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Estimating Policy-Driven Greenhouse Gas Emissions Trajectories in California: The California Greenhouse Gas Inventory Spreadsheet (GHGIS) Model

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Abstract

A California Greenhouse Gas Inventory Spreadsheet (GHGIS) model was developed to explore the impact of combinations of state policies on state greenhouse gas (GHG) and regional criteria pollutant emissions. The model included representations of all GHG-emitting sectors of the California economy (including those outside the energy sector, such as high global warming potential gases, waste treatment, agriculture and forestry) in varying degrees of detail, and was carefully calibrated using available data and projections from multiple state agencies and other sources. Starting from basic drivers such as population, numbers of households, gross state product, numbers of vehicles, etc., the model calculated energy demands by type (various types of liquid and gaseous hydrocarbon fuels, electricity and hydrogen), and finally calculated emissions of GHGs and three criteria pollutants: reactive organic gases (ROG), nitrogen oxides (NOx), and fine (2.5 μm) particulate matter (PM2.5). Calculations were generally statewide, but in some sectors, criteria pollutants were also calculated for two regional air basins: the South Coast Air Basin (SCAB) and the San Joaquin Valley (SJV). Three scenarios were developed that attempt to model: (1) all committed policies, (2) additional, uncommitted policy targets and (3) potential technology and market futures. Each scenario received extensive input from state energy planning agencies, in particular the California Air Resources Board. Results indicate that all three scenarios are able to meet the 2020 statewide GHG targets, and by 2030, statewide GHG emissions range from between 208 and 396 million metric tons of CO_2 equivalent ($MtCO_2e$/yr). However, none of the scenarios are able to meet the 2050 GHG target of 85 $MtCO_2e$/yr, with emissions ranging from 188 to 444 $MtCO_2e$/yr, so additional policies will need to be developed for California to meet this stringent future target. A full sensitivity study of major scenario assumptions was also performed. In terms of criteria pollutants, targets were less well-defined, but while all three scenarios were able to make significant reductions in ROG, NOx and PM2.5 both statewide and in the two regional air basins, they may nonetheless fall short of what will be required by future federal standards. Specifically, in Scenario 1, regional NOx emissions are approximately three times the estimated targets for both 2023 and 2032, and in Scenarios 2 and 3, NOx emissions are approximately twice the estimated targets. Further work is required in this area, including detailed regional air quality modeling, in order to determine likely pathways for attaining these stringent targets.

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Summary

This document summarizes results of the California Greenhouse Gas Inventory Spreadsheet (GHGIS) model developed for the California Air Resources Board (ARB) under contract with Lawrence Berkeley National Laboratory (LBNL). The model represents all greenhouse gas (GHG)-emitting sectors within California between 2010 and 2050. In addition to modeling GHG emissions, it also models emissions of three criteria pollutants within two critical regional air basins as well as statewide. Input data was assembled from a combination of public and proprietary data supplied by a number of state agencies. Not all data used represent final, or official, estimates of state agencies; where official estimates were not available, the best available interim or draft data or estimates were used. A total of three scenarios were developed which are summarized in the below table:

Table 1. Scenarios modeled

Sector	Scenario 1: Committed policies	Scenario 2: Uncommitted policies	Scenario 3: Potential technology and market futures
LDV	EPA/Pavley, SB 375, 1.5M ZEVs	None	–15% VMT, NAS mpg, +ZEVs, automation
Other transport	Shore power	HDV efficiency	NGV, more efficiency, automation
Fuels	LCFS, renewable hydrogen	AB 2076, AB 1007 (30% biofuels by 2030)	Cleaner fuels, renewable NG/jet fuel
Stationary sector	1%/yr retrofits	3%/yr retrofits, ZNE	None
Electricity	33% RPS, SB 1368, OTC/nuclear phaseout	37% RPS, CHP, DG PV, nuclear relicense, CCS	Higher RPS, more CCS, reduced CHP
Water	20% (new const. only)	20% overall savings	None
Waste	50% (new const. only)	75% overall savings	None
High GWP	All reductions	HFC phaseout	Faster phaseout
Other	Forests, dairy, landfills	Local reductions	More local reductions

Abbreviations: AB 1007 = State Alternative Fuels Plan; AB 2076 = Reducing California's Petroleum Dependence legislation; CCS = CO_2 capture and sequestration; CHP = combined heat and power; DG PV = distributed generation (solar) photovoltaic; EPA = Environmental Protection Agency; GWP = global warming potential; HDV = heavy-duty vehicle; HFC = hydrofluorocarbon; LCFS = Low-carbon Fuels Standard; LDV = light-duty vehicle; mpg = miles per gallon; NAS = National Academy of Sciences; NG = natural gas; NGV = natural gas vehicle; OTC = once-through cooling; RPS = renewable portfolio standard; SB 375 = Sustainable

Communities legislation (regional GHG reduction targets for LDVs); SB 1368 = Emission Performance Standards for power plants; VMT = vehicle miles travelled; ZEV = zero-emission vehicle; ZNE = zero net energy (buildings).

The structure of this document is as follows. A description of the model framework along with general assumptions is presented in the first section below. Following this are detailed descriptions of the assumptions used in constructing the three scenarios. Finally, the scenario results are presented in tabular and graphical form. Results not presented in this document are available, along with all details of the calculations, in the GHGIS spreadsheet itself.

Model framework and assumptions

Overview

The GHGIS model was developed using Microsoft Excel for Mac 2011 (Version 14.3.5). It is organized around a number of data sheets or "tabs" broken into the following major sections:

1. General (color key, abbreviations, conversion factors)
2. Control panels & summary results
3. Raw data inputs (organized by major component)
4. Scenario calculations (organized by major component)
5. Criteria pollutant, total energy and GHG calculations
6. Scenario documentation & debugging

The major model components are as follows:

1. General inputs: population, gross state product (GSP)
2. Light-duty vehicle (LDV) sector
3. Heavy-duty vehicle (HDV) sector
4. Other transport sector: rail, airplanes and marine transport
5. Stationary sector: residential, commercial, industrial, various municipal, agriculture
6. Water sector
7. Hydrogen sector
8. Electricity sector
9. Fuels sector (fossil- and biomass-based liquid and gaseous hydrocarbon fuels)
10. High global warming potential (HGWP) gas sector: chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), hydrofluorocarbons (HFCs), other fluorinated gases ("F-gases")[1]

[1] The official state inventory does not include CFCs or HCFCs, but we tracked them in our model because they are potent GHGs. However, they do not contribute to the total GHG inventory.

11. "Other" sector: petroleum extraction, cement, landfills, waste treatment, agriculture and forestry (non-energy emissions not covered in HGWP sector)
12. Cap and trade

The sequence of calculations was to first specify underlying demand drivers (population, GSP; item 1 above) which drove the demand for energy in each end-use sector (items 2-6).[2] Demand was divided into each hydrocarbon fuel type (gasoline, diesel, natural gas = NG, etc.) as well as hydrogen and electricity. The production of hydrogen (item 7) itself drove demand for some fuels and electricity, and so was calculated only after all end-use energy demands were determined. Total state electricity demand (item 8) could then be calculated, but the production of electricity drove demand for more fuels. Finally, total statewide demand for fuels (item 9) could be calculated; total demand for biomass for fuels was also calculated at this stage in the model. See below Figure for a graphical explanation of this process.

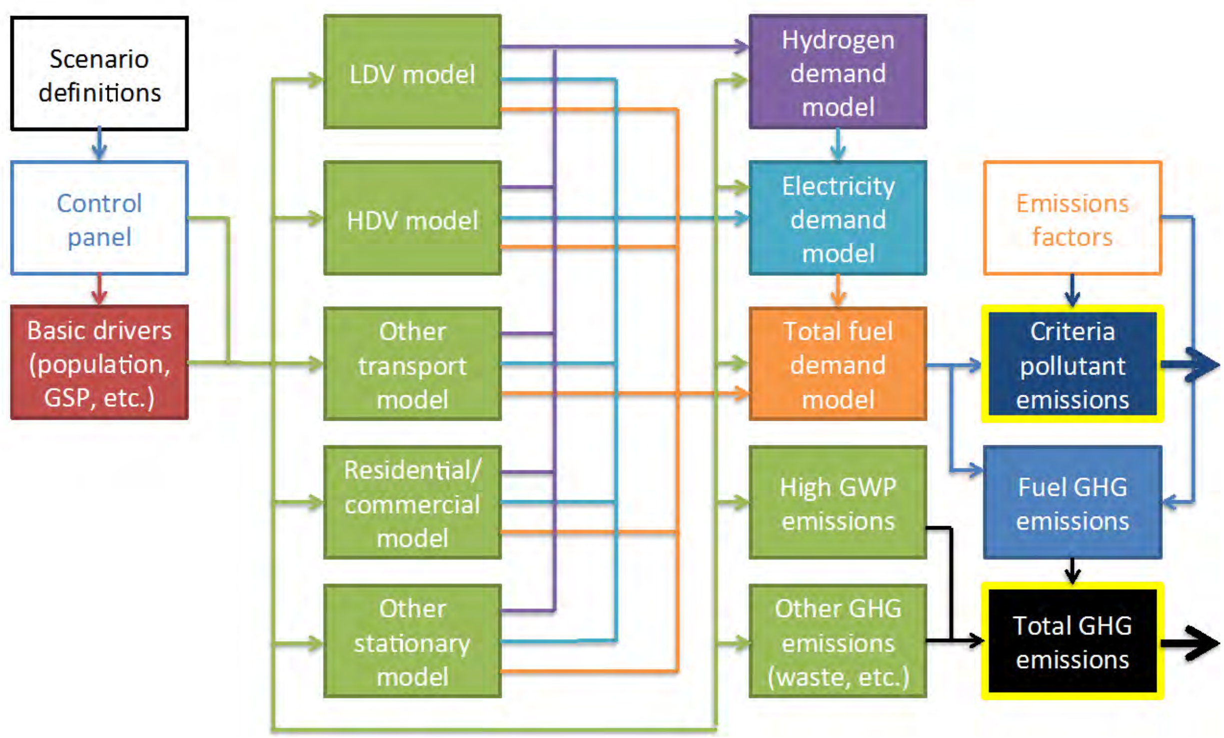

Figure 1. GHGIS model structure and sequence of calculations

GHG emissions included CO_2, CH_4, N_2O, and the HGWP gases listed above. All GHGs were expressed in units of CO_2-equivalent (CO_2e). Except for HGWP gases which were disaggregated into the four categories listed above and tracked separately in the HGWP

[2] Water energy use was handled somewhat differently from other sectors. Since water energy use data was not available from IEPR disaggregated from other stationary demand, we subtracted calculated water energy use savings in the stationary sector scenario, rather than calculating total water energy demand.

sector tab, we did not treat GHG gases separately, but tracked them all as a single entity. GHG emissions were calculated first in the energy sector from total demand by fuel,[3] and then GHG emissions from non-energy sectors (HGWP, "Other" and Cap and Trade: items 10-12 above) were added to those to arrive at statewide totals.

Three criteria pollutant categories were tracked separately throughout the model (though not all sectors had data for emissions of these pollutants):

1. Reactive organic gases (ROG)
2. Nitrogen oxides (NOx)
3. Fine (2.5 μm) particulate matter (PM2.5)

We modeled upstream (fuel extraction, production and transport) and downstream (fuel combustion) emissions separately for GHG, ROG, NOx and PM2.5. Only the in-state fraction of upstream emissions were included, using estimates provided by ARB.[4] Emission factors were distinct for each fuel but identical across sectors, with the exception of criteria pollutant downstream emission factors, which were different for each sector and fuel.

Modeling was statewide except for the transport sectors (LDV, HDV and Other transport), where the model also separately calculated downstream criteria pollutant emissions in two regional air basins: South Coast Air Basin (SCAB) and San Joaquin Valley (SJV). By subtracting these two regional emission totals from the statewide total, a "Rest of CA" region was derived. This regional information was propagated through to the aggregate criteria pollutant emissions in the summary calculation sheets (*Emissions factors*, *Downstream criteria pollutants* and *Total energy* tabs).

The time horizon for modeling was 2010 through 2050. In some tabs, input data from before 2010 was included for reference, and occasionally to provide historical trends for extrapolation.

Definition and control of scenarios were provided in two tabs: *Master panel* and *Control panel*. The *Master panel* specified the scenario to be calculated, and also provided a high-level set of variables that defined a small handful of inputs for each scenario. The *Control panel* provided a much more detailed set of inputs that completely defined each scenario. In some isolated instances, adjustable parameters that were common to all scenarios were specified elsewhere than the *Control panel*; these along with all inputs were indicated with yellow background highlighting. It was easy to toggle among scenarios by changing the value of the *Scenario* cell (B5) on the *Master panel* to select which scenario the model calculates. All scenario and summary tabs reflected results specific to the scenario selected.

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[3] For the HDV, aviation and marine ocean-going vessel transportation sub-sectors, only the in-state portion of fuel consumption and hence GHG (and criteria pollutant) emissions were estimated, in accordance with ARB accounting rules.
[4] Note that this convention is different from what is required by the Low Carbon Fuels Standard (LCFS). One can easily derive the full upstream GHG emissions of fuels from the model by changing the in-state fractions to 100% in the *Fuels data* tab.

The model was built using data from a number of sources, not all of which shared the same underlying assumptions. As a result, data were generally normalized to "driver" variables (chosen depending on the quantity) such as population, GSP, number of households, number of vehicles, commercial floor space, etc. which were used to scale input data using a uniform set of driver variables for the scenarios. Input data that were scaled in this way included:

1. LDV sector
2. HDV sector
3. Other transport sector
4. Stationary sector
5. HGWP sector
6. "Other" sector

Details of each modeled sector follow below.

General inputs

A number of population forecasts exist and were used to develop various components of the inputs. We have relied on the latest California Department of Finance (DOF) population forecast (DOF, 2013) as our reference population for the model, which was provided at the county level every five years from 2010 through 2060. The county-level data was used to apportion the state into three regions (SCAB, SJV and Rest of CA). Data generated using other population projections were scaled using normalized values for use in our scenarios.

Gross state product (GSP) estimates came from two sources: as total statewide personal income from the Integrated Energy Policy Report (IEPR) 2013 preliminary forecast (Kavalec, 2013) (used for stationary sector inputs) and an indirect GSP metric derived from the ARB Vision growth rate of heavy heavy-duty (HHD) vehicles in the HDV sector after 2017 (approximately 2%/yr; Cunningham, 2013). For our reference GSP, we relied upon the IEPR estimates through 2017, and a fixed 2.00%/yr growth thereafter. For regional calculations of GSP, we assumed the same per capita GSP and scaled total GSP in each region by its regional population.

LDV sector

Input data was supplied by the ARB Vision model (ARB, 2012) and supplemented with estimates provided by the Vision team (Cunningham, 2013). The Vision model was developed for the LDV sector through 2050 based on extensive research and cooperation with regional transportation planning agencies. All data were normalized by the DOF 2009 population forecast, which was used when the Vision model was developed. Primary data provided by Vision included vehicle counts for ten different vehicle technology/fuel combinations:

1. Conventional gasoline vehicles
2. Gasoline hybrid electric vehicles (HEVs)
3. Gasoline-electric plug-in hybrid electric vehicles (PHEVs)
4. Electric vehicles (EVs)
5. Hydrogen fuel cell vehicles (FCVs)
6. E-85 flex-fuel vehicles (FFVs) (E-85 is a blend of 85% ethanol/15% gasoline). This category also included other E-85 technologies and methanol vehicles.
7. Conventional diesel vehicles
8. Diesel HEVs
9. Diesel-electric PHEVs
10. Natural gas vehicles (NGVs)

Additional estimates provided by Vision included annual vehicle-miles travelled (VMT) per vehicle, the portion of non-electric miles travelled by gasoline and diesel PHEVs, total energy consumed by vehicle technology/fuel, and total criteria pollutants by region. Data was provided for all of California and separately for SCAB and SJV regions; data were derived for the Rest of CA region. From this data, vehicle shares of fleet, fuel efficiency and total VMT per vehicle type by technology/fuel type were derived. Numbers of vehicles were normalized by population, which were used in the LDV scenario to produce numbers of vehicles with different population assumptions.

Unlike the HDV sector, policy regulating criteria pollutants operate on an aggregate basis, so that total allowable emissions by region are fixed regardless of the number of vehicles, vehicle technologies/fuels, or fuel economy. However, total criteria pollutant emissions do vary with VMT, so total emissions by region were scaled from Vision estimates using the ratio of total VMT in the scenario to the Vision reference case.

One additional input scenario was provided by LBNL staff (Wei, 2013) based on model output from UC Davis used in the *California's Energy Future* (CEF) and LBNL studies (Yang et al., 2011; Wei et al., 2013). This scenario modeled growth of zero-emission vehicles (ZEVs), defined as PHEVs, EVs and FCVs (though the scenario modeled had zero FCVs). This scenario had more aggressive penetration of ZEVs than the Vision scenario after ~2030. Because the number of total vehicles was considerably different from the Vision model, fleet percentages of each major vehicle technology were used rather than absolute numbers of vehicles.

HDV sector

As with the LDV sector, input data was supplied by the ARB Vision model (ARB, 2012) and supplemented with estimates provided by the Vision team (Cunningham, 2013). The Vision HDV model was developed based on extensive research and cooperation with regional transportation planning agencies. Because HDVs are commercial vehicles, all data were normalized by GSP based on the hybrid approach described above under "General inputs."

Primary data provided by Vision included vehicle counts for three different vehicle classes, each of which had seven or eight technology/fuel combinations, for a total of 22 vehicle class/technology/fuel combinations:

1. In-state heavy heavy-duty (HHD) vehicle class
    a. Gasoline conventional vehicles
    b. Diesel conventional vehicles
    c. NG conventional vehicles
    d. Diesel HEVs
    e. Diesel-electric PHEVs
    f. Hydrogen FCVs
    g. EVs
2. Out-of-state (OOS) HHD vehicle class[5]
    a. Gasoline conventional vehicles
    b. Diesel conventional vehicles
    c. NG conventional vehicles
    d. Diesel HEVs
    e. Diesel-electric PHEVs
    f. Hydrogen FCVs
    g. EVs
3. In-state medium heavy-duty (MHD) vehicle class[6]
    a. Gasoline conventional vehicles
    b. Diesel conventional vehicles
    c. NG conventional vehicles
    d. Diesel HEVs
    e. Diesel-electric PHEVs
    f. Hydrogen FCVs
    g. EVs
    h. Gasoline HEVs

Additional estimates provided by Vision included annual vehicle-miles travelled (VMT) per vehicle for each vehicle class, and total energy consumed and total criteria pollutant emissions (ROG, NOx and PM2.5) by vehicle class/technology/fuel. Data was provided for all of California and separately for SCAB and SJV regions; data were derived for the Rest of CA region. From this data, vehicle share of fleet, fuel efficiency, total VMT per vehicle and criteria pollutant emission rates were derived for each vehicle class and technology/fuel type. Numbers of vehicles were normalized by GSP, which were used in the HDV scenario to produce numbers of vehicles with different GSP assumptions.

[5] Only the in-state portion of miles travelled by OOS HHD vehicles was included, so although labeled "out of state," this category only included in-state fuel consumption and hence GHG and criteria pollutant emissions.

[6] No out-of-state MHD vehicles were included in the model.

Other transport sector

Though much less detailed, input data was supplied by the ARB Vision team (Cunningham, 2013) for other transport sectors, including projections for rail (freight only), aviation and several types of marine transport (detailed below).[7] All data were normalized by GSP.

Primary data provided by Vision included total energy consumed by the following vehicle classes and fuels:

1. Rail freight: Diesel
2. Aviation[8]
    a. In-state jet fuel
    b. Aviation gasoline
3. Marine ocean-going vessels (OGV)[9]
    a. Diesel
    b. Electricity
4. Off-road (OR) vehicles: Diesel
5. Cargo-handling equipment (CHE): Diesel
6. Harbor craft (HC): Diesel

Note that aviation was only calculated at the statewide level, so regional disaggregation was accomplished by simple apportionment via population.

To this set of fuels, electric rail was added for scenario modeling. Out-of-state (OOS) jet fuel for aviation was included from historical inventory data from 2000-2010, but was not modeled forward because it was not counted in the state inventory. Calculated numbers of vehicles, VMT or criteria pollutants were not available for this sector, so activity levels were expressed directly as energy consumption (quads/yr).

Stationary sector

The IEPR 2013 preliminary forecast (Kavalec, 2013) contained historical and projected electricity and natural gas demand data for all sectors from 2010-2024, and provided most of the reference data for the stationary sector. Supplemental projected demand savings estimates were provided by Navigant Consulting, who generated several scenarios from their Potentials, Goals and Targets (PGT) model (Swamy, 2013). This data, which calculated additional savings on top of the IEPR baseline, could be subtracted from the IEPR data by enabling appropriate cells in the *Control panel*. In addition, estimates of new construction and demolition for the residential and commercial sectors were obtained from the CEF building model (Greenblatt et al., 2012a).

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[7] Provisions for buses, motor homes and motorcycles were also made but projections were not developed due to lack of data. Passenger rail was not included.
[8] No out-of-state fuel consumption was estimated for aviation.
[9] No out-of-state fuel consumption was estimated for marine OGV.

The model was divided into the following sub-sectors and modeled separately for electricity and NG:

1. Residential
2. Commercial
3. Manufacturing
4. Mining
5. Agriculture
6. Transportation, Communication, and Utilities (TCU) (electricity only)
7. Street lighting (electricity only)
8. Other (NG only)

In addition, the residential and commercial sectors included separate electricity demands for EVs, and the commercial sector included separate NG demand for NGVs. These demands were all subtracted and ignored, as EV and NGV demand forecasts were provided by the LDV and HDV sector models.

The IEPR forecast also provided information on the private supply of electricity generation by sector (also known as self-generation), which included forecasts of photovoltaic (PV) generation, non-PV generation, and electricity losses. This information was used as reference data for the *Electricity sector* model (described below) but in the scenarios were replaced by assumptions specified in the *Control panel*.

Several demographic parameters were provided along with the IEPR forecast:

1. Population
2. Number of households
3. Personal income (interpreted as GSP) (in 2012 dollars)
4. Manufacturing output (in 2005 dollars)
5. Commercial floor space (in square feet)

Energy demand was normalized differently according to sector: residential was normalized to households, commercial was normalized to commercial floor space, manufacturing and mining were normalized to manufacturing output, and agriculture, TCU and street lighting were normalized to population.

Some of the demographic data were also normalized to either population or GSP in order to establish a basis for projecting the quantities beyond 2024.

For the residential and commercial sectors, we developed simple stock turnover models in order to simulate the effect of more efficient new construction and/or retrofits. For each sector, building stock was divided into three categories: new construction, retrofits and remaining unaffected stock. Net rates of construction were derived from underlying driver data (number of households or commercial floor space as appropriate). Rates of new construction and retrofits were specified in the *Control panel* separately for the residential and commercial sectors. Demolition rates were derived from the difference between new and net construction (new construction rates were chosen to approximately match estimated demolition rates provided in Greenblatt et al., 2012a). We assumed that demolition applied entirely to unaffected stock.

To estimate the energy use (expressed as kWh or therms per household for residential; and per square foot for commercial) of building stock that was not new or retrofit (termed "remaining unaffected stock"), we conservatively assumed new construction to have a fixed 10% improvement in unit energy use compared to the remaining unaffected stock in 2024, and retrofits were assumed to have no improvement in energy use.[10] Different values were obtained for residential and commercial electricity and NG. Choosing a different improvement rate for new construction affected the resulting energy use of the remaining unaffected stock slightly, since total energy consumption of the building stock summed to the totals provided in the IEPR base case. These energy use estimates were subsequently used as an input for the scenarios. In the *Control Panel,* the energy use of new construction and retrofits could be specified relative to a reference year (2010; also adjustable in the *Control Panel*). The total energy use of new construction and retrofit building stock was accumulated in each year; energy use running averages for these building stock classes were calculated from this data. Total energy use for the sector was calculated by summing new construction, retrofits and remaining unaffected stock.

Three PGT model scenarios were included in our model assumptions: mid-market, economic and technical. These scenarios specified net electricity and NG savings between 2015 and 2024 that were in addition to the IEPR base case. The *Control Panel* allowed selection of which PGT scenario to subtract from the IEPR base case. At the time of this writing, only a draft version of the PGT mid-market scenario had been provided; the other two scenarios in GHGIS contained identical data as placeholders. (It is not expected that either of these other scenarios will be used in the future).

<u>Water sector</u>

Data on the energy use of water consumption was provided by a California Energy Commission (CEC) report (CEC, 2005) and from ARB staff estimates (Waters, 2013). Energy use was disaggregated by sector (residential, commercial, industrial and agricultural) and fuel (electricity, NG and diesel) and normalized by appropriate metrics. These water energy use metrics were then used to calculate energy savings from water conservation (in the *Stationary scenario* tab). At present, conservation targets were established only for the residential and commercial sectors (in the *Control panel*), but other sectors could easily be added.

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[10] While strictly speaking this is not valid, we felt that the small number of retrofits that resulted in substantial efficiency improvements could be ignored for the purpose of obtaining a reference baseline.

Hydrogen sector

The model included hydrogen as a fuel option in various energy sectors (currently LDVs, HDVs and other transport). To this initial demand, we added hydrogen transmission and storage losses to arrive at a gross hydrogen demand that was then satisfied by a variety of generation technologies:

1. Electrolysis
2. Natural gas reforming
3. Natural gas reforming with carbon capture and sequestration (CCS)
4. Coal gasification
5. Coal gasification with CCS
6. Biomass gasification
7. Direct solar conversion (artificial photosynthesis)

To satisfy renewable hydrogen targets, the fraction of renewable electricity contributing to electrolysis, plus items 6 and 7 above, were calculated.

Hydrogen transmission losses were estimated to be 10%, based loosely on an average value for compression efficiency (88-95%; Hammerschlag and Mazza, 2005) and 1-2% for remaining transmission losses (0.77% per 100 km; Bossel et al., 2003). Storage losses were estimated to be 5%, half of the estimated 10% losses from on-board vehicle storage (DOE, 2012).

Hydrogen storage capacity was also included in the model, which added to total demand via storage losses, but did not count as a generation technology itself.

To calculate the total demand for electricity and fuels from hydrogen production, efficiencies for the above technology were estimated from Kreutz and Williams (2004), DOE (2012) and JCAP (2013).

Electricity sector

As with the hydrogen model, GHGIS included electricity as a fuel option in almost every energy sector. To this initial demand, we added electricity transmission and storage losses to arrive at a gross electricity demand which was then satisfied among a variety of generation resources, broken down into in-state non-renewables, in-state renewables and imported generation:

1. In-state non-renewable generation
    a. Combined heat and power (CHP) (assumed all NG)[11]
    b. Simple cycle (SC) NG

[11] Some coal is used for CHP in the industrial sector, but we ignored this to simplify the model.

c. Combined cycle (CC) NG
d. "Old" CC NG, which served as a proxy for once-through cooling plants which are being phased out in California
e. SC NG with CCS
f. CC NG with CCS
g. SC diesel
h. SC fuel oil
i. Pulverized coal (PC)
j. "Old" PC (not currently distinct from PC, but capacity is zero in all scenarios)
k. Integrated gasification combined cycle (IGCC) coal
l. PC with CCS
m. IGCC coal with CCS
n. Self-generation other than solar photovoltaic (PV) (fuel type unspecified)
o. Nuclear
p. Large hydro

2. In-state renewable generation
    a. Biogas
    b. Biomass
    c. Geothermal
    d. Small hydro
    e. Central PV
    f. Distributed PV
    g. Solar thermal
    h. Onshore wind
    i. Offshore wind
    j. Other renewables (unspecified, but zero-carbon)
    k. Procured distributed generation (DG) renewables (again unspecified, but zero-carbon)
3. Imported generation
    a. SC NG
    b. CC NG
    c. PC coal
    d. Nuclear
    e. Large hydro
    f. Biomass
    g. Small hydro
    h. Other renewables
    i. Unspecified (assumed not renewable)

In addition to the above resources, the model included exported and stored electricity. Exported electricity was counted as a "negative" generation resource (subtracted from state total), while storage was not counted toward the state total at all, though losses did contribute to gross demand as described above.

Electricity transmission losses were estimated from data provided by IEPR (Kavalec, 2013) for the stationary sector. Storage losses were specified in the *Control panel* but were set to

20% for all scenarios, based roughly on average round-trip losses for various storage technologies (see e.g., Table 10 in Greenblatt et al., 2012b).

The model was calibrated using a number of data sources from the California Energy Almanac (CEC, 2013). We began with a specification of recent (2010 or 2011) in-state and imported generation assets, expressed in terms of both capacity (GW) and annual generation (GWh/yr). From these data average capacity factors were obtained. For large hydro, whose generation fluctuates significantly year to year, we used annual generation data from 1983-2011 to obtain a long-term average (about 33,000 GWh/yr). From this starting point, we then added current proprietary assumptions for renewable portfolio standard (RPS) compliance by the CEC (Grant, 2013) to obtain an estimate of total planned generation resources through 2022. Note that the CEC developed three scenarios (labeled "Commercial," "Environmental" and "High DG") with total installed capacities of new renewables ranging from 11,954 to 13,504 MW; we used the "Environmental" scenario in all of our scenarios. Future renewable generation was driven by the proportion of total renewable generation in 2022 and the RPS target in future years, although the proportion contributed by each technology could be specified in the *Control panel*.

Distributed PV beyond what was specified for RPS compliance was assumed not to count toward future RPS goals and was driven by zero net energy (ZNE) goals in the stationary sector.

In-state nuclear capacity and large hydro generation were specified in the *Control panel*. In all scenarios, the recent decision to permanently close San Onofre nuclear station was reflected in the model, but the decision to relicense Diablo Canyon through 2045 was a scenario option. It was possible to specify changes in hydro generation but in all scenarios it was fixed at the long-term average value.

Imported generation was calculated after in-state renewables, where the total amount of imports (expressed as a fraction of gross demand), as well as the fraction of generation from each resource, was specified in the *Control panel*. Imported renewables were counted toward the state RPS goal but the fraction of total eligible renewables was tracked, as state policy currently specifies no more than 25% of total generation should be imported. If this occurred, an alert message was displayed in the *Electricity sector* tab where this quantity was calculated.

Exported electricity was specified by annual generation and scenarios used the 2002-2011 average (5,100 GWh/yr) for 2012 onward, though this could be changed in the *Control panel*.

Current state policy requires power plants with once-through cooling (OTC) to be phased out according to a prescribed schedule through 2030 (CCEF, 2011). The model tracked the removal of these plants explicitly, including calculating the weighted average heat rate of remaining plants until all are shut down. Heat rates for plants was provided by the Environmental Protection Agency (EPA) eGRID database (EPA, 2012).

Out of state coal plants are similarly required to be phased out according to current state policy (CCEF, 2012). The model used a similar approach to the OTC phase-out described above.

CHP and CCS capacity were specified next (which differed according to the Scenario) and represented fixed amounts of generation regardless of demand or the presence of other generation technologies.

The amount of load-following generation, defined as the sum of simple-cycle NG and electricity storage, was specified as a fraction of gross demand in the *Control Panel*. In 2010, the amount of load-following generation (all simple-cycle NG) was calculated to be 3.8%. For Scenarios 1 and 2, a 4% fraction of load-following was maintained for 2020 onward (when electricity storage was present, it was subtracted from the total to arrive at the required simple-cycle NG generation). For Scenario 3, the fraction was increased in later years to account for additional load-following need associated with higher levels of renewables.

After calculating contributions from the above generation resources, the model then satisfied remaining demand with other types of fossil generation, using the fractions of generation in 2011 as a starting point for future years, specifically combined-cycle NG, in-state pulverized coal (a very small amount was present in 2010—approximately 3,000 GWh—which was phased out by 2030), simple-cycle diesel or fuel oil, IGCC coal (without CCS), and other types of CCS technology (simple cycle NG, combined cycle NG, and pulverized coal). Aside from combined-cycle NG and coal, these were all set to zero in each scenario. If the contribution of any fossil resources was negative, an alert message would be displayed in the *Control panel*.

For generation efficiencies, we relied on data from Kreutz and Williams (2004) and Cai et al. (2012); from this data, we calculated heat rates (Btu/kWh) for thermal power plants which were used to calculate fuel demand for each generation technology. With the exception of OTC plants, heat rates were held constant at 2010 values throughout the analysis period. From these heat rates, total demand by generation technology and aggregated by fuel were calculated.

GHG and criteria pollutant emissions were calculated from total demands. Downstream criteria pollutant emission factors were obtained from Cai et al. (2012) and NETL (2010a, 2010b, 2010c), though some factors were estimated from others because data were lacking. Also, factors were assumed to remain fixed at their 2010 values throughout the analysis period.

<u>Fuels sector</u>

The purpose of the fuels scenario was to determine GHG and upstream criteria pollutant emissions of fuels, as well as statewide biomass demand.

Demand for the following hydrocarbon fuels was aggregated across sectors and served as inputs to the *Fuels scenario* tab:

1. Gasoline
2. E-85
3. Diesel
4. NG
5. Jet fuel
6. Aviation gasoline
7. Fuel oil
8. Coal
9. Biomass

The last item, biomass, tracked *raw* biomass used for electricity generation, and *not* biomass used to produce other fuels; the biomass needed for that was calculated later.

The biomass fraction of each of the above fuels was specified in the *Control panel* for each scenario (however, coal should always be 0% and biomass, 100%). From these fractions, the demand for biomass by fuel type was calculated. The model then specified one or more methods of biofuel production for each fuel type:

1. Gasoline
    a. Corn ethanol
    b. Cellulosic ethanol (near-term)
    c. Cellulosic ethanol (advanced)
    d. Fischer-Tropsch gasoline
2. E-85
    a. Corn ethanol
    b. Cellulosic ethanol (near-term)
    c. Cellulosic ethanol (advanced)
3. Diesel
    a. Biodiesel from soybean oil etc.
    b. Drop-in diesel (e.g., Fischer-Tropsch)
4. NG
    a. Biogas
5. Jet fuel
    a. Drop-in jet fuel (e.g., Fischer-Tropsch)
6. Aviation gasoline
    a. Fischer-Tropsch gasoline
7. Biomass
    a. One type for now

For each biofuel production process, we estimated the efficiency (energy yield per ton of biomass) from literature sources (Wanichpongpan and Gheewala, 2007; Sheehan et al., 1998; Anex et al., 2010; Humbird et al., 2011; Cai et al., 2012). We crudely assumed a future mix of production processes that gradually introduced more advanced technologies; these parameters, currently located in the *Fuels data* tab, should be moved to the *Control panel* to allow scenario-specific control of their assumptions. From these data, demand for biomass feedstocks were calculated, disaggregated into the following categories:

1. Corn kernels (gasoline, E-85—corn ethanol)
2. Soybean etc. oil (diesel—biodiesel)
3. Herbaceous/forest biomass (gasoline, E-85—cellulosic ethanol and Fischer-Tropsch gasoline; diesel, jet fuel, aviation gasoline—drop-in Fischer-Tropsch fuels; biomass for electricity)
4. Landfill waste (NG—biogas)

We estimated downstream and upstream GHG emissions for both fossil- and biomass-based fuels using emission factor data and estimates provided by the ARB Vision team (Cunningham, 2013). Data were unavailable for aviation gasoline and fuel oil, so we assumed the same parameters as for conventional gasoline and diesel fuel, respectively. These factors did not vary with time, though the model allowed them to do so if desired.

<u>HGWP gases</u>

Data on HGWP gas emissions were provided by ARB (Gallagher, 2013; ARB, 2013a), which represent staff estimates of emissions of chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), hydrofluorocarbons (HFCs), and other fluorinated gases (SF_6, etc. or collectively "F-gases") through 2050. The data assumed that a CFC phase-out takes place in accordance with international regulations, and that ARB regulations in place meet their HCFC reduction goals, but no HFC phase-down (however, the *Control panel* contained a parameter for HFC phase-out which was invoked for Scenarios 2 and 3). Emissions were estimated for 29 separate categories from 2000-2020, and then every five years through 2050. Major categories included:

1. Residential refrigeration
2. Commercial refrigeration
3. Residential air conditioning (AC)
4. Commercial AC
5. Vehicle AC and transport
6. Insulating foam
7. Electrical insulation

Emissions were broken out by sector according to staff estimates provided by ARB and normalized by various metrics (population for residential and electricity; GSP for commercial, industrial and other transport; number of LDVs for LDV sector, number of HDVs for HDV sector). These metrics were different from those used elsewhere in the model: population was extrapolated from historical data between 1970 and 2010 (reaching ~70 million people in 2050); GSP was the same as used in the stationary sector; and numbers of LDVs and HDVs were extrapolated from EMFAC 2011 model output from ARB

(Zhan, 2013). Emissions were normalized to the same assumptions used throughout the model for the scenarios.

<u>"Other" sector</u>

This catch-all sector included the following GHG emission categories obtained from the official ARB inventory GHG inventory (ARB, 2013b) from 2000-2010:

1. Commercial
    a. CHP (NG)
2. Industrial
    a. CHP (NG, refinery gas, coal)
    b. Oil and gas activities (extraction, refining, venting and pipelines)
    c. Cement
    d. Unspecified industrial emissions
    e. Landfills
    f. Solid waste treatment
    g. Wastewater treatment (domestic and industrial)
3. Military fuel use
4. Agriculture and forestry, including:
    a. Enteric fermentation
    b. Manure management
    c. Agricultural soil management (fertilizer)
    d. Forest and range management
    e. Agricultural residue burning
    f. Agricultural energy use (excluding NG which is counted in stationary sector)
    g. Other (histosol and rice cultivation)
    h. Net CO_2 flux (removals from forested land net biomass decay)
5. Other non-specified emissions (HGWP gases)

As for other sectors, emissions were normalized by population or GSP as appropriate to provide a basis for projections beyond 2010. For oil and gas activities, staff estimates through 2030 were available from ARB (Leeman, 2013).[12] For other emissions, normalized trends from 2000-2010 were either held constant through 2050 or trended downward in all scenarios, but all trends could be specified in the *Control panel*.

Several categories were excluded from the state inventory, because they were either officially not counted (e.g., military fuel use) or were counted elsewhere in the model (CHP, oil and gas activities, HGWP gases). All categories were nonetheless extrapolated to 2050.

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[12] Estimates are for on-shore, unconventional oil extraction only, i.e., fracturing the Monterey Shale Formation under an aggressive drilling scenario.

Because CHP data from the inventory provided both electricity and useful thermal output, it was used to obtain an estimate of CHP efficiency (about 50%) and electricity generation, which was used in the electricity model.

Data from landfill emissions included both net and biogenic emissions (which were omitted from the inventory), allowing calculation of the biogenic share of landfill emissions (about 50%). This information was used as a basis for specifying the biogenic share in future years, though again, it was adjustable in the *Control panel*.

Cap and trade

The cap and trade model is still under development. It currently tracks total emissions in the following sectors:

1. Transportation
2. Industrial emissions (including upstream GHG emissions from all fuels)
3. Electricity

It has the capability of imposing an emissions cap on each sector and calculating the needed (or surplus) emissions credits for that sector. There is also a provision to include "other offsets," which is currently used to reflect the unspecified statewide reductions resulting from local efforts that are additional to all other explicit policies in the model, if enabled in the *Control panel*.

Scenario assumptions

The following three scenarios are reflected in the current version of the GHGIS spreadsheet dated September 16, 2013.

Scenario 1: Committed policies

The following policies were included in Scenario 1 (data sources indicated where applicable):

1. LDVs
   a. SB 375: VMT estimated reductions (statewide average): 2.6% by 2020 and 12% by 2035 (Vision: ARB, 2012 and Cunningham, 2013, with revised estimates 8/27/13)[13]
   b. Pavley and LDV GHG emission standards: ARB/EPA GHG regulations through 2025 (Vision, with revised estimates 8/27/13)
   c. ARB ZEV rule: 1.5 million ZEVs by 2025 (Vision; IEPR data not used)
2. Other transport
   a. Shore power: 18% marine OGV electricity use in 2020 (IEPR: Kavalec, 2013)
3. Fuels
   a. Low-Carbon Fuel Standard (LCFS): 22% biofuel (by energy) in gasoline, 5% biofuel in diesel in 2020 (Vision)
4. Hydrogen
   a. SB 1505: 33% renewable generation for hydrogen
5. Stationary sector[14]
   a. IEPR efficiency measures: All committed savings through 2024
   b. AB 1109 (Huffman): Lighting efficiency savings (IEPR)
6. Electricity
   a. RPS: 33% renewables by 2022 (CEC: Grant, 2013)
   b. Distributed PV: Maintain 2022 PV CEC target (2,159 GWh) in addition to RPS
   c. SB 1368: No coal imports after 2025 (CCEF, 2012)
   d. OTC: Retirement of all OTC plants by 2030 (CCEF, 2011; EPA, 2012)
   e. Nuclear: SONGS offline in 2012; Diablo Canyon offline in 2026
   f. Imports: decreased imported electricity from 20% to 10% by 2025 because imported coal is no longer handled the same way
   g. CHP: Revised amount of CHP to constant 8.8 GW and 55% capacity factor (previous version had variable amount of CHP and 90% capacity factor)

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[13] Note that SB 375 actually employs a CO_2 per capita target; the VMT reduction stated here is an ARB staff best estimate of the corresponding impact on VMT from this policy.

[14] While not driven by specific policy, we assumed 1%/year retrofits rates for both the residential and commercial sectors, and assumed new construction and retrofit efficiencies were 10% better than baseline (for electricity and natural gas).

h. Natural gas (NG): Maintain simple cycle (SC) NG at ~4% of gross generation; balance after all other generation is accounted for is combined cycle (CC) NG at ~16% of gross generation, increasing to ~30% by 2030. Increased capacity factors of SC and CC from 0.7% and 13% to 5% and 38% respectively (based on re-calculation from available data).

7. Water
    a. Included 20% per capita water savings for residential and commercial new construction only (moved 20 by 20 goal to Scenario 2: 20% water reduction in residential and commercial sectors by 2020)
8. Waste
    a. Included 50% construction and demolition debris emissions savings for residential and commercial new construction only
9. Other sectors
    a. Sustainable forests: 5.0 million metric tons CO_2 equivalent ($MtCO_2e$) net CO_2 flux in 2020
    b. Dairy digesters: 1.0 $MtCO_2e$ incremental reduction in 2030
    c. Landfill methane capture: 1.5 $MtCO_2e$ incremental reduction in 2020 (adjusted biogenic portion from 50% to 60% to meet this target)
10. HGWP gases
    a. All existing regulations are accounted for in baseline (ARB: Gallagher, 2013; ARB, 2013a)

At this time of this writing, it was not possible to confirm that the following policies were subsumed in Scenario 1, but our judgment was that they were likely *INCLUDED*:

1. LDVs
    a. Paint and window glazing: 0.9 $MtCO_2e$ in 2020
    b. Low-friction oil: 2.8 $MtCO_2e$ reduction in 2020
    c. Tire pressure: 0.6 $MtCO_2e$ reduction in 2020
2. HDVs
    a. EPA round 1 standards (2014-2018 model years)
    b. Tire tread: 0.3 $MtCO_2e$ reduction in 2020
    c. ARB trailer rule (in-use truck rule): ~10% efficiency savings from existing and new tractor-trailers, beginning in 2013, and fully-phased in by 2020 with ~0.9 $MtCO_2e$ in 2020

At this time of this writing, it was not possible to confirm that the following policies were subsumed in Scenario 1, but our judgment was that they were likely *NOT INCLUDED*:

1. Stationary sector
    a. Local adopted building codes
    b. Proposition 39: Would be an incremental component to the Navigant market potential; ARB staff estimates would constitute retrofitting half of all schools over 5 years to improve efficiency, where 20-40% would reduce emissions resulting in 0.43-0.85 $MtCO_2e$/yr. Using low-GWP insulation in those retrofits would reduce emissions another 0.24 $MtCO_2e$/yr.

    c. AB 1470 (solar hot water): 0.1 $MtCO_2e$ in 2020
2. Electricity
    a. SB 1122, RAM, SGIP, CSI and NEM
3. Cap and trade
    a. Urban forests
    b. Ozone-depleting substances
4. HGWP gases
    a. Building codes

Policies that were *NOT INCLUDED* in Scenario 1:

1. Stationary sector
    a. Navigant market potential: in addition to IEPR baseline (this is implemented in Scenario 2)

Scenario 2: Additional, uncommitted policy targets

In addition to the policies included in Scenario 1, the following policies were included in Scenario 2 (data sources indicated where applicable):

1. Fuels
    a. AB 2076 and AB 1007: 26% petroleum displacement (via biofuels) by 2022, and 30% by 2030 (applied to both gasoline and diesel, with intermediate values of 12% diesel in 2015 and 22% in 2020)
2. HDVs
    a. MHD and HHD vehicle hybridization: 0.5 $MtCO_2e$ reduction in 2020 achieved with 1.3% increase in fuel efficiency of conventional engines (rather than introducing hybrid market shares)
    b. System-wide HDV efficiency: 3.5 $MtCO_2e$ reduction in 2020 achieved with 9.5% decrease in VMT across all vehicle classes
3. Other transport
    a. High-speed rail: 1 $MtCO_2e$ reduction in 2020 achieved by 75% increase in rail energy use (as electricity) with simultaneous 18% decrease in in-state aviation energy use[15]
4. Stationary sector
    a. Baseline energy use: Used IEPR base case plus Navigant PGT net energy mid-market savings from 2015-2024 (Swamy, 2013), with extrapolations to 2050
    b. AB 758/Energy efficiency strategic plan (CPUC, 2008):
        i. Residential new construction: 23% more efficient than 2010 baseline in 2011, 40% in 2015, 53% in 2020 (applied to both electricity and NG)[16]

[15] Technically, we are mixing transportation modes, as all rail data supplied in the model was for freight only, but the approach taken accomplishes the goal; it can be replaced by a more transparent method once passenger rail is added to the model.

ii. Residential retrofits: 20% more efficient than 2010 baseline in 2015, 40% in 2020 (applied to both electricity and NG)[17]
iii. Commercial new construction: 60% more efficient than 2010 baseline in 2020 (applied to both electricity and NG; used averages of 2020 and 2030 values in 2025: 36% for electricity, 37% for NG)
iv. Commercial retrofits: No improvement over baseline

c. Zero Net Energy (ZNE): Sum of electricity and NG primary energy consumed by buildings is offset by distributed solar PV:
i. Residential new construction: 100% of buildings are ZNE by 2020
ii. Residential retrofits: No ZNE buildings
iii. Commercial new construction: 100% of buildings are ZNE by 2030
iv. Commercial retrofits: 50% of buildings are ZNE by 2030 (continued trend to 100% of buildings in 2050)

5. Electricity sector
   a. Imports: ramped down to 0% by 2025; otherwise fossil generation goes negative before 2020.
   b. CHP: AB 32 Scoping Plan for CHP (increase by 30,000 GWh in 2020; total capacity of 15.1 GW) and Governor's CHP goal (6.5 GW new CHP by 2030; total capacity of 15.3 GW): Because capacity factor of CHP was revised significantly downward in Scenario 1, there was now enough electricity demand remaining after other generation types were accounted for meet these goals. Note had to reduce CHP capacity slightly to 15.1 GW by 2040 to prevent remaining fossil generation from falling below zero.
   c. 12 GW of renewable distributed generation by 2020 (25,000 GWh), all in form of PV. This counted toward ZNE goals, which only overtook this total in 2030.
   d. 8 GW of new utility-scale renewables by 2020: Part of meeting RPS target
   e. Local targets for renewables >33%: Increased state RPS target from 33% to 37% to simulate meeting these commitments
   f. 1,325 MW energy storage by 2020 (investor-owned utility target): Scaled up to 1,900 MW to represent statewide target (IOUs are ~70% of state electricity generation), achieved by building storage equal to 0.55% of gross demand assuming an arbitrary 10% capacity factor (~1,600 GWh/yr).
   g. Nuclear: Diablo Canyon relicensed through 2045, then offline

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[16] Values obtained from weighted averages of targets in CPUC Strategic Plan:
2011: 50% of buildings surpass 2005 Title 24 by 35%, and 10% surpass by 55% = 23% average efficiency improvement
2015: 90% of buildings surpass 2005 Title 24 by 35%, and 40% surpass by 55% = 40% average efficiency improvement
2020: 100% of buildings surpass 2005 Title 24 by 35%, and 90% surpass by 55% = 53% average efficiency improvement

[17] Values obtained from weighted averages of targets in CPUC Strategic Plan for 2020: 25% of buildings are 70% more efficient than 2008 baseline, and 75% are 30% more efficient = 40% average efficiency improvement.

h. CCS: One 300 MW IGCC/CCS coal plant online in 2020 (based on HECA plant in Bakersfield, CA). Methodology for implementing this in model was changed, so capacity could now be specified precisely in target years.
i. Natural gas: After storage balance of load-following generation (~3.5%) was supplied by SC NG, and remaining fossil generation was supplied by CC NG: ~16% in 2010, tapering to almost zero by 2020, then varying up to 7% through 2050.

6. Water
    a. 20 by 20: 20% water reduction in residential and commercial sectors by 2020
    b. Water use efficiency, recycling, pumping and treatment efficiency, and urban runoff re-use: additional 3.9 $MtCO_2e$ achieved through 2020 water use savings of 32.5% relative to baseline in residential and commercial sectors (note was 33.5% in 8/16/13 version)
7. Waste
    a. AB 341: 75% waste diversion in 2020 reduced direct and indirect emissions by 4.5 $MtCO_2e$ (consistent with expected 20-30 $MtCO_2e$ reduction in 2020, where 80% of emissions are outside of California)
    b. Zero net emissions by 2035: Achieved by forcing biogenic component of landfills to 100%
8. HGWP gases
    a. HFC phase-out: 50% of HFCs eliminated by 2035, 100% by 2050
    b. Foam recovery and destruction, fire suppressants, and residential refrigerator retirement: estimated 0.5 $MtCO_2e$ reduction in 2020, implemented by reducing HFC usage 2.5% in 2020
    c. Additional reductions in mobile sources, leak tests, refrigerant recovery and federal ban: reduction unknown; assume additional 0.5 $MtCO_2e$ in 2020, implemented by reducing HFC usage an additional 2.5% in 2020 (so total reduction of 5%)
9. Cap and trade
    a. Local reductions beyond state/federal activities: For 90 cities reviewed (Cal Poly study), 44% of actions in CAPs were incremental to state and federal rules, accounting for 8.2 $MtCO_2e$ reductions in 2020. Because activities are so diffuse throughout economy, we chose to represent these reductions via emission offset in the *Cap and Trade* sector.

At this time of this writing, it was not possible to confirm that the following policies were subsumed in Scenario 2, but our judgment was that they were most likely *INCLUDED*:

1. Stationary sector
    a. Transformative HVAC
    b. AB 32 Scoping Plan targets: 11.9 $MtCO_2e$ from 32,000 GWh and 800 million therms of efficiency improvements by 2020 (unclear which baseline this is relative to)

At this time of this writing, it was not possible to confirm that the following policies were subsumed in Scenario 2, but our judgment was that they were most likely *NOT INCLUDED*:

1. Stationary sector
    a. Expanded low-income efficiency programs
    b. Green Building Executive Order

Policies that were *NOT INCLUDED* in Scenario 2:

1. Oil and gas
    a. Oil and gas extraction GHG reduction: 0.2 $MtCO_2e$
    b. Oil and gas transmission leak reduction: 0.9 $MtCO_2e$
    c. Refinery flare recovery process improvements: 0.33 $MtCO_2e$
    d. Removal of methane exemption from refinery regulations: 0.014 MtCO2e

    These can be easily implemented by adding parameters to *Control Panel* to affect upstream emission factors; however, total impact was small (1.4 $MtCO_2e$) so we ignored this
2. Electricity
    a. Increased renewable energy production (unclear on what amounts needed)
3. Water
    a. Department of Water Resources climate action plan estimates only 0.05 $MtCO_2e$ savings (DWR, 2013), so not worth implementing
4. Waste
    a. 25% below 2035 levels by 2050: Since we achieve zero net emissions in 2035 by diverting 100% of non-biogenic waste, it was unclear how to implement this measure in the model
5. Cap and trade
    a. Sectoral caps not implemented due to lack of adequate information and time to formulate a strategy (will implement in revision to model)

<u>Scenario 3: Potential technology and market future</u>

In addition to the policies included in Scenarios 1 and 2, the following policies were included in Scenario 3 (data sources indicated where applicable):

1. LDVs
    a. VMT: Aggregate VMT declines 15% from 2010 to 2025, then approximately constant (US PIRG, 2013 ongoing decline scenario), implemented by ratcheting down VMT from baseline (which shows increasing trend) by 16% in 2020, 22% in 2030 and 30% in 2050
    b. Fuel efficiency: increased conventional gasoline engine fuel consumption based on National Academies report (NAS, 2013): 22.9 mpg in 2010, 52.5 mpg in 2030, 77.9 mpg in 2050, assuming average of passenger car and light-truck EPA fuel efficiencies, times an 0.833 on-road adjustment factor.

   c. Vehicle automation: Additional efficiency savings due to smoother acceleration/braking, decreased traffic congestion, signal light coordination, vehicle platooning, vehicle light-weighting, etc.: 20% in 2030, 50% in 2050 (author estimates)
   d. ZEVs: Used LBNL scenario (Wei, 2013) which has 3 million ZEVs in 2030, >6 million in 2035, and 17 million in 2050
2. HDVs
   a. NG vehicles: Approximately implemented National Petroleum Council (NPC) high petroleum cost scenario (NPC, 2012) by adopting new vehicle shares of NG vehicles to fleet shares:
      i. MHD: 5% in 2020, 10% in 2030, 29% in 2050 (equal to 2030 new vehicle share)
      ii. HHD: 5% in 2020, 15% in 2030, 45% in 2050 (equal to 2030 new vehicle share)
   b. MHD efficiency (classes 3-6): Roughly implemented (NPC, 2012 high petroleum cost scenario):
      i. 2035: Diesel ~12.5 mpg; NG: ~10 mpg; Gasoline: ~11mpg
      ii. 2050: Diesel ~13mpg; NG ~11mpg; Gasoline ~11.5mpg
   c. HHD efficiency (classes 7-8): Approximately implemented NPC high petroleum cost scenario (NPC, 2012): 7 mpg in 2015, 8 mpg in 2020, 9 mpg in 2025, 10 mpg in 2030, 11 mpg in 2035, 12 mpg in 2040
   d. Platooning: Additional 12% savings in 15% of HDV VMT, or ~2% of HHD VMT reduction overall in 2030
3. Fuels
   a. Cleaner petroleum: Fuel carbon intensity linearly down by 5 g/MJ in 2030 (equal to cleanest 25% of California petroleum): Implemented as additional 6% biomass in fuels (fossil fuels are ~90 g/MJ including upstream, and biofuels are ~4 g/MJ, so +6% biofuel is a change of ~5 g/MJ)
   b. Renewable NG: 100 million diesel gallons equivalent (dge) by 2020, 450 million dge by 2035: Implemented approximately by adjusting biomass share of NG to 0.7% in 2020, 2.8% in 2030 and 2.4% in 2050
   c. Renewable jet fuel: 1% renewable jet fuel by 2015 (United Airlines target)
4. Electricity sector
   a. RPS: 40% by 2020, 51% by 2030 (assume local efforts are subsumed in these totals)
   b. CCS: Changed from previous (8/16/13) version: Now builds 1.0 GW of CCS by 2045, which jumps to 2.5 GW in 2046 as nuclear is taken offline.
   c. CHP had to be reduced BELOW levels specified in Scenario 2 in order to keep other fossil generation (e.g., CC NG) from dropping below zero, but was also revised from 8/16/13 version. CHP now capped at 8.8 GW through 2020, then increases to 12 GW in 2020, 9 GW in 2030 and 6 GW in 2040+
   d. Storage: Increase from Scenario 2 value in 2020 to 1% of gross generation in 2030 (~3,000 GWh). In generation capacity, this corresponds to 3.3 GW (assuming arbitrary 10% capacity factor), which is roughly 5% of peak demand (IEPR forecast indicated peak demand in 2024 was 52 GW; with increased EVs this is expected to grow slightly).

    e. Natural gas: After storage, balance of load following supplied by SC NG (~4.5% in 2020, increasing to 6% in 2030 following logic that higher RPS target needs higher fraction of load following, but amount was arbitrary). Remaining fossil was CC NG, which was similar to Scenario 2 case through 2020, then varied up to ~3% through 2050.
5. HGWP gases
    a. Mitigation fee on HGWP gases estimated to reduce emissions by 5 $MtCO_2e$ in 2020: implemented as reduction in HFCs to 70% in 2020 (to maintain consistency with overall phase-out, reduced to 35% in 2035 and 0% in 2050)
6. Cap and trade
    a. Local reductions beyond state/federal activities: Assume an additional 8.2 $MtCO_2e$ reductions in 2030 (so total of 16.4 $MtCO_2e$)

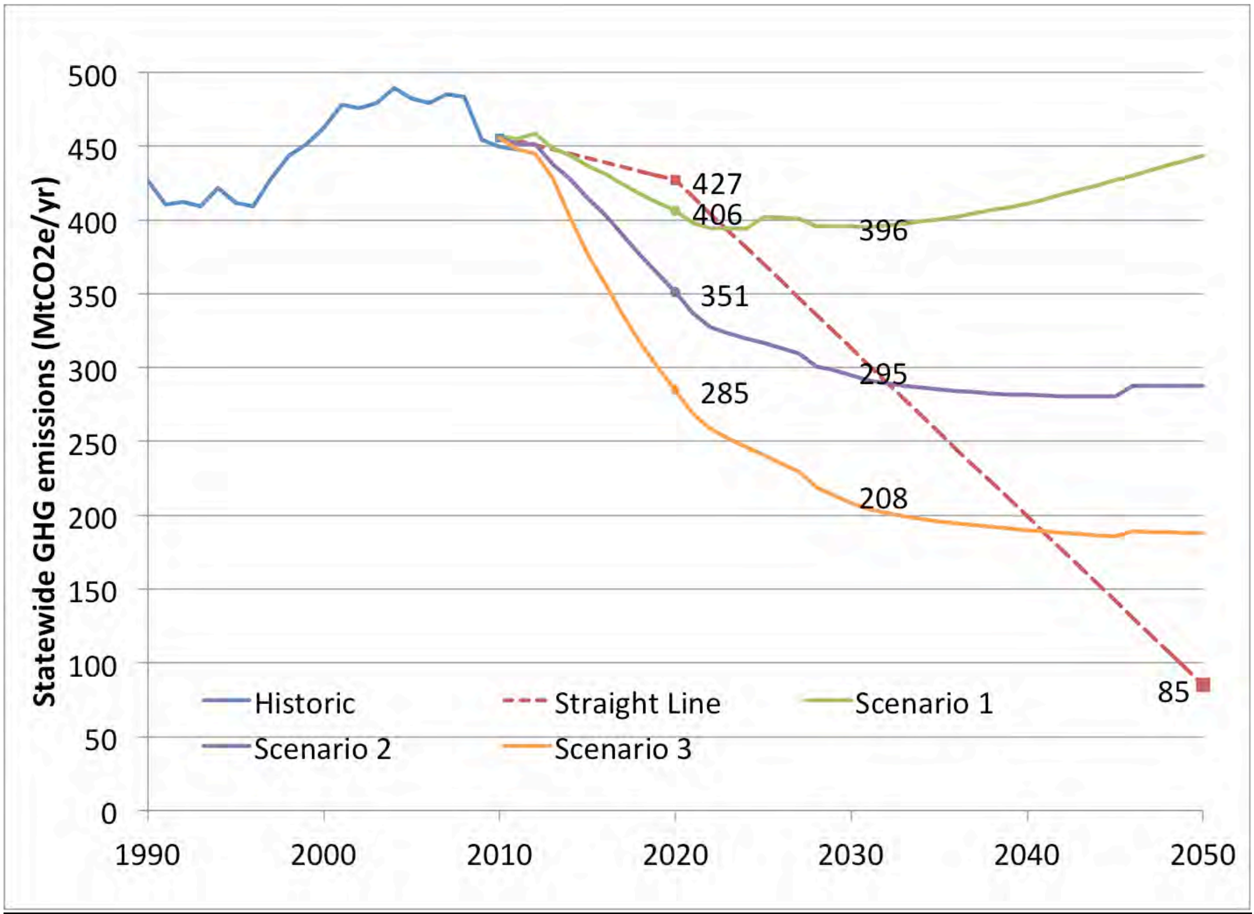
Policies that were *NOT INCLUDED* in Scenario 3:

1. LDVs
    a. Increasing transit associated with lower LDV VMT: Difficult to implement because neither bus nor passenger rail energy use was included in model
    b. Zero emission buses by 2025: All new buses electric or fuel cell by 2025; phase in from today with accelerated rollout after 2018-2020: Not implemented because buses not represented in model
2. HDVs
    a. Electrification of I-710 corridor: Possible to implement, but no quantitative data available
3. Other transport
    a. Natural gas in rail: Currently not possible to implement as NG rail is lacking in model
    b. Electric trucks, cranes, etc. from sustainable freight, vehicle automation and other measures: No quantitative data to implement
4. Fuels
    a. Incremental increase in biofuels beyond LCFS/Scenario 1 & 2: To be determined (reference needed)
5. Stationary sector
    a. Optimistic demand forecast from Navigant (e.g., economic or technical potential scenarios): Unavailable at time of writing
    b. Plug-load energy reductions from solid-state transformers
6. Electricity sector
    a. Incremental distributed generation other than PV: No quantitative data, so could not implement
    b. Demand response: Target to be based on EV demand plus fraction of remaining demand, but not yet determined
7. Cap and trade
    a. Industrial emissions: 2-3% annual reductions in emissions through 2030: To be determined once Cap and Trade model is finalized
    b. Energy intensity: No quantitative data
8. Water

a. 100 gallons/person/day: Threshold in SB X7-7 below which suppliers do not have to meet 5% minimum reduction (15 of the 381 urban water districts that submitted required plans to DWR were below 100 gallons/person/day; there are 448 water suppliers known to DWR who should have submitted plans): No target year information for implementation
b. Public Goods Charge: $100M - $500 M for efficiency and supply improvements (per Scoping Plan): No quantitative data to implement

Scenario results

<u>Scenario comparisons</u>



Comparison of GHG emissions by Scenario, along with historical and "straight-line" connections between 2020 and 2050 policy targets.

GHG emissions by sector ($MtCO_2e/yr$)

Scenario	LDVs	HDVs	Other transport	Residential+ commercial	Industry	Electricity	High GWP	Net offsets	All others	Total
	2020									
1	101.09	43.36	12.14	45.97	32.53	86.15	32.24	-	52.87	406.34
2	101.03	33.76	9.95	43.52	31.93	69.40	31.25	(8.20)	30.11	350.94
3	48.26	29.81	9.91	43.14	31.71	65.60	26.28	(8.20)	30.01	284.71
	2030									
1	73.19	51.55	15.63	46.83	31.95	81.72	27.79	-	67.03	395.68
2	66.27	36.28	12.05	39.98	30.96	50.40	19.39	(8.20)	39.20	294.52
3	22.23	24.56	11.43	38.95	30.09	35.21	14.98	(16.40)	30.57	208.04
	2035									
1	66.62	55.10	17.66	47.61	33.37	83.74	26.60	-	69.91	400.60
2	60.32	38.71	13.60	39.12	32.33	45.51	14.32	(8.20)	41.27	285.17
3	14.35	24.16	12.88	38.19	31.46	31.24	10.63	(16.40)	32.99	195.91
	2050									
1	64.68	63.75	25.57	51.13	41.66	94.96	27.37	-	74.63	443.75
2	58.57	44.73	19.61	38.47	40.36	44.35	0.93	(8.20)	40.55	287.57
3	4.94	21.80	18.51	37.75	39.39	30.88	0.93	(16.40)	33.61	187.81

Criteria pollutants by region (t/yr)

	SCAB			SJV			Statewide		
Scenario	**ROG**	**NOx**	**PM2.5**	**ROG**	**NOx**	**PM2.5**	**ROG**	**NOx**	**PM2.5**
	2020								
1	39,722	92,653	51,381	12,804	34,193	13,562	181,972	249,510	116,457
2	38,958	85,461	47,322	12,371	31,320	12,484	167,765	229,702	107,267
3	27,721	79,395	48,163	9,004	28,124	12,622	135,701	210,368	108,621
	2030								
1	32,878	48,678	25,348	11,308	20,249	7,683	167,970	137,940	59,351
2	31,945	44,371	23,168	10,789	18,341	7,014	142,719	124,094	54,142
3	20,768	42,187	27,848	6,881	15,725	8,207	105,846	113,250	63,926
	2035								
1	31,353	43,090	21,594	11,510	19,454	6,975	169,780	125,848	51,590
2	30,288	37,505	17,981	10,926	17,081	5,837	139,870	108,570	43,056
3	18,350	34,611	22,499	6,453	13,922	7,030	100,579	95,375	52,499
	2050								
1	30,855	44,327	23,295	12,552	21,634	8,407	186,603	133,043	57,314
2	29,437	35,083	15,749	11,809	17,784	5,778	147,237	105,840	39,389
3	15,062	31,815	20,448	5,777	13,716	7,163	98,683	89,610	49,238

Biomass demand by fuel type and source (Mdt/yr)

	Gasoline, E-85	Diesel	Gasoline, E-85, Diesel, Jet fuel, Aviation gasoline	NG	Electricity	All
Scenario	**Corn kernels**	**Soybean oil**	**Herbaceous/forest biomass**	**Landfill waste**	**Herbaceous/forest biomass**	**All**
	2020					
1	24.18	2.76	16.74	-	12.07	55.75
2	23.93	11.11	16.98	-	11.42	63.44
3	12.70	9.49	9.24	6.95	12.59	50.97
	2030					
1	13.11	3.18	20.26	-	13.48	50.04
2	17.19	17.53	28.05	-	11.89	74.66
3	8.90	15.56	15.24	23.47	16.14	79.32
	2035					
1	9.57	3.40	22.31	-	14.11	49.38
2	12.49	18.72	31.18	-	11.40	73.79
3	5.05	15.63	13.69	22.57	15.73	72.68
	2050					
1	1.58	3.89	32.64	-	15.80	53.91
2	1.99	21.57	46.57	-	9.89	80.01
3	0.42	15.61	11.87	21.61	15.03	64.53

Notes on criteria pollutants

National Ambient Air Quality Standards set by the Environmental Protection Agency (EPA) targets ozone and PM2.5 standards. NOx and ROG are the emissions that form ozone, and the standards are not written for each pollutant. As a result, each air district and the ARB must decide what balance of pollutant levels are required to meet the target ozone levels. The ozone standards are:

1. EPA 1997 8-hour ozone standard is 0.08 ppm. For SCAB and SJV, the attainment deadline is 2023.
2. EPA 2008 8-hour ozone standard is 0.075 ppb. For SCAB and SJV, the deadline is 2032.

For the purposes of this project, we used estimated NOx targets as a proxy for the ozone requirements, based on information supplied by the ARB (Cunningham, 2013). Specifically, we estimated that to achieve the 2023 ozone standard, we need ~80% of NOx below 2010 inventory levels, and to achieve the 2032 standard, we estimated the need for ~90% reductions below 2010 levels. Please note that these NOx reductions are estimates for the purpose of modeling; the official standards are written in terms of ozone concentrations.

For PM2.5, the standards are:

1. EPA 2006 PM2.5 standard is 35 μg/m^3 (average 24-hour period). Attainment will be modeled for 2014-2019 depending on the air district.
2. EPA 2012 PM2.5 standard is 12 μg/m^3 (annual average). Attainment will be modeled for 2025 for serious areas.

However, our model did not calculate PM2.5 concentrations per unit air parcel, but only aggregate emissions in each air basin, so there is currently no target level established for emissions of PM2.5.

In the charts displayed in the subsequent sections below, we indicate targets of 80% below the 2010 level in 2023 and 90% below the 2010 level in 2032 for all three criteria pollutants for convenience, but note that the targets only technically apply for NOx (and in any case these targets are approximate and for modeling purposes only).

Also note that there is a likely problem with the input estimates for PM2.5 that results in a prominent “stair-step” pattern in the charts of emissions vs. year. The cause of this issue was not identified in time for publication, but we will try to address it in a subsequent revision.

Sensitivities

All GHG sensitivities are relative to Scenario 1.

(A)

Year	Scenario 2	Scenario 3	DOF 2009 population (59M instead of 50M in 2050)	GSP growth 2.5% instead of 2.0%	Include all HGWP gases	20% water savings instead of new construction only	Cancel VMT reductions (-2.7% in 2020, -13.6% in 2035)	No ZEVs	No LCFS (keep at 2010 values)
2010	(1.03)	(0.97)	12.89	-	26.20	(0.00)	-	-	-
2020	(55.40)	(121.63)	17.26	3.17	11.11	(5.90)	2.72	1.58	21.06
2025	(85.44)	(161.62)	18.69	8.76	5.58	(5.90)	5.52	2.84	18.41
2030	(101.17)	(187.64)	19.93	15.02	2.66	(6.11)	7.48	3.50	16.21
2035	(115.42)	(204.69)	21.48	21.96	0.98	(6.36)	9.41	4.70	15.06
2040	(129.88)	(221.32)	24.14	29.67	0.47	(6.58)	9.14	4.79	14.77
2050	(156.18)	(255.94)	32.98	48.73	-	(6.94)	9.23	5.29	15.03

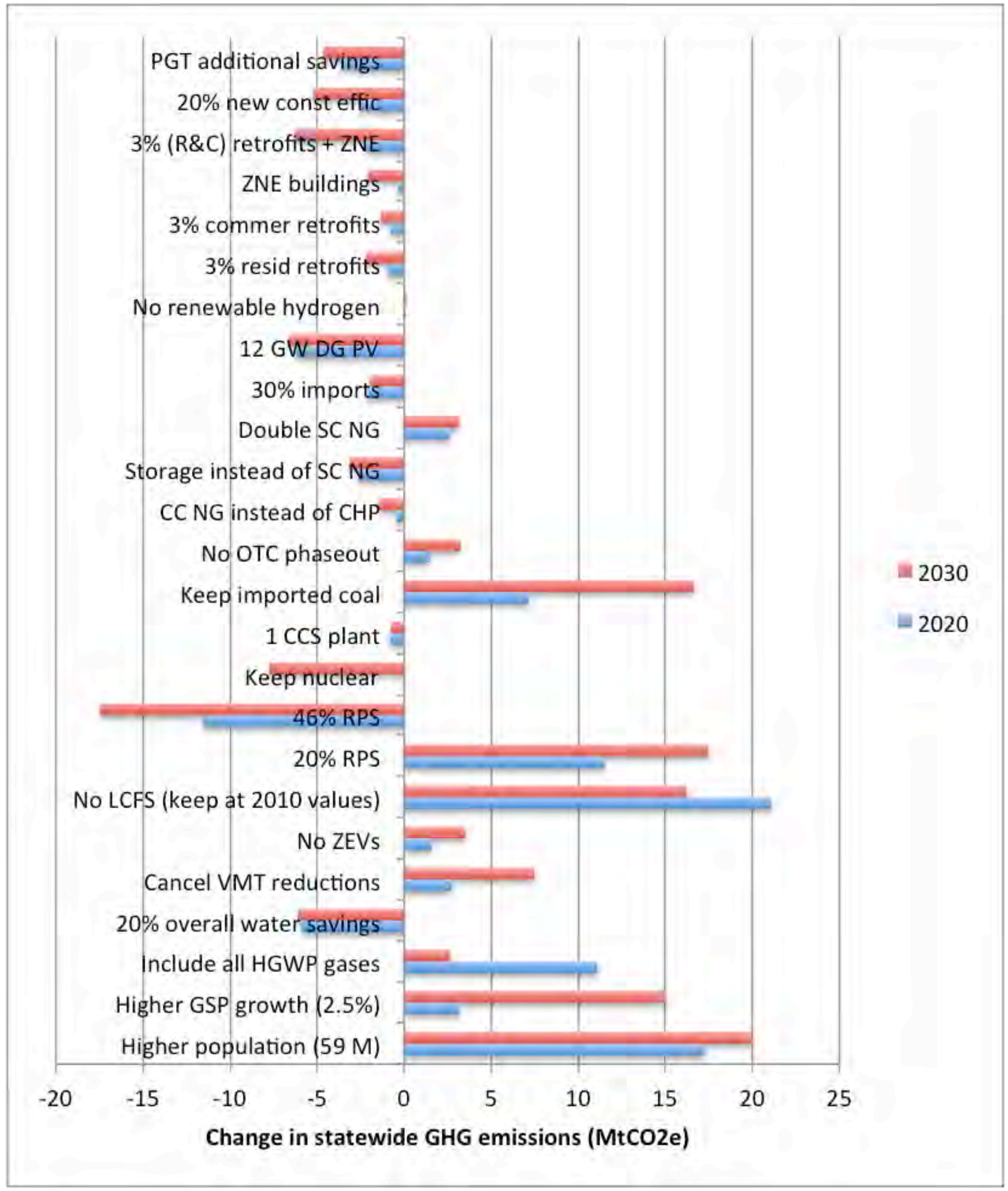
(B)

Year	20% RPS	46% RPS	Diablo Canyon relicensed	CCS plant in 2020	No imported coal phaseout	No OTC phaseout	No CHP (heat rate higher than CC NG)	No SC NG (replace with storage)	Double SC NG (8% of gross demand)
2010	-	-	-	-	-	0.19	(1.41)	(2.65)	2.65
2020	11.55	(11.55)	-	(0.81)	7.14	1.47	(0.45)	(2.62)	2.62
2025	17.37	(17.37)	(7.98)	(0.78)	10.74	2.78	(0.95)	(2.88)	2.88
2030	17.46	(17.46)	(7.76)	(0.75)	16.65	3.24	(1.45)	(3.14)	3.14
2035	18.14	(18.14)	(7.76)	(0.75)	18.19	3.24	(1.45)	(3.27)	3.27
2040	18.79	(18.79)	(7.76)	(0.75)	18.19	3.24	(1.45)	(3.40)	3.40
2050	20.28	(20.28)	-	(0.75)	18.19	3.24	(1.45)	(3.68)	3.68

(C)

Year	30% imported electricity in 2020 instead of 10%	12 GW DG PV	No renewable hydrogen	3% residential retrofit rates instead of 1% (note rolls off beyond 2025)	3% commercial retrofit rates instead of 1% (note rolls off beyond 2025)	ZNE buildings	3% residential AND commercial retrofit rates AND ZNE buildings	New construction is 20% more efficient than baseline instead of 10%	PGT additional savings
2010	0.10	(0.77)	-	-	-	-	-	(0.00)	-
2020	(2.10)	(6.19)	0.01	(0.93)	(0.75)	(0.34)	(2.19)	(2.53)	(3.56)
2025	(2.59)	(6.83)	0.06	(1.77)	(1.23)	(1.05)	(4.47)	(3.85)	(5.07)
2030	(1.96)	(6.64)	0.12	(2.19)	(1.37)	(2.08)	(6.26)	(5.26)	(4.64)
2035	(2.05)	(6.64)	0.22	(2.41)	(1.26)	(2.94)	(7.32)	(6.77)	(4.31)
2040	(2.12)	(6.64)	0.26	(2.47)	(1.10)	(3.89)	(8.21)	(8.34)	(4.01)
2050	(2.30)	(6.64)	0.38	(2.07)	(0.59)	(6.10)	(9.31)	(11.66)	(3.49)

Key:
PGT = Navigant Consulting's Potentials, Goals and Target model
R&C = residential and commercial (Scenario 1 assumed 1% retrofit rates for both sectors)
ZNE = zero net energy buildings (residential, commercial only; Scenario 1 assumed no ZNE buildings)
RPS = renewable portfolio standard (as % of generation; Scenario 1 assumed 33%)
DG PV = distributed generation (solar) photovoltaics (Scenario 1 assumed 1.2 GW in 2022 plus 4.4 GW from RPS)
SC NG = simple cycle natural gas generation (Scenario 1 assumed SC NG was 4% of generation)
CC NG = combined cycle natural gas generation (Scenario 1 assumed ~15 GW in 2020, ~30 GW in 2030)
CHP = combined heat and power (Scenario 1 assumed 8.8 GW)
OTC = once-through cooling generation (Scenario 1 assumed ~15 GW phased out by 2030)
CCS = CO_2 capture and sequestration (1 CCS plant = 300 MW)
LCFS = low carbon fuel standard (Scenario 1 assumed 22% gasoline and 5% diesel fuel would be renewable in 2020)
ZEV = zero-emission vehicle (plug-in all-electric, plug-in hybrid electric, fuel cell; Scenario 1 assumed 1.5 M vehicles in 2025)
VMT = vehicle-miles travelled (Scenario 1 assumed reduction from baseline of 2.6% in 2020 and 12% in 2035 for light-duty vehicles)
HGWP = high global warming potential (Scenario 1 did not include chlorofluorocarbons or hydrochlorofluorocarbons)
GSP = gross state product (Scenario 1 assumed 2.0%/yr after 2018)
Scenario 1 population growth assumed 50 M people in 2050



Sensitivities to key parameters (relative to Scenario 1 results)

Scenario 1 details

GHG emissions by sector ($MtCO_2e/yr$)

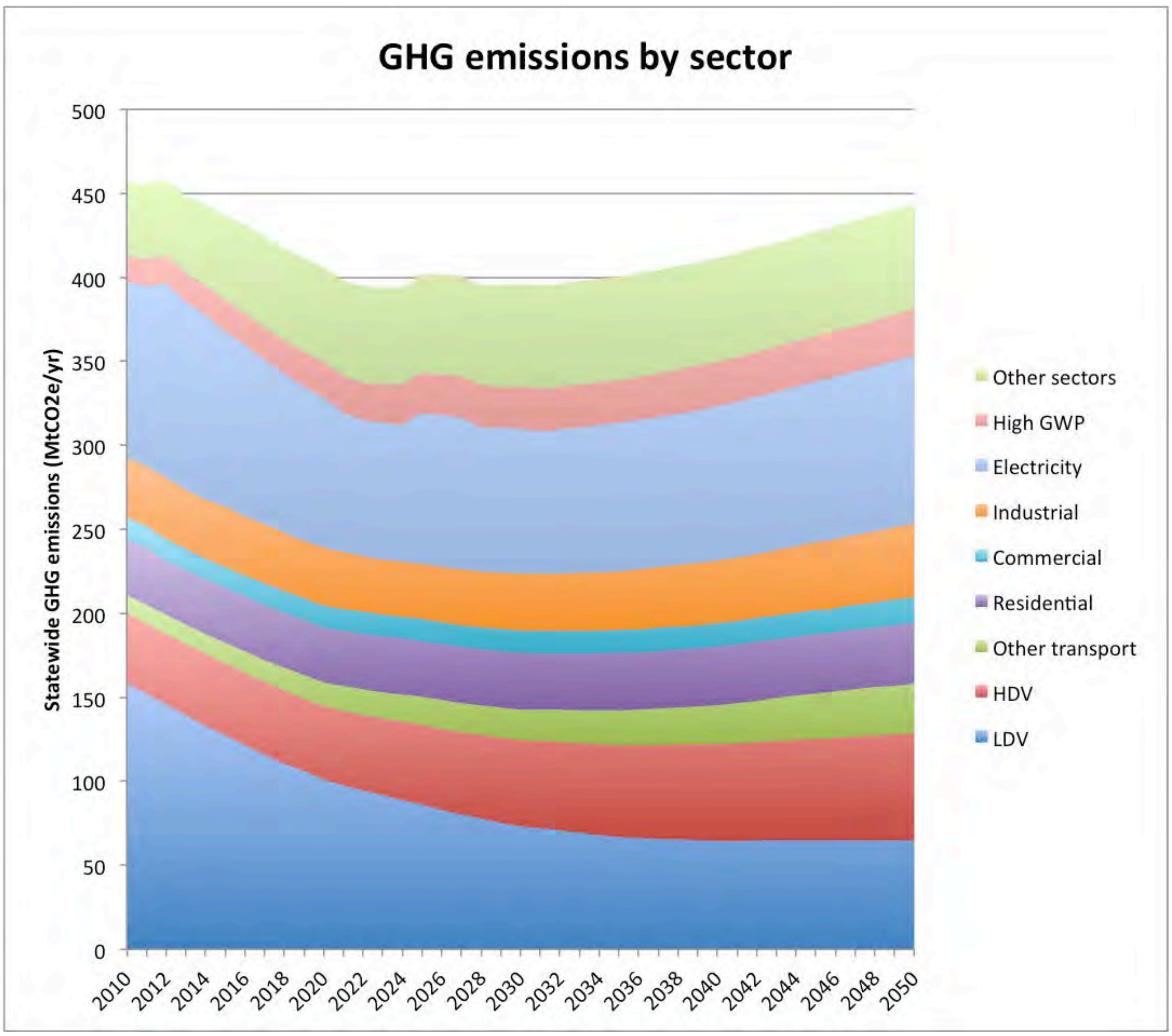
Year	LDVs	HDVs	Other transport	Residential+ commercial	Industry	Electricity	High GWP	Net offsets	All others	Total
2010	158.02	41.89	9.17	46.21	33.56	102.30	41.16	-	24.26	456.57
2020	101.09	43.36	12.14	45.97	32.53	86.15	32.24	-	52.87	406.34
2025	85.99	47.69	14.08	46.35	31.11	86.34	29.45	-	61.10	402.11
2030	73.19	51.55	15.63	46.83	31.95	81.72	27.79	-	67.03	395.68
2035	66.62	55.10	17.66	47.61	33.37	83.74	26.60	-	69.91	400.60
2040	64.49	57.83	19.72	48.58	35.44	87.13	26.74	-	71.39	411.32
2050	64.68	63.75	25.57	51.13	41.66	94.96	27.37	-	74.63	443.75

Criteria pollutants by region (t/yr)

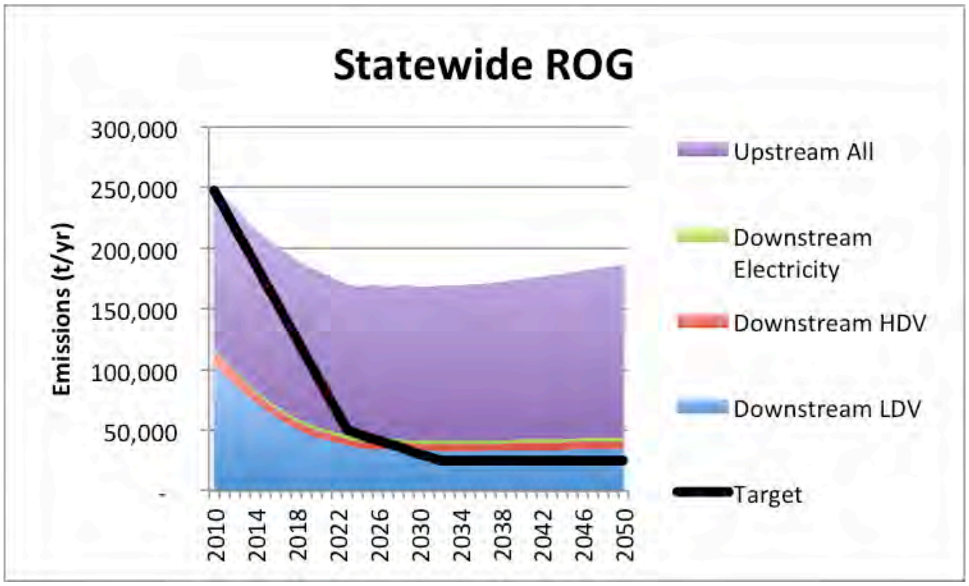
	SCAB			SJV			Statewide		
Year	ROG	NOx	PM2.5	ROG	NOx	PM2.5	ROG	NOx	PM2.5
2010	64,146	163,275	66,590	19,770	69,425	16,680	247,638	466,323	150,710
2020	39,722	92,653	51,381	12,804	34,193	13,562	181,972	249,510	116,457
2025	34,118	68,951	42,954	11,663	25,546	12,093	169,332	185,965	98,221
2030	32,878	48,678	25,348	11,308	20,249	7,683	167,970	137,940	59,351
2035	31,353	43,090	21,594	11,510	19,454	6,975	169,780	125,848	51,590
2040	30,943	43,000	22,052	11,779	20,171	7,436	173,962	127,595	53,280
2050	30,855	44,327	23,295	12,552	21,634	8,407	186,603	133,043	57,314

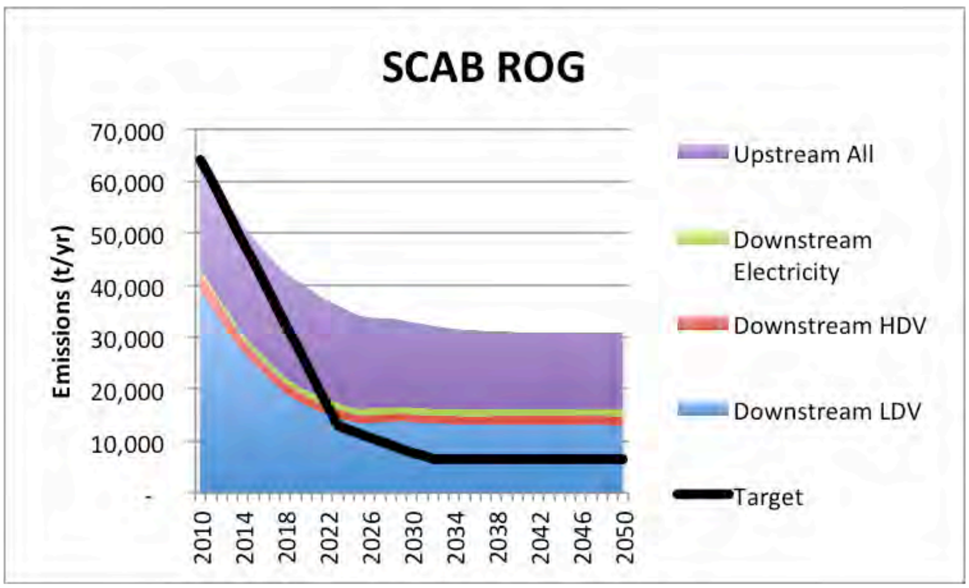
Biomass demand by fuel type and source (Mdt/yr)

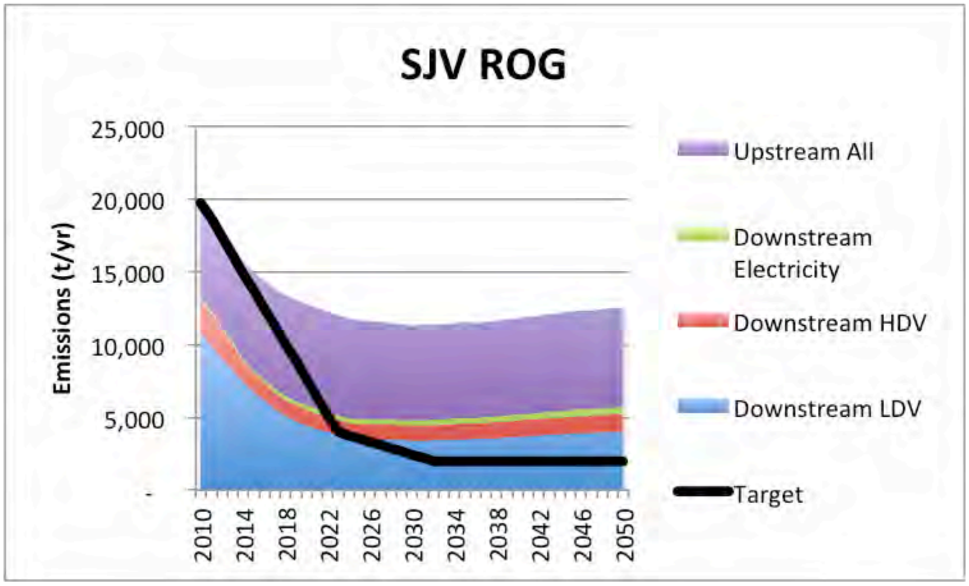
	Gasoline, E-85	Diesel	Gasoline, E-85, Diesel, Jet fuel, Aviation gasoline	NG	Electricity	All
Year	**Corn kernels**	**Soybean oil**	**Herbaceous/forest biomass**	**Landfill waste**	**Herbaceous/forest biomass**	**All**
2010	12.21	2.49	2.92	-	5.25	22.87
2020	24.18	2.76	16.74	-	12.07	55.75
2025	18.06	3.01	18.81	-	12.96	52.84
2030	13.11	3.18	20.26	-	13.48	50.04
2035	9.57	3.40	22.31	-	14.11	49.38
2040	6.82	3.53	25.33	-	14.62	50.29
2050	1.58	3.89	32.64	-	15.80	53.91

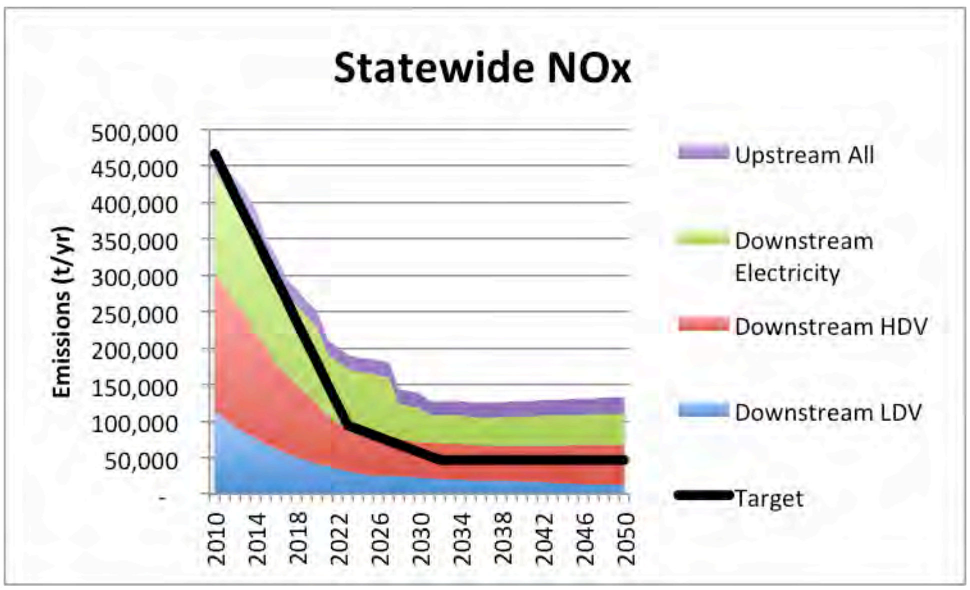


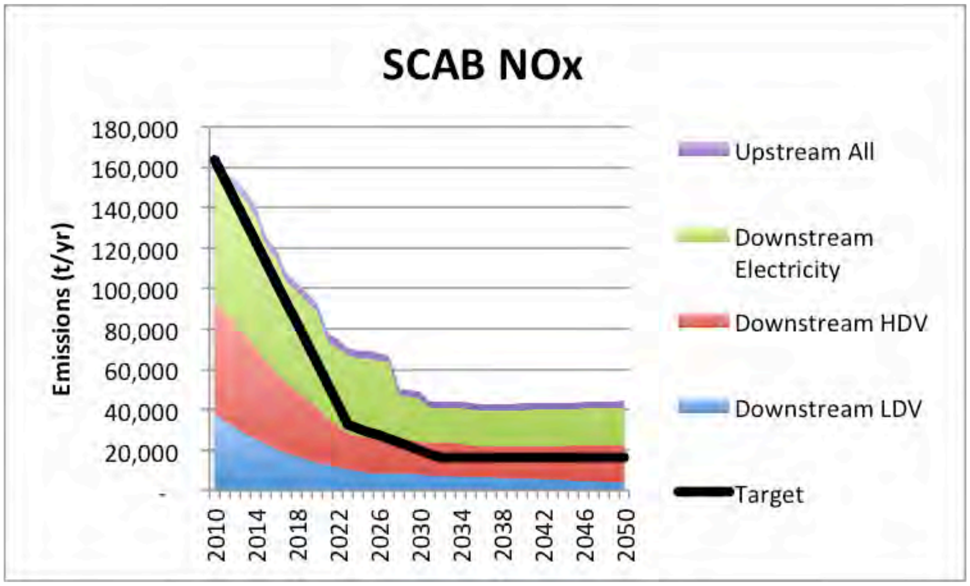
Note: All electricity-related GHG emissions from all sectors are included in electricity sector

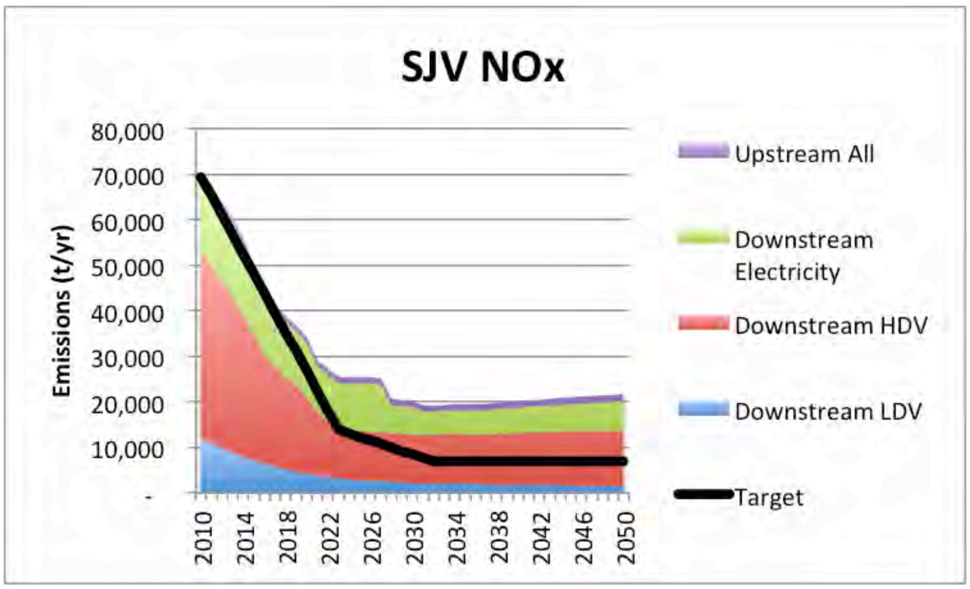

Statewide ROG
300,000
250,000
200,000
150,000
100,000
50,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

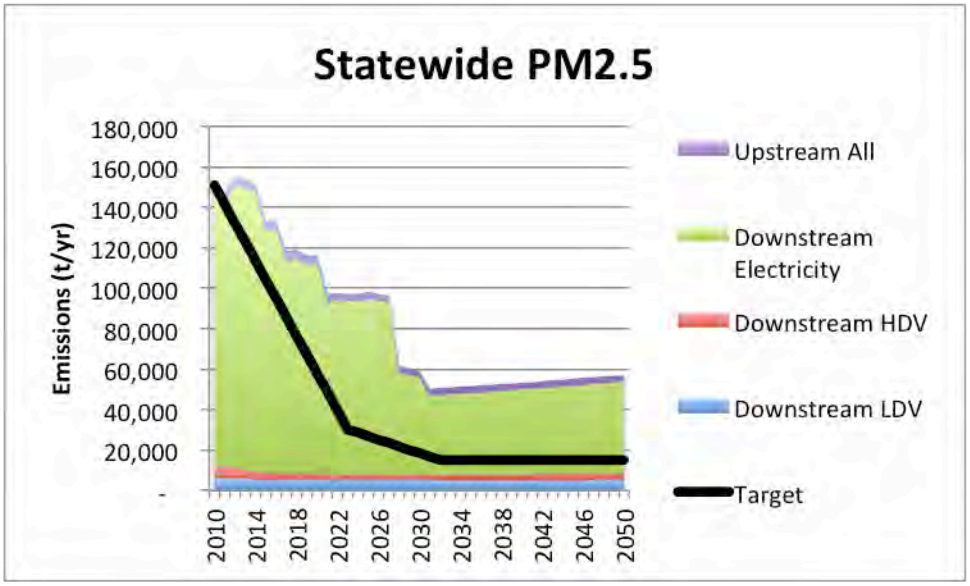

SCAB ROG
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

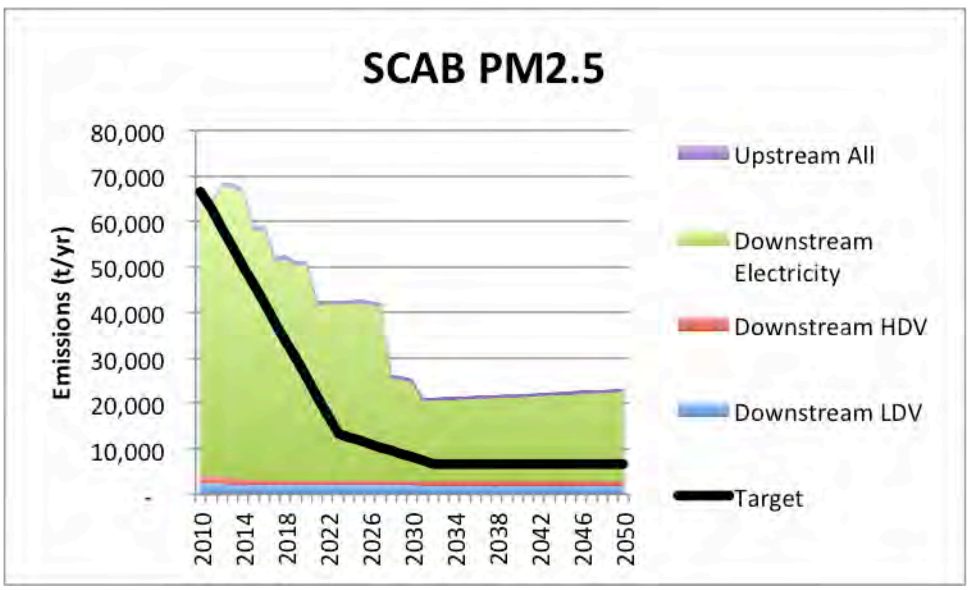

SJV ROG
25,000
20,000
15,000
10,000
5,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

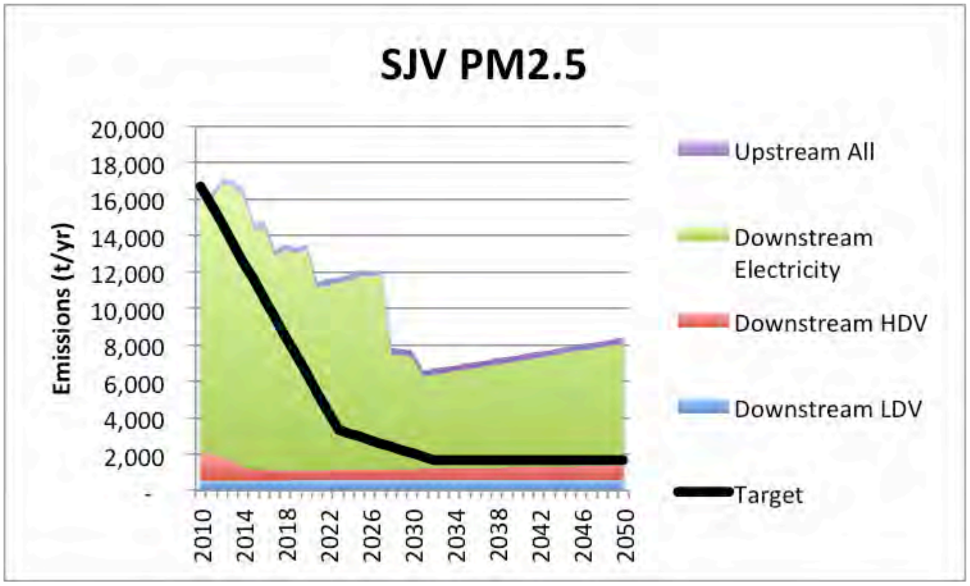

Statewide NOx
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target


SCAB NOx
Emissions (t/yr)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

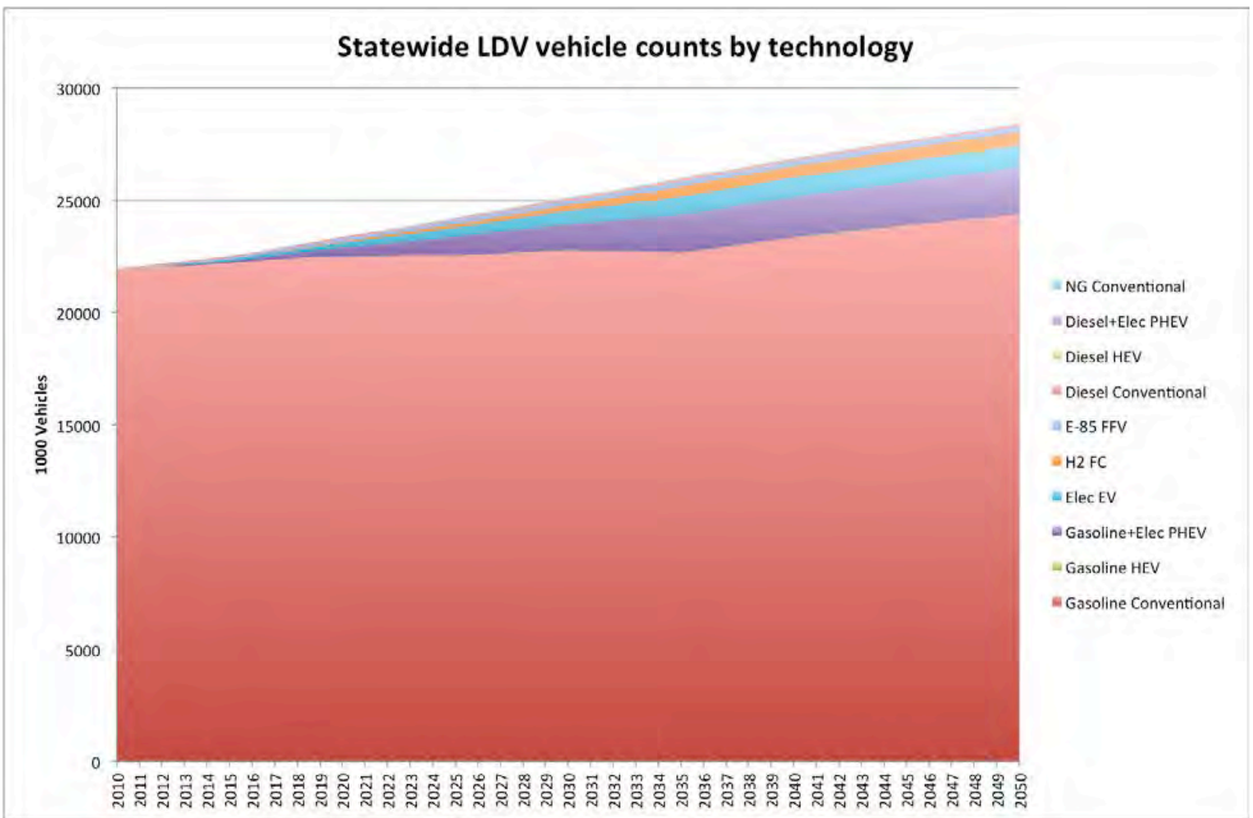

SJV NOx
Emissions (t/yr)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

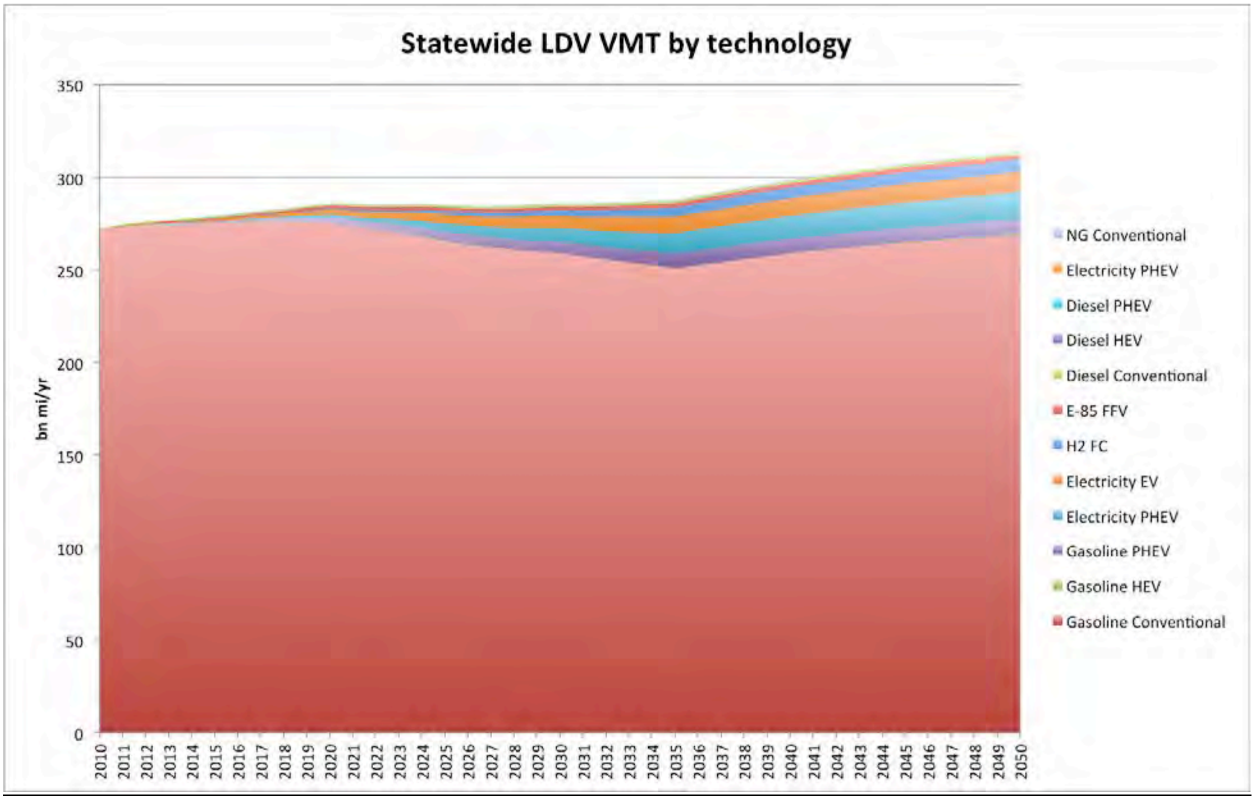

Statewide PM2.5
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

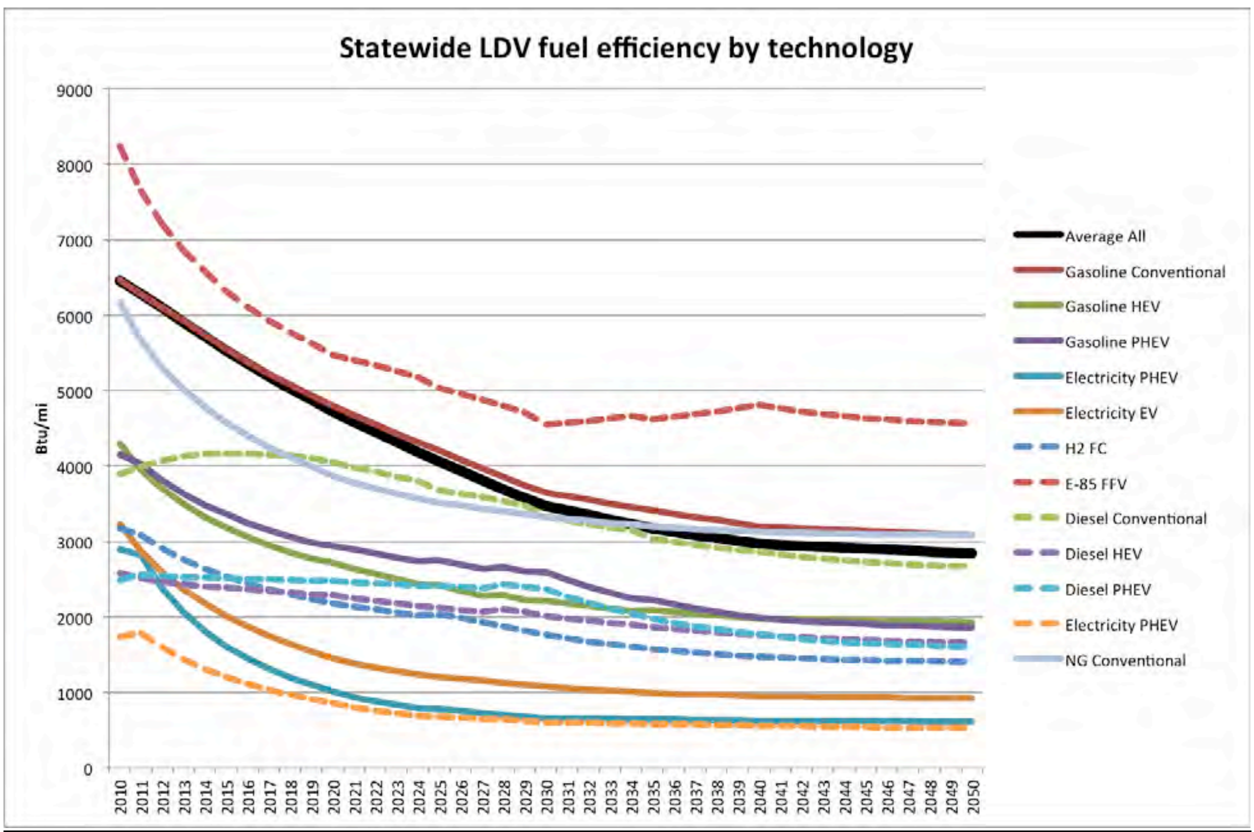

SCAB PM2.5
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

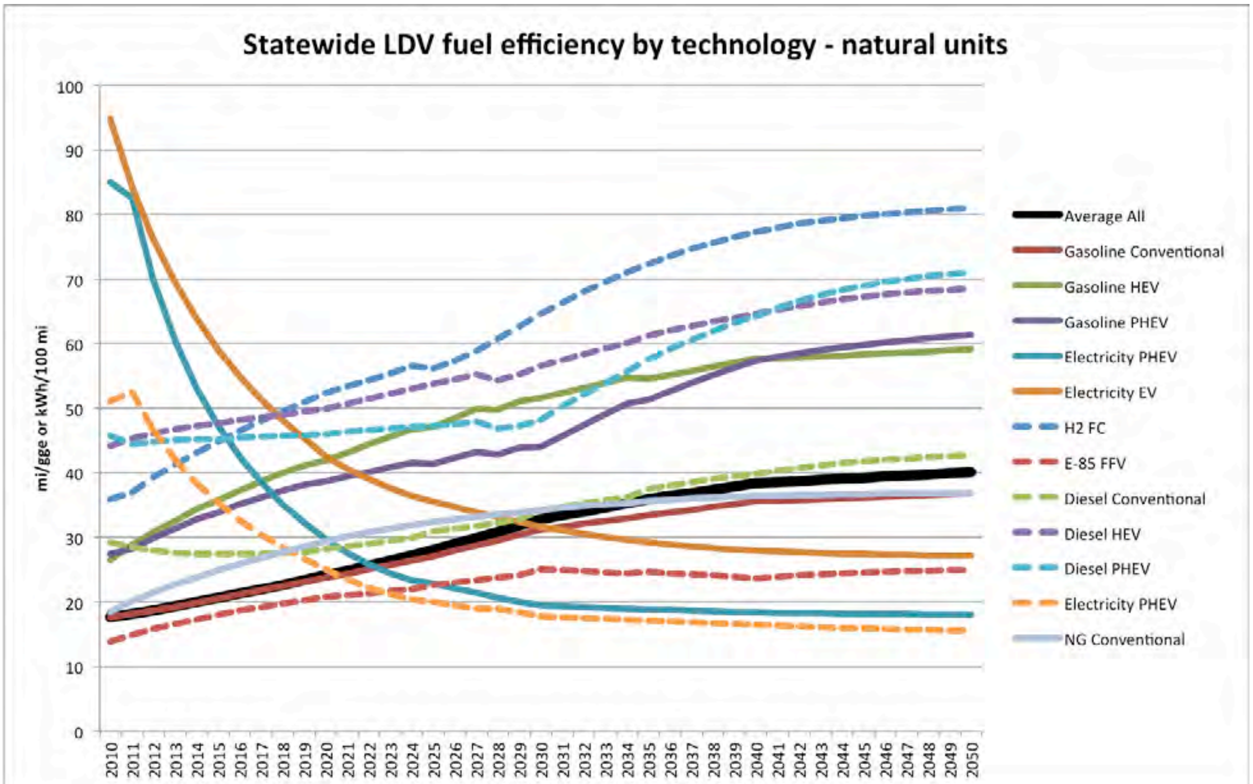

SJV PM2.5
Emissions (t/yr)
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

LDV sector

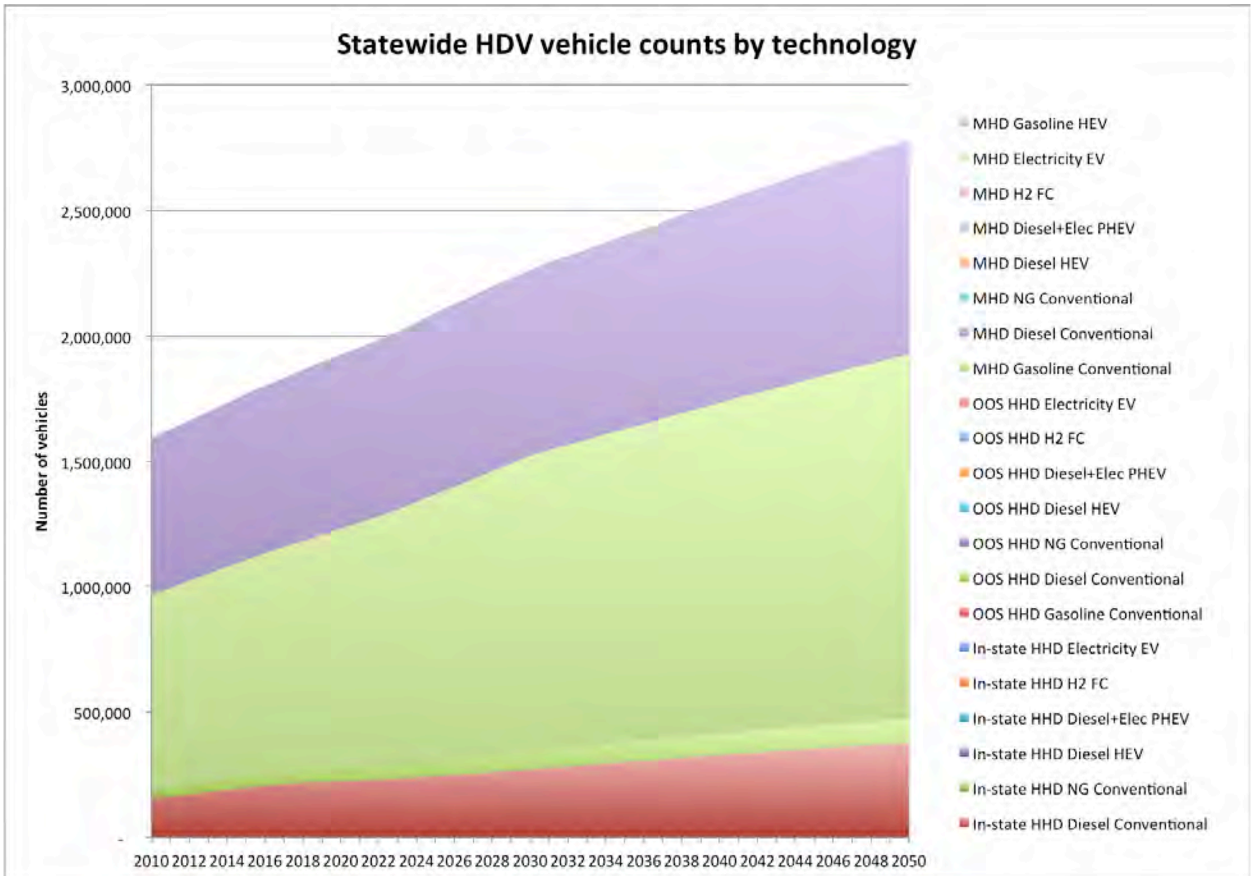

Statewide LDV vehicle counts by technology
1000 Vehicles
30000
25000
20000
15000
10000
5000
0
NG Conventional
Diesel+Elec PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Elec EV
Gasoline+Elec PHEV
Gasoline HEV
Gasoline Conventional

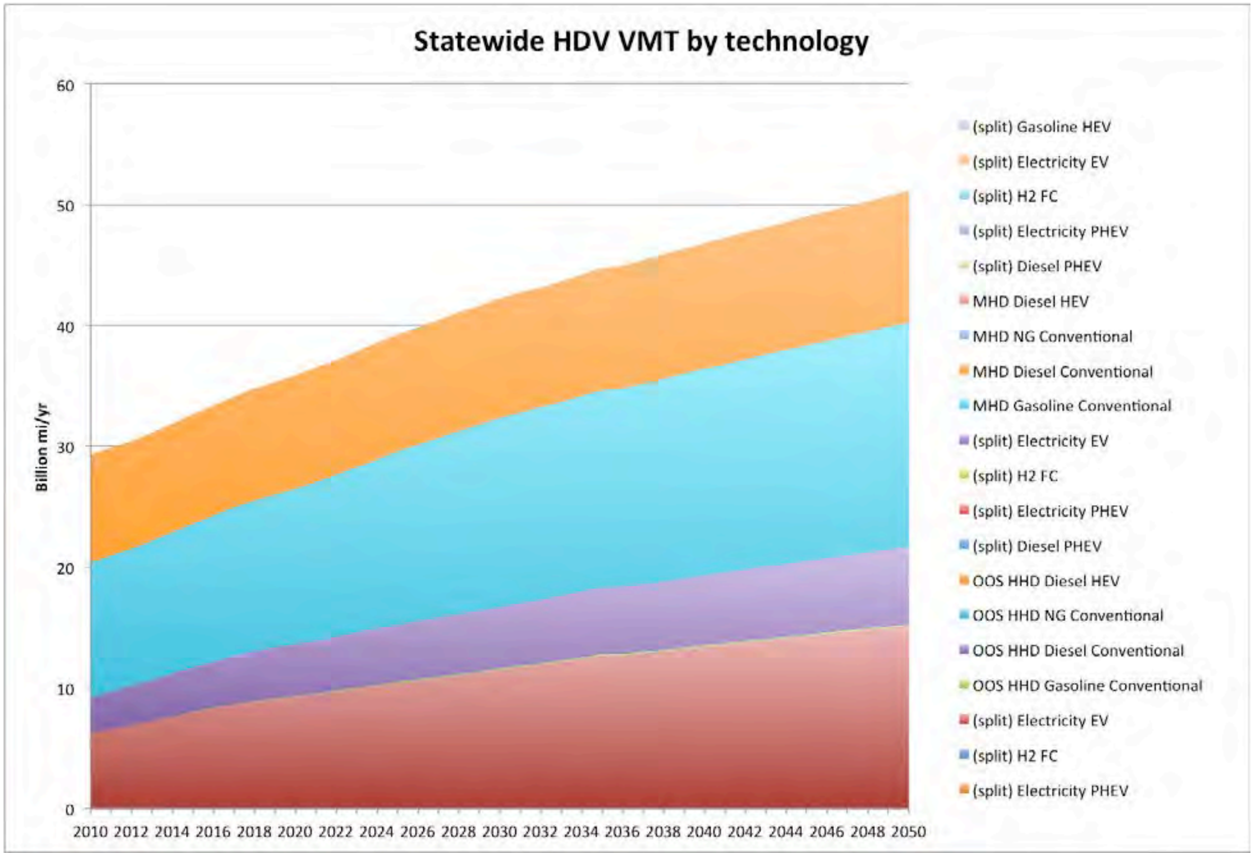

Statewide LDV VMT by technology
bn mi/yr
NG Conventional
Electricity PHEV
Diesel PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Electricity EV
Electricity PHEV
Gasoline PHEV
Gasoline HEV
Gasoline Conventional


Statewide LDV fuel efficiency by technology
Btu/mi
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional

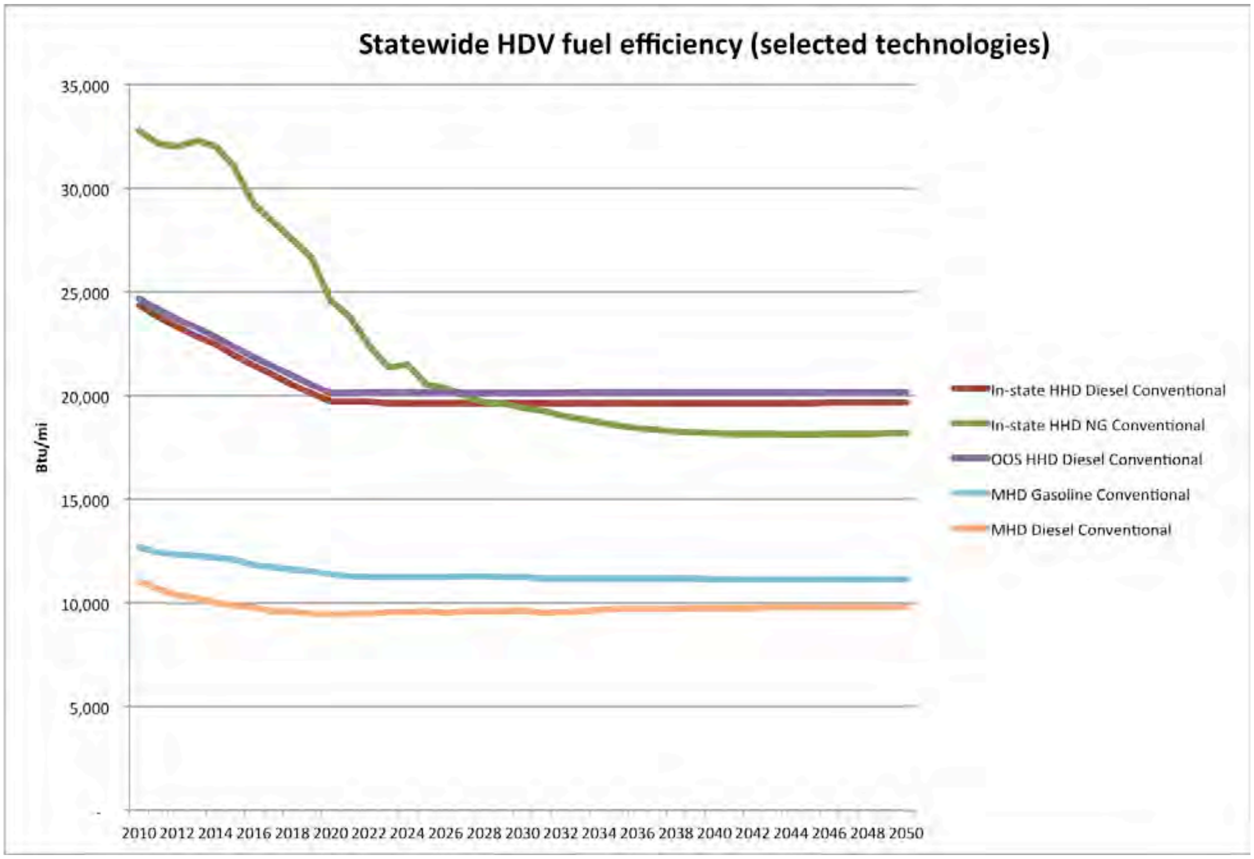

Statewide LDV fuel efficiency by technology - natural units
mi/gge or kWh/100 mi
100
90
80
70
60
50
40
30
20
10
0
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional

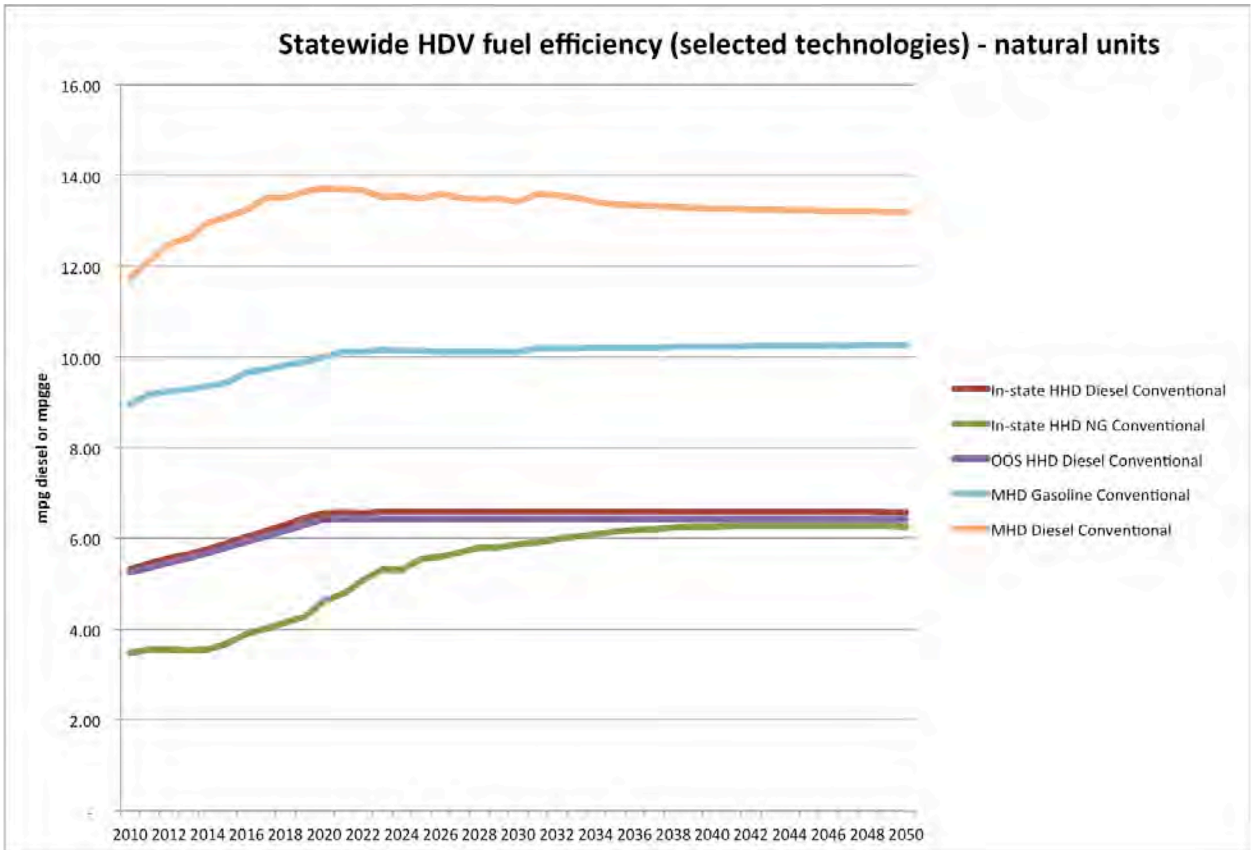
HDV sector


Statewide HDV vehicle counts by technology
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Number of vehicles
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
MHD Gasoline HEV
MHD Electricity EV
MHD H2 FC
MHD Diesel+Elec PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
OOS HHD Electricity EV
OOS HHD H2 FC
OOS HHD Diesel+Elec PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
In-state HHD Electricity EV
In-state HHD H2 FC
In-state HHD Diesel+Elec PHEV
In-state HHD Diesel HEV
In-state HHD NG Conventional
In-state HHD Diesel Conventional

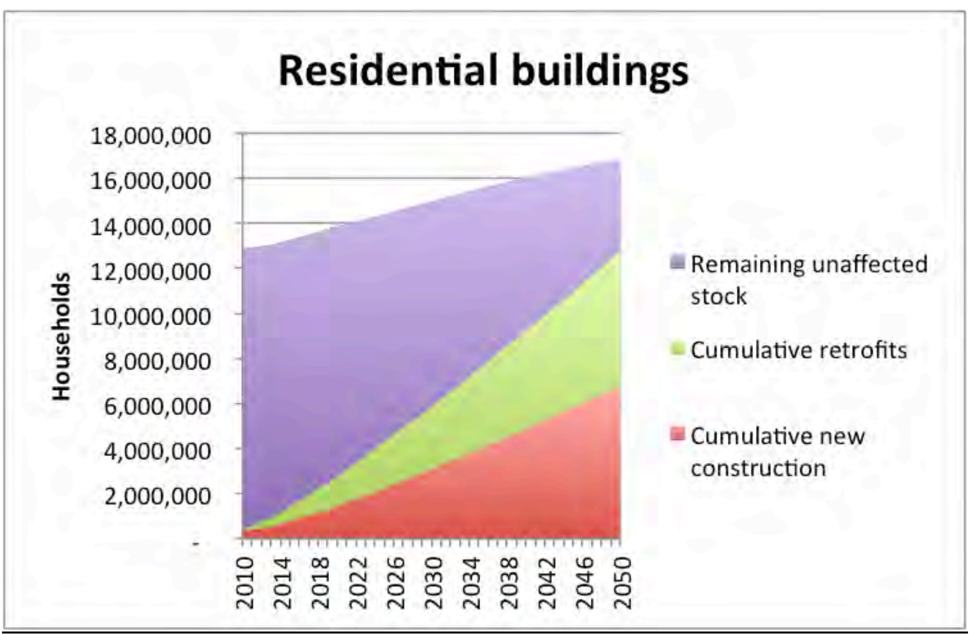


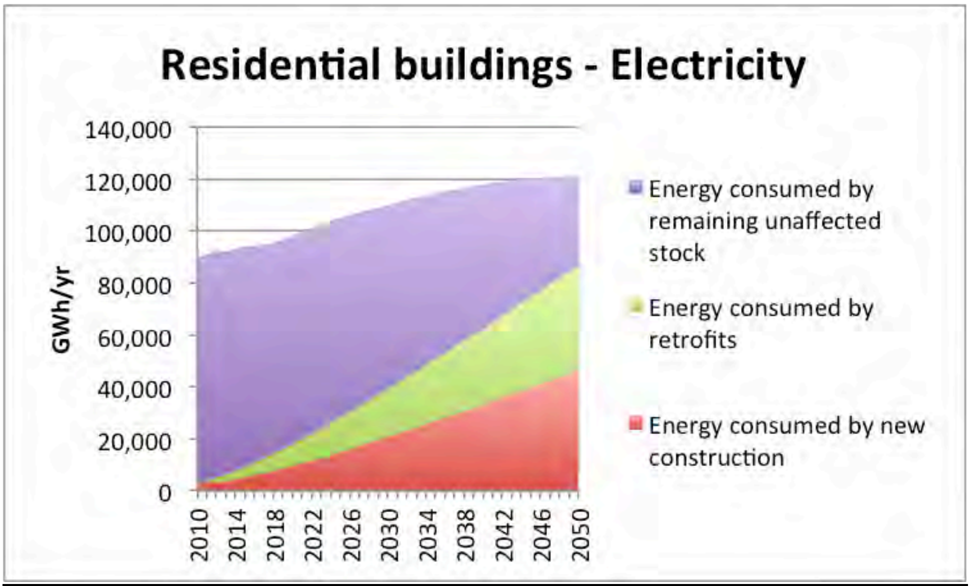
Statewide HDV VMT by technology
Billion mi/yr
60
50
40
30
20
10
0
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
(split) Gasoline HEV
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV

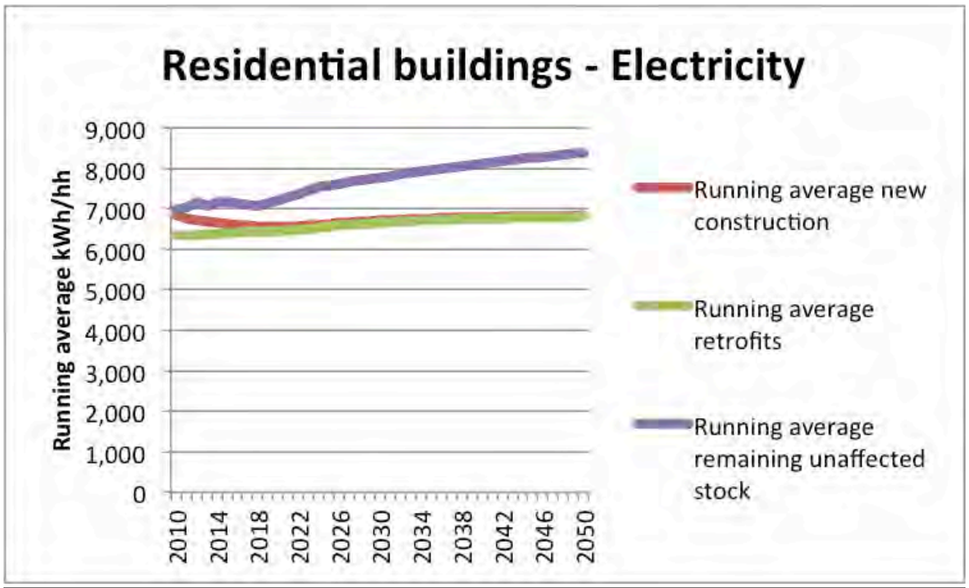

Statewide HDV fuel efficiency (selected technologies)
Btu/mi
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
In-state HHD Diesel Conventional
In-state HHD NG Conventional
OOS HHD Diesel Conventional
MHD Gasoline Conventional
MHD Diesel Conventional

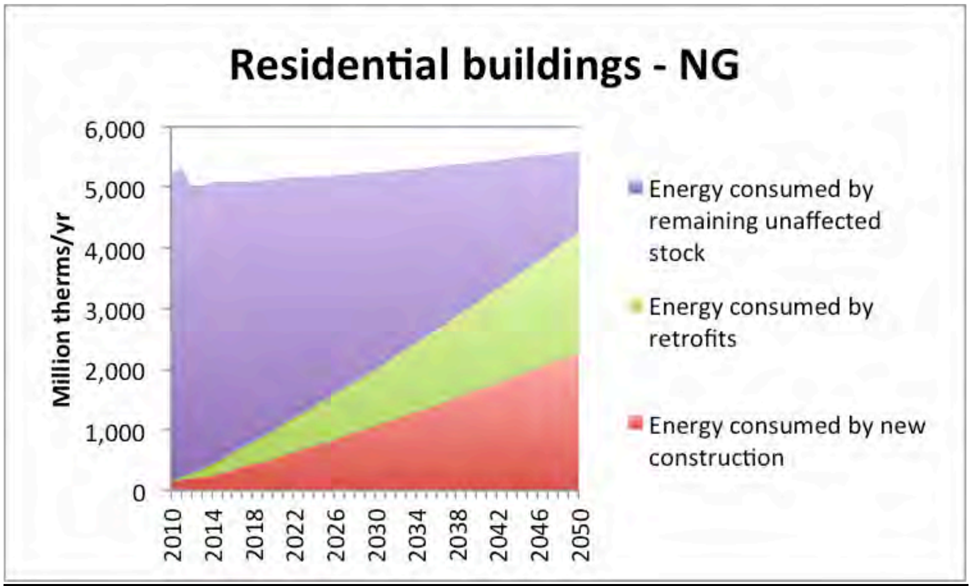


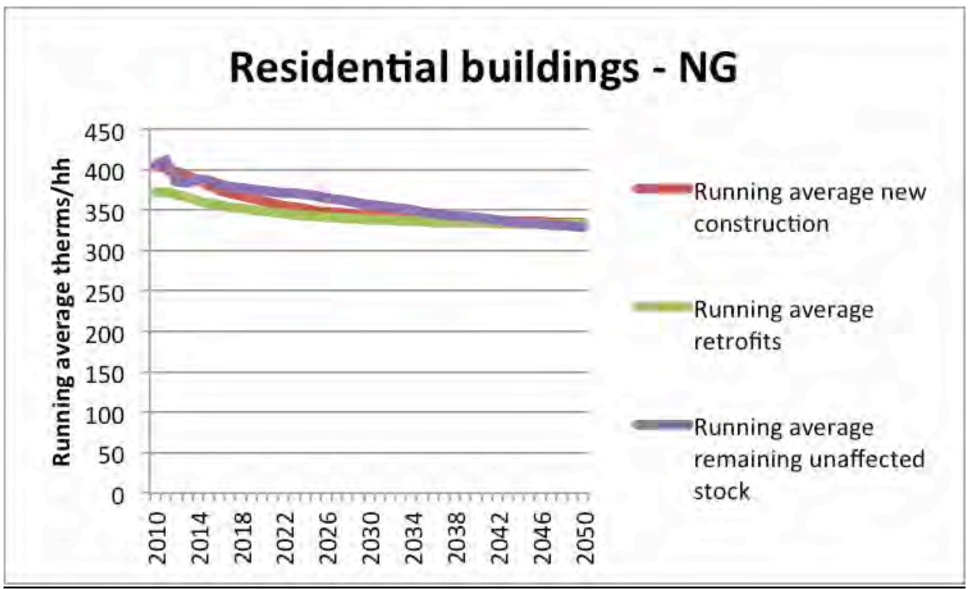
Residential sector



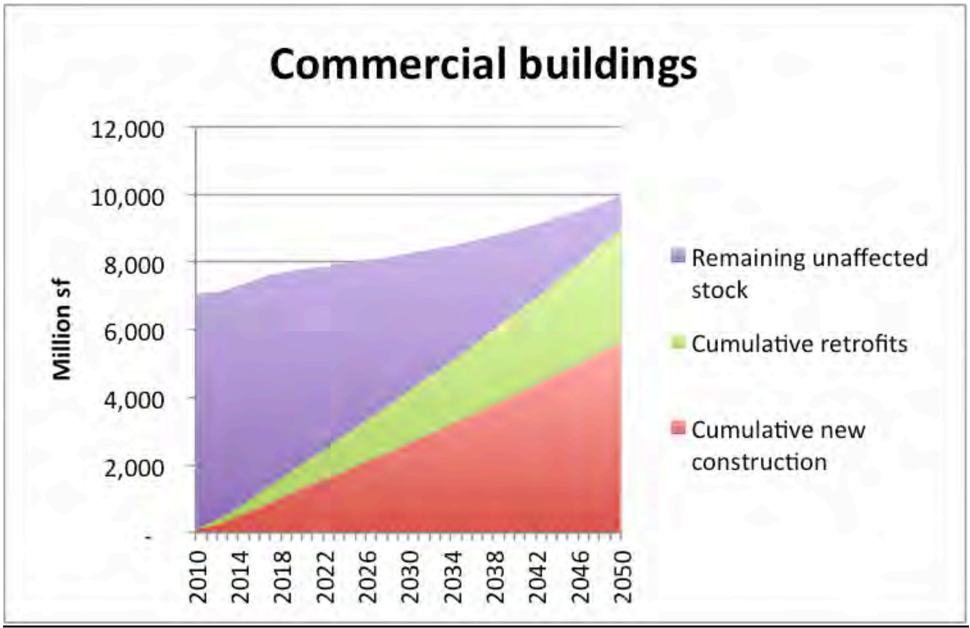

Residential buildings - Electricity
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
GWh/yr
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction

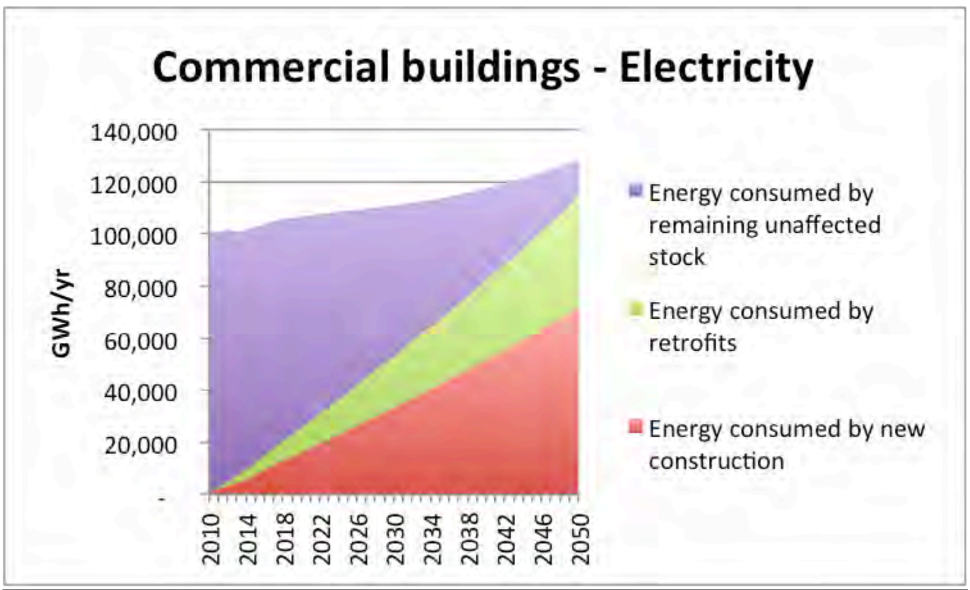

Residential buildings - Electricity
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Running average kWh/hh
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

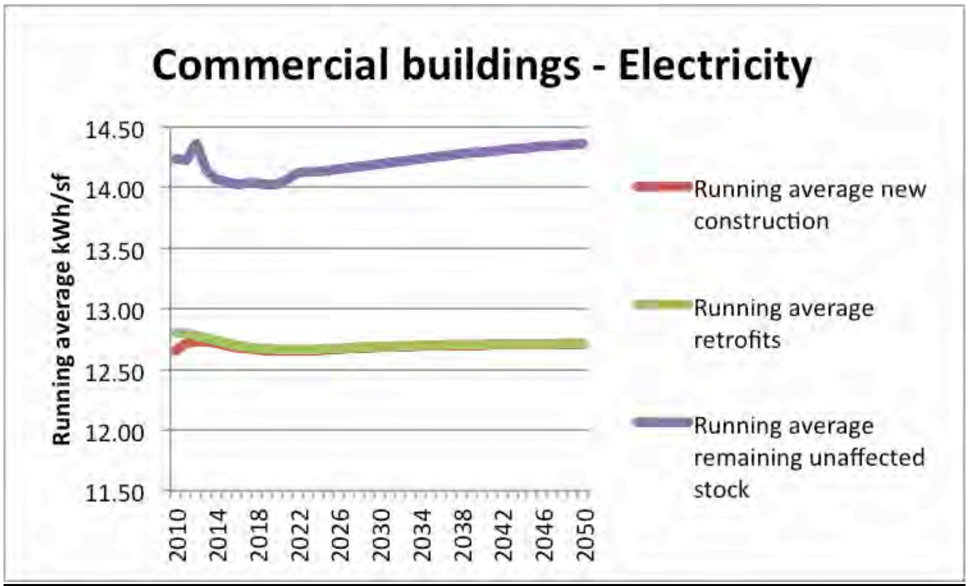


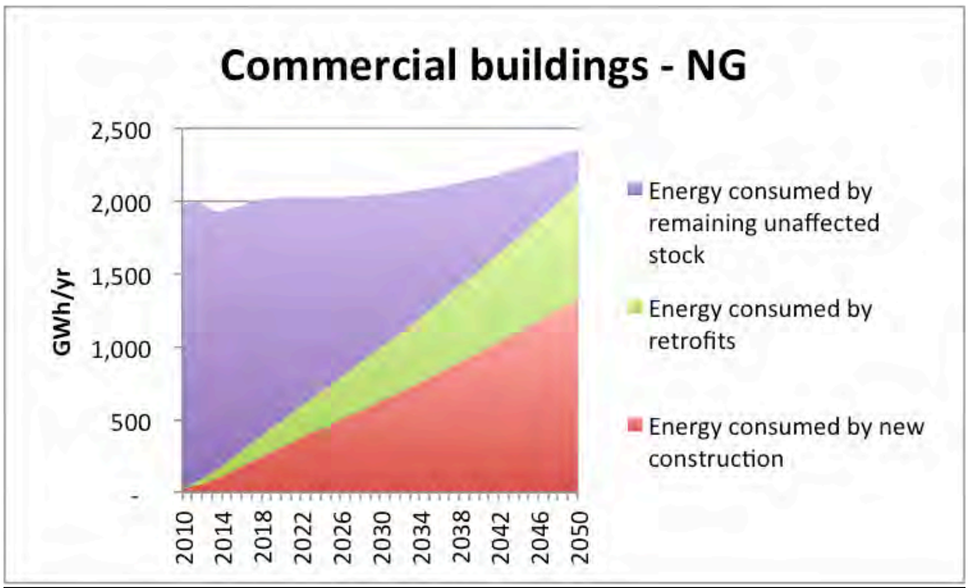


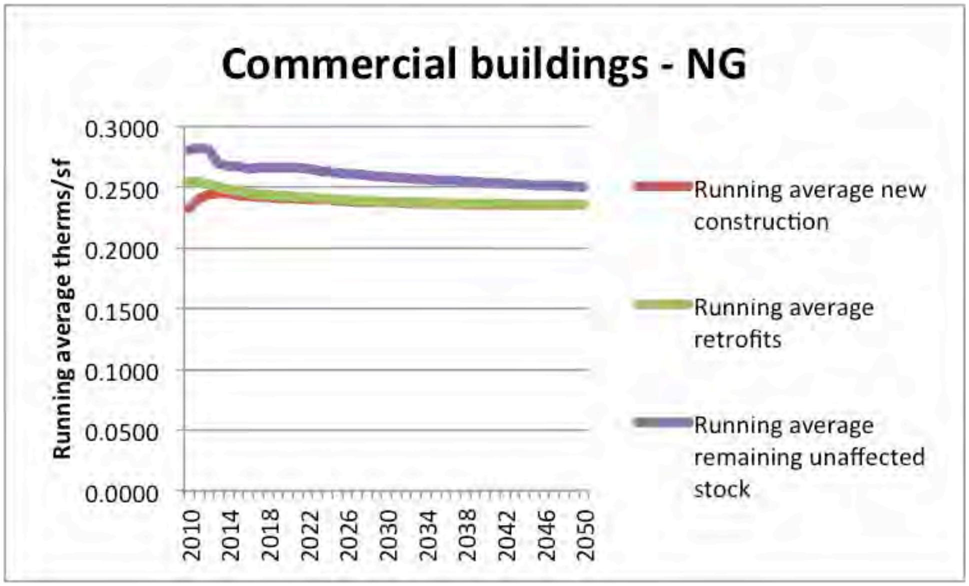
Commercial sector


Commercial buildings
12,000
10,000
8,000
6,000
4,000
2,000
-
Million sf
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Remaining unaffected stock
Cumulative retrofits
Cumulative new construction

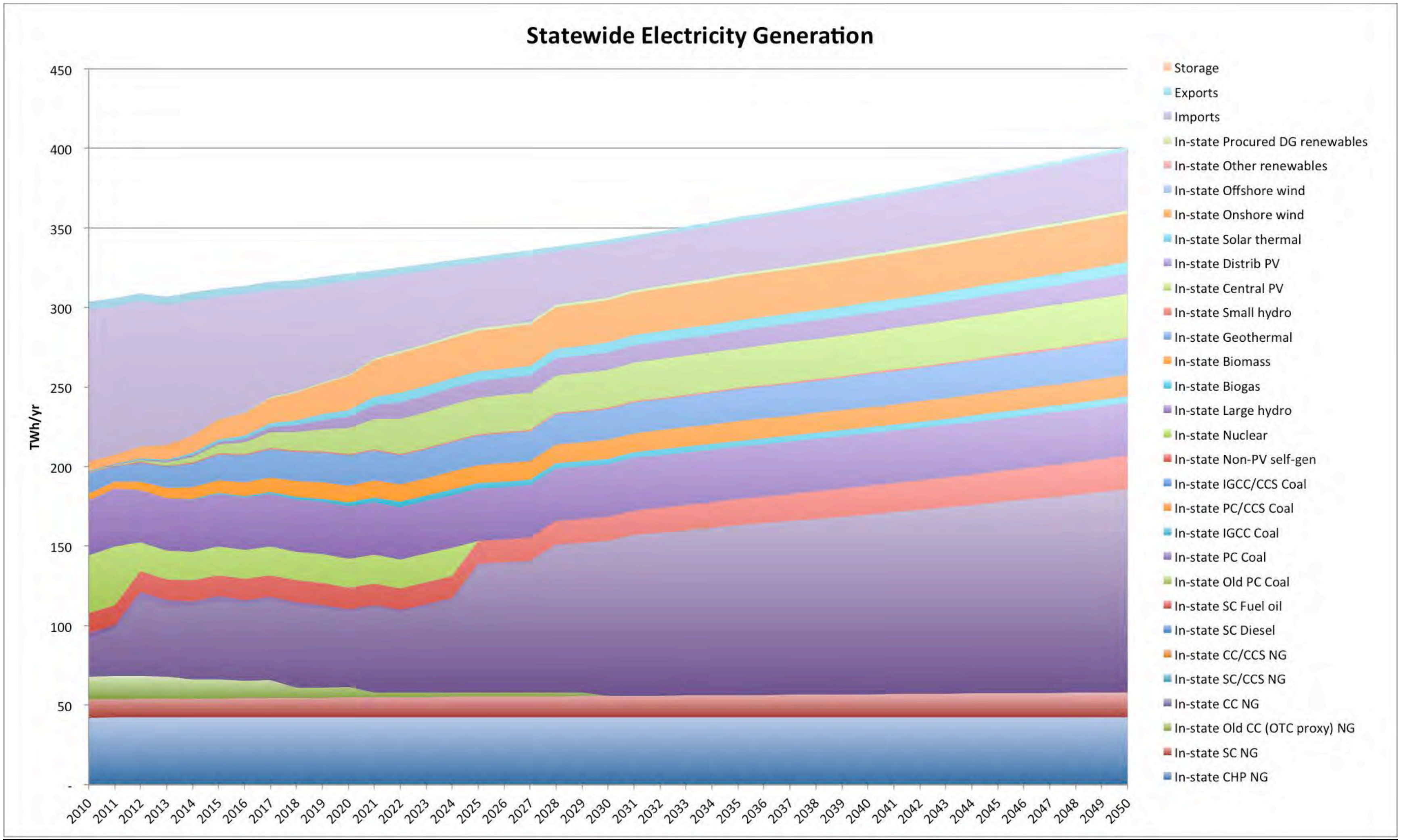

Commercial buildings - Electricity
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
GWh/yr
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction


Commercial buildings - Electricity
Running average kWh/sf
14.50
14.00
13.50
13.00
12.50
12.00
11.50
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock


Commercial buildings - NG
GWh/yr
2,500
2,000
1,500
1,000
500
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction


Commercial buildings - NG
Running average therms/sf
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

Electricity sector



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Scenario 2 details

GHG emissions by sector ($MtCO_2e/yr$)

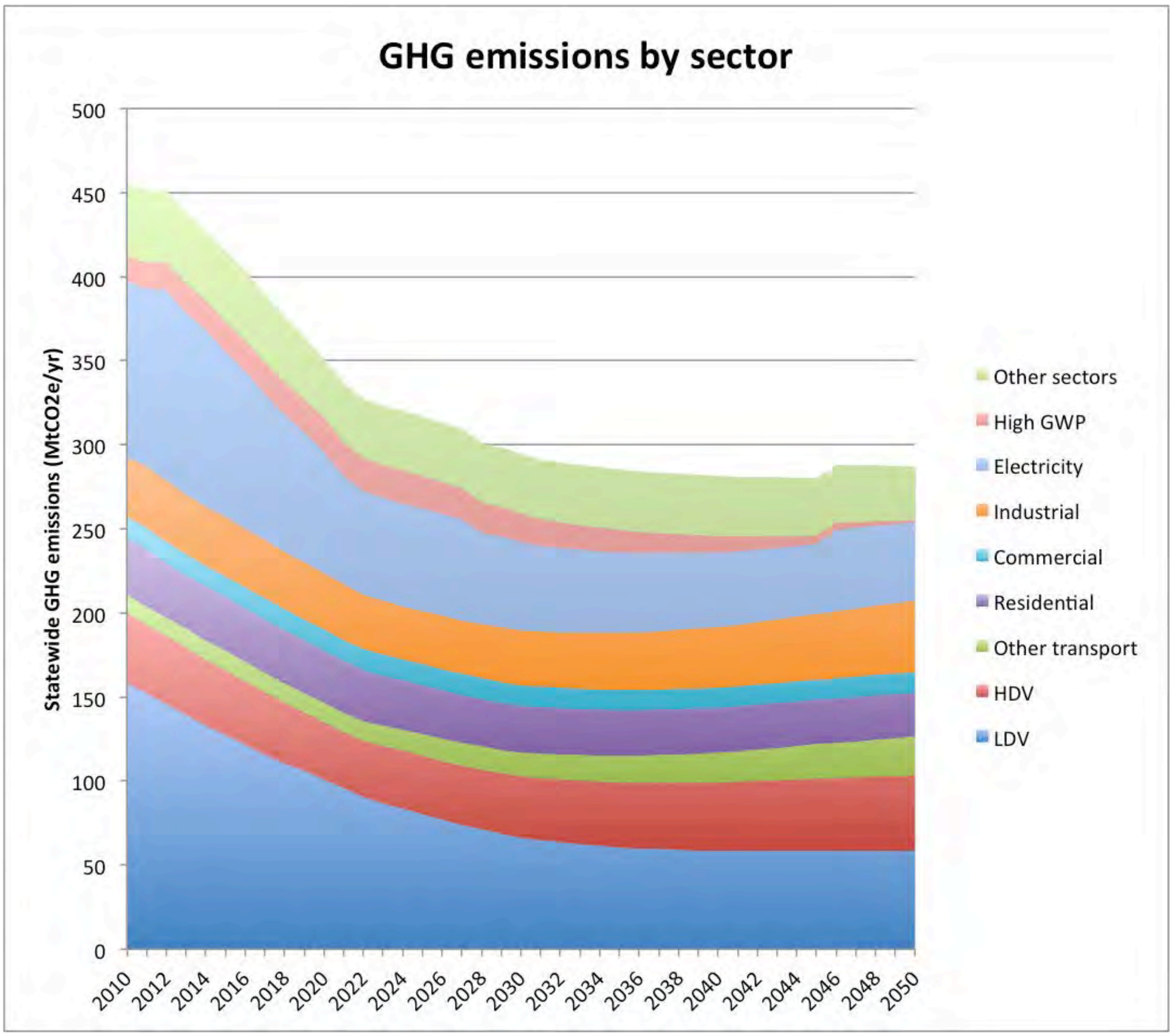
Year	LDVs	HDVs	Other transport	Residential+ commercial	Industry	Electricity	High GWP	Net offsets	All others	Total
2010	158.02	41.89	9.17	46.21	33.56	101.32	41.16	-	24.21	455.54
2020	101.03	33.76	9.95	43.52	31.93	69.40	31.25	(8.20)	30.11	350.94
2025	80.48	34.67	11.08	41.38	30.15	58.26	24.91	(8.20)	35.75	316.67
2030	66.27	36.28	12.05	39.98	30.96	50.40	19.39	(8.20)	39.20	294.52
2035	60.32	38.71	13.60	39.12	32.33	45.51	14.32	(8.20)	41.27	285.17
2040	58.39	40.61	15.17	38.60	34.33	42.11	9.90	(8.20)	42.33	281.44
2050	58.57	44.73	19.61	38.47	40.36	44.35	0.93	(8.20)	40.55	287.57

Criteria pollutants by region (t/yr)

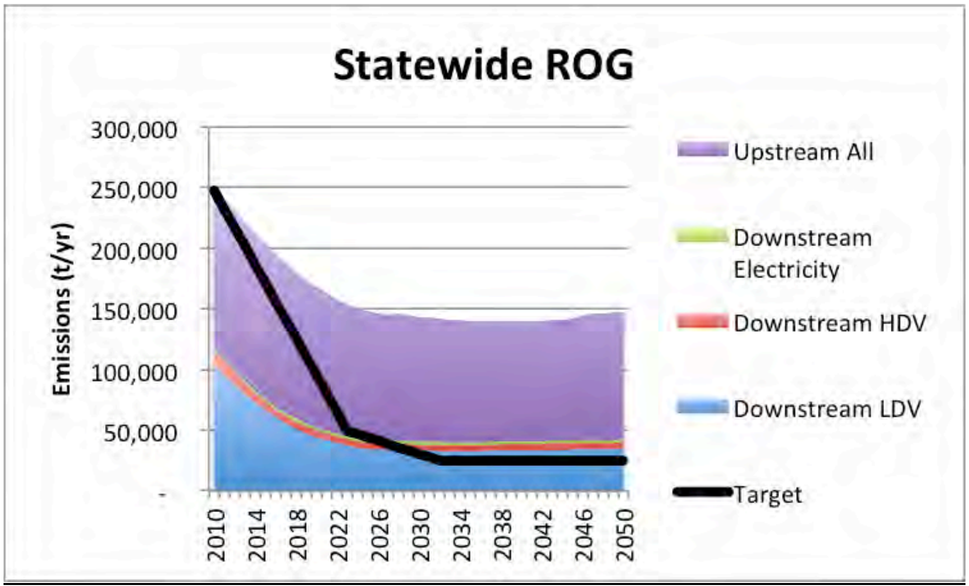
	SCAB			SJV			Statewide		
Year	ROG	NOx	PM2.5	ROG	NOx	PM2.5	ROG	NOx	PM2.5
2010	64,143	163,234	66,600	19,769	69,415	16,682	247,153	466,174	150,726
2020	38,958	85,461	47,322	12,371	31,320	12,484	167,765	229,702	107,267
2025	33,279	63,068	39,394	11,186	23,258	11,084	147,605	168,889	90,011
2030	31,945	44,371	23,168	10,789	18,341	7,014	142,719	124,094	54,142
2035	30,288	37,505	17,981	10,926	17,081	5,837	139,870	108,570	43,056
2040	29,763	36,108	17,050	11,142	17,288	5,803	139,552	106,630	41,461
2050	29,437	35,083	15,749	11,809	17,784	5,778	147,237	105,840	39,389

Biomass demand by fuel type and source (Mdt/yr)

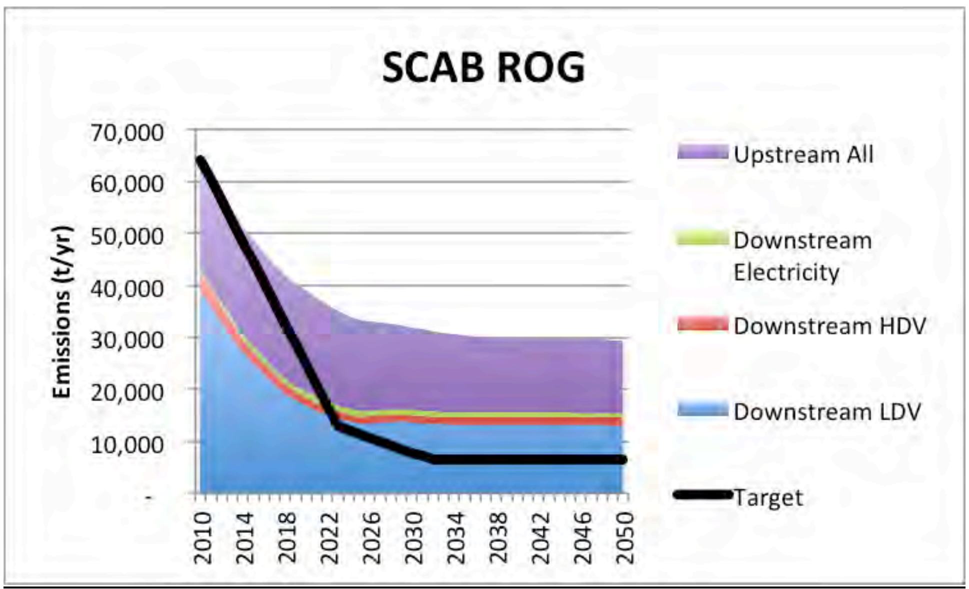
	Gasoline, E-85	Diesel	Gasoline, E-85, Diesel, Jet fuel, Aviation gasoline	NG	Electricity	All
Year	**Corn kernels**	**Soybean oil**	**Herbaceous/forest biomass**	**Landfill waste**	**Herbaceous/forest biomass**	**All**
2010	12.21	2.49	2.92	-	5.27	22.89
2020	23.93	11.11	16.98	-	11.42	63.44
2025	21.86	15.18	23.68	-	12.01	72.74
2030	17.19	17.53	28.05	-	11.89	74.66
2035	12.49	18.72	31.18	-	11.40	73.79
2040	8.85	19.50	35.63	-	10.79	74.77
2050	1.99	21.57	46.57	-	9.89	80.01



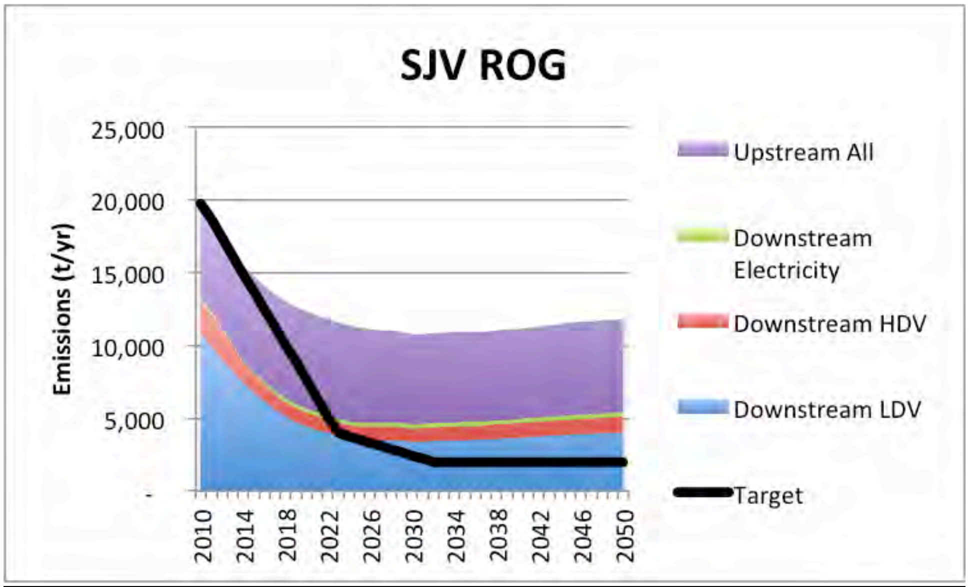
Note: All electricity-related GHG emissions from all sectors are included in electricity sector

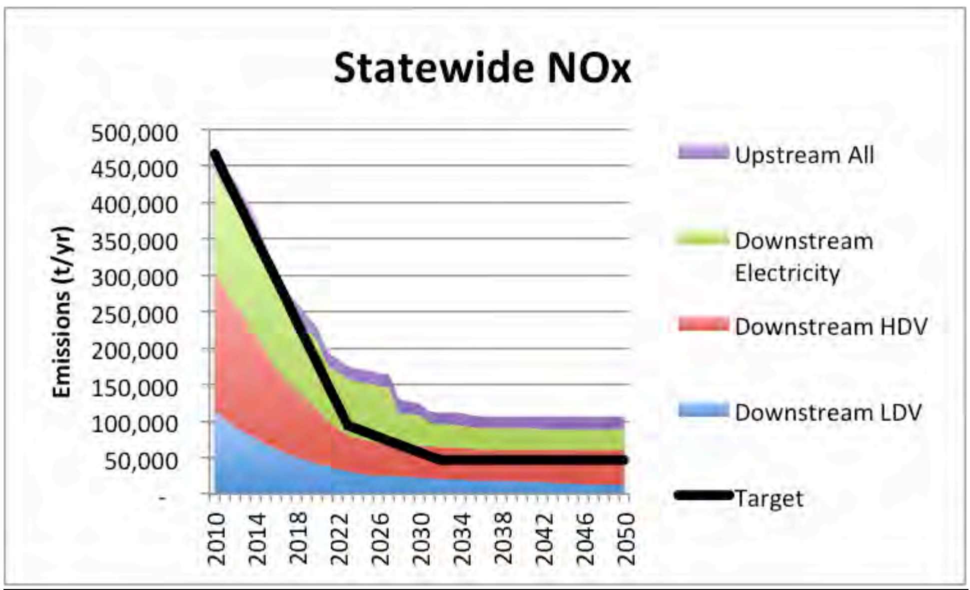


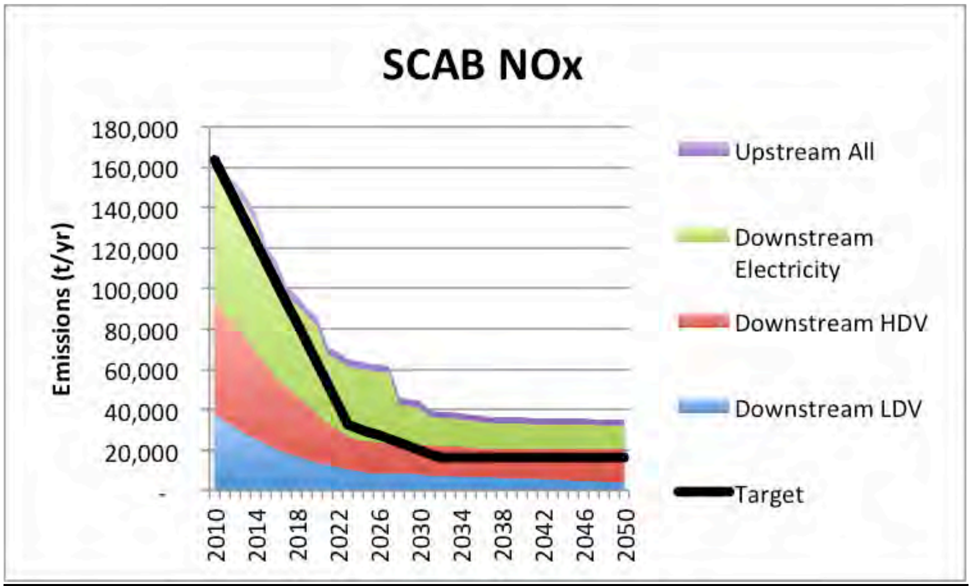
Statewide ROG
300,000
250,000
200,000
150,000
100,000
50,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

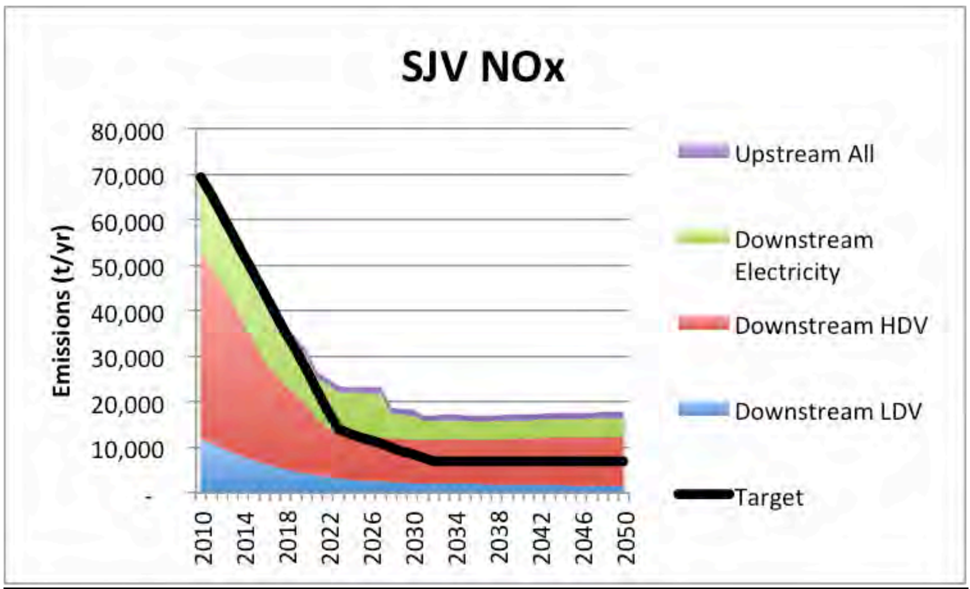


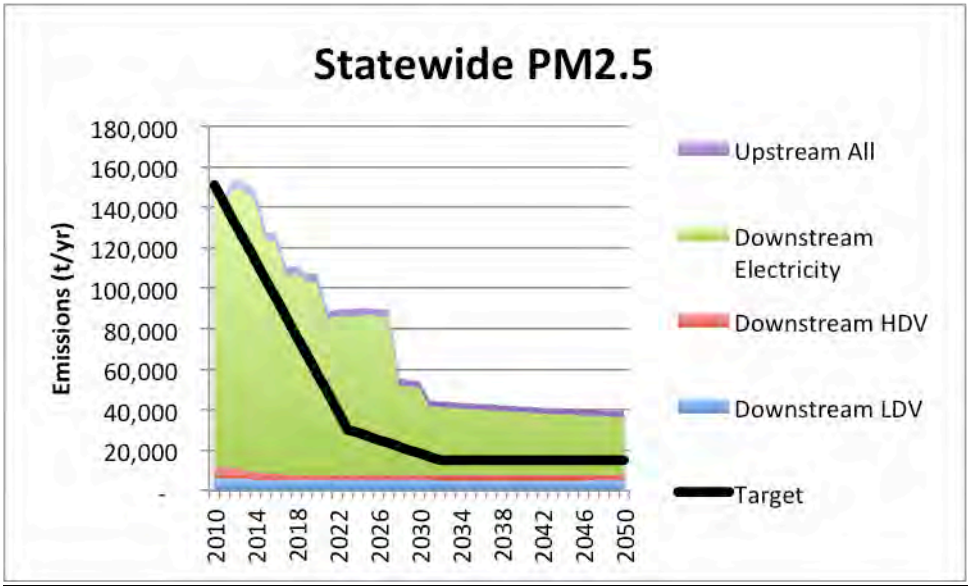
SCAB ROG
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target


SJV ROG
Emissions (t/yr)
25,000
20,000
15,000
10,000
5,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

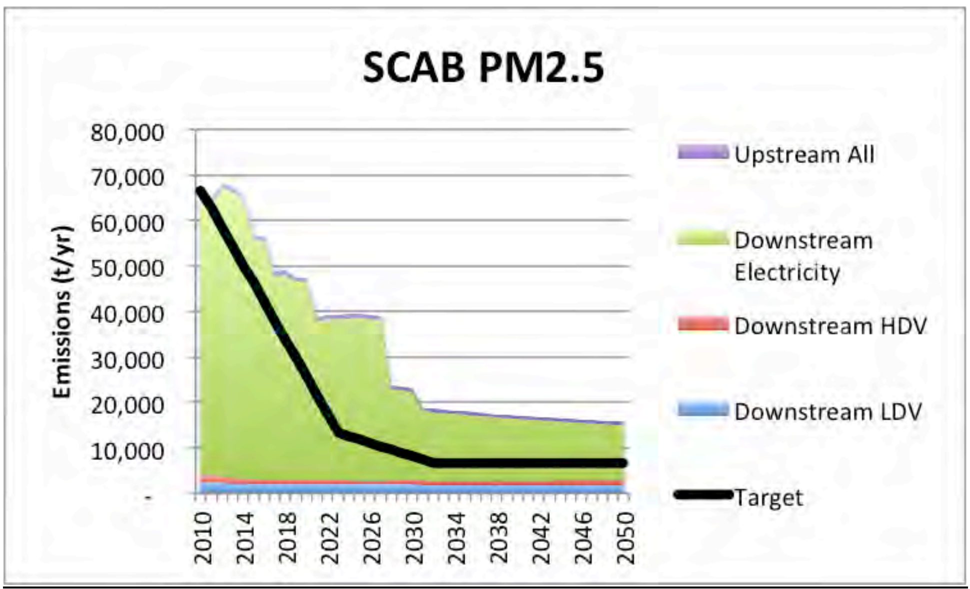

Statewide NOx
Emissions (t/yr)
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target


SCAB NOx
Emissions (t/yr)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

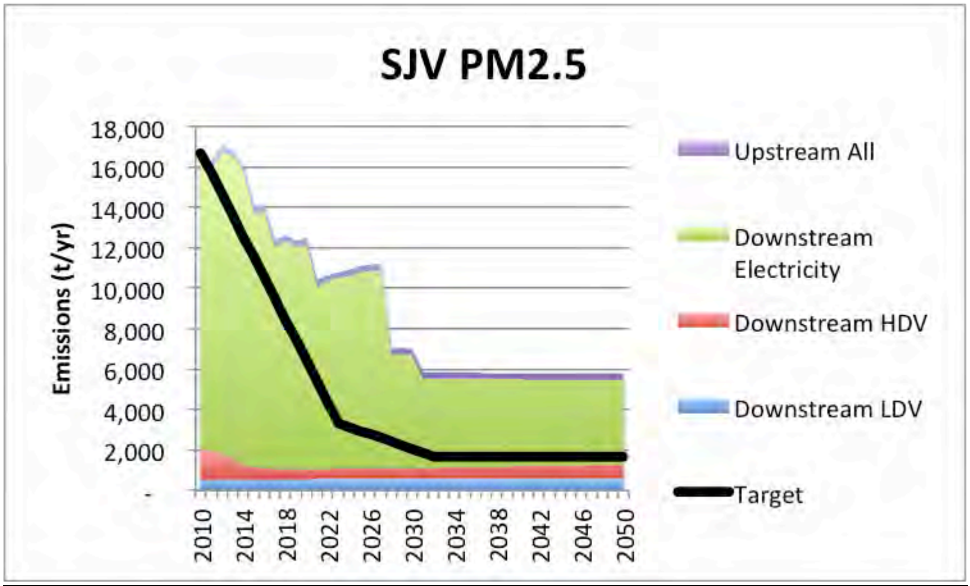

SJV NOx
Emissions (t/yr)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target



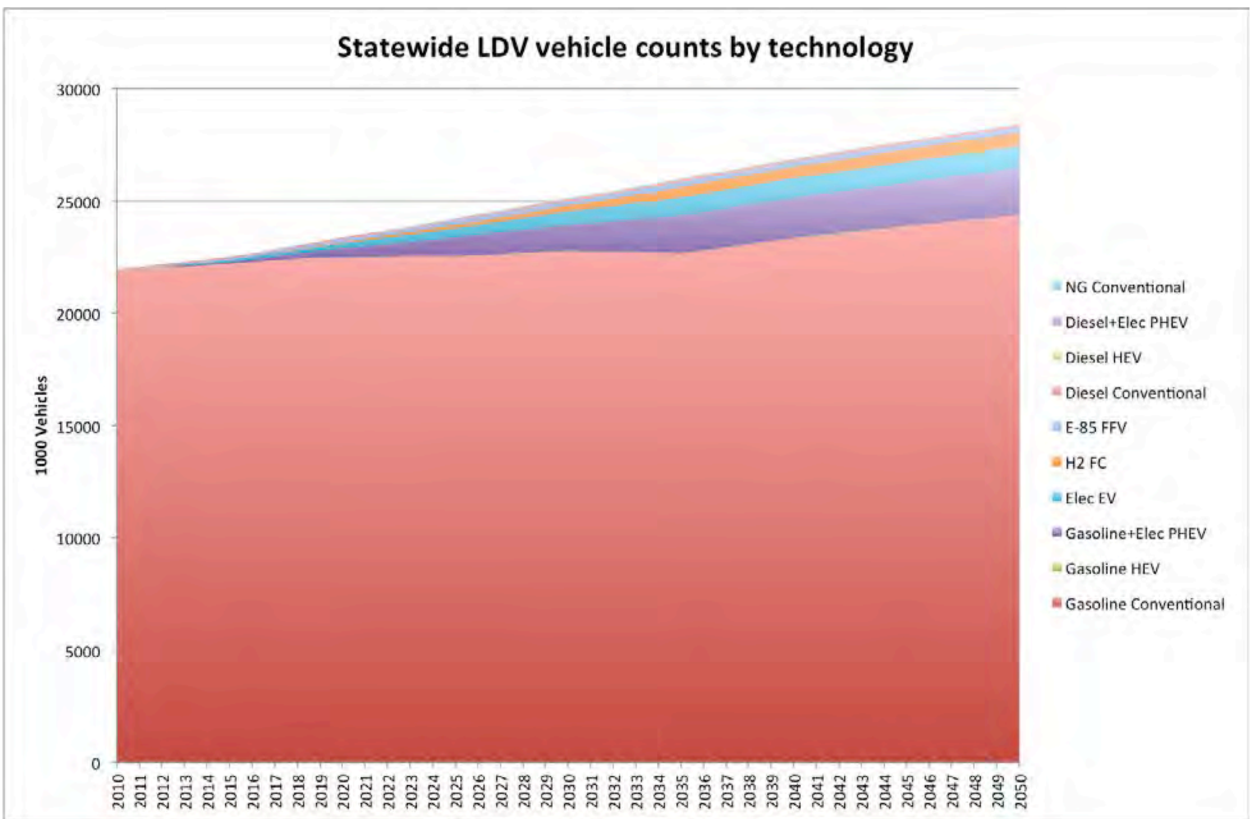
Statewide PM2.5
Emissions (t/yr)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

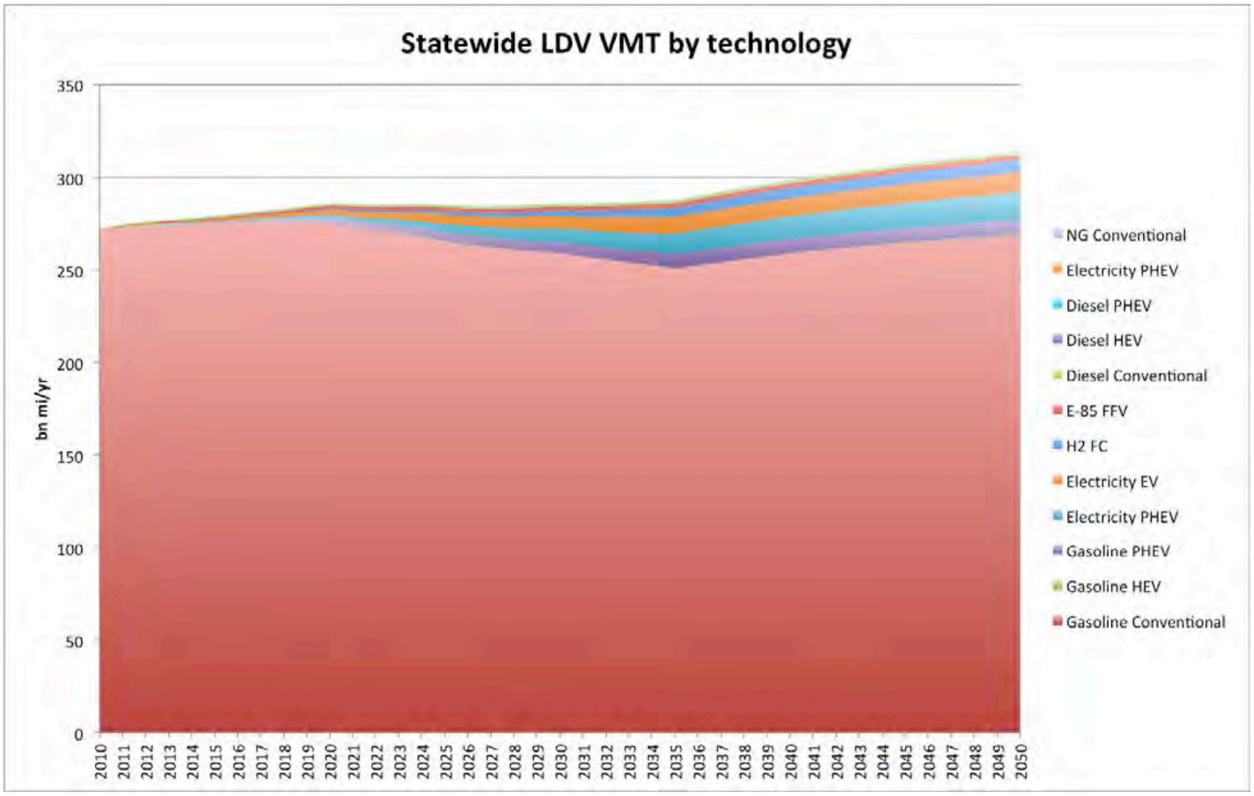


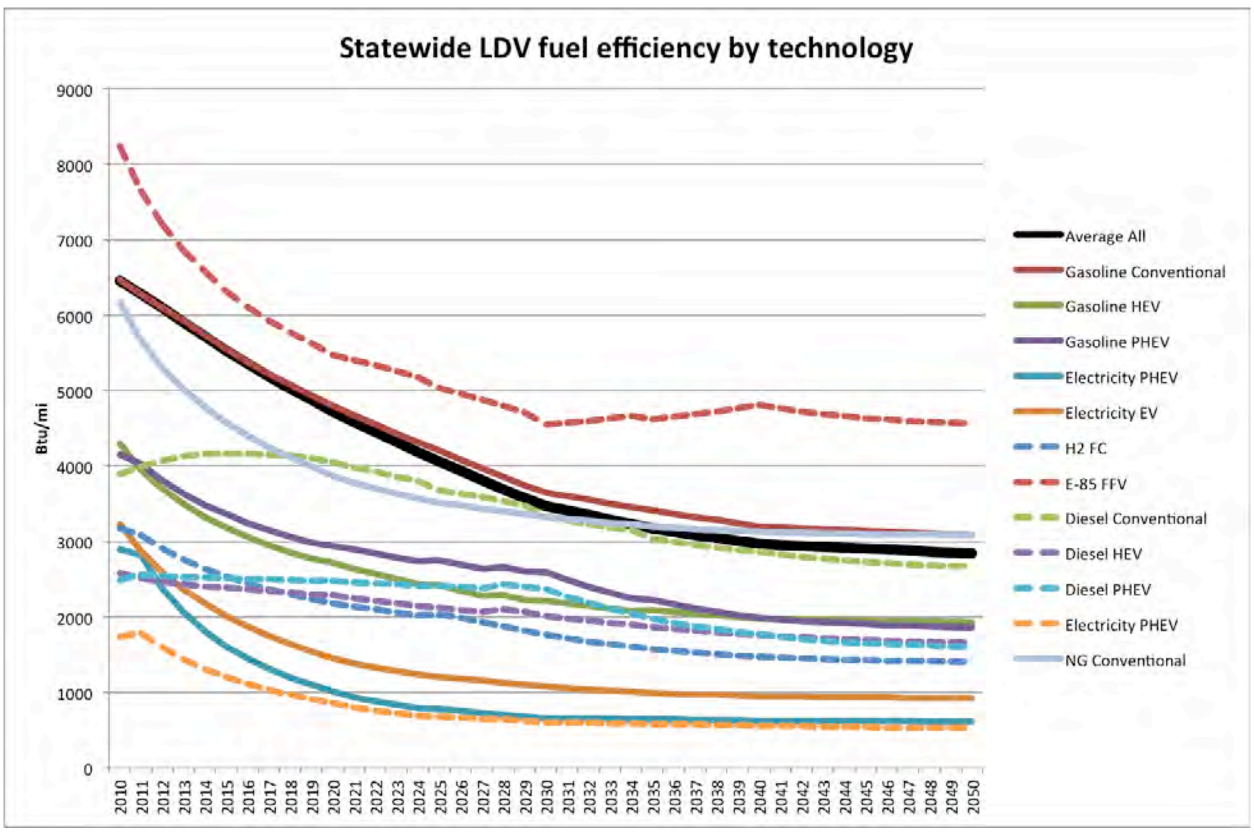
SCAB PM2.5
Emissions (t/yr)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

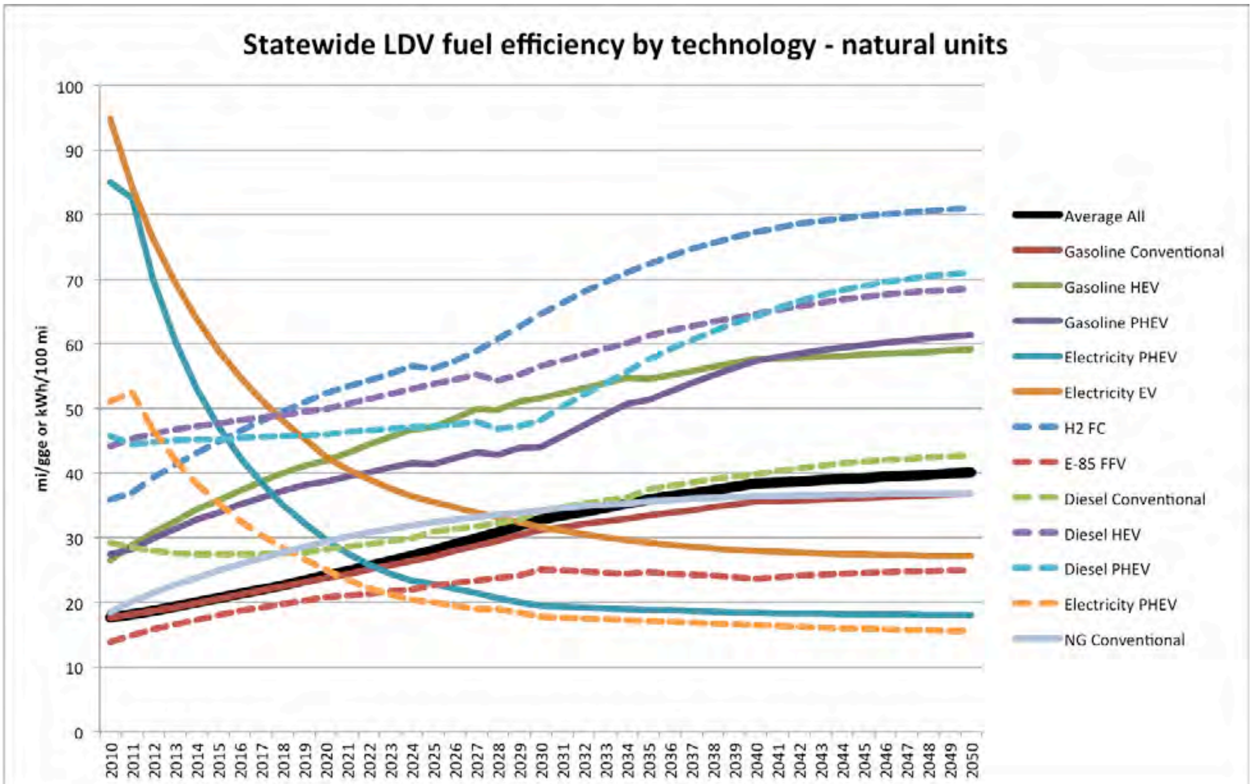

SJV PM2.5
Emissions (t/yr)
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

LDV sector

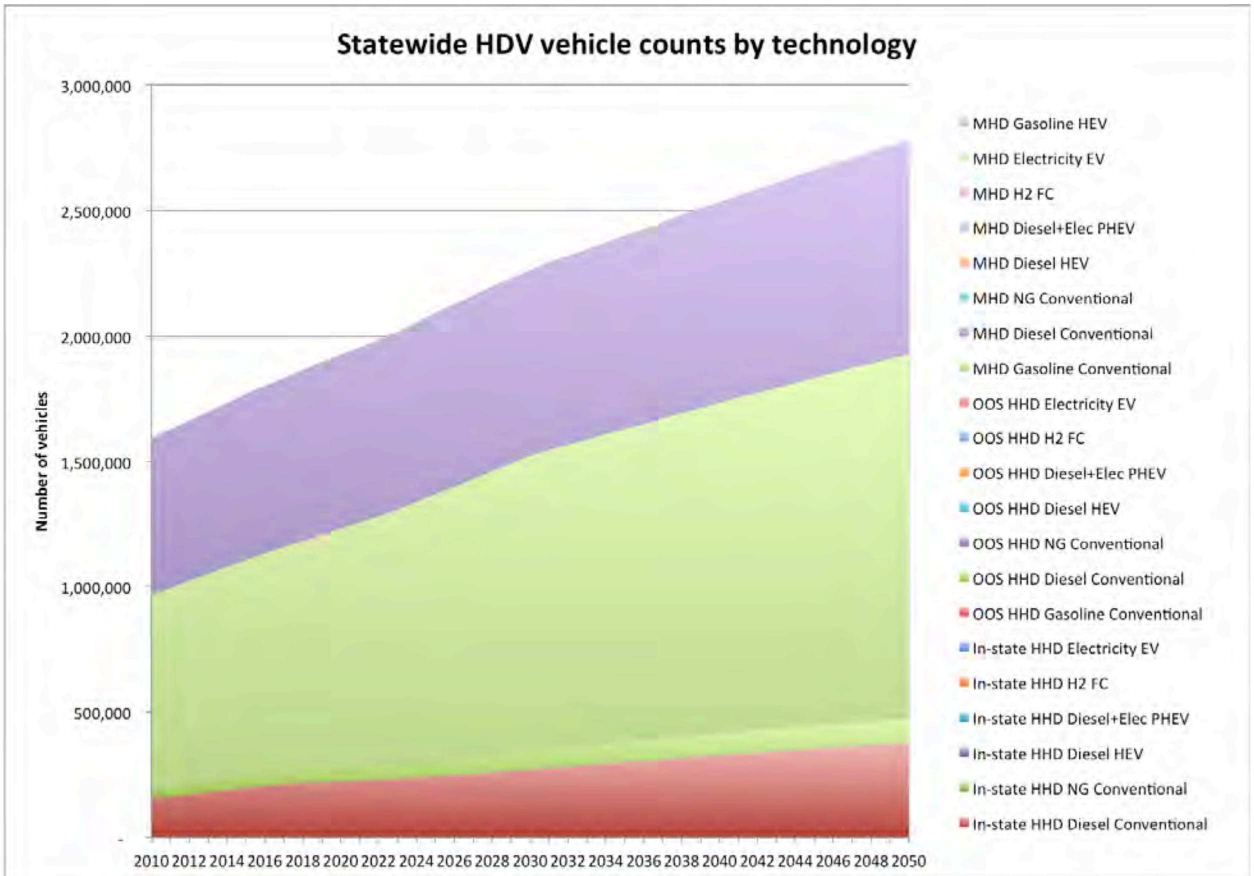

Statewide LDV vehicle counts by technology
1000 Vehicles
30000
25000
20000
15000
10000
5000
0
2010
2050
NG Conventional
Diesel+Elec PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Elec EV
Gasoline+Elec PHEV
Gasoline HEV
Gasoline Conventional

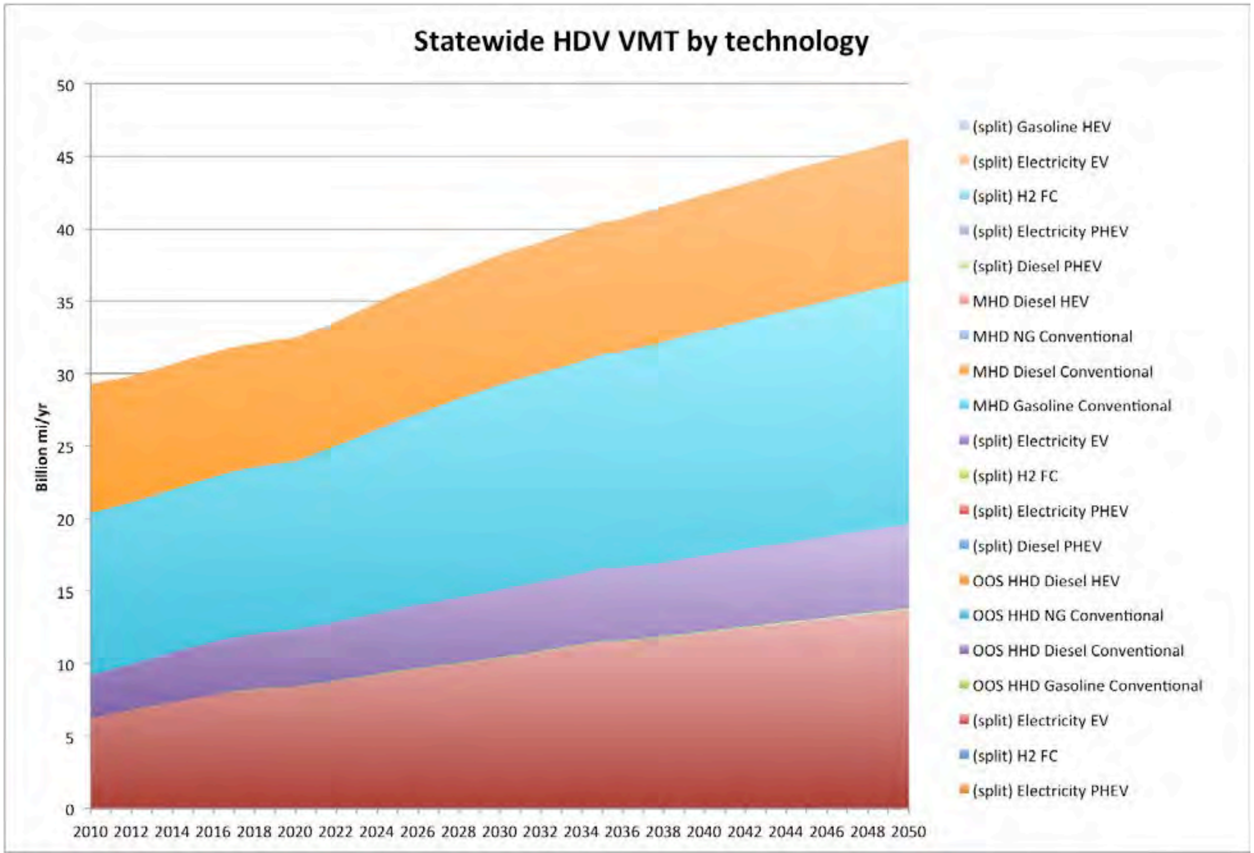

Statewide LDV VMT by technology
bn mi/yr
0
50
100
150
200
250
300
350
NG Conventional
Electricity PHEV
Diesel PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Electricity EV
Electricity PHEV
Gasoline PHEV
Gasoline HEV
Gasoline Conventional
2010 … 2050


Statewide LDV fuel efficiency by technology
Btu/mi
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional
2010 … 2050

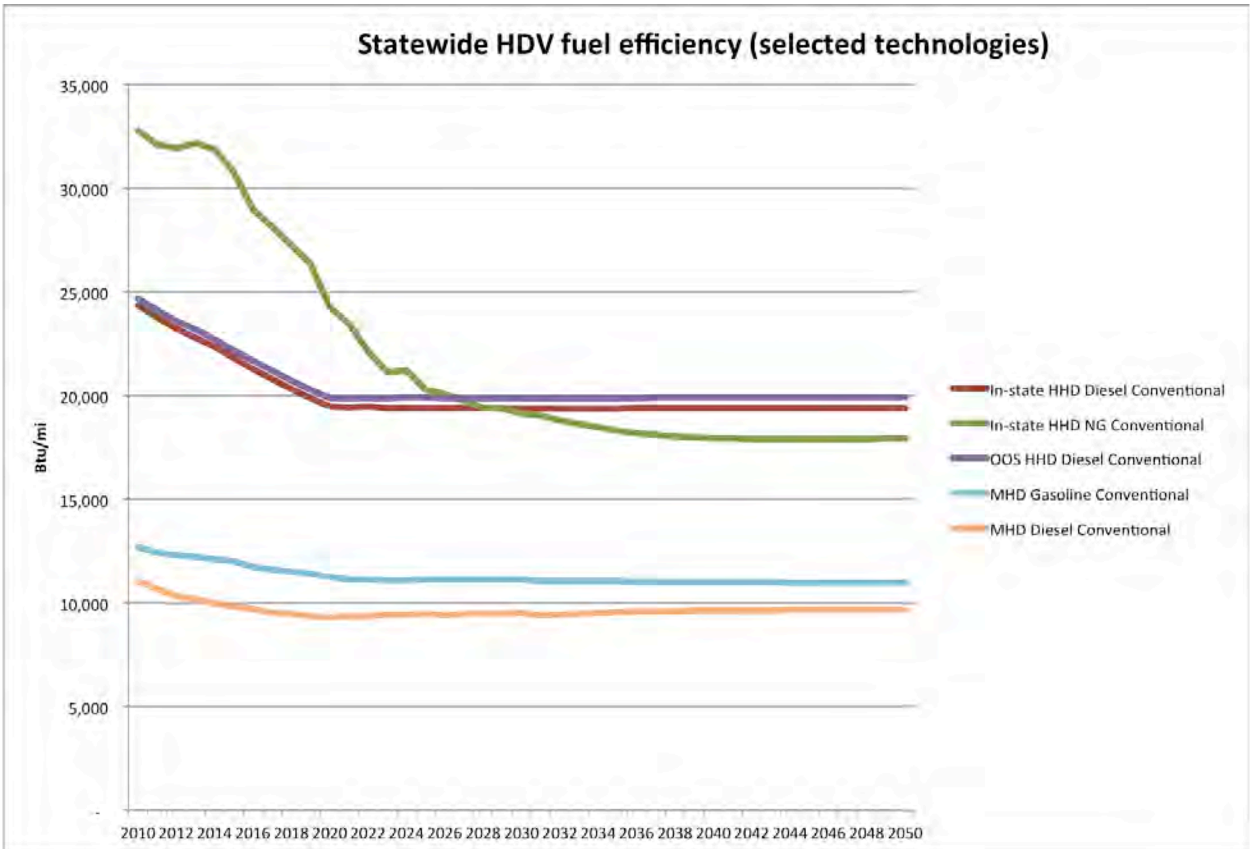

Statewide LDV fuel efficiency by technology - natural units
mi/gge or kWh/100 mi
100
90
80
70
60
50
40
30
20
10
0
2010
2050
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional

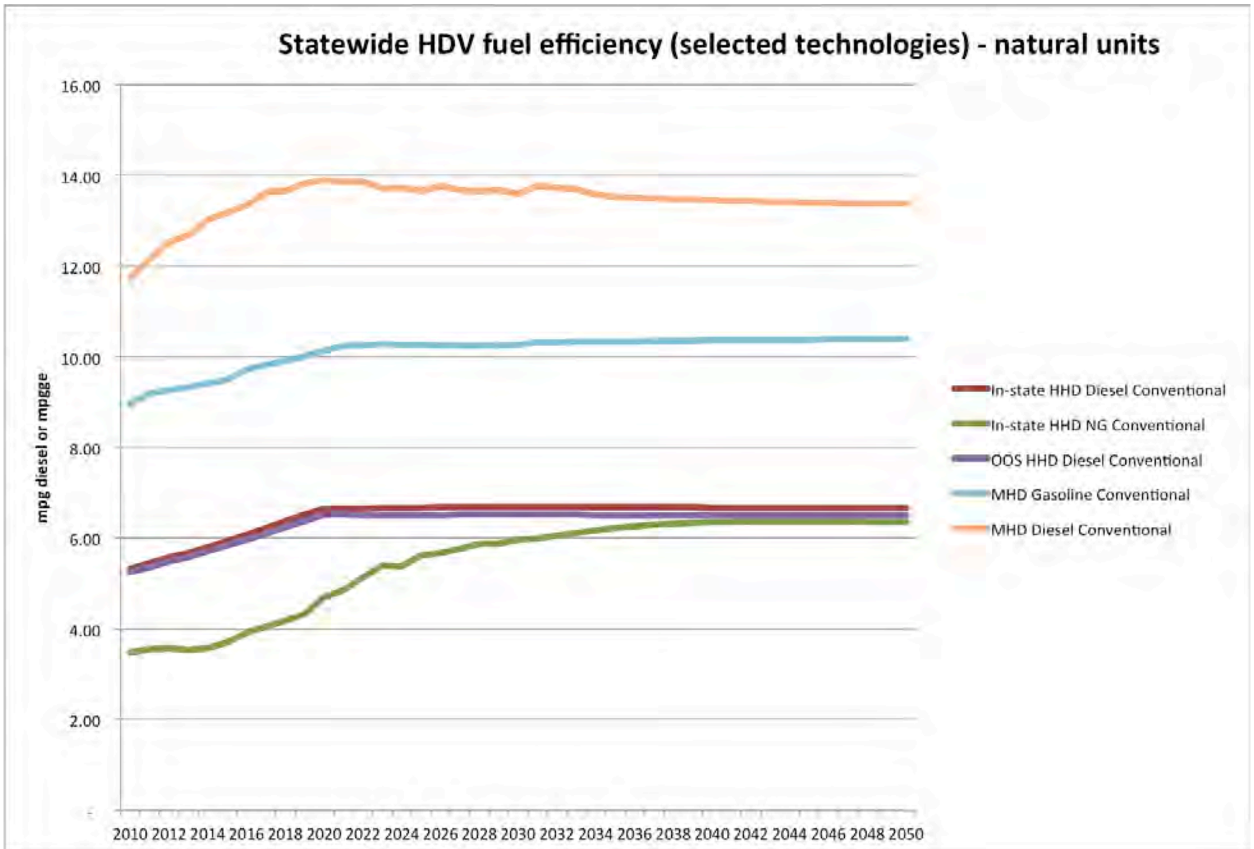
HDV sector


Statewide HDV vehicle counts by technology
Number of vehicles
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
MHD Gasoline HEV
MHD Electricity EV
MHD H2 FC
MHD Diesel+Elec PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
OOS HHD Electricity EV
OOS HHD H2 FC
OOS HHD Diesel+Elec PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
In-state HHD Electricity EV
In-state HHD H2 FC
In-state HHD Diesel+Elec PHEV
In-state HHD Diesel HEV
In-state HHD NG Conventional
In-state HHD Diesel Conventional

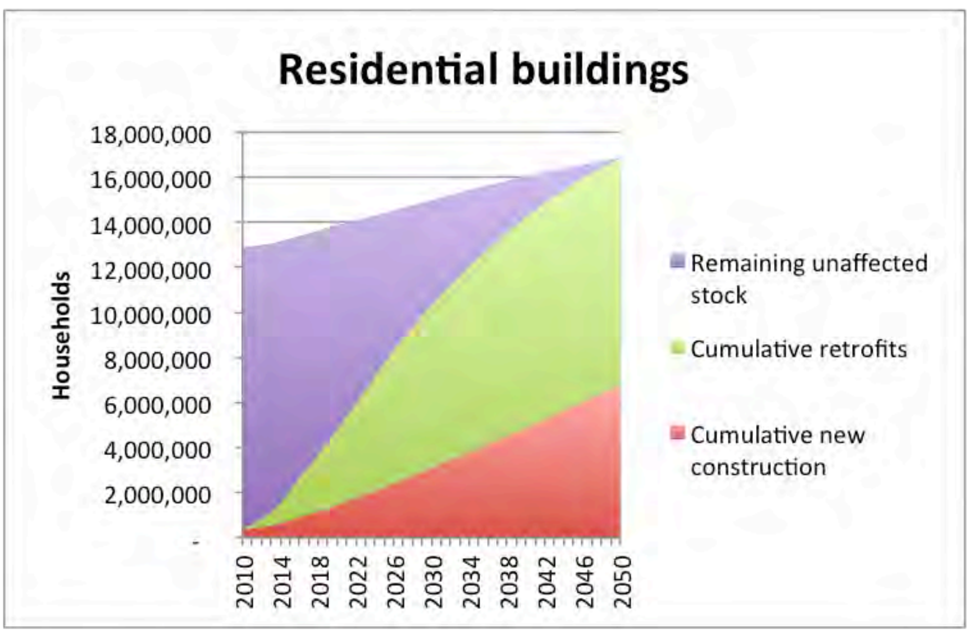


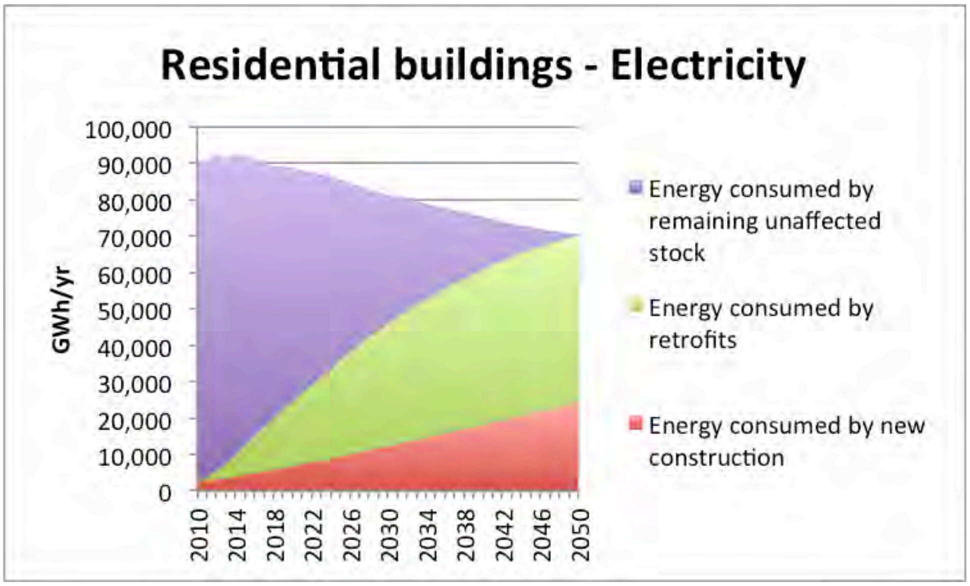
Statewide HDV VMT by technology
Billion mi/yr
50
45
40
35
30
25
20
15
10
5
0
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
(split) Gasoline HEV
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV

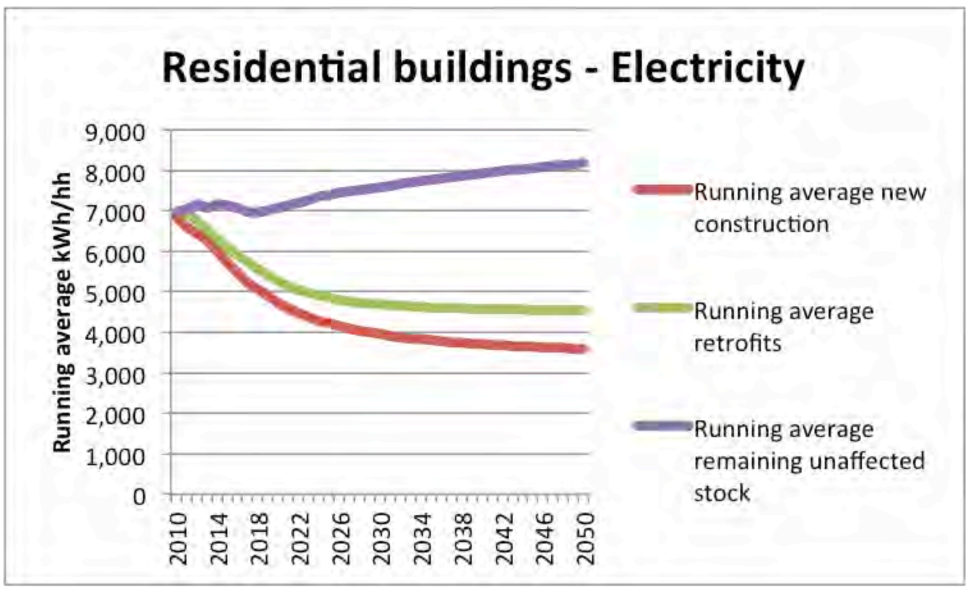

Statewide HDV fuel efficiency (selected technologies)
Btu/mi
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
In-state HHD Diesel Conventional
In-state HHD NG Conventional
OOS HHD Diesel Conventional
MHD Gasoline Conventional
MHD Diesel Conventional

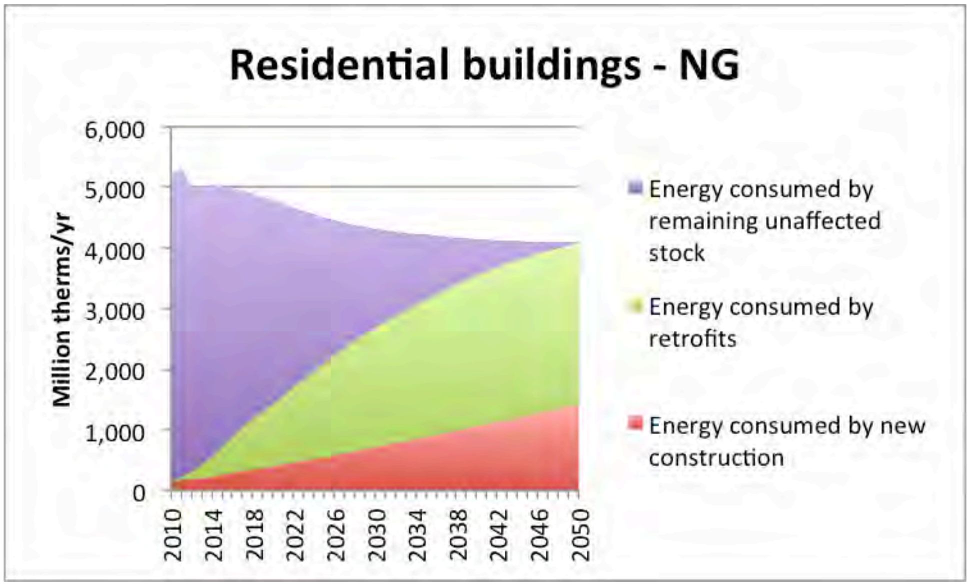


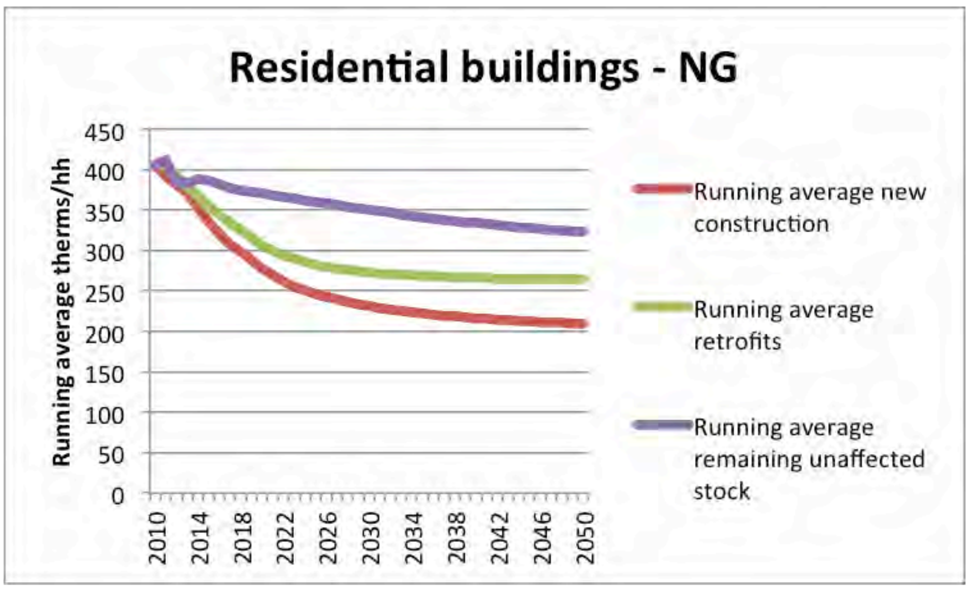
Residential sector



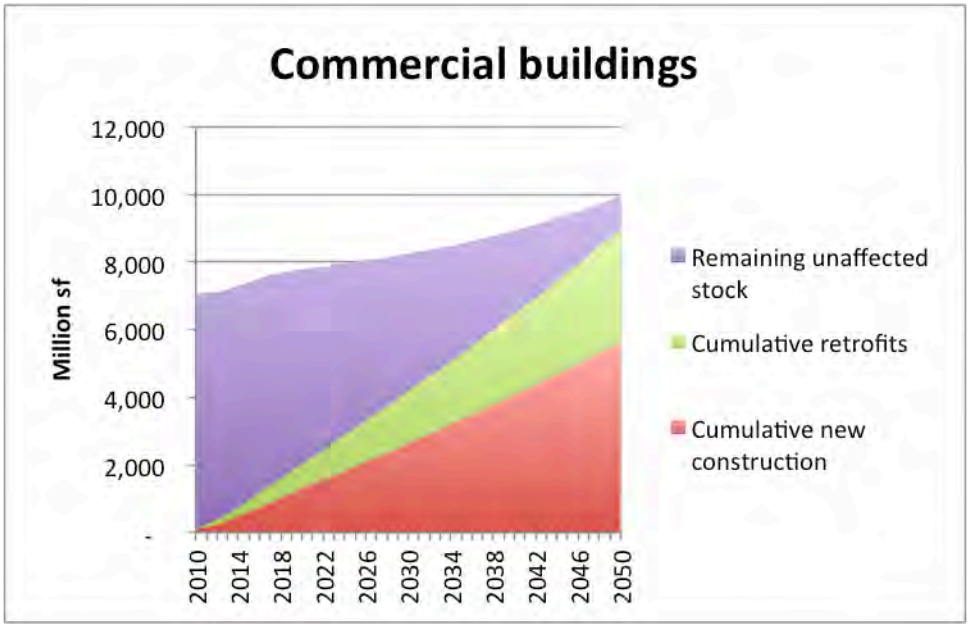

Residential buildings - Electricity
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
GWh/yr
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction

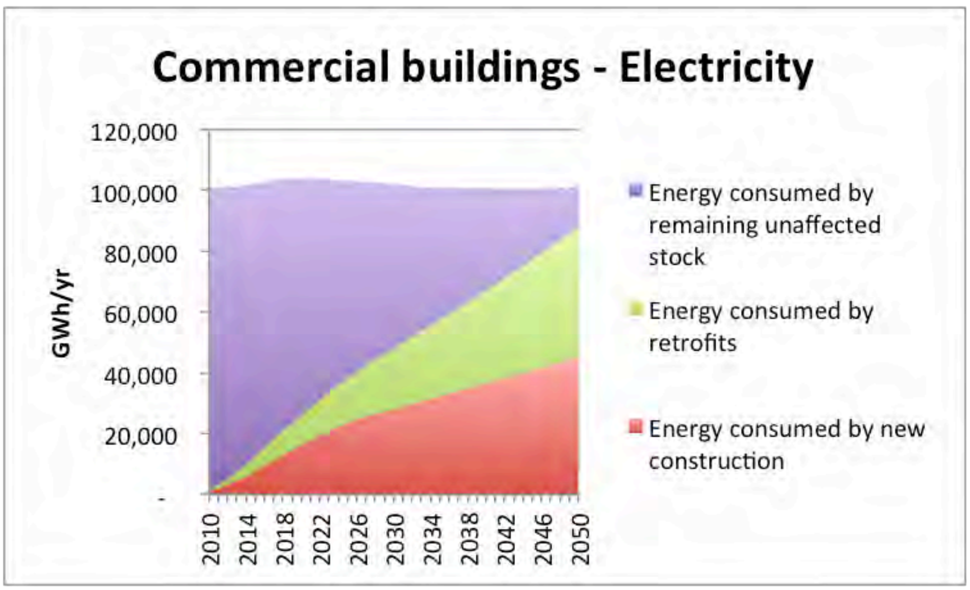

Residential buildings - Electricity
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Running average kWh/hh
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

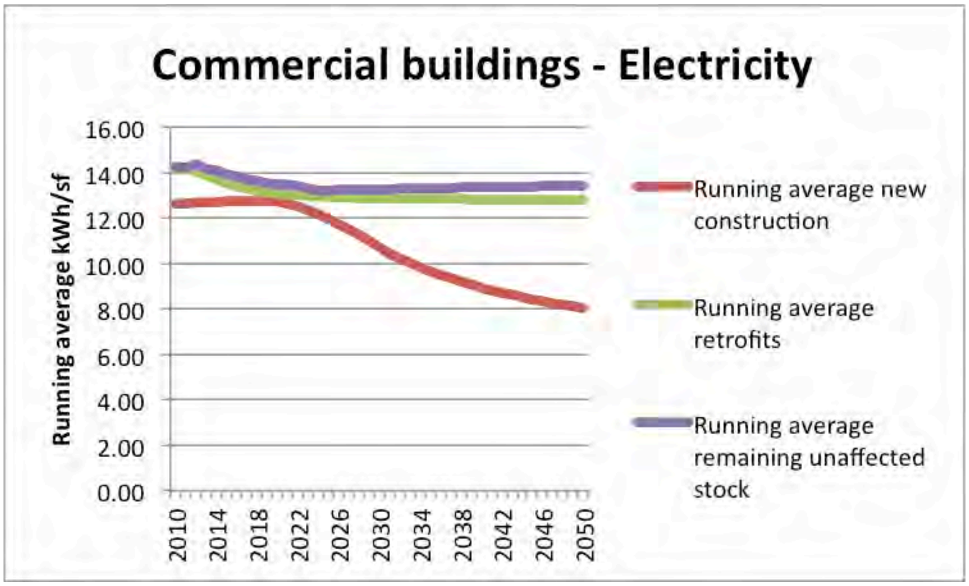


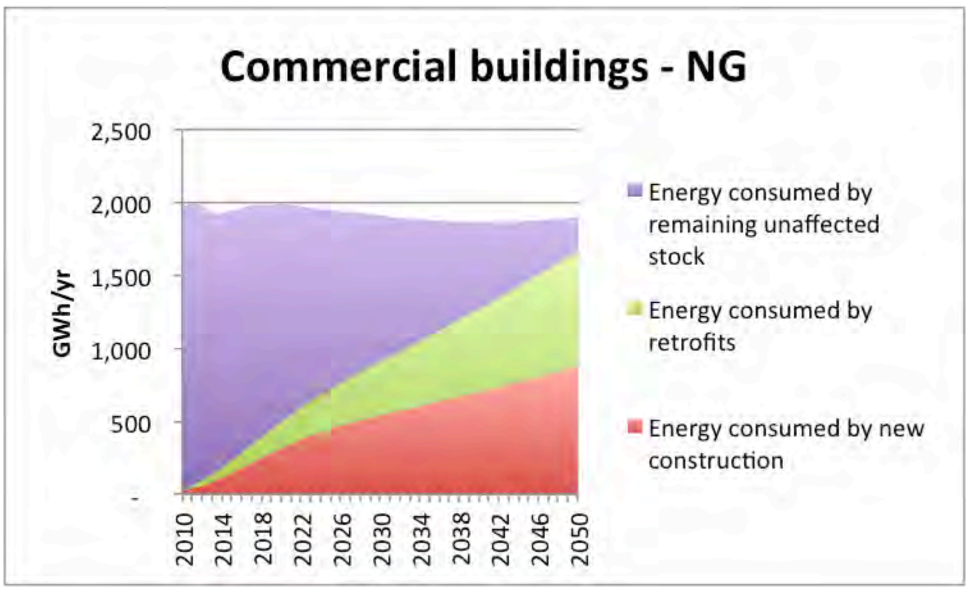


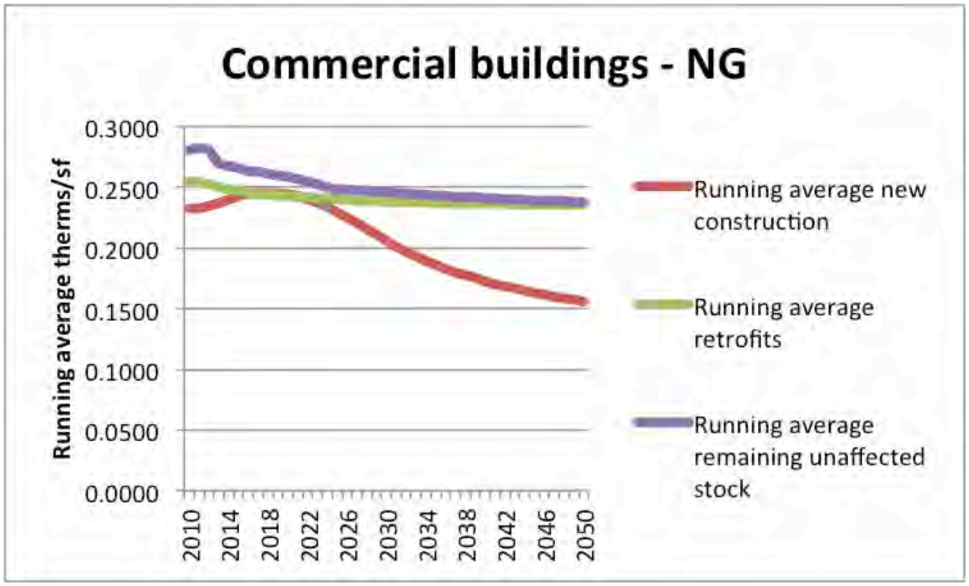
Commercial sector


Commercial buildings
12,000
10,000
8,000
6,000
4,000
2,000
-
Million sf
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Remaining unaffected stock
Cumulative retrofits
Cumulative new construction

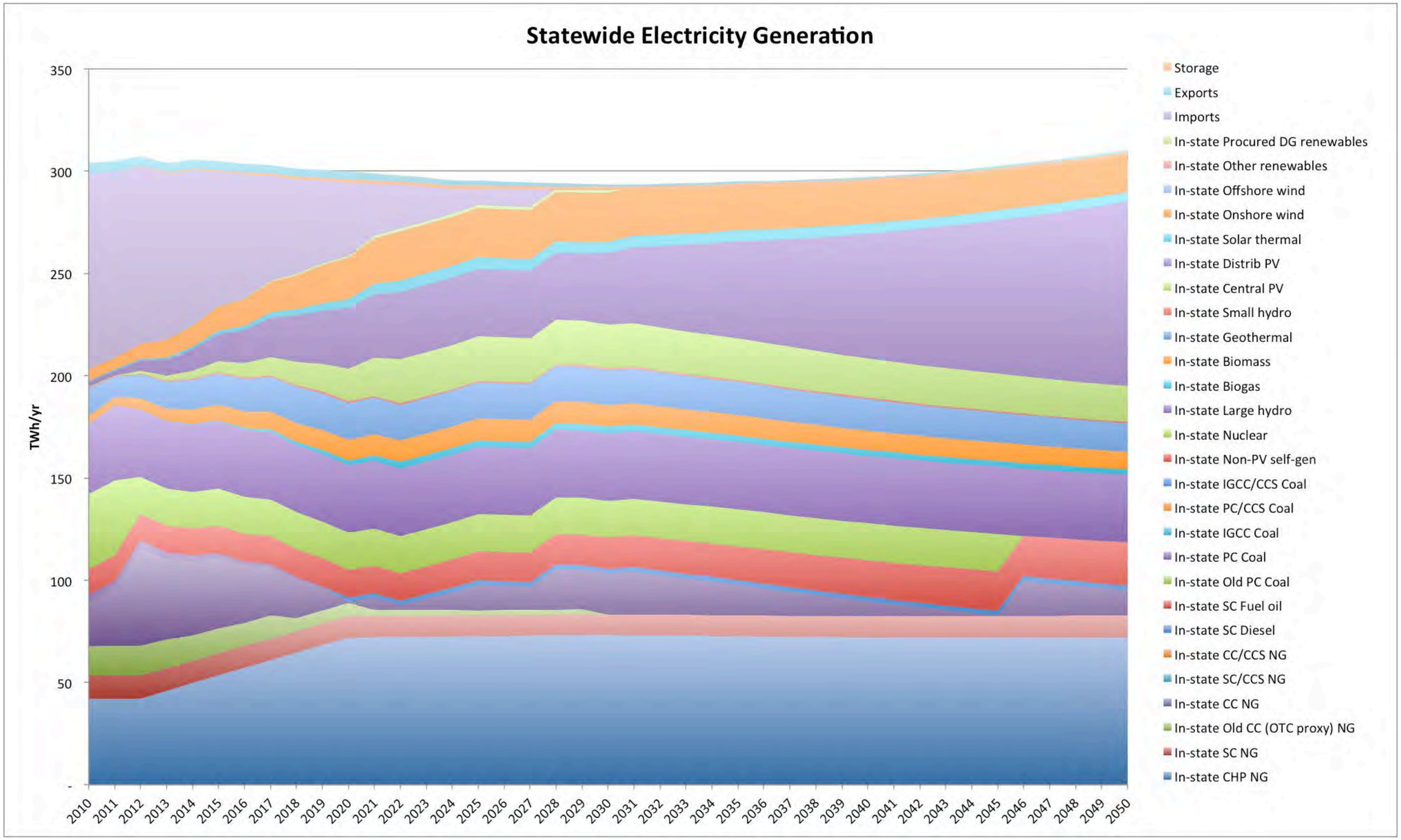

Commercial buildings - Electricity
120,000
100,000
80,000
60,000
40,000
20,000
-
GWh/yr
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction


Commercial buildings - Electricity
Running average kWh/sf
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock


Commercial buildings - NG
GWh/yr
2,500
2,000
1,500
1,000
500
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction


Commercial buildings - NG
Running average therms/sf
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

Electricity sector



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Scenario 3 details

GHG emissions by sector ($MtCO_2e/yr$)

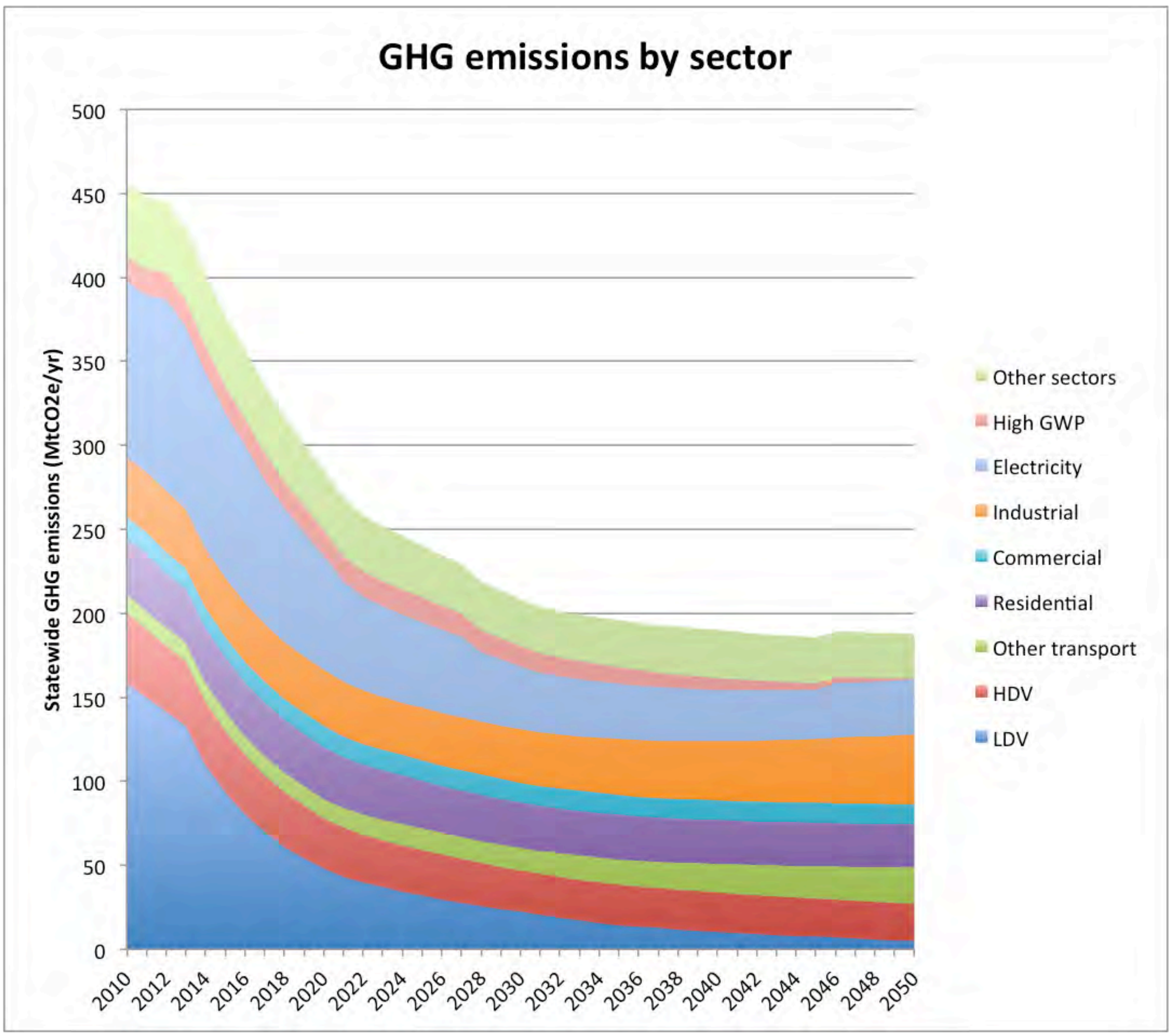
Year	LDVs	HDVs	Other transport	Residential+ commercial	Industry	Electricity	High GWP	Net offsets	All others	Total
2010	158.02	41.89	9.17	46.21	33.56	101.39	41.16	-	24.21	455.61
2020	48.26	29.81	9.91	43.14	31.71	65.60	26.28	(8.20)	30.01	284.71
2025	31.93	27.19	10.84	40.67	29.62	48.90	20.00	(12.30)	31.35	240.49
2030	22.23	24.56	11.43	38.95	30.09	35.21	14.98	(16.40)	30.57	208.04
2035	14.35	24.16	12.88	38.19	31.46	31.24	10.63	(16.40)	32.99	195.91
2040	10.50	23.41	14.36	37.76	33.44	28.80	7.37	(16.40)	34.37	190.00
2050	4.94	21.80	18.51	37.75	39.39	30.88	0.93	(16.40)	33.61	187.81

Criteria pollutants by region (t/yr)

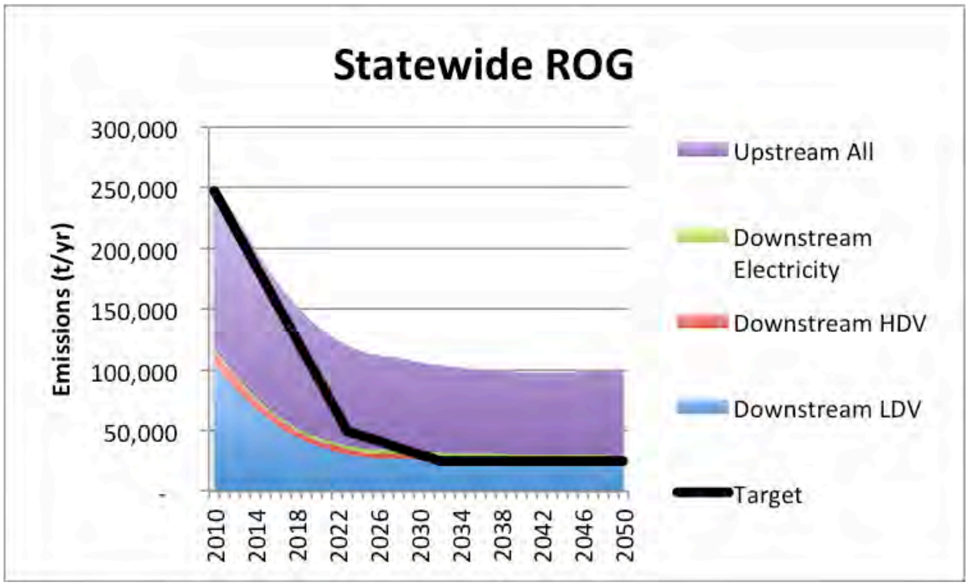
	SCAB			SJV			Statewide		
Year	ROG	NOx	PM2.5	ROG	NOx	PM2.5	ROG	NOx	PM2.5
2010	64,146	163,271	66,608	19,770	69,424	16,684	247,192	466,258	150,744
2020	27,721	79,395	48,163	9,004	28,124	12,622	135,701	210,368	108,621
2025	22,292	59,643	41,791	7,545	20,773	11,617	113,571	155,917	94,724
2030	20,768	42,187	27,848	6,881	15,725	8,207	105,846	113,250	63,926
2035	18,350	34,611	22,499	6,453	13,922	7,030	100,579	95,375	52,499
2040	17,080	32,761	21,389	6,186	13,675	6,988	97,869	91,539	50,502
2050	15,062	31,815	20,448	5,777	13,716	7,163	98,683	89,610	49,238

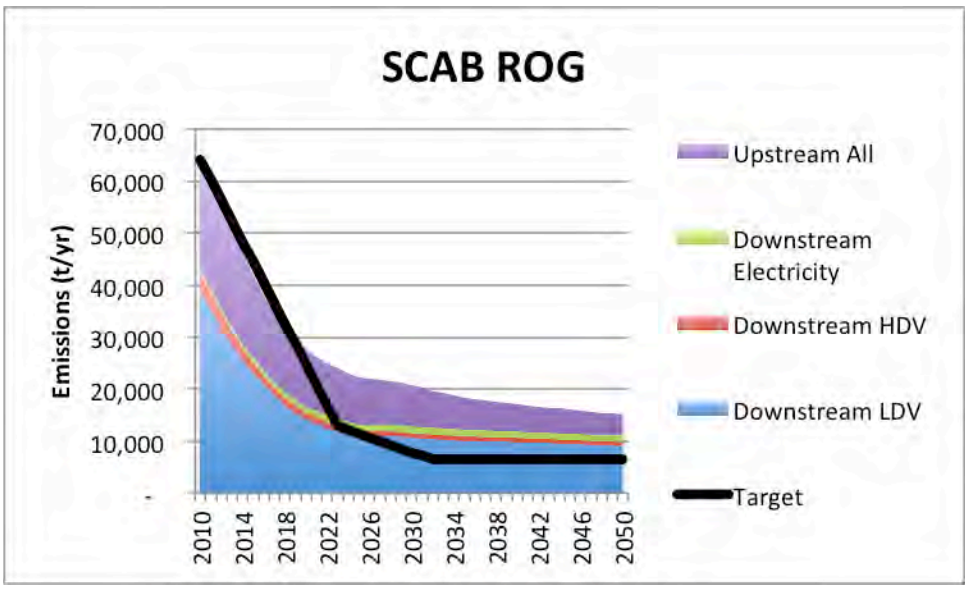
Biomass demand by fuel type and source (Mdt/yr)

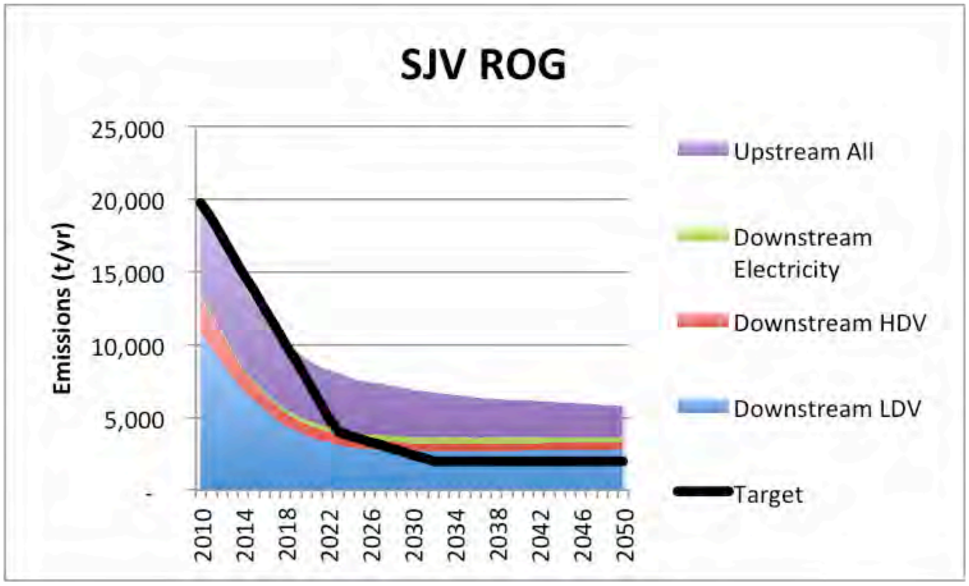
	Gasoline, E-85	Diesel	Gasoline, E-85, Diesel, Jet fuel, Aviation gasoline	NG	Electricity	All
Year	Corn kernels	Soybean oil	Herbaceous/forest biomass	Landfill waste	Herbaceous/forest biomass	All
2010	12.21	2.49	2.92	-	5.27	22.89
2020	12.70	9.49	9.24	6.95	12.59	50.97
2025	11.12	13.07	12.50	15.27	14.57	66.52
2030	8.90	15.56	15.24	23.47	16.14	79.32
2035	5.05	15.63	13.69	22.57	15.73	72.68
2040	2.94	15.43	13.26	21.60	15.19	68.43
2050	0.42	15.61	11.87	21.61	15.03	64.53

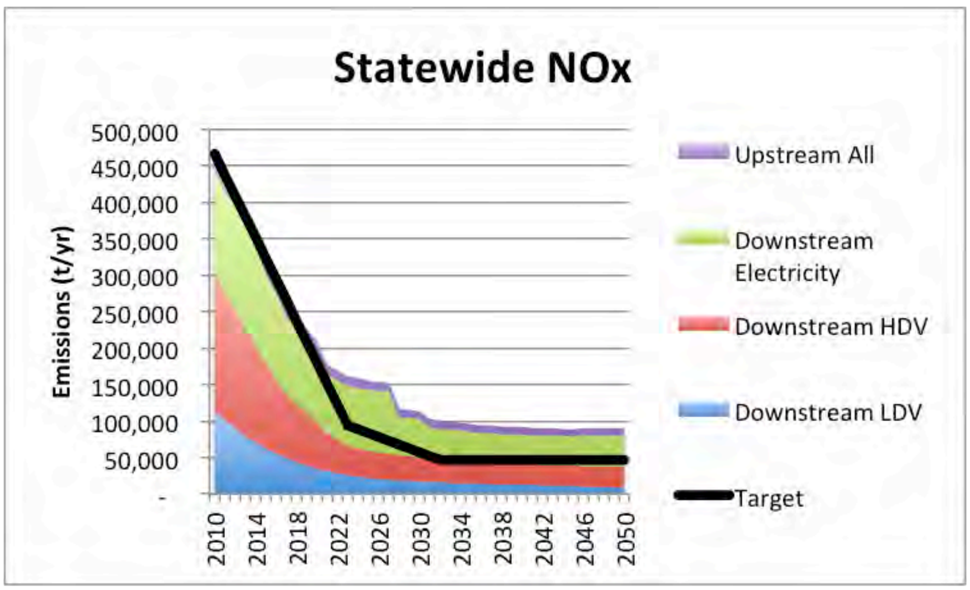


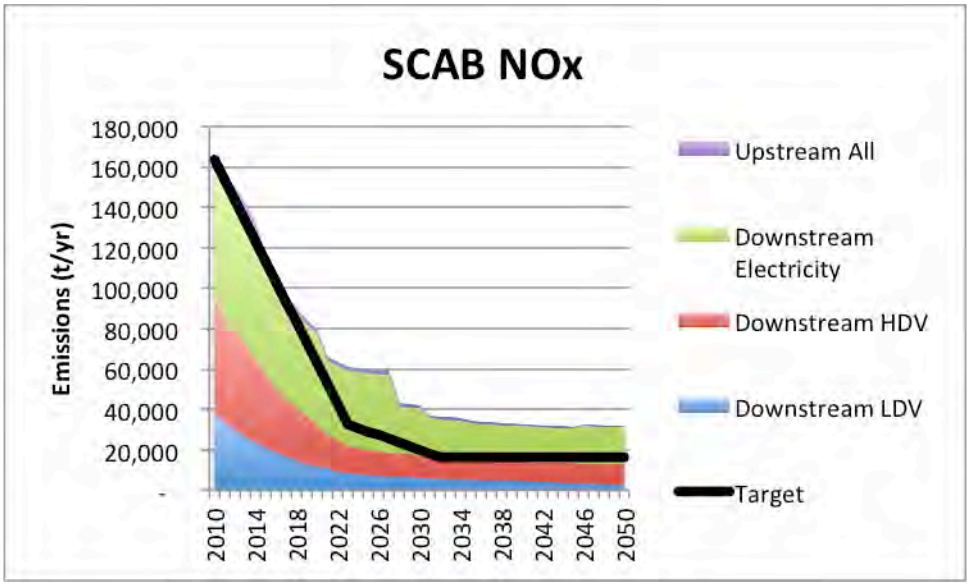
Note: All electricity-related GHG emissions from all sectors are included in electricity sector


Statewide ROG
Emissions (t/yr)
300,000
250,000
200,000
150,000
100,000
50,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

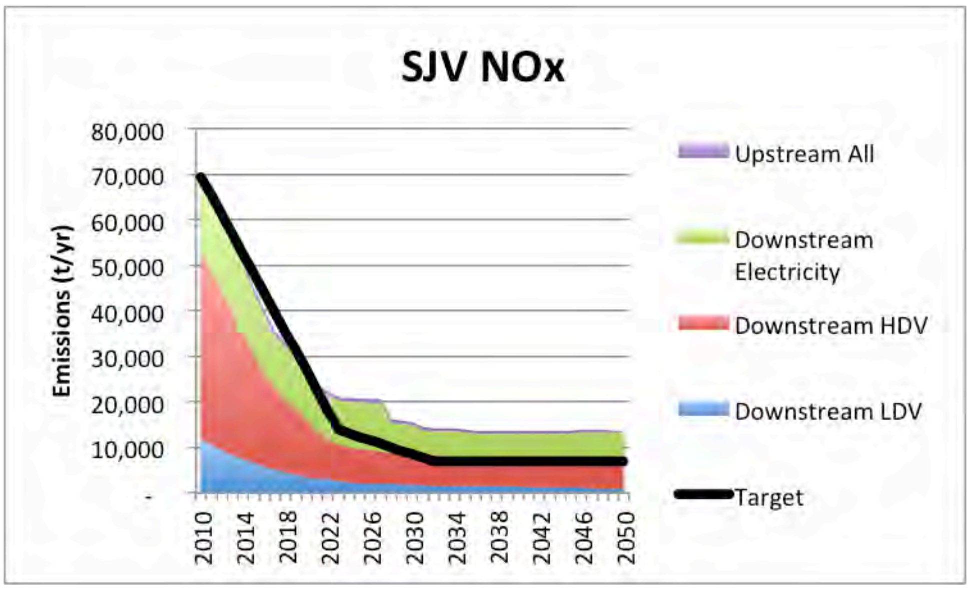

SCAB ROG
Emissions (t/yr)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target


SJV ROG
Emissions (t/yr)
25,000
20,000
15,000
10,000
5,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

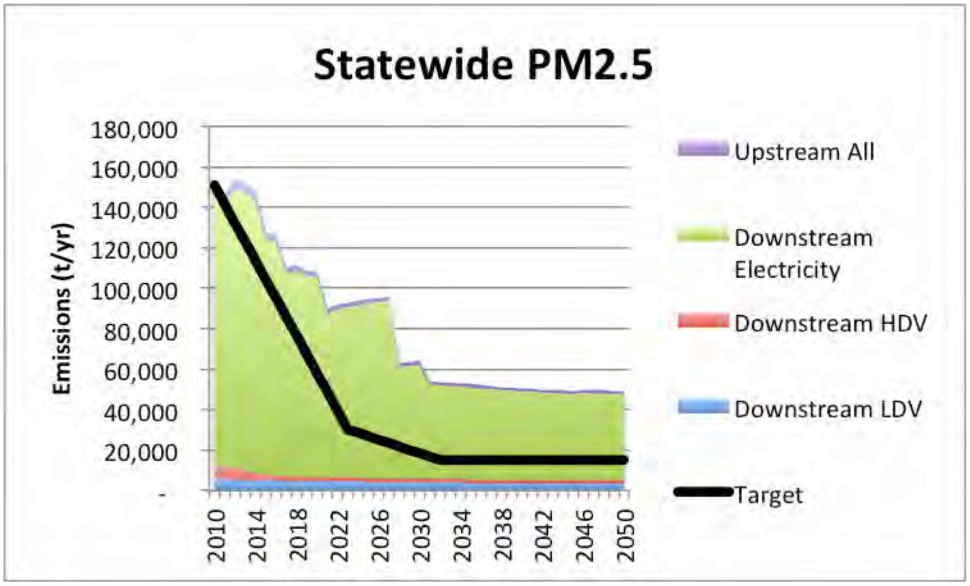

Statewide NOx
Emissions (t/yr)
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target



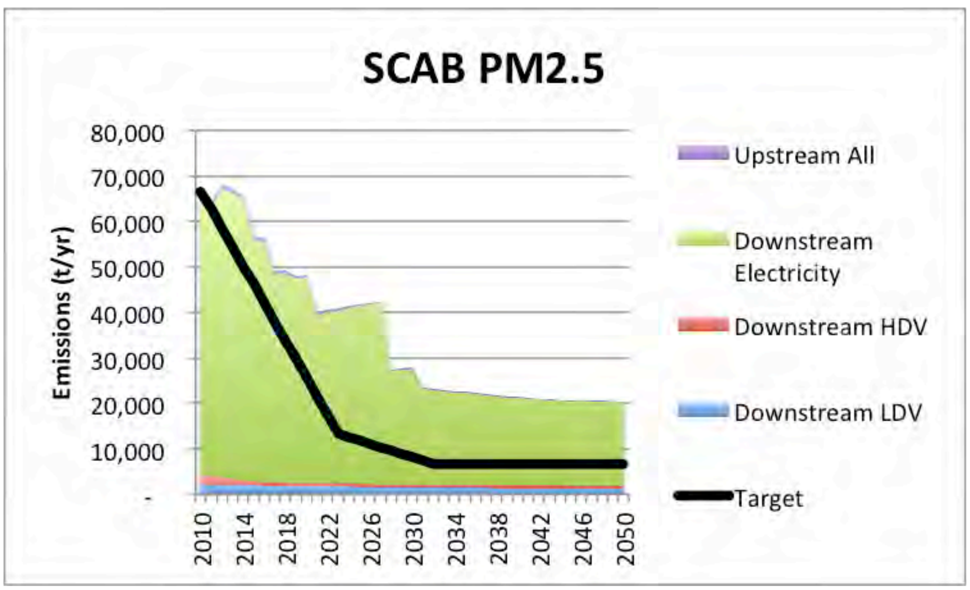
SCAB NOx
Emissions (t/yr)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target



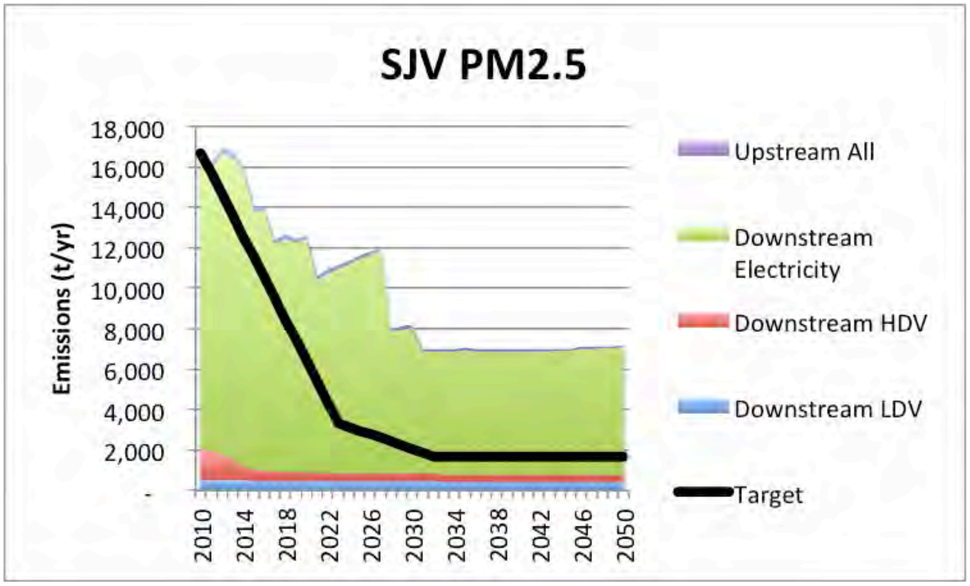
SJV NOx
Emissions (t/yr)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target



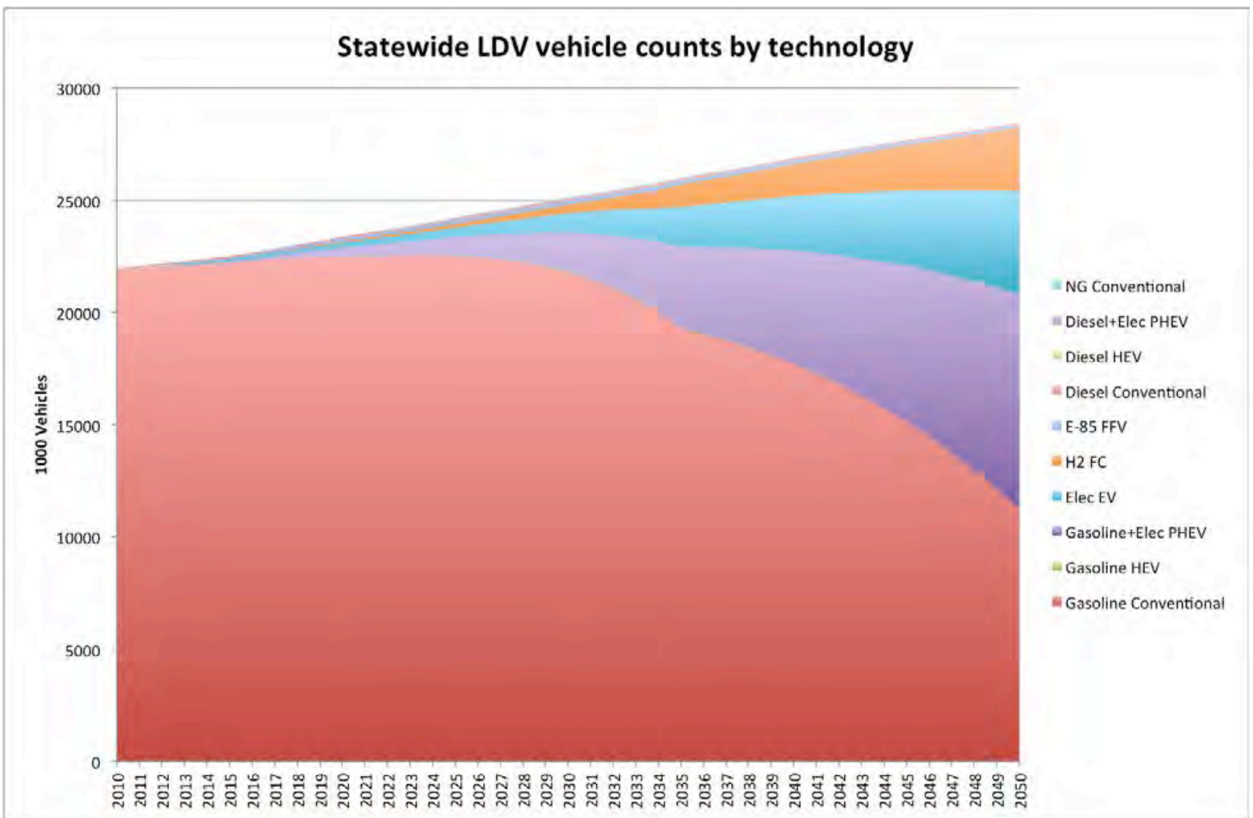
Statewide PM2.5
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

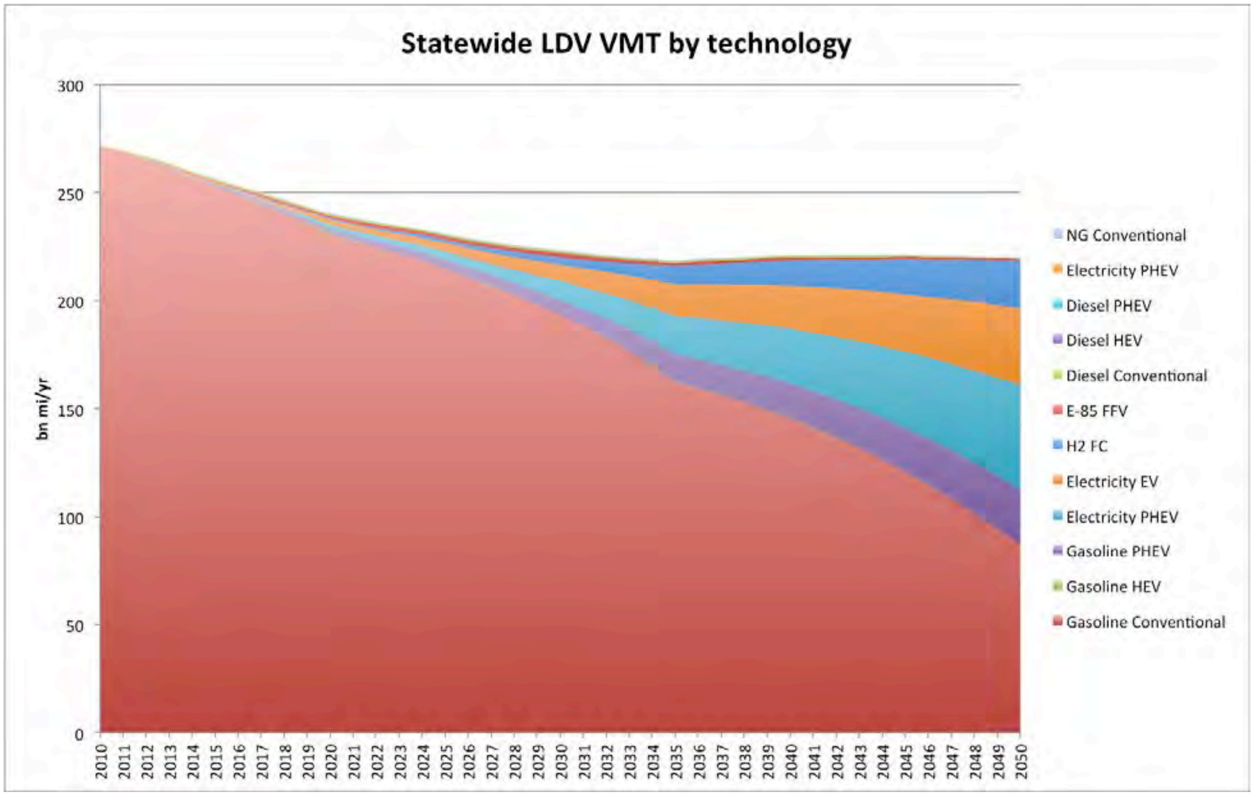


SCAB PM2.5
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Emissions (t/yr)
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

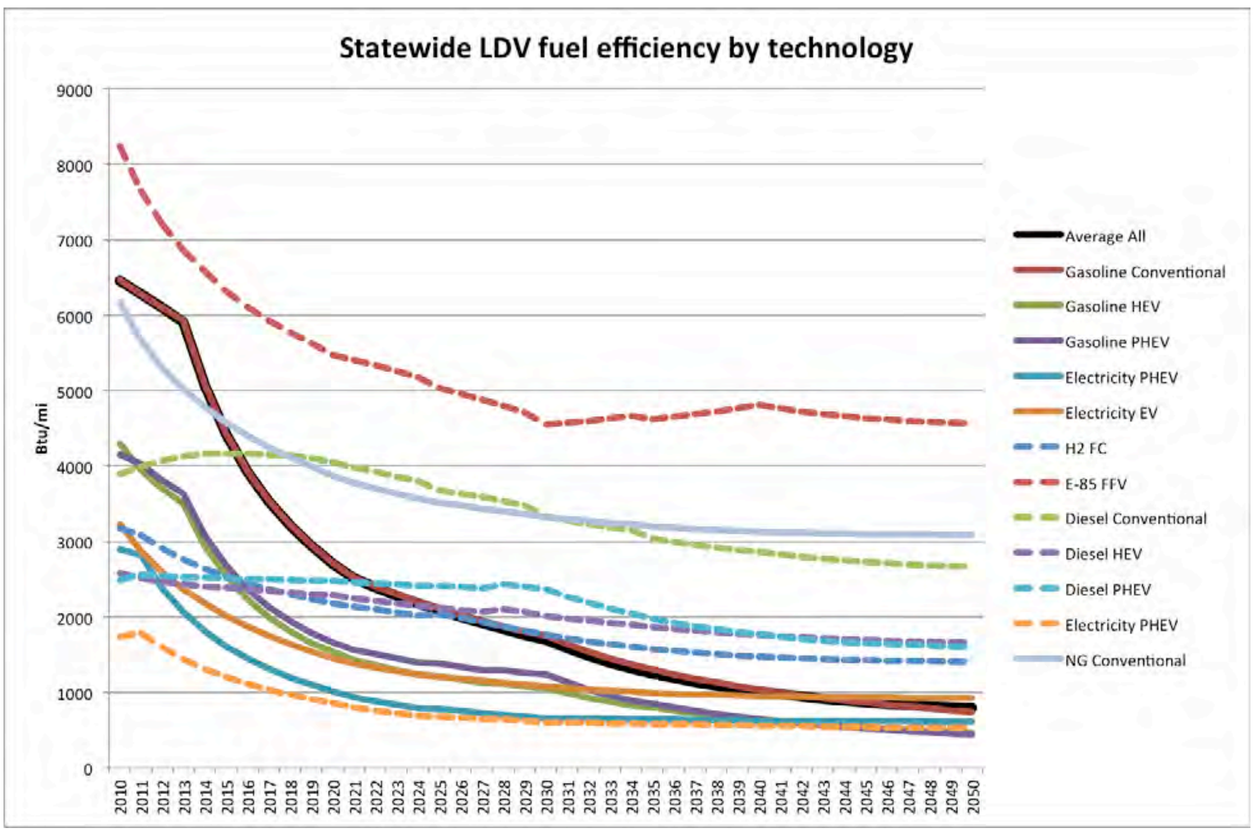

SJV PM2.5
Emissions (t/yr)
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Upstream All
Downstream Electricity
Downstream HDV
Downstream LDV
Target

LDV sector

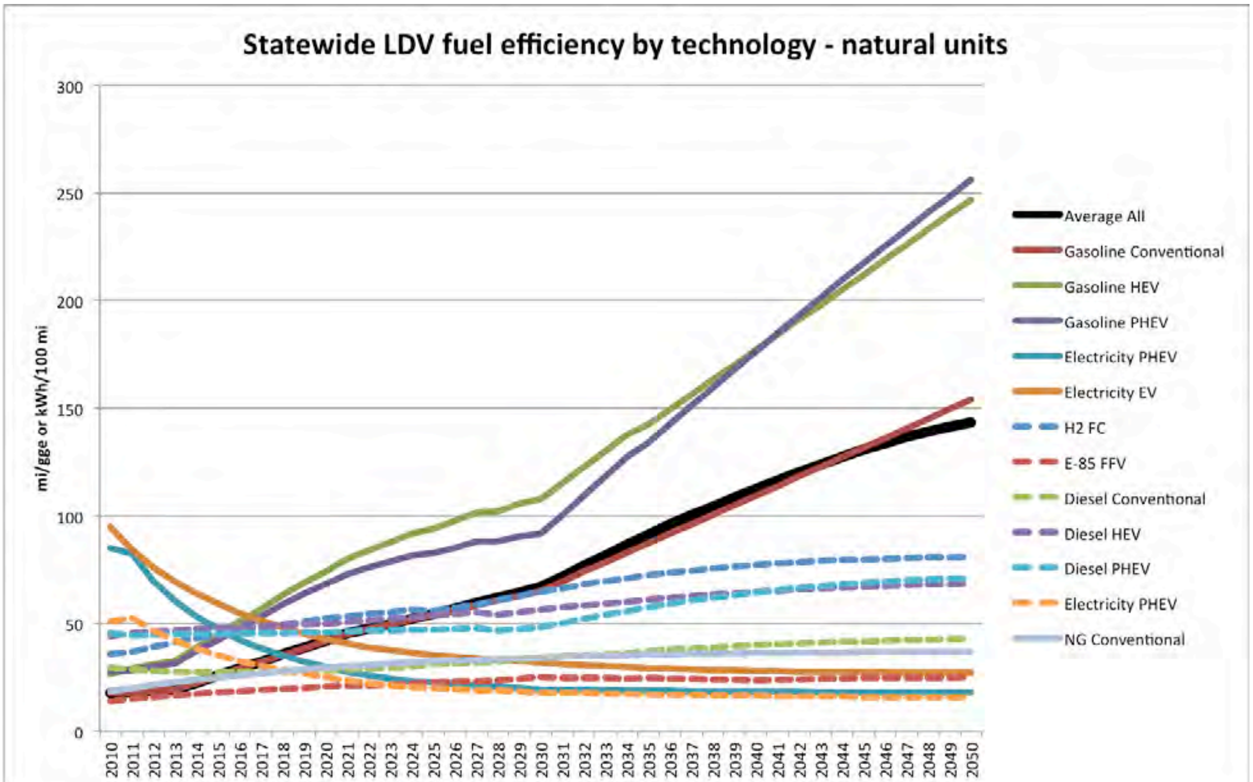

Statewide LDV vehicle counts by technology
1000 Vehicles
30000
25000
20000
15000
10000
5000
0
NG Conventional
Diesel+Elec PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Elec EV
Gasoline+Elec PHEV
Gasoline HEV
Gasoline Conventional



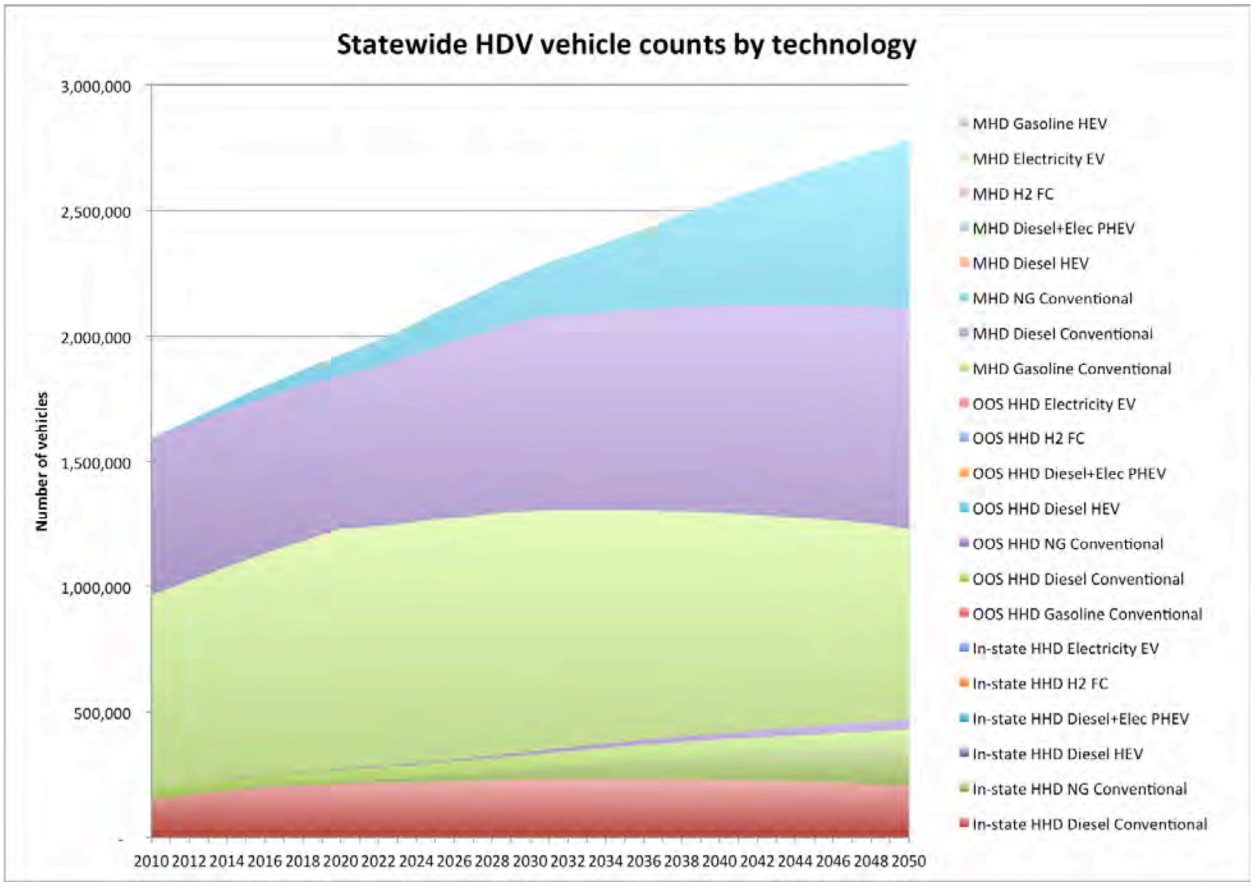
Statewide LDV VMT by technology
bn mi/yr
300
250
200
150
100
50
0
NG Conventional
Electricity PHEV
Diesel PHEV
Diesel HEV
Diesel Conventional
E-85 FFV
H2 FC
Electricity EV
Electricity PHEV
Gasoline PHEV
Gasoline HEV
Gasoline Conventional
2010
2050

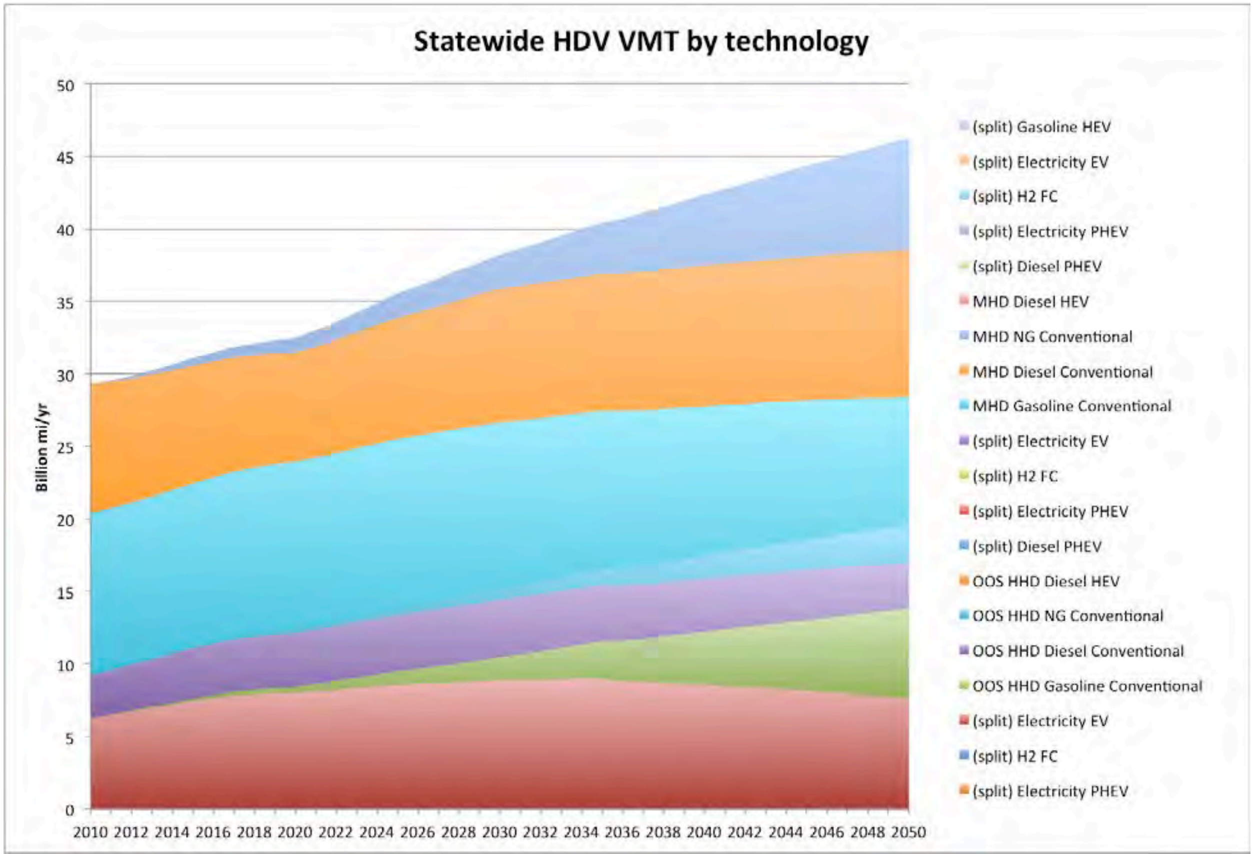


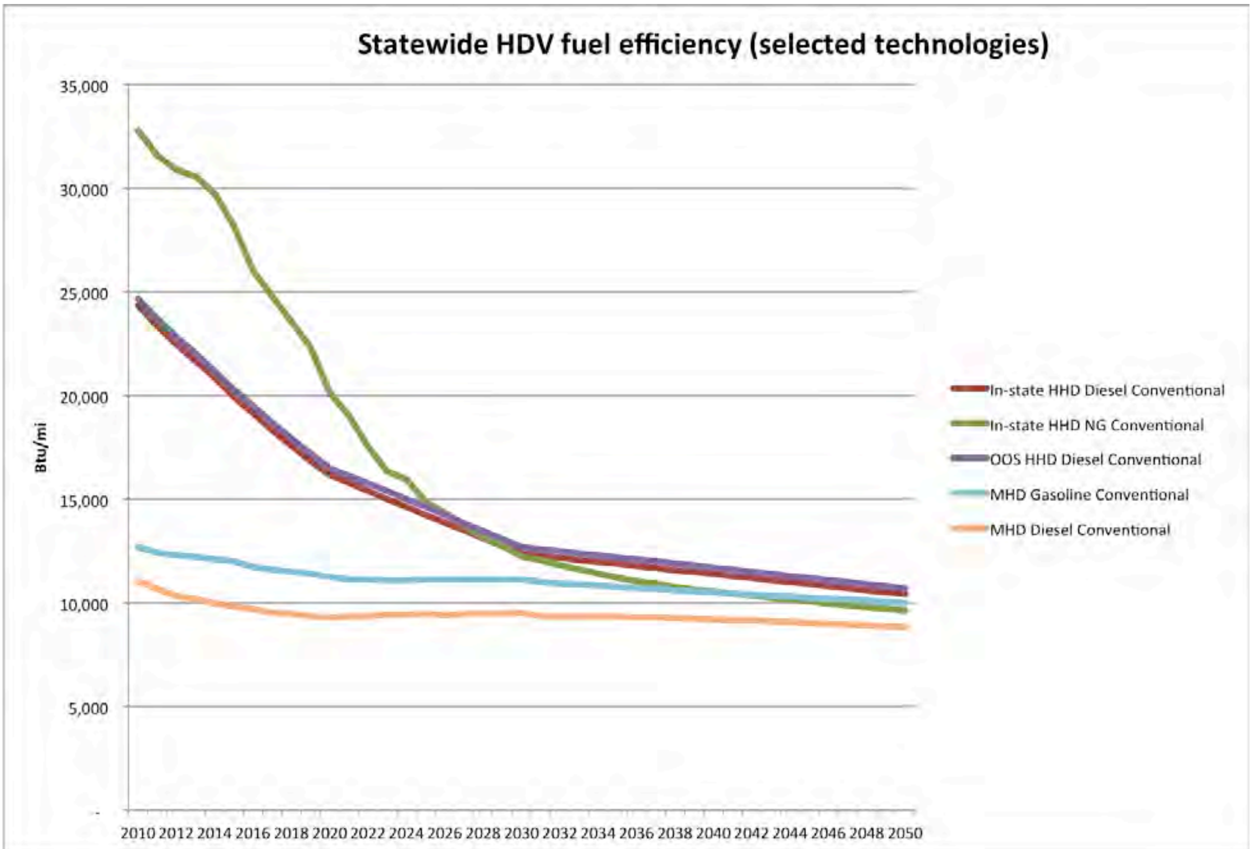
Statewide LDV fuel efficiency by technology
Btu/mi
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional
2010
2050

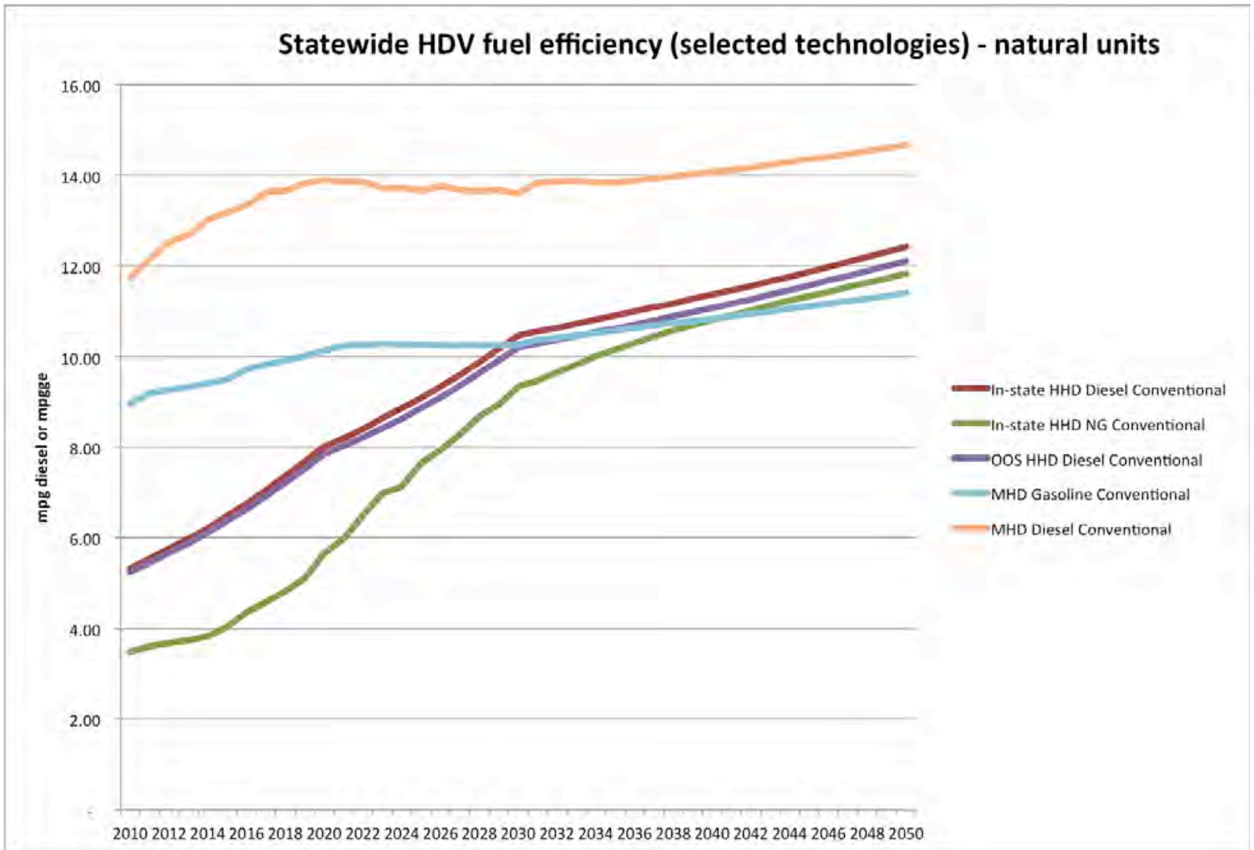

Statewide LDV fuel efficiency by technology - natural units
mi/gge or kWh/100 mi
300
250
200
150
100
50
0
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Average All
Gasoline Conventional
Gasoline HEV
Gasoline PHEV
Electricity PHEV
Electricity EV
H2 FC
E-85 FFV
Diesel Conventional
Diesel HEV
Diesel PHEV
Electricity PHEV
NG Conventional

HDV sector

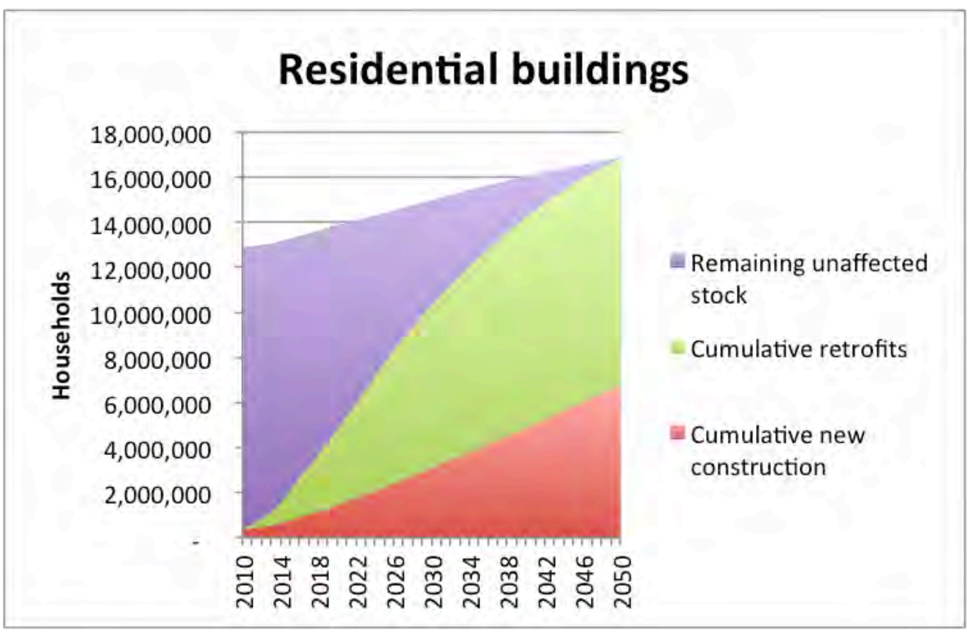

Statewide HDV vehicle counts by technology
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Number of vehicles
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
MHD Gasoline HEV
MHD Electricity EV
MHD H2 FC
MHD Diesel+Elec PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
OOS HHD Electricity EV
OOS HHD H2 FC
OOS HHD Diesel+Elec PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
In-state HHD Electricity EV
In-state HHD H2 FC
In-state HHD Diesel+Elec PHEV
In-state HHD Diesel HEV
In-state HHD NG Conventional
In-state HHD Diesel Conventional

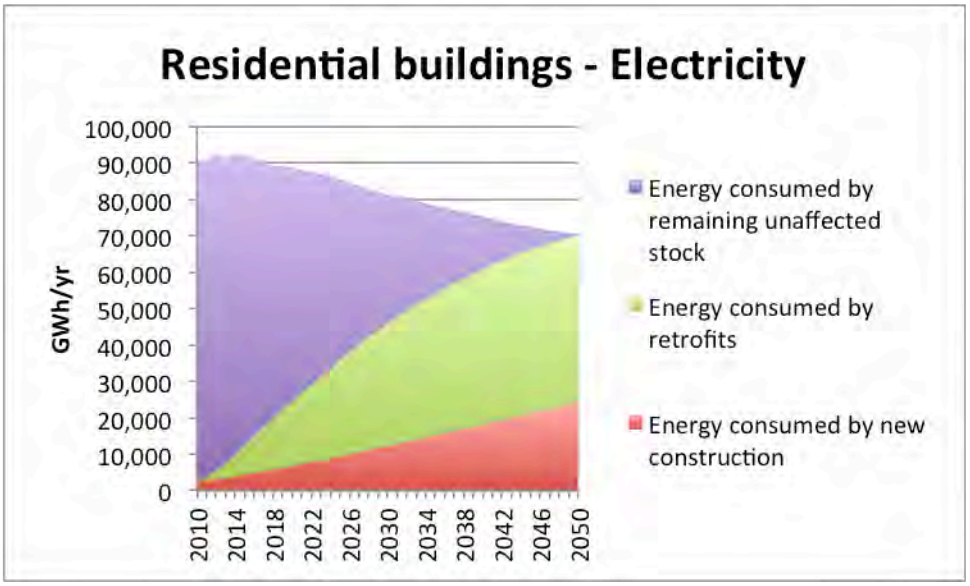

Statewide HDV VMT by technology
Billion mi/yr
0
5
10
15
20
25
30
35
40
45
50
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
(split) Gasoline HEV
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
MHD Diesel HEV
MHD NG Conventional
MHD Diesel Conventional
MHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV
(split) Diesel PHEV
OOS HHD Diesel HEV
OOS HHD NG Conventional
OOS HHD Diesel Conventional
OOS HHD Gasoline Conventional
(split) Electricity EV
(split) H2 FC
(split) Electricity PHEV


Statewide HDV fuel efficiency (selected technologies)
Btu/mi
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
In-state HHD Diesel Conventional
In-state HHD NG Conventional
OOS HHD Diesel Conventional
MHD Gasoline Conventional
MHD Diesel Conventional

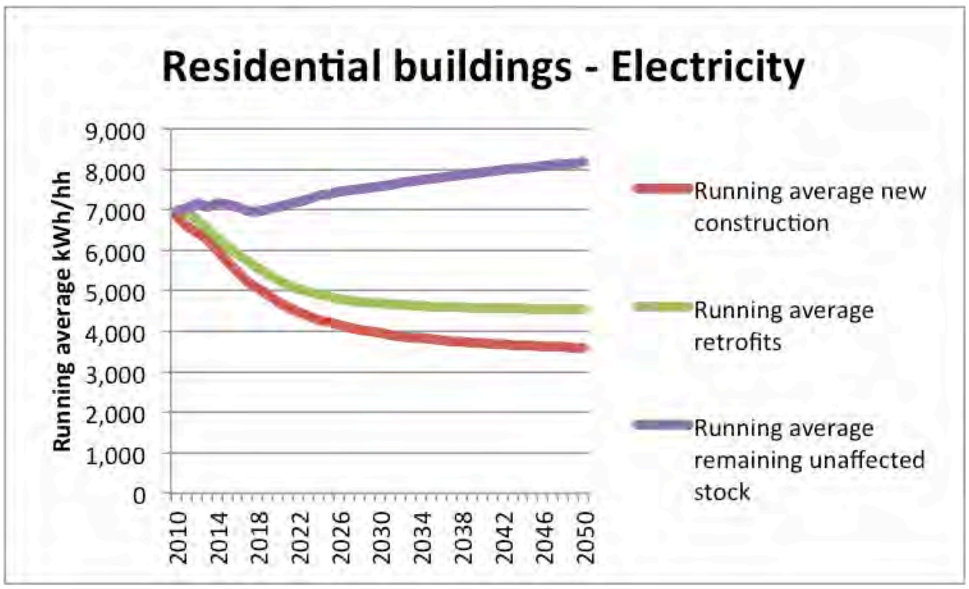


Residential sector

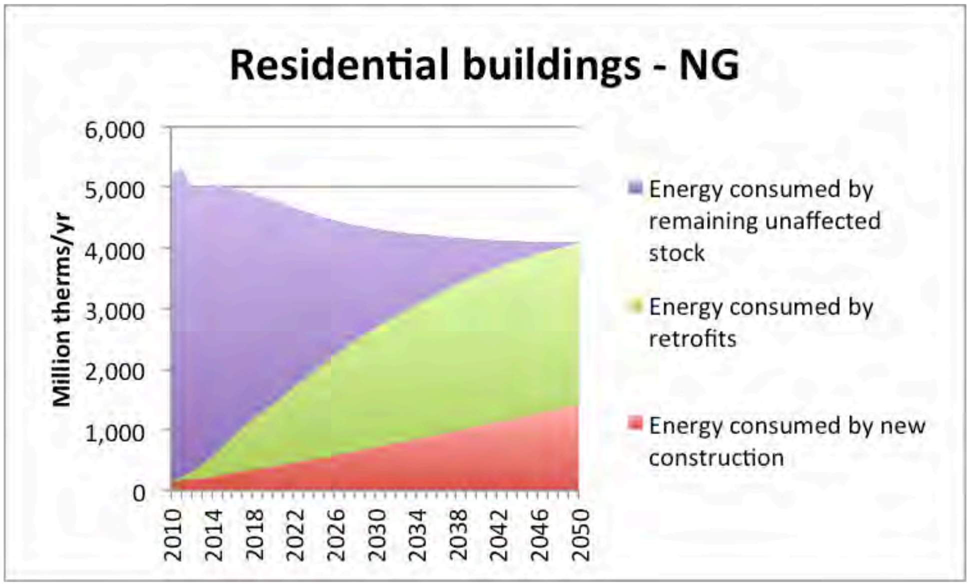


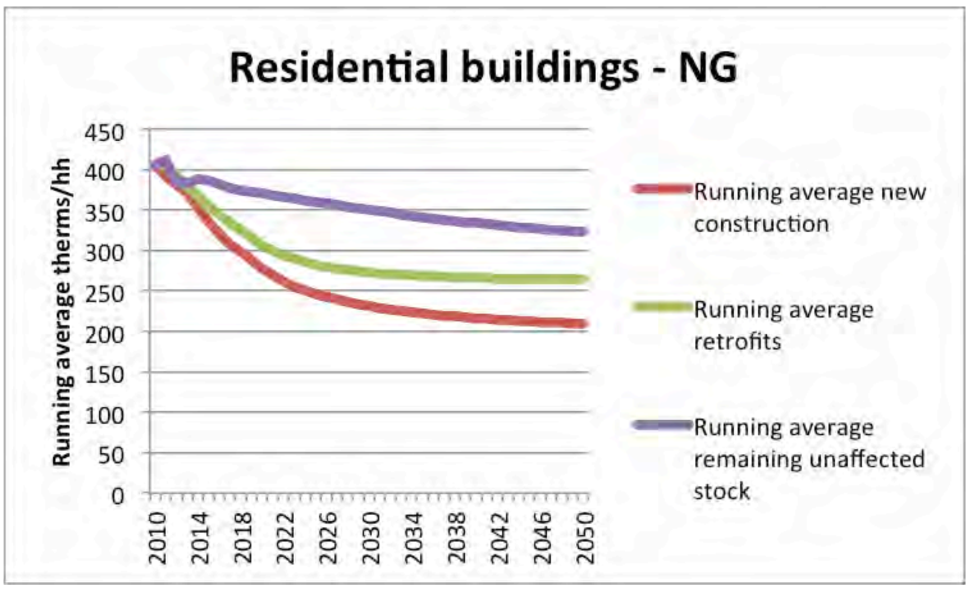


Residential buildings - Electricity
GWh/yr
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction

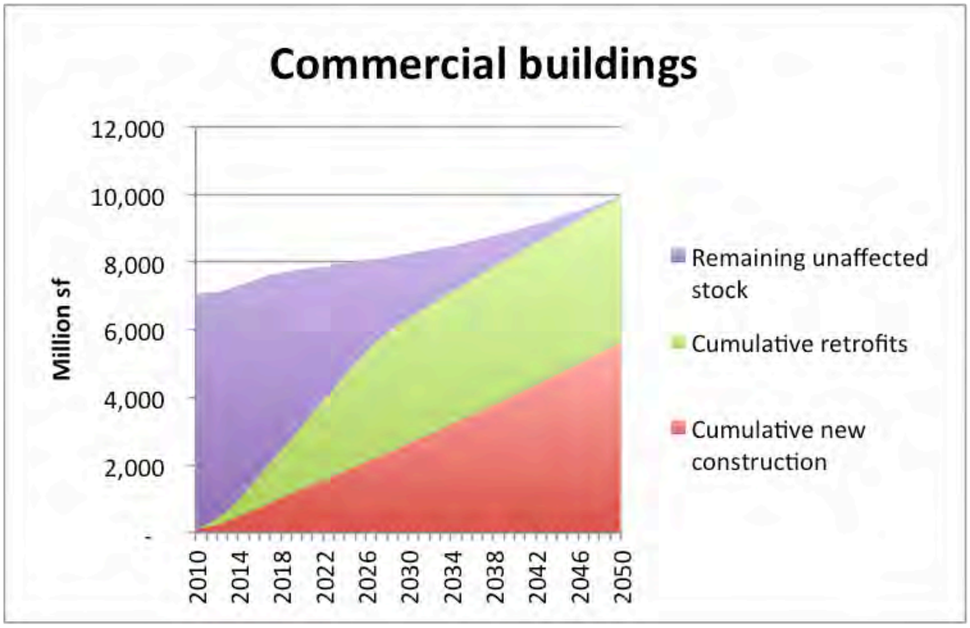


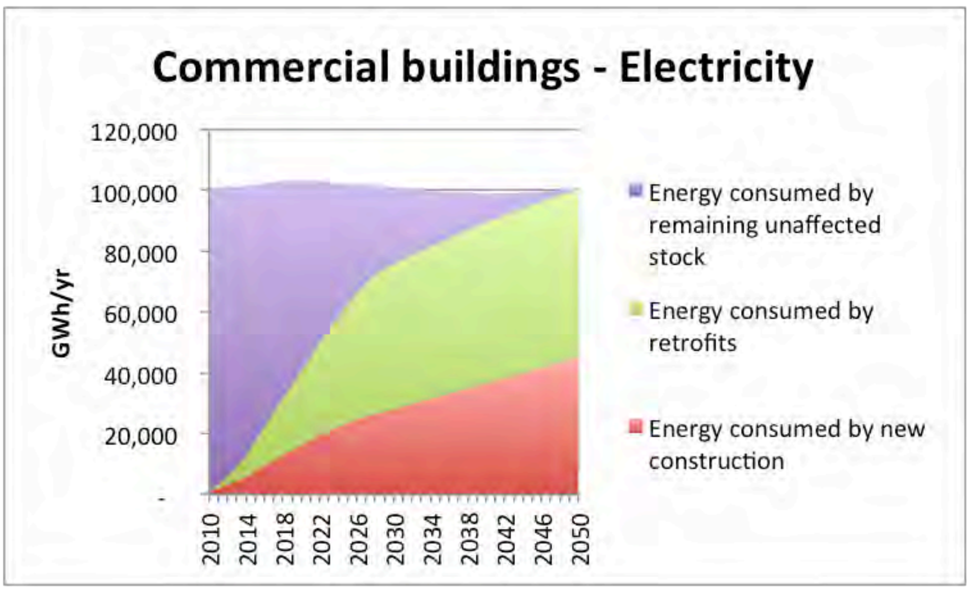
Residential buildings - Electricity
Running average kWh/hh
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

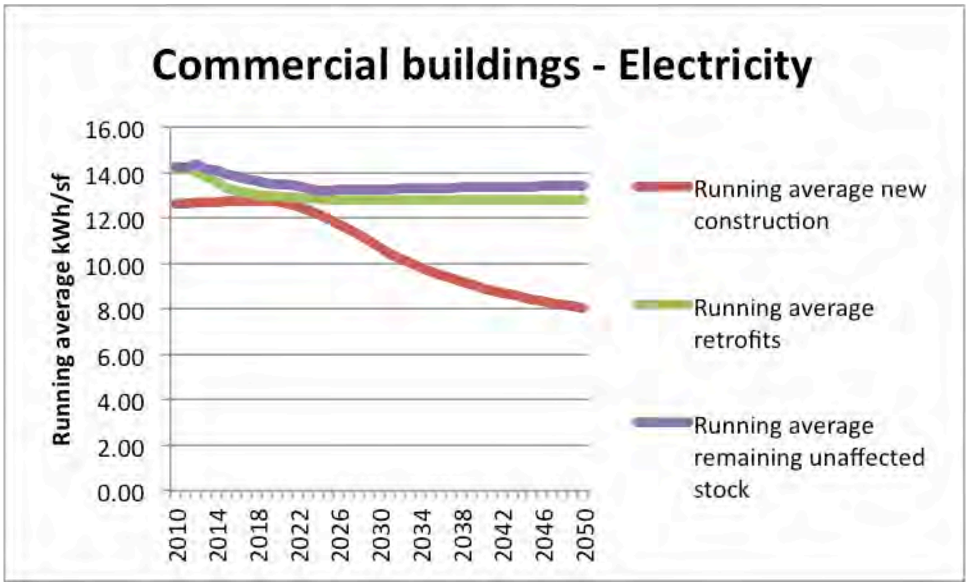




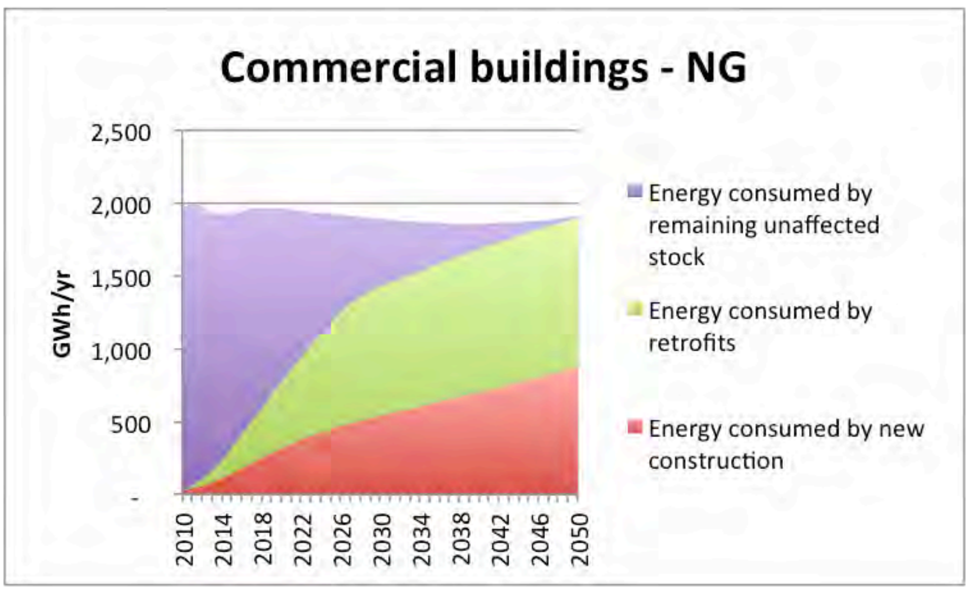
Commercial sector


Commercial buildings
Million sf
12,000
10,000
8,000
6,000
4,000
2,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Remaining unaffected stock
Cumulative retrofits
Cumulative new construction

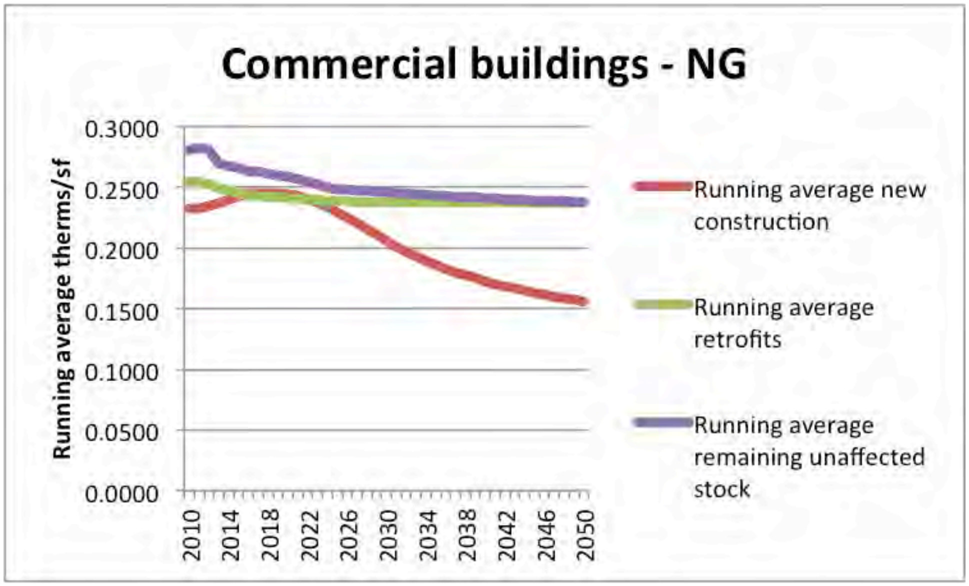

Commercial buildings - Electricity
GWh/yr
120,000
100,000
80,000
60,000
40,000
20,000
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction



Commercial buildings - Electricity
Running average kWh/sf
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

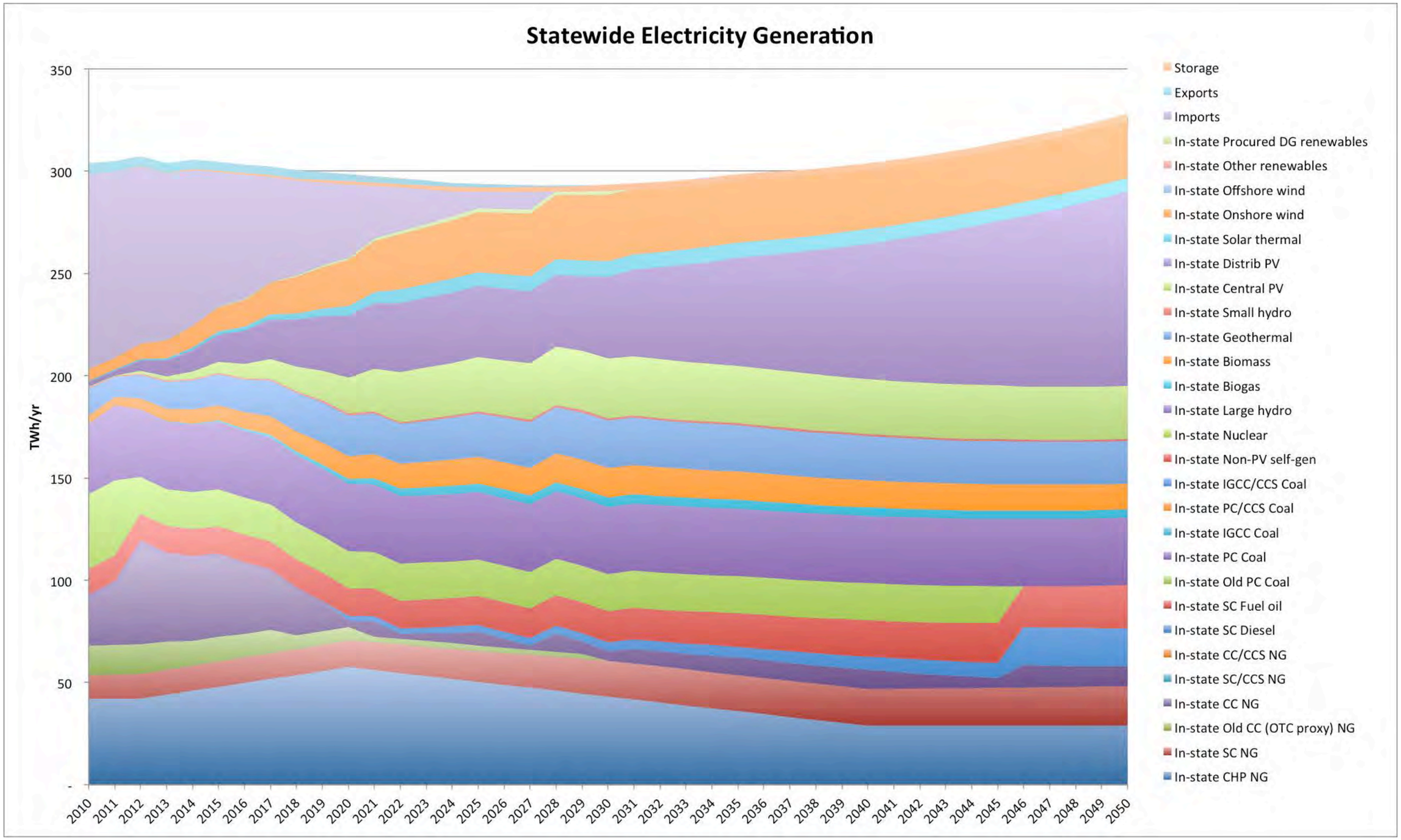


Commercial buildings - NG
GWh/yr
2,500
2,000
1,500
1,000
500
-
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Energy consumed by remaining unaffected stock
Energy consumed by retrofits
Energy consumed by new construction



Commercial buildings - NG
Running average therms/sf
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
2010
2014
2018
2022
2026
2030
2034
2038
2042
2046
2050
Running average new construction
Running average retrofits
Running average remaining unaffected stock

Electricity sector



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