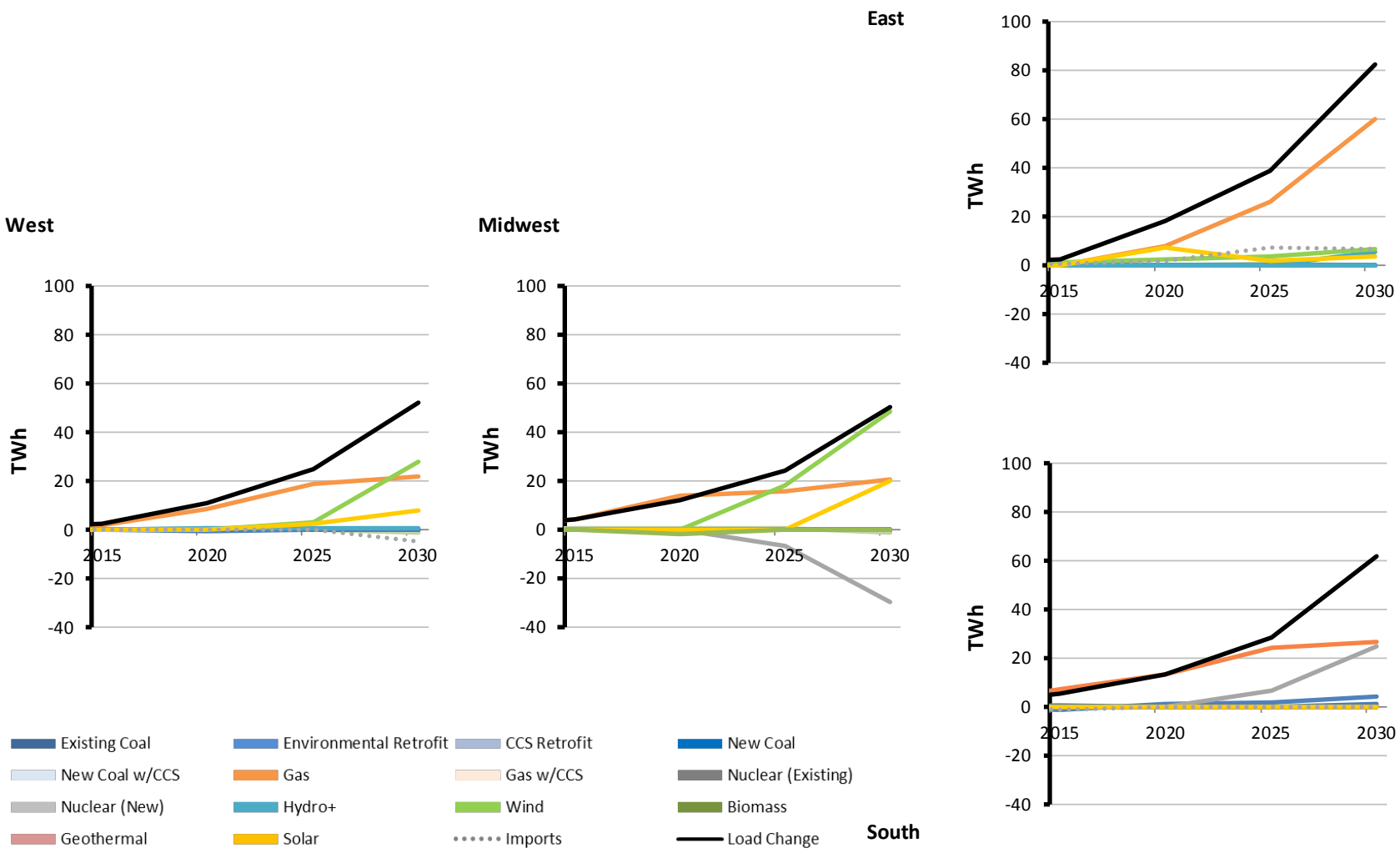


Figure 4-9
Generation change between Base Case and Electrification Case

Figure 4-10 and Figure 4-11 show the total national capacity for the Base Case and Electrification Case, respectively. Total rated capacity edges upwards in the Electrification Case. Wind and solar each gain 20GW of capacity, accompanied by 30GW of natural gas generation. Again, this mix varies by region; the Wind and Solar are concentrated in the West and Midwest, New Nuclear occurs in the South instead of the Midwest, and Combined Cycle Natural Gas increases in all regions.

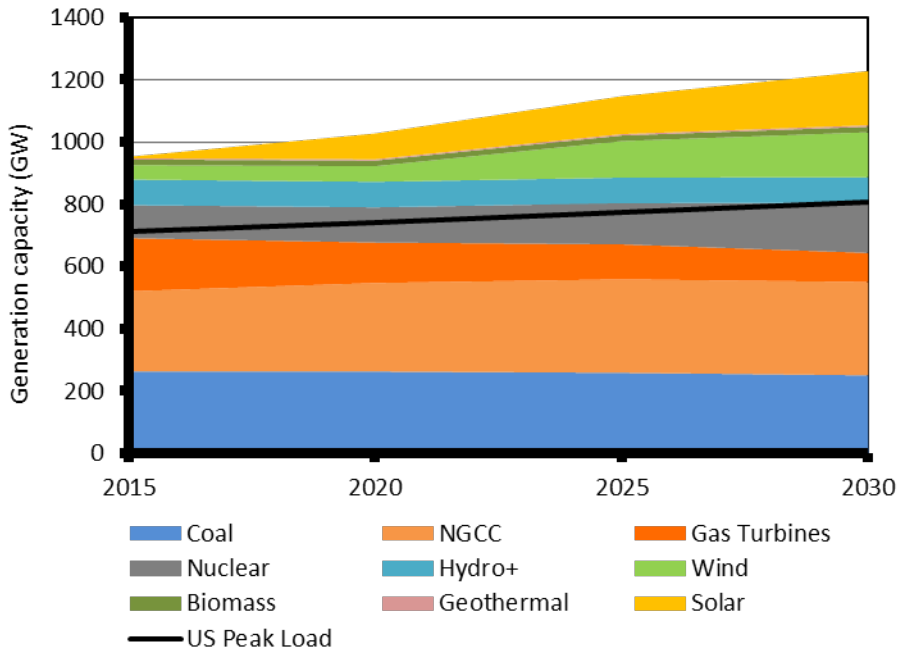


Figure 4-10
Capacity mix in the Base Case

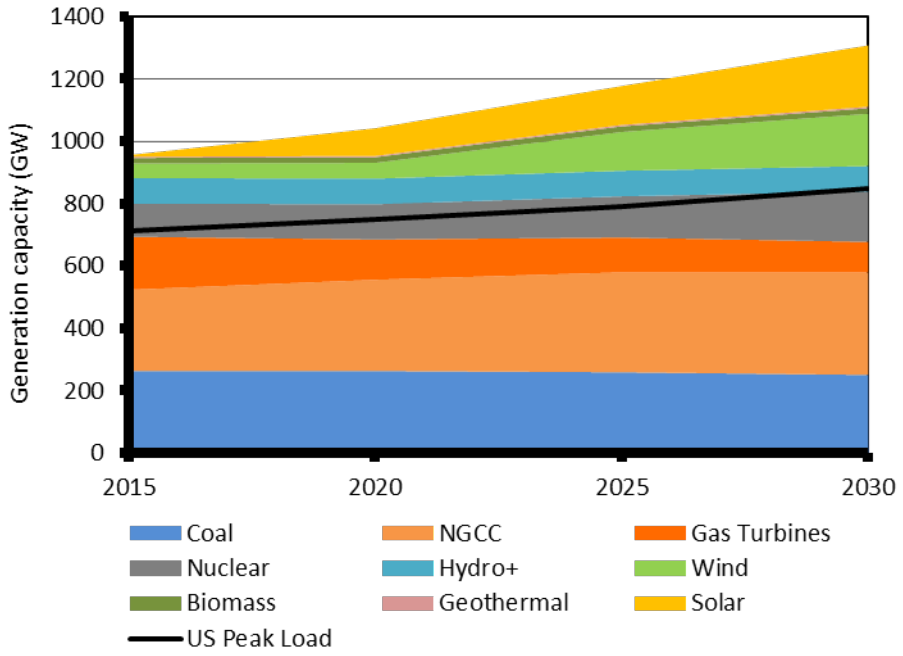


Figure 4-11
Capacity mix in the Electrification Case

Electric-Sector Emissions Results

Long-Run Emissions Trend

Under the technology and policy assumptions imposed in the Base Case, CO_2 emissions fall steadily through to 2030, as shown in Figure 4-12, largely because of the combination of a steadily rising gas-price path (from the AEO) and the assumption of the New Source Performance Standards (NSPS) halting construction of any new coal units. As existing units retire, the existing gas and coal fleet is thus largely replaced by a mix of nuclear and renewables, with some gas baseload and peaking capacity surviving to provide firming for the renewable fleet and generation in areas with cheaper gas or restrictions on new nuclear. In the Electrification Case, CO_2 emissions rise on the order of 1% in 2020 and 2.5% in 2030, attributable largely to increased generation from gas-fired units.

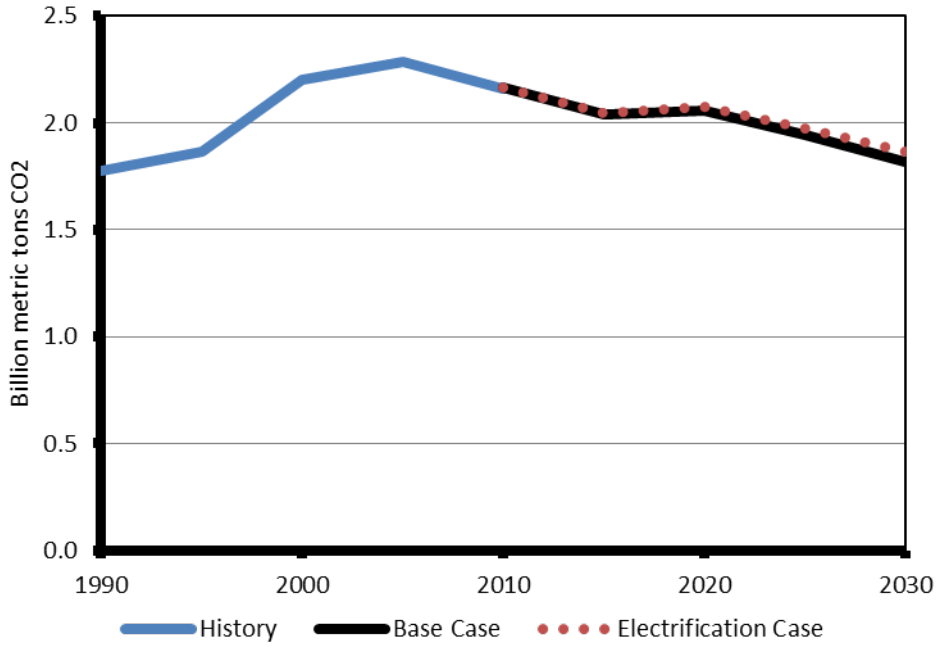


Figure 4-12
Annual CO_2 emissions (billion metric tons CO_2) in the Base Case and Electrification Case

SO_2 and NOx fall dramatically in 2015 as environmental controls are required on existing coal units, and then dwindle to negligible amounts as the existing coal fleet retires. In the modeling, only 241GW of conventional coal-fired units remain in 2030, compared to 317GW in 2010. In 2030, SO_2 emissions are about 0.72 million tons, and NOx emissions are also about 0.72 million tons nationally. The results for SO_2 emissions are shown in Figure 4-13, and the results for NO_x emissions are shown in Figure 4-14.

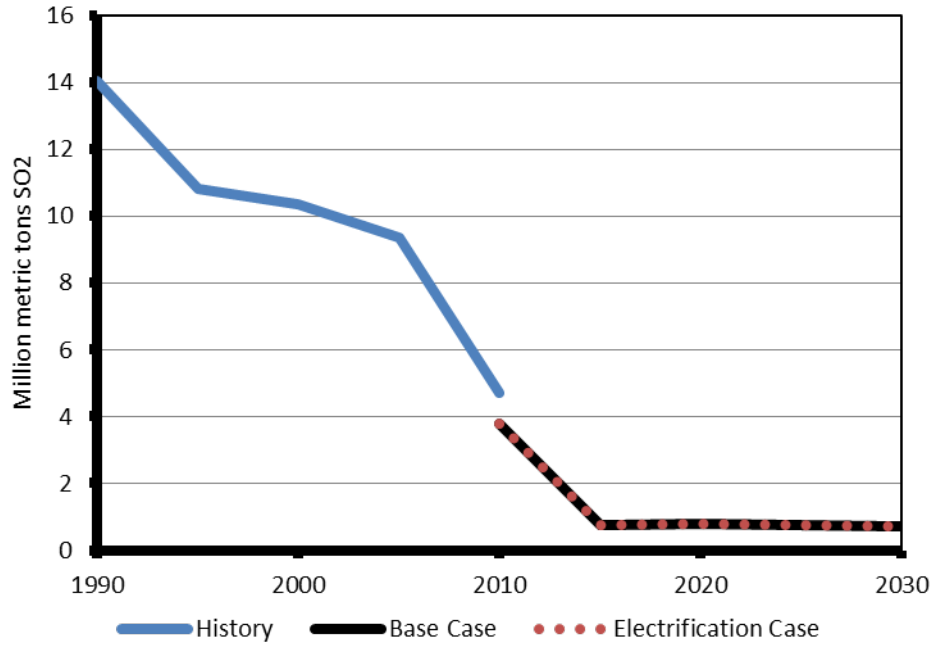


Figure 4-13
Annual SO_2 emissions (million metric tons SO_2) in the Base Case and Electrification Case

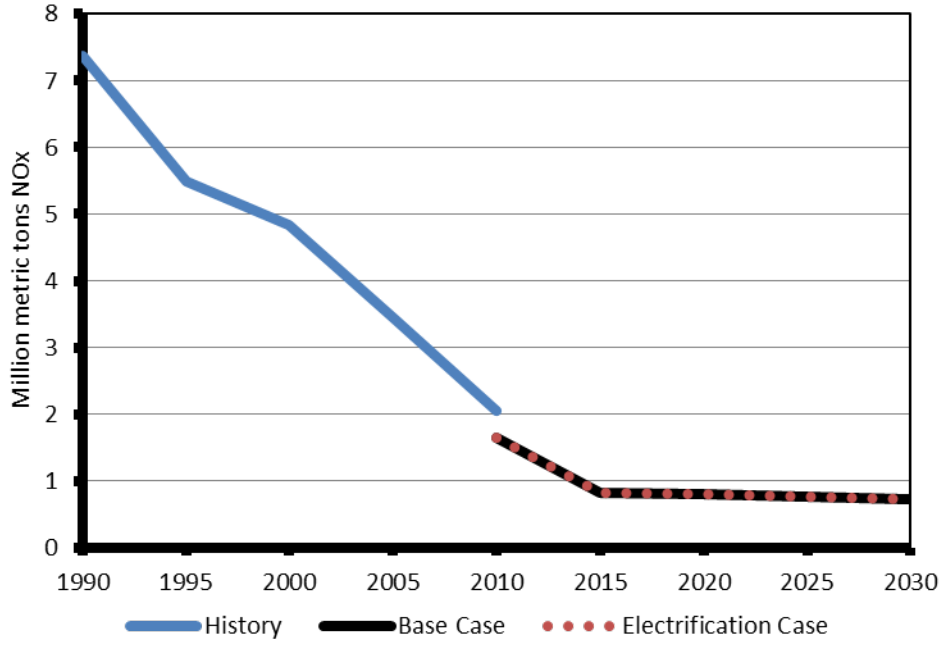


Figure 4-14
Annual NOx emissions (million metric tons NOx) in the Base Case and Electrification Case

Detailed Hourly Emissions for Air Quality Modeling

US-REGEN is a long-run intertemporal model of the United States. In order to solve in a reasonable amount of time, the 8760 hours of each year are approximated by 87 hours selected and weighted to recreate the load shapes and the wind and solar output shapes by region as closely as possible. This methodology is discussed at some length in the US-REGEN documentation. To generate hourly dispatch and emissions profiles, the model has a "static" model—in which electric-sector capacity for a given year can be fixed, and then the dispatch problem solved for a single selected year for the full 8760 hours. For this analysis, the dispatch problem was solved for 2030 in order to generate hourly estimates of pollutant emissions. These estimates were used in the air quality modeling simulations described in Section 8.

Summary Electric-Sector Impacts of Mobile-Source Electrification

In this analysis, mobile-source electrification through 2030 was analyzed using the US-REGEN model—with reference assumptions sourced largely from the AEO and optimistic technology assumptions sourced from EPRI experts. Under these assumptions, and in particular under the steadily rising gas-price path envisaged by the AEO reference case and the 70-year lifetime imposed on the existing coal fleet, emissions fall steadily in the Base Case. Because the coal fleet is largely operated as baseload under these assumptions, mobile-source electrification primarily causes more natural gas–fired units to operate, with a modest increase in renewables and natural gas combined-capacity (NGCC) to supply the additional load. CO_2 emissions rise between 1 and 5% over time, whereas SO_2 and NO_x emissions change minimally. (In fact, NO_x falls slightly, as the new, highly efficient NGCC units displace some of the older coal units at certain times of the day.)

Section 5: Upstream Emissions

Upstream emission sources include emissions associated with the processing, transport, and storage of crude oil and gasoline. In this analysis, upstream-emission reductions were incorporated into the Base Case and the Electrification Case. Base Case upstream emissions were reduced to account for reduced fossil fuel consumption resulting from recent EPA light-duty and heavy-duty vehicle greenhouse gas rulemakings. Electrification Case upstream emissions were further reduced to account for substitution of fossil fuel consumption associated with on-road vehicles and non-road equipment with electricity consumption.

On the up-stream side of oil refineries, crude-oil shipments and related emissions were reduced proportionate to the amount of crude-oil consumption reduced. Emission changes at refineries were also assumed to be reduced proportionate to the amount of crude-oil consumption reduced. Downstream of refineries, emissions were decreased in proportion to the reduced volume of gasoline shipments. The following describes the upstream-emission adjustments:

- Refinery sources: Emissions were reduced based on estimated crude-oil shipment reductions.
- Downstream sources: Downstream emissions are primarily from evaporative processes. Emissions were reduced based on estimated gasoline-shipment reductions.
- Refueling: Refueling emissions only include evaporative processes. Emissions were reduced based on estimated gasoline-shipment reductions.
- Marine: Commercial marine emissions associated with crude-oil shipments were reduced based on estimated crude-oil shipment reductions. It is assumed that 17% of ocean-going vessel emissions were from tanker traffic (Corbett and Wang, 2006) and that emission reductions were uniform geographically.

The extraction and transportation of raw fuels like petroleum, natural gas, and coal were not modeled—with the exception of marine emissions (which implicitly assumes that all marginal petroleum reductions are attributable to imported oil). Excluding these sources of emissions from the study boundary is an omission, although the effects are expected to be small, as discussed in Section 11.

Table 5-1 shows the lists of SCCs that were included in the upstream- emission adjustments. Upstream-emission adjustments were not made to account for

production of batteries and other unique advanced components in the Electrification Case, because data is not available concerning the relative impact on emissions.[14]

Base Case Upstream-Emissions Reductions

Base case emission reductions were made to account for reductions in upstream emissions because of decreased fuel consumption as a result of EPA's light-duty and heavy-duty vehicle greenhouse gas rulemakings. EPA has promulgated three major on-road vehicle greenhouse rulemakings, each applicable to a different group of vehicles:

- Light-duty vehicles of model years 2012–2016
- Light-duty vehicles of model years 2017+
- Heavy-duty vehicles of model years 2014+

The area- and point-source emissions to be used in the 2030 Base Case are from the EPA PM NAAQS air quality modeling platform. Emissions in the PM NAAQS air quality modeling platform do not incorporate the effects of the light-duty 2017+ or heavy-duty 2014+ greenhouse gas emission standards.

Table 5-1
Upstream SCCs that were adjusted for reduced crude-oil and gasoline shipments

Refinery	Refinery	Refinery	Downstream	Downstream	Downstream
30600101	30602101	40301203	40400142	40400263	40600307
30600102	30602201	40600132	40400143	40400271	40600399
30600103	30602301	40600137	40400148	40400272	40600499
30600104	30609901	40600142	40400150	40400273	40600501
30600105	30609905	40600145	40400151	40400278	40600502
30600106	40300101	40600148	40400152	40400401	40600503
30600107	40300103	40600164	40400153	40400402	40600504
30600108	40300302	40600165	40400154	40400403	40600601
30600111	40301001	40600243	40400161	40400404	40600602
30600199	40301002	40600248	40400162	40400405	40600603
30600201	40301003	2501000000	40400163	40400406	40600701
30600202	40301004	2501050000	40400170	40400407	40600702
30600301	40301005	2501050030	40400171	40400408	40600706
30600503	40301006	2501995030	40400172	40600101	40600707
30600504	40301007	2505020000	40400173	40600126	2501000120

[14] The impact of advanced-components manufacture on greenhouse gas emissions is considered in Volume 2.

Table 5-1 (continued)
Upstream SCCs that were adjusted for reduced crude-oil and gasoline shipments

Refinery	Refinery	Refinery	Downstream	Downstream	Downstream
30600505	40301008	**Marine**	40400178	40600131	2501011013
30600508	40301009	2280003100	40400201	40600136	2501011014
30600511	40301010	2280003200	40400202	40600141	2501012013
30600514	40301011	**Downstream**	40400203	40600144	2501012014
30600515	40301012	40400101	40400204	40600147	2501050120
0600516	40301101	40400102	40400205	40600162	2501055120
30600517	40301102	40400103	40400206	40600163	2501060050
30600518	40301103	40400104	40400207	40600199	2501060051
30600519	40301104	40400105	40400208	40600231	2501060052
30600520	40301105	40400106	40400209	40600232	2501060053
30600521	40301106	40400107	40400210	40600233	2501060200
30600701	40301107	40400108	40400211	40600234	2501060201
30600902	40301108	40400109	40400212	40600236	2501995120
30600905	40301109	40400110	40400213	40600237	2505000120
30601011	40301110	40400111	40400231	40600238	2505020030
30601201	40301117	40400112	40400232	40600239	2505020120
30601301	40301131	40400113	40400233	40600240	2505030000
30601401	40301132	40400114	40400240	40600241	2505030120
30601402	40301141	40400115	40400241	40600242	2505040120
30601601	40301142	40400116	40400248	40600253	**Refueling**
30601602	40301151	40400117	40400250	40600260	PM NAAQS Model-Ready Emissions
30601603	40301152	40400118	40400251	40600298	
30601604	40301180	40400119	40400252	40600299	
30601701	40301181	40400131	40400253	40600301	
30601801	40301182	40400132	40400254	40600302	
30601901	40301201	40400140	40400261	40600305	
30602001	40301202	40400141	40400262	40600306	

Crude-oil shipment reductions were estimated as follows for the Base Case:

1. Per the light-duty 2017+ Regulatory Impact Analysis (RIA) (EPA, 2012b), the estimated total crude supply to U.S. refineries in 2030 is 228 billion gallons, in the absence of the light-duty 2017+ and the heavy-duty 2014+ greenhouse gas rulemakings.

2. Per the light-duty 2017+ greenhouse gas RIA (EPA, 2012b), one gallon of gasoline or diesel fuel will be assumed to be produced per one gallon of crude oil supplied to refineries.
3. Per the light-duty 2017+ greenhouse gas RIA (EPA, 2012b), 23.0 billion gallons of gasoline is estimated to be saved in 2030 which yields a 10% reduction in refinery crude supply, per assumption 2) above.
4. Per the heavy-duty greenhouse gas rulemaking RIA (EPA, 2011a), it is estimated that 5.8 billion gallons of diesel fuel and gasoline is estimated to be saved in 2030, which yields a 2.5% reduction in refinery crude supply, per assumption 2) above.
5. Combining the crude throughput reductions resulting from the light-duty and heavy-duty greenhouse gas rulemakings, refinery crude throughput is reduced by 12.5% in 2030. Crude shipment and refinery emissions were assumed to be reduced by the same amount. Reductions were assumed to be uniform across the United States.

Gasoline-shipment reductions were estimated as follows for the Base Case:

1. Per the light-duty 2017+ greenhouse gas rulemaking RIA (EPA, 2012b), on-road gasoline consumption is estimated to decrease by 22.9 billion gallons (18%) in 2030 as a result of the rulemaking. Gasoline-shipment reductions are estimated based on the ratio of the volume of gasoline reduced (22.9 billion gallons) to the total volume of gasoline consumed in the absence of the light-duty 2017+ greenhouse gas rulemaking.
2. Per the heavy-duty greenhouse gas rulemaking RIA (EPA, 2011a), on-road gasoline consumption from heavy-duty vehicles is estimated to decrease by 0.5 billion gallons (or 0.3%) in 2030 as a result of the rulemaking. Gasoline-shipment reductions were estimated based on the ratio of the volume of gasoline reduced (0.5 billion gallons) to the total volume of gasoline consumed in the absence of the heavy-duty greenhouse gas rulemaking.
3. Combining the gasoline-consumption reductions resulting from the light-duty and heavy-duty greenhouse gas rulemakings, a total gasoline-shipment reduction of 18% is estimated. Reductions are assumed to be uniform across the United States.

Crude-oil shipments are used to scale shipping emissions resulting from gasoline and diesel–usage reductions, and gasoline shipments are used to additionally scale primary evaporative emissions from transport and transfer. Estimates of upstream-emission reductions for the Base Case are shown by source type in Table 5-2 and by state in Table 5-3. The majority of upstream VOC emission reductions are from the downstream sector, which is made up primarily of evaporative losses 1) at bulk plants; 2) during gasoline transport, loading, and unloading; and 3) during underground tank filling and breathing losses. PM_{10}, $PM_{2.5}$, and SO_2–emission reductions are dominated by the refinery sector. Approximately 70% of NO_x emission reductions are from the marine sector. Refueling emissions, which are controlled primarily by on-board vapor recovery, account for only 9% of the total upstream-emission reductions.

Table 5-2
Year 2030 lower-48 state upstream emissions and Base Case adjustments

Category	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2
Emissions Change from PM NAAQS to Base Case (tons per year)						
Marine[1]	-966	-2,563	-20,224	-395	-363	-1,302
Refinery	-5,235	-5,361	-8,804	-2,775	-2,453	-10,147
Downstream	-108,664	-304	-109	-17	-16	-10
Refueling	-11,655	0	0	0	0	0
Percent Change from PM NAAQS to Base Case						
Marine[1]	-2%	-2%	-2%	-2%	-2%	-2%
Refinery	-13%	-13%	-13%	-13%	-13%	-13%
Downstream	-18%	-18%	-18%	-18%	-18%	-18%
Refueling	-18%	0%	0%	0%	0%	0%

[1] Domain-wide emissions

Table 5-3
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Base Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change
AL	10,871	8,937	-18%	364	317	-13%	121	105	-13%	451	394	-13%
AR	18,083	14,947	-17%	193	169	-13%	48	42	-13%	18	15	-13%
AZ	11,741	9,639	-18%	0	0	na	0	0	na	0	0	na
CA	23,913	19,770	-17%	4,121	3,600	-13%	1,050	917	-13%	1,989	1,738	-13%
CO	8,084	6,664	-18%	417	361	-13%	477	417	-13%	283	247	-13%
CT	3,374	2,770	-18%	2	1	-18%	0	0	na	0	0	na
DC	138	113	-18%	0	0	na	0	0	na	0	0	na
DE	2,465	2,105	-15%	69	60	-13%	101	89	-13%	917	801	-13%
FL	75,191	61,744	-18%	43	36	-18%	0	0	-15%	2	1	-13%
GA	40,849	33,538	-18%	68	58	-15%	3	3	-13%	0	0	-13%
IA	13,273	10,897	-18%	17	14	-18%	21	18	-13%	0	0	na
ID	1,578	1,295	-18%	0	0	na	0	0	na	0	0	na
IL	14,542	12,112	-17%	5,381	4,702	-13%	1,480	1,293	-13%	19,413	16,967	-13%
IN	16,534	13,594	-18%	1,547	1,352	-13%	93	81	-13%	534	467	-13%
KS	18,435	15,193	-18%	1,813	1,584	-13%	445	387	-13%	475	415	-13%
KY	14,977	12,331	-18%	1,081	945	-13%	264	228	-13%	160	138	-14%
LA	31,767	26,237	-17%	16,813	14,693	-13%	7,352	6,425	-13%	11,163	9,756	-13%
MA	7,381	6,060	-18%	0	0	-13%	15	13	-13%	0	0	-14%
MD	4,798	3,940	-18%	19	16	-17%	0	0	-18%	5	4	-18%
ME	1,752	1,443	-18%	11	9	-18%	4	3	-18%	0	0	-19%

Table 5-3 (continued)
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Base Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change
MI	20,600	16,918	-18%	145	125	-13%	94	82	-13%	66	58	-13%
MN	13,177	10,858	-18%	1,754	1,532	-13%	595	520	-13%	130	113	-13%
MO	24,560	20,169	-18%	36	31	-15%	21	19	-13%	5	5	-13%
MS	19,094	15,706	-18%	3,592	3,140	-13%	288	251	-13%	504	440	-13%
MT	3,520	2,928	-17%	1,359	1,187	-13%	304	266	-13%	980	856	-13%
NC	10,880	8,931	-18%	5	4	-18%	0	0	-18%	0	0	na
ND	1,820	1,495	-18%	407	356	-13%	216	189	-13%	8	7	-13%
NE	7,185	5,905	-18%	17	15	-13%	11	10	-13%	2	2	-13%
NH	387	318	-18%	0	0	na	0	0	na	0	0	na
NJ	16,047	13,212	-18%	1,320	1,151	-13%	413	361	-13%	187	163	-13%
NM	10,903	8,982	-18%	493	430	-13%	90	78	-13%	372	325	-13%
NV	1,907	1,566	-18%	16	14	-13%	5	5	-13%	33	29	-13%
NY	22,894	18,795	-18%	11	9	-18%	2	2	-16%	0	0	-18%
OH	13,414	11,043	-18%	2,622	2,291	-13%	1,037	906	-13%	6,924	6,052	-13%
OK	16,973	14,033	-17%	3,027	2,645	-13%	1,262	1,103	-13%	8,798	7,689	-13%
OR	7,157	5,875	-18%	18	15	-14%	1	1	-16%	1	1	-16%
PA	21,295	17,535	-18%	2,930	2,559	-13%	841	735	-13%	4,227	3,694	-13%
RI	1,276	1,048	-18%	2	2	-13%	0	0	na	0	0	na
SC	24,400	20,032	-18%	6	5	-18%	4	4	-13%	0	0	na
SD	3,635	2,985	-18%	0	0	na	0	0	na	0	0	na
TN	8,143	6,697	-18%	303	264	-13%	162	141	-13%	44	38	-13%

Table 5-3 (continued)
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Base Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change	PM NAAQS	Base Case	Percent Change
TX	81,468	67,564	-17%	14,571	12,732	-13%	3,613	3,158	-13%	12,981	11,345	-13%
UT	7,274	6,108	-16%	463	405	-13%	391	342	-13%	902	788	-13%
VA	21,989	18,100	-18%	249	216	-13%	17	15	-13%	0	0	-13%
VT	318	261	-18%	0	0	na	0	0	na	0	0	na
WA	8,792	7,245	-18%	3,234	2,827	-13%	209	183	-13%	320	280	-13%
WI	9,859	8,132	-18%	155	134	-13%	135	118	-13%	172	150	-13%
WV	5,612	4,608	-18%	701	613	-13%	305	267	-13%	7,396	6,464	-13%
WY	4,108	3,412	-17%	497	435	-13%	514	449	-13%	1,125	983	-13%
Totals	**708,432**	**583,791**	**-18%**	**69,893**	**61,054**	**-13%**	**22,002**	**19,225**	**-13%**	**80,587**	**70,430**	**-13%**

Electrification Case Upstream-Emissions Reductions

Reductions in crude-oil and gasoline shipments as a result of on-road vehicle and non-road equipment electrification are described below. Note that these reductions were applied to the 2030 Base Case inventory that had already been modified to incorporate upstream reductions associated with EPA greenhouse gas rulemakings as described above.

Crude-oil shipment reductions were estimated as follows for the Electrification Case:

1. **On-road vehicles:** Fuel savings for the Electrification Case over the Base Case for the lower-48 states in 2030 of 17% (light-duty gasoline vehicles and trucks), 16% (light-duty diesel vehicles and trucks), 18% (medium- and heavy-duty gasoline vehicles and trucks), and 3% (medium- and heavy-duty diesel vehicles and trucks) were estimated based on the modeling in Section 2.3. The total reduction in fuel consumption across all vehicle types was estimated to be 13% and was assumed to be uniform across all states.
2. **Non-road equipment:** Fuel savings for the Electrification Case over the Base Case for the lower-48 states in 2030 of 8% were estimated across all liquid fuels (gasoline, diesel, liquefied petroleum gas or LPG, and jet fuel) based on the modeling in Section 3.2. The percent reduction across all states varied from 2 to 15% because the suite of non-road equipment and usage patterns in each state determine the magnitude of reductions.
3. **Volumetric reductions** in fossil fuel consumption in 2030 were estimated to be 18.8 billion gallons from on-road vehicles and 4 billion gallons from non-road equipment, for a total of 22.8 billion gallons. The resulting reduction in crude-oil shipments is 11% from the Base Case (or a 23% reduction from the unmodified 2030 scenario, when accounting for both the reduction in fuel use as a result of EPA's on-road vehicle greenhouse gas rulemakings and additional electrification of on-road vehicles and non-road equipment).

Gasoline-shipment reductions were estimated as follows for the Electrification Case:

1. **On-road vehicles:** Lower-48 state, 2030 fuel savings for the Electrification Case over the Base Case of 17% (light-duty gasoline vehicles and trucks) and 18% (medium- and heavy-duty gasoline vehicles and trucks) were estimated based on the modeling in Section 2.3. The total reduction across all gasoline-fueled vehicle types was estimated to be 17% and was assumed to be uniform across all states.
2. **Non-road equipment:** Lower-48 state, 2030 fuel savings for the Electrification Case over the Base Case of 15% were estimated for gasoline fuels for the lower-48 states based on the modeling in Section 3.2. The percent reduction across all states varied from 5 to 31% because the suite of gasoline-fueled non-road equipment and usage patterns in each state determine the magnitude of reductions.

3. **Volumetric reductions** in gasoline consumption for the lower-48 states in 2030 were estimated to be 17.5 billion gallons from on-road vehicles and 1.6 billion gallons from non-road equipment, or a total of 19.2 billion gallons. The resulting reduction in gasoline shipments is 17% from the Base Case (or a 32% reduction from the unmodified 2030 scenario, when accounting for both the reduction in fuel use resulting from EPA's on-road vehicle greenhouse gas rulemakings and additional electrification of on-road vehicles and non-road equipment).

Estimates of upstream-emissions reductions for the Electrification Case are shown by source in Table 5-4 and by state in Table 5-5. Similar to the Base Case upstream adjustments, the majority of upstream VOC–emission reductions are from the downstream sector. PM_{10}, $PM_{2.5}$, and SO_2– emission reductions are dominated by the refinery sector. Approximately 84% of NO_x emission reductions are from the marine sector. Refueling emissions account for only 9% of the total upstream VOC–emission reductions.

Table 5-4
Year 2030 lower-48 state upstream-emissions and Electrification Case adjustments

Category	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2
Emissions Change from Base Case to Electrification Case (tons per year)						
Marine[1,2]	-1,497	-4,652	-32,760	-655	-609	-1,310
Refinery	-4,110	-4,163	-6,859	-2,169	-1,917	-7,973
Downstream	-86,715	-221	-83	-13	-13	-8
Refueling	-8,875	0	0	0	0	0
Percent Change from Base Case to Electrification Case						
Marine[1,2]	-3%	-4%	-4%	-4%	-4%	-2%
Refinery	-11%	-11%	-11%	-11%	-11%	-11%
Downstream	-17%	-16%	-17%	-17%	-17%	-17%
Refueling	-17%	0%	0%	0%	0%	0%

[1] Domain-wide emissions

[2] Includes emission reductions resulting from both upstream adjustments and shoreside power electrification

Table 5-5
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Electrification Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change
AL	8,937	7,424	-17%	317	280	-12%	105	93	-11%	394	349	-11%
AR	14,947	12,494	-16%	169	150	-11%	42	37	-11%	15	14	-11%
AZ	9,639	7,960	-17%	0	0	na	0	0	na	0	0	na
CA	19,770	16,615	-16%	3,600	3,191	-11%	917	813	-11%	1,738	1,541	-11%
CO	6,664	5,546	-17%	361	317	-12%	417	369	-11%	247	219	-11%
CT	2,770	2,291	-17%	1	1	-17%	0	0	na	0	0	na
DC	113	94	-17%	0	0	na	0	0	na	0	0	na
DE	2,105	1,820	-14%	60	54	-11%	89	78	-11%	801	710	-11%
FL	61,744	51,228	-17%	36	30	-17%	0	0	-13%	1	1	-11%
GA	33,538	27,740	-17%	58	50	-13%	3	2	-11%	0	0	-11%
IA	10,897	9,291	-15%	14	12	-15%	18	16	-11%	0	0	na
ID	1,295	1,095	-15%	0	0	na	0	0	na	0	0	na
IL	12,112	10,268	-15%	4,702	4,169	-11%	1,293	1,147	-11%	16,967	15,045	-11%
IN	13,594	11,344	-17%	1,352	1,199	-11%	81	72	-11%	467	414	-11%
KS	15,193	12,640	-17%	1,584	1,404	-11%	387	342	-12%	415	368	-11%
KY	12,331	10,261	-17%	945	838	-11%	228	200	-12%	138	121	-13%
LA	26,237	21,997	-16%	14,693	13,027	-11%	6,425	5,697	-11%	9,756	8,651	-11%
MA	6,060	5,019	-17%	0	0	-11%	13	11	-11%	0	0	-8%
MD	3,940	3,250	-18%	16	13	-17%	0	0	-18%	4	3	-18%
ME	1,443	1,255	-13%	9	8	-13%	3	3	-13%	0	0	-12%

Table 5-5 (continued)
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Electrification Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change
MI	16,918	14,531	-14%	125	111	-12%	82	72	-11%	58	51	-11%
MN	10,858	9,343	-14%	1,532	1,357	-11%	520	461	-11%	113	101	-11%
MO	20,169	16,785	-17%	31	26	-14%	19	17	-11%	5	4	-11%
MS	15,706	13,076	-17%	3,140	2,784	-11%	251	223	-11%	440	390	-11%
MT	2,928	2,490	-15%	1,187	1,052	-11%	266	236	-11%	856	759	-11%
NC	8,931	7,375	-17%	4	3	-17%	0	0	-17%	0	0	na
ND	1,495	1,274	-15%	356	315	-11%	189	167	-11%	7	6	-11%
NE	5,905	4,904	-17%	15	13	-11%	10	9	-11%	2	2	-11%
NH	318	270	-15%	0	0	na	0	0	na	0	0	na
NJ	13,212	10,980	-17%	1,151	1,019	-12%	361	320	-11%	163	144	-11%
NM	8,982	7,480	-17%	430	381	-11%	78	69	-11%	325	289	-11%
NV	1,566	1,285	-18%	14	13	-11%	5	4	-11%	29	26	-11%
NY	18,795	15,705	-16%	9	7	-16%	2	2	-15%	0	0	-17%
OH	11,043	9,203	-17%	2,291	2,032	-11%	906	803	-11%	6,052	5,366	-11%
OK	14,033	11,733	-16%	2,645	2,345	-11%	1,103	978	-11%	7,689	6,818	-11%
OR	5,875	4,873	-17%	15	13	-12%	1	1	-15%	1	1	-15%
PA	17,535	14,594	-17%	2,559	2,268	-11%	735	652	-11%	3,694	3,276	-11%
RI	1,048	870	-17%	2	2	-11%	0	0	na	0	0	na
SC	20,032	16,568	-17%	5	4	-17%	4	3	-11%	0	0	na
SD	2,985	2,523	-15%	0	0	na	0	0	na	0	0	na
TN	6,697	5,559	-17%	264	234	-11%	141	125	-11%	38	34	-11%

Table 5-5 (continued)
Year 2030 lower-48 states – by state upstream emissions (tons per year) and Electrification Case adjustments, excluding marine emissions

State	VOC			NO_x			PM_{10}			SO_2		
	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change	Base Case	Elec Case	Percent Change
TX	67,564	56,617	-16%	12,732	11,286	-11%	3,158	2,800	-11%	11,345	10,060	-11%
UT	6,108	5,223	-14%	405	359	-11%	342	303	-11%	788	699	-11%
VA	18,100	14,974	-17%	216	190	-12%	15	13	-11%	0	0	-12%
VT	261	223	-15%	0	0	na	0	0	na	0	0	na
WA	7,245	6,043	-17%	2,827	2,507	-11%	183	162	-11%	280	248	-11%
WI	8,132	7,055	-13%	134	119	-11%	118	104	-11%	150	133	-11%
WV	4,608	3,811	-17%	613	543	-11%	267	236	-11%	6,464	5,732	-11%
WY	3,412	2,919	-14%	435	385	-11%	449	398	-11%	983	872	-11%
Totals	**583,791**	**487,921**	**-16%**	**61,054**	**54,112**	**-11%**	**19,225**	**17,043**	**-11%**	**70,430**	**62,450**	**-11%**

Section 6: Air Quality Model Scenario Summaries

The development of the emission inventory for air quality simulation in this study is documented and summarized in this section. Air quality modeling requires spatially and temporally resolved estimates of SO_2, VOC, NO_x, CO, NH_3, and PM emissions for all sources, including electrical generating units (EGUs), on-road mobile sources, non-road mobile sources, and other categories that were not modeled in this analysis. These emissions data must be formatted for input to the air quality model. Emission inventories for the Base Case and the Electrification Case were prepared for the 2030 model year using the data described in Section 2 through Section 5. In addition, reference 2007 emissions were prepared for the baseline modeling.

The primary emissions modeling tool used to create the air quality model-ready emissions needed by the Comprehensive Air Quality Model with Extensions (CAMx) was the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. SMOKE requires emissions inventory files and ancillary data files as input data. For this work, the SMOKE input data were built off of the 2007 and 2020 emission inventories prepared by the EPA for the Regulatory Impact Analysis of the 2012 Final NAAQS for particulate matter less than 2.5 microns ($PM_{2.5}$), hereafter referred to as the "PM NAAQS." Emissions from mobile sources and EGUs were generated under this study for the year 2030. For all other source categories, the 2030 emissions were set to the 2020 levels—assuming that activity growth will be offset by technology improvement. This simplified assumption was used because of the lack of any other reliable information needed to project these emissions from 2020 to 2030. Because the focus of this study is to quantify the incremental impact of electrification technology on air quality, this assumption should not have any significant bearing on the results.

Five source categories were modified for the Electrification Case: EGU, on-road mobile, non-road mobile, area, and non-EGU point sources.

Emissions Data Sources

EPA developed a year 2007, 2008-NEIv2-based air quality modeling platform, which was used in the PM NAAQS modeling (EPA, 2012c). The 2007 modeling platform consists of three emissions cases: the 2007 base case, the 2007

evaluation case, and the 2020 base case. Differences between the 2007 evaluation and 2007 base cases lie in fires and EGUs. The evaluation case uses 2007-specific wildfires and prescribed burning emissions and 2007 hour-specific continuous emissions monitoring (CEM) data for EGUs. The 2007 base case uses an average-year scenario for wildfires and smoothed prescribed burning emissions (average fires). The 2020 base case scenario represents the best estimate for the future year without implementation of controls needed for current attainment standards. All of the SMOKE inventory files and ancillary files for the PM NAAQS modeling are available from EPA's Emissions Modeling Clearinghouse (EPA, 2012e). Model-ready emission files by source category in NetCDF format are also available from EPA upon request.

In this study, the present-year (2007) emissions are from the PM NAAQS 2007 inventory, obtained from EPA as model-ready files. This scenario utilizes the 2007 hour-specific CEM data for EGUs and average fires. On-road emissions for 2007 were developed for this study based on EPA's MOVES model, using methodology similar to the methodology used to develop 2030 on-road emissions, as described in Section 2.

Emissions for the two future-year scenarios are from the PM NAAQS 2020 base case, with some modifications (described below). Both scenarios employ the average-fires emissions as used in the 2007 modeling.

Source Categories

On-road Mobile Sources

This category comprises vehicular sources that operate on roadways, such as light-duty gasoline vehicles and heavy-duty diesel vehicles. On-road emissions for the 2007 baseline and two future-year scenarios were estimated from emission factors and activity data that consist of vehicle miles traveled (VMT) and vehicle speed, using EPA's MOVES model. SMOKE spatially and temporally allocates these emissions for each CAMx grid-cell. PM exhaust emissions were developed at 72°F and adjusted with hourly temperature at the grid-cell level. The Electrification Case emissions take into account a market penetration of electric vehicles. This procedure is described in detail in Section 2.

Non-road Mobile Sources

Non-road mobile sources include railroad locomotives, aircraft, commercial marine vessels, farm equipment, recreational boating, lawn and garden equipment, and a variety of other categories. A detailed description of the derivation of these emissions factors is presented in Section 3.

Non-road equipment

The 2030 Base Case and Electrification Case non-road equipment emissions were developed using EPA's NMIM-NONROAD model—except in California where the California ARB OFFROAD model is used.

Cargo-handling equipment

In this study, cargo-handling equipment emissions at ports and rail yards were estimated outside of EPA's NONROAD model and ARB's OFFROAD model, based on existing port and rail yard emission inventories.

Aircraft and Locomotive

Aircraft emissions were projected from 2008 aircraft emissions developed by the EPA for the 2008 National Emissions Inventory (EPA, 2010g). The projection employs landing-takeoff cycles (LTOs) data and control factors.

Locomotive and harbor craft

Locomotive and harbor-craft emissions were obtained from the 2008 RIA for calendar years 2006 to 2040 (EPA, 2008a).

Commercial marine

The Class 3 commercial marine (C3marine) emissions estimates rely upon the Emissions Control Area-International Marine Organization (ECA-IMO) data included in the PM NAAQS modeling database. The C3marine inventory includes ships in several intraport modes (cruising, hoteling, reduced-speed zone, maneuvering, and idling) and underway mode. The PM NAAQS C3 marine emissions were adjusted downward for the base case to account for reduction in crude-oil shipments associated with decreased fossil fuel usage resulting from EPA's light-duty and heavy-duty greenhouse gas rulemakings. This adjustment was uniformly applied to all C3 marine emissions. The Base Case emissions were adjusted further for the Electrification Case emissions to account for reduced petroleum usage and to account for increased usage of shoreside power, which reduces dockside emissions.

Area Sources (Non-Point Stationary Sources)

This category comprises stationary sources that are not identified as individual points and so are treated as being spread over a spatial extent (usually a county). Examples of stationary area sources include (but are not limited to) residential emissions, oil and gas wells, fugitive dust, and road dust. The 2030 Base Case emissions were held constant at the same level as the PM NAAQS 2020

emissions. For the 2030 Electrification Case, emission adjustments were applied to "upstream" emissions related to gasoline refining and distribution and to "downstream" emissions related to refueling, as described in Section 5.

Point Sources

These are stationary sources that are identified by point locations. Point-source emissions are primarily allocated above the surface layer in the CAMx model, according to stack height and plume rise. Point sources are divided into EGU sources and non-EGU sources, such as refineries.

EGU emissions were estimated for the 2030 Base Case and Electrification Case using the US-REGEN model, as discussed in Section 4. Each US-REGEN unit is assigned a Source Classification Code (SCC), based on engine type and fuel type, and is matched to a stack in the PM NAAQS point inventory to obtain stack location. Stack parameters are set for each unit based on their SCCs; hence, co-located stacks with different SCCs (for example, co-located stacks using distillate oil and coal) are treated differently in the CAMx model. Emissions from EGUs added in future years are incorporated by scaling the emissions of the known sources.

Non-EGU emissions for the Base Case are from the PM NAAQS 2020 inventory. The non-EGU sector includes all stationary point sources except sources with SCCs beginning with 101 and 201. For the Electrification Case, the upstream-emission reductions described in Section 5 were applied.

Biogenic Emissions

Biogenic emissions are a function of vegetation type, leaf coverage, and meteorological conditions. The inventory of biogenic emissions was estimated using the Model of Emissions of Gases and Aerosols from Nature (MEGAN). The MEGAN model (Guenther et al., 2006; Sakulyanontvittaya et al., 2008) uses daily meteorology (temperature and solar radiation) from the Weather Research and Forecasting (WRF) model outputs to generate hour-specific biogenic emissions for each CAMx grid cell. Biogenic emissions were generated for the 2007 baseline using 2007 meteorology and held constant to 2030. These emissions were held constant between the 2030 Base Case and Electrification Case.

Sea-Salt Emissions

Emissions of sea-salt particles—including sodium, chloride, and sulfate (SO_4)—were estimated from the 2007 WRF hourly, gridded meteorology. The sea-salt aerosol fluxes from both open oceans (Smith and Harrison, 1998; Gong, 2003) and breaking waves in the surf zone (de Leeuw et al., 2000) are a function of wind speed at 10-meter height. These emissions were held constant between the 2030 Base Case and Electrification Case.

The Sparse Matrix Operator Kernel Emissions (SMOKE) Model

Emissions modeling for the project utilized the SMOKE modeling system, Version 3.1. The overall approach for the SMOKE modeling conducted for the project is described below, including the spatial allocation of inventory data; chemical speciation of VOC emissions sources; and merging of the inventory database. The general emissions-processing steps for the preparation of emission inventories for air quality modeling include:

- Input and QA of emission data.
- Chemical speciation: Emission estimates of criteria pollutants must be speciated for the particular chemical mechanism employed in the air quality model.
- Temporal allocation: Annual or seasonal emission estimates are resolved hourly for air quality modeling. These allocations are generally determined from the particular source category, specified by SCC codes. Monthly, weekly, and diurnal profiles are cross-referenced to SCC codes to provide the appropriate temporal resolution.
- Spatial allocation: Regional- or province-level emission estimates must be spatially resolved to the modeling grid cells for air quality modeling. The spatial allocation is generally accomplished using surrogates cross-referenced to source categories.
- Output of air quality model-ready files.
- QA/QC of emissions modeling.

The PM NAAQs inventories are in SMOKE Flat File Format. SMOKE uses ancillary data to perform temporal, spatial, and chemical allocation of emissions according to source category. This study used the PM NAAQS SMOKE inventory and setup, and it generated emissions inputs for CAMx, Version 6, with Carbon Bond 05 (CB05) chemical mechanism species.

Emissions Summaries

The 2007 baseline emissions are presented in Table 6-1 by major source category. These emissions are from the PM NAAQS emissions inventory, except for U.S. on-road mobile and natural sources (biogenic and sea-salt).

Future-year anthropogenic emissions are summarized by state and major source category in Table 6-2 to Table 6-5. Natural emissions in these tables were prepared from the CAMx-ready gridded emissions by using a grid-cell to state correspondence; as a result, state totals are approximate. C3 Marine emissions are not included in the state summaries, but they are included in the domain-wide summary at the end of this section.

Table 6-1
By-sector emissions summaries of criteria air pollutants for 2007 baseline (ton y-1)

Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Area fugitive dust (afdust-adj)	0	0	0	5,853,639	825,331	0	0
Agricultural (ag)	0	3,595,429	0	0	0	0	0
Area (nonpt)	4,336,565	155,317	1,230,624	767,225	676,243	402,633	6,456,455
Locomotive, and non-Class 3 commercial marine sector (c1c2rail)	218,854	557	1,338,370	43,835	41,019	48,814	61,558
Class 3 commercial marine (c3marine)	12,724	0	138,033	12,476	11,452	104,822	4,902
Nonroad	17,794,112	1,920	1,894,569	188,504	179,165	101,735	2,480,715
Onroad non-refueling	40,071,577	143,286	7,699,523	384,867	251,342	64,732	3,207,137
Onroad refueling (onroad_rfl)	0	0	0	0	0	0	224,681
EGU (ptipm)	703,771	25,428	3,357,384	437,096	329,584	9,136,151	38,071
Non-EGU (ptnonipm)	2,938,024	68,020	2,079,637	586,910	411,085	1,590,091	1,059,429
Average-year wildfires and prescribed fires (avefire)	15,984,435	262,375	219,611	1,627,425	1,379,174	120,584	3,771,643
CONUS Total	**82,060,062**	**4,252,332**	**17,957,751**	**9,901,977**	**4,104,395**	**11,569,562**	**17,304,591**
Off-shore (othpt)	82,146		74,285	780	769	1,021	60,823
C3marine, non-U.S.	58,250	0	706,890	58,529	53,785	436,704	24,749
Canada	6,709,566	419,805	1,197,944	888,945	297,541	897,004	1,294,660
Mexico	1,087,926	112,027	597,786	198,627	142,820	789,835	610,447
Biogenic	3,988,857		700,350				48,212,483
Sea-salt				4,036,800	4,036,800		
Domain Total	**93,986,807**	**4,784,164**	**21,235,006**	**15,085,658**	**8,636,110**	**13,694,126**	**67,507,753**

Table 6-2
Annual NO_x emissions (ton y-1) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Alabama	9,454	28,961	10,106	15,588	20,078	59,070	9,454	27,248	9,321	14,551	20,056	59,033
Arizona	15,892	25,952	12,494	17,466	11,852	14,969	15,892	24,516	11,537	16,339	11,848	14,969
Arkansas	15,257	21,879	6,761	11,915	12,974	32,173	15,257	20,965	6,243	11,130	13,155	32,153
California	70,824	138,402	31,166	74,889	3,402	70,095	70,824	127,199	28,597	70,929	3,125	69,686
Colorado	28,615	22,775	8,711	9,085	19,749	46,426	28,615	21,317	8,029	8,458	19,834	46,382
Connecticut	7,957	10,892	5,125	7,194	1,371	4,125	7,957	9,975	4,727	6,722	1,418	4,125
Delaware	2,222	5,916	1,564	2,132	1,936	2,259	2,222	5,579	1,445	1,981	1,937	2,252
District of Columbia	1,293	1,176	710	438	0	480	1,293	1,087	657	409	0	480
Florida	7,527	75,612	33,297	33,529	27,237	33,190	7,527	71,564	30,721	31,308	27,897	33,184
Georgia	14,304	39,996	19,880	24,299	29,976	46,119	14,304	37,421	18,449	22,709	29,783	46,111
Idaho	11,442	9,664	3,153	5,347	0	12,461	11,442	9,266	2,920	4,854	0	12,461
Illinois	59,362	78,989	21,534	31,648	38,445	64,927	59,362	75,341	19,947	29,485	38,497	64,394
Indiana	31,055	38,265	12,729	28,651	43,002	59,105	31,055	35,640	11,743	26,839	43,018	58,952
Iowa	18,659	33,121	5,501	8,398	16,943	38,594	18,659	32,261	5,075	7,869	16,901	38,592
Kansas	21,617	27,882	5,296	6,894	15,889	52,184	21,617	26,922	4,887	6,440	15,895	52,004
Kentucky	5,639	29,097	8,165	16,861	32,987	37,066	5,639	27,757	7,530	15,808	32,790	36,959
Louisiana	35,528	74,855	7,860	14,700	14,293	126,972	35,528	72,928	7,252	13,764	14,670	125,306
Maine	7,134	8,590	3,013	3,369	175	11,121	7,134	8,210	2,792	3,126	195	11,120
Maryland	10,203	21,365	10,258	9,686	10,913	20,940	10,203	19,858	9,453	9,004	10,930	20,937
Massachusetts	19,490	20,531	8,401	10,909	1,806	10,279	19,490	18,889	7,750	10,165	1,873	10,279

Table 6-2 (continued)
Annual NO_x emissions (ton y-1) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Michigan	39,461	48,238	19,786	23,482	20,933	60,687	39,461	45,314	18,254	21,828	20,977	60,672
Minnesota	25,713	41,702	11,382	13,527	13,615	53,712	25,713	40,056	10,527	12,562	13,649	53,537
Mississippi	6,579	22,914	6,667	12,348	5,914	50,926	6,579	22,009	6,110	11,542	5,916	50,570
Missouri	23,788	46,878	13,734	21,949	34,644	42,553	23,788	44,886	12,687	20,475	34,662	42,548
Montana	3,483	14,982	2,038	4,031	8,977	13,617	3,483	14,775	1,879	3,784	8,939	13,482
Nebraska	10,232	35,230	3,558	5,170	12,019	12,424	10,232	34,722	3,275	4,837	11,984	12,423
Nevada	4,495	12,907	3,665	4,352	4,878	10,036	4,495	12,268	3,357	4,059	4,879	10,034
New Hampshire	6,665	4,823	2,178	2,340	1,869	1,318	6,665	4,462	2,011	2,179	1,907	1,318
New Jersey	48,279	38,657	12,516	8,757	5,515	10,146	48,279	36,393	11,554	8,117	5,512	10,013
New Mexico	32,660	16,905	4,803	9,739	6,884	38,803	32,660	16,471	4,426	9,137	6,890	38,754
New York	72,615	58,907	23,984	20,034	3,525	32,226	72,615	54,733	22,124	18,381	3,439	32,225
North Carolina	19,534	32,398	20,789	21,994	27,178	31,413	19,534	29,858	19,236	20,424	28,195	31,412
North Dakota	1,830	19,917	1,424	2,277	13,821	10,683	1,830	19,734	1,314	2,134	13,790	10,643
Ohio	41,407	59,729	18,860	29,664	41,973	55,665	41,407	55,607	17,403	27,721	41,979	55,405
Oklahoma	89,578	19,527	8,892	12,349	19,202	56,692	89,578	18,636	8,201	11,548	19,630	56,392
Oregon	7,092	21,391	6,293	9,533	2,299	12,741	7,092	20,092	5,815	8,883	2,267	12,739
Pennsylvania	54,272	45,856	18,015	25,461	39,305	63,221	54,272	42,391	16,202	23,688	39,312	62,929
Rhode Island	2,292	3,292	1,390	1,115	71	860	2,292	3,050	1,258	1,042	86	860

Table 6-2 (continued)
Annual NO_x emissions (ton y-1) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
South Carolina	11,895	17,751	9,396	13,227	14,478	25,695	11,895	16,500	8,676	12,315	15,088	25,694
South Dakota	5,152	10,124	1,615	2,592	1,624	6,641	5,152	9,929	1,489	2,433	1,625	6,641
Tennessee	16,449	30,114	13,126	18,958	18,184	41,802	16,449	28,195	12,143	17,725	18,112	41,772
Texas	326,864	149,076	39,823	77,644	88,324	205,281	326,864	142,947	36,755	73,250	88,199	203,836
Tribal Lands	0	0	0	0	16,101	13,368	0	0	0	0	16,127	13,368
Utah	18,855	11,755	5,695	5,904	13,876	24,668	18,855	11,183	5,265	5,483	13,910	24,622
Vermont	3,941	2,323	1,267	1,046	0	110	3,941	2,152	1,137	955	0	110
Virginia	18,754	32,040	16,797	16,894	7,252	42,181	18,754	29,785	15,538	15,755	7,763	42,155
Washington	8,677	38,068	9,506	14,500	5,510	22,243	8,677	35,970	8,772	13,468	5,408	21,922
West Virginia	5,957	14,703	3,961	5,319	31,615	34,028	5,957	14,066	3,658	4,937	31,622	33,958
Wisconsin	30,734	35,956	11,288	10,221	15,090	36,457	30,734	34,080	10,422	9,508	15,102	36,442
Wyoming	23,405	13,277	1,796	3,740	22,231	58,915	23,405	13,169	1,655	3,514	22,253	58,866

Table 6-3
Annual SO_2 emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Alabama	819	189	98	72	19,772	53,392	819	179	82	67	19,636	53,347
Arizona	3,367	415	101	108	9,991	34,949	3,367	398	85	101	9,992	34,949
Arkansas	1,345	108	51	37	14,378	11,113	1,345	102	42	34	14,489	11,112
California	6,692	2,462	1,195	611	137	16,006	6,692	2,304	1,004	573	125	15,809
Colorado	749	513	95	42	20,128	3,817	749	489	79	39	20,050	3,789
Connecticut	12,070	109	52	37	725	409	12,070	101	44	35	731	409
Delaware	670	48	15	9	1,761	2,443	670	46	13	9	1,764	2,353
District of Columbia	790	3	7	3	0	43	790	3	6	3	0	43
Florida	716	1,764	358	238	26,911	26,762	716	1,706	300	222	27,331	26,762
Georgia	753	1,123	171	128	31,221	42,281	753	1,082	144	121	30,938	42,281
Idaho	8,525	73	28	10	0	4,072	8,525	69	24	8	0	4,072
Illinois	7,088	1,280	176	136	39,902	63,197	7,088	1,231	147	127	39,916	61,275
Indiana	15,530	269	114	95	45,635	63,566	15,530	253	95	88	45,636	63,513
Iowa	3,269	122	45	41	19,967	15,743	3,269	115	37	39	19,850	15,743
Kansas	7,751	82	44	33	17,483	5,651	7,751	77	36	31	17,432	5,604
Kentucky	929	345	70	65	35,003	19,625	929	331	58	61	34,711	19,608
Louisiana	2,799	799	77	57	13,945	100,161	2,799	781	64	53	13,942	99,056
Maine	826	77	23	17	6	3,600	826	73	19	16	7	3,600
Maryland	4,826	332	95	54	11,013	27,027	4,826	317	79	51	11,028	27,027
Massachusetts	1,959	347	91	57	972	4,715	1,959	330	76	53	980	4,715

Table 6-3 (continued)
Annual SO_2 emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Michigan	13,934	584	162	132	22,508	32,266	13,934	556	136	123	22,520	32,259
Minnesota	8,982	524	91	67	15,092	14,427	8,982	505	75	63	15,050	14,414
Mississippi	399	139	69	60	5,131	12,807	399	133	57	56	5,085	12,757
Missouri	45,657	425	108	86	40,071	25,647	45,657	407	90	80	39,944	25,646
Montana	441	54	18	16	10,600	4,758	441	52	14	15	10,497	4,661
Nebraska	814	111	27	30	13,790	1,609	814	107	22	28	13,712	1,609
Nevada	4,596	448	44	12	4,939	1,472	4,596	432	36	11	4,887	1,469
New Hampshire	6,007	47	21	15	1,258	1,385	6,007	44	17	14	1,267	1,385
New Jersey	1,444	613	127	49	5,018	1,685	1,444	589	106	45	5,026	1,666
New Mexico	284	89	42	39	5,006	11,003	284	85	35	37	5,011	10,966
New York	16,870	1,272	234	75	3,968	13,029	16,870	1,223	197	69	4,005	13,029
North Carolina	12,068	616	175	123	25,600	17,004	12,068	584	147	114	26,932	17,004
North Dakota	684	65	10	10	14,910	5,097	684	63	8	10	14,839	5,096
Ohio	13,006	538	179	128	44,383	44,653	13,006	507	149	120	44,394	43,967
Oklahoma	5,042	114	77	63	18,784	19,766	5,042	108	64	59	18,872	18,895
Oregon	1,167	252	62	35	2,122	4,021	1,167	239	52	33	2,119	4,021
Pennsylvania	72,318	660	183	119	40,074	23,485	72,318	627	151	111	40,112	23,066
Rhode Island	2,696	56	15	3	1	806	2,696	53	12	3	1	806

Table 6-3 (continued)
Annual SO_2 emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
South Carolina	1,209	144	81	64	13,420	14,943	1,209	134	67	59	13,943	14,943
South Dakota	578	41	12	13	1,676	1,702	578	40	9	12	1,673	1,702
Tennessee	4,798	529	106	111	19,590	13,838	4,798	508	88	104	19,457	13,833
Texas	1,425	2,384	391	390	91,117	94,290	1,425	2,308	325	369	90,187	93,005
Tribal Lands	0	0	0	0	15,500	46	0	0	0	0	15,500	46
Utah	1,701	202	51	30	12,021	6,955	1,701	192	43	28	12,026	6,866
Vermont	1,837	22	12	5	0	149	1,837	21	10	5	0	149
Virginia	13,142	558	136	75	6,300	21,157	13,142	534	114	70	6,477	21,157
Washington	1,632	551	102	78	3,137	10,059	1,632	530	85	72	3,101	10,028
West Virginia	4,818	100	31	24	37,585	17,602	4,818	96	26	22	37,578	16,870
Wisconsin	6,557	287	92	53	16,056	6,829	6,557	272	77	49	16,060	6,812
Wyoming	2,079	33	16	15	24,128	17,585	2,079	32	13	14	24,042	17,474

Table 6-4
Annual VOC emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Alabama	62,946	24,887	10,934	1,705	533	29,671	61,390	19,465	10,378	1,596	536	29,550
Arizona	92,280	28,599	13,569	1,766	278	2,308	90,527	21,278	12,867	1,651	277	2,242
Arkansas	71,318	17,812	7,306	1,256	323	27,180	68,863	14,130	6,906	1,179	328	26,933
California	293,678	183,481	51,603	12,412	186	37,298	291,014	156,266	48,914	11,803	171	36,487
Colorado	107,389	31,357	10,554	1,011	458	45,022	106,850	24,543	9,996	944	462	44,333
Connecticut	30,706	14,695	6,020	805	43	938	30,209	11,117	5,720	753	46	905
Delaware	8,761	3,607	1,634	254	47	2,717	8,616	2,671	1,553	237	47	2,548
District of Columbia	5,340	894	756	50	0	70	5,319	692	719	47	0	70
Florida	208,250	95,796	43,680	4,055	685	27,151	196,948	75,052	41,335	3,782	707	26,896
Georgia	170,340	39,281	18,660	2,798	682	28,194	164,061	29,293	17,859	2,616	678	28,081
Idaho	83,787	18,481	3,174	772	0	1,032	83,589	16,230	3,023	717	0	1,013
Illinois	185,811	63,489	21,947	3,692	864	45,748	184,202	52,194	20,892	3,451	865	45,360
Indiana	149,109	34,610	13,943	2,949	956	39,696	146,822	27,559	13,216	2,771	956	39,490
Iowa	59,940	26,754	6,110	814	373	25,054	58,324	23,662	5,788	761	372	24,905
Kansas	74,756	13,290	5,670	717	349	18,086	72,179	10,520	5,380	670	350	17,832
Kentucky	53,520	18,948	8,965	1,664	747	39,574	51,388	14,871	8,490	1,563	743	39,432
Louisiana	131,560	26,649	9,109	1,549	360	65,681	127,276	22,103	8,635	1,454	379	65,253
Maine	25,299	26,862	3,076	373	10	3,750	25,122	25,125	2,930	347	11	3,720
Maryland	57,851	25,268	10,802	1,096	242	2,442	57,138	18,637	10,243	1,022	243	2,394
Massachusetts	91,942	28,272	8,636	1,216	59	3,553	90,829	22,067	8,218	1,135	62	3,512

Table 6-4 (continued)
Annual VOC emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Michigan	169,897	116,797	22,926	2,820	474	27,704	167,361	106,582	21,666	2,628	476	27,609
Minnesota	101,799	76,428	12,716	1,628	304	23,328	100,318	70,752	12,062	1,517	306	23,148
Mississippi	51,839	16,625	7,033	1,242	172	32,526	49,077	13,439	6,660	1,164	173	32,392
Missouri	114,234	32,953	15,136	2,438	768	15,704	110,564	25,729	14,329	2,284	769	15,650
Montana	15,355	9,941	2,053	357	197	3,826	15,005	8,719	1,942	335	196	3,699
Nebraska	36,438	10,366	3,731	523	263	5,909	35,373	8,532	3,533	487	263	5,875
Nevada	40,529	12,801	6,432	480	114	2,019	40,252	8,997	6,015	450	115	1,991
New Hampshire	23,326	15,464	2,294	236	46	563	23,274	13,816	2,180	220	48	563
New Jersey	104,809	35,800	13,089	1,055	136	9,097	102,604	27,438	12,436	982	135	8,850
New Mexico	50,117	8,165	5,937	920	154	11,435	48,557	6,403	5,605	864	154	11,353
New York	221,431	90,911	22,639	2,838	113	5,687	218,074	76,485	21,581	2,640	108	5,612
North Carolina	156,768	41,055	21,364	2,394	706	36,064	155,198	30,467	20,267	2,233	708	35,930
North Dakota	18,530	9,454	1,571	215	303	3,404	18,305	8,789	1,489	201	302	3,384
Ohio	160,437	60,173	20,066	3,150	1,010	29,454	158,501	46,327	19,050	2,949	1,009	29,370
Oklahoma	240,380	16,818	10,185	1,286	488	22,904	238,110	12,944	9,639	1,204	507	22,652
Oregon	55,818	24,595	6,621	1,059	61	8,586	54,736	19,670	6,292	991	60	8,572
Pennsylvania	189,164	59,749	37,225	2,699	893	28,716	186,130	46,794	34,310	2,523	893	28,468
Rhode Island	9,516	3,410	2,438	123	4	1,116	9,330	2,647	2,258	115	5	1,105
South Carolina	84,574	20,413	10,272	1,494	360	24,363	80,773	15,560	9,727	1,396	381	24,352
South Dakota	24,940	8,037	1,768	234	36	5,676	24,454	7,214	1,674	219	36	5,652

Table 6-4 (continued)
Annual VOC emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Tennessee	94,828	27,027	14,179	2,001	402	35,283	93,651	20,712	13,459	1,868	402	35,217
Texas	1,655,932	83,759	37,446	6,597	2,181	108,085	1,645,169	63,980	35,793	6,217	2,198	106,825
Tribal Lands	0	0	0	0	353	2,897	0	0	0	0	353	2,897
Utah	112,019	17,920	6,260	637	304	7,777	111,349	15,144	5,929	594	305	7,488
Vermont	11,582	9,329	1,485	146	0	507	11,540	8,554	1,381	135	0	507
Virginia	118,823	33,858	17,263	1,806	191	27,562	115,619	24,873	16,402	1,690	226	27,324
Washington	87,673	38,362	10,311	1,735	125	12,017	86,538	31,084	9,785	1,616	122	11,831
West Virginia	21,670	10,674	4,350	568	696	10,696	20,825	8,066	4,121	531	696	10,667
Wisconsin	118,877	84,104	12,987	1,121	335	27,490	117,800	78,032	12,289	1,045	335	27,392
Wyoming	51,319	8,239	1,953	334	487	20,351	50,875	7,516	1,848	314	487	20,255

Table 6-5
Annual primary PM_{10} emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Alabama	65,483	1,749	2,200	867	3,250	22,746	65,483	1,459	2,040	847	3,234	22,734
Arizona	170,913	2,183	2,485	1,363	1,954	7,688	170,913	1,719	2,295	1,331	1,958	7,688
Arkansas	115,125	1,285	1,220	472	2,164	8,398	115,125	1,118	1,125	461	2,186	8,393
California	416,958	15,443	19,637	9,014	28	31,179	416,958	14,997	18,714	8,783	25	31,075
Colorado	125,720	2,060	2,490	504	3,283	18,293	125,720	1,619	2,269	492	3,287	18,246
Connecticut	9,721	893	1,611	501	169	196	9,721	650	1,483	490	170	196
Delaware	3,562	349	437	146	312	828	3,562	282	405	142	312	818
District of Columbia	1,272	65	183	54	0	34	1,272	55	171	53	0	34
Florida	118,190	6,052	8,050	3,263	4,383	10,481	118,190	4,706	7,544	3,184	4,454	10,481
Georgia	128,049	2,900	4,049	1,707	5,075	8,060	128,049	2,254	3,773	1,671	5,037	8,060
Idaho	99,128	1,019	816	128	0	2,496	99,128	908	744	122	0	2,496
Illinois	291,344	4,512	5,711	1,981	6,492	18,360	291,344	3,763	5,235	1,935	6,498	18,214
Indiana	151,665	2,391	3,374	1,148	7,329	34,747	151,665	1,949	3,103	1,121	7,329	34,738
Iowa	195,268	1,737	1,434	474	2,893	10,068	195,268	1,565	1,309	462	2,884	10,066
Kansas	355,170	1,384	1,271	388	2,718	4,916	355,170	1,217	1,168	378	2,716	4,871
Kentucky	49,774	1,529	1,895	723	5,624	22,615	49,774	1,308	1,747	706	5,586	22,587
Louisiana	61,443	3,186	1,680	631	2,219	46,055	61,443	2,945	1,562	615	2,230	45,327
Maine	11,875	1,049	740	209	1	2,683	11,875	957	676	204	2	2,683
Maryland	21,445	1,761	2,586	700	1,854	3,860	21,445	1,305	2,392	684	1,856	3,860
Massachusetts	38,512	1,739	2,869	733	235	1,313	38,512	1,329	2,642	714	237	1,312

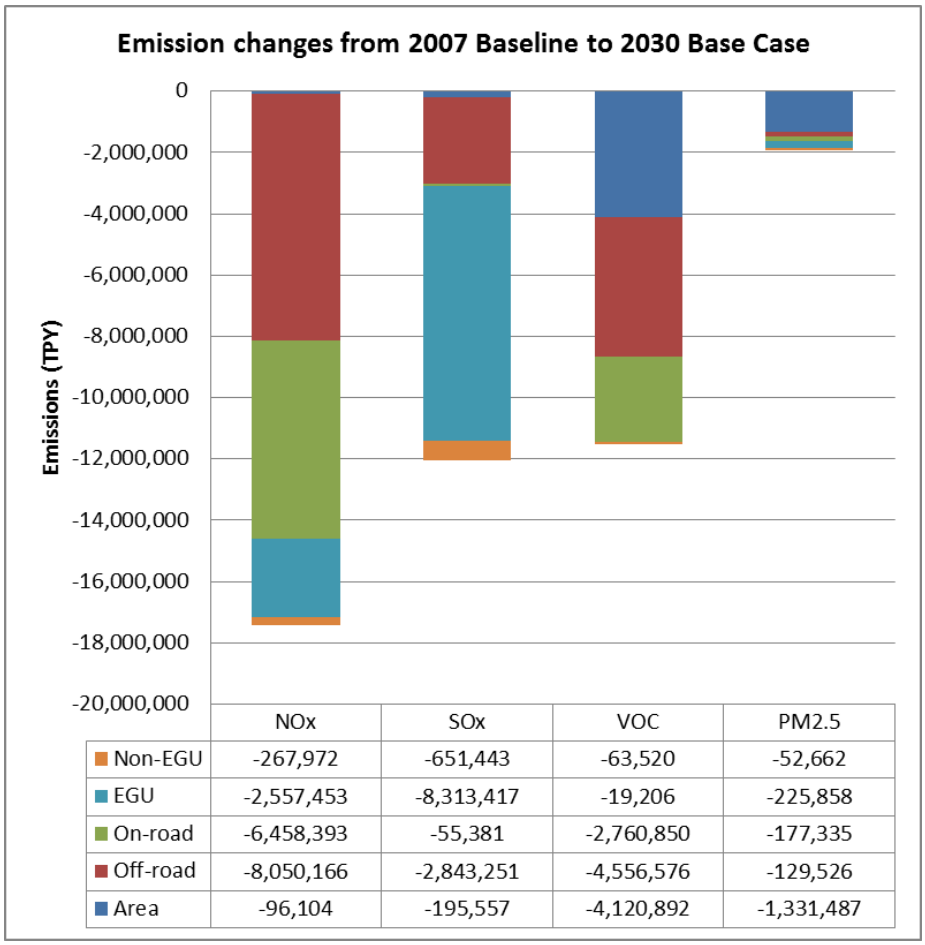
Table 6-5 (continued)
Annual primary PM_{10} emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Michigan	118,772	4,675	5,378	1,891	3,509	19,694	118,772	4,096	4,940	1,846	3,512	19,684
Minnesota	214,645	3,318	3,428	946	2,305	20,083	214,645	2,995	3,110	923	2,304	20,024
Mississippi	74,267	1,213	1,427	600	849	7,119	74,267	1,070	1,323	586	843	7,090
Missouri	219,051	2,522	3,028	1,152	5,894	7,745	219,051	2,094	2,778	1,125	5,890	7,743
Montana	125,194	781	483	164	1,539	4,853	125,194	729	437	160	1,532	4,823
Nebraska	211,531	1,299	888	374	2,060	4,539	211,531	1,199	811	365	2,054	4,538
Nevada	176,475	977	934	152	801	4,330	176,475	735	857	148	796	4,330
New Hampshire	7,603	612	660	169	294	3,037	7,603	516	605	164	296	3,037
New Jersey	17,259	2,596	3,755	715	876	2,565	17,259	2,022	3,468	697	877	2,524
New Mexico	452,575	742	1,069	418	1,164	2,271	452,575	645	979	408	1,167	2,262
New York	75,711	4,640	7,141	1,052	475	3,634	75,711	3,768	6,584	1,023	472	3,634
North Carolina	65,695	2,726	4,351	1,563	4,540	8,708	65,695	2,062	4,044	1,523	4,732	8,708
North Dakota	155,620	1,010	381	116	2,370	3,069	155,620	979	346	113	2,365	3,048
Ohio	124,669	4,096	5,248	1,505	7,013	22,330	124,669	3,226	4,838	1,467	7,020	22,227
Oklahoma	293,539	1,240	1,955	742	3,064	7,424	293,539	1,013	1,806	724	3,089	7,299
Oregon	70,966	1,642	1,550	475	338	9,788	70,966	1,354	1,411	464	337	9,788
Pennsylvania	54,331	3,794	5,381	1,390	6,611	18,073	54,331	3,007	4,883	1,357	6,616	17,990
Rhode Island	3,452	223	459	52	1	128	3,452	172	419	51	1	128
South Carolina	60,506	1,378	1,826	840	2,424	5,745	60,506	1,078	1,698	820	2,522	5,745
South Dakota	100,253	648	421	135	278	5,639	100,253	609	382	132	279	5,639

Table 6-5 (continued)
Annual primary PM_{10} emissions (ton y^{-1}) by state and source category

	2030noElec						2030Elec					
State	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**	**Area**	**Non-road**	**LD On-road**	**HD On-road**	**EGU**	**Non-EGU**
Tennessee	53,110	1,871	2,827	1,162	3,111	11,506	53,110	1,501	2,616	1,133	3,095	11,490
Texas	978,210	8,457	9,322	4,777	13,951	32,812	978,210	7,161	8,674	4,684	13,826	32,454
Tribal Lands	0	0	0	0	2,761	2,773	0	0	0	0	2,766	2,773
Utah	98,373	845	1,358	366	2,380	7,008	98,373	708	1,238	357	2,384	6,970
Vermont	11,322	357	348	54	0	137	11,322	316	316	53	0	137
Virginia	43,030	2,719	3,652	949	1,177	7,305	43,030	2,111	3,384	927	1,240	7,303
Washington	94,075	2,731	2,518	1,080	924	4,295	94,075	2,277	2,295	1,056	908	4,275
West Virginia	14,305	801	827	231	5,410	5,690	14,305	683	760	225	5,409	5,660
Wisconsin	97,917	3,271	3,147	636	2,578	7,139	97,917	2,915	2,864	621	2,578	7,126
Wyoming	233,534	539	442	147	3,812	27,703	233,534	508	399	144	3,815	27,652

Figure 6-1 illustrates the change of emissions from 2007 Baseline to 2030 Base Case. Table 6-6 and Table 6-7 provide an overall summary of the 2030 Base Case and Electrification Case emissions results, respectively, by source category; Figure 6-2illustrates the impact of electrification technology on net emissions of individual species across source categories. Because the C3 marine emissions at port and in the maritime regions were processed together, they are reported as model domain totals.



	NOx	SOx	VOC	PM2.5
Non-EGU	-267,972	-651,443	-63,520	-52,662
EGU	-2,557,453	-8,313,417	-19,206	-225,858
On-road	-6,458,393	-55,381	-2,760,850	-177,335
Off-road	-8,050,166	-2,843,251	-4,556,576	-129,526
Area	-96,104	-195,557	-4,120,892	-1,331,487

Figure 6-1
Emission changes from 2007 Baseline to 2030 Base Case within the continental United States (CONUS)

Table 6-6
Year 2030 Base Case emissions summary by source category

Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Area	**4,671,589**	**3,964,259**	**1,354,131**	**6,676,775**	**1,549,281**	**327,660**	**6,107,222**
Non-point	4,671,589	157,773	1,354,131	823,274	723,977	327,660	5,525,032
Refueling	0	0	0	0	0	0	56,671
Upstream/ Downstream	0	0	0	0	0	0	525,519
Agriculture NH_3	0	3,806,485	0	0	0	0	0
Fugitive Dust	0	0	0	5,853,502	825,303	0	0
Non-road	**15,967,830**	**5,945**	**1,613,866**	**114,977**	**102,936**	**21,918**	**1,532,757**
Non-road	14,923,394	3,244	759,617	80,903	73,266	3,115	1,443,006
Locomotive	199,228	851	437,891	8,924	8,671	465	17,905
Marine	139,315	701	299,004	10,006	9,705	3,471	6,696
Aircraft	705,893	1,149	117,354	15,145	11,294	14,866	65,150
On-road	**16,099,254**	**86,395**	**1,241,130**	**187,799**	**74,008**	**9,352**	**670,968**
LD On-road	13,998,603	74,244	509,967	138,940	50,806	5,576	587,879
HD On-road	2,100,651	12,151	731,163	48,859	23,202	3,776	83,089
EGU	**213,028**	**11,174**	**799,931**	**132,495**	**103,726**	**822,734**	**18,865**
Non-EGU	**2,152,239**	**63,142**	**1,811,665**	**522,160**	**358,423**	**938,648**	**995,909**
Other points	2,114,090	60,932	1,750,611	502,935	341,428	868,218	935,901
Upstream/ Downstream point	38,149	2,209	61,054	19,225	16,995	70,430	60,009
Average-fire	15,985,896	262,375	219,624	1,627,567	1,379,294	120,592	2,200,458

Table 6-6 (continued)
Year 2030 Base Case emissions summary by source category

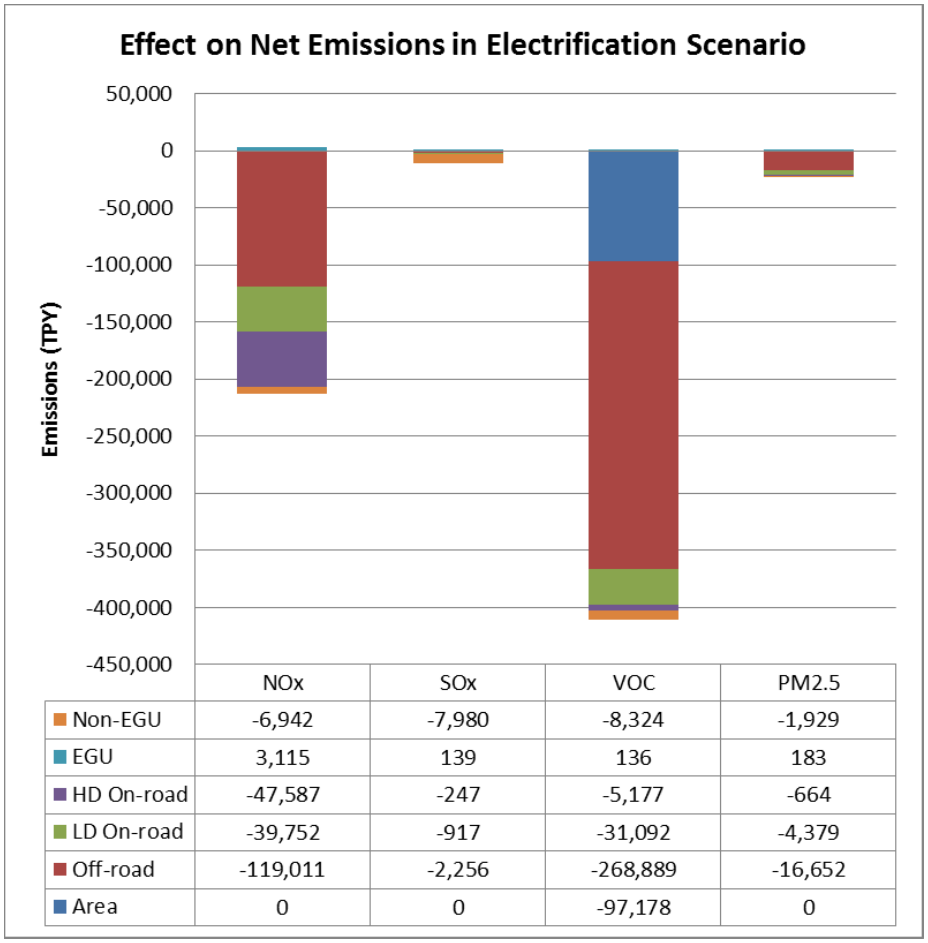
Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
CONUS Total	**55,089,837**	**4,393,289**	**7,040,346**	**9,261,774**	**3,567,667**	**2,240,904**	**11,526,178**
C3marine	116,988		930,620	18,044	16,553	59,421	49,846
Off-shore (othpt)	82,146		74,285	780	769	1,021	60,823
Canada	6,709,566	419,805	1,197,944	888,945	297,541	897,004	1,294,660
Mexico	1,063,871	113,782	816,360	250,833	183,247	1,086,368	729,397
Biogenic	3,988,857		700,350				48,212,483
Sea-salt				4,036,800	4,036,800		
Domain Total	**67,051,265**	**4,926,876**	**10,759,905**	**14,457,176**	**8,102,577**	**4,284,718**	**61,873,387**

Table 6-7
Year 2030 Electrification Case emissions summary by source category

Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Area	**4,671,589**	**3,964,259**	**1,354,131**	**6,676,775**	**1,549,281**	**327,660**	**6,010,047**
Non-point	4,671,589	157,773	1,354,131	823,274	723,977	327,660	5,525,032
Refueling	0	0	0	0	0	0	47,230
Upstream/ Downstream	0	0	0	0	0	0	437,785
Agriculture NH_3	0	3,806,485	0	0	0	0	0
Fugitive Dust	0	0	0	5,853,502	825,303	0	0
Non-road	**12,355,089**	**5,519**	**1,527,879**	**97,623**	**86,893**	**20,971**	**1,262,160**
Non-road	11,319,069	2,841	691,613	64,349	58,011	2,634	1,173,374
Locomotive	196,799	840	427,482	8,703	8,456	460	17,334
Marine	136,992	689	294,018	9,839	9,544	3,413	6,584
Aircraft	702,229	1,149	114,766	14,732	10,882	14,465	64,867

Table 6-7 (continued)
Year 2030 Electrification Case emissions summary by source category

On-road	**14,621,097**	**73,998**	**1,153,791**	**176,352**	**68,965**	**8,188**	**634,700**
LD On-road	12,743,678	62,933	470,216	128,659	46,427	4,659	556,787
HD On-road	1,877,420	11,065	683,576	47,693	22,538	3,528	77,912
EGU	**217,375**	**11,469**	**803,045**	**132,727**	**103,909**	**822,873**	**19,001**
Non-EGU	**2,147,855**	**62,891**	**1,804,722**	**519,978**	**356,494**	**930,668**	**987,585**
Other points	2,114,090	60,932	1,750,611	502,935	341,428	868,218	935,901
Upstream/ Downstream point	33,765	1,959	54,112	17,043	15,066	62,449	51,684
Average-fire	15,985,896	262,375	219,624	1,627,567	1,379,294	120,592	2,200,458
CONUS Total	**49,998,902**	**4,380,511**	**6,863,192**	**9,231,023**	**3,544,836**	**2,230,952**	**11,113,950**
C3marine	112,337	0	897,596	17,388	15,944	58,112	51,555
Off-shore (othpt)	82,146		74,285	780	769	1,021	60,823
Canada	6,709,566	419,805	1,197,944	888,945	297,541	897,004	1,294,660
Mexico	1,063,871	113,782	816,360	250,833	183,247	1,086,368	729,397
Biogenic	3,988,857		700,350				48,212,483
Sea-salt				4,036,800	4,036,800		
Domain Total	**61,955,678**	**4,914,098**	**10,549,727**	**14,425,769**	**8,079,137**	**4,273,457**	**61,462,867**



	NOx	SOx	VOC	PM2.5
Non-EGU	-6,942	-7,980	-8,324	-1,929
EGU	3,115	139	136	183
HD On-road	-47,587	-247	-5,177	-664
LD On-road	-39,752	-917	-31,092	-4,379
Off-road	-119,011	-2,256	-268,889	-16,652
Area	0	0	-97,178	0

Figure 6-2
Effect of electrification on net emissions within the continental United States (CONUS)

Section 7: Air Quality Modeling and Evaluation

Air quality modeling was conducted for the domain covering the continental United States (CONUS) with a 12-km grid resolution using 2007 emissions and meteorological input data. An operational model performance was then conducted for ozone, particulate matter (PM) and wet deposition. This section details the approach for setting up the CAMx annual 2007 baseline modeling and the model-performance evaluation.

2007 Baseline

The 2007 modeling platform is the starting point for future-year modeling to assess the impacts of electric transportation to air quality; therefore, it is important to evaluate the model performance for 2007. A national-scale air quality modeling analysis was performed with the CAMx air quality model for the year 2007 to estimate ozone and $PM_{2.5}$ concentrations. Most of the model inputs are from the EPA's 2007 PM NAAQS modeling database (EPA, 2012d); they include meteorology, initial and boundary conditions, and emissions (except for on-road and biogenic emissions). EPA conducted a 2007 annual run using the Community Multi-scale Air Quality (***CMAQ***) model to support the PM NAAQS final rule (EPA, 2012d). EPA found that the $PM_{2.5}$ concentrations and model-performance results for the 2007 CMAQ simulations are comparable to other recent model applications.

Model Configuration

Air quality modeling for the 12-km CONUS domain and calendar year 2007 used the CAMx model to simulate physical and chemical processes governing the formation and transport of ozone and PM (ENVIRON, 2013). CAMx is a 3-D photochemical transport and dispersion model that has an Eulerian (grid-based) formulation. The key processes treated by CAMx are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species. CAMx, Version 6.0 was chosen for this work because it was the most updated version at the time work was initiated. The model configuration is shown in Table 7-1. The CAMx model was run separately for each of the four quarters of 2007. Each quarter had a 10-day spin-up period to limit the influence of initial concentrations.

Table 7-1
Model configurations options for the CAMx model

Science Options	2007 Baseline
Version	Version 6.0
Vertical Grid Mesh	14 Layers
Horizontal Grids	12 km
Initial Conditions	10 days full spin-up
Boundary Conditions	2007 GEOS-CHEM day specific 3-hour average data
Sub-grid-scale Plumes	No PiG treatment
Chemistry	
Gas Phase Chemistry	CB05
Aerosol Chemistry	ISORROPIA equilibrium
Secondary Organic Aerosols	SOAP
Cloud Chemistry	RADM-type aqueous chemistry
Meteorological Processor	WRFCAMx v3.4
Horizontal Transport	
Eddy Diffusivity Scheme	K-theory with Kh grid size dependence
Source Apportionment	None
Vertical Transport	
Eddy Diffusivity Scheme	K-Theory
Vertical Diffusivity Corrections	Kv-patch depending on land-use category up to 100 m and to cloud tops
Planetary Boundary Layer	From MM5 with PBL below convective clouds raised to cloud top
Deposition Scheme	Zhang
Numerics	
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI) solver
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM scheme)
Parallelization	OMP-MPI

The CAMx modeling grid was the 12-km CONUS grid, as used in the EPA's PM NAAQS modeling. The grid is defined using a Lambert-Conformal map projection (Alpha = 33°, Beta = 45°, and Gamma = -97°, with a center of X = -97° and Y = 40°) with the southwest corner at (-2412 km, -1620 km). The domain covers the 48 contiguous states, along with southern portions of Canada and northern portions of Mexico (Figure 7-1), with 12-km grid resolution, and it has 396 by 246 grid cells and 14 vertical layers.

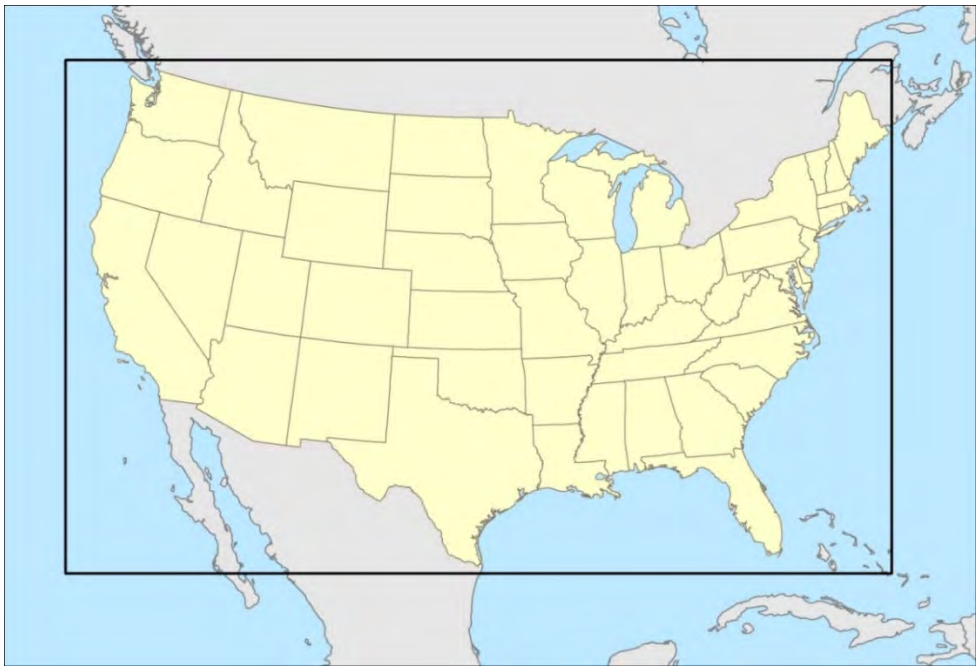


Figure 7-1
The CAMx 12-km modeling domain covering the 48 contiguous states, along with southern portions of Canada and northern portions of Mexico

The CAMx vertical layer structure is constrained by the vertical grid used in the WRF meteorological modeling (described below). The WRF model employs a terrain-following coordinate system defined by pressure, and it was configured with 34 layers extending from the surface to a pressure altitude of 100 mb.

Table 7-2 lists the layer mapping between WRF and CAMx. As is typical in large-scale model applications such as this, CAMx employed fewer layers aloft than WRF to improve the computational efficiency of the air quality simulations.

Table 7-2
Vertical layer definitions for WRF and for CAMx, showing layer-collapsing from WRF to CAMx

WRF					CAMx				
Layer	**Eta**	**Pressure (mb)**	**Height (m)**	**Depth (m)**	**Layer**	**Eta**	**Pressure (mb)**	**Height (m)**	**Depth (m)**
34	0.000	100.0	15726	2095					
33	**0.050**	**145.0**	**13630**	**1620**	**14**	**0.050**	**145.0**	**13630**	**4095**
32	0.100	190.0	12010	1334					
31	0.150	235.0	10676	1141					
30	**0.200**	**280.0**	**9536**	**1001**	**13**	**0.200**	**280.0**	**9536**	**3447**
29	0.250	325.0	8535	894					
28	0.300	370.0	7641	810					
27	0.350	415.0	6831	742					
26	**0.400**	**460.0**	**6089**	**685**	**12**	**0.400**	**460.0**	**6089**	**1919**
25	0.450	505.0	5404	637					
24	0.500	550.0	4766	596					
23	**0.550**	**595.0**	**4170**	**561**	**11**	**0.550**	**595.0**	**4170**	**1091**
22	0.600	640.0	3609	530					
21	**0.650**	**685.0**	**3079**	**502**	**10**	**0.650**	**685.0**	**3079**	**887**
20	0.700	730.0	2577	384					
19	**0.740**	**766.0**	**2192**	**279**	**9**	**0.740**	**766.0**	**2192**	**550**
18	0.770	793.0	1914	271					
17	**0.800**	**820.0**	**1643**	**177**	**8**	**0.800**	**820.0**	**1643**	**521**
16	0.820	838.0	1466	174					
15	0.840	856.0	1292	171					
14	**0.860**	**874.0**	**1121**	**168**	**7**	**0.860**	**874.0**	**1121**	**415**

Table 7-2 (continued)
Vertical layer definitions for WRF and for CAMx, showing layer-collapsing from WRF to CAMx

WRF					CAMx				
Layer	**Eta**	**Pressure (mb)**	**Height (m)**	**Depth (m)**	**Layer**	**Eta**	**Pressure (mb)**	**Height (m)**	**Depth (m)**
13	0.880	892.0	954	165					
12	0.900	910.0	788	82					
11	**0.910**	**919.0**	**707**	**81**	**6**	**0.910**	**919.0**	**707**	**241**
10	0.920	928.0	626	80					
9	0.930	937.0	545	80					
8	**0.940**	**946.0**	**466**	**79**	**5**	**0.940**	**946.0**	**466**	**158**
7	0.950	955.0	387	78					
6	**0.960**	**964.0**	**308**	**78**	**4**	**0.960**	**964.0**	**308**	**155**
5	0.970	973.0	230	77					
4	**0.980**	**982.0**	**153**	**38**	**3**	**0.980**	**982.0**	**153**	**77**
3	0.985	986.5	114	38					
2	**0.990**	**991.0**	**76**	**38**	**2**	**0.990**	**991.0**	**76**	**38**
1	**0.995**	**995.5**	**38**	**38**	**1**	**0.995**	**995.5**	**38**	**38**
0	**1.000**	**1000.0**	**0**	**0**	**0**	**1.000**	**1000.0**	**0**	**0**

Modeling Inputs

Meteorological Data

The CAMx model requires inputs for three-dimensional gridded wind, temperature, humidity, cloud/precipitation, and vertical mixing. EPA applied the WRF meteorological model on 36-km and 12-km continental U.S. grids for the year 2007 and reported reasonably good performance (EPA, 2011b). This WRF dataset was used in the PM NAAQS modeling and is used in this study. WRFCAMx, Version 3.4 was used to format WRF data for CAMx and provide the complete set of meteorological data required by CAMx.

Emissions Inputs

On-road emissions for 2007 were developed using EPA's MOVES model. Emissions for other sources were from the PM NAAQS 2007 emissions inventory. The 2007 scenario utilizes hour-specific CEM data for EGUs and a typical-year scenario for wildfires (average fires). Emissions data are input to CAMx in 2-D, gridded format and CAMx point-source format. Details on emissions files are described in Section 6.

Boundary/ Initial Conditions and Model Initialization

Initial and boundary conditions define the air quality at the start of the CAMx simulation and the chemical composition of air transported into the model domain during the simulation via lateral boundaries. The boundary and initial conditions were obtained from a GEOS-CHEM[15] global model simulation performed for 2007, as in the EPA's PM NAAQS modeling.

The CAMx model was run separately for each quarter of 2007, using a 10-day spin-up period to limit the influence of the assumed initial concentrations.

Land Use

Several GIS and Perl-based processors were used to prepare land cover from the North America Land Cover (NALC) database (Latifovic et al., 2002) and Leaf Area Index (LAI) input datasets[16] for CAMx. The land-use inputs were developed for the Zhang deposition scheme in CAMx.

Photolysis Rates

The photolysis rates were generated for CB05 chemistry using the Tropospheric Ultraviolet and Visible (TUV) program. The TUV program generates a clear-sky

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[15] http://www-as.harvard.edu/chemistry/trop/geos/

[16] LAI databases are based on MODIS data and available from the updated databases for the Model of Emissions of Gases and Aerosols from Nature (MEGAN) biogenic emissions model, developed by NCAR [http://acd.ucar.edu/~guenther/MEGAN/MEGAN.htm]

photolysis lookup table according to the ozone-column inputs for various altitude, terrain height, albedo, and solar zenith angles. CAMx interpolates lookup photolysis rates to cell-specific values; then photolysis rates are adjusted for clouds and haze using the in-line TUV.

Model-Performance Evaluation Metrics and their goals

The CAMx evaluation conducted for the study focuses primarily on the operational model evaluation of the air quality model's performance with respect to ozone, fine particulate matter ($PM_{2.5}$), and wet deposition. To quantify model performance, several statistical measures were calculated and evaluated for all monitors and at individual monitors within the CONUS 12-km domain. The statistical measures selected were based on the recommendations in the EPA's Guidance (EPA, 2007). Table 7-3 lists the definitions of several statistical performance measures that are used in the model-performance evaluation in this study.

The EPA established model-performance goals for Ozone State Implementation Plan (SIP) modeling that bias should be within ±15% and error should be within 35% (EPA, 1991). The EPA 1991 ozone bias and error performance goals were designed for comparison with the Mean Normalized Bias (MNB) and Mean Normalized Gross Error (MNE), calculated using predicted and observed hourly ozone pairs. This study used an observed ozone-concentration cutoff threshold of 40 ppb to screen out predicted and observed hourly ozone pairs whose observed value is below the threshold.

The U.S. Regional Planning Organizations (RPOs) have established model-performance goals and criteria for $PM_{2.5}$, PM_{10}, and components of fine particle mass based on previous model performance for ozone and fine particles. The EPA's modeling guidance for fine particulate matter notes that PM models might not be able to achieve the same level of performance as ozone models. Consistent with the EPA's guidance, the bias/error performance goal set by the RPOs is relaxed to within ±30%/50%. Currently, there is no suggested performance benchmark for the wet deposition.

The use of model-performance goals and criteria set forth by other organizations in this study should not be viewed as endorsements thereof; these goals are used as guidance for the evaluation of the air quality modeling platform for the application of this research effort.

Table 7-4 summarizes EPA's ozone-performance goal and lists the model-performance goals and criteria developed by the RPOs, to assist in evaluating regional model performance for PM species.

Table 7-3
Statistical model-performance evaluation measure definitions

Statistical Measure	Short-hand Notation	Mathematical Expression	Units
Normalized Mean Bias	NMB	$\frac{\sum_{i=1}^{N}(P_i - O_i)}{\sum_{i=1}^{N} O_i}$	Percent
Normalized Mean Error	NME	$\frac{\sum_{i=1}^{N}\lvert P_i - O_i\rvert}{\sum_{i=1}^{N} O_i}$	Percent
Mean Normalized Bias	MNB	$\frac{1}{N}\sum_{i=1}^{N}\frac{(P_i - O_i)}{O_i}$	Percent
Mean Normalized Gross Error	MNE	$\frac{1}{N}\sum_{i=1}^{N}\frac{\lvert P_i - O_i\rvert}{O_i}$	Percent
Mean Fractionalized Bias (Fractional Bias)	MFB or FB	$\frac{2}{N}\sum_{i=1}^{N}\left(\frac{P_i - O_i}{P_i + O_i}\right)$	Percent
Mean Fractional Error (Fractional error)	MFE or FE	$\frac{2}{N}\sum_{i=1}^{N}\left\lvert\frac{P_i - O_i}{P_i + O_i}\right\rvert$	Percent

Table 7-4.
Model-performance goals and criteria

Fractional Bias	Fractional Error	Comment
≤±15%	≤35%	Goal for ozone model performance
≤±15%	≤35%	Goal for PM model performance based on ozone model performance, considered excellent performance[1]
≤±30%	≤50%	Goal for PM model performance, considered good performance.[2]
≤±60%	≤75%	Criteria for PM model performance, considered average performance. Exceeding this level of performance indicates fundamental concerns with the modeling system and triggers diagnostic evaluation.[2]

[1]The ozone performance goals were originally developed for hourly ozone (EPA, 1991), but they have also been shown to be useful for 8-hour ozone and 24-hour PM.

[2]The PM performance goals and criteria were developed for 24-hour PM concentrations.

Model-Performance Evaluation Results

The CAMx results were evaluated against observed ozone and $PM_{2.5}$ concentrations by computing statistical measures that were compared to goals and criteria. The statistics for the 12-km CONUS domain were calculated by quarter (for example, "Quarter 1" is from January to March). In addition, spatial plots showing bias and error in each quarter at individual monitoring sites are also presented. It should be noted when pairing model and observed data that each CAMx concentration represents a grid cell–averaged value, whereas the ambient measurements are made at specific locations.

Ozone Evaluation

Ozone ambient measurements for 2007 were obtained from the Clean Air Status and Trends Network (CASTNet). The model-performance bias and error statistics for each quarter are provided in Table 7-5. Spatial plots of the normalized mean bias and error by quarter for individual monitors are shown in Figure 7-2 and Figure 7-3, respectively.

A concentration threshold of 40 ppb was applied to the observed data to remove the influence of low concentrations such as nighttime values. The model predictions for ozone are slightly biased high in the third quarter (summer) but are generally biased low compared with observations in other quarters, as shown in Table 7-5. All error metrics, namely, MNE (11.7% to 14.7%), NME (12.0% to 14.4%), and FE (12.7% to 14.2%), achieve the EPA performance goal (≤±35%). All bias metrics, MNB (-8.7% to 3.6%), NMB (-9.2% to 2.1%) and FB (-9.9% to 1.9%), achieve the EPA performance goal (≤±15%). In summer

(Quarter 3), the model shows slight over-estimations of ozone in the eastern United States and under-estimations in the western United States (Figure 7-2).

Table 7-5
Ozone-performance statistics by quarter for the 2007 CAMx model simulation (threshold = 40 ppb)

Quarter	Bias Performance Metrics			Error Performance Metrics			N
	FB	NMB	MNB	FE	NME	MNE	
EPA Goal	<15%	<15%	<15%	<35%	<35%	<35%	
All quarters	-3.9	-3.2	-2.4	13.3	13.1	13.0	254512
Quarter 1	-9.9	-9.2	-8.7	12.8	12.0	11.7	44343
Quarter 2	-4.3	-4.2	-3.0	13.0	12.7	12.7	97045
Quarter 3	1.9	2.1	3.6	14.2	14.4	14.7	80407
Quarter 4	-8.5	-7.6	-7.3	12.7	12.1	11.9	32717

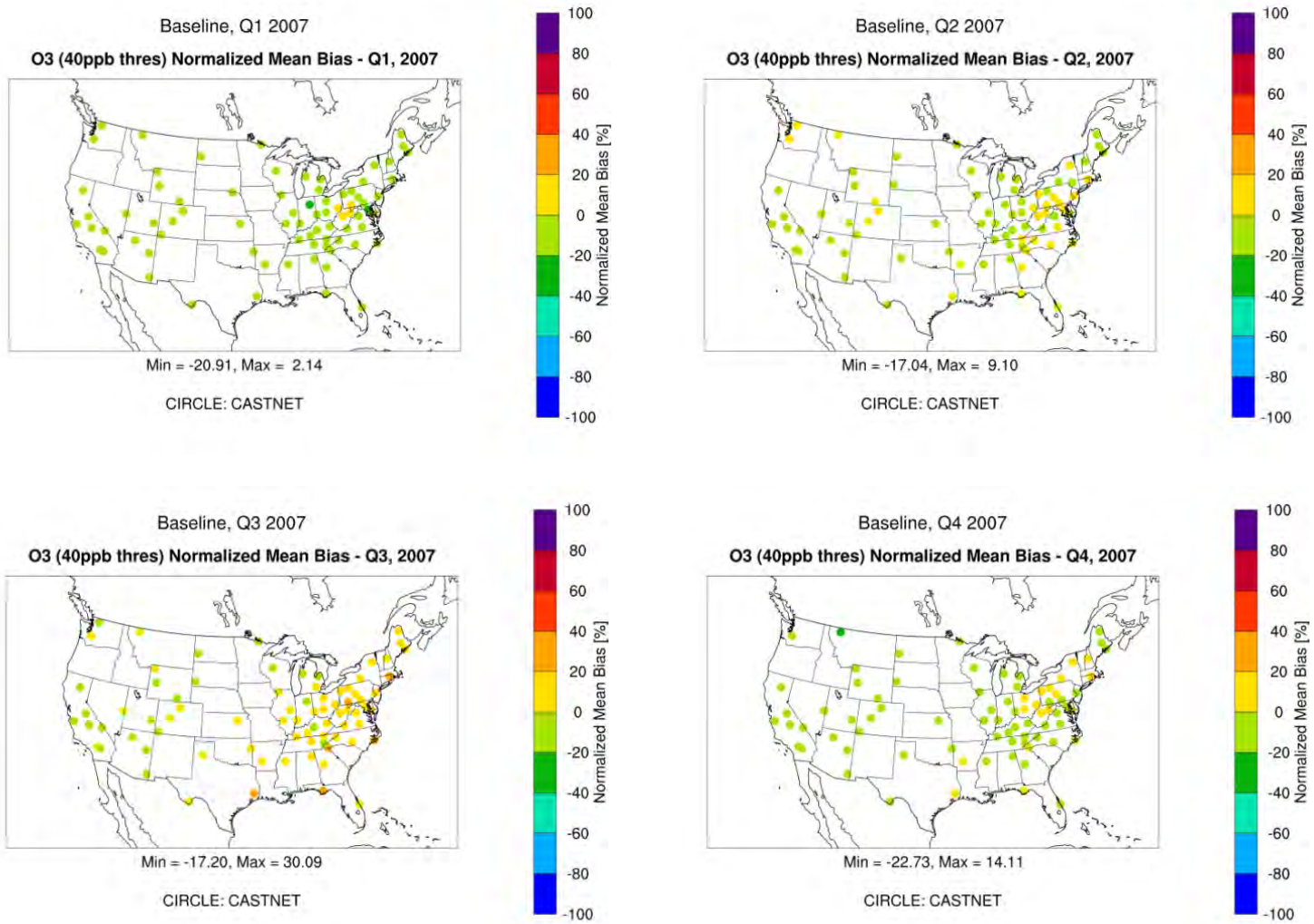

Figure 7-2
Normalized mean bias (%) for ozone above a 40-ppb threshold in the four quarters of 2007 at CASTNET monitoring sites

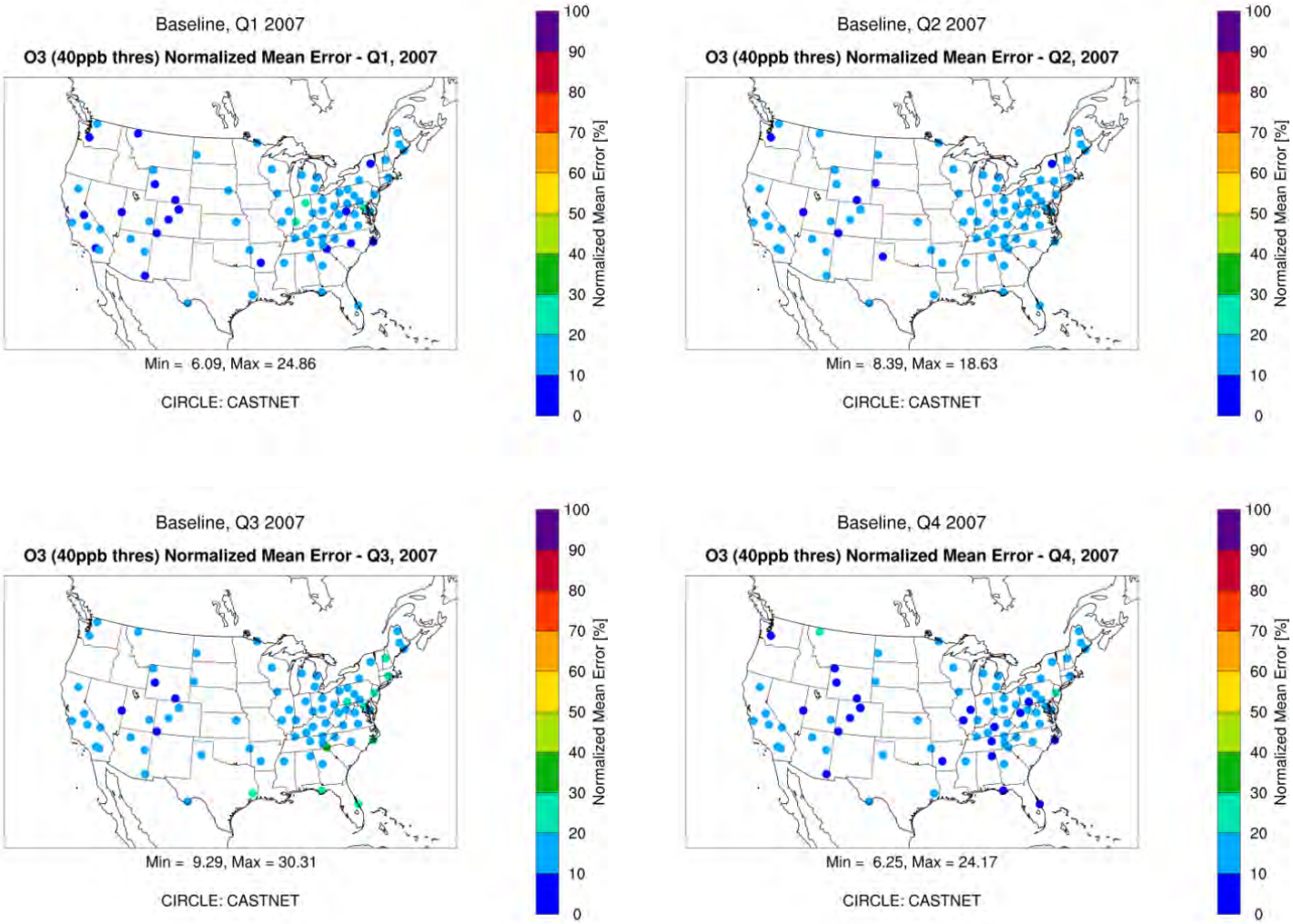

Figure 7-3
Normalized mean error (%) for ozone above a 40-ppb threshold in the four quarters of 2007 at CASTNET monitoring sites

$PM_{2.5}$ Evaluation

The model evaluation for $PM_{2.5}$ focuses on the key $PM_{2.5}$ components—including sulfate

(SO_4), nitrate (NO_3), ammonium (NH_4), elemental carbon (EC), and organic matter (OM). The $PM_{2.5}$ performance statistics were calculated for each quarter. $PM_{2.5}$ ambient measurements for 2007 were obtained from the following networks: Speciation Trend Networks (STN), Interagency Monitoring of PROtected Visual Environments (IMPROVE), and the Clean Air Status and Trends Network (CASTNet). The STN and IMPROVE networks provide 24-hour average concentrations every 3 days. The data at CASTNet sites are weekly averages.

As discussed in EPA's PM-modeling guidance, less abundant PM species should be given less stringent performance goals because mis-prediction has fewer consequences for small concentrations than for large concentrations. Accordingly, the resulting statistics are displayed using Bugle Plots, which show performance goals that are a continuous function of average observed concentrations, as described by Boylan and Russell (2006).

Sulfate Evaluation

Model-evaluation statistics for sulfate are displayed in Bugle Plots of quarterly fractional bias and error in order to compare model performance with the PM-performance goals and criteria. Overall, the model shows fair performance, with all quarterly biases and errors achieving the performance criteria in all cases and the performance goal in many cases (Figure 7-4 and Figure 7-5). The model under-predicts sulfate concentrations and exceeds the bias performance goal in the second and third quarters. Spatial plots of FB and FE by quarter for individual monitors are shown in Figure 7-6 and Figure 7-7, respectively. Under-predictions of sulfate are seen across the CONUS in the second and third quarters. The southwestern region has the poorest performance, which could be attributable partly to over-prediction of sulfate wet deposition, as described below.

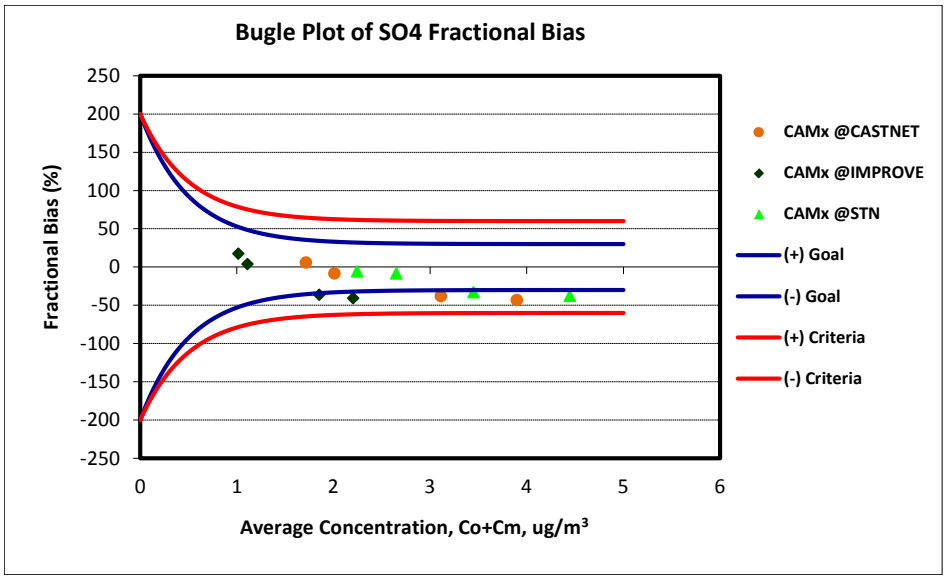

Figure 7-4
Bugle plot of sulfate fractional bias during 2007

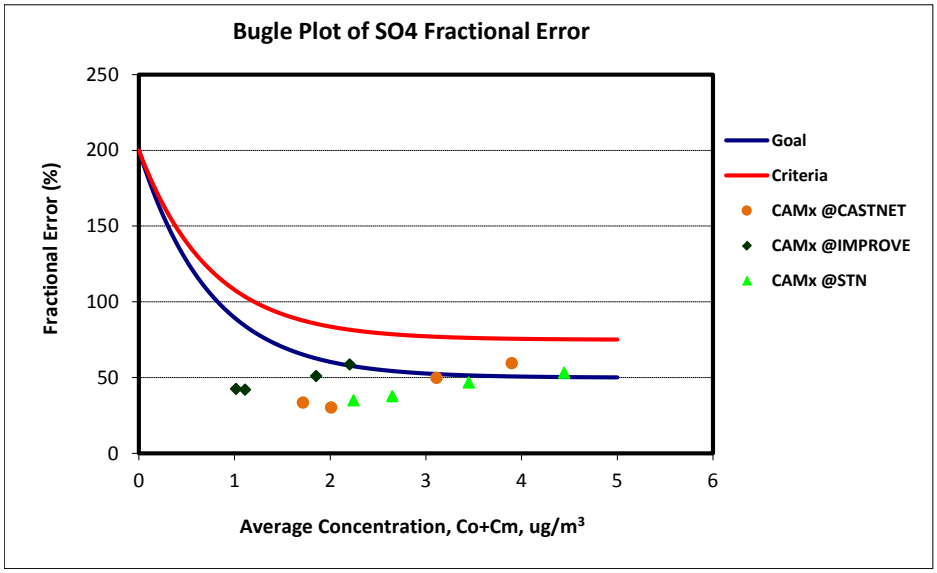

Figure 7-5
Bugle plot of sulfate fractional error during 2007

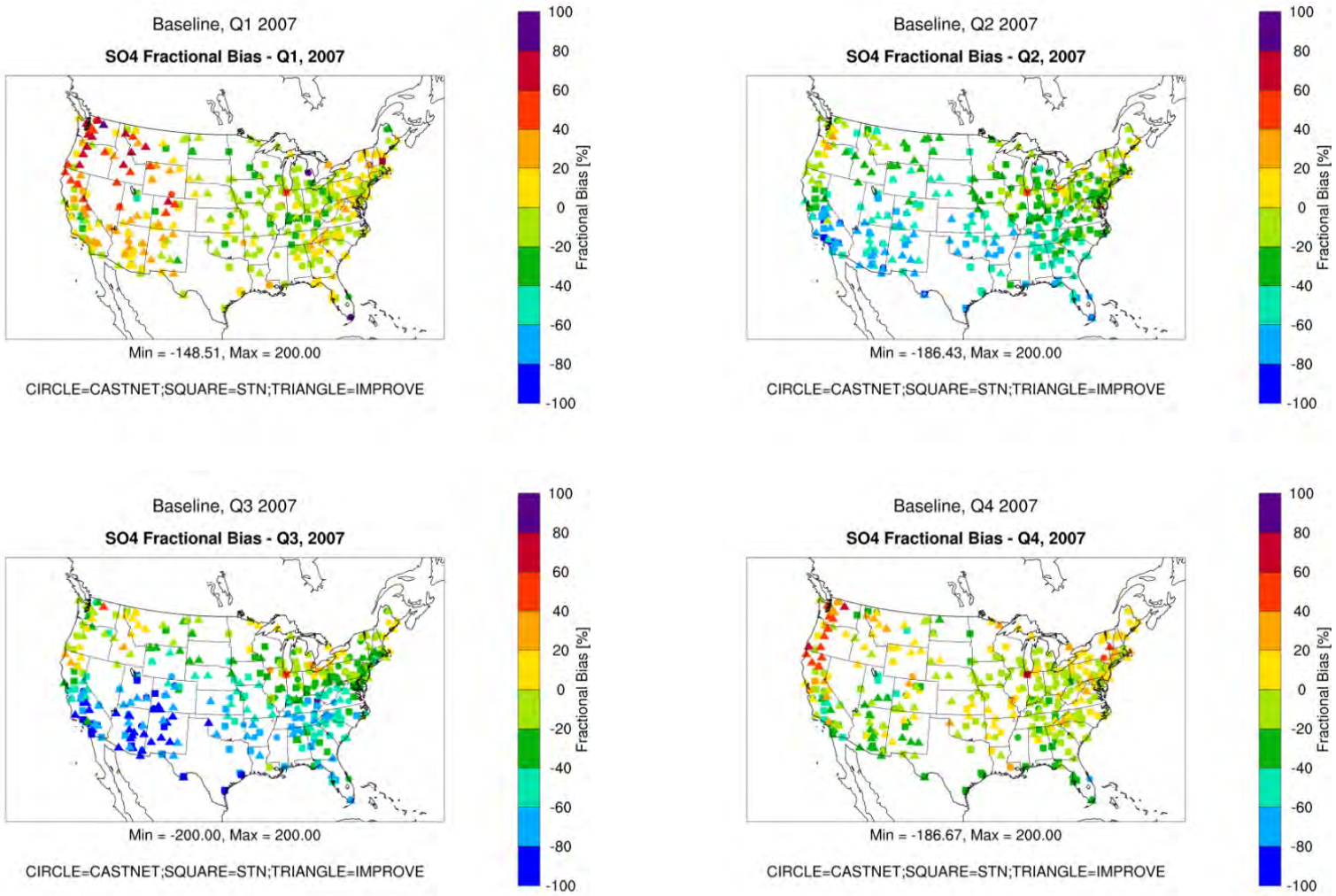

Figure 7-6
Fractional bias (%) for sulfate in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

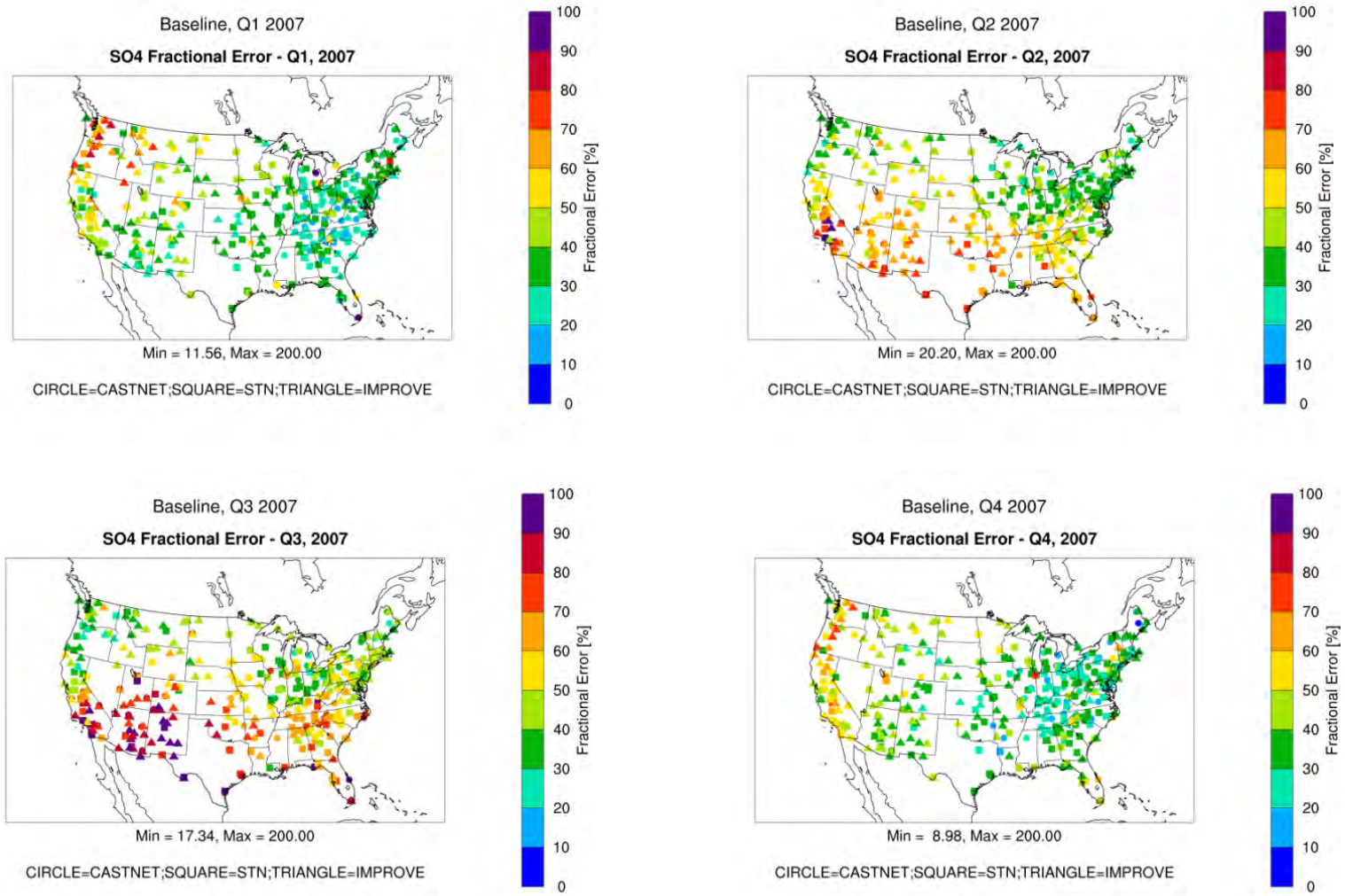

Figure 7-7
Fractional error (%) for sulfate in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

Nitrate Evaluation

Bugle Plots of quarterly fractional bias and error for nitrate are shown in Figure 7-8 and Figure 7-9. Spatial plots of FB and FE by quarter for individual monitors are shown in Figure 7-10 and Figure 7-11, respectively. The model shows fair performance, with all quarterly biases and errors achieving the performance criteria. Nitrate has less than 8% bias (FB) at STN and CASTNET monitors in the first and fourth quarters, when nitrate concentrations tend to be higher. Average concentrations of nitrate are generally higher in winter than in summer because nitrate (in the form of ammonium nitrate) is volatile. Despite the small bias in wintertime, the model performance of nitrate appears to have large unsystematic errors (Figure 7-11). The under-prediction biases and errors are larger at IMPROVE monitors than at STN and CASTNET monitors in all quarters. The EPA reported that nitrate predictions from the PM NAAQS modeling are generally biased high in the east and biased low in the west (EPA, 2012d). This study finds over-predictions in the east in the fourth quarter and, to a lesser extent, the first quarter; the nitrate performance in the west is mixed.

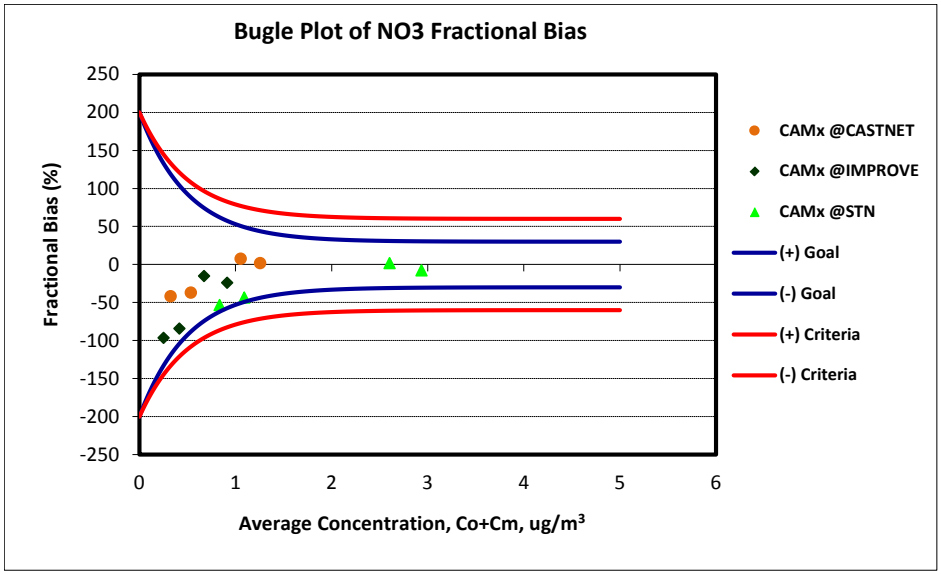

Figure 7-8
Bugle plot of nitrate fractional bias during 2007

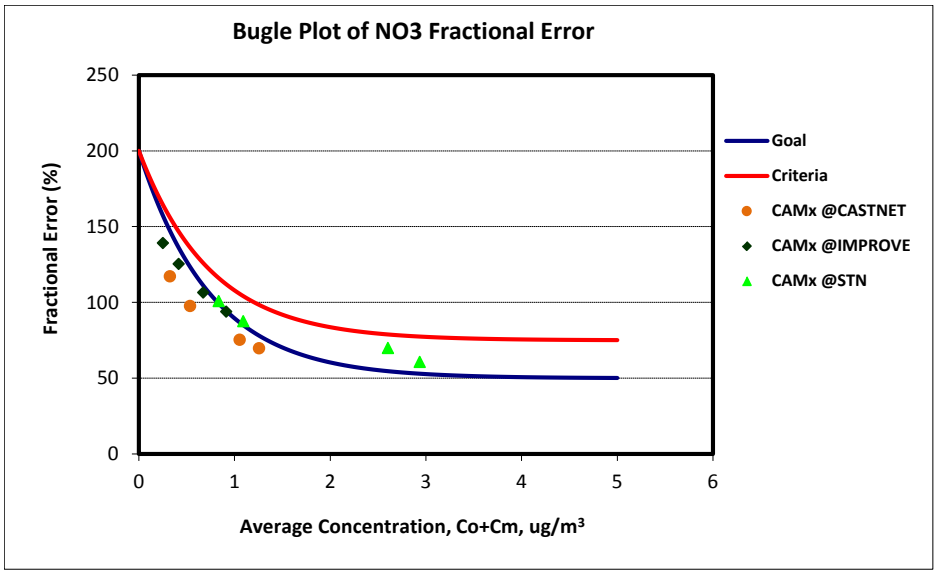

Figure 7-9
Bugle plot of nitrate fractional error during 2007

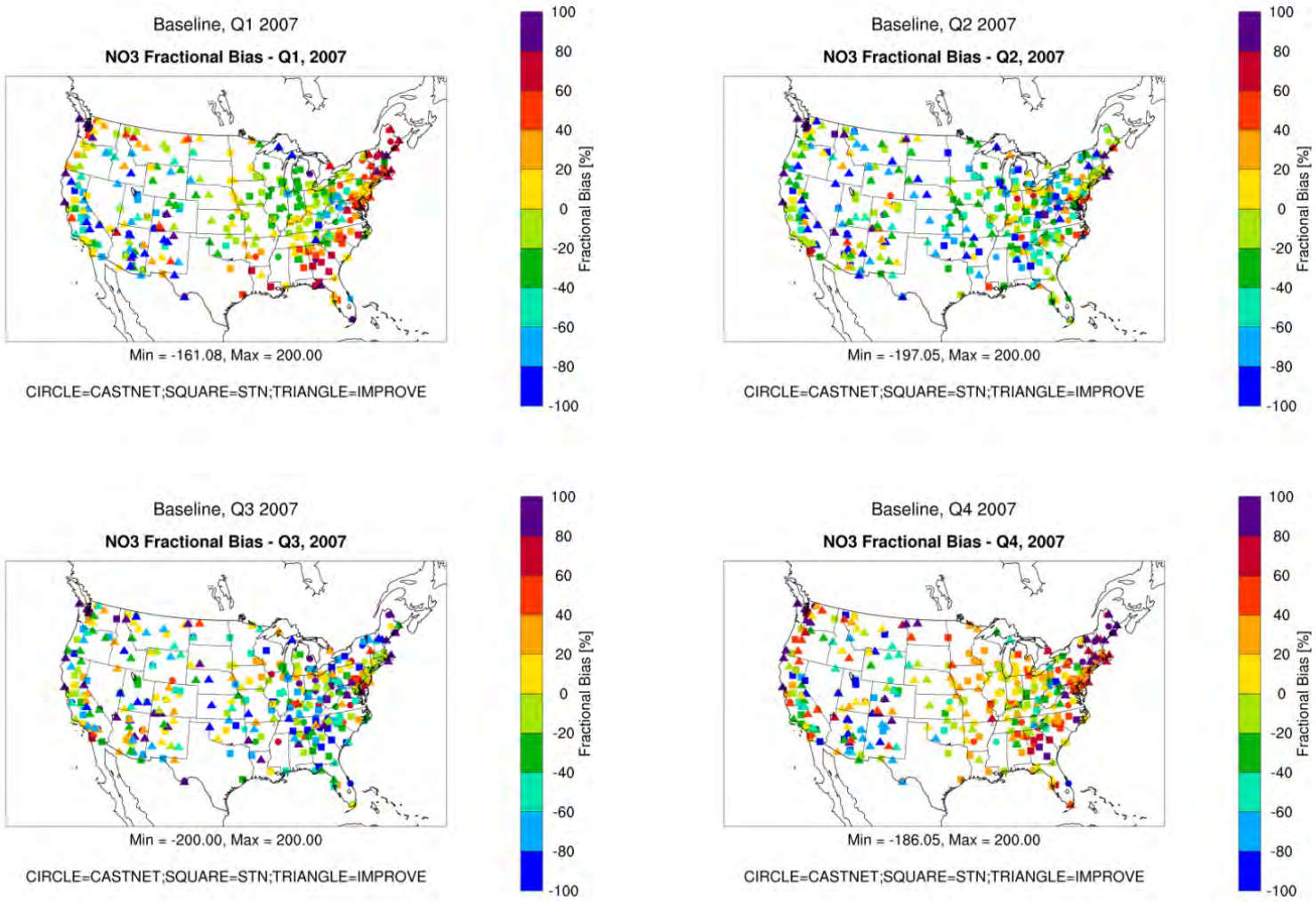

Figure 7-10
Fractional bias (%) for nitrate in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

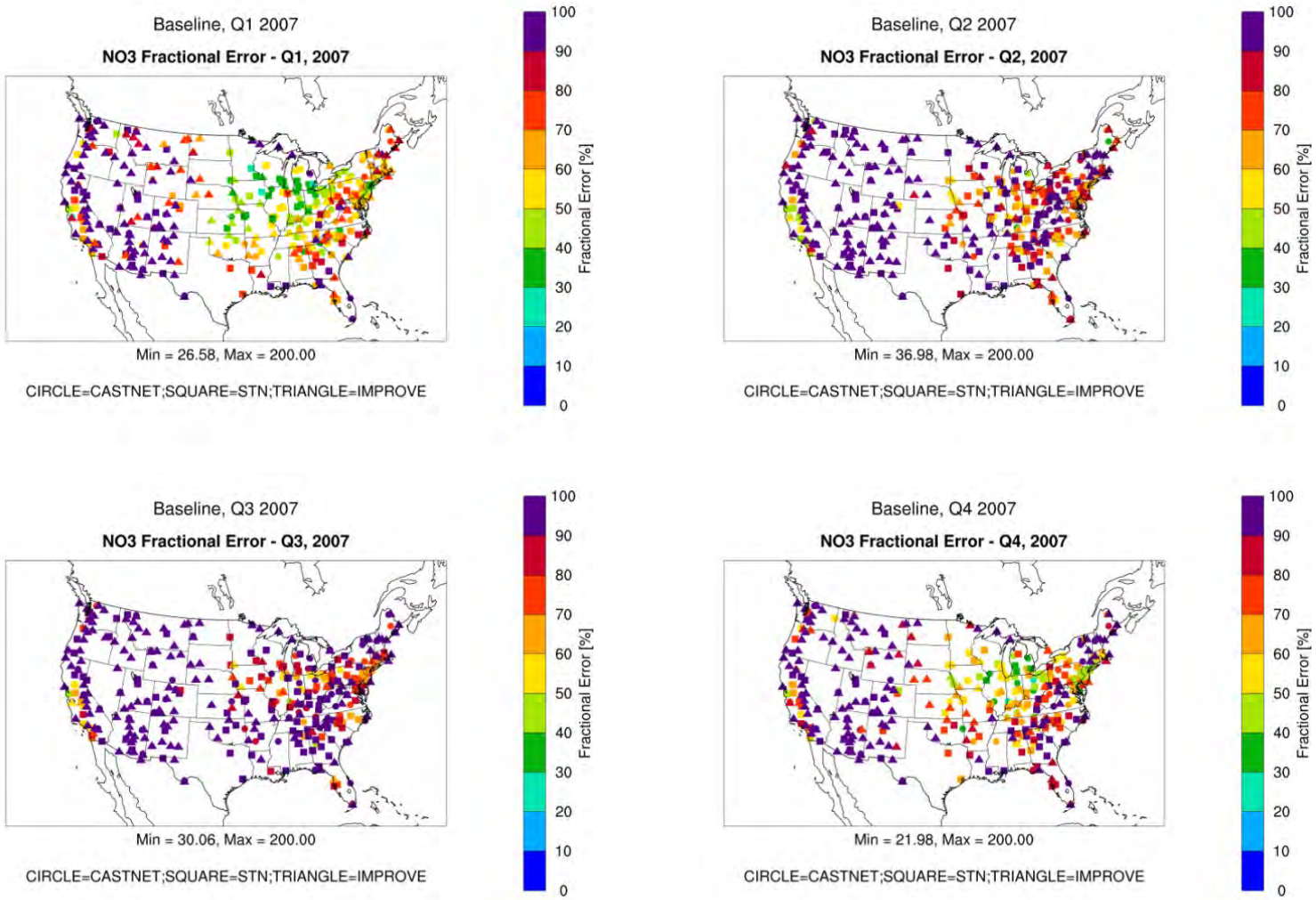

Figure 7-11
Fractional error (%) for nitrate in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

Ammonium Evaluation

Bugle Plots of quarterly fractional bias and error for ammonium are shown in Figure 7-12 and Figure 7-13. Spatial plots of FB and FE by quarter for individual monitors are shown in Figure 7-14 and Figure 7-15, respectively. Although all quarterly biases and errors achieve the performance criteria, the model shows clear under-predictions of ammonium. The model bias for ammonium is lower than for nitrate, but higher than for sulfate. The bias is particularly large in the second and third quarters (FB = -76% to -34%). The model predictions for ammonium, nitrate, and sulfate are linked by chemistry. The performance of ammonium is more similar to that of sulfate at CASTNET and STN monitors. However, the performance at IMPROVE monitors is more similar to that of nitrate.

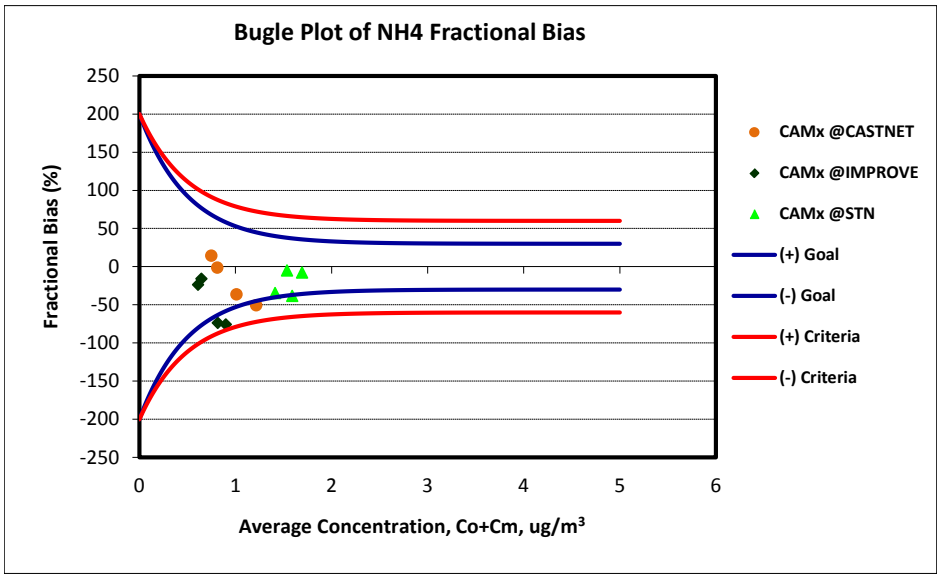

Figure 7-12
Bugle plot of ammonium fractional bias during 2007

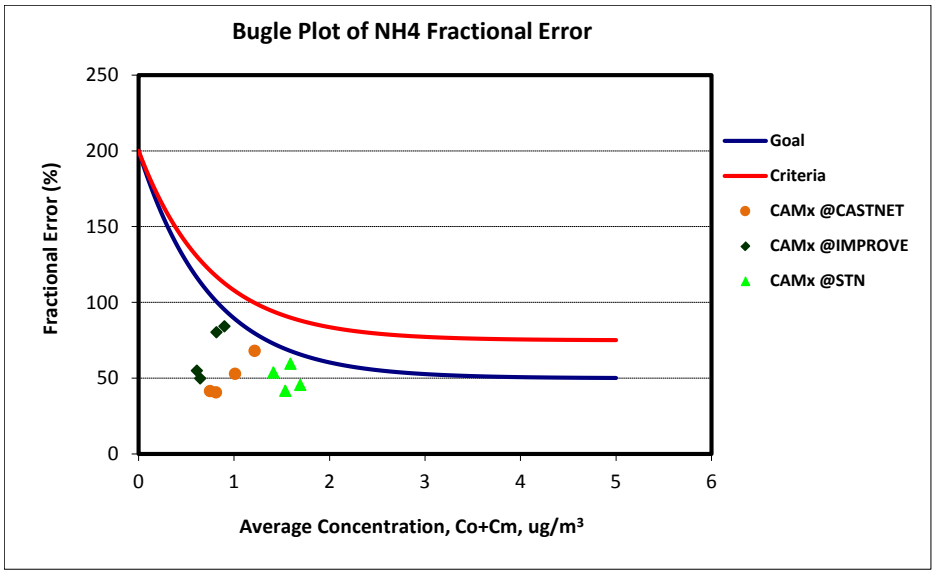

Figure 7-13
Bugle plot of ammonium fractional error during 2007

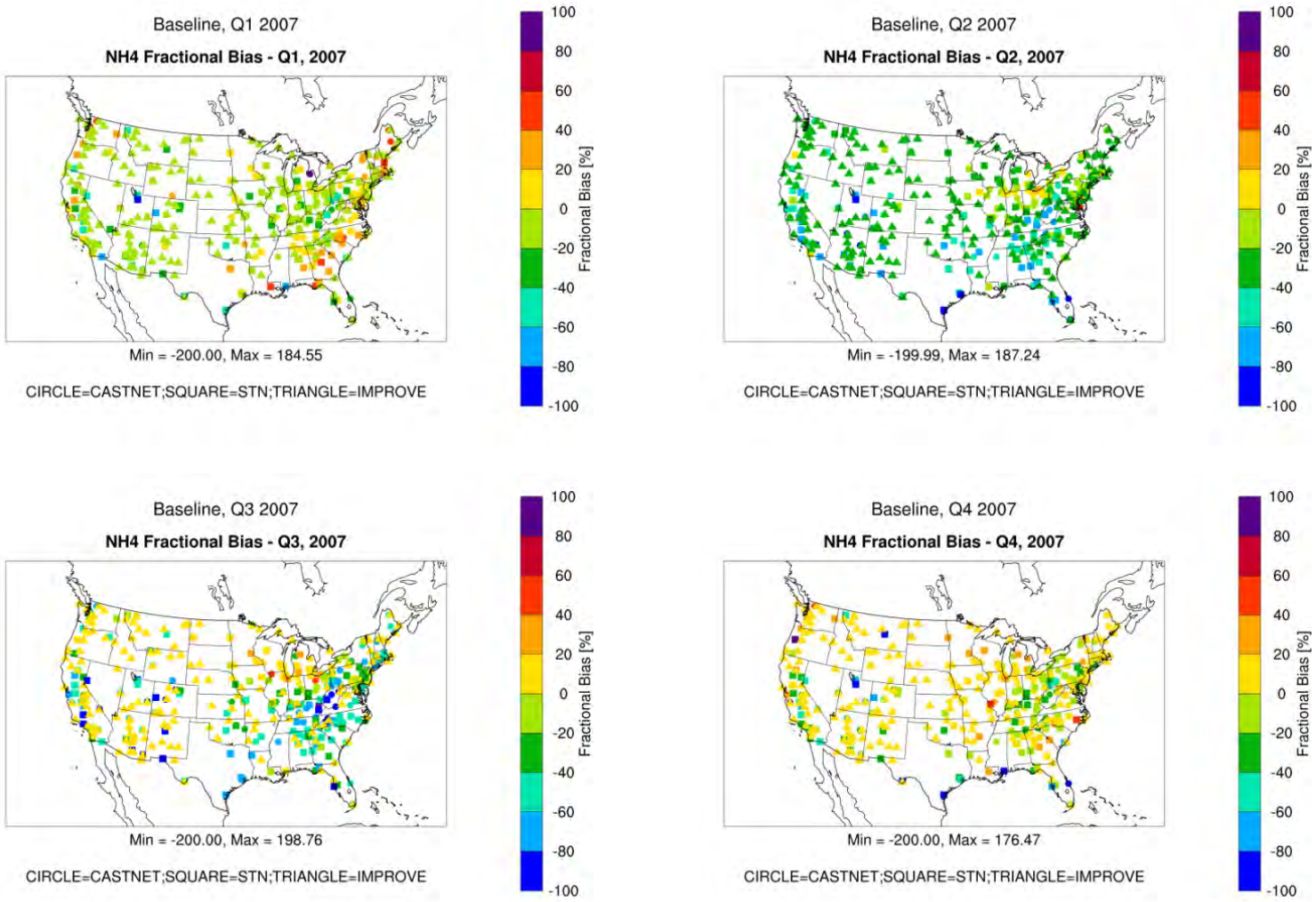

Figure 7-14
Fractional bias (%) for ammonium in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

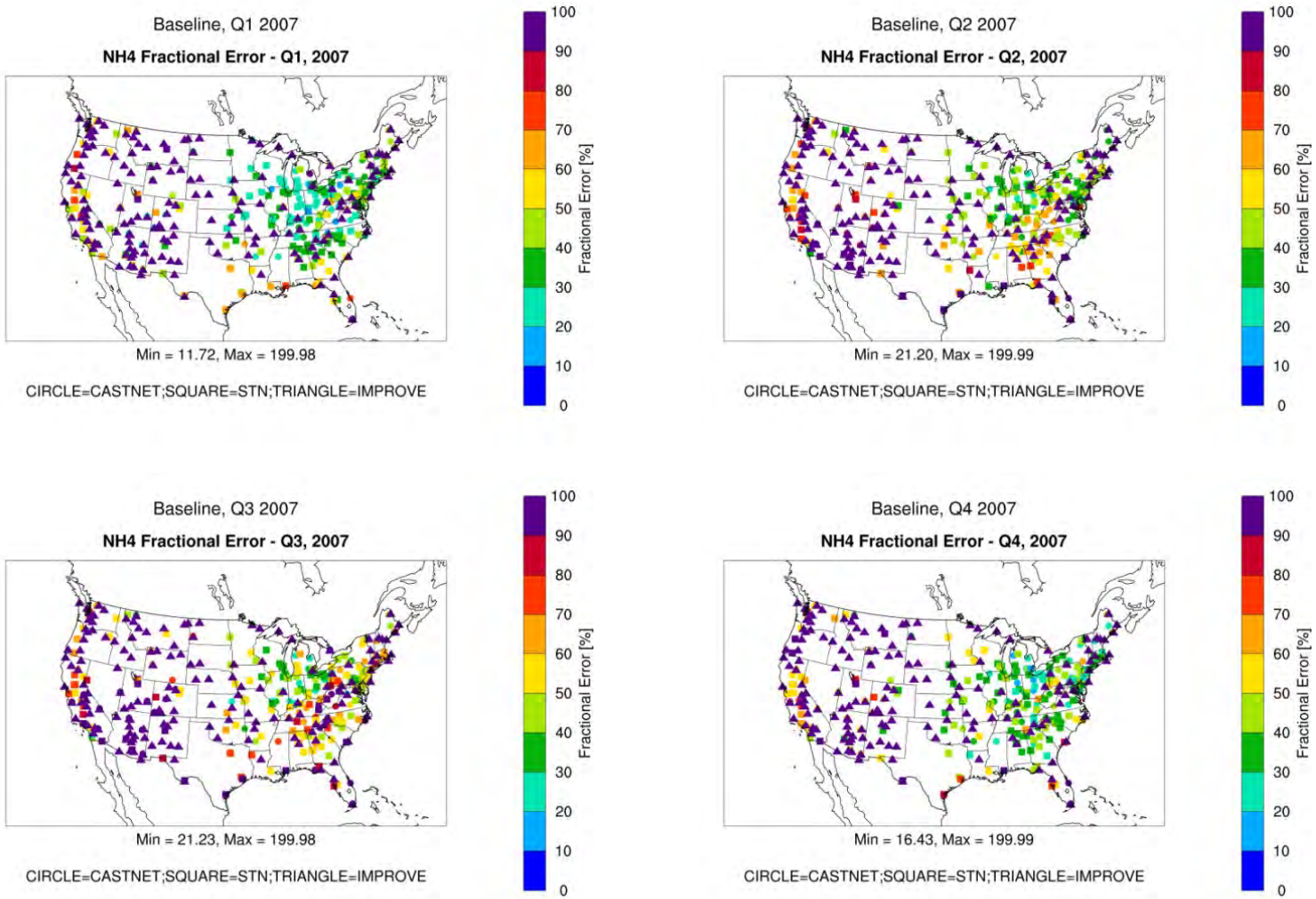

Figure 7-15
Fractional error (%) for ammonium in the four quarters of 2007 at STN, CASTNET, and IMPROVE monitoring sites

Organic Matter (OM) Evaluation

Bugle Plots of quarterly fractional bias and error for organic matter are shown in Figure 7-16 and Figure 7-17. Spatial plots of FB and FE by quarter for individual monitors are shown in Figure 7-18 and Figure 7-19, respectively. The quarterly performance at IMPROVE monitors achieves the performance criteria of bias and error in all quarters, and it achieves the performance goals in most quarters. The third quarter shows 15% bias but about 60% error, indicating that the average concentrations are predicted correctly but with substantial unsystematic error. Performance for OM at STN monitors is poor, showing apparent under-predictions in the second quarter (FB=-80%; FE=83%), although the STN methodology in 2007 is known to have a high bias that could account for the model under prediction. Similar magnitude bias and error statistics indicate that the underestimation trends are consistent both spatially and temporally.

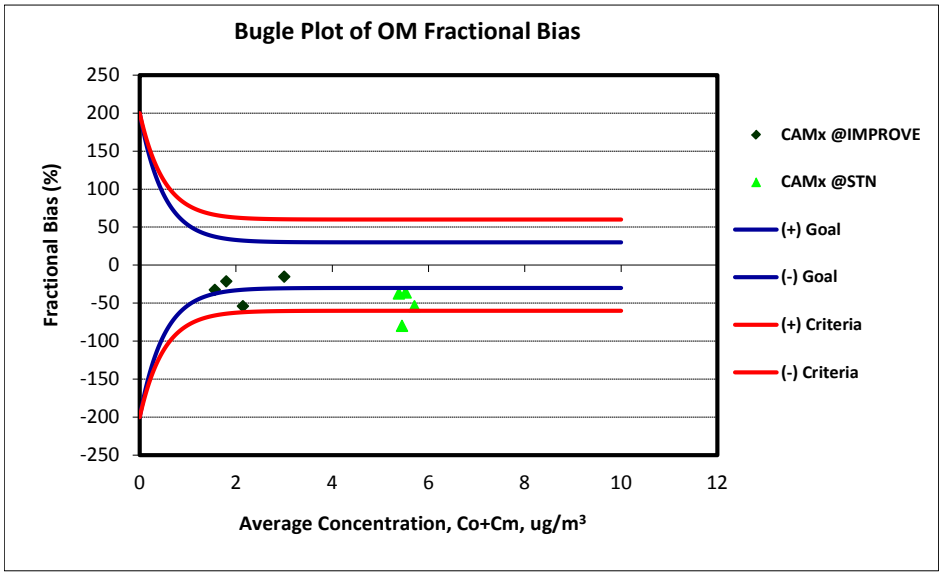

Figure 7-16
Bugle plot of organic matter fractional bias during 2007

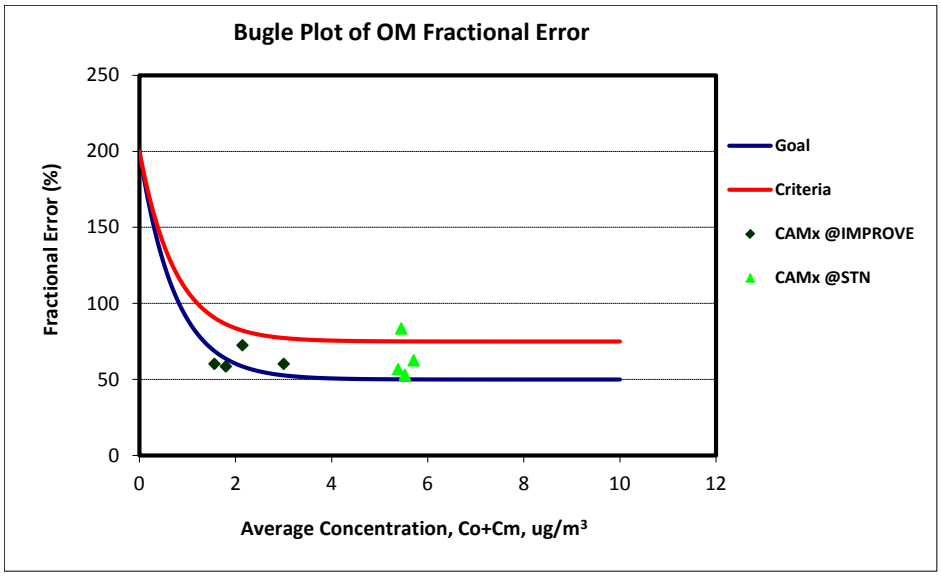

Figure 7-17
Bugle plot of organic matter fractional error during 2007

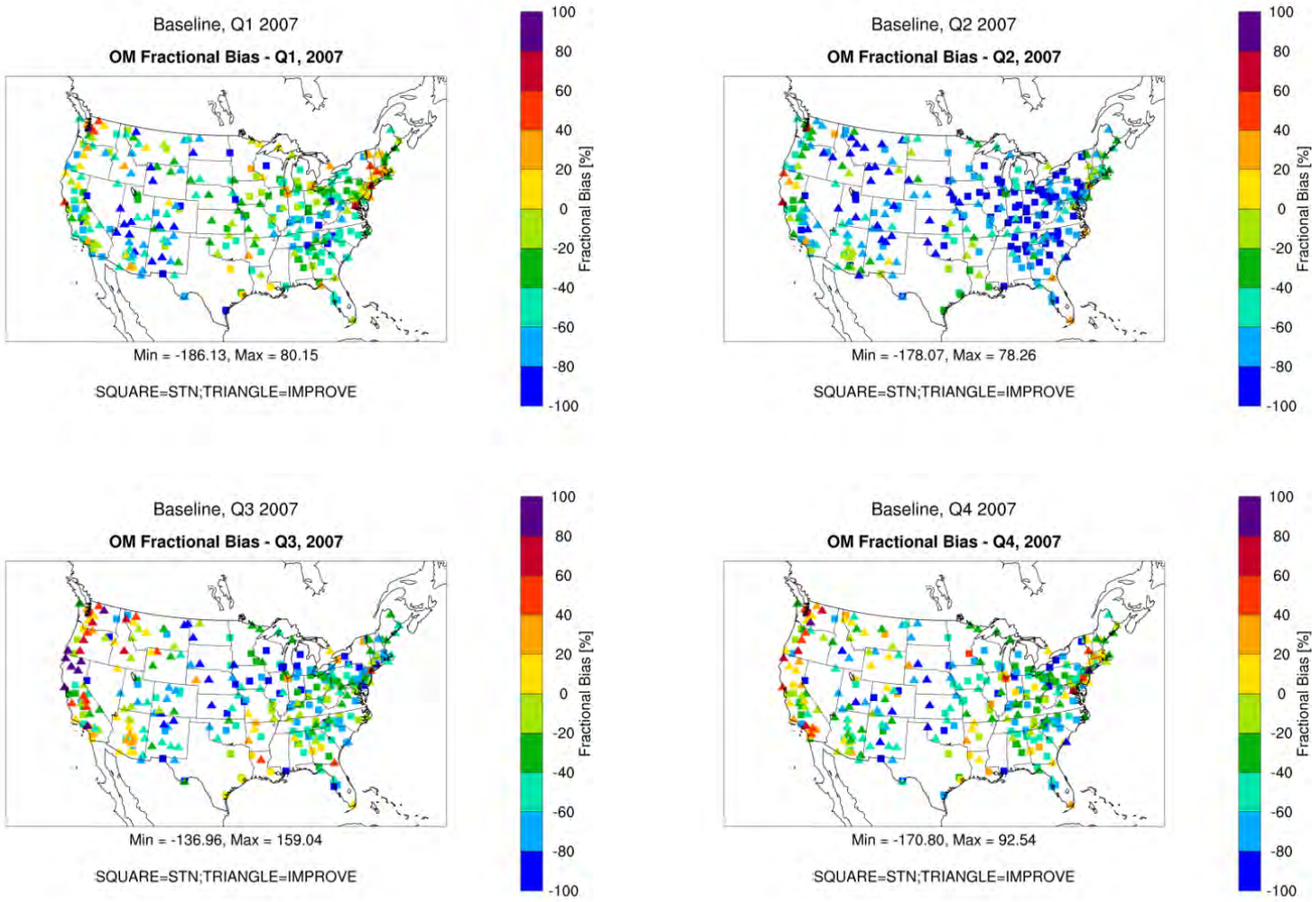

Figure 7-18
Fractional bias (%) for organic matter in the four quarters of 2007 at STN and IMPROVE monitoring sites

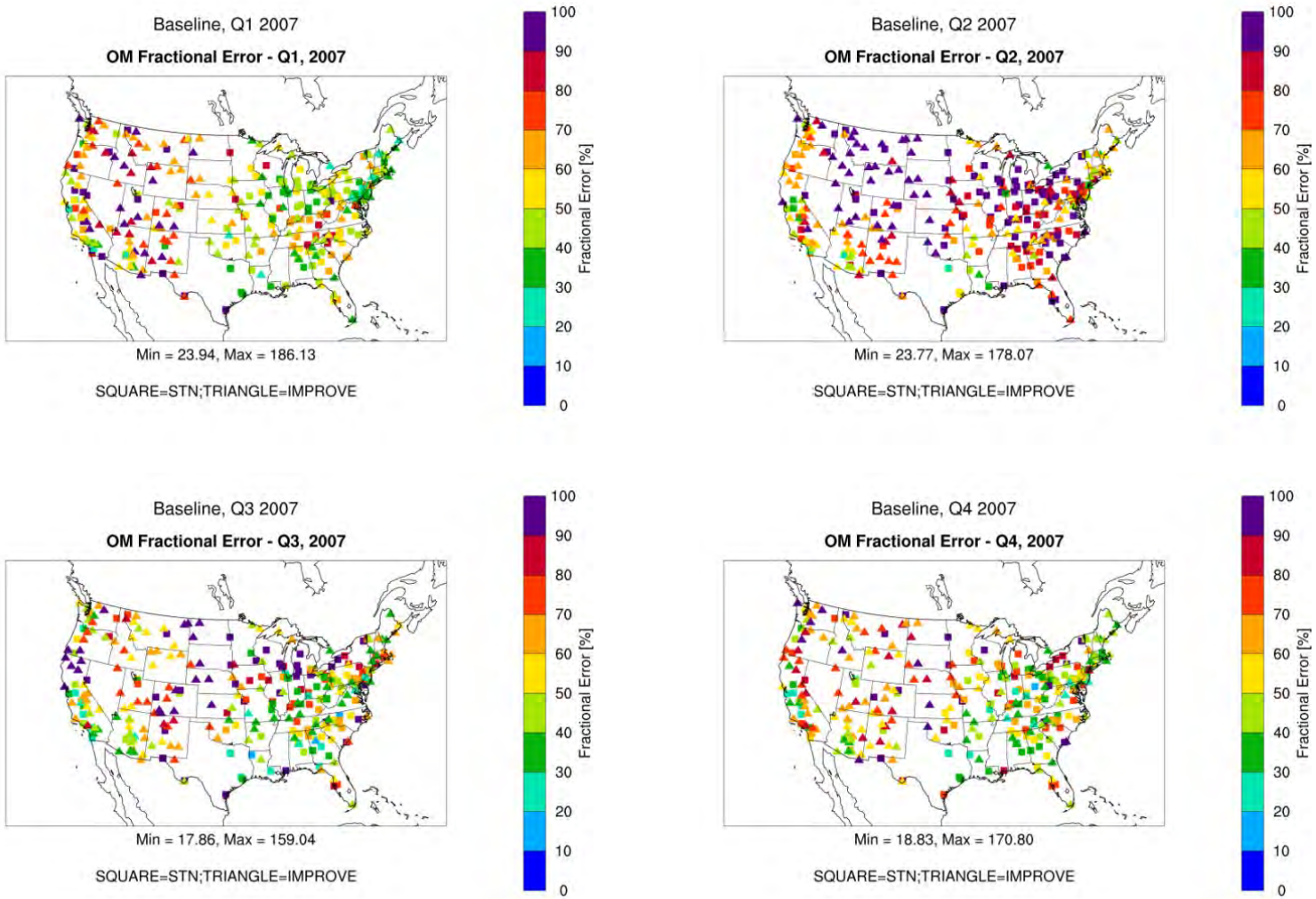

Figure 7-19
Fractional error (%) for organic matter in the four quarters of 2007 at STN and IMPROVE monitoring sites

Elemental Carbon Evaluation

Bugle Plots of quarterly fractional bias and error for elemental carbon are shown in Figure 7-20 and Figure 7-21. Spatial plots of FB and FE by quarter for individual monitors are shown in Figure 7-22 and Figure 7-23, respectively. Overall, the model shows good performance, with all quarterly biases and errors achieving the performance goals and criteria (Figure 7-20 and Figure 7-21). The statistics show clear over-prediction at urban monitors across the CONUS, particularly at major urban sites (such as Houston, Dallas, Los Angeles, and St. Louis). Specifically, the quarterly FB across all STN monitors has a range of 25% to 40%. IMPROVE monitors show much less over-prediction than STN monitors, having quarterly FB less than 23%. The model under-predicted elemental carbon at IMPROVE monitors in the first and second quarters. Some of the over-predictions at IMPROVE monitors in the western coastal states could be from the use of average-fire emissions; however, EPA used episodic fire emissions and also reported over-predictions of EC at these monitors (EPA, 2012d).

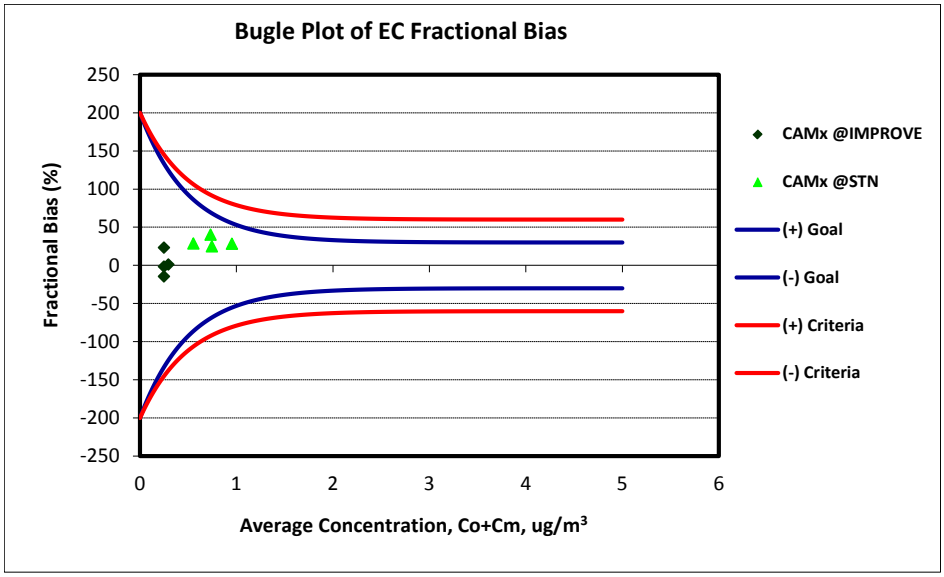

Figure 7-20
Bugle plot of elemental carbon fractional bias during 2007

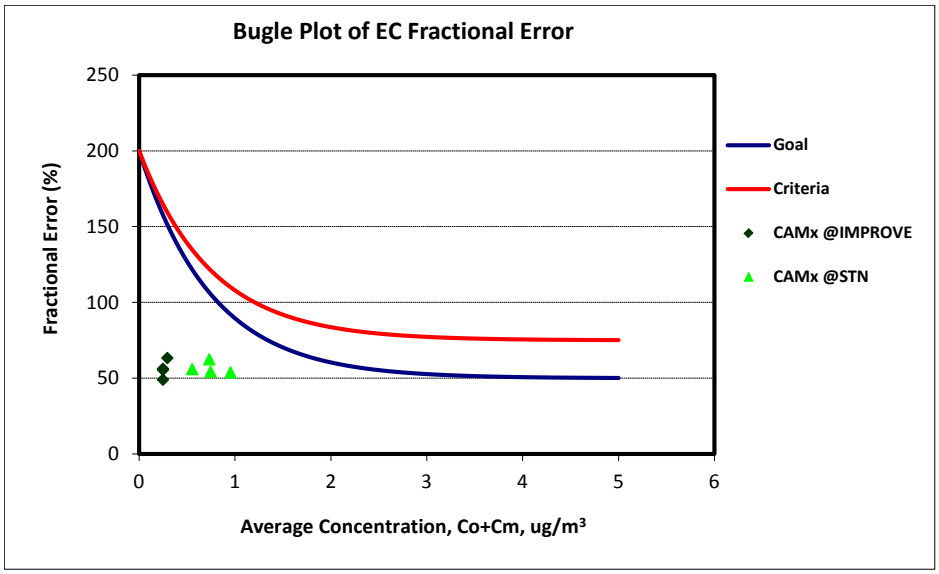

Figure 7-21
Bugle plot of elemental carbon fractional error during 2007

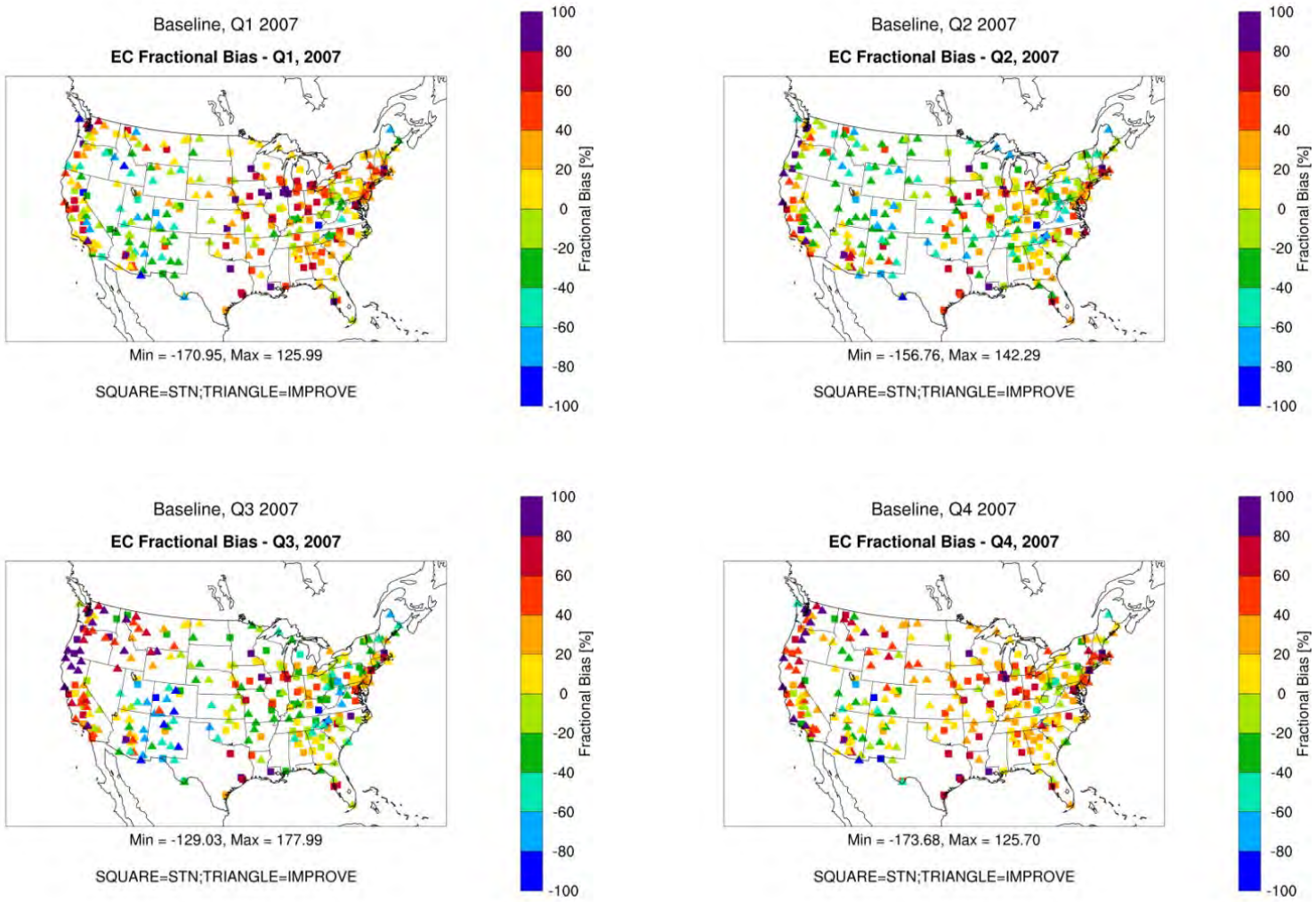

Figure 7-22
Fractional bias (%) for elemental carbon in the four quarters of 2007 at STN and IMPROVE monitoring sites

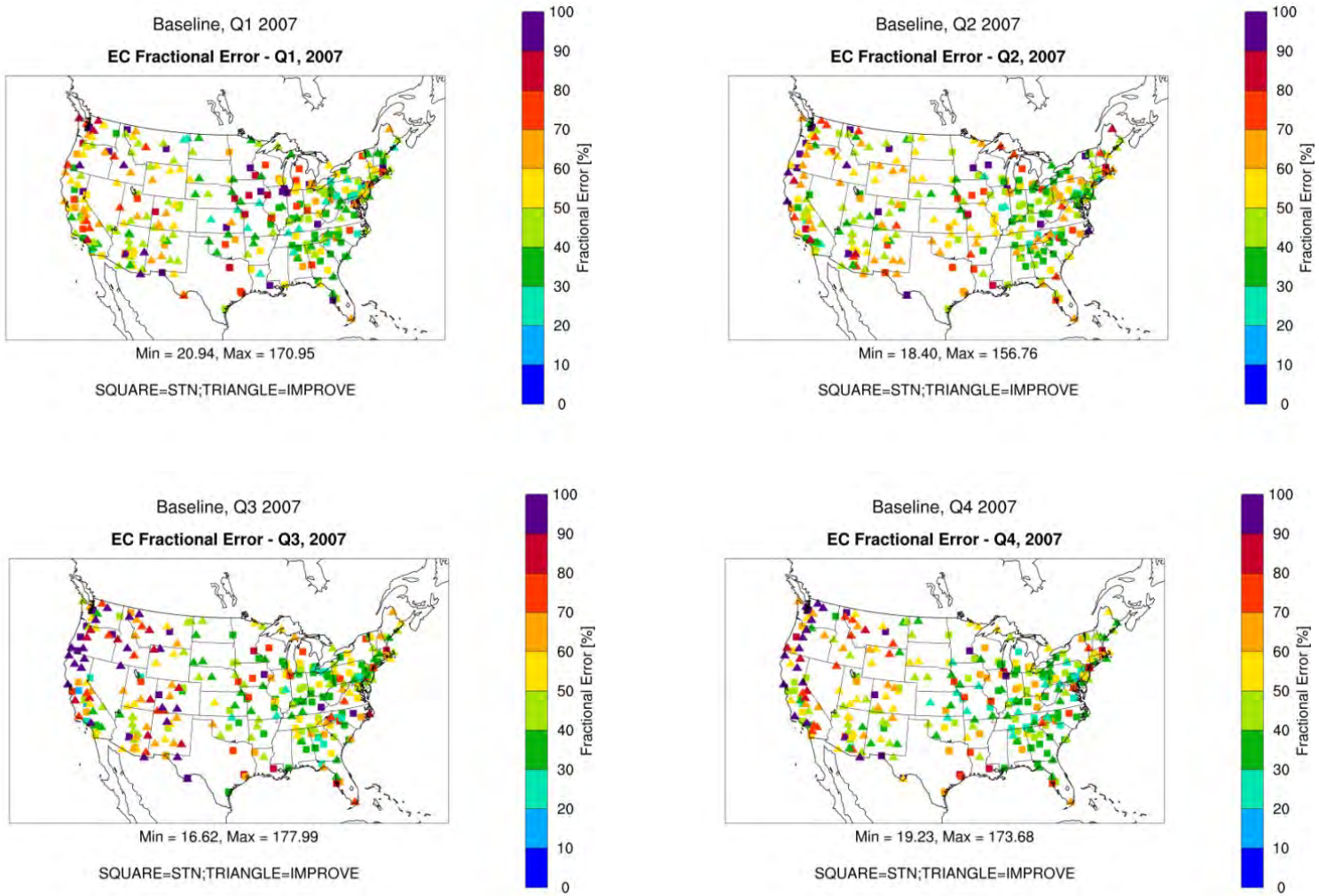

Figure 7-23
Fractional error (%) for elemental carbon in the four quarters of 2007 at STN and IMPROVE monitoring sites

Total $PM_{2.5}$ Evaluation

The model-performance bias and error statistics for total $PM_{2.5}$ in each quarter are provided in Table 7-6. Spatial plots of the normalized mean bias and error by quarter for individual monitors are shown in Figure 7-24 and Figure 7-25, respectively. The model achieves the PM-performance criteria (≤±60% for bias; ≤±75% for error) but achieves the performance goal (≤±30% for bias; ≤±50% for error) only in the first and fourth quarters. The model shows under-estimation bias during the second and third quarters across the CONUS. Exceptions are some moderate positive biases in the west coast and northeastern states. Under-estimations at STN monitors are mainly a result of under-predictions of sulfate and organic matter. Overall, the model shows fair performance for $PM_{2.5}$.

Table 7-6
$PM_{2.5}$ performance statistics by quarter for the 2007 CAMx model simulation

Quarter	Bias Performance Metrics			Error Performance Metrics			N
	FB	NMB	MNB	FE	NME	MNE	
PM Performance Goal	**≤±30%**	**≤±30%**	**≤±30%**	**≤50%**	**≤50%**	**≤50%**	
PM Performance Criteria	**≤±60%**	**≤±60%**	**≤±60%**	**≤75%**	**≤75%**	**≤75%**	
IMPROVE Monitors							
Quarter 1	2.9	10.4	23.6	43.1	45.5	54.3	4389
Quarter 2	-47.0	-31.9	-20.2	64.9	52.4	57.7	4572
Quarter 3	-29.8	-21.5	4.7	59.3	51.5	68.2	4521
Quarter 4	1.7	9.8	30.0	49.1	49.5	65.1	4478
STN Monitors							
Quarter 1	0.0	-3.2	16.2	38.1	38.5	44.9	3057
Quarter 2	-31.5	-30.5	-15.7	47.9	43.1	43.0	3215
Quarter 3	-26.7	-25.1	-13.1	44.5	39.2	40.7	3164
Quarter 4	1.6	2.5	18.3	36.7	36.5	44.9	3267

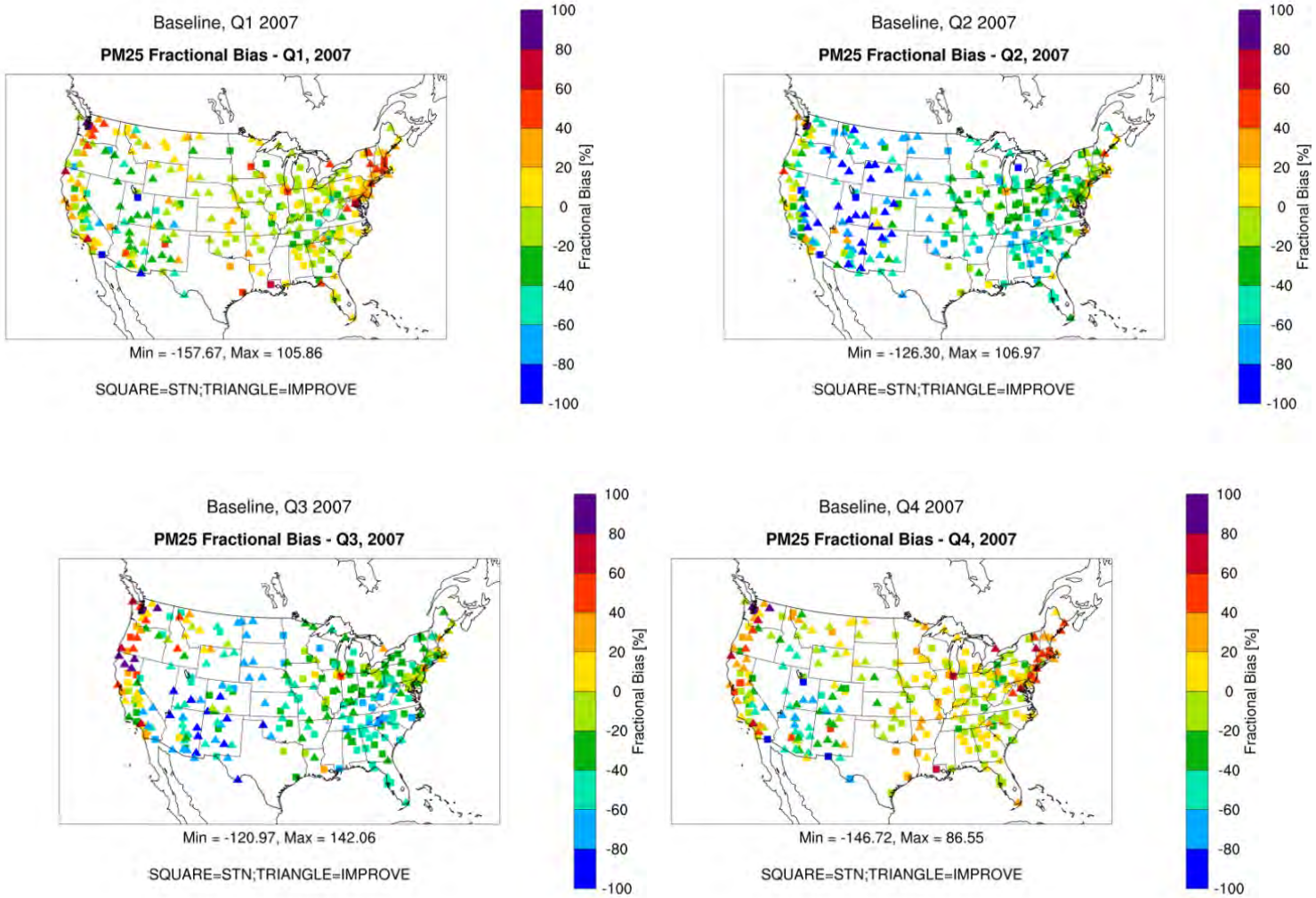

Figure 7-24
Fractional bias (%) for $PM_{2.5}$ in the four quarters of 2007 at STN and IMPROVE monitoring sites

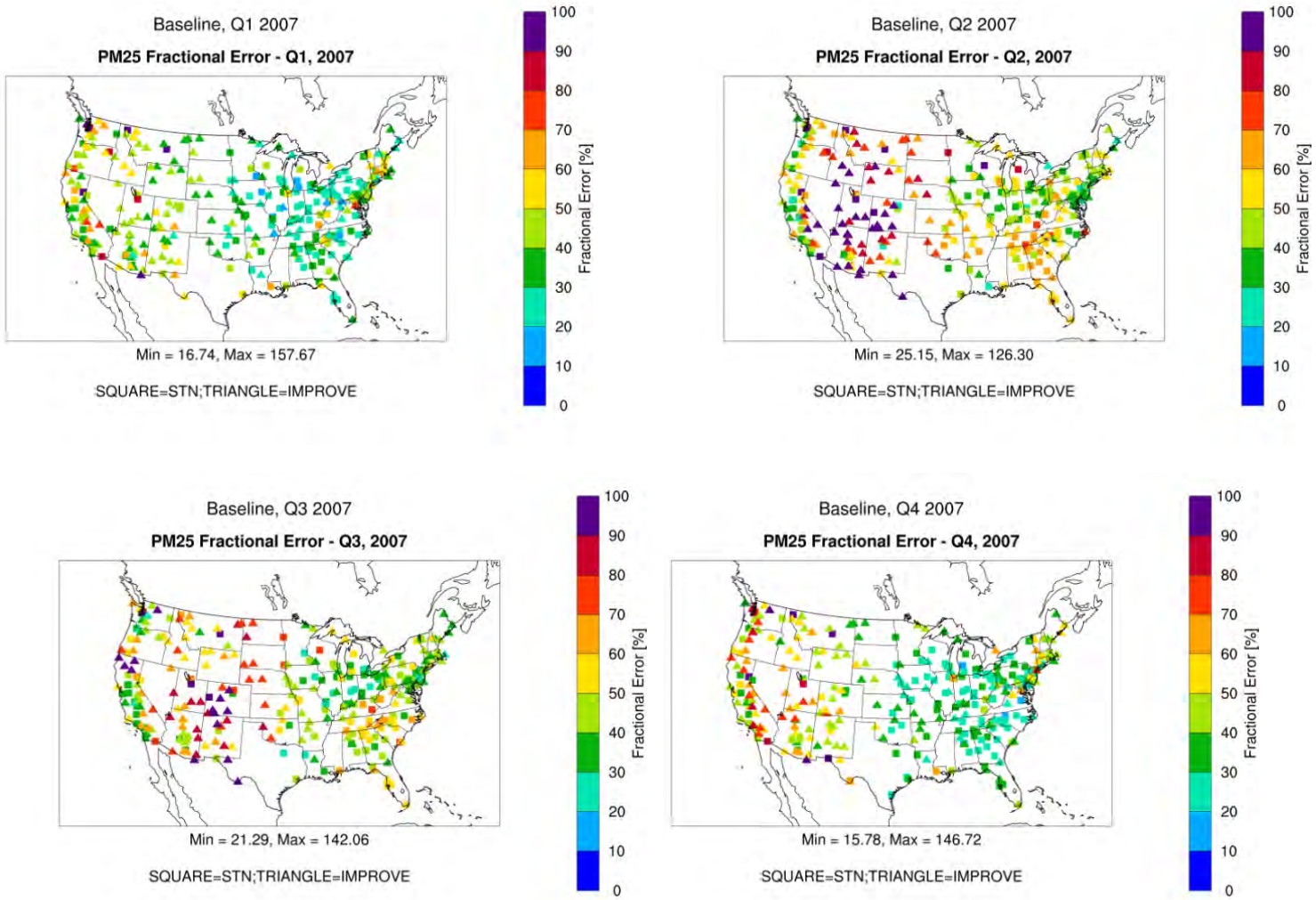

Figure 7-25
Fractional error (%) for $PM_{2.5}$ in the four quarters of 2007 at STN and IMPROVE monitoring sites

Wet-Deposition Evaluation

The model was evaluated for sulfate, nitrate, and ammonium wet deposition. Wet-deposition measurements for 2007 were obtained from the National Atmospheric Deposition Program (NADP). NADP data is collected and reported as weekly average data.

All quarters have poor performance for wet deposition, with errors (FE) that exceed 100 percent for all three species evaluated (Table 7-7). However, the quarterly FB is less than 27%, with a range of -26.7% to 21.7%, indicating that the average deposition amounts are predicted correctly but with considerable unsystematic error. Over-prediction of sulfate wet deposition in the second and third quarters potentially contributed to the under-predictions of sulfate concentrations.

Table 7-7
Total wet-deposition performance statistics by quarter for the 2007 CAMx model simulation

Quarter	Bias Performance Metrics			Error Performance Metrics			N
	FB	NMB	MNB	FE	NME	MNE	
Sulfate							
Quarter 1	-11.4	-34.7	597.7	114.5	97.3	670.9	1242
Quarter 2	19.3	-2.1	624.1	109.6	111.8	678.5	1245
Quarter 3	21.7	19.5	776.0	108.2	115.2	828.2	1299
Quarter 4	-17.4	-33.8	589.7	112.6	95.9	665.8	1274
Nitrate							
Quarter 1	-15.9	-48.3	504.8	116.1	97.4	581.2	1242
Quarter 2	-3.8	-42.3	423.3	108.1	95.6	490.4	1245
Quarter 3	-9.2	-41.0	420.6	106.3	90.0	490.1	1299
Quarter 4	-3.8	-31.8	684.4	114.2	98.0	753.5	1274
Ammonium							
Quarter 1	-17.8	-56.1	450.2	116.1	94.1	527.9	1242
Quarter 2	8.2	-37.6	589.5	110.7	97.8	651.3	1245
Quarter 3	6.3	-24.5	773.1	110.1	99.5	835.8	1299
Quarter 4	-26.7	-59.1	555.4	115.8	92.7	638.4	1274

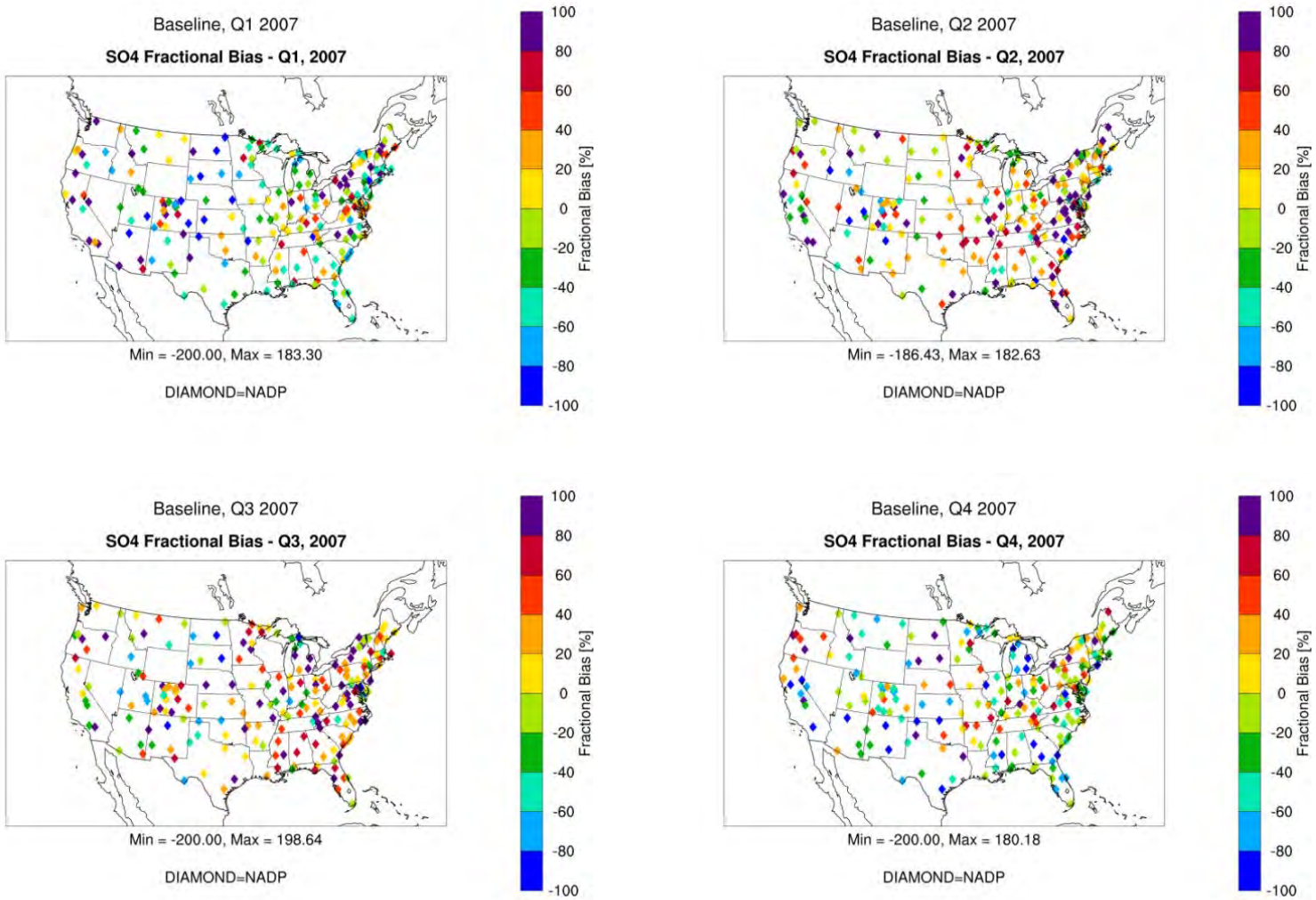

Figure 7-26
Fractional bias (%) for sulfate wet deposition in the four quarters of 2007 at NADP monitoring sites

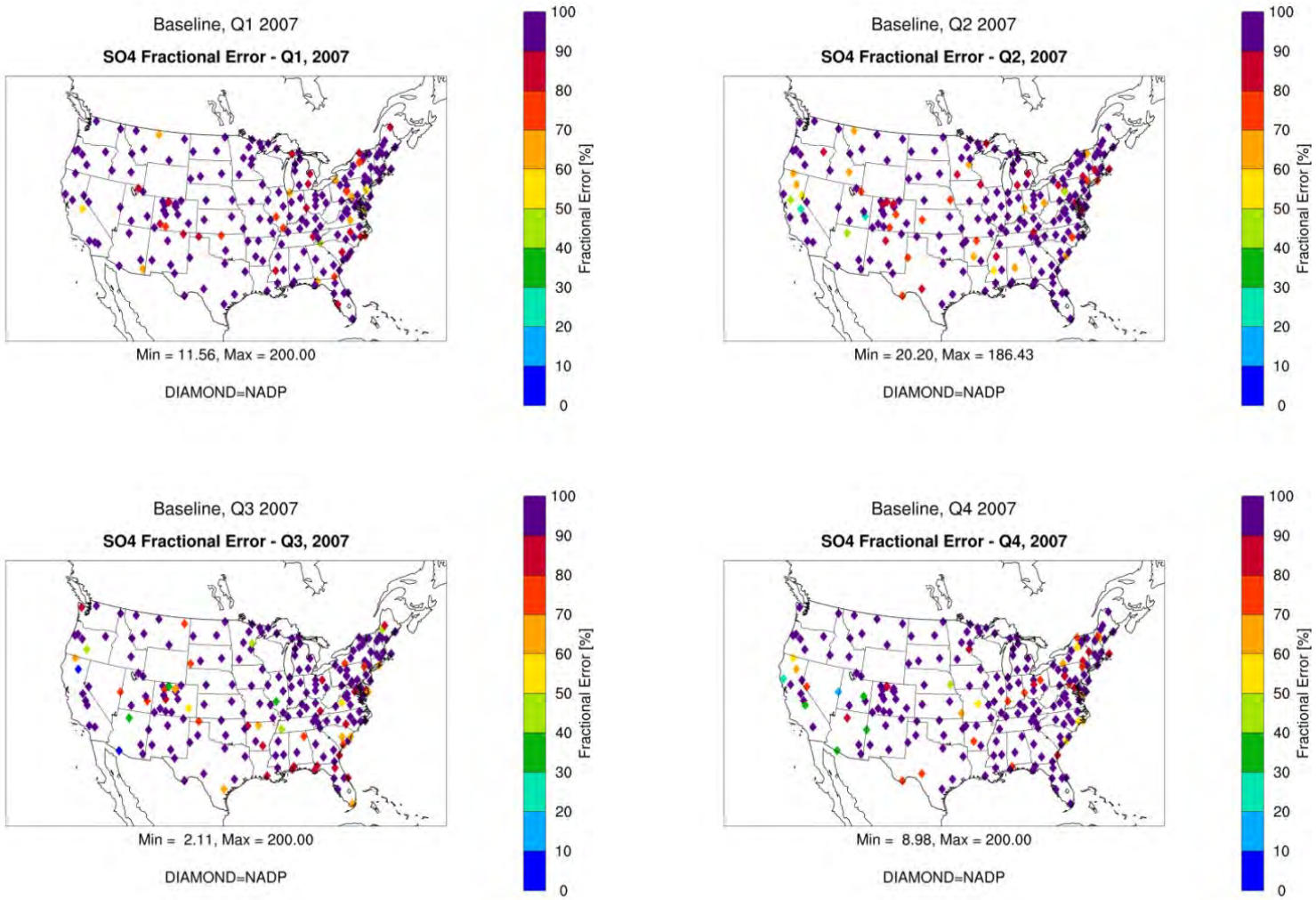

Figure 7-27
Fractional error (%) for sulfate wet deposition in the four quarters of 2007 at NADP monitoring sites

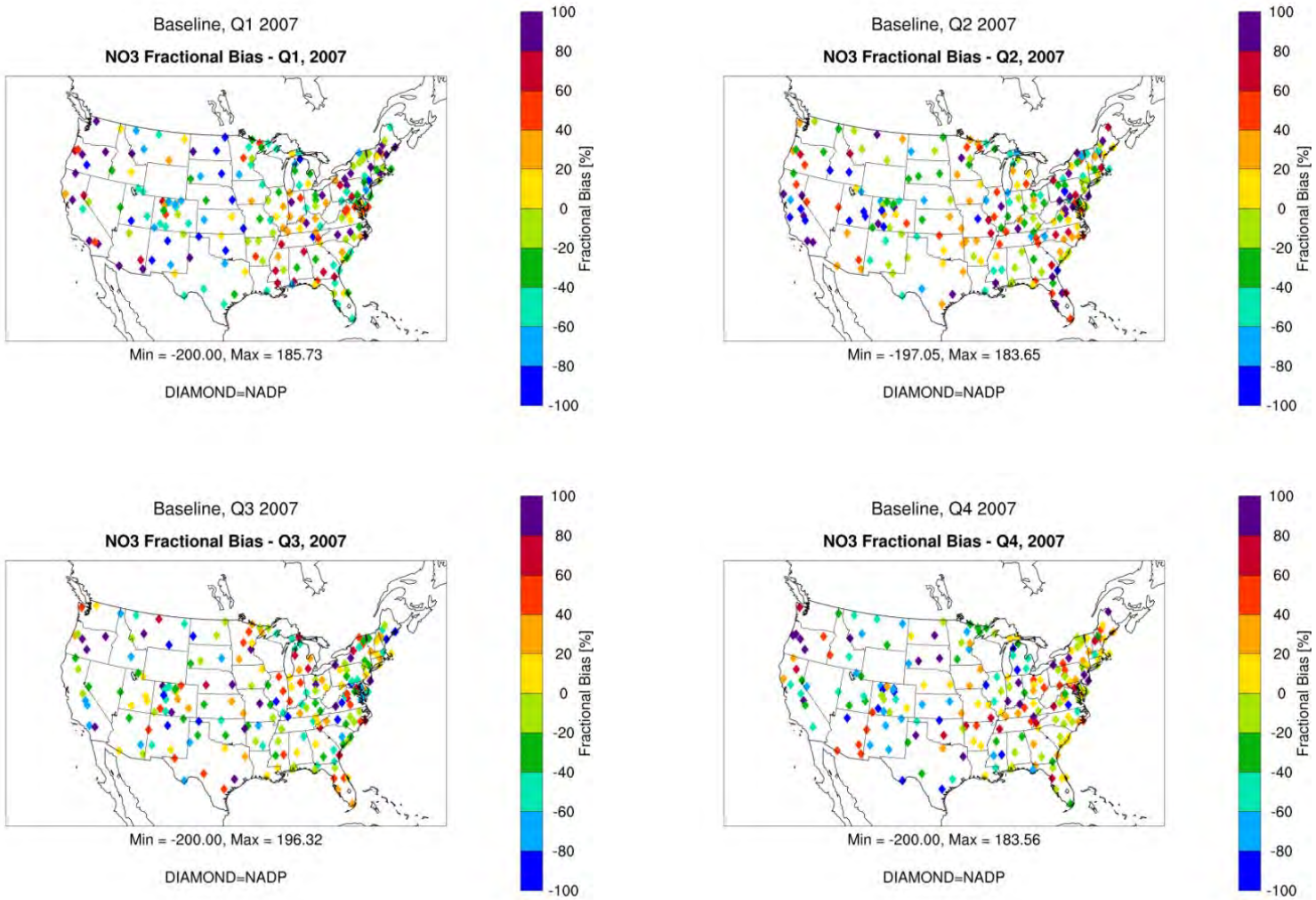

Figure 7-28
Fractional bias (%) for nitrate wet deposition in the four quarters of 2007 at NADP monitoring sites

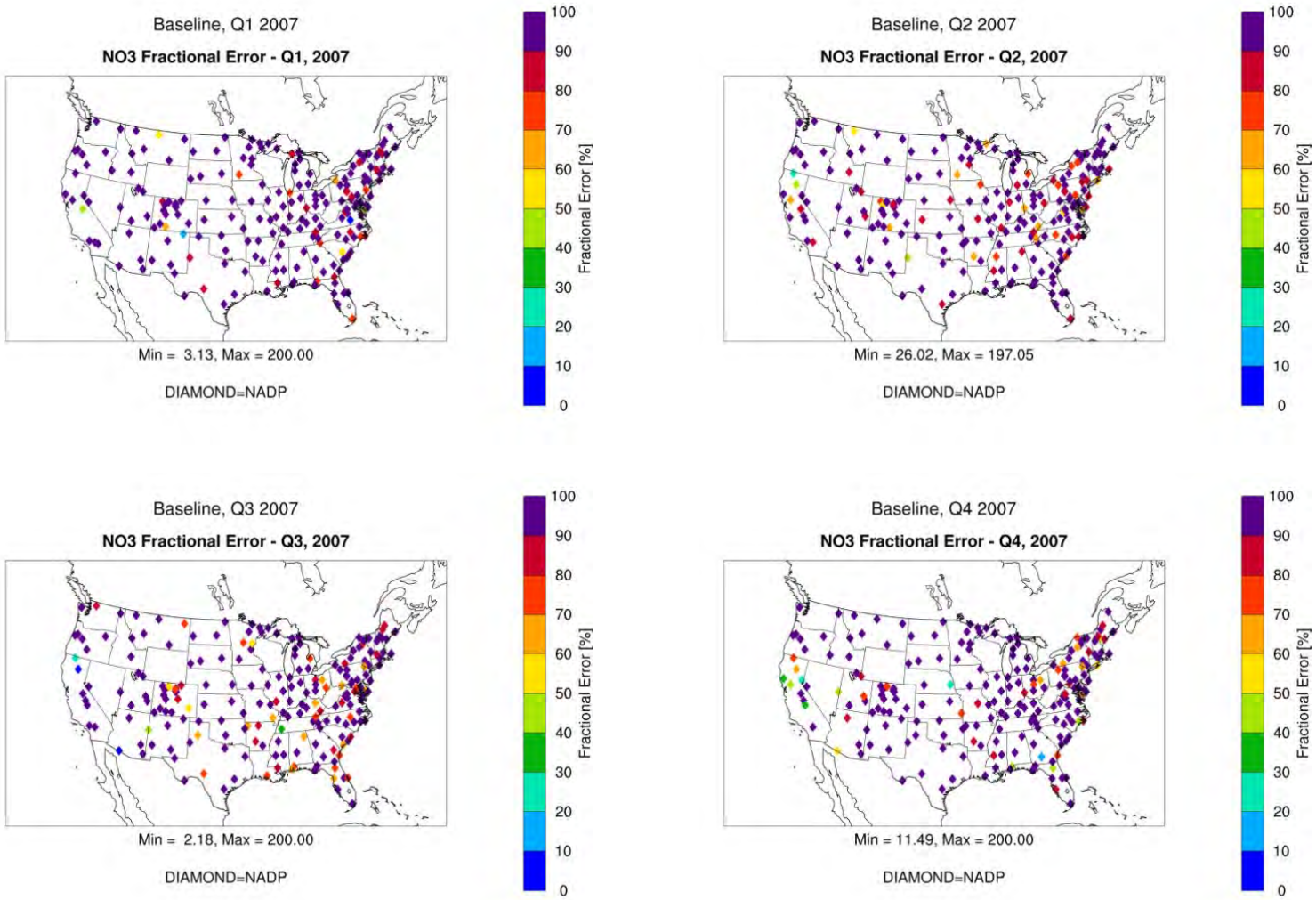

Figure 7-29
Fractional error (%) for nitrate wet deposition in the four quarters of 2007 at NADP monitoring sites

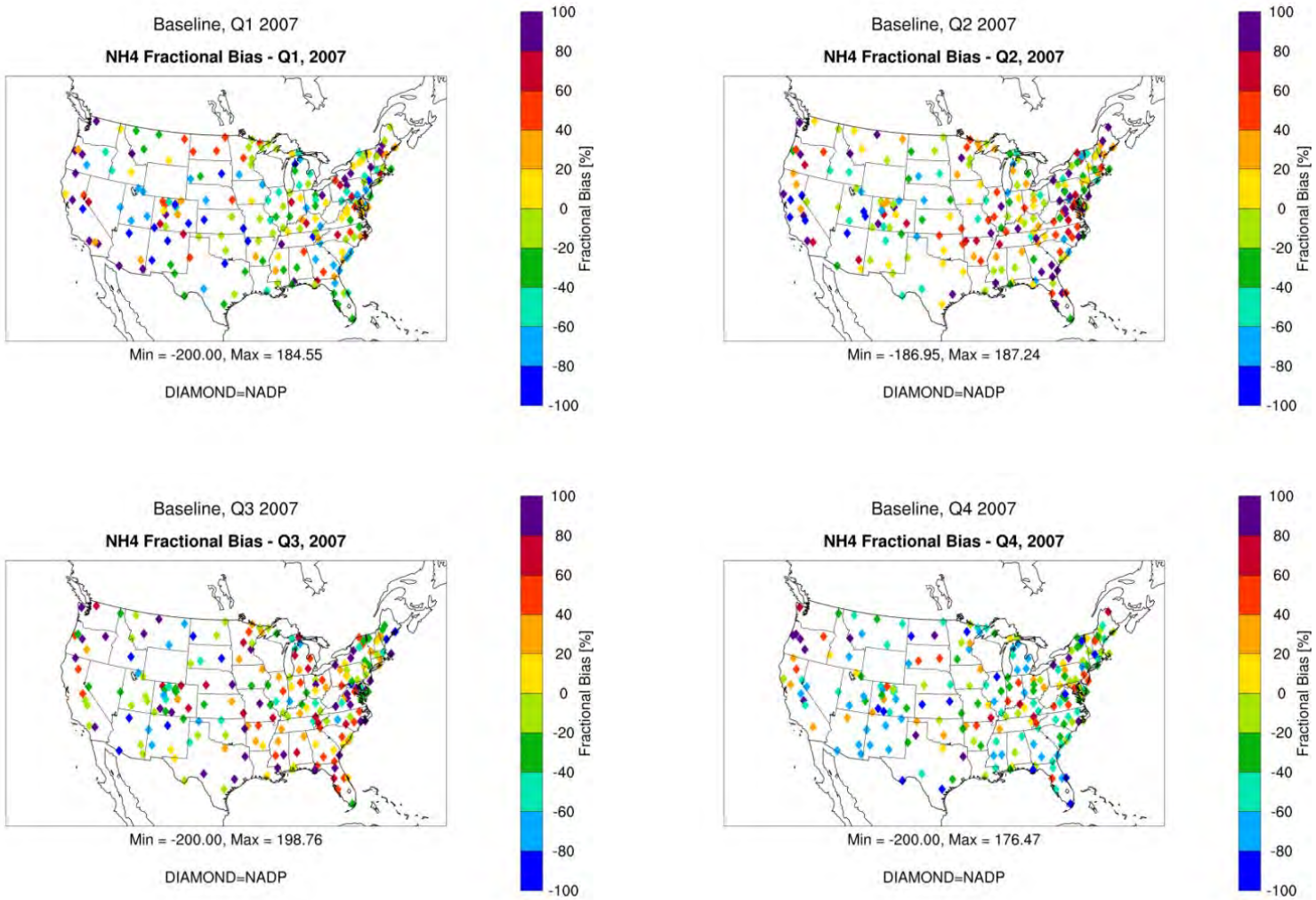

Figure 7-30
Fractional bias (%) for ammonium wet deposition in the four quarters of 2007 at NADP monitoring sites

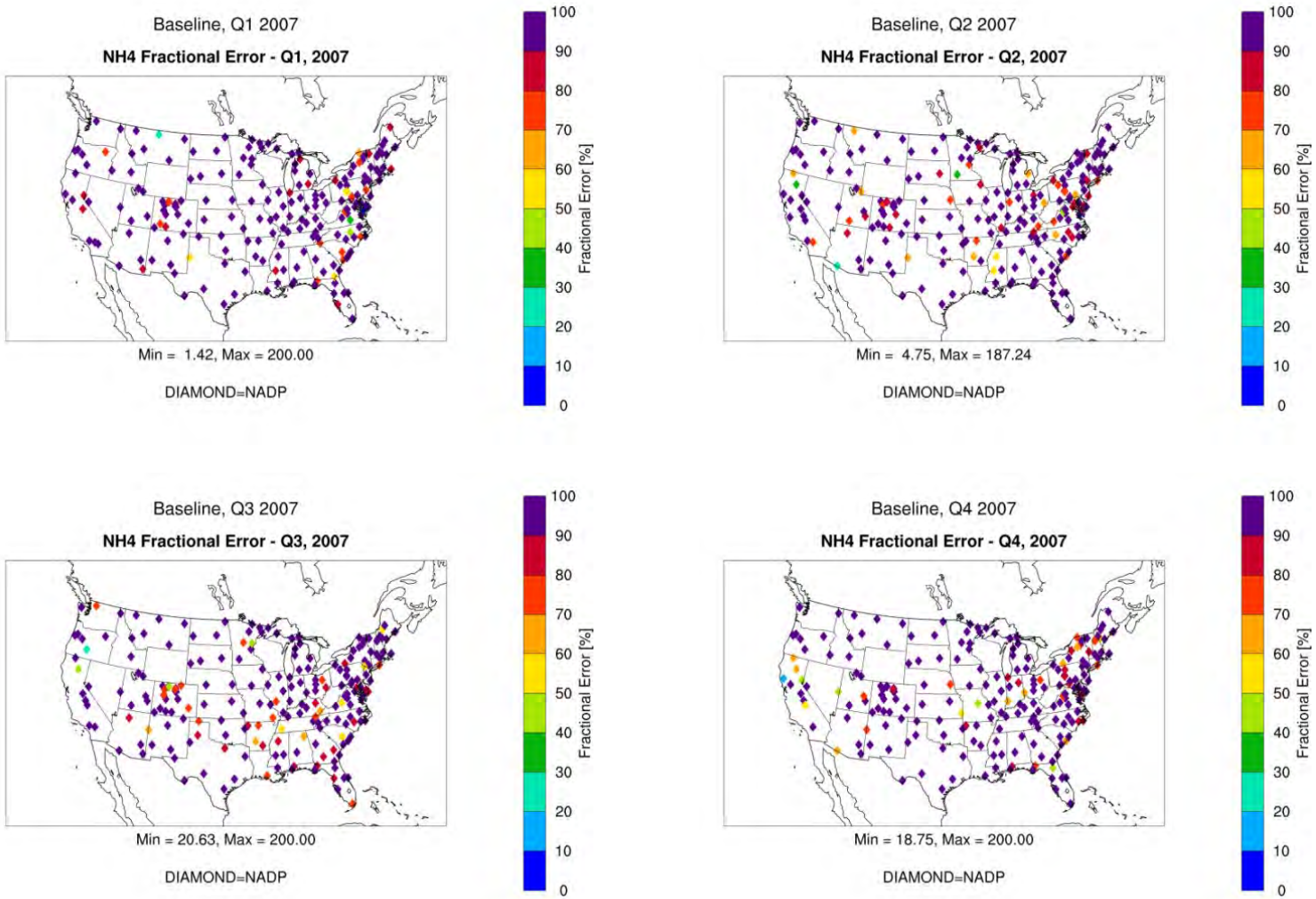

Figure 7-31
Fractional error (%) for ammonium wet deposition in the four quarters of 2007 at NADP monitoring sites

Model-Performance Evaluation Summary

As noted earlier, the use of model-performance goals and criteria set forth by other organizations in this study should not be viewed as endorsements thereof; these goals are used as guidance of the evaluation of the air quality modeling platform for the application of this research effort.

The 2007 CAMx modeling demonstrated adequate ozone performance, achieving the EPA's performance goals for both bias and error. Ozone is slightly over-estimated in the summer but under-estimated in other seasons. The $PM_{2.5}$ performance is generally within commonly used performance benchmarks. There is a tendency for the model to under-predict sulfate in the second and third quarters which could be partly due to over-prediction of sulfate wet deposition. The performance statistics indicate fair performance for elemental carbon, but consistent under-predictions of organic matter across the CONUS. Nitrate predictions appear to have unsystematic errors with a wide range of bias and error. Our organic matter and nitrate model performance are comparable to what EPA reported for the 2007 PM NAAQS modeling. PM_{10} is a more local problem than $PM_{2.5}$ because PM_{10} is removed more rapidly by deposition. PM_{10} emissions are dominated by dust (road or windblown) which is not expected to be modeled well with 12 km grid resolution. Windblown dust is actually not included in the study. For these reasons, our PM evaluation only focuses on $PM_{2.5}$.

This operational evaluation indicates no serious performance issues that would prevent this CAMx database from being used as a starting point for the future-year scenarios for this particular application.

Section 8: Air Quality Simulation Results

Air quality model simulations were used to estimate the air quality impacts of electric transportation with 2030 emissions under 2007 meteorological conditions. The air quality model was run for 2030 for two scenarios: a Base Case with no electrification and an Electrification Case with a significant penetration of electric technology, as described in Section 2 and Section 3. Details on the methodologies for calculating on-road, non-road, and electric-sector emissions have been described in Section 2, Section 3, and Section 4, respectively; the emissions processing necessary to prepare emissions data for the air quality simulation has been described in Section 6.

The air quality model chosen for this work is the Comprehensive Air quality Model with extensions (CAMx), Version 6.0 (ENVIRON, 2013). An operational model-performance evaluation for the 2007 baseline case is presented in Section 7. Each 2030 modeling scenario tracks contributions to air quality from several emissions sectors using source-apportionment capabilities in the CAMx model. The purpose of using source apportionment is to understand how emission changes in different source sectors influence ambient ozone, PM, and acid and nutrient deposition. The seven source sectors are defined as follows:

- Light-duty vehicles;
- Heavy-duty vehicles;
- Non-road mobile sources;
- Electric Generating Units (EGUs);
- Other stationary-point (non-EGU) and area sources;
- Natural sources (biogenic and fires); and
- Non-United States (Non-U.S.) emissions (including marine shipping).

The first two subsections below summarize the air quality model configuration and the source-apportionment approach. The subsequent section documents the assessment methodology for air quality results. The final section presents the air quality modeling results and discusses how electrification could influence air quality and deposition in 2030.

Configuration

The same CAMx configuration was used in 2030 as for the 2007 baseline, except that the ozone and PM source-apportionment features were turned on. The

CAMx model was run separately for each two-month period of 2030, with a 10-day spin-up period added to limit the influence of the assumed initial concentrations.

Ozone and PM Source Apportionment

The CAMx model has mass-tracking algorithms to explicitly simulate the fate of emissions from specific sources accounting for chemical transformations, transport, and pollutant removal. This study utilizes the CAMx Anthropogenic Precursor Culpability Assessment (APCA) version of the Ozone Source Apportionment Technology (OSAT) and the Particulate Source Apportionment Technology (PSAT) to evaluate the impacts and contributions to air quality of the seven emission sectors listed above.

CAMx includes two ozone source-apportionment tools, OSAT and APCA. CAMx also includes PSAT, which performs source apportionment for PM species. All three source-apportionment techniques use reactive tracers (also called tagged species) that run in parallel to the host model to determine the contributions to ozone and PM from individual user-selected Source Groups.

- Ozone Source Apportionment: The OSAT method follows VOC and NO_X emissions from each Source Group. When ozone is formed in the host model, OSAT estimates whether ozone formation was more VOC-limited or NO_X-limited and then allocates the ozone formed to Source Groups based on their relative contributions of the limiting precursor. The APCA ozone source-apportionment technique differs from OSAT in that it recognizes that some emissions are not controllable (for example, biogenic emissions), so it focuses ozone source-apportionment on controllable emissions. In a case in which ozone is formed as a result of the interaction of biogenic VOC and anthropogenic NO_X emissions under VOC-limited conditions (a case in which OSAT would assign the ozone formed to the biogenic VOC emissions), APCA redirects the ozone formed to the controllable anthropogenic NO_X emissions. Thus, in APCA the only ozone attributable to biogenic emissions is when ozone is formed as a result of the interaction of biogenic VOC and biogenic NO_X emissions. For each Source Group, OSAT/APCA uses four reactive tracers to track its ozone contribution: the Source Group's VOC and NO_X emissions and ozone attributed to the Source Group that is formed under VOC-limited or NO_X-limited conditions (O3V and O3N).
- Particulate Source Apportionment: The CAMx PSAT particulate source apportionment method has five different families of tracers that can be invoked separately or together to track source apportionment of the following particulate species: Sulfur (SO_4), Nitrogen (NO_3/NH_4), Primary PM, and Secondary Organic Aerosol (SOA). Because PSAT needs to track the PM source apportionment from the PM precursor emissions to the PM species, the number of tracers needed to track a Source Group's source apportionment depends on the complexity of the chemistry and the number of PM species involved. The sulfur family requires only two reactive tracer species (SO_2 and SO_4) to track the formation of particulate sulfate from SO_2

emission source contributions for each Source Group. In contrast, the SOA family is the most expansive PSAT family, with 18 reactive tracers needed for each Source Group in order to track the four VOC precursors (aromatics, isoprene, terpenes, and sesquiterpenes) and the 7 condensable gas (CG) and SOA pairs.

Assessment Methodology

The objective of the assessment is to determine how electrification could influence air quality and deposition in 2030 by comparing two model-scenarios: the 2030 Base Case and Electrification Case. Spatial maps are shown for the Base Case results, and for differences between the two scenarios for ozone-mixing ratios, PM concentrations, and deposition fluxes. For deposition fluxes, which are strongly influenced by precipitation patterns, it is also instructive to show percent changes in deposition fluxes in order to better ascertain the influence of the emissions changes.

Air Quality Modeling Results

Air quality modeling results for the year-2030 simulations are presented by the pollutant of concern, beginning with ozone.

Ozone

The annual maximum 8-hour ozone concentration may be susceptible to model artifacts, and so we focus on the annual 4th highest 8-hour ozone concentration (Figure 8-1, top).[17] The Base Case modeled annual 4th highest 8-hour ozone shows high values (above 90 ppb) in Los Angeles (CA) and over water bodies close to major urban/industrial areas near the Great Lakes, Gulf Coast, and the Northeastern Seaboard, where emissions are transported over water and confined to a shallow boundary layer. The current ozone standard (0.075 ppm for the 4th highest 8-hour ozone, averaged over 3 years) is exceeded in several urban areas—including Houston (TX), St. Louis (MO), Baton Rouge (LA), and Atlanta (GA).

Source contributions to summer average daily maximum 8-hour ozone concentrations are shown in Appendix E. Area and non-EGU sources are the main contributors to the high 8-hour ozone concentrations (Figure E-1). Non-road sources also contribute to high ozone in many urban areas (up to 19 ppb in Los Angeles) and in areas near the Gulf Coast. The contributions of EGUs to the 8-hour ozone are seen mostly in the Eastern United States, and they are localized (along the Ohio Valley and in Northeastern Texas). The impacts of heavy-duty and light-duty vehicles are widespread in the Eastern United States, but they are generally less than 3 ppb.

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[17] The 4th highest 8-hour ozone concentration is calculated separately for each cell, so the same color represents the same concentration level, but adjacent cells may experience this maximum concentration during different days.

Ozone benefits related to electrification of mobile sources are estimated to occur (Figure 8-1, bottom) across the CONUS. These are modest reductions, mostly less than 1 ppb. Many urban areas, including cities that exceed the current level of the ozone standard, see larger ozone reductions as high as 3 ppb. The largest reduction (of 4 ppb) is estimated to occur in Los Angeles. These ozone reductions result mostly from decreases in the non-road sector emissions resulting from the electrification of non-road equipment. Ozone benefits from the non-road sector are widespread in the United States (Figure 8-1). Areas near the Gulf Coast and Los Angeles also receive benefits from commercial marine emissions reductions in the Electrification Case. Ozone increases (less than 1 ppb) are restricted to a few grid cells in rural areas.

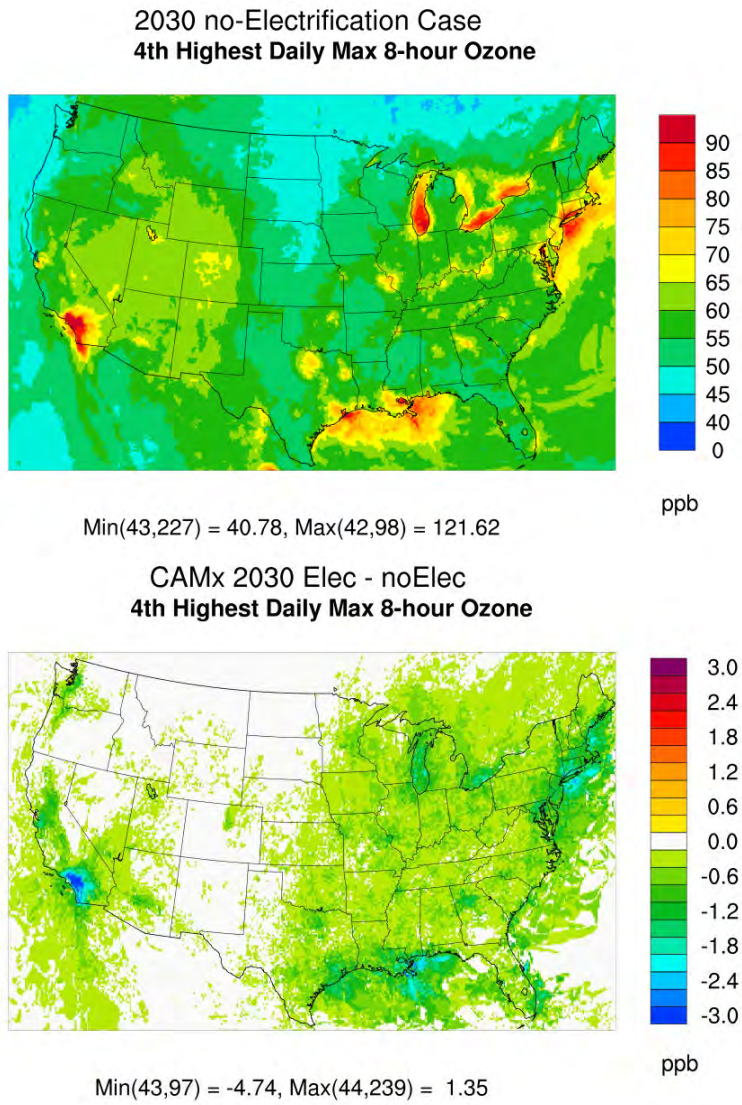

Figure 8-1
Annual 4th highest 8-hour-ozone (ppb) for Base Case (top) and difference between Electrification Case and Base Case (bottom)

Particulate Matter (PM)

PM is a mixture of particles that are directly emitted (primary particles) and particles that form in the atmosphere (secondary particles). Primary particles can be composed of a variety of inorganic and organic compounds. In general, secondary particles are composed of sulfate, nitrate, ammonium, and secondary organic aerosol that originate from emissions of precursor gases: SO2, NOx, NH3, and VOC. The resultant PM mixture in the atmosphere is thus made up of constituents that are of both biogenic and anthropogenic origin.

PM results are presented for both $PM_{2.5}$ (representing fine PM) and PM_{10} (representing the sum of fine and coarse PM). Although there is no longer an annual average standard for PM_{10}, this section presents results for daily design-value relevant measures (98th percentile of all daily concentrations) and annual average concentrations (which only hold design-value relevance for $PM_{2.5}$ at present) for both measures of ambient particles.

The Base Case 8th highest 24-hour average concentrations of fine $PM_{2.5}$ and PM_{10} (Figure 8-2 and Figure 8-3, respectively) show that the highest peak values occur in the Western (especially Idaho and Montana) and Southwestern United States. The causes of the high modeled PM concentrations may be inferred from the source-contribution analysis and chemical composition of the PM. Some peaks in the states with high PM occur in urban areas, such as Portland and Seattle (characterized by high nitrate and organic carbon). Other peaks, especially the peaks in rural areas, are associated with wildfire emissions (indicated by high primary organic carbon). Areas of high PM associated with high wildfire emissions include Idaho, Montana, California, Alabama, Georgia, and North Carolina. The same wildfire emissions are included in the emissions inventory for the Base Case and Electrification Case modeling. The 8th highest 24-hour average concentrations of fine $PM_{2.5}$ are more uniform (generally below 20 $\mu g\ m^{-3}$) in the Eastern United States. High PM concentrations in the Eastern United States have large sulfate and nitrate, with additional contributions from primary organic PM in the south.

Electrification of mobile sources reduces the 8th highest 24-hour average PM concentrations (Figure 8-2 and Figure 8-3) in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are modest (generally less than 0.5 $\mu g\ m^{-3}$), but they are consistent. PM benefits are mostly from electrification of non-road sources, with close to 2 $\mu g\ m^{-3}$ reductions in Los Angeles. Annual average concentrations of $PM_{2.5}$ and PM_{10} (Figure 8-4 and Figure 8-5) show a similar pattern of modest reductions—mostly in urban areas because of electrification of mobile sources.

Source contributions to annual average $PM_{2.5}$ concentrations are shown in Appendix E (Figure E-2). Area and non-EGU sources are the main contributors to average $PM_{2.5}$ concentrations (up to 21 $\mu g\ m^{-3}$). Non-road sources also contribute to average $PM_{2.5}$ in many urban areas (up to 4 $\mu g\ m^{-3)}$ in Los Angeles). Contributions of EGUs to $PM_{2.5}$ are small (generally less than 0.5 $\mu g\ m^{-3}$, and are seen mostly in the Eastern United States. The impacts of heavy-duty and

light-duty vehicles are up to 1 μg m^{-3} in Los Angeles and are generally less than 0.5 μg m^{-3} elsewhere.

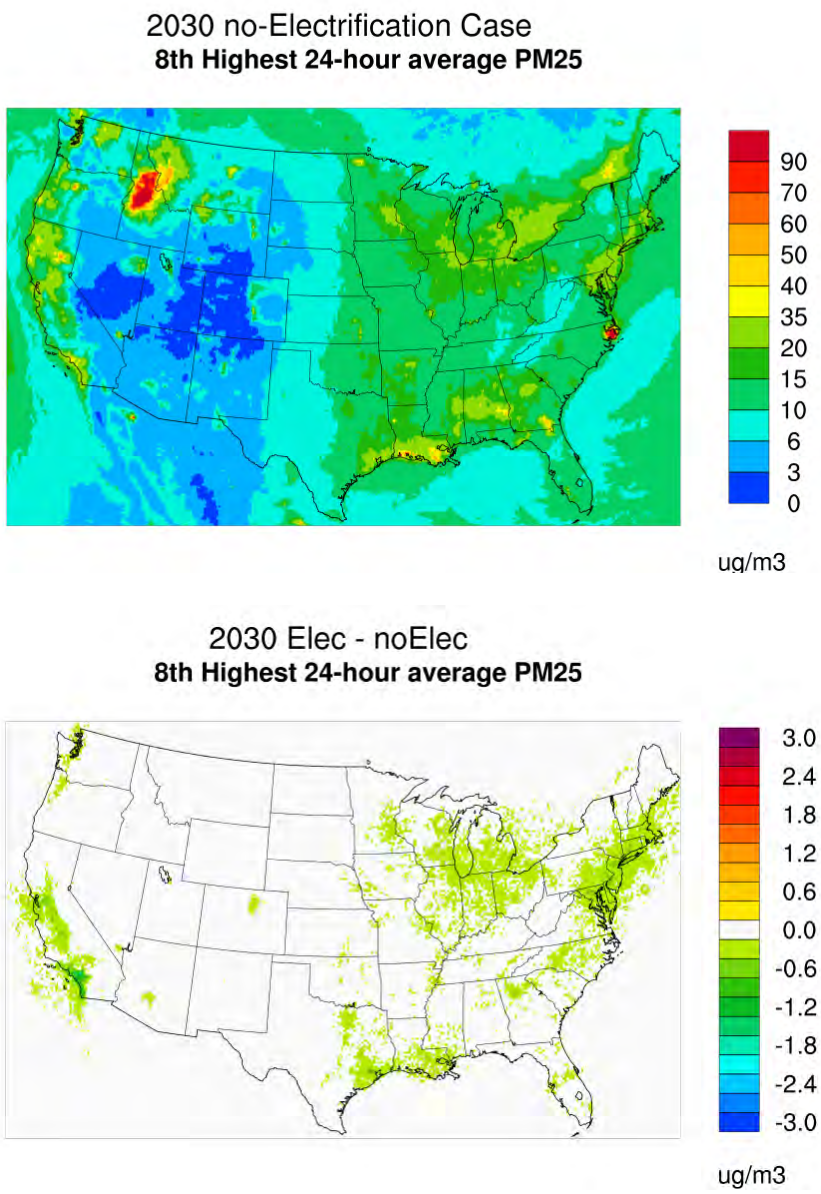

Figure 8-2
Annual 8th highest 24-hour average concentrations (μg m^{-3}) of $PM_{2.5}$ (top) and difference between Electrification Case and Base Case (bottom)

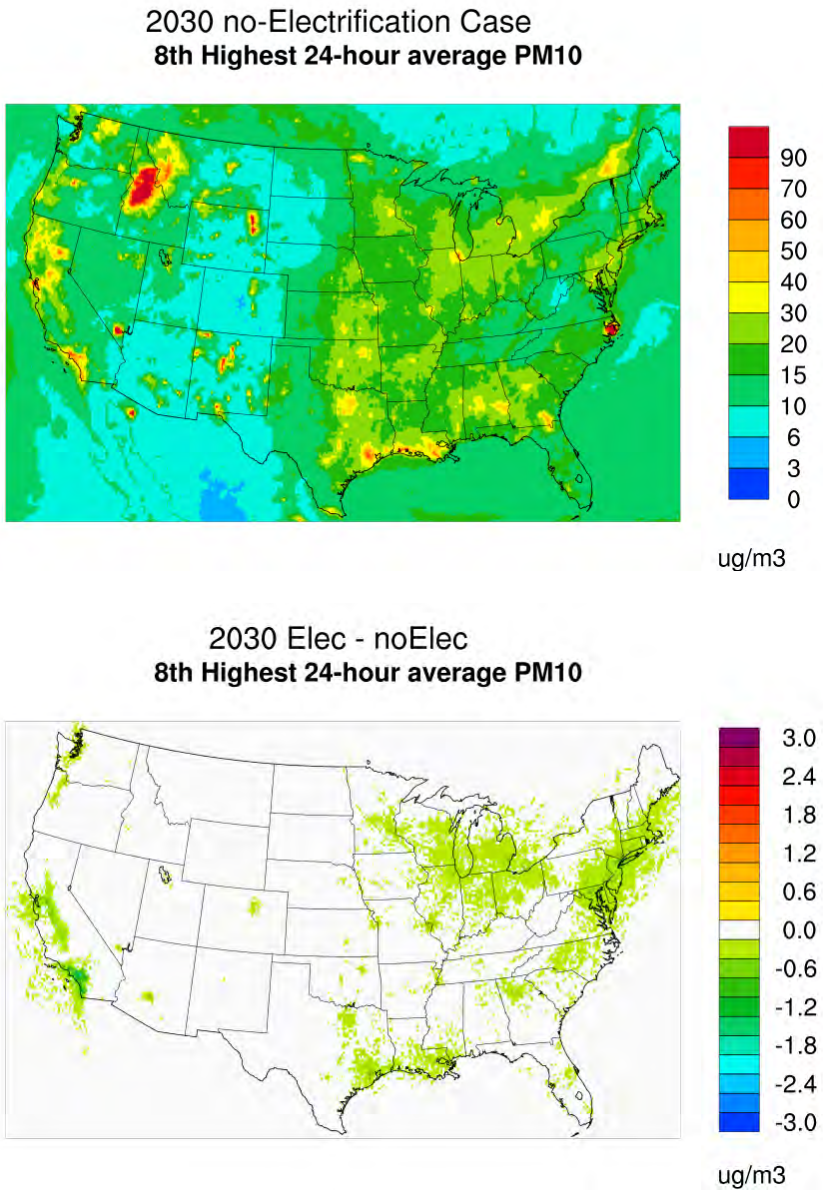

Figure 8-3
Annual 8th highest 24-hour average concentrations (μg m^{-3}) of PM_{10} (top) and difference between Electrification Case and Base Case (bottom)

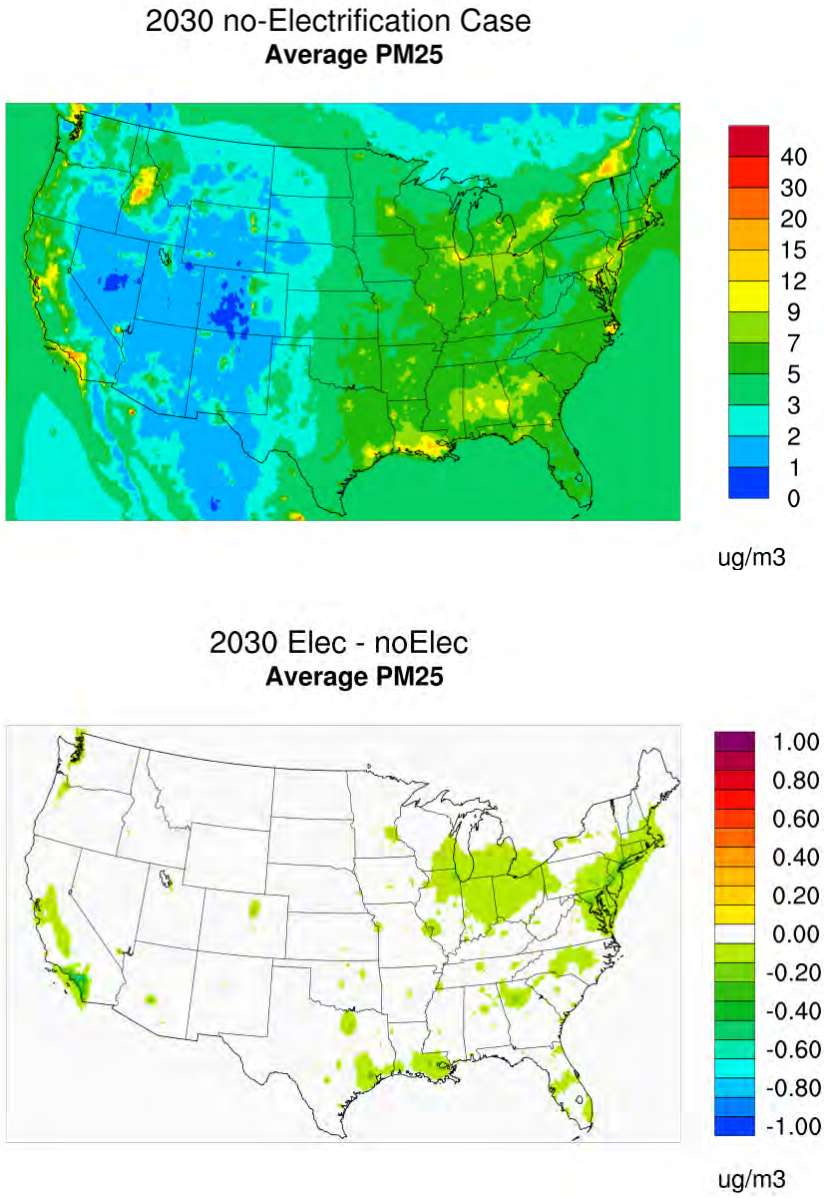

Figure 8-4
Annual average concentrations (μg m^{-3}) of $PM_{2.5}$ (top) and difference between Electrification Case and Base Case (bottom)

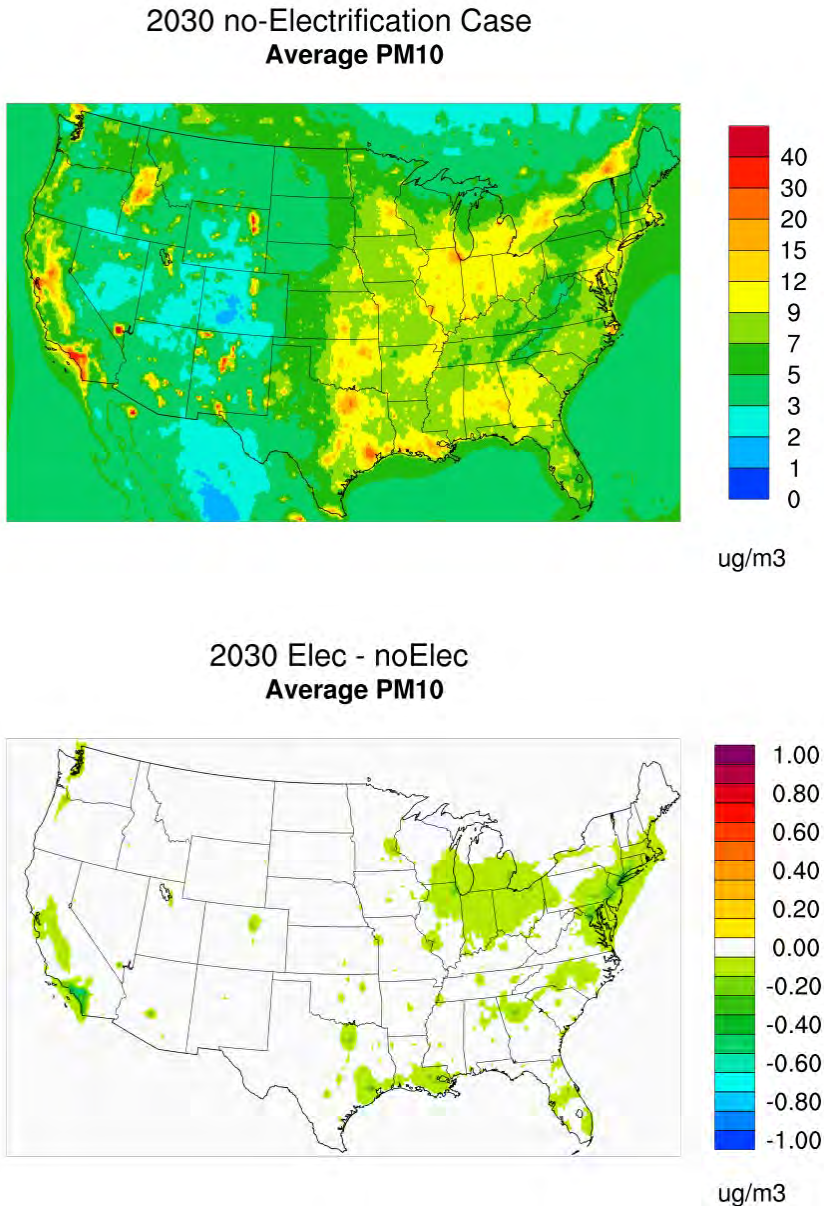

Figure 8-5
Annual average concentrations (μg m^{-3}) of PM_{10} (top) and difference between Electrification Case and Base Case (bottom)

Sulfate, Nitrate, and Total Nitrogen Deposition

Figures illustrating deposition results for sulfate, nitrate, and total nitrogen are presented on the following pages–including maps of annual sulfate (Figure 8-6 and Figure 8-7), nitrate (Figure 8-8 and Figure 8-9), and nitrogen (Figure 8-10, Figure 8-11) deposition.

Base case annual sulfate and nitrate deposition maps (Figure 8-6, top, and Figure 8-8, top, respectively) show that sulfate and nitrate deposition occurs mainly in the Eastern United States. Sulfate deposition (combined particulate sulfate and sulfuric acid) is high in Texas and along the Ohio River Valley, where many power plants are located. High sulfate deposition in southern Texas is influenced by sources in Mexico. Nitrate deposition (combined particulate nitrate and nitric acid) shows a similar distribution, with the addition of some high deposition in urban areas. Total nitrogen deposition (combined nitrate and ammonia/ammonium) is dominated by reduced nitrogen (ammonia and ammonium) and is high in agricultural areas such as the Midwestern United States.

Electrification of mobile sources increases sulfate deposition (Figure 8-6, bottom) in parts of the Eastern United States—including South Carolina, North Carolina, and Virginia—where power plant SO_2 emissions are higher in the Electrification Case than in the Base Case. However, these increases are generally less than 0.1 kg/ha (1% of the Base Case deposition) and increase up to 0.2 kg/ha (3% of Base Case deposition flux) in areas near power plants. The largest sulfate-deposition reductions (of about 0.4 kg/ha) are seen in Texas and Louisiana, and they are probably the result of lower refinery and non-road emissions in the Electrification Case. Along the Ohio Valley, power plant SO_2 emissions are mostly lower in the Electrification Case, resulting in decreases in sulfate deposition (generally less than 0.1 kg/ha) in the Midwest. We note that the 2007 baseline model performance indicates over estimation bias of sulfate deposition. In addition, the air quality model configuration used in this study did not use a sub-grid scale treatment to explicitly simulate the unique chemistry and transport dynamics of power plant plumes.

Figure 8-8 (bottom) shows that electrification of mobile sources reduces nitrate acid deposition across the United States. Several factors can contribute to lower nitrate deposition, with lower mobile-source NO_x emissions reducing the amount of nitrate formed and deposited being the chief factor, especially in urban areas. Los Angeles experiences the highest reduction of nitrate deposition: up to 2.6 kg/ha (10% of the Base Case deposition). Changes in electricity generation reduce NO_x emissions in some locations (for example, some parts of the Ohio River valley) and increase NO_x emissions elsewhere (for example, South Carolina, North Carolina, and Virginia). However, these NO_x emissions increases do not lead to increases in nitrate deposition above 0.1% at any location in the United States.

Total nitrogen includes the deposition of oxidized nitrogen (for example, nitric acid and nitrate) and reduced nitrogen (for example, ammonia and ammonium). Nitrogen deposition results in an increase to nutrient levels in ecosystems which may contribute to adverse ecological impacts, such as eutrophication of water bodies leading to hypoxic conditions that can adversely affect ecosystems. Because nitrogen deposition is dominated by reduced nitrogen (ammonia and ammonium associated with nitrate and sulfate particles), it follows reductions in sulfate and nitrate deposition throughout the Eastern United States (Figure 8-10) and near major urban areas results from lower mobile-source ammonia

emissions in the Electrification Case. Multiple urban areas (including Los Angeles, Dallas, Houston, Denver, and Atlanta) and large port cities (such as Fort Lauderdale, New Orleans, and the San Francisco Bay Area) have nitrogen reductions higher than 3% (Figure 8-11).

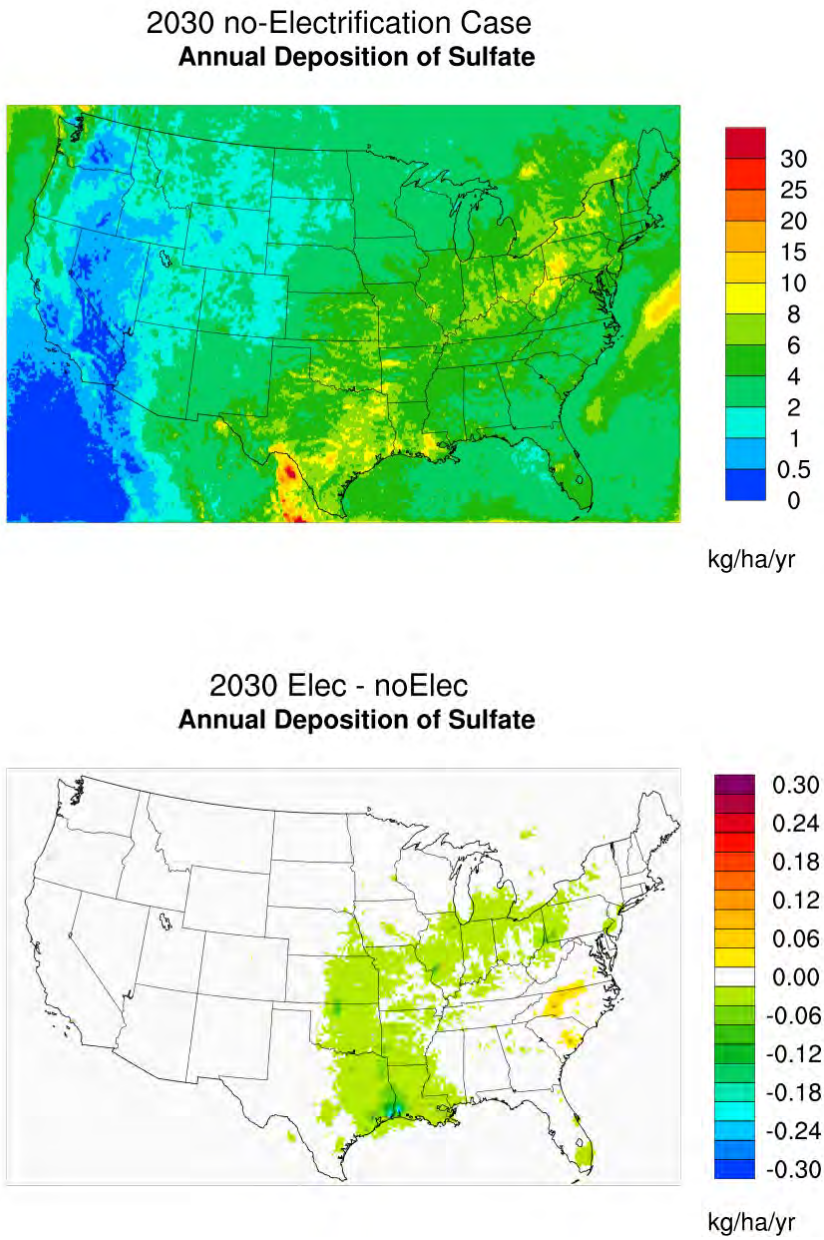

Figure 8-6
Annual deposition (kg Ha^{-1}) of sulfate for 2030 Base Case (top), difference between Electrification Case and Base Case (bottom), and percentage difference between Electrification Case and Base Case (bottom)

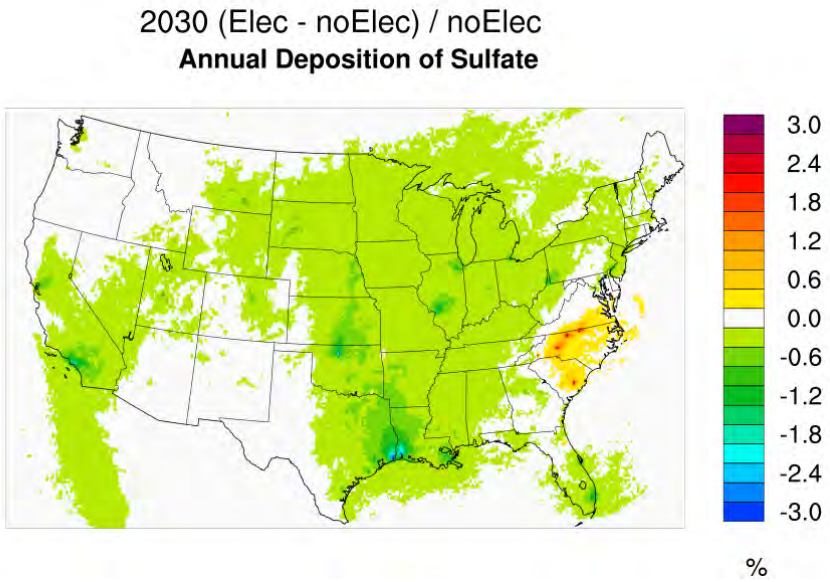

Figure 8-7
Percentage difference in annual deposition (kg Ha^{-1}) of sulfate between Electrification Case and Base Case

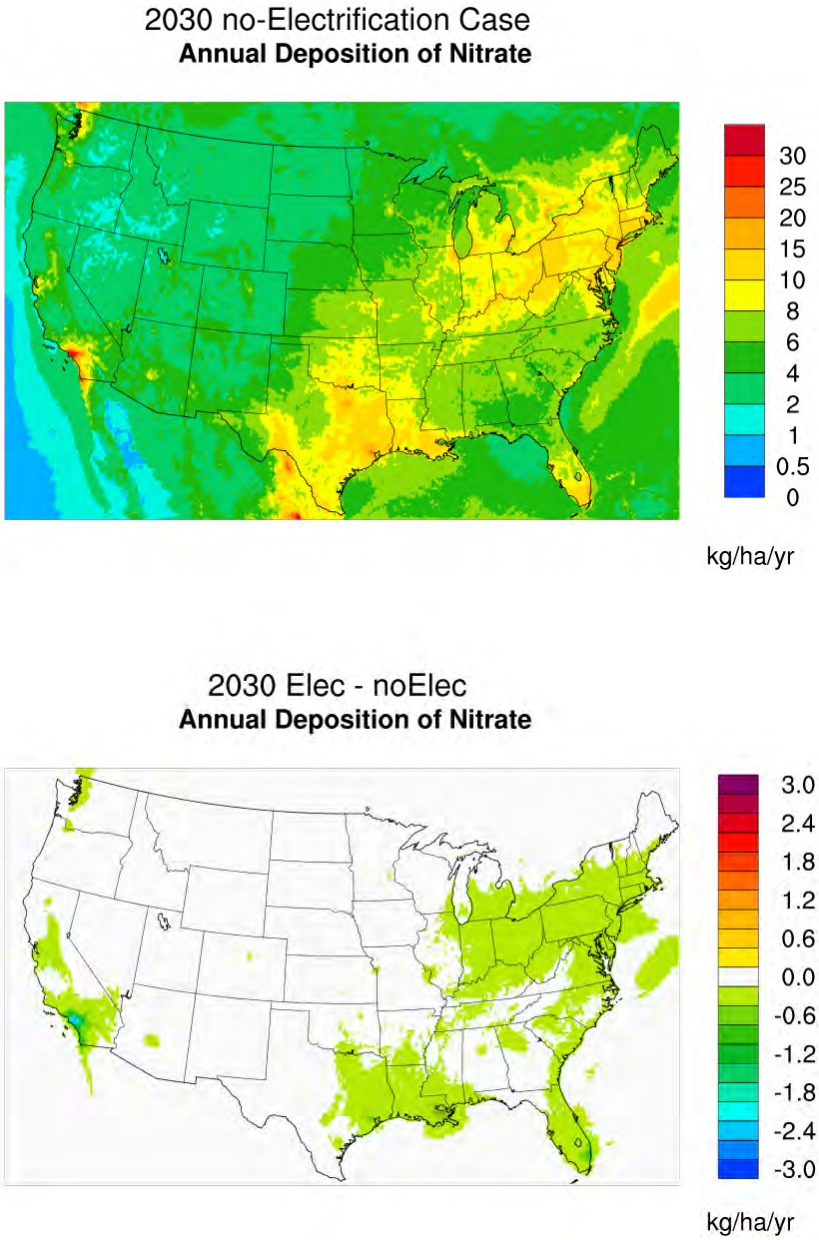

Figure 8-8
Annual deposition (kg Ha-1) of nitrate for 2030 Base Case (top), difference between Electrification Case and Base Case (bottom)

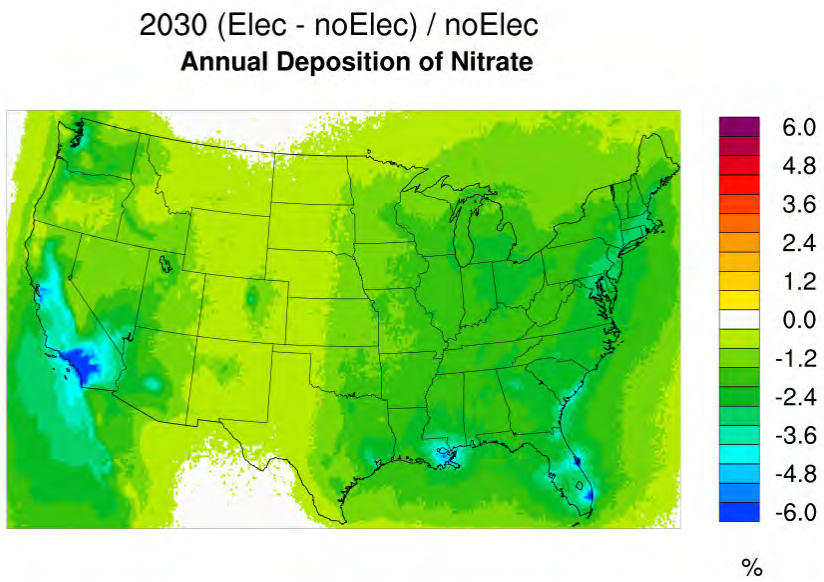

Figure 8-9
Percentage difference in annual deposition (kg Ha-1) of nitrate between Electrification Case and Base Case

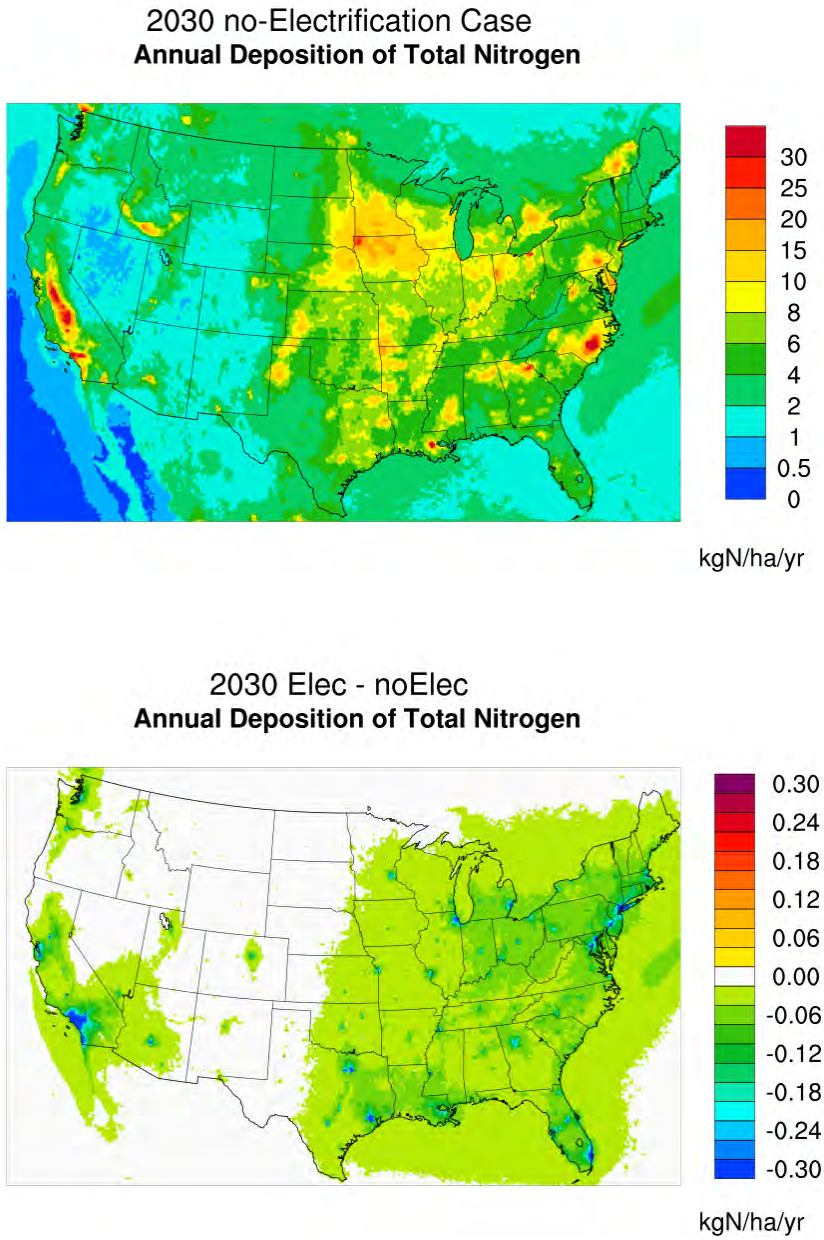

Figure 8-10
Annual deposition (kg Ha^{-1}) of total nitrogen for 2030 Base Case (top), difference between Electrification Case and Base Case (bottom)

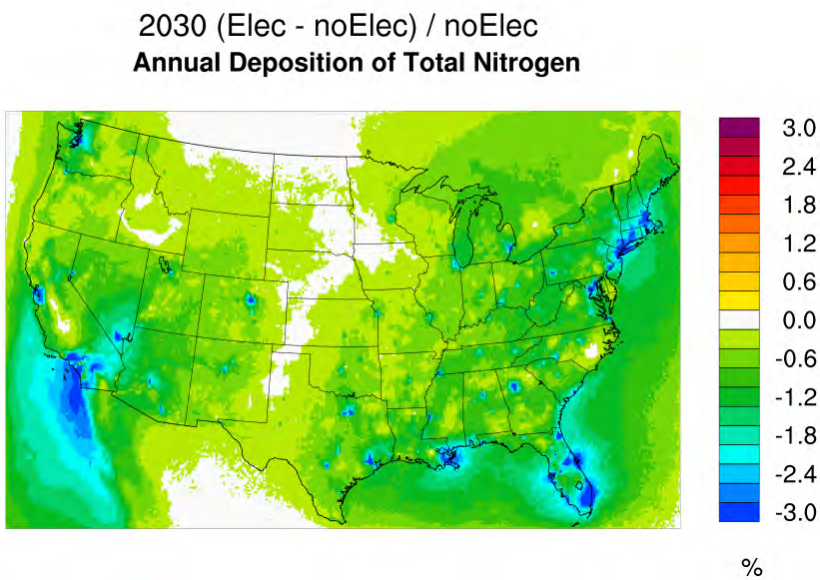

Figure 8-11
Percentage difference in annual deposition (kg Ha^{-1}) of total nitrogen between Electrification Case and Base Case (bottom)

Air Quality Modeling Summary

The air quality impacts of electrification technology are summarized in this section.

Ozone

Mobile-source electrification reduces ozone across the CONUS. Reductions are generally modest: commonly less than 1 ppb. Higher reductions are seen in major urban areas, with the highest reduction (of 4 ppb) in Los Angeles. These reductions are mainly attributable to electrification of non-road sources.

Particulate Matter

Mobile-source electrification reduces high 24-hour average PM concentrations in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are generally less than 0.5 μg m^{-3}. PM benefits mostly result from electrification of non-road sources, with reductions of close to 2 μg m^{-3} in Los Angeles. Annual average concentrations of $PM_{2.5}$ and PM_{10} show a similar pattern of modest reductions, mostly in urban areas as a result of electrification of mobile sources. The PM reductions are attributable partly to decreases in primary emissions of PM, but result mainly from reductions in VOC and NO_x emissions—leading to less secondary PM formation.

Sulfate, Nitrate, and Nitrogen Deposition

Most areas (97%) are exposed to lower sulfate deposition in the Electrification Case. Mobile electrification does not introduce any disadvantage for nitrate deposition. The net impact on nitrogen deposition is an overall reduction in total continental deposition, and benefits are more widespread than disadvantages.

Section 9: Findings

Summary of Results

Emissions of Criteria Pollutants

The overall effect of electrification on emissions across all sectors was a reduction in emissions across all pollutants. Continental United States (CONUS) NO_x emission decreases of 3% were estimated, with 57% of the reduction attributable to non-road sector electrification and 42% of the reduction attributable to on-road vehicle electrification. Smaller emission reductions for VOC (4%) were estimated; 65% of the VOC reduction was attributable to non-road sector electrification and 24% of the VOC reduction came from the area-source sector (primarily attributable to reductions in upstream emissions associated with crude-oil and gasoline shipments and refining). SO_x emission reductions of 0.5% were estimated across the CONUS, with 71% of the reduction coming from upstream non-EGU point sources. PM_{10} emission reductions of 0.4% were estimated, with 57% of the reduction coming from non-road electrification and 36% of the reduction coming from on-road vehicle electrification.

Air Quality

Air quality modeling results indicate that the air quality benefits associated with electrification, while modest, are widespread across the CONUS.

Most ozone reductions are nominal—generally less than 1 part per billion (ppb). Notably, many urban areas, including cities that exceed the current level of the ozone standard, see larger ozone reductions (as high as 3 ppb). The largest reduction (of 4 ppb) is estimated to occur in Los Angeles. These ozone reductions are attributable mostly to decreases in non-road sector emissions resulting from the electrification of non-road equipment. Ozone benefits from the non-road sector are widespread across the CONUS. In the Electrification Case, areas near the Gulf Coast and Los Angeles also receive benefits from commercial-marine emissions reductions associated with reduced crude-oil shipments. Ozone increases (less than 1 ppb) are restricted to a few grid cells in rural areas.

Electrification of mobile sources reduces the 8th highest 24-hour average $PM_{2.5}$ concentrations in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are modest (generally less than 0.5 μg m^{-3}), but they are consistent. PM benefits are mostly from electrification of non-

road sources, with close to 2 μg m^{-3} reductions in Los Angeles. Annual average concentrations of $PM_{2.5}$ and PM_{10} show a similar pattern of modest reductions—mostly in urban areas as a result of the electrification of mobile sources.

Total nitrogen includes the deposition of oxidized nitrogen (for example, nitric acid and nitrate) and reduced nitrogen (for example, ammonia and ammonium). Nitrogen deposition may adversely influence water quality and ecosystems. In the Electrification Case, total nitrogen deposition is reduced throughout the Eastern United States and near major urban areas, primarily resulting from lower mobile-source ammonia emissions. Multiple urban areas (including Los Angeles, Dallas, Houston, Denver, and Atlanta) and large port cities (such as Fort Lauderdale, New Orleans, and the San Francisco Bay Area) have nitrogen reductions of over 3%.

One factor that could improve our estimates would be to include upstream criteria emissions from natural gas and coal extraction resulting from higher electricity demand. Tessum et al (2014) reported that these emissions could add to air-pollution damages. In the Electrification scenario, our study assumed that natural gas generation is the main source to provide an additional 200 MMWh. We estimated that extracting natural gas to meet this need would add 22 and 80 thousand tons per year of NO_x and VOC, respectively. Although these emissions are modest, we did not evaluate their impacts spatially. Nonetheless, the emissions are marginally lower than those associated with domestic crude-oil extraction (96 and 340 thousand tons per year of NO_x and VOC, respectively). The crude-oil extraction emissions would have been included had we assumed that reduced fuel usage attributable to electrification impacts domestic production, whereas crude-oil imports remain unchanged.

Key Findings

Emissions of Criteria Pollutants

- **On-road Vehicles.** Even with the recently promulgated Tier 3 on-road vehicle standards, on-road emissions reductions of VOC (6%), CO (9%), NO_x (7%), PM_{10} (7%), and $PM_{2.5}$ (7%) associated with vehicle electrification are significant. The benefits for on-road vehicle SO_2 and NH_3 emissions are slightly larger, at 16% and 14%, respectively.
- **Non-road equipment.** Non-road emissions decreases as a result of electrification are modest for VOC (17%), CO (22%), PM_{10} (14%), $PM_{2.5}$ (14%)—with lawn and garden equipment accounting for over two-thirds of total non-road electrification emission reductions for these pollutants.
- **EGUs.** Emission increases at EGUs as a result of electrification of mobile sources are small. Relative to reductions in emissions as a result of electrification, emissions increases at EGUs are 2% of NO_x and SO_2 and less than 1% of PM_{10} emission reductions.
- **Upstream.** Emission reductions for upstream sources are in the range of 11 to 17% for refinery, downstream, and refueling sources and between 2 and 4% for marine sources. Relative to emission decreases from mobile sources,

upstream emission reductions are small for all pollutants except VOC. VOC emissions from the upstream sector account for about a quarter of emission reductions resulting from electrification.

Air Quality

- Ozone benefits related to electrification of on-road and non-road mobile sources occur across the United States. Many urban areas, including cities with ambient air quality exceeding the current ozone standard, see reductions in the 4th highest 8-hour average ozone concentration of up to 4 ppb. The ozone decreases are attributable mostly to decreases in non-road sector emissions resulting from electrification of non-road equipment.
- Electrification of mobile sources reduces the 8th highest 24-hour average PM concentration in many areas of the Eastern United States, in California, and in the Pacific Northwest. These reductions are modest (generally less than 0.5 $\mu g\ m^{-3}$), but they are widespread. PM_{10} and $PM_{2.5}$ benefits derive mostly from electrification of non-road sources.
- Most areas in the CONUS (97%) see reductions in sulfate deposition resulting from electrification of mobile sources.
- Electrification of mobile sources reduces nitrate and total nitrogen deposition across the United States.

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Appendix A: Differences Between Grid-Modeling Assumptions in Volume 2 and Volume 3

The grid-modeling scenarios used in the greenhouse gas analysis in Volume 2 differ slightly from the scenario used in the air quality modeling in Volume 3 because of differences in the focus of each analysis and the estimates for certain assumptions when the modeling was completed.

Table A-1 provides a high-level comparison of the timeframe, resolution, and scope of each analysis. These analyses were both designed to be estimates of the effects of a large-scale shift to electric transportation, and they are generally consistent. However, differences in the modeling techniques and analysis requirements for the two focus areas did lead to variation.

Table A-1
Overview of modeling approach for this assessment

	Volume 2: Greenhouse gas impacts	**Volume 3: Air quality impacts**
Timeframe	2015-2050	2030
Measurement methodology	Large-scale marginal	
Regional resolution	US-REGEN regions; most results presented nationally	Electricity modeled using US-REGEN regions; emissions modeled using a 12-km grid
Emissions scope	Direct and upstream for all fuel pathways; battery manufacturing emissions included	Direct and upstream for all fuel pathways[18]

[18] As described in Volume 3, fuel-extraction emissions are not modeled for either petroleum or electricity fuels. This omission is discussed in more detail in Section 10:.

US-REGEN Scenarios for Greenhouse Gas and Air Quality Modeling

Table A-2 shows a comparison of the assumptions used in the three main scenarios. The Air Quality Base Case reflects the default assumptions in US-REGEN at the time modeling was initiated. The Greenhouse Gas Base Case updates some of these assumptions to reflect revised expectations for nuclear generation. The Greenhouse Gas Low-CO_2 Case creates an alternative policy framework with an internalized carbon cost to encourage the reduction in the carbon intensity of generation. Note that the carbon cost specified is not a recommendation of the modeling team; it stands in for a variety of potential carbon-reduction policies. Each of these scenarios is described in more detail in Volume 2 and Volume 3.

Table A-2
Comparison of assumptions for the three main scenarios

Assumption	Greenhouse Gas Base Case	Greenhouse Gas Low-CO_2 Case	Air Quality Base Case
Baseline load growth and fuel prices (except natural gas)[19]	Calibrated to AEO2011	Calibrated to AEO2011	Calibrated to AEO2011
Baseline natural gas	Calibrated to AEO2013	Calibrated to AEO2013	Calibrated to AEO2013
Energy efficiency	Some implicit in AEO2011	Some implicit in AEO2011	Some implicit in AEO2011
Existing nuclear plants	5GW is retired to reflect expected near-term retirements	5GW is retired to reflect expected near-term retirements	**Base assumption (the 5GW is not retired)**
New nuclear plants before 2020	Limits as shown in Figure A-1		
Carbon tax	No explicit tax	**Cost of $20/ton is introduced in 2016 and increased in 5-year timesteps by 28% (average annual rate of 5% per year)**	No explicit tax

[19] "Baseline" describes the load without transportation electrification; separate scenarios add this load to these base cases.

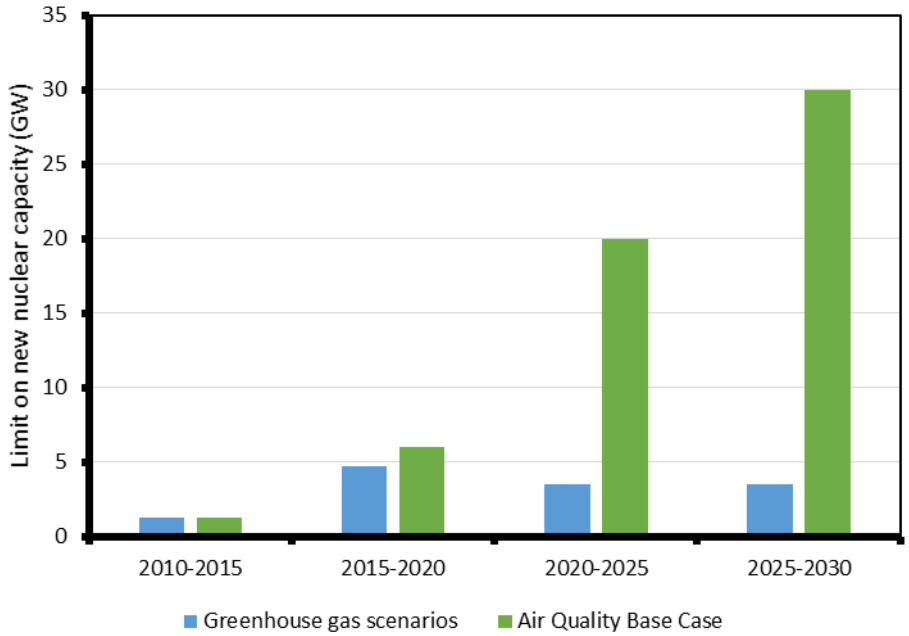

Figure A-1
Capacity limits for new nuclear construction

Comparison of Marginal Generation for Base Case Scenarios in 2030

The assumptions for the greenhouse gas analysis and the air quality analysis were generally selected to be consistent, but the discussion above reflects some differences between the grid-modeling base cases. This is a particular concern, because the main difference between the two scenarios is the increased availability of nuclear in the Air Quality Base Case. With reduced nuclear availability, it is possible that higher-emitting generation could fill this gap. Figure A-1 shows the incremental generation for both base cases. Despite the increased availability of nuclear in the Air Quality cases, there is no net change in generation, so it does not enter the marginal mix at the national level. The difference between these scenarios does change the economics of generation, however, so there are regional shifts in generation that result in Midwestern wind in the Air Quality cases being displaced by Southern natural gas in the Greenhouse Gas Base cases. (There are also some changes in imports and exports that result in regional shifts in total generation.) These changes in generation result in small changes in emissions, mainly in the South. The full effect of these changes on local emissions is uncertain, but it is likely to be minor. (See Appendix E for information on source apportionment.)

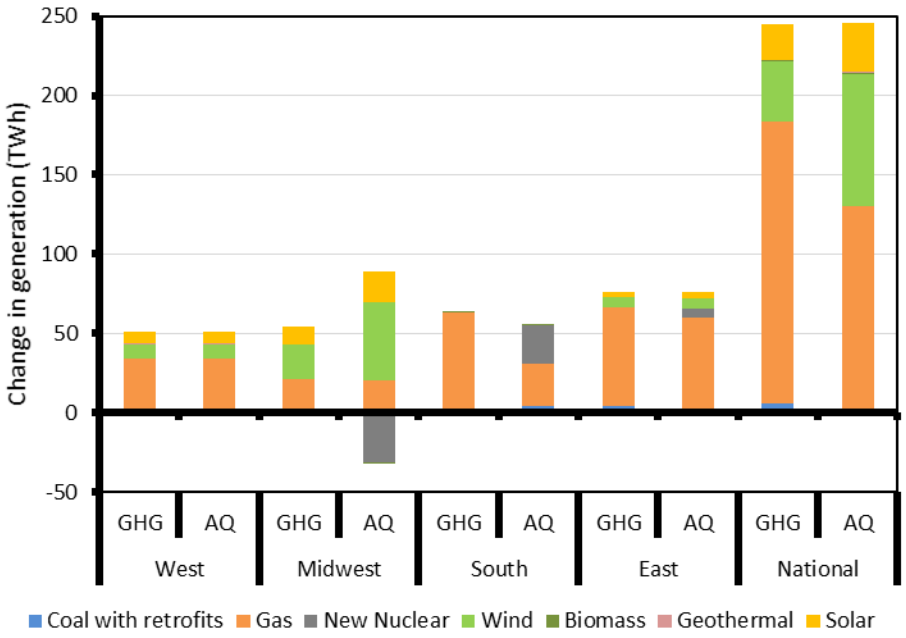

Figure A-2
Incremental 2030 generation resulting from electric transportation for the Greenhouse Gas Electrification and Air Quality Electrification cases

Appendix B: Vehicle Type Crosswalks

Table B-1
SCC Vehicle Type to MOVES Source Type Crosswalk for 2030

SCC Vehicle Type	MOVES Source Type	Percent of VMT
Light-Duty Vehicles		
LDGV	Passenger Car	100.0%
LDDV	Passenger Car	100.0%
LDGT1	Light Commercial Truck	22.4%
	Passenger Truck	77.6%
LDGT2	Light Commercial Truck	22.4%
	Passenger Truck	77.6%
LDDT	Light Commercial Truck	59.0%
	Passenger Truck	41.0%
MC	Motorcycle	100.0%
Heavy-Duty Vehicles		
HDGV	Combination Short-haul Truck	<0.1%
	Light Commercial Truck	22.1%
	Motor Home	3.1%
	Passenger Truck	37.5%
	Refuse Truck	0.0%
	School Bus	0.2%
	Single-Unit Long-haul Truck	4.7%
	Single-Unit Short-haul Truck	32.3%
	Transit Bus	<0.1%
HDDV2b	Light Commercial Truck	57.3%
	Passenger Truck	42.7%
HDDV345	Light Commercial Truck	62.3%
	Passenger Truck	37.7%

Table B-1 (continued)
SCC Vehicle Type to MOVES Source Type Crosswalk for 2030

SCC Vehicle Type	MOVES Source Type	Percent of VMT
HDDV67	Combination Long-haul Truck	5.3%
	Combination Short-haul Truck	16.4%
	Motor Home	3.5%
	Refuse Truck	<0.1%
	Single-Unit Long-haul Truck	9.6%
	Single-Unit Short-haul Truck	65.2%
HDDV8	Combination Long-haul Truck	54.3%
	Combination Short-haul Truck	30.4%
	Motor Home	0.1%
	Refuse Truck	0.6%
	Single-Unit Long-haul Truck	1.9%
	Single-Unit Short-haul Truck	12.7%
HDDB	School Bus	45.5%
	Transit Bus	11.3%
	Intercity Bus	43.2%
Passenger Car	LDDV	0.4%
	LDGV	99.6%
Passenger Truck	HDDV2b	0.3%
	HDDV345	1.3%
	HDGV	5.4%
	LDDT	0.6%
	LDGT1	60.9%
	LDGT2	31.4%
Light Commercial Truck	HDDV2b	1.3%
	HDDV345	6.6%
	HDGV	9.5%
	LDDT	2.8%
	LDGT1	52.7%
	LDGT2	27.2%
Motorcycle	MC	100.0%
Motor Home	HDDV67	48.1%
	HDDV8	1.4%
	HDGV	50.5%

Table B-1 (continued)
SCC Vehicle Type to MOVES Source Type Crosswalk for 2030

SCC Vehicle Type	MOVES Source Type	Percent of VMT
Single-Unit Long-haul Truck	HDDV67	51.0%
	HDDV8	19.0%
	HDGV	30.0%
Single-Unit Short-haul Truck	HDDV67	51.0%
	HDDV8	19.0%
	HDGV	30.0%
Combination Short-haul Truck	HDDV67	22.0%
	HDDV8	78.0%
	HDGV	<0.1%
Combination Long-haul Truck	HDDV67	4.9%
	HDDV8	95.1%
Refuse Truck	HDDV67	2.9%
	HDDV8	93.1%
	HDGV	4.0%
School Bus	HDDB	95.8%
	HDGV	4.2%
Transit Bus	HDDB	98.9%
	HDGV	1.1%
Intercity Bus	HDDB	100.0%

Appendix C: Base and Electrification Case by State On-Road Vehicle Emissions for Light- and Heavy-Duty Vehicle Types

Table C-1
Base case by state on-road vehicle emissions for light-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Light-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
AL	30.6	731.1	27.7	0.3	3.9	172.8
AZ	37.3	597.1	34.2	0.3	4.1	174.8
AR	20.3	462.9	18.5	0.1	2.1	90.7
CA	138.6	1,201.5	85.4	3.3	25.2	1,050.8
CO	29.3	713.4	23.9	0.3	3.4	146.2
CT	16.8	370.1	14.0	0.1	2.2	93.1
DE	4.6	117.9	4.3	0.0	0.6	25.9
DC	2.1	51.9	1.9	0.0	0.3	10.7
FL	119.9	2,102.7	91.2	1.0	13.5	580.7
GA	52.5	1,276.6	54.5	0.5	6.7	282.8
ID	8.9	268.9	8.6	0.1	1.0	41.4
IL	61.6	1,661.9	59.0	0.5	7.1	294.1
IN	39.1	1,175.8	34.9	0.3	4.8	208.2
IA	17.2	545.9	15.1	0.1	2.0	88.5
KS	15.9	445.9	14.5	0.1	2.0	85.3
KY	25.1	594.6	22.4	0.2	3.1	135.1
LA	25.3	530.1	21.5	0.2	3.1	132.5

Table C-1 (continued)
Base case by state on-road vehicle emissions for light-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

Light-Duty Vehicles						
State	**VOC**	**CO**	**NO_X**	**SO_2**	**NH_3**	**VMT**
ME	8.7	270.5	8.3	0.1	0.9	39.4
MD	30.1	757.7	28.1	0.3	3.9	165.1
MA	24.3	738.4	23.0	0.3	3.8	163.2
MI	63.9	1,881.0	54.2	0.5	6.6	281.3
MN	35.9	1,226.5	31.2	0.3	3.8	164.0
MS	19.8	495.1	18.3	0.2	2.8	130.4
MO	42.1	1,039.5	37.6	0.3	4.6	193.7
MT	5.8	184.6	5.6	0.1	0.7	30.7
NE	10.5	325.2	9.8	0.1	1.2	53.5
NV	17.2	215.1	10.0	0.1	1.5	66.3
NH	6.5	205.6	6.0	0.1	0.9	37.9
NJ	36.7	1,007.5	34.3	0.4	5.2	223.7
NM	16.3	327.3	13.2	0.1	1.7	75.3
NY	63.8	1,993.1	65.7	0.7	9.4	402.0
NC	59.5	1,493.6	57.0	0.5	6.8	286.6
ND	4.4	149.2	3.9	0.0	0.5	22.4
OH	56.4	1,864.5	51.7	0.5	7.5	323.6
OK	28.3	640.4	24.4	0.2	3.2	140.8
OR	18.5	542.6	17.2	0.2	2.3	97.5
PA	100.1	1,747.7	49.4	0.5	7.7	322.1
RI	6.6	121.9	3.8	0.0	0.6	26.3
SC	28.6	656.9	25.7	0.2	3.2	137.1
SD	5.0	162.1	4.4	0.0	0.6	25.6
TN	39.5	907.2	36.0	0.3	4.4	185.5
TX	105.6	2,460.9	109.1	1.1	17.1	748.0
UT	17.3	419.0	15.6	0.1	1.8	73.9
VT	4.1	126.0	3.5	0.0	0.5	23.1
VA	48.3	1,198.6	46.0	0.4	5.6	234.6
WA	28.9	816.8	26.0	0.3	3.7	157.6
WV	12.2	364.1	10.9	0.1	1.3	57.9
WI	36.4	1,078.0	30.9	0.3	3.9	164.9
WY	5.5	171.4	4.9	0.0	0.6	26.8
Totals	**1,631.9**	**38,436.4**	**1,397.3**	**15.6**	**203.5**	**8,694.3**

Table C-2
Base case by state on-road vehicle emissions for heavy-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Heavy-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
AL	5.0	120.1	42.7	0.2	0.7	22.0
AZ	5.2	117.1	47.8	0.3	0.9	28.8
AR	3.7	75.7	32.6	0.1	0.4	11.7
CA	35.3	259.5	205.2	1.7	4.5	149.6
CO	3.0	80.2	24.9	0.1	0.4	13.2
CT	2.4	51.6	19.7	0.1	0.3	10.4
DE	0.8	18.9	5.8	0.0	0.1	2.9
DC	0.1	4.8	1.2	0.0	0.0	0.9
FL	11.9	335.6	91.9	0.7	2.0	65.2
GA	8.2	212.7	66.6	0.4	1.1	35.2
ID	2.3	65.4	14.7	0.0	0.2	5.8
IL	10.9	278.5	86.7	0.4	1.3	40.5
IN	8.8	172.0	78.5	0.3	0.9	27.3
IA	2.4	68.0	23.0	0.1	0.4	13.0
KS	2.1	58.7	18.9	0.1	0.3	10.8
KY	4.9	96.1	46.2	0.2	0.6	19.5
LA	4.6	87.4	40.3	0.2	0.5	16.5
ME	1.1	35.7	9.2	0.1	0.2	5.7
MD	3.2	98.5	26.5	0.2	0.5	16.4
MA	3.6	97.4	29.9	0.2	0.5	16.5
MI	8.3	292.5	64.3	0.4	1.2	39.8
MN	4.8	163.3	37.1	0.2	0.7	21.9
MS	3.7	87.9	33.8	0.2	0.6	18.3
MO	7.2	169.8	60.1	0.3	0.9	26.5
MT	1.1	24.5	11.0	0.1	0.2	5.0
NE	1.6	52.3	14.2	0.1	0.3	9.3
NV	1.4	23.7	11.9	0.0	0.1	3.7
NH	0.7	23.5	6.4	0.0	0.1	4.7
NJ	3.1	95.7	24.0	0.1	0.5	15.1
NM	2.7	50.9	26.7	0.1	0.4	11.1
NY	8.4	294.0	54.9	0.2	0.9	28.4
NC	7.1	241.4	60.3	0.4	1.2	39.0
ND	0.6	16.9	6.2	0.0	0.1	3.5

Table C-2 (continued)
Base case by state on-road vehicle emissions for heavy-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Heavy-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
OH	9.3	246.0	81.3	0.4	1.2	38.0
OK	3.8	94.5	33.8	0.2	0.6	18.7
OR	3.1	87.7	26.1	0.1	0.4	11.2
PA	8.0	243.9	69.8	0.3	1.1	36.5
RI	0.4	6.9	3.1	0.0	0.0	1.0
SC	4.4	118.0	36.2	0.2	0.6	19.3
SD	0.7	19.9	7.1	0.0	0.1	4.2
TN	5.9	168.7	52.0	0.3	1.0	32.6
TX	19.6	319.2	212.7	1.1	3.2	103.1
UT	1.9	57.9	16.2	0.1	0.3	9.2
VT	0.4	21.3	2.9	0.0	0.1	2.0
VA	5.3	139.6	46.3	0.2	0.7	23.1
WA	5.1	181.4	39.7	0.2	0.7	24.1
WV	1.7	60.3	14.6	0.1	0.3	8.2
WI	3.3	103.9	28.0	0.2	0.5	17.4
WY	1.0	21.9	10.2	0.0	0.1	4.5
Totals	**244.3**	**5,761.8**	**2,003.4**	**10.9**	**33.7**	**1,091.3**

Table C-3
Electrification case by state on-road vehicle emissions for light-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Light-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
AL	29.0	665.5	25.5	0.2	3.3	172.8
AZ	35.3	545.0	31.6	0.2	3.5	174.8
AR	19.1	422.5	17.1	0.1	1.8	90.7
CA	130.7	1,074.5	78.4	2.8	21.4	1,050.8
CO	27.7	648.7	22.0	0.2	2.8	146.2
CT	15.9	336.9	13.0	0.1	1.8	93.1
DE	4.3	107.5	4.0	0.0	0.5	25.9
DC	2.0	47.4	1.8	0.0	0.2	10.7
FL	113.4	1,915.0	84.1	0.8	11.5	580.7
GA	50.2	1,169.7	50.6	0.4	5.7	282.8
ID	8.5	246.0	8.0	0.1	0.8	41.4
IL	58.6	1,520.4	54.7	0.4	6.0	294.1
IN	37.0	1,070.4	32.2	0.3	4.1	208.2
IA	16.3	496.8	13.9	0.1	1.7	88.5
KS	15.1	406.1	13.4	0.1	1.7	85.3
KY	23.7	541.3	20.6	0.2	2.6	135.1
LA	24.0	482.9	19.9	0.2	2.6	132.5
ME	8.3	247.5	7.7	0.1	0.8	39.4
MD	28.5	690.3	25.9	0.2	3.3	165.1
MA	23.1	671.8	21.2	0.2	3.2	163.2
MI	60.4	1,714.4	50.0	0.4	5.6	281.3
MN	34.0	1,118.8	28.9	0.2	3.3	164.0
MS	18.7	448.9	16.7	0.2	2.4	130.4
MO	39.9	948.6	34.8	0.3	3.9	193.7
MT	5.5	168.0	5.1	0.0	0.6	30.7
NE	9.9	296.1	9.0	0.1	1.0	53.5
NV	16.1	194.9	9.2	0.1	1.3	66.3
NH	6.2	187.1	5.5	0.0	0.7	37.9
NJ	34.8	917.7	31.7	0.3	4.4	223.7
NM	15.4	297.9	12.1	0.1	1.5	75.3

Table C-3 (continued)
Electrification case by state on-road vehicle emissions for light-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

	Light-Duty Vehicles					
State	**VOC**	**CO**	**NO_X**	**SO_2**	**NH_3**	**VMT**
NY	60.8	1,818.6	60.6	0.5	8.0	402.0
NC	56.4	1,365.5	52.7	0.4	5.8	286.6
ND	4.2	135.7	3.6	0.0	0.4	22.4
OH	53.5	1,697.3	47.7	0.4	6.3	323.6
OK	26.8	583.1	22.5	0.2	2.8	140.8
OR	17.6	495.2	15.9	0.1	1.9	97.5
PA	92.1	1,562.8	44.4	0.4	6.4	322.1
RI	6.1	109.5	3.4	0.0	0.5	26.3
SC	27.1	599.1	23.8	0.2	2.7	137.1
SD	4.7	147.5	4.1	0.0	0.5	25.6
TN	37.4	828.9	33.3	0.3	3.7	185.5
TX	100.8	2,242.7	100.7	0.9	14.4	748.0
UT	16.4	382.8	14.4	0.1	1.5	73.9
VT	3.8	113.3	3.1	0.0	0.4	23.1
VA	45.9	1,094.9	42.6	0.3	4.7	234.6
WA	27.4	744.3	24.0	0.2	3.1	157.6
WV	11.5	332.1	10.0	0.1	1.1	57.9
WI	34.4	982.8	28.6	0.2	3.3	164.9
WY	5.2	156.0	4.5	0.0	0.5	26.8
Totals	**1,543.7**	**34,990.8**	**1,288.4**	**13.1**	**172.6**	**8,694.3**

Table C-4
Electrification case by state on-road vehicle emissions for heavy-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Heavy-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
AL	4.7	107.3	39.9	0.2	0.6	22.0
AZ	4.8	104.6	44.8	0.3	0.8	28.8
AR	3.5	67.8	30.5	0.1	0.4	11.7
CA	33.5	235.2	194.4	1.6	4.0	149.6
CO	2.8	71.6	23.2	0.1	0.4	13.2
CT	2.2	46.2	18.4	0.1	0.3	10.4
DE	0.7	16.9	5.4	0.0	0.1	2.9
DC	0.1	4.3	1.1	0.0	0.0	0.9
FL	11.1	299.2	85.8	0.6	1.8	65.2
GA	7.7	189.9	62.2	0.3	1.0	35.2
ID	2.1	58.2	13.3	0.0	0.2	5.8
IL	10.2	248.8	80.8	0.4	1.2	40.5
IN	8.2	154.3	73.5	0.3	0.8	27.3
IA	2.3	60.8	21.6	0.1	0.4	13.0
KS	2.0	52.5	17.6	0.1	0.3	10.8
KY	4.6	86.2	43.3	0.2	0.6	19.5
LA	4.3	78.4	37.7	0.2	0.5	16.5
ME	1.0	31.8	8.6	0.0	0.2	5.7
MD	3.0	87.8	24.7	0.1	0.5	16.4
MA	3.3	87.0	27.8	0.1	0.5	16.5
MI	7.7	260.7	59.8	0.4	1.1	39.8
MN	4.5	145.6	34.4	0.2	0.6	21.9
MS	3.4	78.6	31.6	0.2	0.5	18.3
MO	6.8	151.8	56.1	0.2	0.8	26.5
MT	1.0	21.9	10.4	0.0	0.1	5.0
NE	1.5	46.7	13.3	0.1	0.3	9.3
NV	1.3	21.2	11.1	0.0	0.1	3.7
NH	0.6	21.0	6.0	0.0	0.1	4.7
NJ	2.9	85.3	22.2	0.1	0.4	15.1
NM	2.6	45.7	25.0	0.1	0.3	11.1

Table C-4 (continued)
Electrification case by state on-road vehicle emissions for heavy-duty vehicle types, units of tons or million miles per average day (Total PM10 and PM2.5 emissions are unavailable by vehicle class because cold temperature adjustments to emissions were applied to aggregate emissions over multiple vehicle classes)

State	Heavy-Duty Vehicles					
	VOC	CO	NO_X	SO_2	NH_3	VMT
NY	7.8	261.3	50.4	0.2	0.8	28.4
NC	6.6	214.8	56.0	0.3	1.1	39.0
ND	0.6	15.2	5.8	0.0	0.1	3.5
OH	8.7	219.9	75.9	0.4	1.1	38.0
OK	3.6	84.5	31.6	0.2	0.5	18.7
OR	2.9	78.2	24.3	0.1	0.3	11.2
PA	7.5	217.5	64.9	0.3	1.0	36.5
RI	0.3	6.2	2.9	0.0	0.0	1.0
SC	4.1	105.2	33.7	0.2	0.5	19.3
SD	0.7	17.8	6.7	0.0	0.1	4.2
TN	5.5	150.6	48.6	0.3	0.9	32.6
TX	18.4	288.3	200.7	1.1	3.0	103.1
UT	1.8	51.6	15.0	0.1	0.3	9.2
VT	0.4	18.9	2.6	0.0	0.1	2.0
VA	5.0	124.6	43.2	0.2	0.7	23.1
WA	4.8	161.5	36.9	0.2	0.7	24.1
WV	1.6	53.7	13.5	0.1	0.2	8.2
WI	3.1	92.7	26.1	0.1	0.5	17.4
WY	0.9	19.6	9.6	0.0	0.1	4.5
Totals	**228.8**	**5,149.5**	**1,873.0**	**10.2**	**30.7**	**1,091.3**

Appendix D: By State Non-road Sector Emissions

Table D-1
Year 2030 U.S. lower-48 state Base Case non-road emissions by state (tons per year), excluding OGV emissions

State	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2
AL	22,395	244,674	28,954	1,748	1,572	189
AR	16,069	156,665	21,864	1,284	1,153	108
AZ	25,857	305,391	25,951	2,179	1,948	415
CA	165,608	1,272,066	138,403	15,443	11,897	2,462
CO	28,139	322,523	22,754	2,057	1,866	512
CT	13,132	181,755	10,886	892	817	109
DC	806	11,806	1,175	65	62	3
DE	3,237	46,219	5,913	349	322	48
FL	86,492	1,049,965	75,581	6,044	5,462	1,764
GA	35,381	442,002	39,978	2,897	2,650	1,123
IA	23,981	240,751	33,054	1,730	1,631	121
ID	16,559	119,795	9,654	1,018	911	73
IL	56,980	682,015	78,941	4,506	4,130	1,279
IN	31,091	364,695	38,233	2,388	2,160	269
KS	12,075	155,809	27,841	1,377	1,284	82
KY	17,057	187,957	29,084	1,524	1,422	345
LA	24,023	260,546	74,847	3,182	2,995	799
MA	25,281	349,394	20,518	1,737	1,567	347
MD	22,627	302,624	21,351	1,759	1,613	332
ME	23,883	133,500	8,596	1,051	953	77
MI	103,940	710,563	48,237	4,678	4,295	584
MN	68,109	440,152	41,675	3,317	3,049	524
MO	29,632	368,514	46,829	2,511	2,349	424
MS	14,977	144,840	22,906	1,212	1,096	139
MT	8,969	72,123	14,961	778	721	54
NC	36,874	472,655	32,370	2,722	2,474	616

Table D-1 (continued)
Year 2030 U.S. lower-48 state Base Case non-road emissions by state (tons per year), excluding OGV emissions

State	VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2
ND	8,607	69,471	19,867	1,006	931	65
NE	9,455	110,198	35,194	1,289	1,233	111
NH	13,763	105,042	4,824	613	555	47
NJ	32,013	470,137	38,643	2,593	2,403	612
NM	7,401	85,939	16,903	737	681	89
NV	11,555	143,049	12,904	975	894	448
NY	81,203	948,981	58,879	4,636	4,255	1,272
OH	53,937	679,069	59,679	4,091	3,722	538
OK	15,171	186,615	19,511	1,236	1,126	114
OR	22,094	243,435	21,378	1,641	1,472	251
PA	53,482	612,124	45,836	3,788	3,466	659
RI	3,049	46,627	3,291	223	204	56
SC	18,369	220,002	17,743	1,375	1,251	144
SD	7,262	59,438	10,090	646	598	41
TN	24,330	280,392	30,100	1,868	1,709	529
TX	75,802	1,029,826	149,023	8,450	7,685	2,384
UT	16,051	131,928	11,754	845	760	202
VA	30,393	397,805	32,018	2,711	2,496	558
VT	8,302	50,883	2,323	357	321	22
WA	34,448	392,897	38,047	2,729	2,468	551
WI	74,880	486,862	35,955	3,274	2,966	287
WV	9,558	95,709	14,699	801	736	100
WY	7,391	50,910	13,276	536	505	33
Totals	**1,531,691**	**15,936,342**	**1,612,491**	**114,867**	**102,838**	**21,913**

Table D-2
Year 2030 U.S. lower-48 state Electrification Case non-road emissions by state (tons per year) with percent change from the Base Case, excluding OGV emissions

	VOC		CO		NO_x		PM_{10}		$PM_{2.5}$		SO_2	
State	**Elec (tpy)**	**% Change**	**Elec (tpy)**	**% Change**	**Elec (tpy)**	**% Change**	**Elec (tpy)**	**% Change**	**Elec (tpy)**	**% Change**	**Elec (tpy)**	**% Change**
AL	17,563	-22%	188,388	-23%	27,242	-6%	1,458	-17%	1,304	-17%	179	-5%
AR	12,789	-20%	123,759	-21%	20,951	-4%	1,117	-13%	999	-13%	102	-6%
AZ	19,336	-25%	214,730	-30%	24,515	-6%	1,716	-21%	1,520	-22%	398	-4%
CA	141,291	-15%	1,098,879	-14%	127,198	-8%	14,998	-3%	11,537	-3%	2,304	-6%
CO	22,092	-21%	232,494	-28%	21,299	-6%	1,616	-21%	1,458	-22%	489	-5%
CT	9,959	-24%	132,855	-27%	9,971	-8%	650	-27%	593	-28%	101	-7%
DC	626	-22%	8,978	-24%	1,086	-8%	55	-16%	52	-16%	3	-9%
DE	2,406	-26%	33,039	-29%	5,577	-6%	282	-19%	260	-19%	46	-4%
FL	68,017	-21%	788,951	-25%	71,540	-5%	4,700	-22%	4,220	-23%	1,706	-3%
GA	26,497	-25%	323,087	-27%	37,406	-6%	2,252	-22%	2,051	-23%	1,082	-4%
IA	21,234	-11%	200,168	-17%	32,196	-3%	1,559	-10%	1,472	-10%	115	-5%
ID	14,559	-12%	96,403	-20%	9,257	-4%	906	-11%	809	-11%	69	-5%
IL	46,952	-18%	525,256	-23%	75,300	-5%	3,760	-17%	3,435	-17%	1,231	-4%
IN	24,828	-20%	272,810	-25%	35,612	-7%	1,948	-18%	1,751	-19%	252	-6%
KS	9,612	-20%	121,413	-22%	26,882	-3%	1,210	-12%	1,129	-12%	77	-6%
KY	13,430	-21%	145,997	-22%	27,745	-5%	1,304	-14%	1,217	-14%	331	-4%
LA	19,969	-17%	217,669	-16%	72,921	-3%	2,942	-8%	2,770	-8%	781	-2%
MA	19,777	-22%	259,063	-26%	18,879	-8%	1,328	-24%	1,189	-24%	330	-5%
MD	16,745	-26%	213,646	-29%	19,847	-7%	1,304	-26%	1,193	-26%	317	-4%
ME	22,341	-6%	112,679	-16%	8,217	-4%	959	-9%	868	-9%	73	-4%
MI	94,870	-9%	585,181	-18%	45,318	-6%	4,100	-12%	3,757	-13%	556	-5%
MN	63,067	-7%	370,570	-16%	40,031	-4%	2,994	-10%	2,748	-10%	505	-4%
MO	23,217	-22%	277,925	-25%	44,841	-4%	2,085	-17%	1,953	-17%	406	-4%
MS	12,135	-19%	116,587	-20%	22,001	-4%	1,070	-12%	964	-12%	133	-4%
MT	7,881	-12%	60,175	-17%	14,754	-1%	726	-7%	673	-7%	52	-4%

Table D-2 (continued)
Year 2030 U.S. lower-48 state Electrification Case non-road emissions by state (tons per year) with percent change from the Base Case, excluding OGV emissions

State	VOC		CO		NO_x		PM_{10}		$PM_{2.5}$		SO_2	
	Elec (tpy)	% Change	Elec (tpy)	% Change	Elec (tpy)	% Change	Elec (tpy)	% Change	Elec (tpy)	% Change	Elec (tpy)	% Change
NC	27,464	-26%	338,388	-28%	29,834	-8%	2,059	-24%	1,860	-25%	584	-5%
ND	8,015	-7%	61,944	-11%	19,684	-1%	974	-3%	902	-3%	63	-2%
NE	7,825	-17%	88,743	-19%	34,686	-1%	1,190	-8%	1,140	-8%	106	-4%
NH	12,301	-11%	83,918	-20%	4,463	-7%	516	-16%	465	-16%	44	-7%
NJ	24,594	-23%	357,170	-24%	36,382	-6%	2,020	-22%	1,872	-22%	589	-4%
NM	5,831	-21%	67,361	-22%	16,469	-3%	641	-13%	592	-13%	85	-4%
NV	8,169	-29%	95,508	-33%	12,266	-5%	733	-25%	670	-25%	432	-3%
NY	68,383	-16%	752,727	-21%	54,712	-7%	3,766	-19%	3,447	-19%	1,223	-4%
OH	41,645	-23%	496,696	-27%	55,565	-7%	3,223	-21%	2,918	-22%	507	-6%
OK	11,723	-23%	141,953	-24%	18,621	-5%	1,009	-18%	917	-19%	108	-6%
OR	17,719	-20%	184,495	-24%	20,081	-6%	1,353	-18%	1,206	-18%	239	-5%
PA	41,977	-22%	452,801	-26%	42,375	-8%	3,003	-21%	2,737	-21%	627	-5%
RI	2,372	-22%	35,719	-23%	3,049	-7%	172	-23%	157	-23%	53	-5%
SC	14,049	-24%	160,125	-27%	16,493	-7%	1,076	-22%	974	-22%	134	-7%
SD	6,530	-10%	50,121	-16%	9,895	-2%	607	-6%	562	-6%	40	-4%
TN	18,712	-23%	210,893	-25%	28,182	-6%	1,499	-20%	1,366	-20%	508	-4%
TX	58,190	-23%	785,781	-24%	142,900	-4%	7,156	-15%	6,484	-16%	2,308	-3%
UT	13,581	-15%	105,454	-20%	11,182	-5%	708	-16%	633	-17%	192	-5%
VA	22,417	-26%	279,441	-30%	29,767	-7%	2,105	-22%	1,935	-22%	534	-4%
VT	7,614	-8%	41,629	-18%	2,152	-7%	316	-11%	283	-12%	21	-7%
WA	27,982	-19%	299,566	-24%	35,952	-6%	2,276	-17%	2,048	-17%	530	-4%
WI	69,488	-7%	409,078	-16%	34,082	-5%	2,919	-11%	2,636	-11%	272	-5%
WV	7,240	-24%	72,135	-25%	14,063	-4%	683	-15%	627	-15%	96	-4%
WY	6,748	-9%	43,869	-14%	13,167	-1%	505	-6%	477	-6%	32	-3%
Totals	**1,261,760**	**-18%**	**12,336,218**	**-23%**	**1,526,607**	**-5%**	**97,548**	**-15%**	**86,828**	**-16%**	**20,967**	**-4%**

Appendix E: Source Contributions to Air Quality

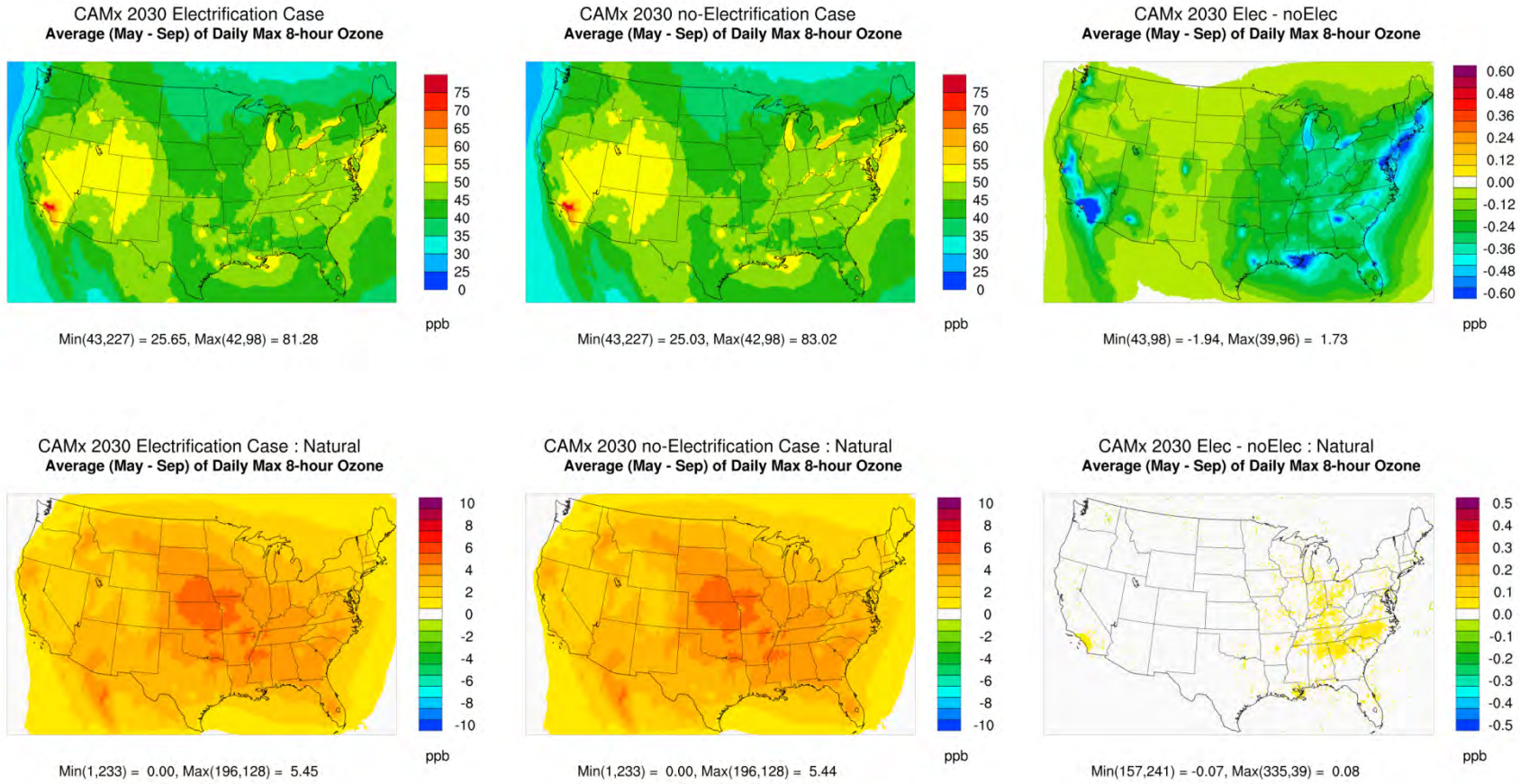

Figure E-1
Source contributions to summer average daily maximum 8-hour ozone concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

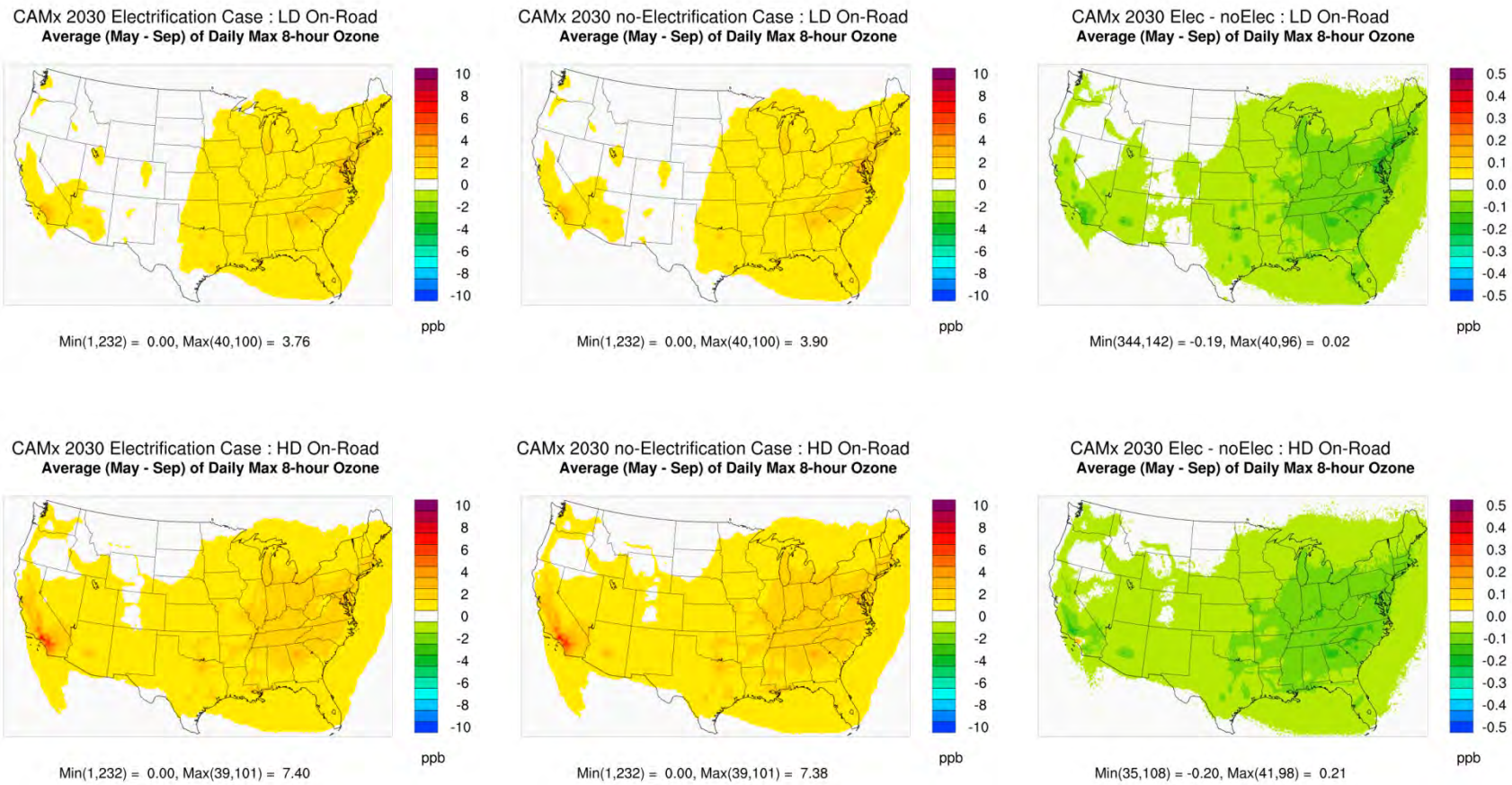

Figure E–1 (continued)
Source contributions to summer average daily maximum 8-hour ozone concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

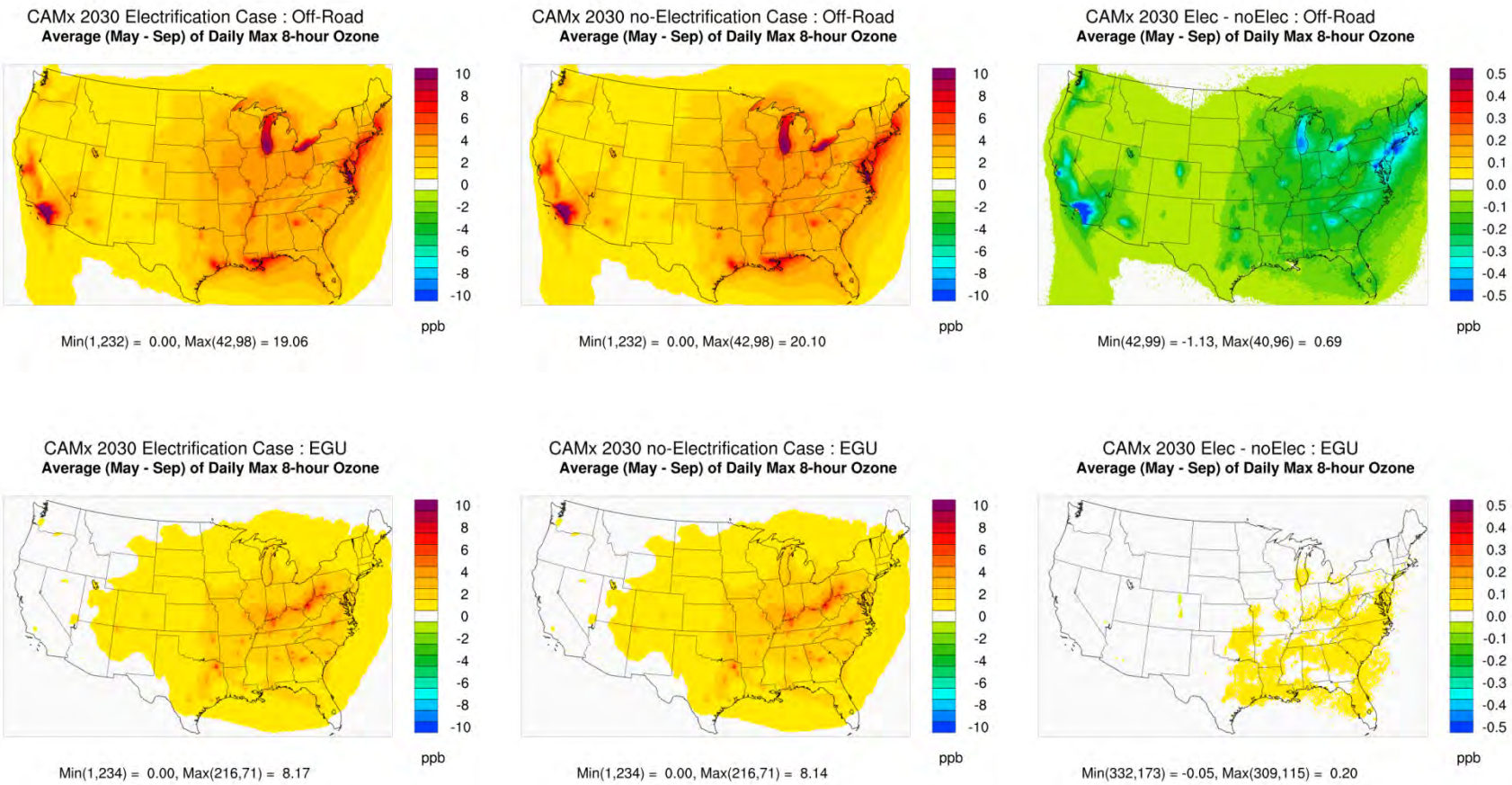

Figure E–1 (continued)
Source contributions to summer average daily maximum 8-hour ozone concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

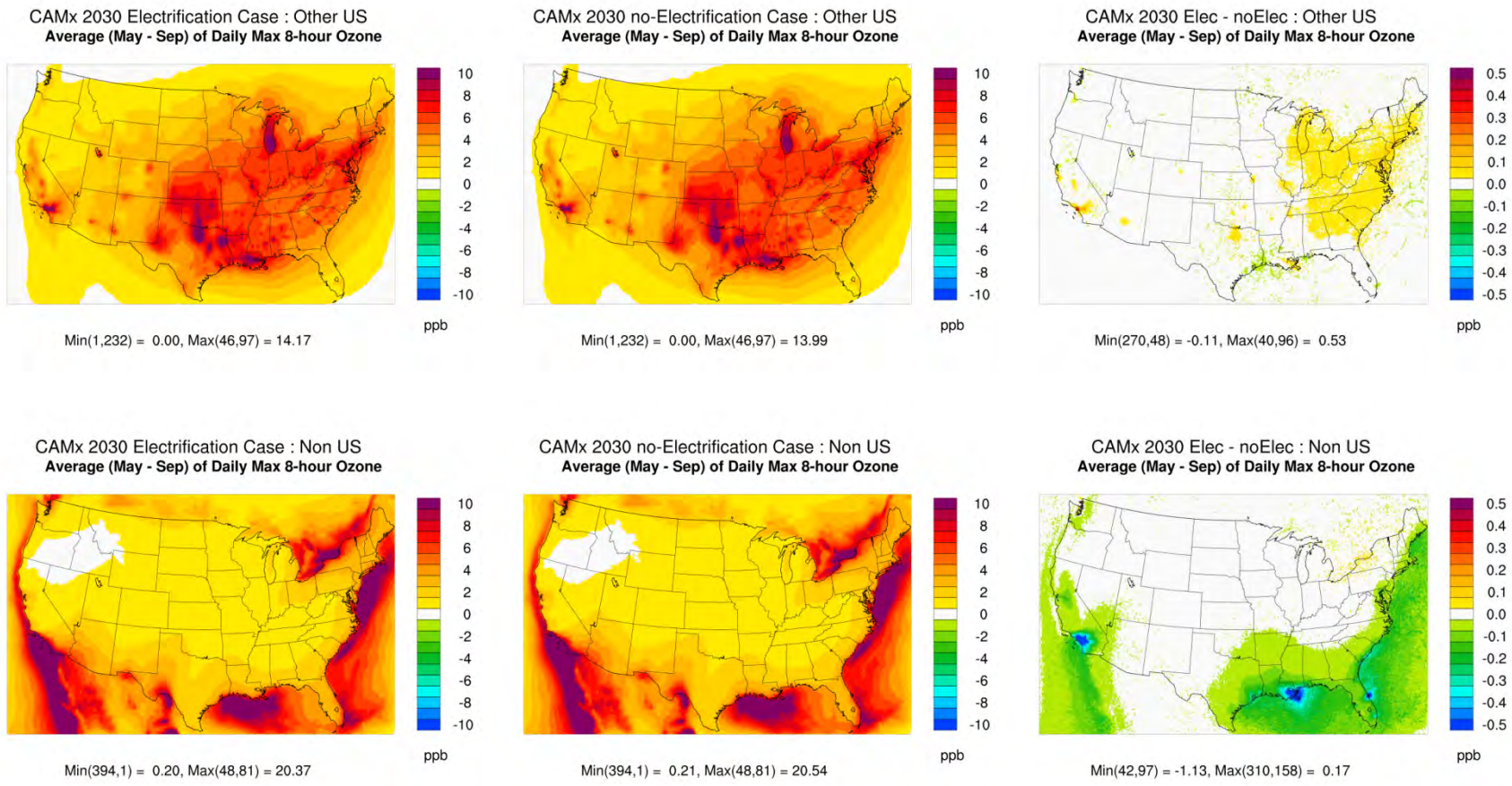

Figure E–1 (continued)
Source contributions to summer average daily maximum 8-hour ozone concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

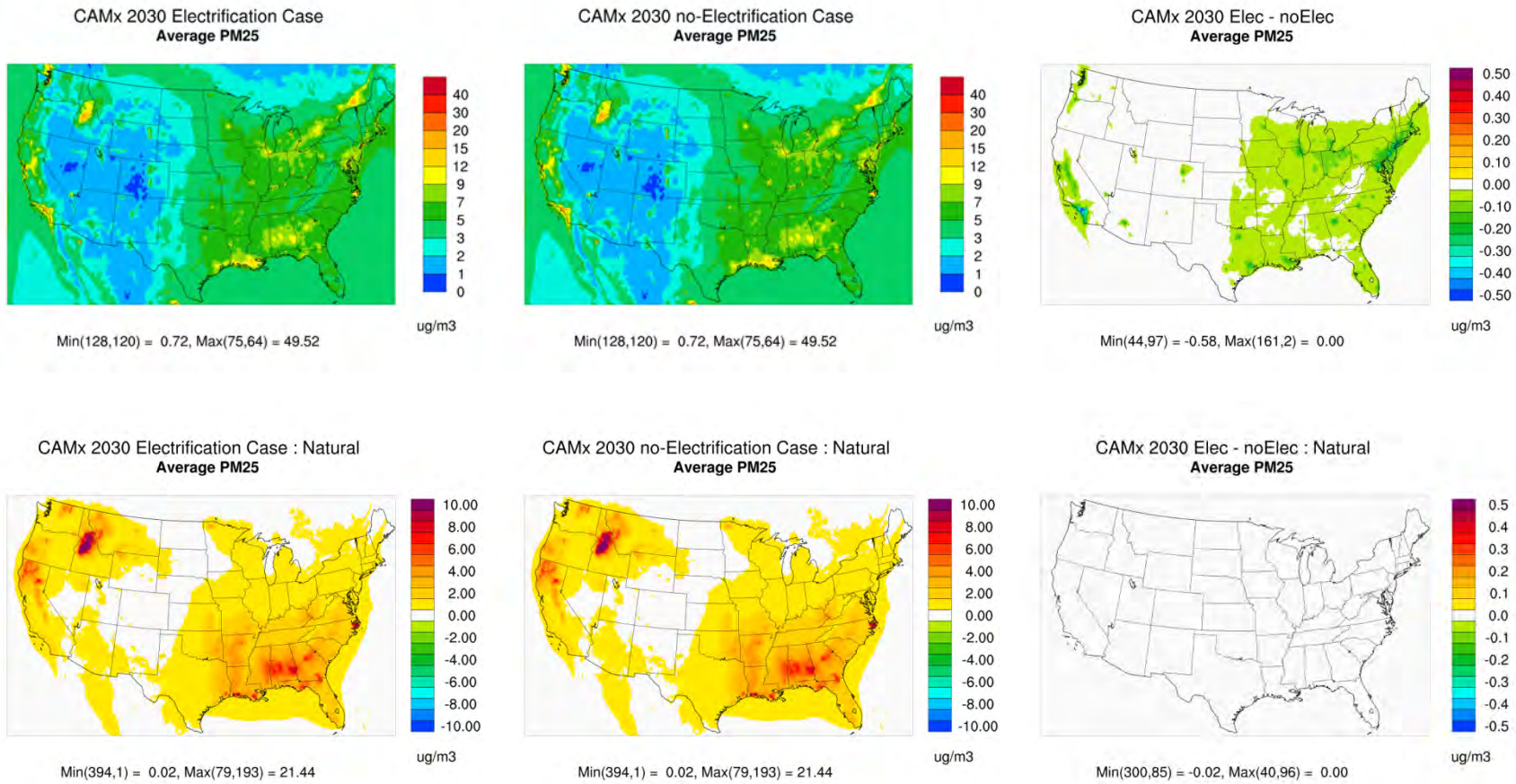

Figure E-1
Source contributions annual average $PM_{2.5}$ concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

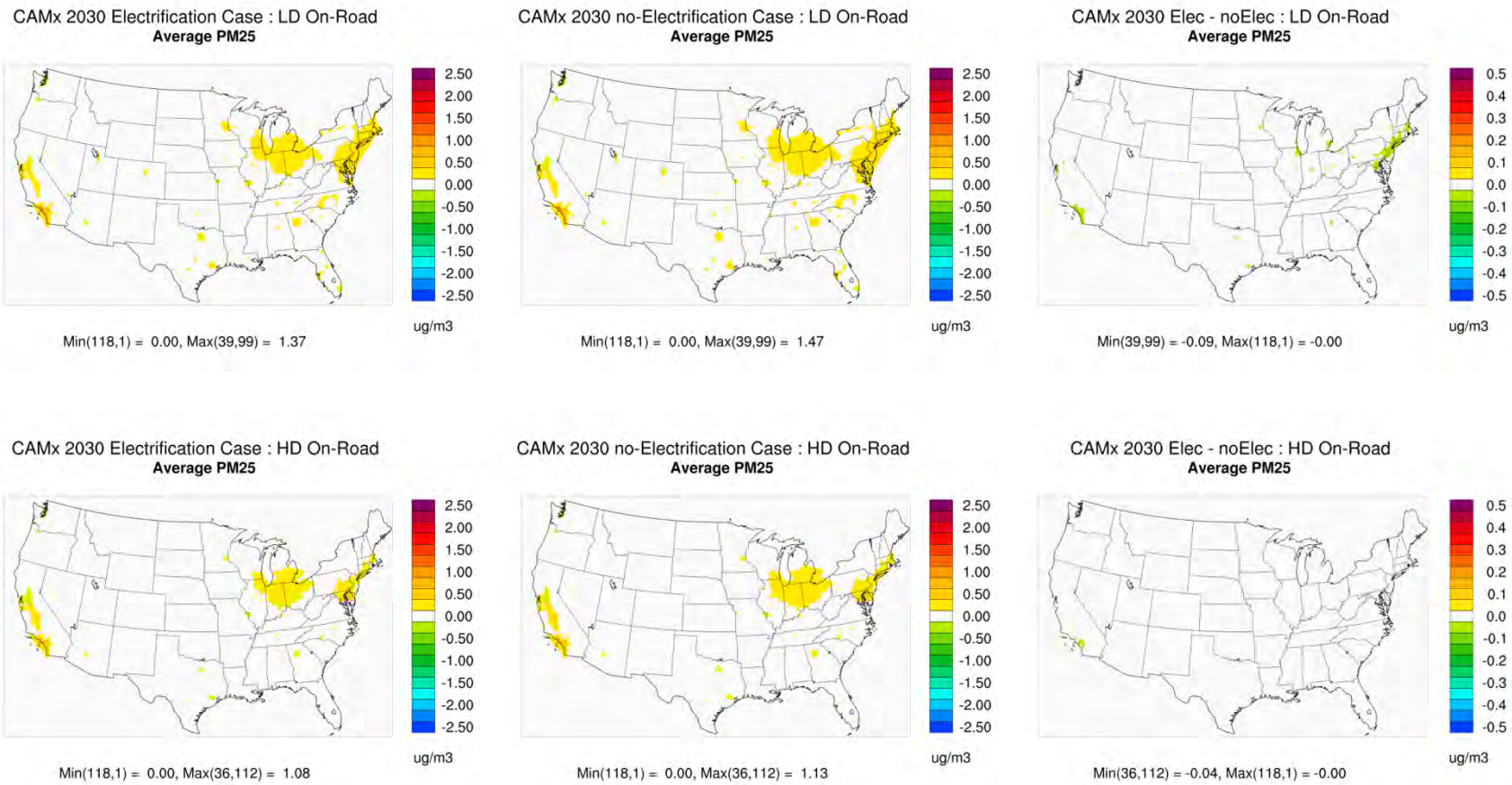

Figure E–2 (continued)
Source contributions annual average $PM_{2.5}$ concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

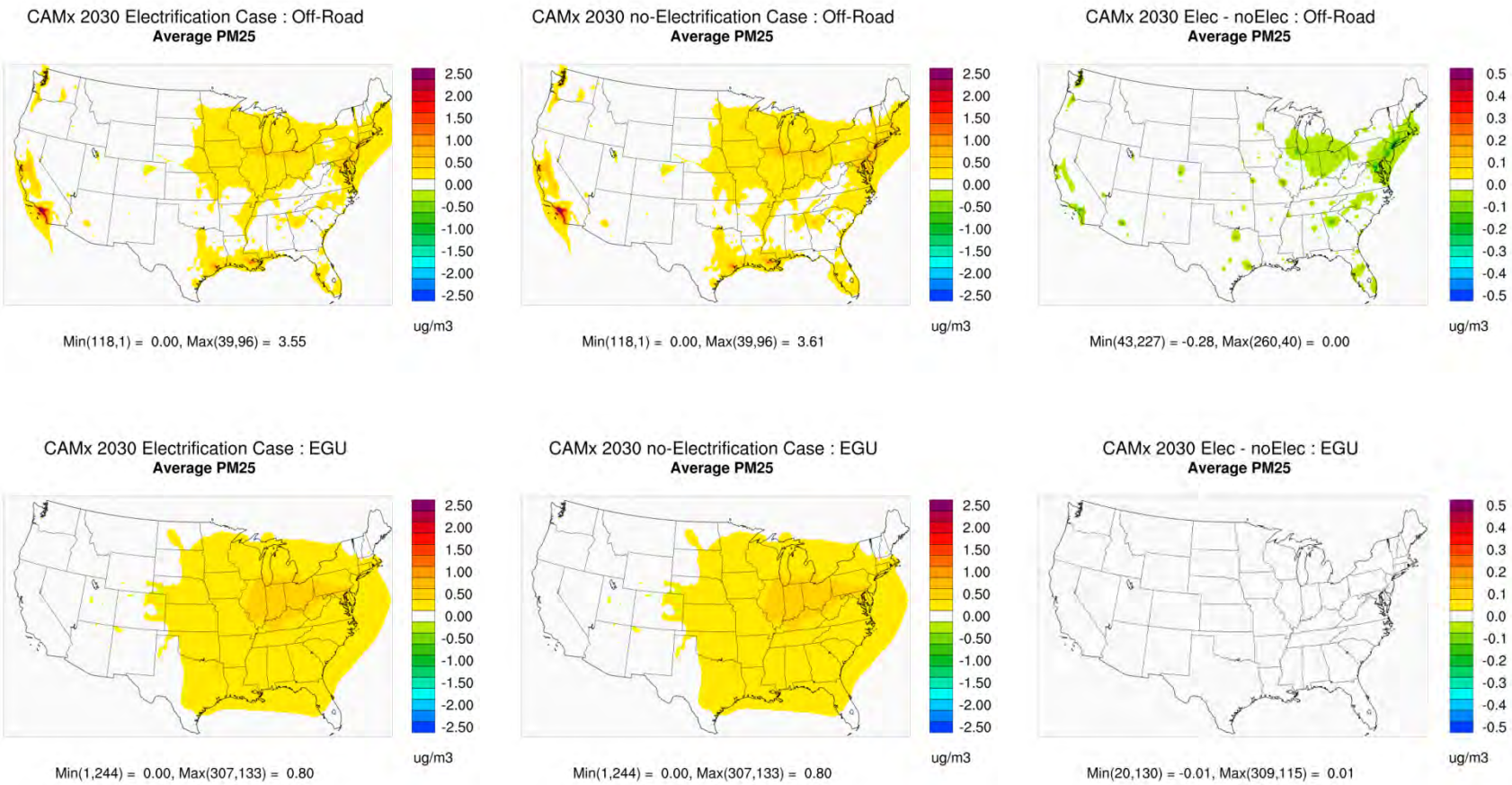

Figure E–2 (continued)
Source contributions annual average $PM_{2.5}$ concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)

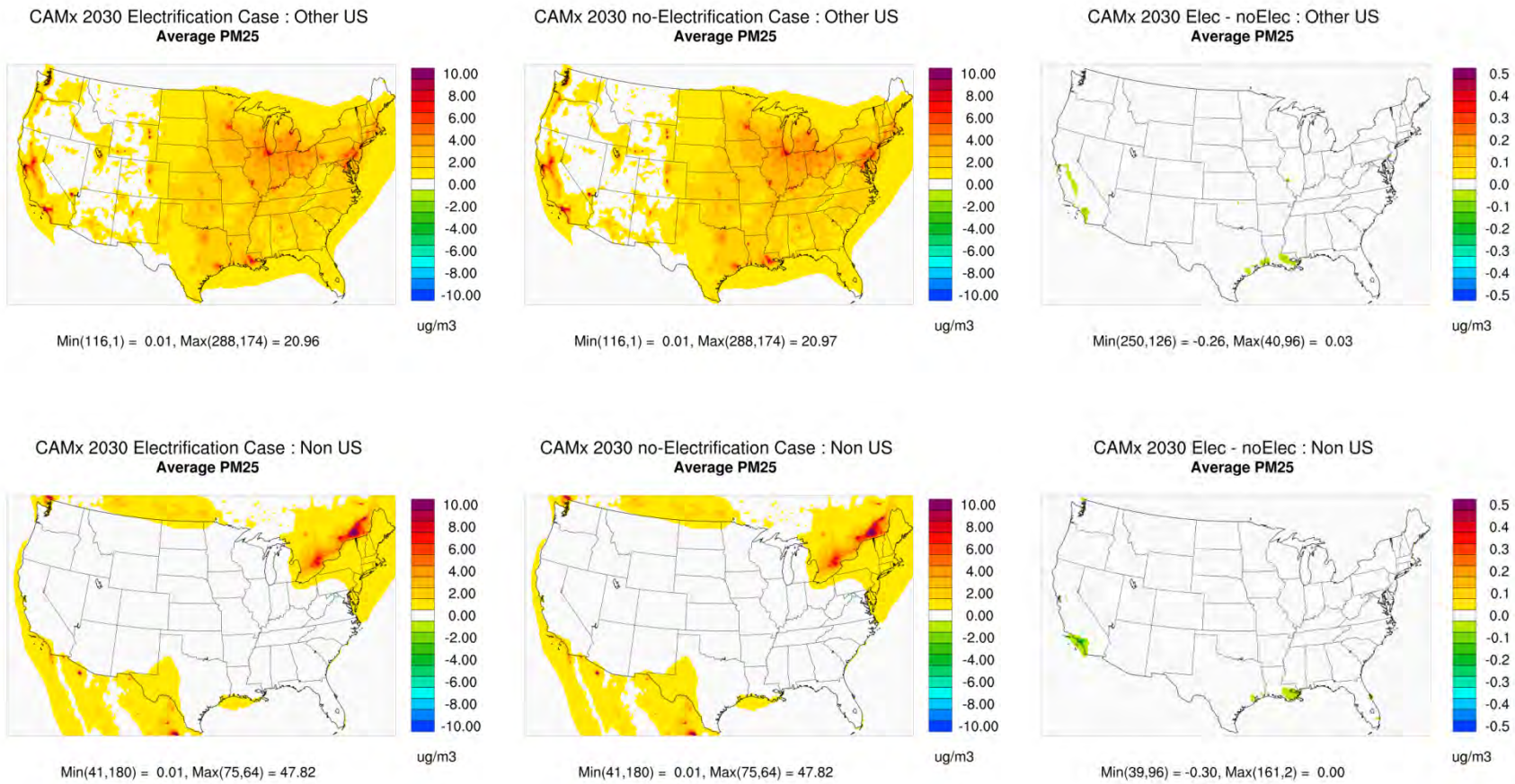

Figure E-2 (continued)
Source contributions annual average $PM_{2.5}$ concentrations for the Electrification Case (left), the Base Case (middle), and difference between Electrification Case and Base Case (right)