Improving the Carbon Dioxide Emission Estimates from the Combustion of Fossil Fuels in California

Prepared for the California Air Resources Board and the California Environmental Protection Agency

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List of Abbreviations and Acronyms

AAGR	Average Annual Growth Rate
AAR	Association of American Railroads
ASM	Annual Survey of Manufacturers
ATC	Available Transfer Capability
BAR	Bureau of Automotive Repair
BTS	Bureau of Transportation Statistics
Btu	British thermal unit
CalCARS	California Conventional and Alternative Vehicle Response Simulator model
CALEB	California Energy Balance Database
CalTrans	California Department of Transportation
CARB	California Air Resources Board
CEC	California Energy Commission
CEM	Continuous Emissions Monitoring
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DMV	Department of Motor Vehicles
EEA	European Environment Agency
U.S. EIA	Energy Information Administration
EMFAC	CARB emissions model for calculating on-road vehicle emissions
FAA	Federal Aviation Administration
FE	Fuel used for electricity production
FHWA	Federal Highway Administration
GHG	Greenhouse Gas
GWh	Giga Watt hour
HPMS	Highway Performance Monitoring System
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
Kbbl	Thousand barrels
kLBS	Thousand pounds of Steam
kst	Thousand of Short Tons
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
LPG	Liquefied petroleum gas
Mcf	Million of Cubic Foot
MECS	Manufacturing Energy Consumption Survey
MMBtu	Million British thermal units
Mt	Million metric tonne
MTBE	Methyl tert-butyl ether
MVSTAFF	Motor Vehicle Stock, Travel and Fuel Forecast model
MW	Megawatt

NAICS	North American Industry Classification System
NGLs	Natural Gas Liquids
O_2	Oxygen
PCA	Portland Cement Association
PIER	Public Interest Energy Research
PIIRA	Petroleum Industry Information Reporting Act
SAGE	System for assessing Aviation’s Global Emissions
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
scf	Standard cubic feet
SEDS	State Energy Data System
SIC	U.S. Standard Industrial Classification
TASAS	Traffic Accident Surveillance and Analysis System
TBtu	Trillion British thermal units
Tbtu	Trillion British Thermal Unit
TEOR	Thermally Enhanced Oil Recovery
TF	Total fuel used
TWh	Terra-watt hours
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
UTO	Useful Thermal Output
VMT	Vehicle Miles Traveled
WSPA	Western States Petroleum Association

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Abstract

Central to any study of climate change is the development of an emission inventory that identifies and quantifies the State's primary anthropogenic sources and sinks of greenhouse gas (GHG) emissions. CO_2 emissions from fossil fuel combustion accounted for 80 percent of California GHG emissions (CARB, 2007a). Even though these CO_2 emissions are well characterized in the existing state inventory, there still exist significant sources of uncertainties regarding their accuracy.

This report evaluates the CO_2 emissions accounting based on the California Energy Balance database (CALEB) developed by Lawrence Berkeley National Laboratory (LBNL), in terms of what improvements are needed and where uncertainties lie. The estimated uncertainty for total CO_2 emissions ranges between -21 and +37 million metric tons (Mt), or -6% and +11% of total CO_2 emissions. The report also identifies where improvements are needed for the upcoming updates of CALEB. However, it is worth noting that the California Air Resources Board (CARB) GHG inventory did not use CALEB data for all combustion estimates. Therefore the range in uncertainty estimated in this report does not apply to the CARB's GHG inventory. As much as possible, additional data sources used by CARB in the development of its GHG inventory are summarized in this report for consideration in future updates to CALEB.

Executive Summary

Central to any study of climate change is the development of an emission inventory that identifies and quantifies the State's primary anthropogenic sources and sinks of greenhouse gas (GHG) emissions. The accounting of carbon dioxide (CO_2) emissions from fossil combustion, which represents the majority of GHG emissions in California, requires having access to reliable and concise energy statistics. In 2005, Lawrence Berkeley National Laboratory (LBNL) evaluated several sources of California energy data, primarily from the California Energy Commission and the U.S. Energy Information Administration, to develop the California Energy Balance Database (CALEB). This database manages highly disaggregated data on energy supply, transformation, and end-use consumption for each type of energy commodity from 1990 to the most recent year available (generally 2004) in the form of an energy balance. CARB used this database in the development of its latest official inventory of greenhouse gas (GHG) emissions for the state of California (CARB, 2007a). For some sources, CARB directly used estimates on fuel use from CALEB; however, for other sources, CARB used their own estimates of fuel use and CO_2 emissions. CARB requested that LBNL undertake an assessment of CALEB to highlight uncertainties and areas of future development of the database.

Futhermore, at CARB's request, the original research contract for improving the characterization of California's CO_2 emissions was augmented to develop a disaggregated estimate of energy-related CO_2 emissions. CO_2 emissions are relatively well characterized at the State level; however no estimates were available at a more disaggregated spatial level. Understanding the CO_2 emission profile, finding ways of validating these on a sector-by-sector basis, and providing a validation approach to the statewide greenhouse gas emission inventory (EI) through disaggregation is an important service for building AB32 GHG EI baselines and projections. The results of this work were published in a LBNL separate report (de la Rue du Can and Wenzel, 2008).

The key areas of uncertainty related to CO_2 emissions include differences between various data sets, estimates of bunker fuel consumption for international transport, estimates of petroleum products used as feedstocks in refineries and chemical plants, and estimates of the carbon content of the various fossil fuels combusted in California.

An attempt was made to quantify some of the uncertainties where a secondary data set was available for comparison with data used in CALEB. Table ES 1 shows the distribution of state CO_2 emissions and rough estimates of their uncertainty by sector, for the year 2004. In this report only in-state CO_2 emissions from fuel combustion are considered; other GHG and CO_2 from electricity imports are excluded. CO_2 emissions from in-state electricity generation represent about 75% of total GHG emissions. A positive percentage in the table indicates that the current estimate of CALEB CO_2 emissions may be too low, while a negative percentage indicates that the current estimate may be too high. The estimated uncertainty for total CO_2 emissions ranges between -19 and +37 Mt, or -5% and +11% of total CO_2 emissions.

Table ES 1. 2004 CO_2 emissions from CALEB and percent uncertainty, by sector

Category	2004 emissions		Estimated uncertainty		
	CO_2 (Mt)	%	CO_2 (Mt)	% over each category total	% over total inventory
Electricity/CHP*	**62**	**18%**	**0.40**	**1%**	**0.1%**
coal	*4*	*1%*	0.47	*12%*	0.1%
petroleum products	*9*	*3%*	*-0.07*	*-1%*	-
natural gas	*49*	*14%*	-	-	-
Refining**	**29**	**8%**	-	-	-
Oil/gas extraction	**14**	**4%**	**4.00**	**28%**	**1.1%**
Industry feedstocks	**1.8**	**1%**	**±1.77**	**±100%**	**±0.5%**
Transportation	**177**	**51%**	***-8.04***	**-5%**	**-2.2%**
On-road vehicles	*167*	*48%*	*-7.17*	*-4%*	
Gasoline	*138*	*39%*	*-8.52*	*-6%*	-2.4 %
Diesel	*29*	*8%*	1.35	*5%*	0.4 %
Aviation	*3*	*1%*	*-0.84*	*-28%*	-0.2 %
Marine	*3*	*1%*		*-6%*	-
Rail	*3*	*1%*	*-0.03*	*-1%*	-
Other***	**66**	**19%**	-	-	-
Reconciliation errors	-	-	**-6.2 to 13.0**		**-2% to 4%**
Emission Factors	-	-	**-2.7 to 17.6**		**-1% to 5%**
Total	**350**	**100%**	**-18.7 to 36.8**		**-5% to 11%**

*Combined Heat and Power (CHP)
** Uncertainties with hydrogen production are not estimated
***includes emissions from other sectors such as other industry, residential, commercial/institutional, agriculture/forestry/fishing/fish farms and non-specified.

The table indicates that the largest uncertainties come from unresolved reconciliation errors between supply and consumption data (-2% to +4%), carbon emission factor uncertainties (-1% to +5%), gasoline use by motor vehicles (2%), and fuel use in upstream (+1.1%) oil and gas operations. There also are small uncertainties in emissions from fuel used as feedstock in chemical plants, fuel used in electric and Combined Heat and Power (CHP) plants, diesel used by motor vehicles, and fuel used for commercial aviation.

The largest uncertainty lies in reconciling statistics on fuel supply and consumption; available data do not match for most fuels. Many data gaps remain in accounting for total energy flows in California, especially for petroleum products such as natural gas liquids (NGLs), liquefied petroleum gas (LPG), or still gas. The second largest uncertainty comes from the use of national carbon emission factors as default factors, as no specific factors are available for the state of California. In terms of sectors, the transport sector represents a large source of uncertainty. Uncertainty in gasoline used by vehicles is estimated by comparing results from a bottom-up emissions inventory model (EMFAC) with total gasoline sales. The representation of combined heat and power (CHP) in the energy balance needs to be improved by allocating all energy used for commercial and industrial CHP to the sector where the generated electricity is used; all CHP energy use by facilities whose primary business is to sell electricity and heat should be allocated to the electricity generation sector. Finally, reported data on energy use in upstream oil and gas operations is lacking, as reflected in the uncertainties in Table ES-1.

Clearly understanding these uncertainties and developing new methodologies or data collection activities to reduce them can significantly improve the characterization of California's CO_2 emissions. We recommend that the California Air Resources Board (CARB) conduct surveys on key industries where data are missing or unreliable, mostly the refinery sector, the oil and gas industries and the chemical industries. Development of bottom-up models to estimate CO_2 emissions by sector would also help understand where energy is ultimately used. We recommend collaboration with the U.S. Energy Information Administration (U.S. EIA) and U.S. Environmental Protection Agency (U.S. EPA), who collect data and develop methodologies at the national level, in order to benefit from their work and experience. Finally, as the transport sector is such a large source of CO_2 emissions in California, further data collection is needed to better understand the trends in activity in this sector.

1. Introduction

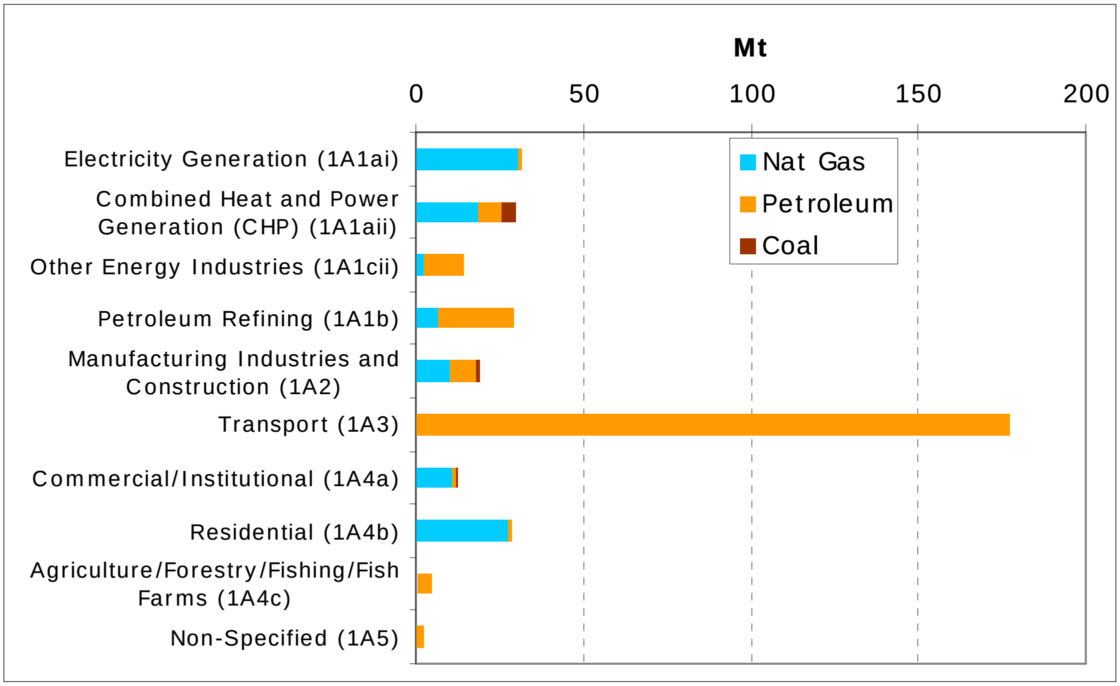
Analysts assessing energy policies and energy modelers forecasting future trends need to have access to reliable and concise energy statistics. Lawrence Berkeley National Laboratory (LBNL) evaluated several sources of California energy data, primarily from the California Energy Commission (CEC) and the U.S. Energy Information Administration (U.S. EIA), to develop the California Energy Balance Database (CALEB). This database manages highly disaggregated data on energy supply, transformation, and end-use consumption for each type of energy commodity from 1990 to the most recent year available (generally 2004) in the form of an energy balance, following the methodology used by the International Energy Agency (IEA). In addition to displaying energy data, CALEB also calculates state-level energy-related carbon dioxide (CO_2) emissions using the methodology of the Intergovernmental Panel on Climate Change (IPCC) (Murtishaw et al., 2005).

The California Air Resource Board (CARB) used the initial version of CALEB to construct its official inventory of greenhouse gas (GHG) emissions, published on line in November 2007 (CARB, 2007a). This report evaluates the areas where improvement to CALEB is needed and assesses uncertainties associated with CO_2 emissions accounting from the CALEB database. The key areas of uncertainty related to CO_2 emissions in CALEB include differences between various data sets, estimates of bunker fuel consumption for international transport, estimates of petroleum products used as feedstocks in refineries and chemical plants, and estimates of the carbon content of the various fossil fuels combusted in California. Clearly understanding these uncertainties and developing new methodologies or data collection activities to reduce these uncertainties can significantly improve the characterization of California's fuel consumption and CO_2 emissions.

This report qualitatively estimates the level of uncertainty related to emissions from fuel consumption in the CO_2 emissions estimates based on the CALEB database, investigates the development of new or improved methodologies for estimating the consumption of specific fuels for which data are scarce or unreliable, and provides recommendations regarding new data collection activities to improve the accuracy of fuel consumption and CO_2 emissions in California.

CO_2 emissions from fuel combustion are the principal GHG emitted in California. In 2004, CO_2 emissions from fuel combustion in California accounted for 80% of total emissions (CARB, 2007a). As fossil fuel is combusted, CO_2 is emitted as a result of oxidation of the carbon in the fuel. Figure 1 shows CO_2 resulting from fuel combustion in California from the California Inventory (CARB, 2007a).

Figure 1. 2004 Carbon Dioxide Emissions from Fuel Combustion in California, Million Metric Tons (Mt) CO_2



Source: CARB, 2007a

Note: Code indicated in parentheses refers to IPCC category associated with the source of emissions

Three energy commodities consumed in the economy produce CO_2 emissions: natural gas, oil, and coal. Figure 1 shows the relative importance of CO_2 emissions by product and sector. In California, the transport sector is by far the main source of CO_2 emissions resulting from fuel (petroleum) combustion, followed by the electric and CHP sector. However, it is worth noting that CO_2 emissions related to electricity imports (roughly 27% of supply) are not accounted for in this figure.

2. Uncertainties by Sector

2.1 Electricity and CHP Sector

The main purpose of an energy balance such as CALEB is to reconcile the supply and eventual use of each energy product. The transformation sector, which includes the energy used during the conversion of primary energy into secondary energy products, represents one of the largest sectors in the energy balance. Electricity generation is included in the transformation sector, where inputs of fuel are shown as negative values and outputs of electricity are shown as positive values. In the case of combined heat and power (CHP) facilities, the quantity of fuel to produce electricity is shown in the transformation sector while the quantity of fuel used to produce heat is shown in the sectors where the heat is ultimately used, and not in the transformation sector. Therefore, no data on heat output is shown in the transformation sector.

The electricity sector is disaggregated into five types of energy providers, following the U.S. EIA classifications currently used in the *Electric Power Annual* publications and data sets: utilities; integrated power producers (IPPs); combined heat and power (CHP), electric power sector; CHP, industrial sector; and CHP, commercial sector. The category “CHP, electric power sector” includes facilities whose primary business is to sell electricity, or electricity and heat, to the public; i.e. North American Industry Classification System (NAICS) category 22 plants. The data is shown by four fuel input categories: coal, natural gas, other gases and total petroleum products.

2.1.1 Data Sources

In the CALEB database, data on fuel consumption by provider type come from the U.S. EIA’s *Electric Power Annual* (U.S. EIA, 2007). The U.S. EIA collects the information through questionnaire EIA-906 for electric power plants and EIA-920 for CHP facilities. Prior to 2004, the EIA-906 form was also used to collect data from CHP plants. In January 2004, a new form, the EIA-920, was introduced to collect data from CHP plants only. The reporting is mandatory for all power plants with a nameplate rating of 1 MW and above that are connected to the electric grid[1]. Table 1 shows the data reported in U.S. EIA’s *Electric Power Annual* and used in the CALEB database for 2004.

Table 1. Fossil Fuel Consumption for Electricity and Heat Generation by Industry Type, 2004

(TBtu)	Coal	Petroleum	Natural Gas	Other Gases
Total Electric Power Industry	**27**	**24**	**887**	**21**
Electric Utilities		1	102	
Independent Power Producers		13	455	
CHP, Electric Power	22	8	173	1
CHP, Commercial Power		0	16	
CHP, Industrial Power	5	2	142	20

Source: U.S. EIA, 2007

2.1.2 Uncertainties

There are mainly two shortcomings in the representation of the power sector and CHP in the CALEB database.

Fuel Input Breakdown

One of the shortcomings of the current CALEB database is that it does not provide a breakdown of fuel inputs beyond the four categories that are directly available from the U.S. EIA’s Electric Power Annual (i.e. coal, natural gas, other gases and petroleum products). Disaggregated data by petroleum product (distillate fuel oil, residual fuel oil, petroleum coke, and waste and other oil) are available at the facility level for non-utility plants on the U.S. EIA website, starting in 1998 only. This disaggregation could be

[1] Beginning for reporting year 2007, the EIA-906 and EIA-920 forms were replaced by combined form EIA-923 “Power Plant Operations Report.

integrated in future versions of CALEB. In the case of "other" gases, defined as "blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels", no more detail is available. This lack of detail reduces the accuracy of calculating CO_2 on a product basis and also reduces the ability to balance each energy product between supply and consumption, which is the essence of an energy balance. We propose to disaggregate petroleum used by electricity generation/CHP facilities by distillate fuel oil, residual fuel oil, petroleum coke, and waste and other oil in future versions of CALEB.

CHP representation

The second weakness of the CALEB database concerns the treatment of energy used solely to produce heat in CHP plants. In CALEB, fuel used to generate electricity is shown in the transformation sector, while fuel used to produce heat is shown in the end-use sector where the heat is ultimately used (commercial and industrial sectors).

In the case of natural gas, end-use data were taken from the CEC (CEC, 2005) which do not include input of natural gas for heat production from CHP plants. In order to adjust for these quantities of natural gas consumed for the useful thermal output of CHP in the end-use sectors, the amounts of natural gas used by individual CHP facilities solely to generate heat were gathered from the U.S. EIA *Form 906/920 Databases* (U.S. EIA, 2007b). However, these data are only available for non-utility facilities starting in 1998 (Table 2). Therefore, in CALEB, data for natural gas for useful thermal output (UTO) from CHP facilities from 1990 to 1997 are not included in the end-use sectors in which the heat was ultimately used. This represents an omission of 4 to 9 Mt CO_2, based on data from the period 1998 to 2004 when data are available.

Table 2. Natural Gas Used for Useful Thermal Output

Unit	1998	1999	2000	2001	2002	2003	2004
MMcf	119,735	88,535	154,321	158,794	165,561	142,317	71,698
Mt CO_2	6.63	4.90	8.54	8.79	9.17	7.88	3.97

Source: U.S. EIA, 2007b

Data on coal energy consumption comes from the U.S. EIA *Annual Coal Report* (U.S. EIA, 2005a) which includes all coal used by CHP facilities in three sectors: industrial, commercial and electric power sectors. The U.S. EIA report does not distinguish whether fuel inputs are used to generate electricity or heat. In CALEB, coal use to produce electricity is reported in the transformation sector with data from the U.S. EIA *Electric Power Annual* (U.S. EIA, 2007a). Coal use in the end-use sector comes from the U.S. EIA *Annual Coal Report* without adjusting for coal use to produce electricity. Therefore the data on final consumption includes coal use in industrial CHP facilities to produce electricity, which is already accounted in the transformation sector, and excludes coal use in NAICS category 22 CHP facilities to produce heat, which is included in the electric power sector in the U.S. EIA *Annual Coal Report.* As coal from industrial CHP to produce electricity is larger than coal used by NAICS category 22 CHP plants use to produce heat, CALEB is overestimating coal consumption in the final sector by 206 thousand of short ton of coal, which represents 0.47 Mt CO_2 in 2004. Over the year, the difference ranges by month from 0.14 Mt CO_2 to 0.71 Mt CO_2.

In the case of petroleum products, data for final consumption in CALEB comes from diverse sources. For distillate fuel oil and residual fuel oil, data come from U.S. EIA's "Sales of Fuel Oil and Kerosene" report (U.S. EIA, 2007c). Energy use for commercial and industrial CHP facilities is also reported in the commercial and industrial sectors, while the electric power sector includes energy used by NAICS category 22 CHP plants. For petroleum coke, CALEB only reports final energy use consumption from cement plants (USGS, 2007), and includes all energy use by CHP plants. Petroleum coke is also used by refineries for their own use, which is reported in the energy sector in CALEB.

Overall, the reconciliation of many different data sources to represent a full picture of energy use in the power sector and in the end-use sectors has lead to some uncertainties in understanding what exactly is included in each sector. Residual fuel oil, distillate oil and coal used for electricity production from industrial and commercial CHP facilities are overestimated, as quantities used to produce electricity are accounted for in both the power sector and the end use sector. On the other hand residual fuel oil, distillate oil and coal used for heat production by NAICS category 22 CHP facilities are not included in either the power sector or the end use sectors. Finally, in the case of natural gas, data before 1998 does not account for energy use for UTO production in the end use sectors.

2.1.3 Alternative Sources/Methods and Recommendations

The representation of CHP in an energy balance is a complex matter, as attention needs to be taken to ensure that no double-counting occurs. In the CALEB database, more evaluation of each data point for each energy product type in each subsector needs to be carried out. Uncertainties lie in the accounting of CHP as part of the end use sectors or as part of the power sector for the energy used for heat and for electricity production.

In the future, we recommend that all the energy used by industrial and commercial CHP facilities be included in the appropriate end use sectors. This is consistent with the 2006 IPCC guidelines on GHG inventories. Moreover, all energy used by CHP NAICS category 22 facilities will be included in the transformation sector, with fuel input shown as a negative value, and electricity and heat output shown as a positive value. This adjustment to CALEB will also require that data on heat output by end use be collected, to indicate where the heat produced by CHP NAICS category 22 plants is ultimately consumed.

Furthermore, we recommend collaborating with the U.S. EIA team that processes the U.S. EIA *Annual Power database*. Several attempts were made to obtain data before 1998 on natural gas consumption by individual non-utility facilities, but with no success. Also, data by fuel type can potentially be obtained by the U.S. EIA. For its latest inventory, CARB obtained the most detailed data from U.S. EIA, via a special data request. We hope that to obtain the same detailed data in the future to update the CALEB database.

Overall, we estimated that the uncertainties with data used in CALEB may underestimate CO_2 emissions from coal used by 0.47Mt of CO_2 (0.1% of total CO_2 emissions) and overestimate CO_2 emissions from oil by 0.07Mt of CO_2 (negligible compared to total CO_2)

2.2 Refinery Sector

CO_2 emissions from refineries originate from three main sources: fuel combustion, fugitive sources and industrial processes. Fugitive emissions are broadly defined as all GHG emissions from oil and gas systems except from fuel combustion (IPCC, 2006). Industrial process emissions occur from production processes where CO_2 is a by-product of chemical reactions. Estimates of the uncertainty of fugitive and industrial process emissions are outside the scope of this report.

2.2.1 Data Sources

Fuels used in refineries are shown in the transformation and energy sectors of CALEB. **The transformation sector** shows inputs of crude oil, unfinished oil and additives[2] as negative numbers, and outputs of each petroleum product as positive numbers. Input and output data are from the CEC (*Yearly Input and Output at Refineries*, CEC 2006a) reported through form U.S. EIA 810. Table 3 shows fuel inputs to refineries. When calculating CO_2 emissions, the transformation of crude oil and feedstocks into petroleum products does not involve combustion, so no CO_2 emissions from fuel input are accounted for in CALEB. However, this process does result in fugitive CO_2 emissions.

Table 3. Input to California Refineries in 2005 (kbbl)

Inputs	kbbl
Crude Oil	672,032
Butane	1,729
Isobutane	2,380
Other Hydrocarbons, Hydrogen and Oxygenates	10,718
Unfinished Oils	27,191

Source: CEC 2006a

The energy sector shows the consumption of energy needed to operate refineries. In CALEB, this is shown in the sub-category “Energy Sector: Own Use” and data for refineries come from the CEC *Ca* Petroleum Industry Information Reporting Act *lifornia Refinery Monthly Fuel Use Report Form M13* (CEC, 2006b. Table 4 shows data reported in M13 for 2005. Fuels used in this category were assumed to be entirely combusted.

[2] Additives includes the category called “Other hydrocarbons, hydrogen and Oxygenates” from EIA 810.

Table 4. CEC Form M13 Report, 2005

Description		
Distillate Fuel Oil, Used As Refinery Fuel	kbbl	155
Liquefied Petroleum Gases, Used As Refinery Fuel	kbbl	1,706
Natural Gas, Used As Refinery Fuel	MCf.	132,707
Still Gas, Used As Refinery Fuel	kbbl	40,795
Marketable Petroleum Coke, Used As Refinery Fuel	kbbl	1,660
Catalyst Petroleum Coke, Used As Refinery Fuel	kbbl	11,675
Purchased Electricity	GWh	3,107
Purchased Steam	k LBS	12,508
Other Fuel Used at Refinery 1	Varies	4

Source: CEC, 2006b

2.2.2 Uncertainties

One of the main uncertainties when collecting energy use for the refinery sector is the determination of how much energy is used for different purposes. CO_2 emissions are estimated differently if the quantity of fuel used is consumed for its heating value or for its chemical proprieties, i.e. whether it is burned or used as a feedstock for the production of other products.

Refinery Fuel Input

Crude oil intake into California refineries was taken from aggregated numbers from the Petroleum Industry Information Reporting Act (PIIRA) database provided by the CEC (*Yearly Input and Output at Refineries*, CEC 2006a). Another Energy Commission data set (*Oil Supply Sources to California Refineries,* CEC 2006c) provides alternate figures for crude oil receipts by source. Those figures tend to be from 1% to 3% higher than the figures reported in the *Yearly Input and Output at Refineries* report. For the year 2005 for example, the *Yearly Input and Output at Refineries* report shows 672,032 kbbl of crude oil intake while the *Oil Supply Sources to California Refineries* report shows 674,276 kbbl.

Data on butane, isobutene, other hydrocarbons and unfinished oils (see Table 3), as well as specific petroleum products, are provided by the Energy Commission based on the U.S. EIA report 810 submissions (*Yearly Input and Output at Refineries*, CEC 2006a). Due to the complexity of the refining industry, some products are reported as both input and output. In order to avoid double counting, LBNL subtracted the reported outputs from inputs so that only net inputs are shown. However, no specific information is available to differentiate inputs that are used in the refining process from feedstocks used to produce hydrogen (see next section). Also, no conversion factor or carbon content is provided or detailed information that described these inputs to allow the use of precise energy conversion and carbon content factors.

Fuel Use for Industrial Process - Hydrogen Feedstocks

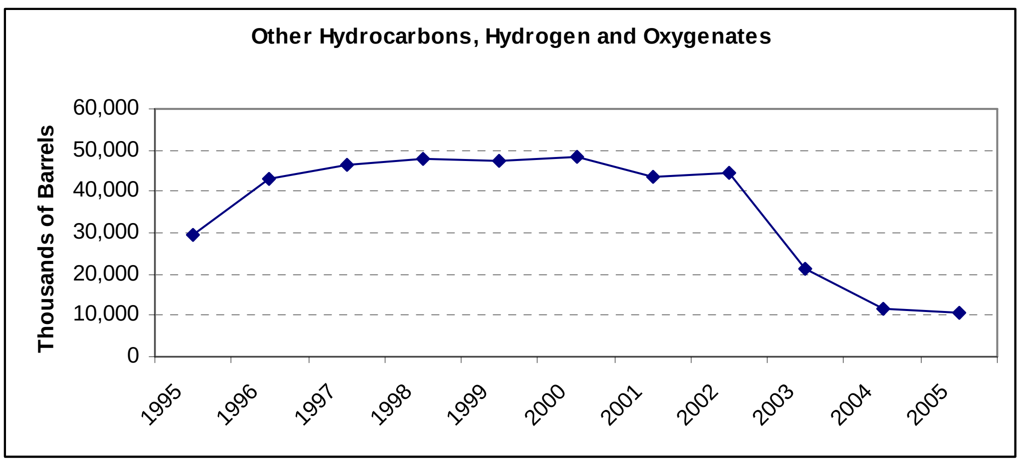
The production of hydrogen in California is growing rapidly as it allows oil refineries to meet limits on sulfur content in refined fuels. Because most of the refineries are switching to heavier crude oil, increasing amounts of hydrogen are needed to strip the sulfur and to crack the hydrocarbons. Demand is met by own production from refineries and also by independent industrial hydrogen plants (Ritchey, 2006). The production of hydrogen results in CO_2 emissions from a chemical reaction. Feedstocks used in California to produce hydrogen include natural gas, LPG, naphtha, and refinery fuel gas. Emissions associated with hydrogen production for use in refining activities needs to be included in refinery activities and not in the petrochemical manufacture sector. Care should be taken to ensure that the feedstock for the hydrogen plant is not also reported as fuel combustion, and vice versa.

Inputs of fuel in refineries, reported by the CEC (CEC 2006a) includes a category called "*Other Hydrocarbons, Hydrogen and Oxygenates*" which is defined as followed:

> "Other Hydrocarbons, Hydrogen and Oxygenates: Materials received by a refinery and consumed as a raw material. Includes hydrogen, coal tar derivatives, gilsonite, oxygenates and natural gas received by the refinery for reforming into hydrogen. Natural gas to be used as fuel is excluded." (U.S. EIA Form 810)

These quantities are reported as input to refineries in CALEB and are shown under the product category "Additives". However, data reported over time in this category is decreasing, which is going against the observed trend of increasing hydrogen production. Figure 2 shows the time series for the category *Other Hydrocarbons, Hydrogen and Oxygenates*.

Figure 2. Other Hydrocarbons, Hydrogen and Oxygenates from U.S. EIA 810



More information is needed to differentiate the type of feedstock used in the refinery sector. Hydrogen feedstock and production needs to be clearly stated, as estimation of CO_2 emissions will differ depending on whether natural gas, refinery fuel gas, LPG or naphtha is used as the feedstock.

Fuel Combusted

A significant portion of the energy products in a refinery is used for process energy. Fuel use reported by refineries to the CEC in form M13 (CEC, 2006b) was assumed to represent the fuel used for the energy production process and entirely combusted.

The instructions for the M13 refinery questionnaire are limited[3] and a better understanding of the coverage of fuel reported in this data set is needed. The accounting of fuel use in the production of hydrogen is a major uncertainty. It is not clear if form M13 includes fuel use by hydrogen plants for energy purposes. Moreover, a growing number of independent hydrogen merchants are producing hydrogen outside refinery facilities. The amount of energy used by these industries is unknown.

Uncertainties concerning fuel used by refineries also includes the use of conversion factors. Since refinery fuel gas is a highly variable source of CO_2 emissions across refineries, a conversion factor specific to California refineries needs to be calculated. Similarly, petroleum coke is provided under two different items: marketable petroleum coke and catalyst petroleum coke; however no specific energy and carbon factors are available to better account for these products.

Finally, consumption of natural gas by refineries is also available from a different source: the CEC collects data from utilities on natural consumption disaggregated by SIC/NAICS codes (CEC, 2005). Table 5 shows data from the CEC M13 and the CEC SIC/NAICS code. Data from the two sources differ over time. According to experts, some of the difference is explained by the fact that the CEC M13 not only includes pipeline quality natural gas, but also lease fuel gas or associated gas. A better understanding of what each category accounts for is needed. In CALEB, data from M13 is reported in the energy sector and the difference, when data from the CEC SIC/NAICS are higher, is reported as input to refineries.

Table 5. Natural Gas Consumption in Refineries

Mcf	Source	1990	1995	2000	2004
Petroleum and Coal Products Manufac.	CEC SIC-NAICS	80,035	103,475	148,134	136,061
Refinery Fuel	M13	91,972	89,402	121,401	129,338

Combined Heat and Power (CHP) Plants

As mentioned earlier, little is known on the fuel use reported by CEC M13 from the instruction form that complements the data collection. Hence, concerns were raised that CALEB was double-counting fuel consumption in refinery CHP facilities in cases where CEC M13 forms were including this energy use. CALEB already reports energy use for electricity production in CHP in the electricity sub-sector with data reported by the U.S. EIA *Annual Power* database (U.S. EIA, 2007a).

However, during their work on the inventory, CARB staff determined that the CEC M13 form does not include fuel used in CHP.

[3] CEC-M13 Instructions:
"The CEC Form M13 is used to collect data on fuel, electricity, and steam consumed for all purposes at the refinery. Refiners in the state of California are required to file this report."

2.2.3 Alternative Sources/Methods and Recommendations

In its latest inventory, ARB used data obtained from the *Journal of Oil & Gas* to estimate the amount of hydrogen generated by refineries each year. From this, they back-calculated the CO_2 released and estimated the fuel input needed (natural gas, refinery gas, naphtha or residual oil) to generate this hydrogen. Access to these data would help LBNL would improve their estimate; LBNL intends to follow the same methodology when it updates the CALEB database.

However, the issue remains as some refineries report natural gas used in hydrogen production in the CEC M13 data set. With increasing production and use of hydrogen, it is becoming necessary to collect data that allow for the accounting of process emissions associated with hydrogen production, as well as to make sure that energy used for energy purposes are included in CALEB. In the future, mandatory reporting from refineries will resolve these issues.

In this report, we did not estimate uncertainties with hydrogen production as too little information is available. In future versions of CALEB, the potential of using data from the *Journal of Oil & Gas* will be assessed[4] as well as the possibility of using mandatory reporting from refineries in future years,

2.3 Oil and Gas Extraction Industries

2.3.1 Data Sources

Oil and gas extraction energy use covers the energy used for pumping and processing crude oil as well as extraction of natural gas and natural gas liquids (NGL). In California, the quantities of energy used for oil and gas extraction tend to be exceptionally high due to the use of thermally enhanced oil recovery process (TEOR). TEOR uses large amounts of natural gas to heat crude oil to render it less viscous. Natural gas use for oil and gas extraction grew from 190 Bcf in 1990 to 295 Bcf in 2001 (Murtishaw, 2005).

Main data sources in CALEB:

Natural gas consumption is taken from the CEC disaggregated data on natural gas consumption by SIC/NAICS code (NAICS category 211 and 213) (CEC, 2005) to which was added data on CHP fuel input to produce heat[5] from U.S. EIA 906/920 compiled at the facility level for the years 1996 to 2004 (U.S. EIA, 2007b).

Petroleum Products: data from the U.S. EIA *Annual Fuel Oil and Kerosene Report*[6] (U.S. EIA, 2007c) were used, subtracting the value obtained by the M13 form on refinery fuel use already accounted for under the category "refinery". The U.S. EIA *Annual Fuel*

[4] We have inquired in the past about the possibility of obtaining data from the *Journal of Oil & Gas*, but were refrained by the cost. However, as it seems to be the only publicly available source of data on hydrogen production, we will work with CARB and the journal staff to get these data for future CALEB updates.

[5] In CALEB, the energy use for electricity production in CHP is shown under the electricity sub-sector in the transformation sector while the energy use for heat production appears in the end use sectors directly.

[6] Energy Information Administration, Form EIA-821, "Annual Fuel Oil and Kerosene Sales Report"

Oil and Kerosene Report publishes statistics on distillate fuel, residual fuel and kerosene fuel oil used by each oil company, defined as the company's own use for operations in drilling equipment, use at the refinery, exploration company, oil drilling company, and pipeline company, but excluding feedstocks.

Table 6 shows the energy used in oil and gas extraction sector as estimated in CALEB.

Table 6. Oil and Gas Extraction Energy Use as Estimated in CALEB

	Unit	1990	2000	2004
Distillate Fuel Oil	kbbl	493	233	297
Fuel Oil	kbbl	27	0	0
Natural Gas	Bcf	191	297	267

Note: 1990 do not include natural gas for producing heat from CHP, in 2000 and 2004, these amounts to 19 and 13 Bcf respectively.

2.3.2 Uncertainties

No comprehensive data set showing all fuel types used for oil and gas extraction is collected at the state or national level. Hence CALEB gathers data from several different sources, increasing the risk of coverage issues. This is a particularly important issue as a considerable amount of energy is used for TEOR in California. A review of the CALEB data for oil and gas operations in a Western States Petroleum Association (WSPA) Memo to CARB (Lev-On, 2007) indicates omissions of crude oil and associated gas consumed at upstream operations for steam generation and other combustion needs. According to this memo, emissions from the use of crude oil not captured in the CALEB database contributed up to 4 Mt CO_2 in 1990, but appear negligible for 2000 and 2005. Emissions from the combustion of associated gases not captured in the CALEB database may contribute up to 4 Mt CO_2 for 2004.

2.3.3 Alternative Sources/Methods and Recommendations

Natural Gas

Alternative data on natural gas consumption is available from the U.S. EIA *Natural Gas Navigator* database (2008).

Table 7 shows natural gas used for processing oil and gas in California from the U.S. EIA *Natural Gas Navigator* database. These data were not included in CALEB to avoid double-counting with CEC disaggregated data on natural gas consumption by SIC/NAICS code (code category 211 and 213), which provides much higher numbers. In 2004, the CEC data shows 267 Bcf natural gas used in oil and gas extraction, while the U.S. EIA shows only 62.5 Bcf (

Table 7).

Table 7. Use of Natural Gas in Oil and Gas Extraction (Mcf)

	2004	**2005**	**2006**	**Definitions**
Re-pressuring	22,405	29,134	29,001	Injection of gas into oil or gas reservoir
Lease Fuel Consumption	37,337	37,865	33,211	Natural gas used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors.
Gas Plant Fuel Consumption	2,760	2,875	2,475	Natural gas used as fuel in natural gas processing plants.
Total	62,502	69,874	64,687	

Source: U.S. EIA *Natural Gas Navigator* (U.S. EIA, 2008a)

More information is needed to understand how natural gas use by oil and gas companies is reported in the CEC data set. In the case of oil and extraction, consumption of natural gas can be injected to re-pressure oil or gas reservoir formations, or burned to produce steam that will serve to liquefy the heavy crude oil extracted. This implies different CO_2 emissions accounting.

Associated Gas, Crude Oil and Distillates

NGLs consumption in CALEB includes input to refineries under the transformation sector, based on data from the CEC (CEC 2006a) and data on industrial consumption from API (API, 2002). However, considerable statistical difference exists between NGL supply and demand, with consumption and/or exports totaling much less than production. This was noted in the 2005 CALEB report as an area for future improvement (Murtishaw, 2005). One possible source of NGL consumption is the use of NGL directly by oil companies in their oil and gas extraction processes.

In its inventory, CARB uses data from the Division of Oil, Gas, and Geothermal Resources (DOGGR) of the California Department of Conservation to determine how much crude oil, lease fuel and distillate are used in this sector. For years prior to 2001, when DOGGR data were not available for lease fuel use, U.S. EIA data were used, as recommended by the DOGGR.

Emissions from the combustion of associated gases not captured in the CALEB database may contribute up to an additional 4 Mt CO_2 for 2004.

2.4 Industry Feedstocks

Some of the fuel supplied to an economy is used as raw material (or feedstock) for the manufacture of products such as plastics and fertilizer. In some cases, the carbon from the fuels is oxidized quickly to CO_2; in other cases, the carbon is stored (or sequestered) in the product, sometimes for as long as centuries. Hence, this use of energy products has a different accounting methodology in terms of carbon emissions. The carbon balance for non-energy use is complex. The amount of carbon stored is calculated by multiplying the potential emissions of each fuel used as a feedstock by a fuel specific storage factor. This requires collecting information on both the energy use and non-energy use of fuel in the chemical industry, as well as collecting data on the type of chemicals produced to determine the storage factors.

The chemical industry is an important part of the California economy that has increased at an annual average growth rate (AAGR) of 7.5% from 1997 to 2006 (Table 8). The California chemical industry includes a very wide mix of products. The dominant chemical sub-sector in California is pharmaceuticals, representing 62% of shipments in the California chemical industry in 2006, with an average annual growth rate of nearly 13% since 1997.

Table 8. Chemical Manufacturing Value of Shipments in California (in millions of dollars)

NAICS		1997	2006	AAGR
325	**Chemical mfg**	**19,303**	**36,922**	**7.5%**
3251	Basic chemical mfg	2,664	2,621	-0.2%
3252	Resin, syn rubber, & artificial syn fibers & filaments mfg	1,100	1,414	2.8%
3253	Pesticide, fertilizer, & other agricultural chemical mfg	502	840	5.9%
3254	Pharmaceutical & medicine mfg	8,006	23,075	12.5%
3255	Paint, coating, & adhesive mfg	2,272	3,218	3.9%
3256	Soap, cleaning compound, & toilet preparation mfg	2,965	3,733	2.6%
3259	Other chemical product & preparation mfg	1,794	2,019	1.3%

Source: US Census, 2006;

Most of the chemical manufacturing in California consists of industrial gas production (hydrogen, nitrogen, oxygen, argon), dyes and pigments, and other basic inorganic chemical manufacturing, which includes products such as bleach, borax, sulfuric acid, plating materials, high temperature carbons and graphite products and catalysts (Galitsky and Worrell, 2005).

2.4.1 Data Sources

Natural Gas

- *Energy Use Chemical Industries:* the CEC maintains a database on natural gas consumption at three different levels of aggregation (CEC, 2005). The most detailed data are at the 3- to 4-digit NAICS category level. These values do not include the shares of natural gas used for CHP-generated heat, which were added from the U.S. EIA 906/920 database (U.S. EIA, 2007b) as explained in Section 2.1.

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- Table 9 shows natural gas consumption in the chemical industry at the 4th digit level.

Table 9. 2004 Natural Gas Consumption in Chemicals Plants in California (Mcf)

Category	**NAICS 4 digit Category**	**Source**	**Mcf**
3251	Basic Chemical Manufacturing	CEC	4,617
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers	CEC	1,023
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	CEC	752
3254	Pharmaceutical and Medicine Manufacturing	CEC	3,700
3255	Paint, Coating, and Adhesive Manufacturing	CEC	324
3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing	CEC	391
3259	Other Chemical Product and Preparation Manufacturing	CEC	384
NS	Heat production in CHP	U.S. EIA	1,495

NS: Not Specified
Source: CEC, 2005; U.S. EIA, 2007b

- *Non-Energy Use:* The portion of natural gas that is used as feedstock is unknown. However, these data are available at the national level from U.S. EPA National US Inventory (U.S. EPA, 2008). In order to estimate the portion that was used in California, we calculated that California accounts for 3% of the total US shipments of basic chemical and fertilizer products in 2001, and applied this share to the total natural gas used for non-energy use in the US chemical industry. As a result we estimate that 10.2 TBtu of natural gas were used as feedstocks in producing basic chemical and fertilizer products in California in 2001. The share of natural gas used as feedstock to total natural gas used in the chemical industry was then calculated (47%) and applied to other years. Table 10 summarizes our estimates for non-energy use of fuel in the chemical industry for California for 2000.

Table 10. Non-Energy Use of Fuel in 2000 (TBtu)

	Natural Gas	LPG	Petrochemical feedstocks
Chemicals and Allied Products	25	13	11
of which used as feedstoks	12	13	11
Storage Factors	91%	91%	54%

- *Carbon Stored:* the storage factor for natural gas (91%) comes from the inventory of California greenhouse gases and sinks (CEC, 2002), which is higher than the national storage factor (67%).

Petroleum Product

- *Energy Use in Chemical Industries:* data for LPG and petrochemical feedstock consumption by end-use sector were taken largely from *State Energy Data System* (SEDS, U.S. EIA, 2007d), since it provides a comprehensive set of data for ten categories of petroleum products. However no breakdown by sub-sector is available. Moreover, as SEDS only provides data with a four-year delay, different sources were used for more recent years. For LPG, consumption estimates were provided by the U.S. EIA (Lindstrom, 2008) which are based on data from the *American Petroleum Institute* (API). Data on petrochemical feedstock consumption were taken from SEDS and assumed to be entirely consumed in the chemical industry sub-sectors. When data were not available for recent years, we estimated consumption based on the same principle used in SEDS: allocating the total US consumption to the states according to the value-added of their organic chemical industries.

- *Non-energy Use*: we assumed LPG and petrochemical feedstocks to be entirely consumed for non-energy purposes.

- *Carbon Stored:* the storage factor for LPG (91%) and for petrochemical feedstocks (54%) came from the inventory of California greenhouse gases and sinks (CEC, 2002). The storage factor for LPG is higher from the national storage factor (66%), while the storage factor for the petrochemical feedstock is lower than the national storage factor (66%).

2.4.2 Uncertainties

CO_2 emissions from the chemical industry represent 0.5% of the total CO_2 emissions in California. However, the chemical industry in California accounted for 8.2% of industry natural gas consumption and 17% of industry petroleum product consumption.

Complex Accounting

There is no easy method to estimate CO_2 emissions for the chemical industry. The chemical industry is a very complex industry that produces a wide range of products. It is divided into seven broad categories under NAICS category 325, which are further broken down into multiple subcategories that include over 1,000 products. The basic chemical industry is the most energy-intensive segment, and also the most diverse, within the chemical industry. This industry sector alone accounts for nearly 50% of the chemical sector's total energy use in California. In many instances basic chemicals are utilized as inputs in the production process of other industries.

The difficulties in gathering data are many. First, data on energy consumption by fuel type need to be available by industrial subsector. This is the case for natural gas, but not for other petroleum products. Second, data on the share of this energy use needs to be broken down further to define the quantity used as feedstock to the chemical process, as opposed to the quantity of fuel combusted. Finally, depending on the type of chemical produced, a percentage of the fuel used as feedstock will be stored in the product or emitted. This percentage also needs to be estimated.

Lack of Information

Uncertainties relating to the CO_2 emissions from energy use in the chemical industry come principally from a lack of available data. First, data on energy use by industrial subsectors is only available for natural gas. Second, the share of the energy use for non-energy purposes, i.e. as feedstock, is not available. Finally, production of the different chemical outputs produced is not available, which makes it difficult to estimate the storage factors. Import and export of feedstocks to the state are also crucial.

At the national level, the *Manufacturing Energy Consumption Survey* (MECS, U.S. EIA, 2005b) collects data on energy use at the sub-sectoral level. The survey also specifically requests participants to report on energy used for purposes other than for heat, power, and electricity generation (feedstocks). MECS provides this information only for four regions[7], and not at the state level, and with an increasing level of data withheld for confidentiality reasons.

The *Annual Survey of Manufacturers* (U.S. Census, 2005) provides information about the quantities of chemicals produced, but only at the national level. This allows the assessment of the types of chemicals produced in the US, for which carbon storage is calculated.

Storage factors

The CEC calculated storage factors for California in 1999; however, neither the time nor the resources were available to conduct a thorough survey. Moreover, this was the first attempt to conduct an inventory for the state and many other issues were also at stake.

The U.S. EPA national inventory calculates annually a single aggregate storage factor for eight fuel feedstocks. For 2006, the storage factor was 62%, meaning that 62% of the net non-fuel use was destined for long-term storage in products, while 38% was emitted to the atmosphere directly as CO_2 (U.S. EPA, 2008). The approach to estimate this factor is based on identifying the commodities derived from petrochemical feedstocks, and calculating the net import/export for each.

A similar approach needs to be done for California in order to improve CO_2 emissions accounting for the state. However, this requires access to data that currently are not collected.

2.4.3 Alternative Sources/Methods and Recommendations

The need for data on energy use in the chemical industry, on energy use as feedstock, on quantity of chemical output produced, and on feedstock trade movement, is essential to improve the accounting of CO_2 emissions for the chemical industry.

[7] Northeast, Midwest, South and West; the West region includes California.

A survey of the major chemical plants in California involved in the production of chemical material that require feedstocks would be a beneficial input. It would help provide data on the quantity of energy used as feedstock and the major chemical outputs produced.

We estimate the uncertainty of all feedstocks combined as 1.8Mt of CO_2, or 0.5% of total CO_2. This number corresponds to the total CO_2 emissions from natural gas. LPG and petroleum feedstocks used in the chemical industry, without including energy use for CHP. Data are not available to estimate California specific energy use and storage factors for individual feedstocks.

2.5 Transportation

Transportation is the major source of CO_2 emissions in California, with on-road vehicles representing 94% of all transportation emissions. The estimation of CO_2 emissions from mobile sources is challenging, as fuel sales are very decentralized and end users are mobile rather than stationary sources.

2.5.1 Data Sources

We used U.S. EIA *State Energy Data System* (U.S. EIA, 2007d) data for California fuel sales by fuel type. U.S. EIA uses several state-level data series to allocate total national product supplied, reported in *Petroleum Supply Annual* (U.S. EIA, 2008b), to the states.

U.S. EIA conducts three surveys to track the monthly sale of petroleum-based fuels: EIA-782A, a survey of all (100) refiners and gas plant operators; EIA-782B, a survey of a sample (27,000) of fuel resellers and retailers; and EIA-782C, a survey of all (170) prime suppliers that produce, import or transport a refined petroleum product across state borders. Data from all three surveys are reported at the state level in U.S. EIA's *Petroleum Market Annual* series (U.S. EIA, 2008c).

The volumes reported nationally and for each state vary among the three surveys for several reasons: EIA-782A reports sales at the point of production, whereas EIA-783C reflects sales at the point of likely consumption. Therefore, states with major refining operations, such as California, have higher reported sales in EIA-782A (at the point of production) than in EIA-782C (at the point of eventual use). In addition, EIA-782C also includes fuel imports by firms that are neither refiners nor gas plant operators; such imports are not included in volumes reported in EIA-782A (U.S. EIA, 2008c).

The fuel sales reported by prime suppliers (EIA-782C) is substantially lower than total product supplied (EIA-782A), for a variety of reasons. For example, the prime supplier data does not include sales of bonded jet fuel for international flights. Also, to the extent that airlines import their own jet fuel, the prime supplier sales would not capture those sales since an airline is not considered a prime supplier. In addition, diesel fuel may get 'winterized' by adding jet fuel later down the supply chain before a sale. As a result, the product supplied data would classify the product as jet fuel whereas the prime supplier would report it as diesel fuel (Heppner, 2008). In SEDS the total national product supplied (EIA-782A) is allocated to states using the detailed state level data from fuel resellers and retailers (EIA-782B) and prime suppliers (EIA-782C).

U.S. EIA further disaggregates total annual sales by end use. In SEDS, motor gasoline and distillate (diesel) fuel used for on-road vehicles is allocated to states using Highway Statistics Table MF-21 (FHWA, 2007), which is based on state reported fuel tax receipts. Jet fuel is allocated to the states using *Petroleum Marketing Annual* (PMA) sales by prime suppliers (EIA-782C), which is reported by state. Diesel fuel used for railroads and vessel bunkering, and residual fuel used for vessel bunkering, are allocated to states using EIA-821 "*Annual Fuel Oil and Kerosene Sales Report*". EIA 821 is a mandatory reporting questionnaire sent to companies that sell fuel oil and kerosene to gather information on quantity sold to the different end uses.

According to IPCC guidelines, fuels consumed for international maritime shipping as well as international aviation should be excluded from national inventories (IPCC, 1996). However, in the IEA energy balance format, aviation fuels consumed for both international flights and domestic flights are also reported as separate items. Murtishaw et al. (2005) describes the methodology used to estimate this breakdown of marine and air transportation to intrastate, interstate, and international destinations. About 95% of California's 2000 transport-sector residual fuel consumption is allocated as international marine bunker fuel. For the remaining 5% of 2000 transport-sector residual fuel, 3.5% was used by interstate marine shipping, while only 1.5% was consumed by intrastate marine shipping. Distillate fuel use by ocean-going vessels was estimated by applying a ratio of 0.06 gallons of distillate fuel for every gallon of residual fuel used, resulting in an estimate of 2.2 million barrels of distillate used by ocean-going vessels. We applied the same interstate and intrastate breakdown for ocean-going vessels that we used for residual fuel, resulting in 2.1 million barrels distillate fuel for international, 0.07 million barrels for interstate, and 0.03 million barrels for intrastate shipping by ocean-going vessels. Based on U.S. EIA data, there were an additional 1.6 million barrels of distillate fuel used by non-ocean-going (i.e. commercial harbor craft and personal recreational) vessels, which we allocated to intrastate shipping. Of the distillate fuel consumed by all marine vessels, we estimated that 55% were consumed by international marine activity, 43% by intrastate activity, and the remaining 2% by interstate activity.

Concerning air transport, CALEB estimated that 39.9% of California's 2000 jet fuel consumption was for international flights, 52.7% was for interstate flights, and 7.4% was for intrastate flights, using the EEA's aircraft movement methodology (Murtishaw et al., 2005; EEA, 2004).

2.5.2 Uncertainties

One method to assess the accuracy of the estimates of fuel use by transport sector is to estimate fuel use using a sectoral, or bottom-up approach, where the number of vehicles and miles traveled are multiplied by a CO_2 emission factor to obtain total CO_2 emissions. CARB has already developed such models for on-road vehicles and watercraft; we developed a similar simple bottom-up model for aviation fuel use. In this section we compare fuel use reported in SEDS with bottom-up estimates of fuel use by each major transport mode.

On-road vehicles

CARB's EMFAC mobile source emission modeling system combines tailpipe emission rates, activity data, and vehicle population data to estimate CO_2 emissions from on-road vehicles by vehicle type and county (Eslinger, 2008). CARB used these model outputs to allocate CO_2 emissions from total fuel sales reported to the Bureau of Equalization in the official GHG inventory. The 2004 reported sales of gasoline for use by on-road vehicles in 2004 were 5.8% lower than modeled using EMFAC, while sales of diesel fuel were 5.3% higher than modeled using EMFAC.

CARB staff recently compared EMFAC's estimate of statewide CO_2 emissions and gasoline use with that from the CalCARS model developed by the CEC (CARB, 2004). The analysis found that, for the entire light-duty vehicle fleet, the EMFAC model estimated 6% greater gasoline use in 2000 and 4% greater in 2002 than the CalCARS model. While the two models are in good agreement for the entire vehicle fleet, fuel use by individual model years can vary greatly. For instance, the EMFAC model estimated 17% lower gasoline use for model year 2000 vehicles in 2002 than the CalCARS model. CARB should update this analysis using more recent output from the revised EMFAC and CalCARS models.

The California Department of Transportation (CalTrans) also has developed estimates of vehicle gasoline and diesel fuel use by county, using the Motor Vehicle Stock, Travel and Fuel Forecast (MVSTAFF) model. MVSTAFF allocates estimated vehicle miles traveled and fuel consumption to counties based on VMT on state highways from the Traffic Accident Surveillance and Analysis System (TASAS) file, and VMT on all other public roads from the Highway Performance Monitoring System (HPMS, CalTrans 2006).

Figure 3 through Figure 6 compare 2005 data on fuel sales by county from CalTrans' MVSTAFF model with 2004 fuel use by county from CARB's EMFAC model. Figure 1 and Figure 4 show the absolute fuel use and sales, where each point represents a county; Figure 5 and Figure 6 show the percent difference between the two estimates, by county. Statewide gasoline sales estimated by CalTrans are 8% lower than statewide gasoline use estimated by CARB; on the other hand, statewide diesel sales estimated by CalTrans are 10% higher than diesel use estimated by CARB.

Figure 3. Comparison of gasoline use (2004 CARB) and sales (2007-08 CalTrans) by county, millions of gallons

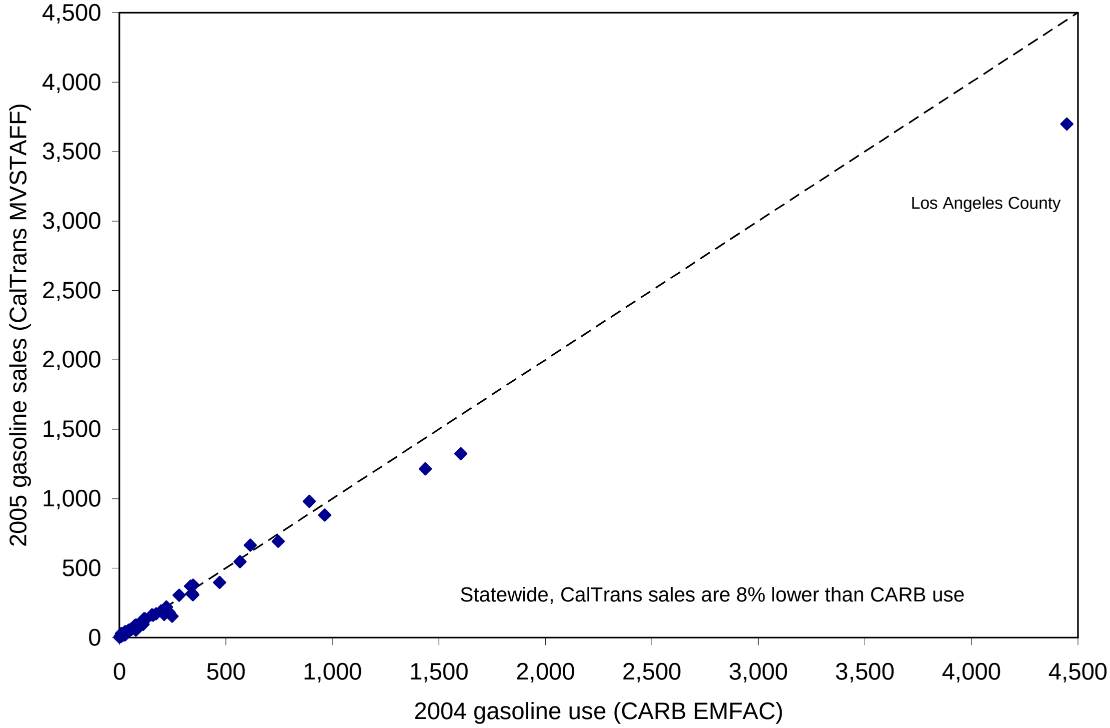
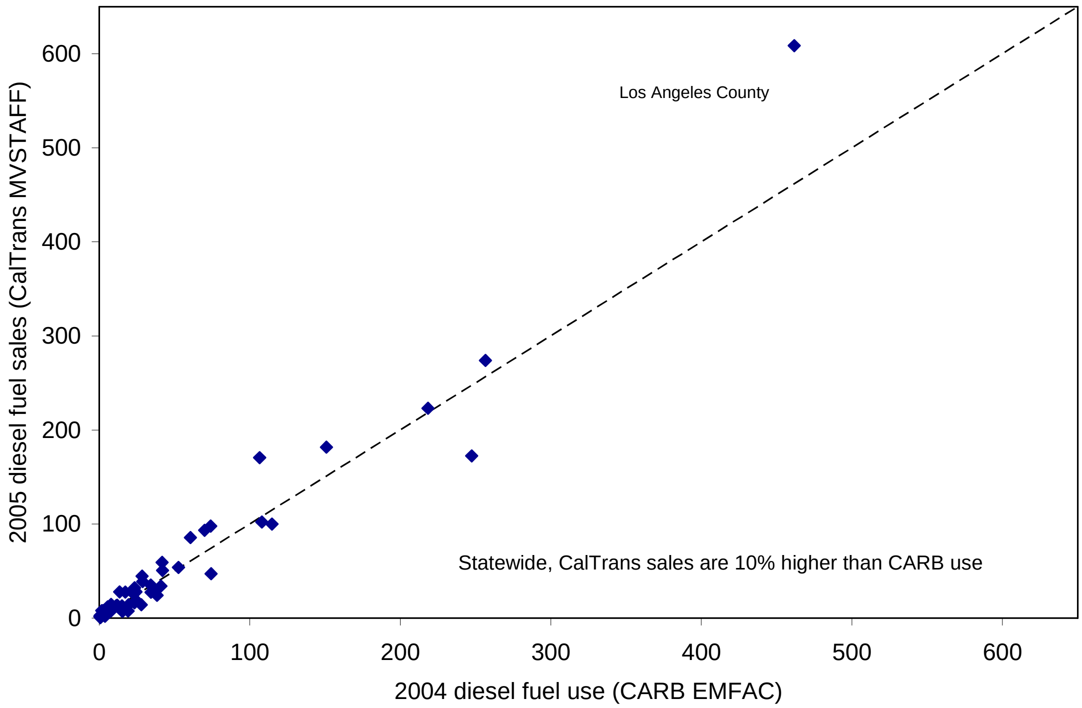


Figure 4. Comparison of diesel fuel use (2004 CARB) and sales (2007-08 CalTrans) by county, millions of gallons



Note in Figure 5 and Figure 6 that the four counties with the greatest gasoline use (according to CARB; Los Angeles, San Diego, Orange, Riverside, shown in pink in Figure 5), which account for half of all gasoline use, all have lower gasoline sales estimated by CalTransthan gasoline use estimated by CARB. Six of the ten counties with the greatest diesel use (according to CARB; Los Angeles, San Bernardino, Riverside, San Diego, Orange, San Joaquin, shown in pink in Figure 6), which account for half of all diesel use, all have higher diesel sales estimated by CalTrans than use estimated by CARB.

Figure 5. Percent difference in gasoline use (2004 CARB) and sales (2007-08 CalTrans) by county

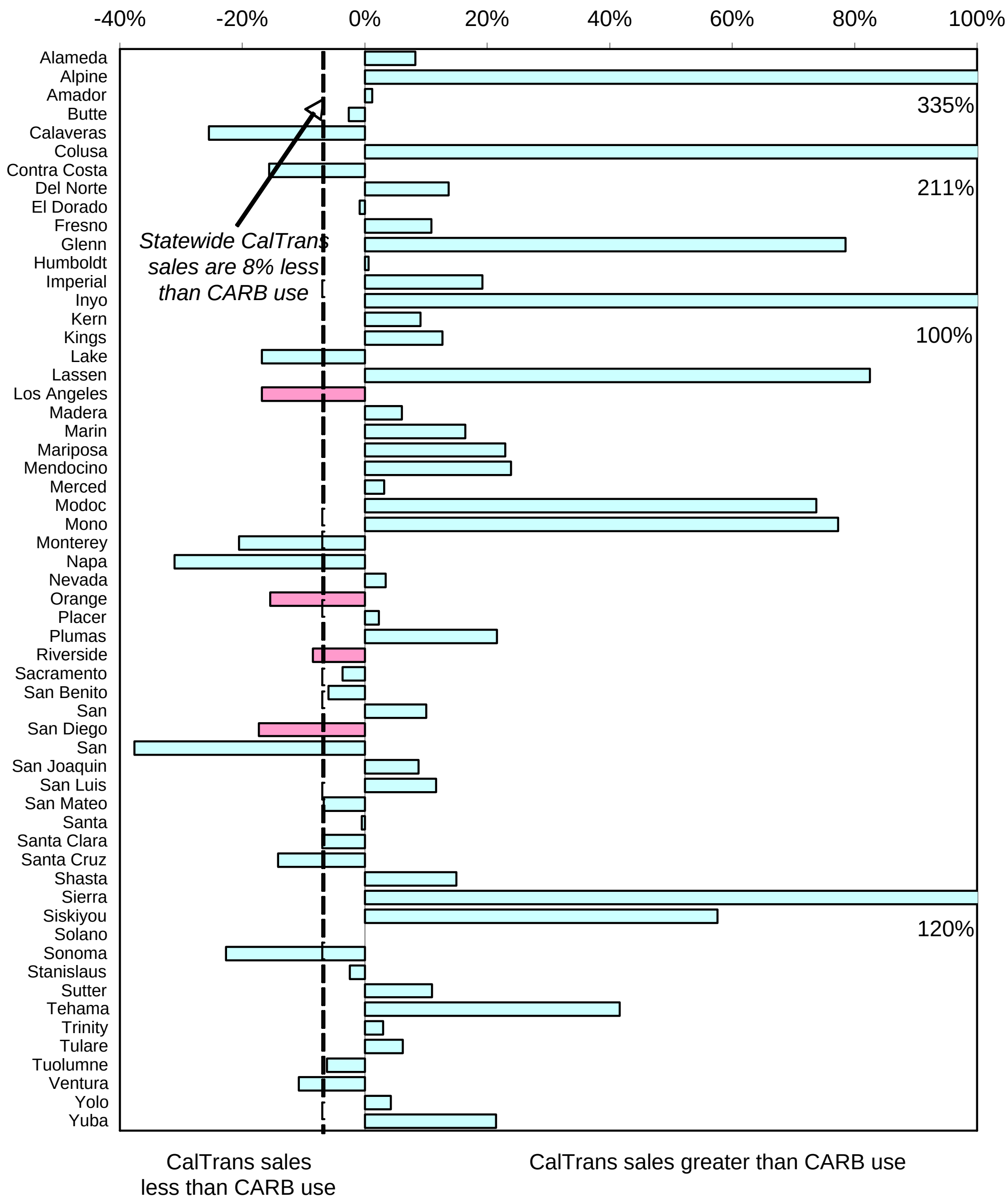
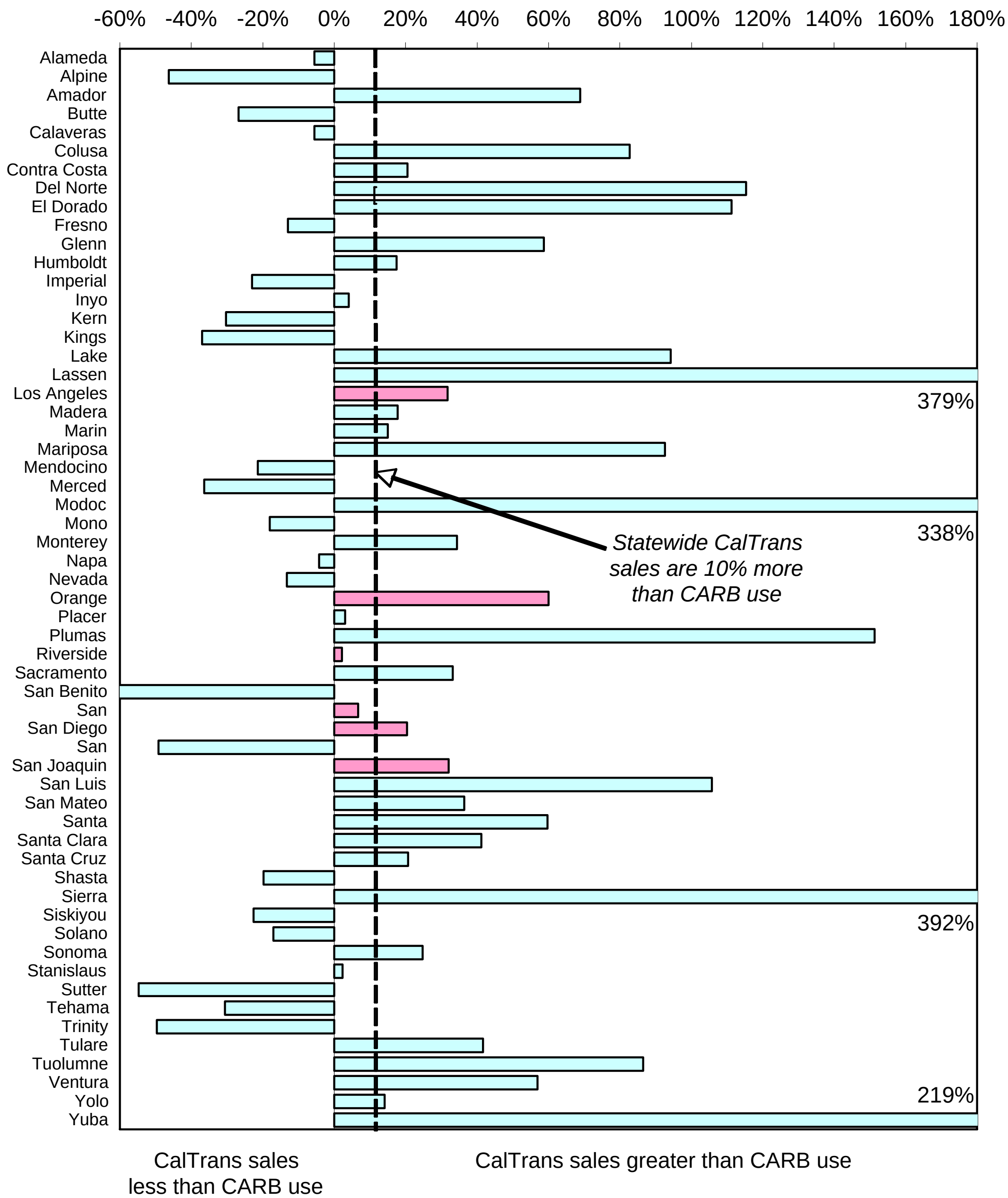


Figure 6. Percent difference in diesel fuel use (2004 CARB) and sales (2007-08 CalTrans) by county



Aviation

LBNL has developed a bottom-up model of the fuel used by commercial aircraft taking off from California airports for the year 2000 (Murtishaw et al., 2005). In this report, we extended the calculation for the period 1990 to 2006. The model uses the U.S. Bureau of Transportation Statistics *Air Carriers: T-100 Segment* data sets from 1990 to 2006 for detailed information on flights and passenger-miles by origin/destination and aircraft type, and average fuel intensity by aircraft type and flight distance from European Environment Agency's EMEP/CORINAIR Emission Inventory Guidebook (EEA 2006).

The model was used in Murtishaw et al., 2005 to allocate total jet fuel sales to intrastate, interstate, and international flights originating in California.

Figure 7 shows the trend in passenger-miles reported by the U.S. Bureau of Transportation Statistics (BTS) and CO_2 emission rate (per passenger-mile) calculated by LBNL, of all flights originating in California from 1990 to 2006. Passenger-miles increased dramatically between 1990 and 2000, nearly doubling in that ten-year period. Passenger-miles declined in 2001 through 2003, likely due to the aftermath of the terrorist attacks on September 11, 2001. However, passenger-miles began to increase again in 2004. In general the CO_2 emission rate has decreased during this period, with the exception of 2001 to 2003. Note that passenger-miles are used to calculate the emission rate, even though 13% of all California aviation CO_2 emissions in 2003 are attributable to flights with no passengers (rather they are flights for transporting freight and mail).

Figure 7. Passenger-miles and CO_2 emission rate of flights originating in California

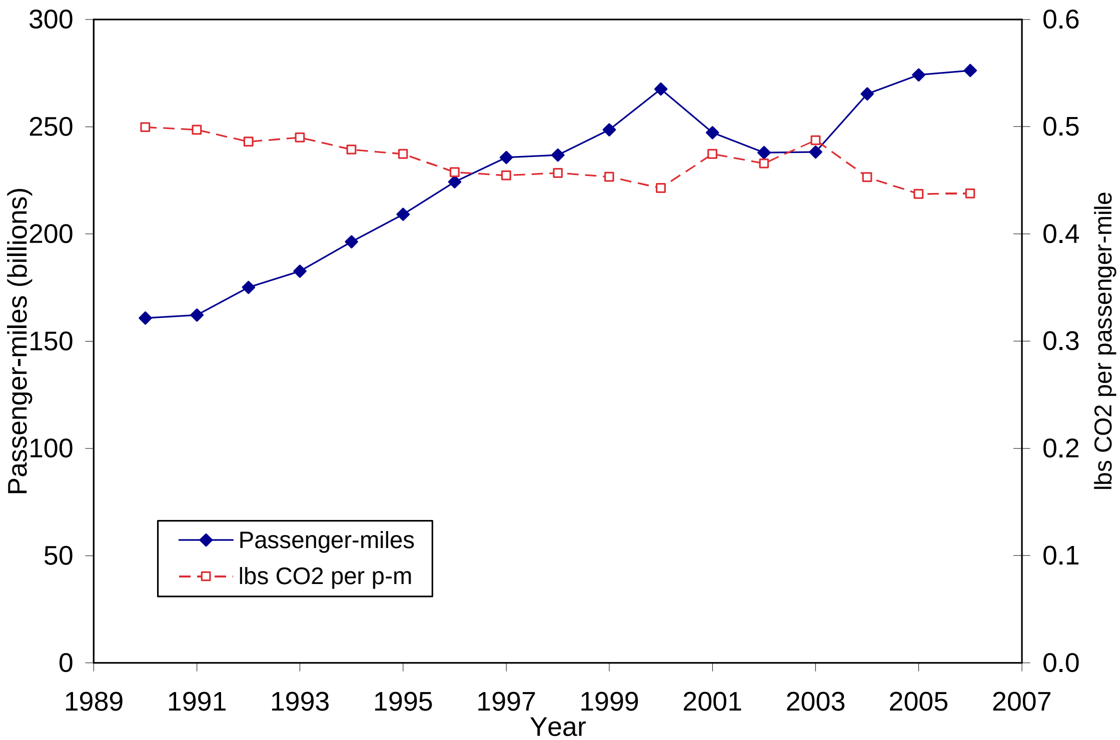


Figure 8 through Figure 10 show the trend in fuel use for intrastate (California), interstate (US domestic), and international flights originating in California. Note that for earlier years the EEA report does not have fuel factors for some older aircraft types; the fraction of all passenger-miles flown by aircraft for which fuel factors are not provided are shown in red in each figure. Historically, fuel use grew fastest for international flights; however, international flights were also most affected by the terrorist attacks in 2001. Since 2001, fuel use has grown at a similar rate for intrastate, domestic and international flights.

Figure 8. Fuel use of intrastate flights originating in California

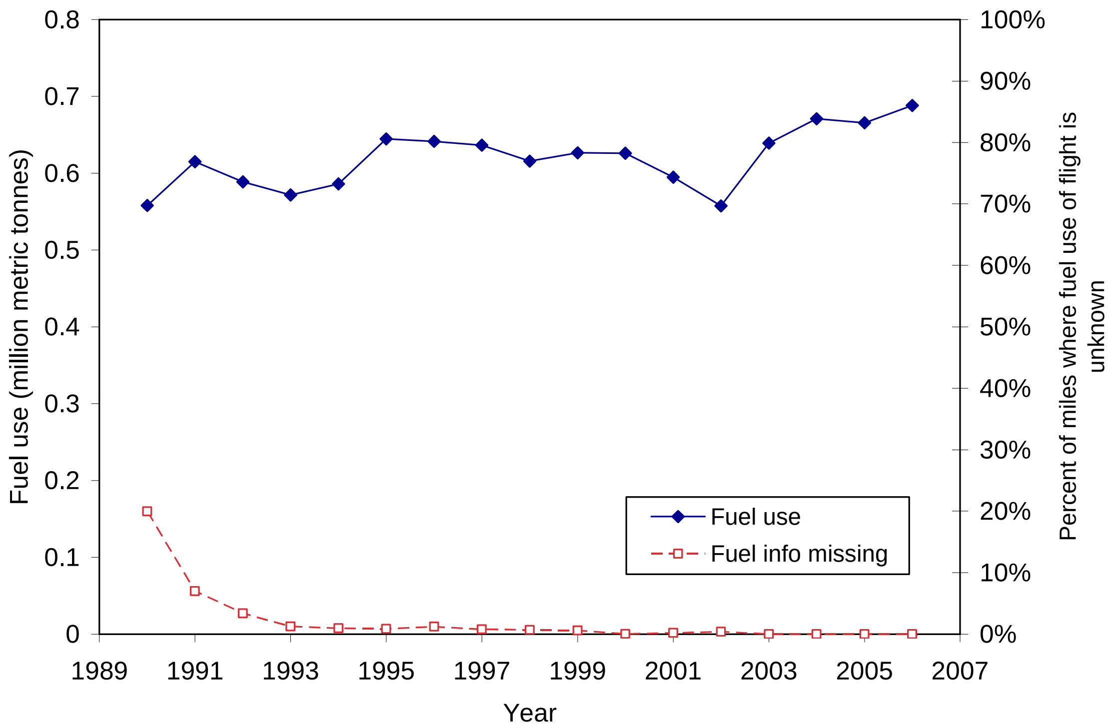


Figure 9. Fuel use of interstate flights originating in California

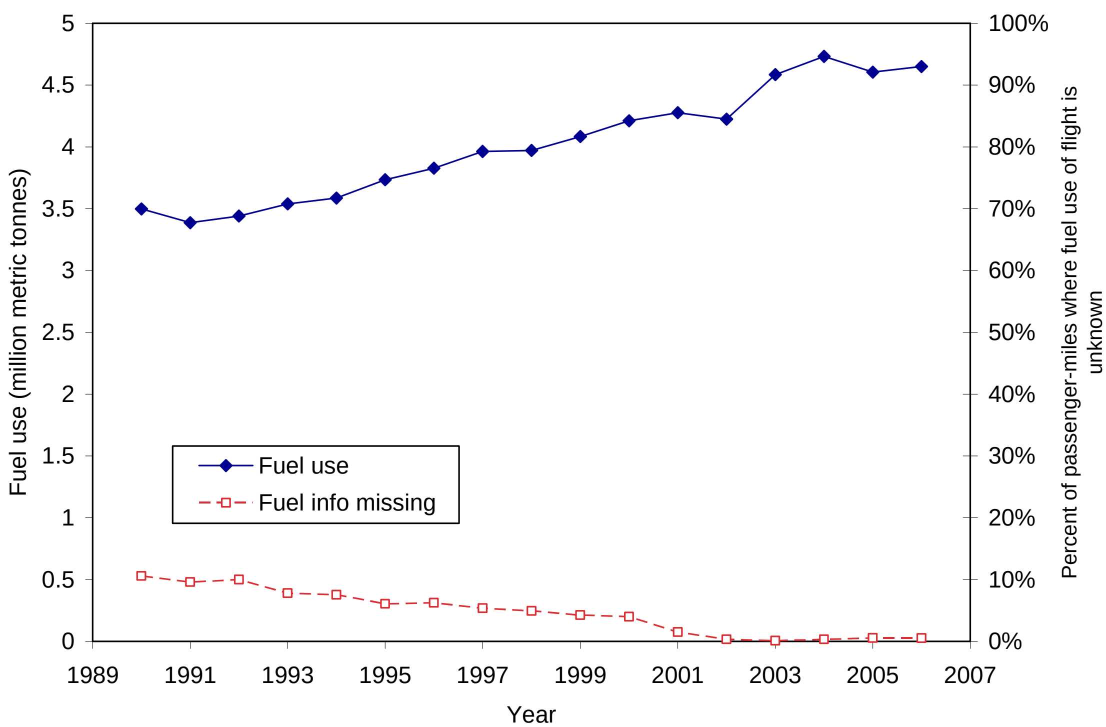


Figure 10. Fuel use of international flights originating in California

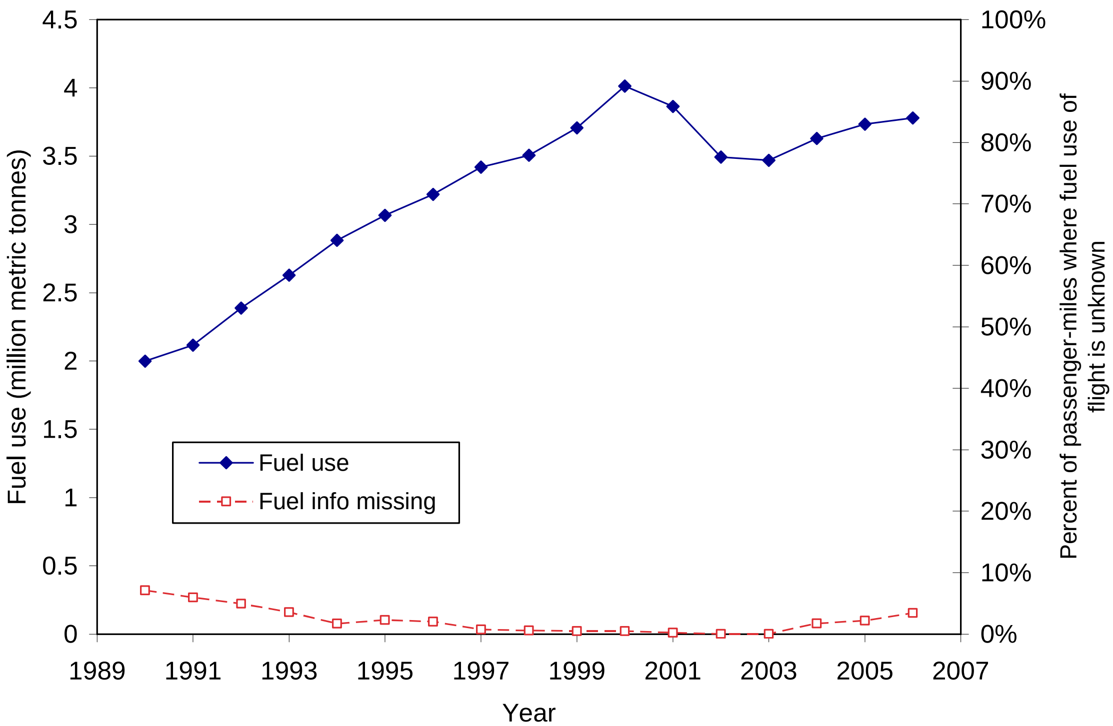
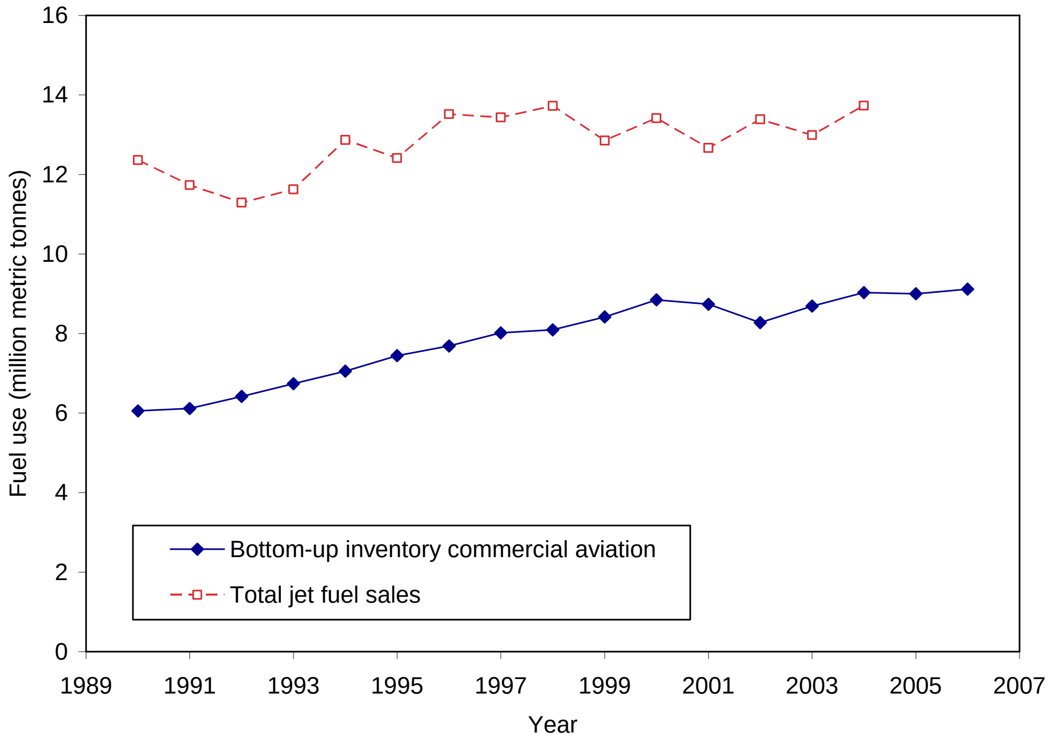


Figure 11 compares the LBNL bottom-up inventory of fuel use from aviation in California with reported jet fuel sales in California, from SEDS 2007. The figure indicates that our bottom-up inventory substantially under-estimates jet fuel use, by 34% in 2004 and up to 50% in earlier years. The figure also indicates that jet fuel sales (in red) waver from year to year, while estimated fuel use (in blue) increased consistently in most years (except for 2001 and 2002, following the terrorist attacks).

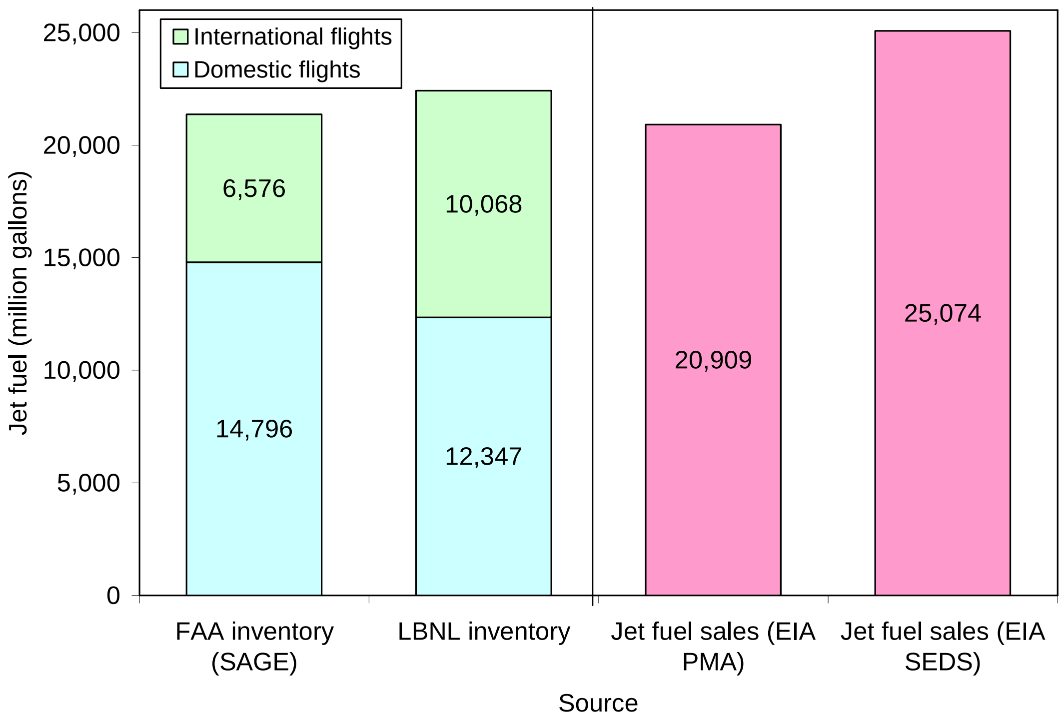
One source of error in our estimate is the miles by flight segment reported in the BTS air travel data; these are clearly air route distances between airports, rather than the distances actually flown. One study has found that route changes and aircraft circling because of delays (referred to as "uplift") can add an additional 9% to 10% to flight distances (EUROCONTROL 1992). Assuming an additional 10% of fuel use from uplift in our bottom-up inventory reduces the gap between our inventory and SEDS to 28%.

Figure 11. Comparison of bottom-up emissions inventory with California total jet fuel sales



The US Federal Aviation Administration has developed SAGE, a more sophisticated model to estimate fuel use by commercial aircraft (FAA 2005a). SAGE has been used to estimate fuel consumption by the country in which the flight originated (FAA 2005b). Figure 12 compares 2004 commercial aviation fuel use for the US from SAGE and from the LBNL model. The figure indicates that the LBNL model estimates 5% more total jet fuel use than SAGE, even though fuel use is not estimated for aircraft accounting for 10% of the flight miles in the LBNL model, and SAGE accounts for uplift and the LBNL model does not. Correcting both of these factors would increase the LBNL estimate, possibly by as much as 20%. The figure also indicates that the LBNL model understates the fraction of fuel use from domestic flights (in blue), and overstates the fraction from international flights (in green), relative to the SAGE estimate. Finally,Figure 11 compares the two bottom-up estimates with U.S. EIA prime supplier and total supplied jet fuel use in SEDS (in pink). SEDS reports 25 million gallons of national jet fuel sales in 2004, 17% higher than the SAGE estimate and 11% higher than the LBNL estimate. The SEDS estimate to total jet fuel supplied is 20% higher than the prime supplier fuel sales, which excludes jet fuel imported by airlines.

Figure 12. Comparison of 2004 US commercial aviation fuel use, from four sources



Marine

CARB has developed bottom-up inventories of CO_2 emissions from ocean-going vessels (3.1 Mt CO_2, CARB, 2005) and harbor craft (1.2 Mt CO_2, CARB, 2007b). Emissions from ocean-going vessels are estimated from 0 to 24 nautical miles (2.3 Mt CO_2), and 24 to 100 nautical miles (0.8 Mt CO_2), off the coast of California; in its official inventory CARB includes only emissions up to 100 nautical miles, but reports an additional 11.1 Mt CO_2 from international bunker fuels used beyond 100 nautical miles.

We compared the CO_2 emissions from the combustion of residual fuel oil and distillate fuel in ocean vessels and harbor craft, as estimated in the CARB inventory, with the 2004 fuel sales, as estimated in SEDS. Table 11 indicates that the CARB inventory estimates greater CO_2 emissions from water craft using distillate fuel than SEDS. The table also suggests that the CARB inventory estimates less CO_2 emissions than SEDS from combustion of residual fuel oil from international marine travel. However, this could be an accounting issue, as the CARB inventory includes 1.1 million metric tonnes of CO_2 emissions from international marine vessel port activitives and transit while in California waters in its "other" category and total emissions from combustion of residual fuel oil are identical in the inventory and in SEDS.

The CARB inventory reports CO_2 emissions from international ships traveling beyond 100 nautical miles of California's coast, based on the SEDS estimate of sales of international bunker fuels. However, it is clear that these numbers do not account for the total CO_2 emissions from international ships using California's ports. CARB plans to develop in the future an estimate of all CO_2 emissions from interstate and international marine traffic using California ports (Alexis, 2008).

Table 11. Comparison of CARB CO_2 emission estimates and SEDS fuel sales, for water craft

Trip type (included/ excluded in CARB inventory)	Fuel	2004 CO_2 emissions(Mt)		Difference
		CARB inventory	SEDS fuel use	
International (excluded)	Residual fuel oil	11.1	12.5	12%
	Distillate fuel	0.0	0.6	NA
Other* (included)	Residual fuel oil	2.0	0.7	-67%
	Distillate fuel	1.3	0.5	-60%
Total	Residual fuel oil	13.1	13.1	0%
	Distillate fuel	1.3	1.0	-23%
	Combined	14.4	13.6	-6%

* includes port activities and transit in California waters of intrastate, interstate, and international marine travel, as well as harbor craft.

Rail

In 1991 Booz-Allen & Hamilton developed a 1987 bottom-up inventory of criteria pollutant emissions for CARB (CARB, 1991). This inventory estimated 141 million gallons of diesel fuel use by locomotives for five different service types: intermodal freight, mixed freight, short haul, yard operations, and passenger transport. CARB updated this inventory in 2006 (CARB, 2006); the updated inventory estimates 306 million gallons of diesel fuel used by locomotives (CARB, 2007a).

The official CARB greenhouse gas inventory uses SEDS estimates of 226 million gallons of diesel fuel (and 348 million scf of natural gas) for locomotives in 1990, and 310 million gallons of diesel (280 million scf of natural gas) in 2004. Therefore CARB's bottom-up inventory estimates 1% less diesel fuel use for locomotives in 2004 than the official inventory based on SEDS estimates.

2.5.3 Alternative Sources/Methods and Recommendations

We contacted the California Energy Commission and inquired about the PIIRA database. PIIRA requires qualifying petroleum industry companies to submit weekly, monthly, and annual data to the California Energy Commission. Data collection began in 1982. In 2006, the PIIRA regulations were amended to increase the frequency and level of detail in the information reported by the industry. Specifically, the A15 survey collects data on fuel sales by retail outlet. About 80% of outlets have provided data in the first year of the survey; however, these data are not yet available for analysis (Schremp, 2008).

We also contacted the Board of Equalization and downloaded data from their website (CBE, 2008). However, two problems were identified with the fuel tax data. First, gallons sold are reported by fiscal, not calendar year. Data for some of the later years are reported by month, so we could recreate calendar year sales; however, monthly data are not available for years before 2000. Another issue is total vs. taxable gallons; while all motor gasoline sold is taxed, only about 90% of diesel fuel, and a small percentage of jet fuel, is taxed, and therefore included in the Board of Equalization estimates (see Figure 13; it is not clear why SEDS reports much higher diesel fuel sales in 2003).

Figure 13. Trends in California transportation fuel sales and use, estimated by U.S. EIA SEDS and reported by California Board of Equalization

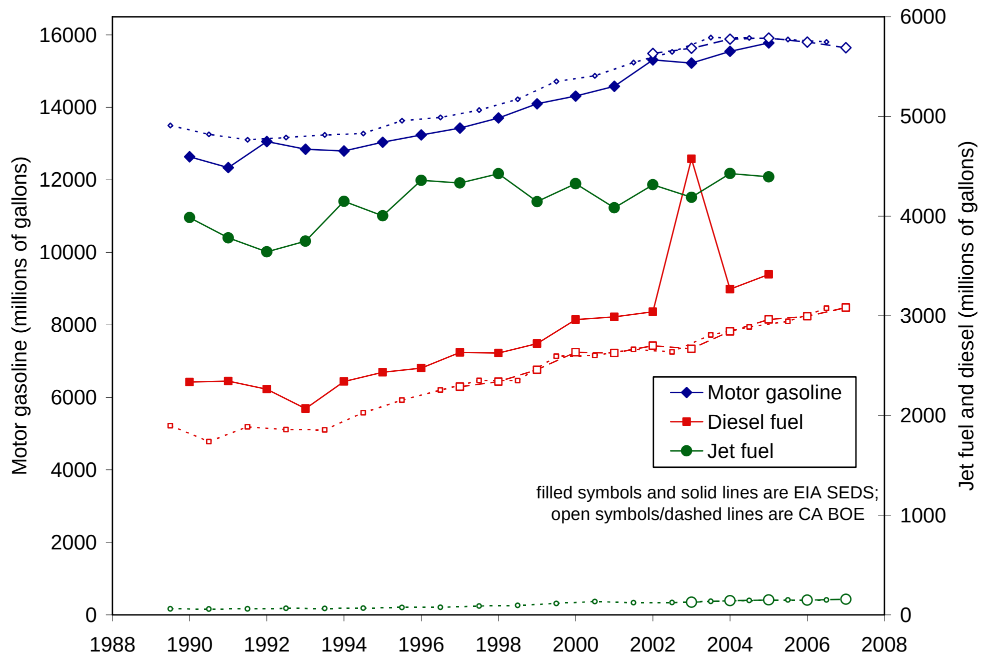


Figure 13 indicates that California's estimates of motor gasoline sales from tax receipts closely match those estimated in SEDS. Trends for diesel fuel sales also track SEDS estimates fairly well, although a portion of diesel fuel sales are exempt from taxation. However, because most jet fuel sold in California is exempt from tax, California data on jet fuel tax receipts cannot be used to estimate total jet fuel use in the state.

3. Uncertainties by Fuel

3.1 Reference versus Sectoral Approach

The CO_2 emissions from fuel combustion can be calculated by one of two methods: the reference approach or Tier 1 and the sectoral approach or Tier 2 (IPCC, 1996; Murtishaw et al., 2005). The reference approach is a "top-down" which focuses on estimating the emissions from the carbon content of fuels supplied to or sold in a jurisdiction. The reference approach assumes that all fuel reported as "supplied to the economy" is combusted (adjusting for known non-energy uses). The sectoral is a "bottom-up", approach that calculates CO_2 emissions at the source where fuel is ultimately combusted, using actual end-use consumption data or estimates of activity multiplied by energy intensity factors. For verification purposes, IPCC recommends reporting results of their calculations using both approaches, and to explain differences between estimates under the two approaches.

CALEB displays a "total consumption" energy flow, which for each fuel type is the sum of all end-use consumption of energy, use for transformation, own use of energy in the energy sector, transformation losses, and distribution losses. In theory, these totals should match the total amount supplied, but since supply, transformation, and end use data are collected and reported separately, the totals rarely balance precisely. Thus, reconciliation errors, which the International Energy Agency (IEA) calls "statistical differences", refer to the difference between total supply of any given fuel and the total consumption of that fuel for transformative and end use consumption. This expresses the unresolved discrepancies between the supply, transformation, and end use consumption figures.

The energy balance constructed in 2005 for the year 2000 shows the reconciliation error for every energy product supplied and consumed in California (Murtishaw et al., 2005). Table 12 shows in Tbtu the reconciliation errors for every fuel. The table also shows the percent of total consumption that the fuel represents in total fuel consumed and the percent reconciliation error between the quantity supplied and consumed to the total amount of fuel consumed. For example, in 2000, natural gas consumption represents 40.3% of total fuel consumption, the reconciliation error between consumption and supply is 225 TBtu (consumption is 225 TBtu greater than supply), which represents 8.9% of total natural gas consumption. The net reconciliation error in CALEB is 21 TBtu, which represents about 0.3% of total energy consumption (6,227 TBtu).

Table 12. Reconciliation Errors by Energy Source in Trillion Btu

Product	**Percent of total consumption**	**Difference between supplied and consumption (reconciliation error)**	**Difference as percent of total product consumption**
Nat Gas	40.3%	225	8.9%
NGL	0.4%	-6	-22.7%
Additives	2.5%	21	13.6%
Crude	-	-17	-0.5%
Tot Pet. Products	55.7%	-86	-2.5%
Still Gas	*3.3%*	*-42*	*-20.3%*
LPG	*0.9%*	*-18*	*-31.5%*
Motor Gas	*27.8%*	*-61*	*-3.5%*
Aviation Gas	*0.1%*	*-1*	*-27.4%*
Jet Fuel	*9.3%*	*0*	*0.0%*
Kerosene	*0.0%*	*-1*	*-49.3%*
Dist Fuel	*8.8%*	*0*	*0.0%*
Res Fuel	*0.2%*	*0*	*0.0%*
Pet Coke	*1.7%*	*0*	*0.0%*
Lubricants	*0.5%*	*-22*	*-70.8%*
Asphalt	*2.0%*	*25*	*20.0%*
Waxes	*0.1%*	*-2*	*-54.6%*
Special Naphtha	*0.1%*	*3*	*34.4%*
Petrochem feedstocks	*0.2%*	*-4*	*-34.9%*
Other Petro Prods	*0.8%*	*-14*	*-27.4%*
Coal	1.1%	-65	-90.2%
Net reconciliation error		21	0.3%
Total Consumption	100%	6,227	

3.1.1 Data Sources

Tracking energy consumption for all end uses and fuel types used in California is a difficult task. It requires collecting information from multiple sources and assessing data gaps. The report *Development of Energy Balances for the State of California* (Murtishaw et al., 2005) describes in detail the different sources of data used to construct the energy balance table above.

3.1.2 Uncertainties

Overall, the reconciliation errors are comparable to those found for many countries in the IEA data (IEA, 2003a; IEA, 2003b). However, individual reconciliation errors by fuel can be substantial.

***Coal**:* Prior to 2003, substantial reconciliation errors exist, where supply is much higher than end use consumption. The reconciliation error ranges from 4% in 2003 to -64% in 2001 (Table 13). At this point, it is unclear what explains such large differences, as all data come from the same source, U.S. EIA.

Table 13. California Coal Supply and Consumption (kst)

	Source	2000	2001	2002	2003	2004	2005
Import	U.S. EIA, 2006	5,691	7,881	6,543	2,762	3,001	2,726
Stock	U.S. EIA, 2006	61	-54	-1	46	-33	NA
Total Consumption	SEDS, 2007d	2,954	2,834	2,943	2,866	2,847	2,849
Statistical differences	Cons-Supply	-2,737	-5,047	-3,600	104	-154	123
Reconciliation Error	%	-48%	-64%	-55%	4%	-5%	4%

***Natural Gas**:* reconciliation errors of natural gas range from -199 Bscf in 2004 to 238 Bscf in 2000, which represent -9% to 10% of total natural gas supplied to California. The smallest reconciliation error, for 2002, is 4 Bscf, representing only 0.2% of total natural gas supplied to California. The use of several sources of data to account for natural gas supplied and used in California could account for these differences. The primary source for all natural gas supply data is the U.S. EIA's *Natural Gas Navigator* (U.S. EIA, 2008), while consumption mainly comes from the CEC (CEC, 2005). Consumption of natural gas data are also available through the U.S. EIA's *Natural Gas Navigator* database, but with less detail. Moreover, U.S. EIA's consumption data are 2% lower than CALEB consumption data in 2001, and 11% higher than CALEB data in 2004.

***Petroleum Products**:* data on consumption of petroleum products in the state is the most challenging to gather, because there are about 20 different types of products in use and the distribution system is managed by many operators, rather than a few large utilities. Table 12 shows the 2000 statistical differences for every petroleum product. Kerosene, lubricants, asphalt, waxes, special naphtha, and petrochemical feedstocks all have substantial statistical differences but each product only represents a small share of the total energy consumption in California.

Comparing supply with consumption is a meaningful way of assessing data coverage. However, neither the supply data nor the consumption data are complete for all fuel consumed in California. For example, no data were available on trade of some petroleum products, such as LPG, NGL, jet kerosene, etc. Statistics on movement of petroleum products between states does not exist for every product and may be cumbersome to collect. This highlights the difficulty of tracking energy flows in California.

3.1.3 Alternative Source/Methods and Recommendations

Improved accounting of fuel supplied and used in California is needed to narrow the differences shown in Table 12. This is a challenging task as many fuel products enter and exit the state without being reported. The recent amendment of the PIIRA database to increase the frequency and level of detail in the information reported by the industry will help in improving the reconciliation between supply and consumption. The U.S. EIA conducts about 76 surveys with different time frames, from weekly to every four years. A list of such surveys is provided in Appendix A. Some of the data gathered through these surveys are available at the state level, such as *Annual Refinery Report* (U.S. EIA-820) which is also processed by the CEC. These data were used in CALEB. The CEC has ongoing work with staff at the U.S. EIA to gather more of the information collected through these surveys. A next step would be to collaborate further with the U.S. EIA and assess if more data could be obtained from the data reported to the state or estimated to the state level by U.S. EIA.

We estimated that uncertainties associated with reconciliation errors due to data gap range from -6Mt CO_2 to 13Mt CO_2 (Table 14). These results are based on CALEB database for 2000 data.

Table 14. 2000 CO_2 Emissions from CALEB (Mt CO_2)

	Nat Gas	Petroleum	Coal	**Total**
Reference Approach	119	219	13	**350**
difference	13	4	-6	**11**
Sectoral Approach	132	223	7	**361**

3.2 Calorific Values and Carbon Emission Factors Uncertainties

3.2.1 Data Sources

Energy balances use a common energy unit to allow comparison and balancing between flows and products. However, data are usually collected in physical units, such as volume or mass. Conversion from physical units to energy units is determined by the quality of a product, and can vary between regions, over time, and by uses. SEDS (U.S. EIA, 2007d) provides detailed annual conversion factors for California for natural gas and coal, and distinguishes between their heating value depending upon whether the fuel is used in the electricity sector, the industry sector, or in other sectors. Conversion factors for petroleum products are generally considered constant over time and uses. The U.S. EIA's annual U.S. average conversion factor for liquefied petroleum gas (LPG), which reflects the quantity-weighted average of their components that may fluctuate over time, is used in CALEB. For motor gasoline, CALEB uses an annual California-specific conversion factor calculated by the Energy Commission (Bemis, 2004).

Once an energy balance has been constructed, CO_2 emissions resulting from fossil fuel combustion can be calculated. CALEB has been designed to calculate CO_2 emissions from energy consumption. According to IPCC, conversion of fuel combustion to CO_2 emissions requires three types of carbon factors: (1) emission factors, (2) storage factors, and (3) oxidation factors (IPCC, 1996). Carbon emission factors convert the fuel consumed into the maximum amount of carbon that can be released in the atmosphere during combustion. U.S. average emission factors are used in CALEB (U.S. EPA, 2005). Carbon storage factors are applied to the share of carbon stored when consuming fuel for non-energy purposes, as explained in Section 2.4. Non-energy uses also include asphalt and road oil use for road construction, as well as waxes and lubricants that are used directly for their chemical proprieties and are not combusted. The storage factors for asphalt, waxes and lubricants were taken from the California GHG inventory (CEC, 2002). Finally, carbon oxidation factors are the proportion of carbon in fuel that is oxidized to CO_2 during combustion. A small proportion of carbon is stored in solids such as ash and soot arising from incomplete combustion of carbon in fuel. Average international values from the IPCC are used for those factors (IPCC, 1996).

The first column in Table 15 shows the carbon factors that have been used in the calculation of carbon emissions from fuel combustion in CALEB. All of these factors were taken from U.S. EPA (U.S. EPA, 2008) except for the energy commodity “additives” and “petrochemical feedstocks”. For the former, we used the same emissions factor and oxidized fraction as crude oil. Petrochemical feedstocks are composed of two products: naphtha and other oils, which have different emission factors. The production of each of these products is available from the annual CEC reports on refinery operations (CEC, 2005). Hence, the share of each product was used to calculate an average emission factor.

Table 15. Carbon Content Factors, Storage Factors and Fraction of Oxidation used in CALEB

Unit	**Carbon Coefficient** *kgC/MMBtu*	**Storage Factor** *%*	**Fraction Oxidized** *%*
Natural Gas	14.47	91%	99.5%
Still Gas	17.51	-	99.5%
LPG	16.98 *	91%	99%
Motor Gas	19.34 *	-	99%
Aviation Gas	18.87	-	99%
Jet Fuel	19.33 *	-	99%
Kerosene	19.73	-	99%
Distillate Fuel	19.96	-	99%
Residual Fuel	21.50	-	99%
Pet Coke	27.85	-	99%
Lubricants	20.23	50%	99%
Asphalt	20.64	100%	99%
Waxes	19.81	100%	99%
Special Naphtha	19.86	0%	99%
Petrochemical feedstocks	19.87 *	51% *	99%
Other Petro Prods	20.23 *	10%	99%
NGL	18.24	80%	99.5%
Coal	25.76	-	98%
Crude Oil	20.23 *	-	99%

Mustishaw et al., 2005; * vary annually (factors presented are for 2000)

3.2.2 Uncertainties

The heating value and carbon content of some fuels varies across time and across region. Uncertainties with the carbon content of gasoline are discussed first because approximately half of all California CO_2 emissions from fossil fuel combustion are associated with motor gasoline consumption (Table 16). Uncertainties with carbon content of natural gas are provided next, as about 40% of California greenhouse gas emissions from fossil fuel combustion are attributable to natural gas consumption. Finally, carbon contents of coal and petroleum products are discussed. However, it should be noted that California energy consumption statistics include more than 20 different petroleum products.

Table 16. Ranking of CO_2 Emissions from Fuel Combustion in 2004 (million metric tonne (Mt) of CO_2)

Fuel	Mt CO_2	%
Motor Gasoline	140.2	32.8%
Natural Gas	112.6	26.3%
Distillate	40.8	9.5%
Coal	37.5	8.8%
Imported Electricity	27.6	6.5%
Refinery Gas	19.6	4.6%
Associated gas	15.8	3.7%
Other	6.7	1.6%
Catalyst Coke	6.1	1.4%
Petroleum Coke	4.1	1.0%
Bituminous Coal	4.0	0.9%
Jet Fuel	2.8	0.7%
LPG	2.4	0.6%
Residual Fuel Oil	2.1	0.5%
Lubricants	1.0	0.5%
Naphtha	0.6	0.2%
Petroleum feedstocks	0.5	0.1%
Natural Gas Liquids	0.3	0.1%
Municipal Solid Waste	0.2	0.1%
Aviation Gasoline	0.2	0.1%
Tires	0.2	0.0%
Kerosene	0.2	0.0%

Source: CARB, 2007

- Motor gasoline consumption is the largest source of CO_2 emissions from fuel combustion in California. Uncertainties linked to the heating value and carbon factors of motor gasoline are directly transferred to the total emissions of motor gasoline. For example, if these factors increase by 1%, emissions increase accordingly. The composition of California reformulated gasoline, designed to meet CARB regulations, differs from that of average US gasoline. For the conversion of motor gasoline from physical (barrels) to energy (Btu) units, CALEB uses a California-specific conversion factor calculated by CARB (Bemis, 2004). However, this was available only for 1995 and

1997. Concerning carbon content, a national average estimate was used. Calculation of annual heating values and carbon contents of gasoline used in California will improve the precision of California emission inventory. Moreover, the increased use of ethanol, as opposed to MTBE, as a blending component of gasoline needs to be clearly specified, as no carbon is associated with ethanol use. Ethanol is produced from the fermentation of biomass and is considered carbon neutral by the IPCC. In the energy balance, it is accounted as an input to the refineries under the product category biomass and it is subtracted before calculating carbon emissions emitted from motor gasoline consumption.

- Natural gas is a major fuel used in California, representing 39% of total CO_2 emissions from fuel combustion in 2004. California relies heavily on imported natural gas. In 2002, only about 15% of the natural gas supply is from in-state sources, while almost half is imported from the Southwest U.S., a little over one-quarter from Canada, and the remainder from the Rocky Mountain states, which began supplying natural gas to California in 1992 (Murtishaw et al., 2005). Heating value and carbon content values vary according to the natural provenance. Data on the heating value used in CALEB comes from SEDS that provides a conversion factor for California annually and for its different use. However, a US average factor for the carbon content of natural gas was used.

- Coal burned in California[8] is imported from Colorado, Kentucky, New Mexico, Utah, West Virginia, and Wyoming. Coal imports were relatively steady from 1990 to 1997, at which point they jumped from 2,794 thousand short tons (kst) (65 TBtu) to 7,881kst (179 TBtu) in 2001 and started to decrease to reach 2,726 in 2005. Similarly to natural gas, the heating value used in CALEB comes from SEDS, which varies annually and by use. However, the carbon content of coal is an US average. This is a shortcoming, since the carbon content of coal varies by the state in which it was mined and by coal rank, and because the sources of coal for each consuming sector vary year by year.

- Other Fuel: California-specific carbon factors must be estimated for other fuels. The fuels that are most likely to deviate from the US average are LPG, NGL, still gas and petrochemical feedstocks. As mentioned in Section 2.2 data on petroleum coke consumption in refineries are available under two distinct categories: marketable petroleum coke and catalyst petroleum coke. However, the same energy conversion and carbon emission factors were applied to both types of coke in CALEB. In a memo to CARB from the Western States Petroleum Association (Lev-On, 2007), a survey of some WSPA members indicated that the 27.85 kg (61.4 lb) C/MBtu factor used in CALEB may overestimate the carbon content for catalyst coke by about 10 to 15%. The heating value used by WSPA members may also be different from the one used in CALEB. WSPA reports that the heating value varies significantly by time and across refineries.

We estimated that uncertainties associated with the carbon content values used in CALEB are in the range of -1% to +5%. This range was calculated by using lower and upper carbon content factors given in the IPCC guidelines (IPCC, 2006) in the 2000 CALEB database.

[8] Excluding coal used to produce imported electricity

3.2.3 Alternative Source/Methods and Recommendations

Testing procedure

U.S. EPA's Acid Rain Program requires that the emissions of electricity generation facilities throughout the country be measured with continuous emissions monitoring (CEM) systems. The program requires the reporting of hourly emissions measurements of CO_2, SO_2, and NO_x emissions from all facilities over 25 megawatts, and new facilities under 25 megawatts that do not use low-sulfur fuel (sulfur content less than 0.05% by weight). Utilities can report CO_2 emissions either by measuring them using a CO_2 CEM, or through estimation using an O_2 CEM or a mass balance estimation (U.S. EPA 2008b).

We obtained CEM CO_2 measurements from 68 generation facilities in California, and matched their 2004 CO_2 emissions with fuel consumption estimates from U.S. EIA's 906/920 and 860 time series data. We were able to match 64 of the 68 facilities in the CEM database with their counterpart in the U.S. EIA database, accounting for virtually 100% of the measured CO_2 emissions. These facilities account for 27% of the total fuel consumption reported in the U.S. EIA database; it is not clear why the remaining four facilities are not included in the CEMS database. We then calculated the actual 2004 CO_2 emission factor per Btu for each facility matched in both databases. The average CO_2 emission factor for all matched facilities is 0.060 grams of CO_2 per Btu of fuel; this factor is 13% higher than the 0.053 g/Btu emission factor for natural gas, but lower than the 0.073 g/Btu emission factor for diesel fuel (CARB 2007a; 95% of all fossil fuel used for in-state electricity generation is natural gas). Table 17 shows the fuel use, emissions, and emissions factor for the ten largest facilities in both the U.S. EIA and CEM datasets (all of these facilities used only natural gas); these facilities account for 15% of the total reported fuel use (U.S. EIA), and 55% of the total measured CO_2 emissions (CEM), from electricity generation in California. As shown in the table, the emission factors of the ten largest individual plants vary from 0.057 to 0.090 g/Btu, or 5% less than to 50% more than the statewide average of 0.060 g/Btu, and 8% to 70% more than the statewide average of 0.053 g/Btu for energy generation facilities burning natural gas.

Table 17. Fuel use, CO_2 emissions, and CO_2 emission factors of ten largest California electricity generating facilities in U.S. EPA CEM database

Facility	U.S. EIA fuel use (TBtu)	CEM CO_2 emissions (Mt)	CO_2 emission factor (grams/Btu)
Moss Landing Power Plant	46.3	2.8	0.061
La Paloma Generating LLC	41.1	2.7	0.066
Delta Energy Center	41.1	2.4	0.057
Encina	34.3	2.1	0.061
AES Alamitos LLC	35.0	2.1	0.059
Elk Hills Power LLC	26.9	1.7	0.062
High Desert Power Project LLC	27.8	1.6	0.058
Los Medanos Energy Center	26.4	1.6	0.060
AES Huntington Beach LLC	16.1	1.4	0.090
Ormond Beach	24.0	1.4	0.059
Total	319.1	19.8	0.062

National Inventory

For the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, U.S. EPA estimates CO_2 emissions from fuel combustion based on the heat content of the fuel and carbon content coefficients in terms of carbon content per quadrillion Btu (QBtu), using data from the U.S. EIA. Carbon content factors are similar to the carbon content coefficients contained in the IPCC's default methodology (IPCC, 2006), with modifications reflecting fuel qualities specific to the United States. Carbon content factors are derived from fuel sample data, using descriptive statistics to estimate the carbon share of the fuel by weight. The heat content of the fuel is also estimated based on the sample data, or where sample data are unavailable or unrepresentative, by default values that reflect the characteristics of the fuel as defined by market requirements.

The U.S. EPA provides a complete description of the method and data sources used in *Annex 2- Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion* from the US *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. EPA, 2008). It is possible to replicate the methodology used, but data that are available at the national level may not always be available at the state level.

Other Sources

For coal, the U.S. EIA provides a description of the coal used in California by electric utility, industrial plant or other use; for each subsector, it provides the quantity of fuel by its source. These data enable the calculation of a coal carbon factor specific to California (*Distribution of U.S Coal by Destination,* U.S. EIA, 2008)[9]

Calculation of specific carbon factors for all energy products consumed in California should be carried over to allow for a more precise estimate of the CO_2 emissions in the state. We estimate that uncertainties associated with the carbon content values used in CALEB are in the range of -1% to +5%. This range was calculated by using lower and upper carbon content factors given in the IPCC guidelines (IPCC, 2006) in the CALEB database.

4. Conclusion

There are several important improvements to the energy balance that can be made to better account for CO_2 emissions from fuel combustion in California. This is mainly because CALEB is built on data from many different sources. Care needs to be taken that energy supply and consumption are properly matched, to eliminate or minimize any double-counting. A difficulty is that surveys and questionnaires gathering the data across the US are centralized through a federal agency, the U.S. EIA. Data are not always reported at the state level, and when they are, they are often allocated to states using proxies for actual supply and consumption. Finally, energy is used through a multitude of different products and across many different end use activities. Gathering all the data

[9] http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/d_ca.html

necessary to have a complete picture of all energy flows is a challenging task and data are not always available.

This report focuses mainly on evaluating the areas where improvement is needed and assessing uncertainties associated with CO_2 emissions accounting. An attempt was made to quantify uncertainties using alternative data, when such data were available. We estimate a low and high uncertainty relative to current total CO_2 emission estimates. However, for some sectors these uncertainties are underestimated, as alternative data were not available for all sectors or processes. For example, we did not estimate a range of uncertainty for hydrogen production, as no alternative data were found. Moreover, when alternative data was available, the range chosen for each sector was intentionally large, to include all possible errors that could be identified and quantified with the category considered. Table 18 shows the resulting range in percent uncertainty by category and for the total state CO_2 emissions, for the year 2004. A positive percentage indicates that the current estimate of CO_2 emissions is too low, while a negative percentage indicates that the current estimate is too high. The table indicates that the largest uncertainties come from unresolved reconciliation errors between supply and consumption data (-2% to +4%), carbon emission factor uncertainties (-1% to +5%), gasoline use by motor vehicles (2%), and fuel use in upstream (+1.1%) oil and gas operations. There also are small uncertainties in emissions from fuel used as feedstock in chemical plants fuel used in electric and CHP plants, diesel used by motor vehicles, and fuel used for commercial aviation. The estimated uncertainty for all sectors ranges from -19 and +37 Mt, or -5% and +11% of total CO_2 emissions.

Table 18. Percentage Uncertainties

Category	2004 emissions		Estimated uncertainty		
	CO_2 (Mt)	%	CO_2 (Mt)	% over each category total	% over total inventory
Electricity/CHP*	**62**	**18%**	**0.40**	**1%**	**0.1%**
coal	*4*	*1%*	0.47	*12%*	0.1%
petroleum products	*9*	*3%*	*-0.07*	*-1%*	-
natural gas	*49*	*14%*	-	-	-
Refining**	**29**	**8%**	-	-	-
Oil/gas extraction	**14**	**4%**	**4.00**	**28%**	**1.1%**
Industry feedstocks	**1.8**	**1%**	**±1.77**	**±100%**	**±0.5%**
Transportation	**177**	**51%**	***-8.04***	**-5%**	**-2.2 %**
On-road vehicles	*167*	*48%*	*-7.17*	*-4%*	
Gasoline	*138*	*39%*	*-8.52*	*-6%*	-2.4 %
Diesel	*29*	*8%*	1.35	*5%*	0.4 %
Aviation	*3*	*1%*	*-0.84*	*-28%*	-0.2 %
Marine	*3*	*1%*		*-6%*	-
Rail	*3*	*1%*	*-0.03*	*-1%*	-
Other***	**66**	**19%**	-	-	-
Reconciliation errors	**-**	**-**	**-6.2 to 13.0**		**-2% to 4%**
Emission Factors	**-**	**-**	**-2.7 to 17.6**		**-1% to 5%**
Total	**350**	**100%**	**-18.7 to 36.8**		**-5% to 11%**

*Combined Heat and Power (CHP)

** Uncertainties with hydrogen production are not estimated

***ncludes emissions from other sectors such as other industry, residential, commercial/institutional, agriculture/forestry/fishing/fish farms and non-specified.

The largest uncertainty lies in reconciling statistics on fuel supply and consumption; available data do not match for most fuels. Many data gaps remain in accounting for total energy flows in California, especially for petroleum products such as natural gas liquids (NGL), liquefied petroleum products (LPG), or still gas. The second largest uncertainty comes from the use of national carbon factors which do not reflect California factors. The largest uncertainty in the transport sector, gasoline used by vehicles, is estimated by comparing results from a bottom-up emissions inventory model (EMFAC) with total gasoline sales. The representation of combined heat and power (CHP) in the energy balance needs to be improved by allocating all energy used for commercial and industrial CHP to the sector where the generated electricity is used; all CHP energy use by facilities whose primary business is to sell electricity and heat should be allocated to the electricity generation sector. Finally, reported data on energy use in upstream oil and gas operations is lacking.

5. Recommendations

5.1.1 Improve CALEB

There are a few areas where the CALEB database can be updated with new data identified in this report. This mainly includes the energy used in CHP and the disaggregation of individual petroleum product inputs to the electricity generation sector. To the extent possible, improvements identified in this report will be included in the update of CALEB to 2006, which will be funded by CEC.

In addition to the new sources identified in this report, there are several other improvements that can be made to CALEB. Those improvements, and the data required to make them, are discussed below.

5.1.2 Conduct Surveys

For these industries where the accounting of CO_2 emissions requires more data on energy use, such as refineries, oil companies and chemical industries, surveys that collect the additional data needed would help to fill the gaps in the CALEB database. This could be done on the basis of the national MECS survey (U.S. EIA, 2005b), or more specifically directed to the accounting of CO_2 emissions in these industries. This will also allow the industry to have a better representation of their CO_2 emissions trends over time and give CARB the opportunity to monitor progress in reducing emissions.

5.1.3 Bottom-Up Models

Bottom-up models are a very helpful tool to assess the energy use in end use sectors and to corroborate top-down sales data. CARB has developed a few bottom-up models to account for particulate and other criteria pollutant emissions. An adaptation of these models to account for CO_2 emissions would be very valuable for the GHG emissions inventory. For example, little is known regarding the quantity of diesel fuel used by the agriculture sector. It would help to develop an estimation based on equipment penetration and time of use to compare with available data on fuel sales. This type of analysis would be most valuable for petroleum products used, where sales data do not always indicate the breakdown of consumers by sector.

5.1.4 Collaboration with the U.S. EIA and U.S. EPA

The U.S. EIA gathers a wealth of information on fuel production and supply through multiple questionnaires and surveys. CEC and/or CARB should obtain dedicated access to these data to improve data collection for the state. For example, data disaggregated at the petroleum product level representing inputs to non-utility electricity generation facilities are only available from 1998. We requested that U.S. EIA provide these data prior to 1998; however, these data are confidential and were not provided to us.

Collaboration with the U.S. EPA could also help assess what information is necessary to develop specific carbon factors for California. Consultation with U.S. EPA would be beneficial for CARB to develop specific carbon factors and feedstock carbon storage factors for California.

5.1.5 Compare measured and calculated CO_2 emissions from electric utilities

U.S. EPA's Continuous Emission Monitoring program measures hourly CO_2 emissions from electricity generating facilities in California and throughout the US. CARB should analyze these data to determine if measured CO_2 emissions match annual emissions calculations based on reported fuel use, for individual facilities. In addition, these data can be used to analyze the temporal (hourly) distribution of CO_2 emissions from individual electricity generation facilities.

5.1.6 Improve methods for Transportation

Methods to better quantify emissions from on-road vehicles

U.S. EIA SEDS and California Bureau of Equalization tax receipt data currently provide fairly accurate estimates of statewide use of motor gasoline and diesel fuel by on-road vehicles. Sales data reported annually on new PIIRA form A15 will allow for spatial disaggregation of annual vehicle fuel sales in the future. Any reductions in statewide fuel use by motor vehicles can be monitored using these data sources; however, additional data will be necessary to understand how much of these reductions are attributable to households switching to higher fuel economy vehicles in their current "fleet", purchasing new vehicles with higher fuel economy, or reducing their driving altogether.

CARB's EMFAC model is a very sophisticated tool to estimate what effect changes in vehicle stock, emission rates, and activity have on criteria pollutant and CO_2 emissions. However, EMFAC is updated only every few years. CARB should consider more frequent analyses of existing databases (DMV vehicle registration data, BAR Smog Check records with vehicle odometer readings, etc.) in order to better understand recent changes in the composition of the current vehicle fleet (by type and age), by household size, location and income. These databases can be monitored in the future to understand how changes in fuel prices and policies affect household vehicle holdings and new vehicle purchases, as well as vehicle miles traveled.

Similarly, CARB should explore new methods to obtain information on household driving habits and actual on-road fuel economy. Possible methods include ongoing analysis of California Highway Patrol crash databases (with information on vehicle-driver combinations present on California roadways); ongoing surveys and instrumented vehicle programs to measure household vehicle ownership, use, and fuel use; and maintaining a database of self-reported actual on-road fuel use at the time of vehicle refueling, by vehicle age, type and model.

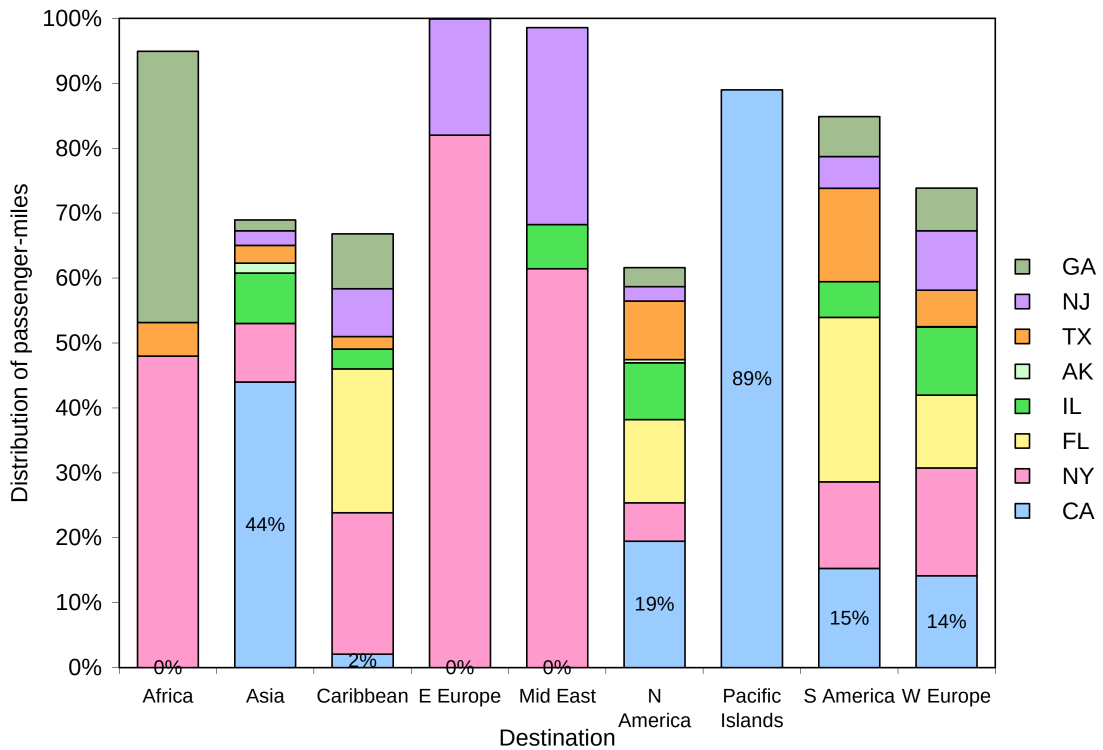
CARB's EMFAC model only accounts for intrastate travel of heavy duty vehicles. CARB should investigate available data and methods for estimating the fuel use and CO_2 emissions generated by long-haul heavy duty trucks transporting freight into California.

Aviation

The bottom-up model of aviation fuel use that LBNL developed is sufficient to allocate total aviation fuel use in SEDS to intrastate, interstate, and international trips originating in California. However, uncertainty still exists in the total amount of fuel used by commercial aviation. CARB should explore using FAA's SAGE model to better estimate the fuel use of intrastate, interstate, and international flights originating in California, and reconcile SAGE modeling outputs with fuel sales in SEDS.

A more fundamental uncertainty regarding commercial aviation fuel use and CO_2 emissions is how to attribute responsibility for interstate and international flights originating in California. CARB could analyze the fuel use of all US flights, to determine what fraction of US interstate and international flights depart from and arrive in California. For example, Figure 14 shows the distribution of passenger-miles on direct international flights taking off from US airports, by US state and international destination. The figure indicates that 89% of passenger-miles on direct US flights to the Pacific Islands (e.g. Australia, New Zealand) fly out of California airports (the columns do not sum to 100% as not all states' airports are included in the figure). This suggests that a large fraction of these passenger-miles are flown by non-Californians that made a connecting flight from their home state to California before boarding the international flight. On the other hand, none of the direct US flights destined for Africa, Eastern Europe, or the Mid East took off from California; instead, Californians took connecting flights to New York, New Jersey, and Georgia airports before boarding their international flights to those destinations. This type of information could be used to allocate a portion of CO_2 emissions from US international flights to California's greenhouse gas emissions inventory; a similar analysis could be done for interstate flights. In addition, CARB should monitor the results of the upcoming report from the Transportation Research Board (TRB) on how to allocate the CO_2 emissions from interstate and international flights to states.

Figure 14. Distribution of passenger-miles on international flights, by originating state and international destination



Marine

CARB has developed a bottom-up inventory of fuel use and CO_2 emissions from marine transportation within 100 nautical miles of California's coast. Data appear to be available to estimate total CO2 emissions from ocean-going vessels traveling to and from California ports; CARB should use those data to develop such an estimate, and allocate total emissions to intrastate, interstate, and international shipping.

Rail

CARB is in the process of updating the 1987 bottom-up inventory of energy use by locomotives.

The Federal Transit Administration maintains the National Transit Database, which provides fuel use, vehicle-miles, and passenger-miles traveled as reported by each transit provider in the US, including 37 transit providers in California. These data can be used for a bottom-up estimate of the fuel consumption and CO_2 emissions from public transit modes (commuter rail, light-rail, and bus service) in California. The data can also be tracked over several years to assess whether California fuel prices and policies are resulting in increases in transit use. Finally, data on transit bus activity and fuel use by California transit providers can be compared with outputs from CARB's EMFAC model.

5.1.7 Independent methods for verifying emission inventory

Measurements of atmospheric radiocarbon CO_2 ($^{14}CO_2$) have been used to provide an independent estimate of the total amount of fossil fuel CO_2 being added to the global atmosphere. Work in Europe suggests that even limited $^{14}CO_2$ sampling could be used to provide an independent constraint on trends in regional European fossil fuel emissions with a resolution of 10-20% (Levine and Rödenbeck, 2008). Recent work in California, shows that a network of radiocarbon vegetation sampling can resolve the spatial distribution of season-averaged fossil fuel CO_2 emissions (Riley et al., 2008). This work suggests that the combination of radiocarbon measurements and modeling has the potential to identify errors in the fossil CO_2 emissions inventories, and verify whether emissions reductions are occurring over time.

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Appendices

Appendix 1- List of U.S. EIA Energy Survey Form

Form Number	Title
DOE-887	DOE Customer Surveys
EIA-1	Weekly Coal Monitoring Report--General Industries and Blast Furnaces (Standby Form)
EIA-3	Quarterly Coal Consumption and Quality Report, Manufacturing Plants
EIA-4	Weekly Coal Monitoring Report--Coke Plants (Standby Form)
EIA-5	Quarterly Coal Consumption and Quality Report, Coke Plants
EIA-6A	Coal Distribution Report - Annual
EIA-6Q	Quarterly Coal Report (Standby)
EIA-7A	Coal Production Report
EIA-8A	Coal Stocks Report - Annually
EIA-14	Refiners' Monthly Cost Report
EIA-20	Weekly Telephone Survey of Coal Burning Utilities (Standby Form)
EIA-23L	Annual Survey of Domestic Oil and Gas Reserves (Field Version)
EIA-23S	Annual Survey of Domestic Oil and Gas Reserves (Summary Version)
EIA-28	Financial Reporting System
EIA-63A	Annual Solar Thermal Collector Manufacturers Survey
EIA-63B	Annual Photovoltaic Module/Cell Manufacturers Survey
EIA-64A	Annual Report of the Origin of Natural Gas Liquids Production
EIA-176	Annual Report of Natural and Supplemental Gas Supply and Disposition
EIA-182	Domestic Crude Oil First Purchase Report
EIA-191A	Annual Underground Gas Storage Report
EIA-191M	Monthly Underground Gas Storage Report
EIA-411	Coordinated Bulk Power Supply Program Report
EIA-412	Annual Electric Industry Financial Report
EIA-423	Monthly Cost and Quality of Fuels for Electric Plants Report
EIA-457A/G	Residential Energy Consumption Survey
EIA-767	Steam-Electric Plant Operation and Design Report
EIA-782A	Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report
EIA-782B	Resellers'/Retailers' Monthly Petroleum Product Sales Report
EIA-782C	Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption
EIA-800	Weekly Refinery and Fractionator Report
EIA-801	Weekly Bulk Terminal Report
EIA-802	Weekly Product Pipeline Report
EIA-803	Weekly Crude Oil Stocks Report
EIA-804	Weekly Imports Report
EIA-805	Weekly Terminal Blenders Report
EIA-810	Monthly Refinery Report
EIA-811	Monthly Bulk Terminal Report
EIA-812	Monthly Product Pipeline Report
EIA-813	Monthly Crude Oil Report
EIA-814	Monthly Imports Report
EIA-815	Monthly Terminal Blenders Report
EIA-816	Monthly Natural Gas Liquids Report
EIA-817	Monthly Tanker and Barge Movement Report

EIA-819	Monthly Oxygenate Report
EIA-820	Annual Refinery Report
EIA-821	Annual Fuel Oil and Kerosene Sales Report
EIA-826	Monthly Electric Utility Sales and Revenue Report with State Distributions
EIA-846(A,B,C)	Manufacturing Energy Consumption Survey
EIA-851A	Domestic Uranium Production Report (Annual)
EIA-851Q	Domestic Uranium Production Report (Quarterly)
EIA-856	Monthly Foreign Crude Oil Acquisition Report
EIA-857	Monthly Report of Natural Gas Purchases and Deliveries to Consumers
EIA-858	Uranium Marketing Annual Survey
EIA-860	Annual Electric Generator Report
EIA-860M	Monthly Update to the Annual Electric Generator Report
EIA-861	Annual Electric Power Industry Report
EIA-863	Petroleum Product Sales Identification Survey
EIA-871A/I	Commercial Buildings Energy Consumption Survey
EIA-877	Winter Heating Fuels Telephone Survey
EIA-878	Motor Gasoline Price Survey
EIA-882T	Generic Clearance for Questionnaire Testing, Evaluation, and Research
EIA-886	Annual Survey of Alternative Fueled Vehicle Suppliers and Users
EIA-888	On-Highway Diesel Fuel Price Survey
EIA-895A	Annual Quantity and Value of Natural Gas Production Report
EIA-895M	Monthly Quantity and Value of Natural Gas Production Report
EIA-902	Annual Geothermal Heat Pump Manufacturers Survey
EIA-906	Power Plant Report
EIA-910	Monthly Natural Gas Marketers Survey
EIA-912	Weekly Underground Natural Gas Storage Report
EIA-914	Monthly Natural Gas Production Report
EIA-920	Combined Heat and Power Plant
EIA-923	Power Plant Operations Report
EIA-1605	Voluntary Reporting of Greenhouse Gases
FE-746R	Import and Export of Natural Gas
OE-781R	Annual Report of International Electrical Export/Import Data
Federal Energy Regulatory Commission (FERC)	Various Collections of Information on Electricity, Natural Gas, Hydroelectric Power, and Oil

Source: http://www.eia.doe.gov/oss/forms.html