To illustrate the amount of pollution from heavy-duty vehicles with different engine-types, urban buses powered by various fuels were examined as a representative case study. Global warming emissions, particulate matter (PM), and nitrogen oxide (NO_x) emissions were estimated using a life cycle emissions model developed by Argonne National Laboratory (ANL) modified for California-specific fuel pathways (CA-GREET 2.0) as well California's scenario planning tool (2015 Vision 2.0). The Vision model was used to estimate tailpipe emission rates of PM and NO_x for diesel and compressed natural gas (CNG) buses.

The emissions analysis had three components:

- A comparison of life cycle global warming emissions from 40-foot transit buses;
- A similar comparison of global warming emissions focusing on low-carbon biofuels; and
- A comparison of PM and NO_x emissions from urban buses, not limited to 40-foot transit buses

This appendix describes the choice of electricity and fuel pathways and the modifications made to the CA-GREET 2.0 model by Life Cycle Associates to best reflect the current knowledge of fuel production.

Comparison of Global Warming Emissions from Urban Buses

Description: The global warming emissions from diesel, CNG, hydrogen fuel cell, and battery electric buses were estimated. CA-GREET 2.0, with modifications described below, was used to determine the upstream and tailpipe emissions factors for all fuel types.

Key assumptions

- For diesel and natural gas pathways, the comparison did not include biofuel content in the fuel (see biofuel comparison in the next section).

- The fraction of hydrogen generated with renewable resources was taken to be 33 percent; the remainder was from steam reforming of natural gas. California law (Senate Bill 1505) requires 33 percent of hydrogen for transportation to be from renewable sources. Estimates show that the renewable content of hydrogen is currently even higher at 45 percent and is expected to remain at this level at least through 2021 (CARB 2015).

- Two scenarios for electricity are presented. The California average grid mix estimated for 2016 is presented as well as a grid mix containing 50 percent natural gas and 50 percent carbon-free electricity (i.e. solar and wind). See below for further discussion of electricity scenarios. Note that California's current electricity mix results in global warming emissions that are lower than California's Low Carbon Fuel Standard (LCFS) carbon intensity for electricity.

- Efficiency values for diesel, CNG, and battery electric buses were based on recent testing of equivalent New Flyer Xcelsior 40-foot buses (Altoona 2015). Fuel cell bus efficiency was based on the LCFS Energy Economy Ratio (EER) factor of 1.9 (compared to diesel) because an equivalent test of a New Flyer fuel cell bus was not available. The EER factors are 0.9 and 4.2 for CNG and electric vehicles, respectively.

Comparison of Global Warming Emissions from Urban Buses using Low-Carbon Biofuels

Description: The global warming emissions benefit of blending low-carbon biofuels with fossil-based diesel or natural gas was examined. Emissions from using biomethane to generate electricity for an electric bus were also examined.

Key assumptions

- Values for vehicle efficiency in the low-carbon biofuel scenarios were identical to those used for the analysis of conventional fuels described above.

- 25 percent diesel biofuel pathway: Included 5 percent biodiesel (BD) and 20 percent renewable diesel (RD) on an energy basis; 25 percent of both BD and RD were assumed to be used cooking oil while the remainder was soy-based.

- 25 percent landfill gas pathway: Low-carbon biomethane was assumed to be 100 percent landfill gas (LFG). The alternative fate for LFG for life cycle accounting was assumed to be flaring at the landfill, which is consistent with the LCFS. This blend ratio is consistent with the biofuels ratio used for diesel (see above). LFG and other biogas sources are limited in quantity and there are many competing uses of natural gas besides vehicles.

- 25 percent LFG/75 percent fossil fuel natural gas electricity: This pathway examined the emissions from an electric bus powered by electricity from natural gas power plants fueled with 25 percent LFG and 75 percent fossil fuel natural gas on an energy basis. This pathway assumes LFG is processed to meet pipeline standards and injected into a pipeline before being consumed in a combined cycle natural gas power plant (51 percent energy efficiency) along with fossil fuel natural gas. A 6.5 percent transmission and distribution loss associated with delivering electricity to the electric bus from the power plant was accounted for. Based on LCFS efficiency factors of 0.9 for a CNG bus and 4.2 for a battery electric bus, an electric bus travels 4.7 times farther than a CNG bus for the same amount of energy delivered to the vehicle. Accounting for the efficiency of these vehicles, of natural gas power plants, and of transmission and distribution of electricity, an electric bus powered by electricity from a natural gas power plant can travel the same distance as a CNG bus using 55 percent less natural gas. Whether electric and CNG buses are compared on a per mile basis or a per energy basis, the most efficient use of natural gas is in power plants that generate electricity for electric vehicles.

- For liquid biofuels (i.e. biodiesel and renewable diesel) the carbon in the finished fuel is – by convention – treated as neutral, so the tailpipe CO_2 emissions are zero (CH_4 and N_2O emissions are non-zero). For biogas fuels (e.g. landfill gas), the California Air Resources Board (CARB) has adopted a different accounting system – avoided global warming emissions are applied to upstream emissions.

Comparison of PM and NO_x Emissions from Urban Buses

Description: Emissions of particulate matter 2.5 micrometers in diameter and smaller (PM2.5) and oxides of nitrogen (NO_x) were compared across different urban bus types and fuels using CA-GREET 2.0 for fuel production emissions and Vision 2.0 for tailpipe emissions. The baseline for comparison across fuel types and technologies was a diesel-powered bus fueled with ultra-low sulfur diesel (ULSD).

Key assumptions

- Tailpipe emission rates were from vehicles of model year 2016. For PM and NO_x tailpipe emissions, Vision 2.0 was utilized because this model provides emission rates specific to diesel and CNG buses, which is not the case in California's EMFAC 2014 model. There is no breakdown of bus sizes or types in Vision's "Urban Bus" category, so the emission rates represent the average of buses in this category for a given fuel type in California. The Vision 2.0 tailpipe emissions factors for diesel and CNG buses were used without modification. Emissions rates are based on new buses and do not include any estimates for degradation, tampering, or maintenance effects on emissions over the life of the bus.

- Efficiency factors for diesel and CNG buses from Vision 2.0 were used to determine the amount of upstream PM and NO_x emissions from the modified CA-GREET 2.0 model. It should be noted that the composite energy consumption for CNG urban buses in California is estimated in Vision 2.0 to have a higher miles per gallon rating than the average diesel urban bus (5.4 miles per diesel gallon equivalent for CNG vs. 4.5 miles per diesel gallon). This is not consistent with the EER of 0.9 in the LCFS or consistent with other analyses that directly compare diesel and CNG vehicles. However, it is possible that the average CNG bus in California is smaller than the average diesel bus, thus accounting for this discrepancy.

- Hydrogen and electric buses are not modeled in Vision 2.0, so EER values from the LCFS (1.9 for hydrogen and 4.2 for electric) were used to determine the fuel economy of these buses and their upstream NO_x and PM emissions.

- Emissions from a low-NO_x CNG engine were examined and assume the engine has been certified to meet the lowest NO_x certification level (a 90 percent reduction from what is currently required for diesel and natural gas engines). The low-NO_x tailpipe emissions were assumed to be 90 percent lower than current CNG buses in this analysis but further on-road testing is needed to confirm this level of reduction. No penalty on fuel economy from using the low-NO_x engine was assumed. While a low-NO_x engine has been certified to reduce PM emissions, tailpipe emissions account for just 4 percent of the life cycle PM emissions from traditional CNG transit buses. Because this contribution is so small and little data is available, PM emissions from low-NO_x engines were taken as equivalent to traditional CNG engines. A low-NO_x engine has also been certified to reduce tailpipe emissions of methane. Like PM, tailpipe emissions of methane are a small fraction (9 percent) of life cycle global warming emissions from CNG buses. For comparison, tailpipe emissions of NO_x makeup 25 percent of the total life cycle NO_x emissions from traditional CNG buses.

Electricity Pathway Assumptions

The electricity grid is powered by multiple sources of electricity each with its own emissions attributes. However, when a vehicle is powered by the grid, the electrons powering that vehicle are not directly tied to an individual power source. This makes it difficult to attribute the emissions from charging a vehicle to a particular source of electricity. There are numerous approaches that have been taken for estimating these emissions. The most straightforward approach is to assume the electricity used to power the vehicle is associated with the average mix of electricity sources. Other methods include dispatch modeling to determine what type of power plant is likely to increase its output from an instantaneous increase in electricity demand, and others look at the longer term impact of increased electricity demand over time (EPRI 2015). Each approach has its limitations and complexities.

For this analysis, two electric pathways are presented: (1) an average California grid mix based on today's generation (estimated for 2016 based on data from the California Energy Commission in 2015, including electricity imported from other states to California; Table C-1); and (2) a mix of 50 percent electricity from zero-carbon renewable energy and 50 percent electricity from natural gas power plants (CEC 2015). These pathways assign equal emission rates to all uses of electricity including electric vehicle charging. This is the approach used in previous UCS analyses to estimate global warming emissions of light-duty vehicles (UCS 2015). The scenario with electricity from 50 percent renewable energy and 50 natural gas power plants illustrates the potential impact a growing fraction of renewable electricity generation could have on electric vehicle emissions.

While using average electricity emissions rates is a straightforward way to compare emissions from vehicle electrification, the results require thoughtful interpretation. The challenge with using the average electricity grid mix is that it does not capture how the electrical grid will respond, in the short- or long-term, when additional loads such as electric vehicles are added to the grid.

The analysis of PM2.5 emissions using the average mix helps illustrate this point. The PM emissions rates under the average California grid mix for 2016 represent a 20 percent reduction compared to the diesel baseline. PM2.5 emissions from electricity generation result almost entirely from the combustion of coal and biomass. These electricity sources currently account for about 10 percent of the electricity used in California (including electricity imported to the state) but represent 94 percent of the estimated PM2.5 emissions in this pathway (Table C-2).

Despite an increase in electricity demand from electrifying trucks and buses, an increase in emissions from coal and biomass power plants—two of the most polluting sources of electricity for California—is unlikely to result. Coal is being phased out in California according to Senate Bill 1368 (in-state generation from coal was over 4,000 GWh in 2001 and dropped to less than 600 GWh in 2015) and contracts with out-of-state coal plants, which represent the largest share of coal fired electricity generation at nearly 17,000 GWh in 2015, cannot be renewed (CEC 2016, CEC 2015). Electricity from coal will be virtually eliminated from California by 2026.

TABLE C-1. **CALIFORNIA ELECTRICITY GRID MIX**

Fuel Type	2015 In-State Generation (GWh)	2015 NW Imports (GWh)	2015 SW Imports (GWh)	2015 Total CA Mix (GWh)	2015 Total CA Mix (%)	2015 Total CA Mix normalized w/o "unspecified" power	2016 Estimate CA Mix (%)
Coal	538	0	16,903	17,735	6.0%	6.9%	6.9%
Large Hydro	11,569	2,235	2,144	15,948	5.4%	6.2%	8.0%
Natural Gas	117,490	49	12,211	129,750	44.0%	50.8%	49.0%
Nuclear	18,525	0	8,726	27,251	9.2%	10.7%	10.7%
Oil	54	0	0	54	0%	0%	0%
Other	14	0	0	14	0%	0%	0%
Renewables	48,005	12,321	4,455	64,781	21.9%	25.4%	25.4%
Biomass	6,362	1,143	42	7,546	2.6%	3.0%	3.0%
Geothermal	11,994	132	757	12,883	4.4%	5.0%	5.0%
Small Hydro	2,423	191	2	2,616	0.9%	1.0%	1.0%
Solar	15,046	0	2,583	17,629	6.0%	6.9%	6.9%
Wind	12,180	10,855	1,072	24,107	8.2%	9.4%	9.4%
Unspecified	N/A	20,901	18,972	39,873	13.5%	0%	0%
Total	196,195	35,800	63,410	295,406	100%	100%	100%

Notes: "NW" and "SW" indicate electricity imports from the northwest and southwest regions of the United States, respectively.

SOURCE: CEC 2016, CEC 2015

Furthermore, the amount of electricity in California from biomass plants has been relatively constant over the past 15 years. In 2001, biomass plants generated 5,762 GWh of electricity and in 2015 generated 6,356 GWh of electricity, averaging 6,120 GWh annually over the entire period. On the other hand, solar, geothermal, and wind power generation increased from 17,900 GWh to 39,220 GWh over the same period (CEC 2016). So, the results should not be interpreted to mean that powering an electric bus will actually increase PM emissions from coal and biomass plants. A more accurate interpretation of the average electricity pathway is that a portion of the PM emissions from those plants is being assigned to an electric bus as well as all other sources of electricity demand equally. These estimates were incorporated into prior fuel cycle analyses conducted by CARB (Unnasch, Browning, and Kassoy 2001).

TABLE C-2. **PM2.5 EMISSIONS BY SOURCE FOR CHARGING A BATTERY ELECTRIC BUS IN CALIFORNIA IN 2016**

Source	Portion of PM2.5 emissions from electricity generation	Portion of electricity generated in CA in 2016
Oil	0%	0%
Natural gas	6%	49%
Coal	45%	7%
Biomass	48%	3%

Notes: Data based on the estimated California grid in 2016. Emissions from electricity generation were assigned to all sources of electrical demand equally (see text for further explanation). Data for coal include electricity generated by out-of-state coal-fired power plants.

SOURCES: CEC 2016, CEC 2015

50 percent renewable energy/50 percent natural gas electricity pathway: In addition to the 2016 average electricity mix, an additional scenario was chosen to illustrate emissions from electricity produced from a mix of renewable power and natural gas. This grid mix illustrates a near-term “marginal” electricity mix scenario—where additional charging demand is likely to be met with solar power during the day and by natural gas power plants at other times. A 50 percent renewable and 50 percent natural gas scenario could also be considered a conservative estimate of the average grid mix in 2030, when California law (Senate Bill 350) requires 50 percent of electricity to come from renewable sources.[1]

Future grid scenarios constructed by the California Independent Service Operator (CAISO) show that the supply of solar electricity during the day is expected to grow as California moves towards meeting the 50 percent Renewable Portfolio Standard (RPS) in 2030 (CAISO 2016). Integrating large quantities of renewables, including solar in the middle of the day will require flexible grid resources including demand management (e.g. encouraging vehicle charging when renewable generation is abundant) and energy storage. The CAISO expects solar to play an increasingly large role in meeting electricity demands during the day but other generation resources will likely be called upon to meet electricity demand when the solar resource is not present (i.e., after the sun has set). During these time periods, the marginal source of electricity generation is likely to be natural gas. Given these grid conditions, an equal share of renewable and natural gas electricity was chosen to illustrate the sources of electricity that may be used to meet increased demand for electric power due to electric trucks and buses, either on the margin or under future RPS requirements.

Modifications to CA-GREET 2.0 by Life Cycle Associates, LLC

This section describes the updates made to the CA-GREET 2.0 model by Life Cycle Associates for determining emission factors for different fuel pathways.

2016 California grid mix

California’s estimated grid mix in 2016 is provided in Table C-1 and was based on the 2015 grid mix. To estimate the 2016 grid mix, the “large hydro” category was increased to 8 percent (to reflect the 10-year average in California) with a commensurate

[1] This is a conservative estimate because other zero-carbon sources of electricity such as large hydroelectric power plants do not meet the definition of renewable sources and would be in addition to the 50 percent requirement.

decrease in natural gas. In addition, the "unspecified" category in the 2015 grid mix was removed and the rest of the values were renormalized.

Hydrogen production pathway

For the hydrogen production pathway utilizing natural gas steam reforming, the GREET model uses a small industrial boiler as a proxy for emissions from a steam reformer. Several years ago, Life Cycle Associates obtained source test data from a natural gas reformer in the South Coast Air Quality Management District demonstrating that reformer emission factors are an order of magnitude lower than the GREET default values for NO_x and PM2.5. Source test emission factors shown in Table C-3 were used for this analysis.

TABLE C-3. **COMPARISON OF NATURAL GAS BOILER AND NATURAL GAS REFORMER EMISSION FACTORS**

	NO_x (g/MMBtu)	PM2.5 (g/MMBtu)
GREET default (natural gas industrial boiler)	41	3.5
Source test data (natural gas steam reformer in CA)	2.45	0.32

Additionally for the hydrogen reforming pathway, the GREET model contains values for "non-combustion emissions." According to the report accompanying the 2005 model update, these values appear to have been supplied by the petroleum industry (hydrogen producers) and are in fact combustion emissions (Brinkman, Wang, and Weber 2005). Because the source test data discussed above encompasses emissions from natural gas reforming activities, it appears these older "non-combustion emission" values may be double counting. For this analysis, these factors were set to zero.

Similarly, the default emission factors for natural gas fired electricity generators are significantly higher than emissions from actual power plants in California. Life Cycle Associates queried EPA's Clean Air Markets Division (CAMD) database and determined the average NO_x emission factors in 2015 for California natural gas fired steam generators and combustion turbines (EPA n.d.). The default emission factors in GREET and the average NO_x factors in California are provided in Table C-4. The California average factors were utilized in this analysis.

TABLE C-4. **GREET AND ACTUAL NO_X EMISSIONS FROM NATURAL GAS POWER PLANTS IN CALIFORNIA**

	Boiler (g/MMBtu)	**Combustion turbine (g/MMBtu)**
GREET default	36.4	32.0
CA average values	4.7	6.1

SOURCE: EPA N.D.

Unfortunately, the CAMD database does not include particulate matter emission factors. The default PM2.5 emission factor for natural gas turbines in GREET is 0.0079 lb/MMBtu. However, results from a comprehensive field testing program indicate that the default PM2.5 emission factors are more than an order of magnitude higher than emissions from actual power plants (England 2004). Based on tests at a number of sites, the average natural gas fired combustion turbine PM2.5 emission factor was 0.00019 lb/MMBtu, or 2.5 percent of the GREET default value. This analysis utilized the lower emission factor, but the global PM2.5 emission factor for the electricity pathway decreased only by approximately 2.5 percent as these emissions are dominated by biomass combustion.

Biomass boiler emissions

Although biomass boilers represent only a small fraction of total electricity generation in California, their emission factors are orders of magnitude higher than from natural gas power plants. Table C-5 compares the default GREET emission factors from biomass boilers to the most recent compilation of air pollutant emission factors by the Environmental Protection Agency (AP-42) and to permit limits for actual biomass boilers in California (Birdsall et al. 2012; OAQPS 2003). The permit limits were taken from a figure in a report by the California Energy Commission and were difficult to read precisely and the units were in MWh, not MMBtu, so a boiler efficiency of 10,000 Btu/kWh was assumed for purposes of comparison. The GREET values are not significantly different from either the AP-42 values or the California boiler permit values. As such, our analysis used the default emission factors in GREET.

TABLE C-5. **COMPARISON OF GREET, EPA AP-42, AND CALIFORNIA AVERAGE BIOMASS BOILER EMISSIONS**

	NO_x (g/MMBtu)	**PM10 (g/MMBtu)**	**PM2.5 (g/MMBtu)**
GREET default	103	36.6	32.8
EPA AP-42	161	25.9	22.7
CA average permit limit	113	34	N/A

SOURCES: BIRDSALL ET AL. 2012, OAQPS 2003

Updated CH_4 and N_2O GWP factors

The global warming potential (GWP) factors for CH_4 and N_2O in CA-GREET 2.0 are from the IPCC 4th Assessment Report (AR4). The 5th Assessment Report (AR5) has provided updated values for 100-year and 20-year factors. In this analysis, we used the updated 100-year values. Table C-6 summarizes the different values for GWP.

TABLE C-6. **GLOBAL WARMING POTENTIAL (GWP) VALUES**

	Methane (CH_4)	Nitrogen dioxide (N_2O)
IPCC AR4 100-yr (CA-GREET Defaults)	25	298
IPCC AR5 100-yr with climate-carbon feedback	34	298
IPCC AR5 20-yr with climate-carbon feedback	86	268

SOURCES: MYHRE ET AL. 2013, FORSTER ET AL. 2007

Updated share of natural gas produced from shale

The CA-GREET 2.0 default share of natural gas produced from shale is 22.8 percent. In 2015, the actual share was 66 percent and this fraction was used in our analysis (EIA 2016).

Updated leak estimates for natural gas production, transmission, and distribution

One significant issue for natural gas pathways is the quantity of methane that leaks and is vented during recovery, processing, transmission, and distribution. For the most recent version of the national GREET model (GREET1_2015), ANL updated the leak rates to be consistent with the 2015 EPA Greenhouse Gas Inventory (GHGI), which is based on 2013 data (Burnham, Elgowainy, and Wang 2015). The Environmental Defense Fund (EDF) recently commissioned a suite of studies to try to better quantify methane emissions in the natural gas industry. Table 5 of the ANL report provides a comparison of methane leakage rates from the EPA GHGI and EDF studies. The EDF sponsored reports include analysis of gas field emissions (Allen et al. 2013), emissions from gathering and processing of natural gas (Marchese et al. 2015), emissions from transmission of natural gas (Zimmerle et al. 2015), and emissions from the distribution of natural gas (Lamb et al. 2015). To compare the emission estimates, ANL divided the emission estimates in these reports by estimates of total withdrawals of natural gas from the Energy Information Administration to arrive at an emission rate normalized to gas throughput.

Table C-7 summarizes methane leakage rates from different studies, including the EPA's GHGI and default values in GREET1_2015. The EPA GHGI gas field emission estimate is similar to the value estimated by Allen et al. but lower than those estimated by both Marchese et al. and Tong et al. Note that the estimates for processing, transmission, and distribution in GREET1_2015 are higher than the EDF study but similar to those estimated by Tong et al. For this study, we utilized the GREET1_2015 values.

TABLE C-7. **SUMMARY OF RECENT UPSTREAM NATURAL GAS METHANE LEAKAGE ESTIMATES**

Activity	GREET1_2015	CA-GREET 2.0	EPA GHGI, 2015	Allen et al., 2013	Other EDF Studies 2015	Tong et al. 2015[c]
Gas Field	0.30%, 0.34% shale	0.37%, 0.30% shale	0.31%	0.38%	0.58%[a]	0.49% [d]
Processing	0.13%	0.13%	0.15%	n/a	0.09%[b]	0.04%
Transmission	0.41%	0.39%	0.36%	n/a	0.25%	0.46%
Distribution	0.33%	0.31%	0.22%	n/a	0.07%	0.31%

Notes:

[a] This gas field leakage rate utilizes EPA's value for gas field emissions (0.31 percent) and Marchese et al.'s value for gathering (0.27 percent).

[b] This processing leakage rate is a combination of EPA's value for routine maintenance and Marchese et al.'s processing value.

[c] These leakage rates (% volume) were calculated using fuel properties in GREET based on grams per megajoule leakage rates reported by Tong et al.

[d] This estimate includes emissions from road construction, well drilling, and hydraulic fracturing.

SOURCES: BURNHAM, ELGOWAINY, AND WANG 2015, LAMB ET AL. 2015, MARCHESE ET AL. 2015, TONG ET AL. 2015, ZIMMERLE ET AL. 2015, ALLEN ET AL. 2013

Biomethane pipeline length

For biomethane used in a CNG bus, the emissions pathway involved processing landfill gas to meet pipeline standards and delivering the gas for off-site refueling. The default pathway in CA-GREET 2.0 assumes that the pipeline-quality natural gas is transported 3,600 miles to the refueling station. Life Cycle Associates reduced this to 1,200 miles. In addition, the default pathway assumes that the LFG would have otherwise been flared, and as a result receives a credit for avoided flaring emissions.

Biomethane to electricity pathway

To create the biomethane to electricity pathway, emissions from compressing the LFG were eliminated, and emissions associated with power plant combustion and electricity distribution were added. A credit for avoided flaring emissions was also applied.

Summary of Life Cycle Emissions from Transit Buses

Table C-8 summarizes the life cycle global warming emissions from transit buses of different engine and fuel types. Tables C-9 and C-10 summarize the NO_x and PM2.5 emissions across these same engine and fuel types.

TABLE C-8. **SUMMARY OF LIFE CYCLE GLOBAL WARMING EMISSIONS FROM 40-FOOT TRANSIT BUSES**

Engine and Fuel Type	Tailpipe (g $CO2_e$/mi)	Upstream (g $CO2_e$/mi)	Total (g $CO2_e$/mi)
Conventional diesel (ultra-low sulfur diesel - ULSD)	2,106	772	**2,878**
Diesel 5% biodiesel/5% renewable diesel/90% ULSD	1,897	818	**2,715**
Diesel 5% biodiesel/20% renewable diesel/75% ULSD	1,585	878	**2,463**
Diesel 100% renewable diesel	22	1,173	**1,194**
CNG with conventional natural gas	1,940	666	**2,606**
CNG with 25% LFG/75% conventional natural gas	1,940	321	**2,261**
CNG with 100% LFG	1,940	-713	**1,227**
Low NO_x with conventional natural gas	1,770	666	**2,436**
Low NO_x with 25% LFG/75% conventional natural gas	1,770	321	**2,091**
Low NO_x with 100% LFG	1,770	-713	**1,057**
H_2 from 100% natural gas steam reforming	0	1,677	**1,677**
H_2 from 33% renewable energy for electrolysis and 67% natural gas steam reforming	0	1,188	**1,188**
H_2 from 100% LFG for steam reforming	0	687	**687**
H_2 from 100% renewable energy for electrolysis	0	194	**194**
Electricity today (CA 2016)	0	748	**748**
Electricity from 100% natural gas power plants	0	1,158	**1,158**
Electricity from 50% renewable energy/50% natural gas power plants	0	579	**579**
Electricity from natural gas power plants fueled with 25% LFG/75% conventional natural gas	0	957	**957**
Electricity from natural gas power plants fueled with 100% LFG	0	354	**354**
Electricity from 50% renewable energy/50% natural gas power plants fueled by LFG	0	177	**177**
Electricity from 100% renewable energy	0	0	**0**

Notes: Tailpipe and upstream emissions may not sum to the total due to rounding.

TABLE C-9. **SUMMARY OF LIFE CYCLE NO_X EMISSIONS FROM URBAN BUSES**

Engine and Fuel Type	Tailpipe ($g\ NO_x/mi$)	Upstream ($g\ NO_x/mi$)	Total ($g\ NO_x/mi$)
Conventional diesel (ultra-low sulfur diesel - ULSD)	1.82	0.99	**2.80**
Diesel 5% biodiesel/5% renewable diesel/90% ULSD	1.82	1.01	**2.82**
Diesel 5% biodiesel/20% renewable diesel/75% ULSD	1.82	1.02	**2.84**
Diesel 100% renewable diesel	1.82	1.08	**2.90**
CNG with conventional natural gas	0.47	1.34	**1.80**
CNG with 25% LFG/75% conventional natural gas	0.47	1.27	**1.73**
CNG with 100% LFG	0.47	1.06	**1.53**
Low NO_x with conventional natural gas	0.047	1.34	**1.38**
Low NO_x with 25% LFG/75% conventional natural gas	0.047	1.27	**1.31**
Low NO_x with 100% LFG	0.047	1.06	**1.11**
H_2 from 100% natural gas steam reforming	0	1.25	**1.25**
H_2 from 33% renewable energy for electrolysis and 67% natural gas steam reforming	0	0.91	**0.91**
H_2 from 100% LFG for steam reforming	0	0.35	**0.35**
H_2 from 100% renewable energy for electrolysis	0	0.23	**0.23**
Electricity today (CA 2016)	0	0.89	**0.89**
Electricity from 100% natural gas power plants	0	1.13	**1.13**
Electricity from 50% renewable energy/50% natural gas power plants	0	0.56	**0.56**
Electricity from natural gas power plants fueled with 25% LFG/75% conventional natural gas	0	1.07	**1.07**
Electricity from natural gas power plants fueled with 100% LFG	0	0.90	**0.90**
Electricity from 50% renewable energy/50% natural gas power plants fueled by LFG	0	0.45	**0.45**
Electricity from 100% renewable energy	0	0	**0**

Notes: Tailpipe and upstream emissions may not sum to the total due to rounding.

TABLE C-10. **SUMMARY OF LIFE CYCLE PM2.5 EMISSIONS FROM URBAN BUSES**

Engine and Fuel Type	Tailpipe (g PM/mi)	Upstream (g PM/mi)	Total (g PM/mi)
Conventional diesel (ultra-low sulfur diesel - ULSD)	0.010	0.078	**0.088**
Diesel 5% biodiesel/5% renewable diesel/90% ULSD	0.010	0.077	**0.087**
Diesel 5% biodiesel/20% renewable diesel/75% ULSD	0.010	0.073	**0.083**
Diesel 100% renewable diesel	0.010	0.055	**0.065**
CNG with conventional natural gas	0.001	0.023	**0.024**
CNG with 25% LFG/75% conventional natural gas	0.001	0.004	**0.005**
CNG with 100% LFG	0.001	-0.051	**-0.050**
Low NO_x with conventional natural gas	0.001	0.023	**0.024**
Low NO_x with 25% LFG/75% conventional natural gas	0.001	0.004	**0.005**
Low NO_x with 100% LFG	0.001	-0.051	**-0.050**
H_2 from 100% natural gas steam reforming	0	0.052	**0.052**
H_2 from 33% renewable energy for electrolysis and 67% natural gas steam reforming	0	0.042	**0.042**
H_2 from 100% LFG for steam reforming	0	-0.013	**-0.013**
H_2 from 100% renewable energy for electrolysis	0	0.020	**0.020**
Electricity today (CA 2016)	0	0.078	**0.078**
Electricity from 100% natural gas power plants	0	0.016	**0.016**
Electricity from 50% renewable energy/50% natural gas power plants	0	0.008	**0.008**
Electricity from natural gas power plants fueled with 25% LFG/75% conventional natural gas	0	0.002	**0.002**
Electricity from natural gas power plants fueled with 100% LFG	0	-0.041	**-0.041**
Electricity from 50% renewable energy/50% natural gas power plants fueled by LFG	0	-0.020	**-0.020**
Electricity from 100% renewable energy	0	0	**0**

Notes: Tailpipe and upstream emissions may not sum to the total due to rounding.

Updates to Analysis

This report was updated in May 2017 to incorporate vehicle charging efficiency in the life cycle emissions analysis of electric buses. A charging efficiency of 90 percent was chosen based on data from The Altoona Bus Research and Testing Center. This represents a conservative value compared to the 95 percent efficiency cited in the California Air Resources Board's *Technology Assessment: Medium- and Heavy-Duty Battery Electric Trucks and Buses* and conversations with industry representatives. Analysis in this appendix was also updated to include engine certification data of methane emissions from low NO_x natural gas engines (Hebert 2015). The life cycle emissions from battery electric buses and CNG buses with low NO_x engines changed only slightly with these updates. All conclusions regarding the emissions of battery electric buses compared to other buses remained unchanged.

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