

Development of GHG efficiency benchmarks
for the distribution of free emissions
allowances in the California Cap-and-Trade
Program

Refineries – Preliminary Work Product



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A cooperation of: Ecofys and UC Berkeley

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1 Introduction

The California Greenhouse Gas Cap-and-Trade Program aims to control greenhouse gas emissions of the participants in a cost-effective way by creating a system of tradable greenhouse gas (GHG) emissions allowances. The associated emissions cap and market-based compliance mechanisms are defined by the final Cap-and-Trade Regulation that went into effect on January 1, 2012.¹

The program includes three compliance periods in which the covered entities need to balance emissions with allowances. The first one of these periods will start on January 1, 2013 and ends in December, 2014. The second period will start in 2015 and ends in 2017. The third period will start in 2018 and end 2020. The program initially covers industrial facilities, electricity generators, electricity importers and suppliers of carbon dioxide. With the start of the second compliance period in 2015, the program will also include suppliers of natural gas, RBOB, distillate fuel oil and liquefied petroleum gas. Only entities that need to balance annual emissions above a threshold of 25 kt CO₂ are included automatically. Entities with emissions below this threshold may apply to be included via opt-in provisions.

Most covered industrial facilities will receive an amount of allowances for free based on GHG emissions intensity benchmarks:

- The Cap-and-Trade Regulation defines product-based benchmarks for 23 activities. Facilities that perform one or more of these activities receive an amount of allowances that is based on the relevant yearly amount of output (expressed in unit of output per year) and the corresponding benchmark (expressed in allowances per unit of output), a cap adjustment factor and, an assistance factor. The amount of allowances is updated each year to reflect changes in output, cap adjustment, and assistance factor.
- For industrial activities that are not covered by a product-based benchmark, facilities receive an amount of allowances that is based on steam and fuel consumption in an historical baseline period (steam and/or fuel, expressed in MMBtu per year) and one or two energy-based benchmarks (0.06244 allowances per MMBtu of steam and/or 0.05307 per MMBtu of fuel). Unlike the allowances distributed via product-based benchmarks, the amount of allowances distributed via energy-based benchmarks is calculated only once and not updated each year.

For the first compliance period, the amount of free allocation to refineries is determined using a two-step approach. First, the total amount of free allocation to California refineries is determined using a "simple output barrel" product-based benchmark². In a second step, this total amount is distributed over individual refineries on the basis of a complexity-adjusted energy efficiency metric for complex refineries and the simple barrel benchmark for simple refineries. After the first compliance period,

¹ Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations.

² This benchmark is based on the primary products produced including aviation gasoline, motor gasoline, kerosene-type fuel jet fuel, distillate fuel oil, renewable liquid fuels and asphalt.

this two-step approach will be replaced by a uniform complexity-adjusted approach for all refineries known as the Carbon Dioxide Weighted Tonne (CWT) approach.

This document³ compares the different allocation approaches. It investigates the use of the CWT approach in the California Cap-and-Trade Program to identify potential issues and proposes different ways to deal with those issues. The goal of this document is to support California rulemaking. In particular, this document serves as a basis for discussions with stakeholders. It does not aim to make any judgment about the California Cap-and-Trade Regulation, but rather to objectively describe consequences of different policy decisions.

The structure of this report is as follows:

- Chapter 2 provides a general overview of the California refinery industry.
- Chapter 3 describes the oil refining process and associated CO₂ emissions.
- Chapter 4 discusses and compares different benchmarking approaches.
- Chapter 5 focuses on the Carbon Dioxide Weighted Tonne (CWT).
- In Chapter 6, the CWT approach is applied to California refineries using data that was available to the authors as of July 2012.
- Finally, chapter 7 summarizes the conclusions and recommendations.

³ This document has been developed as part of a larger assignment by ARB to a consortium of Ecofys and UC Berkeley.

2 Overview of California Refinery Industry

The Cap-and-Trade Regulation defines a “Petroleum Refinery” or “Refinery” as any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through re-distillation, cracking, or reforming of unfinished petroleum derivatives. The regulation further states that facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

There are 23 facilities in California that meet the definition in the Cap-and-Trade Regulation. These facilities are classified as follows in the North American Industry Classification System (NAICS), (NAICS, 2007):

- 20 petroleum refineries; these facilities are primarily engaged in refining petroleum from crude petroleum (NAICS code: 32411)
- 1 facility categorized under “all other basic inorganic chemical manufacturing” (NAICS code: 325188)⁴
- 1 petroleum lubricating oil and grease manufacturing facility; the products are lubricating oils and greases made by blending or compounding refined petroleum and/or re-refining used petroleum lubricating oils (NAICS code: 324191).⁵
- 1 asphalt paving mixture and block manufacturing facility; the products are asphalt and tar paving mixtures and blocks (NAICS code: 324121).⁵

The locations of petroleum refineries are shown in

Figure 1. The figure shows that refineries are mainly located in the San Francisco Bay Area, Los Angeles area, and the Central Valley.

⁴ This facility is a sulfur recovery plant that can be seen as a support facility for one of the petroleum refineries (source: South Coast Air Quality Management District)

⁵ This facility has emissions below the inclusion threshold of <25 ktCO₂ and has not been included in earlier work on benchmark development by ARB staff (see also next section on emissions).



Figure 1. Refinery locations in California (source: URS Corporation, 2007 from California Energy Commission)

Emissions

Refineries are a major source of GHG emissions in California. While only accounting for 4% of the total number of facilities in the Cap-and-Trade Program, refinery emissions represent about 30% of total covered emissions. Table 1 shows the yearly emissions from non-biomass fuel consumption in the period 2008–2010 as reported under California’s Mandatory Greenhouse Gas Reporting Program.⁶A number of facilities that reported under the primary reporting sector “Petroleum Refinery” did not only manufacture petroleum products, but produced electricity, heat, calcined coke, and/or hydrogen as well. Out of the 23 refineries, 16 refineries also reported under a secondary reporting sector (see Table 1). Relevant definitions for secondary reporting sectors as found in the ARB Mandatory Reporting Regulation (ARB MRR) are provided below. The definition of petroleum refinery can be found on page 3.

- “Cogeneration” means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery....
- “Hydrogen plant” means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.
- “Electricity generating facility” means a facility that generates electricity and includes one or more generating units at the same location.

Operators of installations that had annual emissions equal to or greater than 25 kt CO₂ in 2009 through 2011 are included in the first compliance period of the Cap-and-Trade Program. Any facility that exceeds the threshold in subsequent years is a covered entity starting in the year that the threshold is exceeded. Table 1 shows that the facility classified as petroleum lubricating oil and grease manufacturing facility and the facility asphalt paving mixture and block manufacturing facility have annual emissions below 25 kt CO₂. Despite having emissions below the inclusion threshold, these installations may elect to opt in to the Cap-and-Trade Program, provided that the ARB’s Executive Officer approves.

⁶ For more background see: http://www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/ghg-reports.htm



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Table 1 Facilities in California reporting under primary reporting sector 'Petroleum Refinery' in California's Mandatory Greenhouse Gas Reporting Program; and their reported 2008-2010 emissions.

Facility/Sector	ARB MRR ID #	City	Secondary reporting sector	Emissions from fuel combustion (metric ton CO ₂ -eq. / year) ^e		
				2008	2009	2010
<i>NAICS 324110 - Petroleum Refineries</i>						
Alon Bakersfield Refinery - Area 3 (formerly Big West of California ^a Bakersfield Refinery)	100884	Bakersfield		89,377	4,644	2,144 ^A
Alon Bakersfield Refinery - Areas 1&2 (formerly Big West of California ^a Bakersfield Refinery)	101237	Bakersfield	Hydrogen Plant	534,473	73,229	70,039
BP West Coast Products LLC, Refinery ^f	101246	Carson	Hydrogen Plant, Cogeneration Facility	4,504,286	4,426,851	4,432,520
Chevron Products Company - El Segundo Refinery	100138	El Segundo	Electricity Generation	3,357,821	3,205,873	3,452,447
Chevron Products Company - Richmond Refinery	101384	Richmond	Hydrogen Plant, Cogeneration Facility	4,798,282	4,522,383	4,511,882
ConocoPhillips ^c Refining Company - SF Refinery	100303	Rodeo	Hydrogen Plant, Cogeneration Facility	1,888,895	1,873,464 ^A	1,595,317
ConocoPhillips ^c Los Angeles Refinery, Wilmington Plant	100329	Wilmington	Hydrogen Plant, Cogeneration Facility	2,015,742	1,770,492 ^A	1,668,386
ConocoPhillips ^c Los Angeles Refinery, Carson Plant	100913	Carson	Hydrogen Plant	908,761	807,558	770,437
ConocoPhillips ^c Santa Maria Refinery	101226	Arroyo Grande	Electricity Generation	210,745	220,801 ^A	240,912
Edgington Oil Company ^b	101320	Long Beach		40,919	31,452 ^B	20,370
ExxonMobil Torrance Refinery	100217	Torrance	Hydrogen Plant, Cogeneration Facility	2,852,373 ^C	2,694,574	2,907,770
Kern Oil and Refining Company	101507	Bakersfield	Cogeneration Facility	171,140	161,313	145,469
Lunday-Thagard Company	101162	South Gate		37,384	35,983	34,040
Paramount Petroleum Corporation ^b	101056	Paramount	Cogeneration Facility	189,360 ^C	194,484	217,533
San Joaquin Refining Company	101239	Bakersfield	Hydrogen Plant	90,742	85,979	87,520
Shell Oil Products US	100914	Martinez	Hydrogen Plant, Cogeneration Facility	4,570,475	4,322,192	4,467,460
Tesoro Refining and Marketing Co. - LAR ^d	100335	Wilmington	Hydrogen Plant, Cogeneration Facility, Electricity Generation	1,627,861 ^D	1,455,976 ^A	1,403,710
Tesoro Refining and Marketing Company	101331	Martinez	Hydrogen Plant	2,703,145	2,291,909	2,102,726



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Facility/Sector	ARB MRR ID #	City	Secondary reporting sector	Emissions from fuel combustion (metric ton CO ₂ -eq. / year) ^e		
				2008	2009	2010
Ultramar Inc – Valero	101205	Wilmington		951,913	994,536 ^A	1,116,222
Valero Refining Company -California, Benicia Refinery and Benicia Asphalt Plant	100372	Benicia	Hydrogen Plant, Cogeneration Facility	2,796,057	2,889,804	2,651,106
<i>NAICS 325188 - All Other Basic Inorganic Chemical Manufacturing</i>						
Tesoro Refining and Marketing Co. - SRP ^d	101492	Carson		133,275	121,531	105,895
<i>NAICS 324191 - Petroleum Lubricating Oil and Grease Manufacturing</i>						
Evergreen Oil, Inc, Refinery	101035	Newark		10,753 ^C	9,876	n.a
<i>NAICS 324121 - Asphalt Paving Mixture and Block Manufacturing</i>						
Santa Maria Refining Company	101155	Santa Maria		16,266	5,202 ^B	n.a.

- a. Acquired by Alon in 2010
- b. Acquired by Alon in 2006
- c. Became Phillips 66 in May 2012. The San Francisco Refinery comprises two facilities linked by a 200-mile pipeline: the Santa Maria facility located in Arroyo Grande and the Rodeo facility in the San Francisco Bay Area. The Santa Maria facility upgrades heavy crude oil for final processing in the San Francisco Bay facility. The Los Angeles Refinery Complex is composed of two facilities linked by a five-mile pipeline. The Carson facility serves as the front end of the refinery by processing crude oil, and Wilmington serves as the back end by upgrading the products (source: 10-K forms)
- d. Spent DEA solution (hydrogen sulfide rich solution) and sour water (containing hydrogen sulfide and ammonia) are transferred, via pipeline, from the refinery (LAR) to the sulfur recovery plant (SRP) for sulfur recovery and ammonia removal. The lean (hydrogen sulfide free) DEA solution from the SRP is sent back to the refinery (LAR) for reuse. Because of the operational dependency between the two facilities, the SRP is considered a support facility for the refinery even though the two facilities are neither contiguous nor adjacent to each other (source: South Coast Air Quality Management District)
- e. As available in May 2012: Overall report verification finding of 2010 and 2009 emissions was 'positive' unless indicated otherwise by superscript A ('adverse') or B ('unverified'). Report emissions status of 2008 emissions 'certified' unless indicated otherwise by superscript C ('in revision') or D ('not certified')
- f. Will become Tesoro in 2013. Tesoro plans to connect the refinery with their Wilmington refinery, making them a single unit, with crude oil and product pipelines (source: <http://www.mysanantonio.com/business/article/Tesoro-to-buy-BP-refinery-for-2-5B-3785269.php#ixzz23Wrn1i27>)

Capacity

Table 2 shows the capacity of the major process units within California refineries as available in the 2011 Refinery Capacity Report⁷ by the U.S. Energy Information Administration (EIA).

Capacity can either be reported per stream day or as per calendar day⁸:

- Barrels per stream day: the maximum number of barrels of input that a distillation facility can process within a 24-hour period when running at full capacity under optimal crude and product slate conditions with no allowance for downtime.
- Barrels per calendar day: the amount of input that a distillation facility can process under usual operating conditions. The amount is expressed in terms of capacity during a 24-hour period and reduces the maximum processing capability of all units at the facility under continuous operation (see "barrels per stream day") to account for the following limitations that may delay, interrupt, or slow down production:
 1. The capability of downstream processing units to absorb the output of crude oil processing facilities of a given refinery. No reduction is necessary for intermediate streams that are distributed to other than downstream facilities as part of a refinery's normal operation;
 2. The types and grades of inputs to be processed;
 3. The types and grades of products expected to be manufactured;
 4. The environmental constraints associated with refinery operations;
 5. The reduction of capacity for scheduled downtime due to such conditions as routine inspection, maintenance, repairs, and turnaround; and
 6. The reduction of capacity for unscheduled downtime due to such conditions as mechanical problems, repairs, and slowdowns.

⁷ Capacities as available in the 2011 Refinery Capacity Report by the U.S. Energy Information Administration (EIA) (Available at: <http://www.eia.gov/petroleum/refinerycapacity>).

⁸ Descriptions from: <http://petrofortune.com/Resources/Glossary/B.aspx>

Table 2 Refinery capacity data by individual refinery as of January 1, 2011 (U.S. EIA, 2011)

Facility/Sector	Crude (b/sd) ²	Downstream charge capacity ¹ (b/sd) ¹							Production capacity (b/sd)							
		Catalytic cracking ³	Catalytic hydrocracking ⁴	Catalytic reforming ⁵	Desulphurisation ⁶	Fuels solvent deasphalting	Thermal cracking ⁷	Vacuum distillation	Alkylates	Aromatics	Asphalt & road oil	Hydrogen (MMCFD)	Isomerisation ⁸	Lubricants	Petcoke	Sulphur (st/d)
NAICS 324110/SIC 2911 - Petroleum Refineries ⁹	2,689,412	716,000 ^a 13,400 ^b	289,200 ^a 215,700 ^b	213,200 ^a 216,700 ^b	443,600 ^a 332,800 ^b 196,100 ^c 283,300 ^d 632,200 ^e 175,700 ^f	66,000	449,900 ^a 52,000 ^b 5,000 ^c	1,721,368	181,526	1,500	414,345	1,124	34,325 ^a 114,600 ^b 200 ^c	39,800	134,700	4,804
Alon Bakersfield Refinery - Areas 1&2 ¹⁰	-		14,500 ^a	8,000 ^a	8,000 ^a							22	300 ^a 500 ^b 200 ^c			70
Alon Bakersfield Refinery - Area 3 ¹⁰																
BP West Coast Products LLC, Refinery ¹⁴	266,000	102,500 ^a	50,000 ^b	10000 ^a 43000 ^b	45,000 ^a 21,000 ^b 10,000 ^c 27,000 ^d 95,000 ^e		67,100 ^a	140,000	17,000			105	3,500 ^a 23,000 ^b		13,800	420
Chevron Products Company – El Segundo Refinery	286,900	73,800 ^a	52,300 ^a	49000 ^a	59,000 ^a 42,000 ^b 36,300 ^c 73,700 ^d 14,000 ^f		77,600 ^a	169,100	33,500			77	8,500 ^a 22,300 ^b		25,500	600
Chevron Products Company - Richmond Refinery	257,200	90,000 ^a	103,400 ^a	71300 ^a	57,600 ^a 64,800 ^b 96,000 ^c 64,800 ^d 65,000 ^e 34,000 ^f	66,000		123,456	23,426			181	7,200 ^a 46,000 ^b	34,000		789
ConocoPhillips Refining Company - SF Refinery ¹¹	128,000		62,000 ^a	34000 ^b	27,500 ^a 32,000 ^b		51,000 ^a	92,300				84	3,800 ^a 10,000 ^b		14,500	640
ConocoPhillips Santa Maria Refinery ¹¹																
ConocoPhillips Los Angeles Refinery Wilmington Plant ¹¹	147,000	51,600 ^a	27,500 ^b	36,200 ^b	50,800 ^a 32,000 ^b 12,900 ^c 55,000 ^d		53,200 ^a	82,000	9,900			105	3,100 ^a 12,800 ^b		16,800	370
ConocoPhillips Los Angeles Refinery, Carson Plant ¹¹																
Edgington Oil Company ¹³	35,000							25,000			15,000					

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Facility/Sector	Crude (b/sd) ²	Downstream charge capacity ¹ (b/sd) ¹							Production capacity (b/sd)							
		Catalytic cracking ³	Catalytic hydrocracking ⁴	Catalytic reforming ⁵	Desulphurisation ⁶	Fuels solvent deasphalting	Thermal cracking ⁷	Vacuum distillation	Alkylates	Aromatics	Asphalt & road oil	Hydrogen (MMCFD)	Isomerisation ⁸	Lubricants	Petcoke	Sulphur (st/d)
ExxonMobil Torrance Refinery	155,800	87,800 ^a 12,400 ^b	22,200 ^b	18,000 ^b	24,700 ^a 18,000 ^b 106,500 ^e		53,000 ^a	102,300	24,200			146			16,700	400
Kern Oil and Refining Company	27,000			2,500 ^a 3,300 ^b	5,000 ^a 9,000 ^f											11
Lunday -Thagard Company	10,000							7,000			5,833					
Paramount Petroleum Corporation ¹³	55,000			12,000 ^b	15,000 ^a 13,000 ^b 8,500 ^c			30,000			16,500					40
San Joaquin Refining Company	25,000				3,000 ^f		5,000 ^c			1,500	8,000	4		5800		3
Shell Oil Products US	158,000	72,000 ^a	42,000 ^b	31,000 ^a	27,500 ^a 50,000 ^d 81,500 ^e 48,500 ^f		25,000 ^a 22,500 ^b	102,000	12,000		10,000	193			8,600	413
Tesoro Refining and Marketing Co. – LAR	103,500	35,000 ^a	22,000 ^a 10,000 ^b	33,000 ^b	34,500 ^a 10,000 ^b 17,000 ^c 38,000 ^e 22,000 ^f		42,000 ^a	65,000	11,000			12	4,125 ^a		11,000	280
Tesoro Refining and Marketing Company	170,000	72,000 ^a 1,000 ^b	35,000 ^a	24,000 ^a	27,000 ^a 40,000 ^b 43,300 ^d 69,500 ^e 18,500 ^f		53,000 ^a	156,900	15,400			82			11,000	200
Ultramar Inc – Valero ¹²	80,000	56,000 ^a		17,400 ^a	32,000 ^a 45,000 ^b 64,000 ^e		28,000 ^a	45,000	18,000						10,000	265
Valero Refining Company -California, Benicia Refinery and Benicia Asphalt Plant	135,000	75,300 ^a	34,000 ^b	37,200 ^b	30,000 ^a 15,000 ^b 15,400 ^c 43,200 ^d 39,000 ^e 26,700 ^f		29,500 ^b	81,300	17,100	9,000		135	3,800 ^a		6,800	303

¹ The input (feed) capacity of the refinery processing facilities

² Barrels per stream day, except for hydrogen in millions of cubic feet per day (mmcf) and sulphur in short tons per day (st/d)

³ The feeds used for catalytic cracking are ^afresh feed and ^brecycled feed.

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⁴ The feeds used for catalytic hydrocracking are ^agas oil and ^bdistillate.

⁵ Catalytic reforming can occur at ^alow pressure or ^bhigh pressure.

⁶ The feeds used for desulphurisation: ^anaphtha/reformer, ^bdiesel oil, ^ckerosene and jet, ^dgasoline, ^eheavy gas oil and ^fother distillate.

⁷ The types of thermal cracking used are ^adelayed cooking, ^bfluid cooking and ^cvis breaking.

⁸ Isomerisation of ^aisobutane, ^bisopentane/isohexane and ^cisooctane; does not include sulphur and hydrogen.

⁹ In the EIA data, capacity data of Tenby Inc owned by Oil Holding Inc is given. However, this company does not appear on ARB's list of operable facilities and has therefore been excluded from the total capacity calculation.

¹⁰ Acquired by Alon in 2010

¹¹ Became Phillips66 in May 2012

¹² In EIA data Valero Refining Co Wilmington Asphalt Plant is mentioned separately. It is assumed that this plant is not part of facility as defined for the Cap-and-Trade Program

¹³ Acquired by Alon in 2006

¹⁴ Will become Tesoro in 2013. Tesoro plans to connect the refinery with their Wilmington refinery, making them a single unit, with crude oil and product pipelines (source: <http://www.mysanantonio.com/business/article/Tesoro-to-buy-BP-refinery-for-2-5B-3785269.php#ixzz23Wrn1i27>)

3 Oil Refining Process and Related CO₂ Emissions

3.1 Refinery process

The basic processes in the production of refined oil products from crude oil can be categorized in the following groups (Ecofys, 2009):

- Distillation processes: physical separation methods to decompose homogeneous liquid mixtures under usage of the different boiling behavior of the mixture components.
- Conversion processes: chemical methods to change the chemical structure of hydrocarbons contained in the different crude oil fractions (mostly producing smaller molecules and increasing the hydrogen to carbon ratio).
- Finishing processes of refined oil products: the gases, liquefied gases, gasoline, middle distillates and gas oils produced by the distillation and conversion processes are cleaned by removing compounds which disturb further processing or the quality of finished products.
- Other processes: besides these basic procedures mentioned above, a number of further procedures are necessary to achieve the desired quality of the oil products and process by-products such as sulfur.

In addition to the process steps that are typically found in refineries, several refineries also include petrochemical units for the production of basis chemicals such as steam crackers and units for the production of aromatics. A simplified process diagram of a typical oil refinery is shown in Figure 2.

The processes in a refinery vary depending on the complexity of the refinery. Below, the key process steps in a refinery are briefly explained in more detail (unless noted otherwise, descriptions are based on Öko Institut (2008); other overviews are, amongst others, provided by LBNL (2004), LBNL (2005) and BREF Refineries-draft (2012)).

Crude oil distillation: The first step in the oil refining process is the separation of crude oil into various fractions by distillation in atmospheric and vacuum towers. The main fractions obtained have specific boiling-point ranges and can be classified in order of decreasing volatility into gases, light distillates, middle distillates, gas oils, and residues.

The distillation products are further processed, depending on the desired product mix. Refinery gas is used as fuel in the refinery operations to generate heat (furnaces), steam (boilers) or power (gas turbines), while some of the refinery gas may be flared. Parts of the refinery gas may also be used to blend with LPG or for hydrogen production. Hydrogen is used in different processes in the refinery to remove sulfur (e.g., hydrotreating) and to convert to lighter products (e.g., hydrocracking).

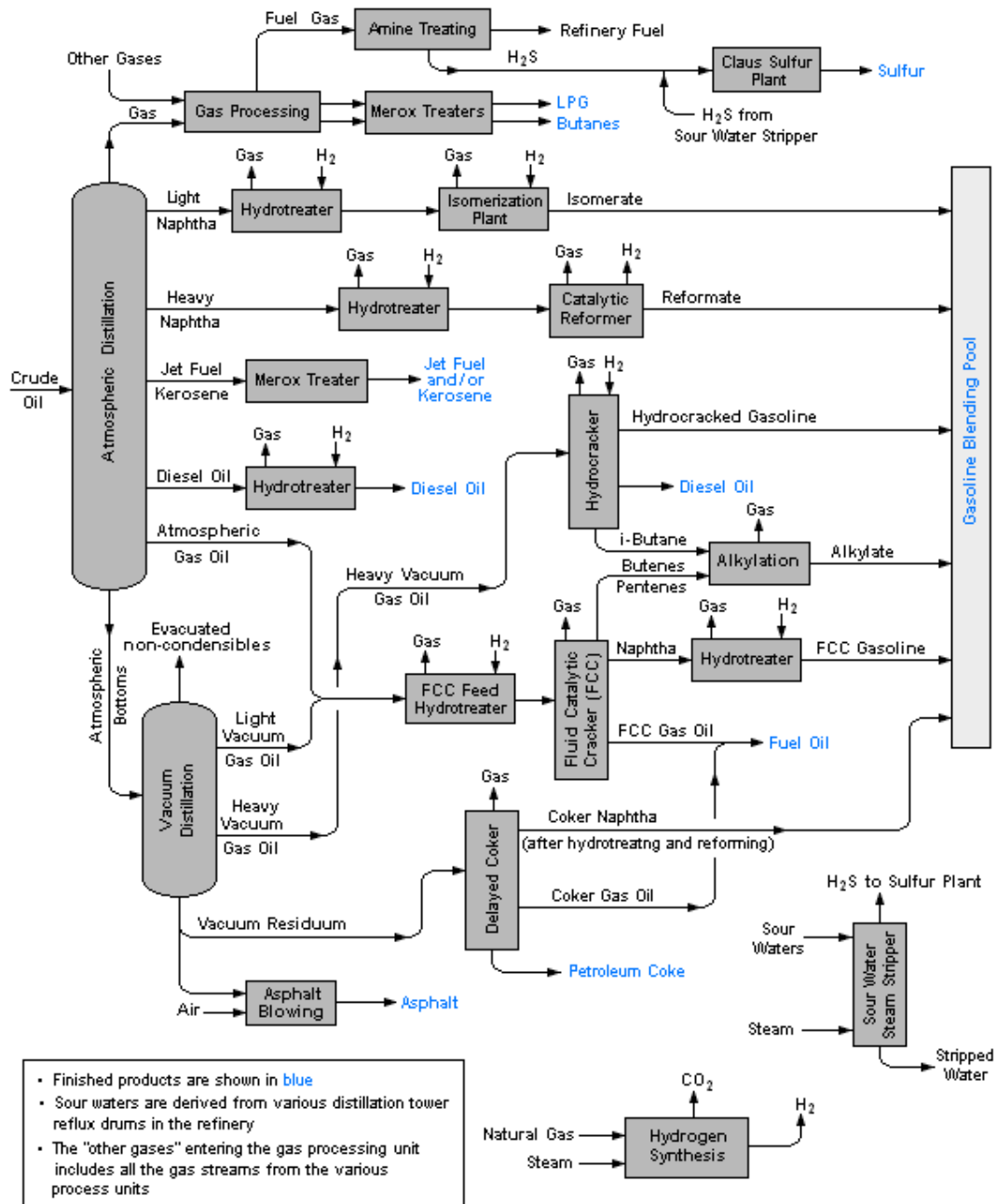


Figure 2. Simple diagram of an oil refinery (Source: http://en.wikipedia.org/wiki/Petroleum_refining)

Thermal operations: Since not all products of the simple distillation of crude oil can directly be sold to the market, subsequent refinery processes change the product mix by altering the molecular structure of the hydrocarbons. One of the ways of accomplishing this change is through "cracking," a process that breaks or cracks the heavier, higher boiling-point petroleum fractions into more valuable products such as gasoline, fuel oil, and gas oils. The two basic types of cracking are thermal cracking, using heat and pressure, and catalytic cracking.

Coking process: Coking is a severe method of thermal cracking used to upgrade heavy residuals into lighter products or distillates. Coking produces gasoline and various middle-distillate fractions used as catalytic cracking feedstock. The process completely reduces hydrogen such that the residue is a form of carbon called "coke."

The most important processes are delayed coking and flexicoking, both developed by Exxon and used at various refineries around the world. Refineries in California generally use lots of heavy feedstocks. Therefore, California refineries have a relative large coking capacity. The coking capacity in California is mostly made up of delayed cokers. In the U.S., only the Shell Martinez-refinery in the San Francisco Bay Area has a flexicoker installed (LBNL, 2004).

Coke calcining: See section 5.10.

Catalytic cracking: Catalytic cracking breaks complex hydrocarbons into simpler molecules in order to increase the quality and quantity of lighter, more desirable products and decrease the amount of residuals. This process rearranges the molecular structure of hydrocarbon compounds to convert heavy hydrocarbon feedstock into lighter fractions such as kerosene, gasoline, LPG (liquified petroleum gas), heating oil, and petrochemical feedstock. Use of a catalyst (a material that assists a chemical reaction but does not take part in it) in the cracking reaction increases the yield of products. The most common catalytic cracking process is the FCC (fluid catalytic cracking). Most California refineries pre-treat the FCC-feed by hydrotreating (LBNL, 2004).

Hydrocracking: Hydrocracking is a two-stage process combining catalytic cracking and hydrogenation. In this process, heavier feedstocks are cracked in the presence of hydrogen to produce more desirable products. The process employs high pressure, high temperature, a catalyst, and hydrogen. Hydrocracking is used for feedstocks that are difficult to process by either catalytic cracking or reforming.

Catalytic reforming: Catalytic reforming is an important process used to convert low-octane naphtha into high-octane gasoline blending components called reformates. Reforming represents the total effect of numerous reactions such as cracking, polymerization, dehydrogenation, and isomerisation taking place simultaneously. Hydrogen, a significant by-product, is separated from the reformat for recycling and use in other processes.

Catalytic hydrotreating: Catalytic hydrotreating is a hydrogenation process used to remove about 90% of contaminants such as nitrogen, sulfur, oxygen, and metals from liquid petroleum fractions.

These contaminants, if not removed from the petroleum fractions as they travel through the refinery process units, can have effects on the equipment, the catalysts, and the quality of the finished product. Typically, hydrotreating is carried out prior to processes such as catalytic reforming so that the catalyst is not contaminated by untreated feedstock. Hydrotreating is also used prior to catalytic cracking to reduce sulfur and improve product yields, and to upgrade middle-distillate petroleum fractions into finished kerosene, diesel fuel, and heating fuel oils.

California refineries have additional high-pressure gas oil hydrotreating capacity installed to treat the FCC feed, as California crude oil contains relatively high amounts of nitrogen (LBNL, 2004).

Isomerisation: Isomerisation converts n-butane, n-pentane and n-hexane into their respective isoparaffins of substantially higher octane number. Isomerisation is similar to catalytic reforming in that the hydrocarbon molecules are rearranged, but unlike catalytic reforming, isomerisation just converts normal paraffins to isoparaffins.

Polymerization: Polymerization in the petroleum industry is the process of converting light olefin gases into hydrocarbons of a higher molecular weight and higher octane number that can be used as gasoline blending stocks. Polymerization may be accomplished thermally or in the presence of a catalyst at lower temperatures.

Alkylation: Alkylation combines low-molecular-weight olefins in the presence of a catalyst. The product is called alkylate. Alkylate is a premium blending stock because it has exceptional antiknock properties and is clean burning. The octane number of the alkylate depends mainly upon the kind of olefins used and upon operating conditions.

Hydrogen production: see section 5.9.

Asphalt production: Asphalt is a portion of the residual fraction that remains after primary distillation operations. It is further processed to impart characteristics required by its final use.

Lubricating: Lubricating oils and waxes are refined from the residual fractions of atmospheric and vacuum distillation. The primary objective of the various lubricating oil refinery processes is to remove asphalts, sulphonated aromatics, and paraffinic and isoparaffinic waxes from residual fractions.

Etherification (Oxygenates): A number of chemicals (mostly alcohols and ethers) are added to motor fuels either to improve performance or to meet environmental requirements. Alcohols and ethers have been added to gasoline to increase octane levels, reduce carbon monoxide generation and reduce atmospheric ozone due to the lower reactivity of resulting VOC (volatile organic compound) emissions. The most common ethers being used as additives are methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), and tertiary amyl methyl ether (TAME). Some refineries manufacture their own supplies of those ethers.

Gas separation: Low boiling hydrocarbons are usually treated in a common separation plant operating at elevated pressures. The purpose of a gas plant is to recover and to separate carbon compounds from various refinery off-gases by distillation.

Sulfur recovery: Hydrogen sulfide is removed from the refinery fuel gas system through the use of amine scrubbers. While the selectivity of hydrogen sulfide removal is dependent on the type of amine solution used, these scrubbers also tend to extract CO₂ from the fuel gas. The concentrated sour gas is then processed in a sulfur recovery plant to convert the hydrogen sulfide into elemental sulfur or sulfuric acid. The most common type of sulfur recovery plant is the Claus unit, which produces elemental sulfur. The first step in a Claus unit is a burner to convert one-third of the sour gas into sulfur dioxide prior to the Claus catalytic reactors. After that, the sulfur dioxide and unburned hydrogen sulfide are reacted in the presence of a bauxite catalyst to produce elemental sulfur (EPA, 2008).

California has a much higher capacity (relative to crude distillation capacity) of hydrocracking and hydrotreating, when compared to the U.S. average. This is due to the relative higher desired output of lighter products (e.g., gasoline) and the regulatory demand for lower sulfur-content from gasoline to reduce air pollution from transport. On the other hand, California refineries do not produce any aromatics as a chemical feedstock, as no large petrochemical industry is present in the state (LBNL, 2004).

3.2 Sources of CO₂ Emissions

The sources of CO₂ emissions that are associated with refineries can be summarized as follows:

- Direct emissions occurring on site⁹
 - 1) Stationary combustion sources, including process heaters, boilers, combustion turbines, and similar devices.
 - 2) Flares
 - 3) Catalytic cracking units
 - 4) Coking units
 - 5) Catalytic reforming units
 - 6) Sulfur recovery vents
 - 7) Hydrogen plants
 - 8) Asphalt blowing stills
 - 9) Coke calcining units
- Indirect emissions from energy import: this includes electricity consumption from power imported from the grid or a third party, and heat and steam imports from a third party. The emissions associated with this electricity, heat and steam occur at the location of the production.

A more detailed description of the GHG emissions sources is given by U.S. EPA (2008).

⁹ Breakdown of direct emission sources was obtained from U.S. EPA (2010)

3.3 Determinants of Emissions Intensity

The total emissions of refineries can differ extremely, as is illustrated by Table 1 in section 2. The main determinants of a refinery's emissions are listed below:

- Amount of crude processed: all other things being equal, a refinery that processes more crude will have higher emissions. The amount of crude processed depends on a refinery's capacity and its capacity utilization.
- Configuration: different refineries are configured to perform a different combination of processes, each with its own different emissions intensity.
- Feed composition: properties of crude and other inputs intermediate product for further processing; Crude oil varies in its weight and chemical form. The terms heavy and light are used to refer to density. Heavy oil – more dense – contains a higher share of heavy hydrocarbons. The terms sweet and sour refers to the sulfur content of the crude. In general, to produce a similar product mix, heavier, sourer crude requires more processing and lead to increased energy use and more CO₂ emission.
- Product mix: a high share of light products (gasoline and diesel) requiring higher processing and more CO₂ emissions. Refineries in California produce a larger share of reformulated gasoline and fuels with lower sulfur content. Because of this market in which the California refineries operate, it has a relatively high share of advanced conversion processes—more than most other states. This makes the oil refining industry in California more energy intensive in its product-mix than the U.S. average (LBNL, 2004).
- Fuel quality requirements: more stringent quality requirements for transportation fuels will affect the energy intensity of processing (e.g., reduction of sulfur content or other requirements). Note that there may be positive effects of fuel quality on the efficiency of automotive internal combustion engines, however, with a penalty for refining energy use.
- Fuel types used: different fuels are burnt for various oil refining processes, resulting in different CO₂ emissions per unit of energy use (IEA, 2005). Typically used fuels are refinery fuel gas, natural gas, LPG, distillate fuel oil, residual fuel and coke. The emissions are relatively low when fuels such as refinery fuel gas, low-sulfur fuels oil or natural gas are combusted. If heaters are fired with refinery fuel pitch or residuals, emissions can be significantly higher.
- By-product processing: in modern conversion-type refineries, heavy by-products may be generated. These can be processed onsite or offsite to products (e.g., bitumen) or converted to process inputs and energy through gasification. The gasifier can be used for power generation in an Integrated Gasifier Combined Cycle (IGCC; see also next bullet). This technique is currently not being used in California.
- Import and export of energy: many refineries import electricity leading to indirect emissions, although electricity may be exported as well. Refineries may also import and/or export steam.
- Energy efficiency; this is influenced by operational factors like capacity utilization, maintenance practices, process management, as well as age of the equipment. It is noted

that most California refineries are older than the U.S. refineries on average, reflecting the long history of oil exploration and processing in the state (LBNL, 2004).

The factors listed above change over time and with them do refinery energy use and emissions. It is noted that the determinants do not stand by themselves but are interrelated; e.g., the product mix of a refinery depends on its feed composition, configuration, and operation.

4 Overview of Approaches for Benchmarking Emissions Efficiency

All refineries process crude to make a broadly similar range of products (LPG, gasoline, kerosene, gasoil/diesel and fuels oils). Different refineries may produce these products in different relative and absolute quantities. Refineries can, however, differ in terms of types of process units and relative and absolute size (as illustrated by Table 2 in chapter 2). More complex refineries typically are better able to produce a higher share of lighter products. Different routes with different CO₂ footprints exist to make a certain product. Production routes and products are interdependent, i.e., a refinery cannot produce only gasoline. A single refinery will typically use several production routes.

As a result of the above, energy consumption and CO₂ emissions do not readily correlate with simple indicators such as crude throughput, product make or the like. A lower emissions intensity on the basis of these indicators does not necessarily mean a higher efficiency.¹⁰ This poses challenges when comparing the emissions efficiency of different refineries. Other challenges that may arise when comparing refineries include:

- Differences in degree of incorporation of emissions from on-site production of electricity,
- The import and export of electricity and steam,
- Transfer of intermediate fractions from one refinery to another, and
- Integration and overlap with the petrochemical industry (steam cracking, hydrogen and synthesis gas production, propylene production and production of aromatics).

4.1 Benchmarking on the Basis of Crude Oil Processed or Output of Products

The determination of a benchmark on the basis of the amount of crude oil processed or product output is relatively easy to develop. A benchmark based on either metric is transparent and based on information that is generally readily available. However, neither of the resulting benchmarks would take into account the relative complexity of different refineries.

A single refinery will use different techniques with different CO₂ footprints to make a certain product and production routes and products are interdependent, i.e., a refinery cannot produce only gasoline. Energy consumption and CO₂ emissions do therefore not readily correlate with simple indicators such as crude throughput and final product mix. A benchmarking approach only based on one of these indicators would therefore not solely reflect performance in terms of emissions (Öko Institut, 2008; Ecofys, 2009).

Comparisons of different refineries with different complexities on the basis of emissions per barrel of crude throughput or barrel of final product have been found to show wide distributions. Öko Institut

¹⁰ See Appendix C for a discussion on the difference between intensity and efficiency

(2008) compared Italian, German and Dutch refineries and found a factor of 3-4 difference in emission intensities evaluated per barrel of crude. CARB (2011a) found a similar difference when comparing California refineries on the bases of emissions per barrel of primary refinery product.¹¹ (see Figure 3)

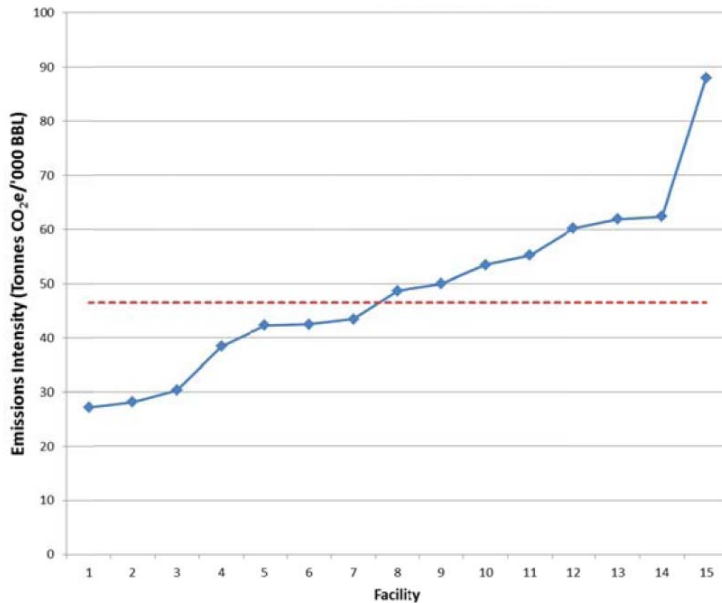


Figure 3. Emissions intensity of California refineries in terms of primary products produced together with benchmark based on 90% of weighted average emissions intensity (CARB, 2011a).

An even wider range was found when comparing California refineries in terms of emissions per barrel of crude input. This range is shown in Figure 4¹² which shows:

- Estimated 2010 emissions per barrel of crude input for California refineries,

¹¹ "Primary Refinery Products" means aviation gasoline, motor gasoline, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt.

¹² Emissions were obtained from California's Mandatory Greenhouse Gas Reporting Program. To improve the comparison of the emissions intensity of the refining process, the emissions have been corrected for purchased and sold electricity and heat, using 0.431 metric ton CO₂/MWh and 0.06244 tCO₂/MMBtu steam, to the extent this was feasible using data provided by ARB staff. Crude charge capacity was obtained from U.S. Energy Information Administration's Refinery Capacity Report of June 2011 (available at <http://www.eia.gov/petroleum/refinerycapacity/>). Crude input was estimated by multiplying this capacity by a State-wide capacity utilization estimated using total annual crude input from California Refinery "Fuels Watch Report" and U.S. EIA capacity data. For a small number of refineries, facility specific capacity utilization could be derived from 10-K forms. For some refineries, there is not a one-to-one relation between the facility listed in the GHG reporting program and in U.S. EIA's refinery capacity report. Appendix C shows the mapping used in this assessment.

- The distance to a benchmark¹³, and
- The 2010 crude charge capacity of the crude distillation unit.

Comparing the crude input to emissions intensity shows that, in general, smaller refineries with a lower crude charge capacity have lower emissions intensities. These refineries are in general less complex in the sense that they have fewer process units and therefore a lower ability to convert crude in light products. It is worthwhile mentioning that for German refineries, Öko Institut (2008) did not find a correlation between emissions intensity in terms of crude input and complexity.

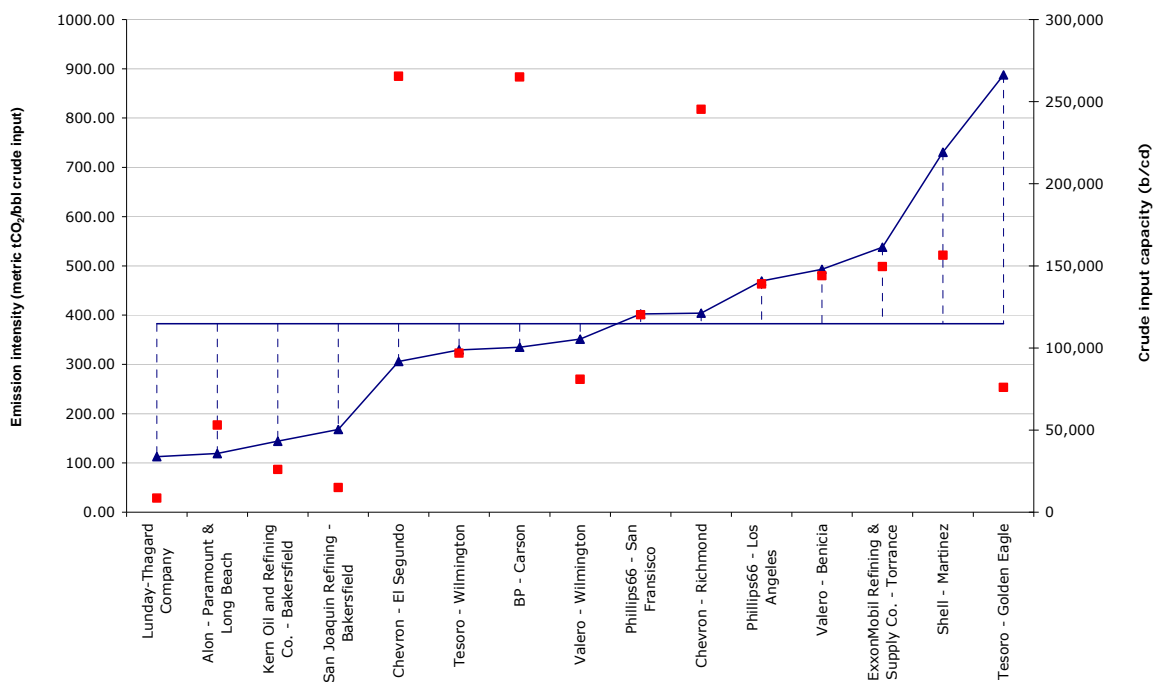


Figure 4. 2010 estimated emissions intensity of California refineries in terms of crude input (triangles; left axis) together with benchmark (horizontal line; left axis) and 2010 capacity of crude distillation unit (squares; right axis).

4.2 Process-Specific Benchmarks

This approach is based on a modular system in which emissions benchmarks are developed for each refinery process unit (Öko Institut, 2008). The allocation is then a composite of the individual benchmarks of the process units that are in the respective refinery as process components.

From a methodological point of view, an advantage of this approach is that it reflects the configuration of refineries. The approach does not however, reflect the complex ways in which

¹³ The benchmark is defined as 90% of weighted average emissions intensity

different units interact. As a result of these interactions, no refinery can operate each unit at best achievable performance at the same time.

From a practical point of view, an advantage of this approach is its flexibility with regard to adjusting the benchmarks for individual units: if technical improvements arise in the case of individual process units or innovations appear on the market, the benchmark value can be flexibly adapted or new benchmark values can be developed without the overall unit having to be newly modeled.

A practical disadvantage is that no modular benchmarks have yet been developed as far as the authors are aware. The development of such benchmarks would require deep knowledge of oil refining processes and significant efforts to solve methodological issues and to obtain required data.

4.3 Hybrid Approach

Another alternative is the 'hybrid' benchmarking approach (Öko Institut, 2008). The hybrid approach can be thought of as a combination of a benchmark solely based on the amount of crude oil processed and the process-specific approach. It does not account for all differences in refinery configurations, but tries to capture the most important ones.

One important drawback of the hybrid approach is that it has never been developed as far as the authors are aware. Although less so than for the process-specific approach, development of the hybrid approach would, therefore, require significant efforts to solve methodological issues and to obtain required data.

4.4 Complexity Weighted Approaches

A complexity weighted approach compares facilities with different configurations and sizes by redefining the activity level. In its most simple form, this activity level is calculated by weighting the throughputs of different process units using weighting factors that reflect standardized performance levels. The main difference with the process-specific approach described in section 4.2 is that benchmarks are not defined per unit but that one benchmark is defined for the refinery as a whole on the basis of a complexity weighted index.

Solomon Associates developed complexity weighted approaches to benchmark energy and emissions efficiency in refineries. Solomon's benchmarking methodologies are based on detailed information provide by companies on refineries' layouts, feedstock characteristics, operating rates and operating conditions. Solomon's approach is understood by all complex refineries. The Solomon Energy Intensity Index (EII®), which is used to compare refinery energy efficiency, has been recognized under the U.S. Environmental Protection Agency's (EPA) ENERGY STAR® Program and will be used in

the first compliance period of the California Cap-and-Trade Program to determine the amount of free allocation provided to each complex refinery.¹⁴

Solomon also developed the Carbon Emissions Index (CEI™) to benchmark refineries' greenhouse gas emissions. ^{See footnote 14}

The Complexity Weighted Barrel (CWB) and Carbon Dioxide Weighted Tonne (CWT) approach are simplified versions of the CEI™ approach that have been developed for regulatory purposes. The CWT approach has been used in the European Union's Emissions Trading System (EU ETS) to determine the amount of free emissions allowances to refineries in the period 2013-2020 and will be used for the same purpose in the California Cap-and-Trade Program after the first compliance period. The CWT approach is described in more detail in section 5.1.

4.5 Comparison of Approaches

Table 3 compares the approaches discussed in this chapter on the basis of three criteria that according to the authors gives a good indication of the differences between the different approaches: the level of transparency, costs of development and the extent to which they take into account differences between refineries in terms of configuration and size. These criteria are not necessarily the (only) relevant ones or the ones that ARB used when choosing the CWT methodology for the refinery allocation after the first compliance period.

Table 3 Comparison of approaches

	Transparency	Efforts required to develop	Takes into account differences in configuration
Benchmark based on amount of crude oil processed or amount of products produced	++	++	--
Separate benchmarks for different process units	+ ¹	--	+
Hybrid approach	+ ¹	-	-/+
Complexity Weighted Benchmarks	--	-/+	++

¹ Depending on the way that the benchmarks are defined.

¹⁴ For a description of the methodology that underlies the EII®, the reader is referred to papers on Solomon's company website (<http://solomononline.com/benchmarking-performance/refining/>). The details of the methodology cannot be described without Solomon's permission.

5 CO₂ Weighted Tonne (CWT) Approach

After an introduction to complexity weighted approaches in section 4.4, this chapter in detail discusses the CWT methodology. The CWT approach is the complexity weighted approach that has been used in the EU ETS to determine of the amount of free emissions allowances to refineries in the period 2013-2020.

Throughout the discussion, it is important to distinguish between benchmarks indicating a level of performance and the allocation to refineries. The allocation to refineries is based on the benchmark but also on other factors—most importantly the level of activity. The benchmark has a fixed value, whereas the allocation is updated annually.

5.1 Description of CWT Methodology

5.1.1 Determination of Amount of CWT

When using the CWT approach, the single “product” of the refinery is the CWT. For the calculation of the “production” of a refinery in terms of CWTs, Solomon Associates defined a list of about 50 generic process units. It is estimated that refineries will typically contain 10-15 of these process units. Each of the generic process units was assigned an emission factor relative to crude distillation, which is denoted as the CWT factor. The CWT factor of the crude distillation unit is taken as 1. Factors of other units are representative of their CO₂ emissions intensity at:

- A standard level of performance,
- For the same standard fuel type for each process units for combustion, and
- For average process emissions of the process unit.

CWT factors incorporate net energy consumption of fuel, heat and electricity (i.e., any net import of steam or electricity is added and any net steam or electricity export is deducted). Section 5.4 discusses the CWT factors in more detail. Details of the CWT process units are provided in Appendix B.

The “production” of a refinery in terms of CWTs represents a combination of the throughputs of the different process units, and therefore the “activity” of the refinery. The calculation can be described as follows:

- The amount of CWTs of each process unit is determined by multiplying its CWT factor by its intake during a given period,
- The amounts of CWTs of all process units are subsequently summed up, and
- A correction is made to account for off-sites and for non-crude feedstock (see section 5.6 for explanation and discussion)

For each refinery the “production” can be calculated in the following way:

$$CWT_k = 1.0183 \cdot \sum_{i=1}^n (TP_{i,k} \cdot CWT_Factor_i) + 298 + 0.315 \cdot TP_{AD,k}$$

with:

CWT_k :	The amount of CWT for a refinery in year k
$TP_{i,k}$:	Throughput of process unit i in year k of the baseline period as defined for the purpose of the CWT approach
CWT_Factor_i :	CWT factor for process unit i as defined by for the purpose of the CWT approach
$1.0183 \cdot \dots + 298 + 0.315 \cdot TP_{AD,k}$:	Generic correction for off-sites and for non-crude feedstock. $TP_{AD,k}$ is the throughput of the Atmospheric Crude Distillation in year k of the baseline period defined as fresh feed (kt) per year. This correction is discussed in more detail in section 5.6)

Appendix A provides the calculation above in a table.

5.1.2 Determination of Benchmark

The emissions intensity of the refinery in terms of CWT can be obtained by dividing emissions by the amount of CWT. Corrections need to be made with respect to steam and electricity. The way to do this depends on the design of the overall allocation methodology and is further discussed in sections 5.7 and 5.8. Product-based benchmarks in the California Cap-and-Trade Program are generally defined as 90% of the weighted average emissions intensity.¹⁵ Taking the same approach for refineries, the benchmark emissions intensity is calculated as follows:¹⁶

$$B_{CWT} = 0.9 \cdot \frac{\sum_R Em_{R,corrected}}{\sum_R CWT_R}$$

with:

B_{CWT} :	Benchmark emissions intensity
$Em_{R,corrected}$:	Emissions of refinery R in the baseline period corrected with respect to steam and electricity (see sections 5.6 and 5.7).
CWT_R :	The amount of CWT for refinery R in the baseline period

In the EU, the benchmark emissions intensity includes all emissions related to electricity and steam consumption including purchased electricity and steam. The EU refinery benchmark emissions intensity is defined as the arithmetic average of the 10% mainstream refineries with the lowest emissions intensity in the period 2005-2007.

¹⁵ An exception is only made in case no refinery would perform below the benchmark resulting from this approach. In that case the benchmark would be based on the 'best-in-class'.

¹⁶ The calculation of the benchmark emissions intensity may exclude a number of atypical refineries (see section 6.3)

5.1.3 Determination of Allocation

Once the benchmark emissions intensity has been established, the allocation to an individual refinery can be determined using the benchmark and the activity level expressed in CWT.¹⁷

Note that the benchmark is based on a reference period and remains constant over time whereas the amount of CWT and with it the allocation is updated annually.

5.2 Technology and Input Differentiation

When using the CWT approach, the single 'product' of the refinery is the CWT. The CWT methodology does not prescribe what process units should be used. The methodology, for instance, contains three types of cokers: delayed coker, fluid coker and the flexi coker. The methodology does not prescribe what process routes should be used to produce a product. In fact, products in a refinery will typically be produced via multiple routes, each resulting in a different amount of CWT. Refineries using exactly the same type of crude and producing an identical range of products still could theoretically get a different allocation.

Due to the complexity of the refining process, the relation between the density and sulfur content of crude, CO₂ emissions and amount of CWT is not straightforward. Still, it can be argued that the CWT approach indirectly allows input differentiation:

- Processing of sour (sulfur-rich) crude requires more processing to meet imposed fuel emission specifications covering the products' sulfur content. Refineries achieve sulfur control using hydrodesulfurization processes, which consume hydrogen. Increased need for desulfurization, increases hydrogen consumption and CO₂ emissions.¹⁸
- Similarly, heavier crude, in general requires more processing leading to increased CO₂ emissions, but also to increased amounts of CWT.

5.3 Background to the Development and Adoption in the EU ETS

5.3.1 Development at Solomon

Solomon Associates have been benchmarking energy efficiency in refineries since 1981. More recently, Solomon has also developed a methodology to benchmark greenhouse gas emissions from refineries. Solomon's benchmarking methodologies are based on detailed information provided by companies on refineries' lay-out, feedstock characteristics, operating rates and operating conditions.

Solomon's Energy Intensity Index (EII[®]) and the Carbon Emissions Index (CEI[™]) are used to make detailed assessments of a refinery's energy and greenhouse gas emissions performance, respectively. The Complexity Weighted Barrel (CWB) approach is a simplified version of the CEI[™] approach that

¹⁷ See § 95891 of the Final Regulation Order

¹⁸ Primarily because of its linkage to hydrogen consumption, incremental CO₂ production due to sulfur control is a non-linear function of target sulfur level (IEA, 2005).

has been developed for regulatory purposes. Carbon Dioxide Weighted Tonne (CWT) as used in Europe has been developed based on the CWB approach for the distribution of the amount of free emission allowances to European refineries in the European Union's Emissions Trading System (EU ETS). Because of the simplifications, the CWB and CWT approaches take less refinery specifics into account than Solomon's EII[®] or CEI[™] and have reduced data requirements.

The CWB and the CWT approach differ with respect to the metric used (barrel vs. tonne), the treatment of electricity production and the level of detail of process units. Also, the CWT approach has been adapted to typical operations of European refineries. For more insight on the extent of this adaptation, the input from CONCAWE and Solomon Associates would be needed. Since it is part of European regulations, the CWT approach is available in the public domain, whereas the CWB approach is not.

5.3.2 Adoption in EU Regulations

The CWT approach is presently used in the EU for the determination of the amounts of free emissions allowances to refineries in the EU ETS. Below follows an overview of the process that led to the adoption of the approach. This overview in particular describes the relationship between Solomon Associates, the European refinery sector and the European Commission with respect to the ownership of the methodology and data used:

- In 2006/2007, it became clear that the allocation approach for the industry for the third phase of the EU ETS (2013–2020) would be based on benchmarking.
- In 2007/2008, Europia and CONCAWE (the sector associations for the refinery sector in Europe) became convinced that any benchmark-based approach for the refinery sector in Europe should be based on the existing benchmarks for the sector as developed by Solomon Associates. Together with Solomon Associates, the CWT approach was developed based on the Energy Efficiency Index methodology.
- In 2008/2009, the consortium hired by the European Commission to develop the allocation methodology in Europe came to the conclusion that the CWT approach was the most logical choice to be used in the EU ETS allocation.
- In 2009, CONCAWE bought the right to use the CWT factors (i.e., the weighting factors between the various refinery units) for the EU ETS allocation. Together with the European Commission's consortium, the method was refined¹⁹ and CONCAWE developed a template to collect the data required to calculate the final benchmark values (in tonnes CO₂/CWT).

¹⁹ Three aspects of the original CWT approach had to be modified before it could be used in the EU ETS to make it consistent with the overall design of the system:

- Benchmarks in the EU ETS in general should not distinguish between technologies. The original CWT approach contained different units for hydrogen production using different technologies. This was found to be too technology-specific. The different units were therefore been grouped to one.
- The EU ETS does not allow free allocation for electricity production or consumption. The original CWT approach was therefore modified and a correction factor was used in the determination of the allocation.
- In the EU ETS, imported heat is included in the product-based benchmark whereas export of heat is not. The original CWT approach has been brought in line with the way this was corrected for in other sectors.

- The underlying data on the calculation of the CWT factors remained the property of Solomon associates and in the agreement between CONCAWE and Solomon Associates it was agreed that the factors were only to be used for the EU ETS. Ultimately, however, the factors itself entered the public domain via the allocation decision of the European Commission.²⁰

5.4 Weighting Factors

5.4.1 Introduction

Weighting factors (in the CWT approach and from here on referred to as CWT factors) are used to weigh the contribution of different process units. The factors are defined relative to the crude distillation unit, which has a weighting factor of 1. Factors of other units are representative of their CO₂ emissions intensity:

- At a standard level of performance,
- For the same standard fuel type for each process units for combustion, and
- For average process emissions of the process unit.

5.4.2 Effect on benchmark and allocation

The contribution that a process unit delivers to the activity level of a refinery is obtained by multiplying the throughput of that process unit by the relevant CWT factor. The higher the CWT factor for a particular process unit is, the more that process unit (if present in the refinery) will contribute to the activity level of the refinery.

California product-based benchmarks are in general calculated by taking 90% of the total emissions from all covered entities in a sector divided by the total production from all covered entities. Using the CWT approach, the refinery benchmark would be calculated by dividing the total refinery emissions by the total CWT and multiplying by 90%. The allocation to a refinery is obtained by multiplying the benchmark (expressed in tCO₂e/CWT) by the amount of CWT of that refinery (see section 5.1). A different set of CWT factors therefore will not automatically result in a lower or higher allocation to the sector as a whole.²¹ They would, however, lead to different amounts of CWT for individual refineries and therefore to a different distribution of the total allocation.

In general, any corrections in respect of steam and electricity depend on the overall design of the allocation methodology. The way to deal with steam and electricity consumption, production, import and export in the California contexts is further discussed in sections 5.7 and 5.8.

²⁰ Decision 2011/278/EU - determining transitional Union-wide rules for harmonized free allocation of emission allowances pursuant to Article 10a of Directive 2003/87/EC
(available at: http://ec.europa.eu/clima/policies/ets/benchmarking/documentation_en.htm)

²¹ In fact, if the throughputs of all process units of all refineries would remain constant, the total amount of allocation to the sector would not change with different CWT factors since the amount of CWT is both in the nominator and denominator

The CWT factors define how changes in throughputs of process units affect the activity level of the refinery. They therefore influence the sensitivity of the allocation to changes in a refinery's operation and capacity.

CWT factors reflect historical average performance. It may be expected that newly build capacity will perform better than the historical averages. This will lead to relatively high allocation for new lower-carbon capacity. This feature is not isolated to the refinery sector but is a general consequence of not updating the value of product-based benchmarks.

5.4.3 CWT Factors used in Europe

To develop the CWT used in European CWT approach, Solomon used an extensive database on some 200 worldwide refineries, which have for many years supplied energy consumption data, as well as consulted process licensors. The present set of values has been in use since 2006.

The CWT approach used in Europe has been developed by Solomon for the purpose of application to European refineries. The CWT factors have therefore been flavored to typical operation of European refineries.

5.4.4 Weighting Factors for California

The CWT factors represent average performance levels based on historical data. An average will always be dependent on the geography and period of the data used. For example, refineries in different regions will process different crudes and produce different product mix because of differences in regulations aimed at reducing air pollution from transport.

For some processes, the factors will be more representative than others. Based on interviews with experts, probably the most important difference will be with the cat cracker. Differences in hydrotreating, reforming and fuel mix will probably have less impact. Without detailed statistical analysis, it is not possible to quantify to what extent the CWT factors used in Europe are representative for California. Any detailed analysis requires process-specific data and a detailed understanding of the way the CWT factors were constructed. This information is not available in the public domain and would require input from Solomon.

The CWT methodology is based on metric tons of throughput. U.S. refineries however commonly measure in barrels. Two ways exist to deal with this issue:

- Use input data expressed in metric tons; mass flows can be obtained via direct measurements where available. If these are not available, they can be obtained by from volumetric flows and (estimated) density. Since densities of crude input, intermediates and products vary substantially between refineries, it is recommended to use process-specific densities.
- Redefine weighting factors to allow the use of input data expressed in barrels. Since densities of crude input, intermediates and products vary substantially between refineries, it is recommended to not do this using generic densities, but to involve Solomon. Solomon already developed the CWB approach, which uses input data expressed in barrels.

5.5 Definition of Process Units

5.5.1 Introduction

Solomon has a comprehensive list of about 170 actual units (see Appendix B). In the development of the CWB and CWT approaches units have been grouped together.

The definition of the process units determines the level of detail of the approach. The more aggregated, the less the approach takes into account differences between refineries and the less input data are required. Aggregation can be therefore be desirable in view of the overall regulatory framework, but also reduces the strength of the approach, which is to allow comparison of refineries with different configurations. Grouping different types of cokers would for instance imply that one should be able to determine which process units can be replaced by less CO₂-intensive ones (with everything else remaining equal). A different type of coker will also have implications for other units of the refinery. Grouping of the units would ignore this. If all process units in a refinery would be grouped together, the result would be a uniform benchmark based on throughput of crude oil.

5.5.2 Definition Used in Europe

The CWT methodology defines a list of about 50 generic process units. Compared to the CWB approach, a number of units have been pooled together to meet requirements in European regulation, e.g., different process units for hydrogen production were pooled together since legislation specifies that benchmarks should not distinguish between different technologies.

5.5.3 Definitions for California

The authors do not have an indication that the definition of process units as used in Europe would not be appropriate for California refineries.

5.6 Corrections for Off-Sites and Non-Crude Feedstock

5.6.1 Introduction

Energy is required to operate the non-process assets (off-sites) such as tank farms, blending facilities, terminals as well as ancillary facilities such as effluent treatment. Also, non-crude feedstock (e.g., atmospheric residues or vacuum distillates) may be directly fed cold (or relatively cold) to the units downstream of the crude distiller and therefore need be brought to the temperature level required when transferring material from the crude distiller to downstream units.

The emissions related to the operations above are not fully reflected by the CWT factors accounts for process units.²² The amount of CWT for European refineries was corrected to account for those emissions.

5.6.2 Corrections Used in Europe

In Europe, the amount of CWT is corrected for off-sites and for non-crude feedstock by a simplified empirical correlation developed by Solomon that captures both aspects. The size of the correction is modest compared to the uncorrected amount of CWTs.

5.6.3 Corrections for California

An assessment of to what extent the correction used in Europe meets California practices requires detailed process-specific data and a detailed understanding of the way the correction was determined. This information is not available in the public domain. When assessing the consequences of using a simplified correlation instead of a California- or refinery-specific correction, it is important to consider that since California product-based benchmarks are based on 90% of emissions from all refineries, changing the correction does not affect the total allocation to the refinery sector, but would lead to a redistribution of the allocation over individual refineries.

5.7 Steam Import and Export

5.7.1 Determination of the Benchmark

(Benchmark) emissions intensities are calculated by dividing emissions by the amount of CWT. Since the CWT factors were developed on the basis of net energy consumption, the amount of CWT in the denominator includes net heat consumption and excludes net heat production. For consistency, the emissions in the nominator need to include (indirect) emissions related all heat consumed and exclude emissions related to heat exported.

So, the benchmark includes emissions from all *heat consumption* and excludes emissions related to any *heat export*. This is consistent with the overall California allocation methodology. This is visualized in Figure 5. The calculation of the benchmark is provided in Box 1.

²² Note that the import of intermediate products by a more complex refinery from a simpler refinery for further processing contributes to the throughput of process units and therefore leads to an increase in CWT. The correction discussed here is only made to reflect the difference in temperature

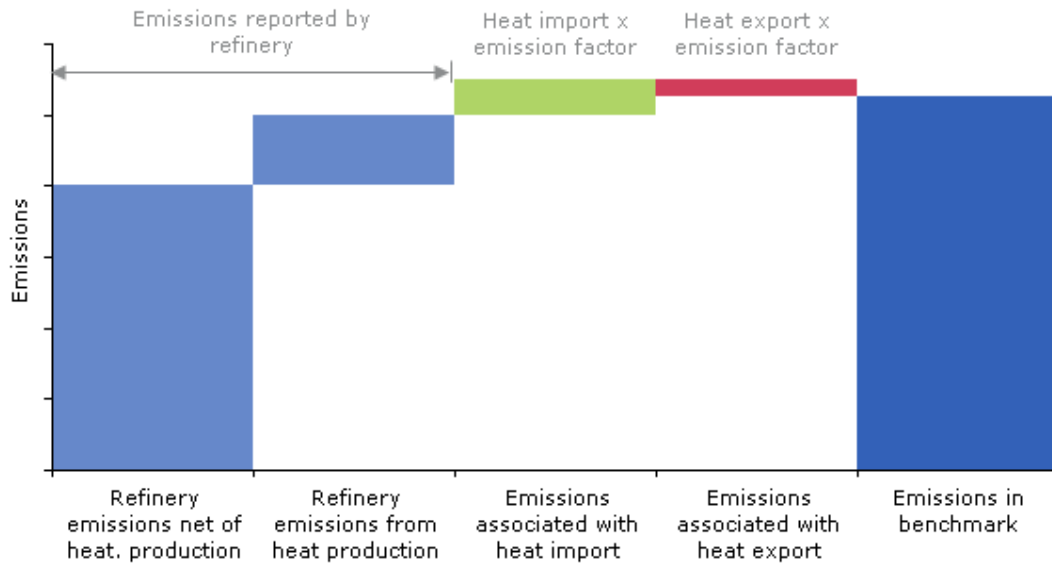


Figure 5. Benchmarked emissions include emissions related to heat consumption and exclude emissions related to heat export

Box 1. Correction for heat import and export in the determination of the benchmark

To simplify the discussion here, the equations do not include corrections related to electricity. These will be discussed in section 5.8.

$$B = \left(0.9 \cdot \frac{\sum_{\text{sector}} (E_{\text{Refining}} + E_{\text{HeatProduction}} + E_{\text{HeatImport}} - E_{\text{HeatExport}})}{\sum_{\text{sector}} CWT} \right)_{\text{baseline}}$$

with,

- B = Benchmark
- CWT = Amount of CWT for a refinery
- E = Emissions

The emissions from the refinery as reported according to California’s Mandatory Greenhouse Gas Reporting Program include emissions from heat production. The benchmark and the allocation are therefore based on the sector’s weighted average emissions intensity of heat production.

Different emission factors can be used to correct for imported and exported heat. Overviews of different options are shown in Table 4 and Table 5. It is important to understand that the choice of

emission factor only influences the benchmark, which remains constant over time and not the amount of CWT, which is updated annually.

Table 4. Comparison of options for emission factors for imported heat

Options for emission factors for imported heat	
1) Emission factors of heat-importing refineries (or less refinery specific; e.g., a sector average)	<ul style="list-style-type: none"> - Does not distinguish between heat produced on site and heat import - It may be challenging to come to a good estimate of this emission factor: one way would be to use the average fuel mix and a standard heat generation efficiency. - On average these emission factors are most probably higher than the real emissions related to imported heat. The compensation for imported heat would therefore be higher compensation than the emissions related to this heat.
2) Actual emission factors of imported heat	<ul style="list-style-type: none"> - Most representative of actual performance in the baseline period - Challenging to obtain the right data, especially if heat is also supplied by non-covered entities
3) Emissions efficiency benchmark per unit of steam (0.06244 metric ton CO ₂ /MMBtu steam as defined by the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - Consistent with approach for other sectors: any net heat imported or exported by other sectors is subtracted using this emission factor. - No issues related to data availability - This emission factor on average is typically lower than the other emission factors listed in this table. This option therefore results in the lowest benchmark value. - This option is consistent with the overall California benchmarking methodology

Table 5. Comparison of options for emission factors for exported heat

Options for emission factors for exported heat	
1) Emission factors of heat produced in heat-exporting refineries (or less refinery-specific: a sector average)	<ul style="list-style-type: none"> - Most representative of actual performance in baseline period. - It may be challenging to come to a good estimate of this emission factor: one way would be to use the average fuel mix and a standard heat generation efficiency. - These emission factors on average are higher than benchmark emissions efficiency (see below). This option would therefore result in the lowest benchmark value.
2) Emissions efficiency benchmark per unit of steam (0.06244 metric ton CO ₂ /MMBtu steam as defined by the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - Consistent with approach for other sectors: any net heat imported or exported by other sectors is considered using this emission factor. - No issues related to data availability. - This emission factor is lower than the average of the actual emission factors of produced heat. This option therefore results in the highest benchmark value. - This option is consistent with the overall benchmarking methodology

5.7.2 Determination of the Allocation

Since the amount of CWT is not corrected for heat import or export, the allocation to an individual refinery is independent of whether the refinery actually imports or exports heat.

As a general remark, the current allocation methodology does not distinguish between export to and import from facilities that are covered by cap-and-trade and entities that are not. This has the following consequences:

- Refineries (and other covered facilities) may receive allocation in respect of heat import from entities that have no compliance obligation because they are below the inclusion threshold of 25,000 metric tons of CO₂e annually. Refineries will still receive allocation for this heat.
- Covered facilities receive allowances for heat imported from refineries (and other covered facilities). Non-covered entities do not.

5.8 Electricity Consumption and Production

5.8.1 Determination of the benchmark

(Benchmark) emissions intensities are calculated by dividing emissions by the amount of CWT. Since the CWT factors were developed on the basis of net energy consumption, the amount of CWT in the denominator includes net electricity consumption and excludes net electricity production. For consistency, the emissions in the denominator need to include (indirect) emissions related all electricity consumed and exclude emissions related to electricity sold.

So, the benchmark emissions intensity includes emissions related to *electricity consumption* and excludes emissions related to any *electricity sold*.²³ This is visualized in Figure 6. The calculation of the benchmark is provided by Box 2.

²³ Two possibilities can be distinguished to arrive at a benchmark expressed in CWT that does not include electricity consumption,

1. Modify the CWT factors to exclude electricity consumption. This would imply a reasonably uniform and constant percentage of electricity in the total energy use for each process in different refineries.
2. Correct the benchmark value for the emissions related to electricity consumption. This would imply a reasonably uniform and constant percentage of electricity in the total energy use in different refineries.

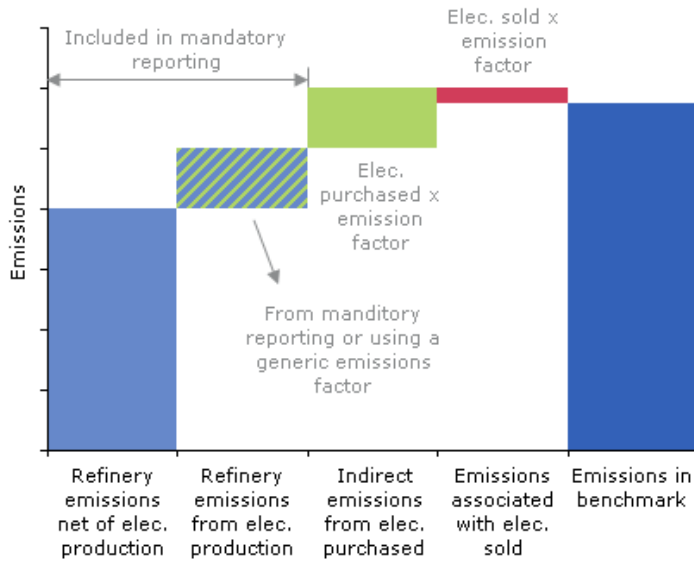


Figure 6. Benchmarked emissions include all emissions-related electricity consumption and exclude emissions related to electricity sold.

Box 2. Correction for electricity in the determination of the benchmark

To simplify the discussion here, the equations do not include corrections related to heat, which have been discussed in section 5.7.

$$B = \left(0.9 \cdot \frac{\sum_{\text{sector}} (E_{\text{Refining}} + E_{\text{Elec. Produced}} + E_{\text{Elec. Purchased}} - E_{\text{Elec. Sold}})}{\sum_{\text{sector}} CWT} \right)_{\text{baseline}}$$

with,

- B = Benchmark
- CWT = Amount of CWT for a refinery
- E = Emissions

The benchmark can be set up either take into account or not take into account the emissions efficiency of electricity generation by refineries. Both approaches discussed in Table 6, Table 7 and Table 8 provide overviews of the emission factors that can be used to correct for purchased and sold electricity.

Table 6. Allocation can either take into account emissions efficiency of electricity generation by refineries or not

	Option 1) Take into account emissions efficiency of electricity generation by refineries	Option 2) Not take into account emissions efficiency of electricity generation by refineries
Description	Reported emissions are simply corrected for purchased and sold electricity. This means that emissions related to on-site produced electricity are within the benchmark insofar this electricity is consumed within the refinery.	First electricity generation is virtually removed from the refinery by subtracting actual emissions related to on-site electricity production from the reported emissions. In a second step, emissions from the total amount of consumed electricity are added assuming all electricity was generated with one standard emission factor. This way, all electricity consumed by the refinery is treated equally whether it is produced on site or purchased.
Equation	$E_{\text{Refining}} + E_{\text{Elec. Produced}} + E_{\text{Elec. Purchased}} - E_{\text{Elec. Sold}} = \dots$ $\dots = E_{\text{Reported}} + E_{\text{Elec. Purchased}} - E_{\text{Elec. Sold}} = \dots$ $\dots = E_{\text{Reported}} + \text{ElecPurchased} \cdot EF_{\text{Elec.Purchased}} - \dots$ $\dots \text{Elec.Sold} \cdot EF_{\text{Elec.Sold}}$	$E_{\text{Refining}} + E_{\text{Elec. Produced}} + E_{\text{Elec. Purchased}} - E_{\text{Elec. Sold}} = \dots$ $\dots = E_{\text{Reported}} - E_{\text{Elec. Produced}} + E_{\text{Elec. Consumed}} = \dots$ $\dots = E_{\text{Reported}} - E_{\text{Elec. Produced, actual}} + \dots$ $\dots \text{Elec.Cons.} \times EF_{\text{Elec. Consumed}}$
Difference 1	The benchmark is based on the electricity supply structure in the baseline period	The benchmark is independent on the origin of consumed electricity.
Difference 2	Relative positions of refineries in the benchmark curve depend on whether the refinery purchases electricity or produces electricity itself.	Relative positions of refineries in the benchmark curve are independent on the origin of consumed electricity.

Table 7. Comparison of options for emission factors for purchased electricity (option 1 in Table 6) or consumed electricity (option 2 in Table 6)

Options for emission factors for purchased electricity (in case of option 1 in Table 6) or consumed electricity (in case of option 2 in Table 6)	
1) Emission factor of electricity produced by refineries in the baseline period (or less refinery-specific: a sector average)	<ul style="list-style-type: none"> - Does not distinguish between electricity generated on site and electricity purchased - This option would require determining emission factors from refinery specific data; in case of option 2 these factors would need to be defined anyway to subtract emissions from produced electricity. - On average these emission factors are most probably higher than the real emissions-related purchased electricity and therefore to a higher benchmark than would be justified by emissions.
2) Actual emission factor of electricity in the baseline period	<ul style="list-style-type: none"> - Most representative of actual performance in baseline period - This option would require determining the emission factor from purchased electricity from third parties or using a grid-average - The Renewables Portfolio Standard will require utilities to increase renewables procurement to 33% by 2020 causing a reduction in emissions intensity. This option may therefore overestimate the future real emissions factor of utility-provided power and may therefore lead to a higher benchmark than would be justified by emissions.

Options for emission factors for purchased electricity (in case of option 1 in Table 6) or consumed electricity (in case of option 2 in Table 6)	
3) Emissions efficiency benchmark per unit of power (0.431 metric ton CO ₂ /MWh as defined by the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - Consistent with approach for other sectors: any electricity sold by other sectors is subtracted using this emission factor. - No issues related to data availability. - The Renewables Portfolio Standard will require utilities to increase renewables procurement to 33% by 2020 causing a reduction in emissions intensity. This option may therefore overestimate the future real emissions factor of utility-provided power and may therefore lead to a higher benchmark than would be justified by emissions.
4) Future expected emissions intensity	<ul style="list-style-type: none"> - If estimated correctly, this emissions intensity would not lead to a higher compensation than would be justified by emissions: a potential drawback of the other options. - It may be challenging to come to a reasonable estimate.

Table 8. Comparison of options for emission factors for sold electricity (option 1 in Table 6)

Options for emission factors for sold electricity (option 1 in Table 6)	
1) Actual emissions factors of electricity sold in the baseline period (or less refinery-specific: a sector average)	<ul style="list-style-type: none"> - Most representative of actual performance in baseline period - This option would require determining/estimating this emission factors from refinery-specific data. - These emission factors on average are higher than benchmark emissions efficiency (see below). This option would therefore result in the lowest benchmark value.
2) Emissions efficiency benchmark per unit of electricity (0.431 metric ton CO ₂ /MWh as defined by the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - Consistent with approach for other sectors: any electricity sold by other sectors is considered using this emission factor. - No issues related to data availability. - This emission factor is lower than the average of the actual emission factors of electricity sold. This option would therefore result in the highest benchmark value.

Approach in Europe

In the EU ETS, there is no free allocation for electricity production or consumption. To achieve this, the actual emissions related to electricity production were first subtracted from the refinery emissions (see option 2 in Table 6). Indirect emissions from all electricity consumption (both produced on site and purchased) were subsequently added. These indirect emissions were determined on the basis of a generic emissions factor. This way, electricity produced on site and purchased is treated equally. The corrected emissions (so actual emissions minus actual emissions from electricity production plus indirect emissions from electricity production) were used to determine the benchmark. So, the EU benchmark includes emissions from consumed electricity.

To prevent allocation for electricity consumption, a refinery-specific correction was made in the calculation of the allocation based on the ratio of direct emissions (not including electricity consumption) and total emissions (including emission from electricity consumption)

Approach for California

Taking into account the emissions efficiency of electricity generation (option 1 in Table 6) would be in line with the approach outlined in CARB (2010) and CARB (2011a).

Electricity sold by other sectors is corrected for using an emissions efficiency benchmark per unit of power (0.431 metric ton CO₂/MWh). It would therefore be consistent with the overall allocation methodology to use the same benchmark emissions intensity to correct for electricity sold by refineries.

Benchmarks for other sectors only cover direct emissions and indirect emissions from steam import. In the development of these benchmarks, it was therefore not needed to correct for electricity purchases. Because of the architecture of the CWT approach, such a correction is needed for refineries. Using an emissions factor for purchased electricity that is higher than future actual emissions may lead to a higher benchmark than would be justified by emissions. In this context, it is important to consider the Renewables Portfolio Standard, which will require utilities to increase renewables procurement to 33% by 2020, causing a reduction in emissions intensity. On the other hand, benchmarks in general have been determined based on historic reference periods whereas future emissions intensities may decrease. Also, the compensation to a refinery does not depend on the benchmark alone, but also on the way that the final allocation is distributed (see next section).

5.8.2 Determination of the allocation

The benchmark emissions intensity, calculated as described in the previous section, includes emissions related to *electricity consumption* and excludes emissions related to any *electricity sold*. Applying this benchmark without making a correction in the determination of the allocation would therefore mean that the refinery sector would receive allocation for all electricity consumption, including purchased electricity.

Approach in Europe

In the EU ETS, there is no free allocation for electricity production or consumption. As mentioned earlier, the benchmark emissions intensity includes emissions related to electricity consumption. To prevent allocation for electricity consumption, a correction was made in the calculation of the allocation based on the ratio of direct emissions (not including electricity consumption) and total emissions (including emission from electricity consumption). This correction was determined separately for each refinery since a generic correction would imply a reasonably uniform percentage of electricity use in refineries, which is not the case.

Approach for California

Within the regulatory framework, only costs related to direct emissions and indirect costs from purchased steam will be compensated by direct free allocation determined by output-based benchmarks. Compensation for costs related to indirect emissions from purchased electricity will be given to electricity utilities on behalf of the ratepayers, including the refineries. Electricity producers do not receive any compensation. Investor-owned utilities (IOUs) (which provide 80% of electricity in the state), are required to auction all their allocated allowances and provide reimbursement to facilities using auction revenues. Publicly owned distribution utilities (POUs) are, for the most part, allowed to use allowances directly for meeting their compliance obligations instead of having to use auction revenues to compensate ratepayers.

As mentioned earlier, applying the benchmark without making a correction in the determination of the allocation would mean that the refinery sector would directly receive allocation for purchased electricity; this approach (i.e., ARB providing direct reimbursement in the form of allowances) would be more efficient and equitable.

5.9 Hydrogen Production

5.9.1 Introduction

Hydrogen is used in refineries for hydrotreating to remove sulfur, hydrocracking to produce diesel feedstock, as well as saturation and alkylation processes to generate high-octane streams needed for reformulated gasoline. As a general rule, the tighter the sulfur standard, the higher the hydrogen consumption. Compliance with the CARB reformulated gasoline and diesel requirements in California requires a significant amount of hydrogen.

Hydrogen can be provided by one of the following processes:

- Reforming operations of the catalytic reformer. Hydrogen is produced as a by-product. Refineries with the simplest configuration may produce sufficient quantities. Complex plants with extensive hydrotreating and/or hydrocracking operations typically require more hydrogen than is produced by their catalytic reforming units.
- Steam reforming: a catalytic process that reacts natural gas or other light hydrocarbons with steam to form a mixture of hydrogen, carbon monoxide, carbon dioxide and water. Hydrogen is produced as the primary product. Hydrogen production from steam methane reforming results in a highly concentrated CO₂ process vent stream. This is one of the significant process emission sources from refineries that have a hydrogen production plant. The carbon dioxide can also be captured for use on site, or sold to other industries.
- Partial oxidation (gasification) of heavy oil fractions to produce syngas where hydrogen can be separated. Hydrogen is produced as a by-product. To the authors' knowledge, no hydrogen is produced in California using this technique.

Hydrogen production facilities can be owned by the refinery or by a third-party. The production of liquid hydrogen involves compressing as an additional production step leading to increased consumption of electricity. To the authors' knowledge, in California, liquid hydrogen is only produced by merchant plants not affiliated with refineries.

5.9.2 Refinery-Owned versus Merchant Production

Hydrogen production in a refinery is part of the CWT methodology; it is defined as a separate process and has its own CWT factor. As indicated before, hydrogen production facilities are not always owned by the refinery. This complicates the development of an allocation methodology. ,

The Cap-and-Trade Regulation included identical benchmark values for gaseous and liquid hydrogen production. This benchmark value is taken from the EU ETS benchmark for the production of gaseous

hydrogen. The EU-ETS hydrogen benchmark is obtained by multiplying the CWT factor for hydrogen production by the EU ETS benchmark for refineries. This methodology as well as alternative methodologies are discussed Table 9.

Table 9. Options for allocation methodology for hydrogen production

Options for allocation methodology for hydrogen production	
1) CWT approach for <i>production</i> in refineries; hydrogen benchmarks for others determined by multiplying the CWT factor for hydrogen production by the refinery benchmark (this approach was chosen in Europe and is also the one adopted in the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - All hydrogen production will be treated equally. - This approach is methodologically straightforward - The CWT factor for hydrogen production represents standardized performances based on historical averages of hydrogen production in refineries worldwide. It is not clear to what extent it is representative of California performance. The approach may lead to under or over allocation to merchant hydrogen producers.
2) CWT approach for <i>production</i> in refineries; hydrogen benchmarks based on actual efficiency for other production.	<ul style="list-style-type: none"> - If the CWT factor for hydrogen production would stay the same, hydrogen production will be treated differently in terms of allocation of allowances, depending on its location and ownership. This violates the 'one product-one benchmark' principle. To avoid this drawback, the CWT factor for hydrogen production could be modified based on the value of the hydrogen benchmark and the refinery benchmark (this is the inverse approach as done option 1) - This approach would require data collection and determination of a hydrogen benchmark.
3) Exclude hydrogen from the CWT approach and use hydrogen benchmark based on actual efficiency for all production	<ul style="list-style-type: none"> - All hydrogen production will be treated equally. - This approach would require data collection and determination of a hydrogen benchmark. - If hydrogen produced as by-product or recovered from process streams would be taken into account, the benchmark would be relatively low compared to emissions intensity of steam reformers. This could be dealt with by only basing a benchmark on dedicated hydrogen production (i.e., steam reforming) and only allocate for this production.

5.9.3 Gaseous versus Liquid Hydrogen

The Cap-and-Trade Regulation defines two product-based benchmarks with the same value for liquid and gaseous hydrogen. The production of liquid hydrogen involves compressing as an additional production step leading to increased consumption of electricity. Compensation for indirect emissions will be given to electricity utilities, which in turn will compensate rate payers such as hydrogen producers.

5.10 Coke Calcining

5.10.1 Introduction

Calcined petroleum coke (CPC) is used to make anodes for the aluminium, steel and titanium smelting industry.

Calcined petroleum coke is the product from calcining petroleum coke, which is the product of the coker unit. Petroleum coke calcining is a process whereby petroleum coke is thermally upgraded to remove associated moisture and volatile combustion matter (VCM) and to otherwise improve physical properties (e.g., electrical conductivity, real density and oxidation characteristics). The calcining process is essentially a time-temperature function with the most important control variables being heating rate, VCM/air ratio and final calcinations temperature (Metso company website).

There are two petroleum coke calcining facilities in California: Phillips66 Carbon Plant in Rodeo and BP West Coast Products LLC, Wilmington Calciner. Coke calcining facilities can be owned by the refinery but operated separately from the refinery or integrated to refinery operations as well as owned and operated by a third-party. This complicates the development of an allocation methodology.

5.10.2 Refinery-Owned versus Merchant Production

Coke calcining in a refinery is part of the CWT methodology; it is defined as a separate process and has its own CWT factor. As indicated before, calciners are not always owned by the refinery. This complicates the development of an allocation methodology.

The Cap-and-Trade Regulation defines a benchmark for coke calcining outside refineries. This benchmark has been determined by ARB by multiplying the CWT factor for coke calcining by the EU ETS benchmark for refineries. This methodology, as well as alternative methodologies, are discussed in Table 10.

Table 10. Options for allocation methodology for coke calcining

Options for allocation methodology for coke calcining	
1) CWT approach for coke calcining in refineries; separate benchmark for others determined by multiplying the CWT factor for coke calcining by the refinery benchmark (this approach is adopted in the Cap-and-Trade Regulation)	<ul style="list-style-type: none"> - All coke calcining is treated equally. - This approach is methodologically relatively straightforward - The CWT factor for coke calcining represents standardized performances based on historical averages of coke calciners worldwide. The benchmark for refineries is based on the operation of refineries as a whole. The CWT factor for calcined coke production is based on average standard performance in refineries worldwide. It is not clear to what extent the current benchmark for coke calcining is representative of California performance. The approach may lead to under or over allocation to independent producers.
2) CWT approach for <i>production</i> in refineries; separate benchmark based on actual efficiency for other entities	<ul style="list-style-type: none"> - Coke calcining will be treated differently in terms of allocation of allowances, depending on their location and ownership. This violates the 'one product-one benchmark' principle. To avoid this drawback, the CWT factor for coke calcining could be modified based on the value of the new coke calcining benchmark and the refinery benchmark (this is the inverse approach as done option 1). - This approach would require data collection and determination of a benchmark.
3) Exclude coke calcining from CWT approach and use a benchmark based on actual efficiency for all production.	<ul style="list-style-type: none"> - All coke calcining will be treated equally. - This approach would require determining the emissions and production from all coke calciners.

6 CWT Approach Applied to California Refineries

This chapter presents the application of the CWT approach to California refineries using data that were available to the authors as of July 2012.

6.1 Data Sources and Approach

Throughput of refinery units was estimated by multiplying capacities of main process units by a State-wide capacity utilization estimated using total annual crude input from California Refinery "Fuels Watch Report" and U.S. EIA capacity data. For a small number of refineries, facility-specific capacity utilization could be derived from 10-K forms. Capacities of main refinery units were obtained from U.S. EIA capacity data. Expert judgments were used to link the main refinery units in U.S. EIA capacity data to CWT process units and to convert barrels of throughput to metric tons as required by the CWT approach.

Emissions were obtained from California's Mandatory Greenhouse Gas Reporting Program. To improve the comparison of the emissions intensity of the oil refining process, the emissions have been corrected for purchased and sold electricity and heat, using adjustment factors of 0.431 metric ton CO₂/MWh and 0.06244 tCO₂/MMBtu steam (CARB, 2011a), to the extent this was feasible using data provided by ARB staff. The analysis was performed for 2010, which is the most recent year for which all data described above are available.

For some refineries, there is not a one-to-one relation between the facility listed in the GHG reporting program and in U.S. EIA capacity data. Appendix C shows the mapping used in this assessment. For the purpose of completeness, the table also shows the refinery as listed in EPA facility data.

6.2 Results

Figure 7 shows the first results of the application of the CWT methodology to California refineries using 2010 data. A benchmark was defined as 90% of weighted average emissions intensity. The figure also shows 2010 crude charge capacity of the crude distillation unit. Emissions intensities have been corrected for import and export of electricity and heat.

Results should be regarded as a first estimate based on the currently available information. Results based on primary data available at refineries may deviate substantially. The present assessment suffers from the lack of accurate data, in particular:

- The present assessment is based on main refinery process units only and therefore underestimates the amount of CWT and overestimates the emissions intensity.
- With a few exceptions, the present assessment is based on one State-wide capacity utilization rate. In reality, utilization varies from refinery to refinery and process unit to process unit.

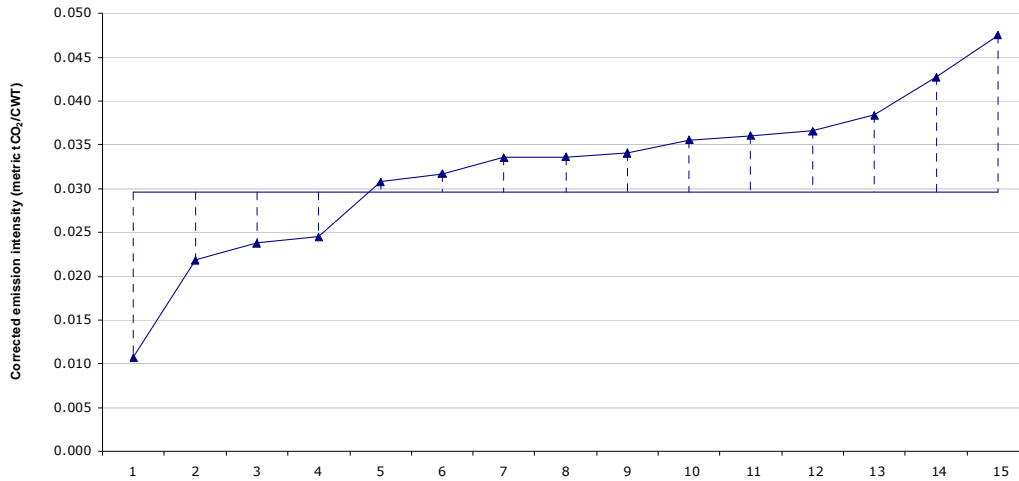


Figure 7. 2010 Estimated emissions intensity of California refineries in terms of CWT (triangles; left axis) together with benchmark based on 90% of weighted average (horizontal line; left axis) and 2010 capacity of crude distillation unit (squares; right axis).

This assessment finds an average weighted emissions intensity of 0.033 metric ton CO₂/CWT and a typical range of 0.02 – 0.05 metric ton CO₂/CWT. These results are similar to values found for European refineries which were found to have an average emissions intensity of 0.037 metric ton CO₂/CWT and a typical range of 0.02 – 0.05 metric ton CO₂/CWT (see Figure 8) (Lane, 2011). A benchmark based on 90% of this average would have a value of 0.030 metric ton CO₂/CWT, which is similar to the EU benchmark, which is based on the average of the 10% most efficient European refineries. Again, we stress that these results are indicative and that results based on primary data may deviate substantially.

the

Emissions intensity (kg CO₂/CWT)

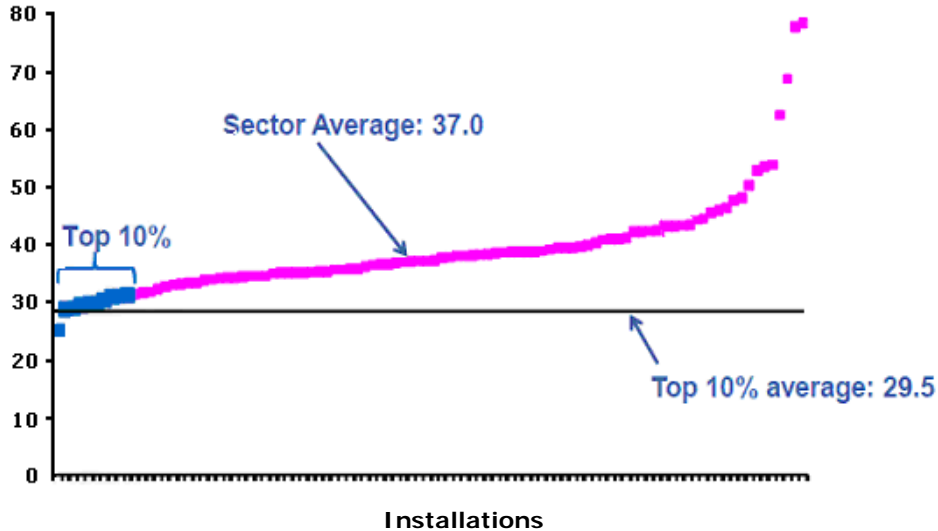


Figure 8. CO₂ benchmarking curve for 89 mainstream refineries in EU ETS; Curve based on 2007/2008 data (Lane, 2011; reformatted)

6.3 Exclusion of Atypical Refineries

It is observed that some of the California refineries with the lowest capacity are found at either end of the benchmark curve. Since it is known that the CWT approach is not suitable for smaller refineries, it may be speculated that the CWT approach is not suited for some of the smaller, “atypical” refineries in California. For these atypical refineries it may be more appropriate to use alternative allocation methodologies such as energy benchmarking.

Table 11 lists a number of small refineries in California and provides indications for why these refineries may be regarded as “atypical.” In case a smaller refinery is connected with a nearby larger refinery, these refineries could be grouped together to form on mainstream facility for the purpose of applying the CWT methodology. We propose to assess the appropriateness of applying the CWT methodology to these facilities on a case-by-case basis. The threshold used in Europe (see Box 3) could be used as a starting point in this assessment.

Box 3. Atypical refineries in the EU ETS

In Europe, the CWT methodology was not used to that did not produce a: “*Mix of refinery products with more than 40% light products (motor spirit (gasoline) including aviation spirit, spirit type (gasoline type) jet fuel, other light petroleum oils/ light preparations, kerosene including kerosene type jet fuel, gas oils) expressed as CO₂ weighted tonne (CWT).*” Refineries with other product mixes (so-called atypical sites producing mainly lubricants or bitumen) receive allocation on the basis of energy-based benchmarks. In Europe, emissions from atypical refineries represent a very small share of the total emissions of the refinery sector.

Table 11 Potentially atypical refineries together with indication for not being a 'mainstream' refinery

Facility	Indications for not being a 'mainstream' refinery
Evergreen Oil, Inc, Refinery	Emissions <25 ktCO ₂ ; account closed;
Santa Maria Refining Company	Emissions <25 ktCO ₂ ; account closed; Relatively low capacity of crude atmospheric distillation unit
Lunday-Thagard Company	Emissions <35 ktCO ₂ ; Relatively low capacity of crude atmospheric distillation unit
Tesoro Refining and Marketing Co. - SRP	Report under NAICS code 325188 (All Other Basic Inorganic Chemical Manufacturing) instead of 324110 (Petroleum Refineries); For the purpose of applying the CWT methodology, this facility could perhaps best be grouped with Tesoro LA refinery.
Edgington Oil Company	Emissions <35 ktCO ₂ ; For the purpose of applying the CWT methodology, this facility could perhaps best be grouped with Alon USA – Paramount
Alon Bakersfield Refinery - Area 3 (formerly Big West of California Bakersfield Refinery)	Emissions <35 ktCO ₂ ; For the purpose of applying the CWT methodology, this facility could perhaps best be grouped with Alon Bakersfield Refinery - Areas 1&2
Kern Oil and Refining Company	Relatively low capacity of crude atmospheric distillation unit
San Joaquin Refining Company	Relatively low capacity of crude atmospheric distillation unit

7 Conclusions and Recommendations

The California Cap-and Trade Regulation states that, from the second compliance period (starting in 2015) onwards, the free allocation to refineries will be based on the CWT approach. The CWT approach is used in the EU Emissions Trading System (EU ETS). The approach involves weighting the throughput of pre-defined different refinery process units by so-called CWT factors. In contrast to other benchmarking approaches, the CWT approach has been shown to reduce differences in emissions intensities (tCO₂/CWT) of refineries with different configurations and sizes to higher or lower energy efficiency and fuel emission factors.

The main features of the approach as well as some selected specific issues have been discussed within the context of the California Cap-and-Trade Program. A number of issues raised require further analysis and/or discussion. These include:

1. How appropriate is the use of current CWT factors, process units and correction for off-sites and non-crude feedstocks?
2. How to deal with production, consumption, import and export of electricity?
3. How to deal with hydrogen that can be produced inside or outside facility boundaries of refineries?
4. How to deal with coke calcining which can be done inside or outside facility boundaries of refineries?
5. Should certain refineries be regarded as atypical and be included in the CWT approach?

This study included application of the CWT approach to California refineries using data available in the public domain.

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Appendix A: CWT Calculation Table

The table below shows the calculation of the amount of CWT for a refinery in the EU ETS. The table was taken from Guidance Document n°9 on the harmonized free allocation methodology for the EU-ETS post 2012.

Table 12 Calculation of amount of CWT in the EU ETS; Basis for activity level are net fresh feed (F), reactor feed (R, includes recycle), product feed (P), Synthesis gas production for POX units (SG)

CWT function	Activity level			CWT factor		CWT
	Basis	(kt in year k)				
				(-)		(kt in year k)
Atmospheric Crude Distillation	F	..	×	1.00	=	..
Vacuum Distillation	F	..	×	0.85	=	..
Solvent Deasphalting	F	..	×	2.45	=	..
Visbreaking	F	..	×	1.40	=	..
Thermal Cracking	F	..	×	2.70	=	..
Delayed Coking	F	..	×	2.20	=	..
Fluid Coking	F	..	×	7.60	=	..
Flexicoking	F	..	×	16.60	=	..
Coke Calcining	P	..	×	12.75	=	..
Fluid Catalytic Cracking	F	..	×	5.50	=	..
Other Catalytic Cracking	F	..	×	4.10	=	..
Distillate/Gasoil Hydrocracking	F	..	×	2.85	=	..
Residual Hydrocracking	F	..	×	3.75	=	..
Naphtha/Gasoline Hydrotreating	F	..	×	1.10	=	..
Kerosene/Diesel Hydrotreating	F	..	×	0.90	=	..
Residual Hydrotreating	F	..	×	1.55	=	..
VGO Hydrotreating	F	..	×	0.90	=	..
Hydrogen Production	P	..	×	300.00	=	..
Catalytic Reforming	F	..	×	4.95	=	..
Alkylation	P	..	×	7.25	=	..
C4 Isomerisation	R	..	×	3.25	=	..
C5/C6 Isomerisation	R	..	×	2.85	=	..
Oxygenate Production	P	..	×	5.60	=	..
Propylene Production	F	..	×	3.45	=	..
Asphalt Manufacture	P	..	×	2.10	=	..
Polymer-Modified Asphalt Blending	P	..	×	0.55	=	..
Sulphur Recovery	P	..	×	18.60	=	..

CWT function	Activity level			CWT factor		CWT
	Basis	(kt in year k)				
Aromatic Solvent Extraction	F	..	×	5.25	=	..
Hydrodealkylation	F	..	×	2.45	=	..
TDP/TDA	F	..	×	1.85	=	..
Cyclohexane production	P	..	×	3.00	=	..
Xylene Isomerisation	F	..	×	1.85	=	..
Paraxylene Production	P	..	×	6.40	=	..
Metaxylene production	P	..	×	11.10	=	..
Phtalic anhydride production	P	..	×	14.40	=	..
Maleic anhydride production	P	..	×	20.80	=	..
Ethylbenzene production	P	..	×	1.55	=	..
Cumene production	P	..	×	5.00	=	..
Phenol production	P	..	×	1.15	=	..
Lube solvent extraction	F	..	×	2.10	=	..
Lube solvent dewaxing	F	..	×	4.55	=	..
Catalytic Wax Isomerisation	F	..	×	1.60	=	..
Lube Hydrocracking	F	..	×	2.50	=	..
Wax Deoiling	P	..	×	12.00	=	..
Lub & Wax Hydrotreating	F	..	×	1.15	=	..
Solvent Hydrotreating	F	..	×	1.25	=	..
Solvent Fractionation	F	..	×	0.90	=	..
Mol sieve for C10+ paraffins	P	..	×	1.85	=	..
Partial Oxidation of Residual Feeds (POX) for fuel	SG	..	×	8.20	=	..
Partial Oxidation of Residual Feeds (POX) for Hydrogen or Methanol	SG	..	×	44.00	=	..
Methanol from syngas	P	..	×	-36.20	=	..
Air Separation	P (kNm ³ O ₂)	..	×	8.80	=	..
Fractionation for purchased NGL	F	..	×	1.00	=	..
Flue gas treatment	F (MNm ³)	..	×	0.10	=	..
Treatment and Compression of Fuel Gas for Product Sales	Elec. consump. (kW)	..	×	0.15	=	..
Seawater Desalination	P (km ³)	..	×	1.15	=	..
Sum						SUM
Final activity level after correction for off-sites and for non-crude feedstock (= 1.0183 x HAL _{Basic} + 0.315 x TP _{AD} + 298) (for TD _{AD} see first line in table)						Final activity level

Appendix B: Details of CWT Process Units

The table below provides descriptions of CWT process units. The table was taken from Guidance Document n°9 on the harmonized free allocation methodology for the EU-ETS post 2012.

Table 13 CWT Process units

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Atmospheric Crude Distillation	CDU		Fresh feed	1.00	<p>Primary atmospheric distillation of crude oil and other feedstocks. The factor includes ancillary equipment such as crude desalter, naphtha splitting, gas plant and wet treatment of light streams for mercaptan removal. Some units may have more than one main distillation column.</p> <p>The classification between MCU and SCU unit depends on the TBP cut point of the bottom product. The unit is classified as an SCU if this cutpoint is >316°C, otherwise it is classified as an MCU.</p>	Crude oil, other feedstocks	Full range of distillates from light gases to heavy gasoil, atmospheric residue
Mild Crude Unit		MCU					
Standard Crude Unit		SCU					
Vacuum Distillation	VAC		Fresh feed	0.85	<p>Distillation of atmospheric residues under vacuum. The process line up must include a heater. Some units may have more than one main distillation column.</p> <p>VAC and MVU represent different levels of vacuum. VFR is typically used for lubes production and include a higher level of fractionation between distillate products.</p>	Atmospheric residue	Vacuum gasoils, vacuum residue
Mild Vacuum Fractionation		MVU					
Standard Vacuum Column		VAC					
Vacuum Fractionating Column		VFR					
<i>Vacuum Flasher Column</i>		VFL	<i>n.c.</i>	<i>n.c.</i>	<i>Normally associated with a visbreaker (VBR) or a thermal cracker (TCR). It does not include a heater. Its</i>		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
					<i>contribution is included in the CWT factor of the VBR and TCR units</i>		
<i>Heavy Feed Vacuum Unit</i>		<i>HFV</i>	<i>n.c.</i>	<i>n.c.</i>	<i>Additional column taking feed from the bottom of an MVU. Its contribution is included in the generic CWT factor for VAC.</i>		
Solvent Deasphalting	SDA		Fresh feed	2.45	Separation of the lighter fraction of a vacuum or cracked residue by means of a solvent such as propane, butane or heavier.	Vacuum or cracked residue	Deasphalted oil (DAO), asphalt
Conventional Solvent		CONV					
Supercritical Solvent		SCRT					
Visbreaking	VBR		Fresh feed	1.40	Mild thermal cracking of residual feedstocks to produce some distillates and reduce the viscosity of the cracked residue. The different types represent different feedstocks and process configurations. May include a vacuum flasher (VFL).	Atmospheric or vacuum residue, asphalt	Full range of cracked distillates from light gases to heavy gasoil, cracked residue
Atmospheric Residuum (w/o a Soaker Drum)		VAR					
Atmospheric Residuum (with a Soaker Drum)		VARS					
Vacuum Bottoms Feed (w/o a Soaker Drum)		VBF					
Vacuum Bottoms Feed (with a Soaker Drum)		VBFS					
Thermal Cracking	TCR		Fresh feed	2.70	Thermal cracking of distillate feedstocks. May include a vacuum flasher (VFL). Units that combine visbreaking and distillate cracking generate a contribution for both processes based on the residue and the distillate throughput respectively.	Virgin vacuum or cracked gasoils	Full range of cracked distillates from light gases to heavy distillate
Coking	COK		Fresh		Severe thermal cracking of residual feedstocks	Vacuum	Full range of

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
			feed		producing coke as an intermediate or final process residue.	residue, asphalt	cracked distillates from light gases to heavy gasoil, coke or low BTU gas
Delayed Coking		DC	Fresh feed	2.20	Semi-continuous process, similar in line-up to a VBR, where the heat of reaction is supplied by a fired heater. Coke is produced in alternate drums that are swapped at regular intervals. Coke is cut out of full coke drums and disposed of as a product. Facilities include coke handling and storage.		
Fluid Coking		FC	Fresh feed	7.60	Proprietary continuous process where the fluidised powder-like coke is transferred between the cracking reactor and the coke burning vessel and burned for process heat production. Surplus coke is drawn off and disposed of as a product.		
Flexicoking		FX	Fresh feed	16.60	Proprietary process incorporating a fluid coker and where the surplus coke is gasified to produce a so-called "low BTU gas" which is used to supply the refinery heaters.		
Coke calcining	CALCIN		Product	12.75	Process whereby so-called "green coke" from a DC is stripped of residual light hydrocarbons by heating in a kiln to produce calcined coke.	Green coke	Waste gases, calcined coke
Vertical-Axis Hearth		HARTH					
Horizontal-Axis Rotary Kiln		KILN					
Fluid Catalytic Cracking	FCC		Fresh feed	5.5	Cracking of vacuum gasoil and residual feedstocks over a catalyst. The finely divided catalyst is circulated in a fluidised state from the reactor where it becomes coated with coke to the regenerator where coke is burned off. The hot regenerated catalyst returning to the reactor supplies the heat for the endothermic cracking reaction and for most of the downstream	Vacuum gasoils, atmospheric residues, deasphalted oils	Full range of cracked distillates from light gases to heavy cracked distillate.
Fluid Catalytic Cracking		FCC					
Mild Residuum Catalytic Cracking		MRCC					
Residual Catalytic Cracking		RCC					

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
					fractionation of cracked products. Splitting of the gasoline product has been included in the FCC CWT factor.		Coke is not a product as it is fully combusted within the process.
Other catalytic cracking			Fresh feed	4.1			
Houdry Catalytic Cracking		HCC			Early catalytic cracking processes on fixed catalyst beds.	Vacuum gasoils	
Thermoform Catalytic Cracking		TCC					
Distillate/gasoil Hydrocracking	HYC		Fresh feed	2.85			
Mild Hydrocracking		HMD			Cracking of vacuum gasoils and cracked heavy distillates over a fixed catalyst bed, at high pressure and in the presence of hydrogen. The process combines cracking and hydrogenation reactions. HMD and HSD represent different severities resulting in different levels of conversion and hydrogen consumption. Higher severity generally requires higher operating pressures. In order to qualify for the HMD (or HSD) status a plant needs to comply with both of the following criteria: <ul style="list-style-type: none"> • Total operating reactor pressure: ≥ 70 barg • Conversion (defined as the % of feed material boiling over 350°C that is upgraded to lighter products): $\geq 20\%$ mass on feed 	Vacuum gasoils and cracked heavy distillates, deasphalted oils, hydrogen	
Severe Hydrocracking		HSD					

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Naphtha Hydrocracking		HNP			Special hydrocracking process for converting naphtha into C3-C4 hydrocarbons.	Naphtha, hydrogen	Saturated C3-C4 hydrocarbons
Residual Hydrocracking				3.75	Hydrocracking of residual feedstocks. Different Proprietary processes involve continuous or semi-continuous catalyst replenishment. The HYC unit must be designed to process feed containing at least 50%mass of vacuum residue (defined as boiling over 550°C) for it to qualify as a Residue HC unit (H-Oil, LC-Fining or Hycon).	Atmospheric or vacuum residues, hydrogen	Full range of hydrocracked distillates from light gases to vacuum gasoil, unconverted residue
H-Oil		HOL					
LC-Fining™ and Hycon		LCF					
Naphtha/Gasoline Hydrotreating	NHYT		Fresh feed	1.10	A number of processes involving treating and upgrading of naphtha/gasoline and lighter streams.		Various gasoline blending components
Benzene Saturation		BSAT			Selective hydrogenation of benzene in gasoline streams over a fixed catalyst bed at moderate pressure.	Various gasoline streams, hydrogen	
Desulfurization of C4-C6 Feeds		C4C6			Desulphurisation of light naphthas over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.	Light naphtha, hydrogen	
Conventional Naphtha H/T		CONV			Desulphurisation of virgin and cracked naphthas over a fixed catalyst bed at moderate pressure and in the presence of hydrogen. For cracked naphthas also involves saturation of olefins.	Virgin and cracked naphthas/gasolines,	

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
						hydrogen	
Diolefin to Olefin Saturation		DIO			Selective saturation of diolefins over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen, to improve stability of thermally cracked and coker gasolines.	Thermally cracked or coker gasolines	
Diolefin to Olefin Saturation of Alkylation Feed		DIO			Selective saturation of diolefins in C4 streams for alkylation over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.	Thermally cracked or coker LPG streams, hydrogen	
Naphtha/Gasoline Hydrotreating (continued) FCC gasoline hydrotreating with minimum octane loss		GOCT			Selective desulphurisation of FCC gasoline cuts with minimum olefins saturation, over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.	FCC gasoline cuts, hydrogen	
Olefinic Alkylation of Thio S		OATS			A gasoline desulphurisation process in which thiophenes and mercaptans are catalytically reacted with olefins to produce higher-boiling sulphur compounds removable by distillation. Does not involve hydrogen.	FCC gasoline cuts	
S-Zorb™ Process		ZORB			Desulphurisation of naphtha/gasoline streams using a proprietary fluid-bed hydrogenation adsorption process in the presence of hydrogen.	Various naphthas/gasolines	
Selective H/T of Pygas/Naphtha		PYGC			Selective or non-selective desulphurisation of pyrolysis gasoline (by-product of light olefins production) and	Pyrolysis gasoline,	

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Pygas/Naphtha Desulfurization		PYGD			other streams over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.	hydrogen	
Selective H/T of Pygas/Naphtha		PYGS					
<i>Reactor for Selective Hydrotreating</i>		<i>RXST</i>	n.c.	n.c.	<i>Special configuration where a distillation/fractionation column containing a solid catalyst that converts diolefins in FCC gasoline to olefins or when the catalyst bed is in a preheat train reactor vessel in front of the column. Contribution for this configuration is included in the generic NHYT CWT factor.</i>		
Kerosene/Diesel Hydrotreating			Fresh feed	0.90	A number of processes involving treating and upgrading of kerosene and gasoil streams.	Kerosene, hydrogen	Kerosene blending components
Kerosene Hydrotreating	KHYT						
Aromatic Saturation		ASAT					
Conventional H/T		CONV/KUS					
Solvent aromatics hydrogenation							
					Saturation of aromatic rings over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. This process includes the desulphurisation step which should therefore not be accounted for separately.		
					Desulphurisation of virgin kerosene over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen.		
					Aromatics saturation of kerosene cuts over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen for solvent manufacture.		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Kerosene/Diesel Hydrotreating (continued) Diesel Hydrotreating	DHYT						
Aromatic Saturation		ASAT			Saturation of aromatic rings over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. This process includes the desulphurisation step which should therefore not be accounted for separately.	Virgin and cracked gasoils, hydrogen	Gasoil blending components, small quantities of naphtha and lighter products
Conventional Distillate H/T		CONV		Desulphurisation of virgin and cracked gasoils over a fixed catalyst bed in the presence of hydrogen. CONV, DHS and DUS correspond to different depths of desulphurisation.			
High Severity DistillateH/T		DHS					
Ultra-High Severity H/T		DUS					
Middle Distillate Dewaxing		MDDW		Cracking of long paraffinic chains in gasoils to improve cold flow properties over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. This process includes the desulphurisation step which should therefore not be accounted for separately.			
S-Zorb™ Process		ZORB		Desulphurisation of gasoil using a proprietary absorption process. Does not involve hydrogen.	Gas oils		
Selective Hydrotreating of Distillates		DIST		Hydrotreatment of distillates for conversion of diolefins to olefins	Cracked gasoils		
Residual Hydrotreating	RHYT		Fresh	1.55	Desulphurisation of residues over a fixed catalyst bed	Atmospheric	Desulphurised

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Desulfurization of Atmospheric Resid		DAR	feed		at high pressure and in the presence of hydrogen. Results in a limited degree of conversion of the residue feed into lighter products.	and vacuum residues, hydrogen	residue and relatively small quantities of lighter hydrocarbon liquids and fuel gas
Desulfurization of Vacuum Resid		DVR					
VGO Hydrotreating (or cracking feed Hydrotreating)	VHYT		Fresh feed	0.90	Desulphurisation of vacuum gasoils usually destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure and in the presence of hydrogen. Although these processes involve some conversion of the VGO feed to lighter products, they generally operate at lower pressure, consume less hydrogen, require less sophisticated fractionation equipment and therefore are much less energy intensive than hydrocrackers.	Vacuum gasoils	Desulphurised vacuum gasoils and relatively small quantities of lighter hydrocarbon liquids and fuel gas
Hydrodesulphurisation/denitri-fication		VHDN					
Hydrodesulphurisation		VHDS					
Hydrogen production	HYG		Product	300.00	Hydrogen production from light hydrocarbons through either steam reforming or partial oxidation. Includes hydrogen purification.	C1 to C4 hydrocarbons	Hydrogen, CO ₂
Gas feeds							
<i>Steam Methane Reforming</i>		HSM					
<i>Partial Oxidation Units of Light Feeds</i>		POX					
Steam Naphtha Reforming		HSN					
Hydrogen Purification	H2PURE			<i>n.c.</i>	<i>Purification of hydrogen-rich streams for use in</i>		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
<i>Cryogenic Unit</i>		CRYO			<i>hydrogen consuming units. These processes are not associated with a hydrogen-producing unit. The contribution of these processes is included in the off-sites CWT.</i>		
<i>Membrane Separation Unit</i>		PRSM					
<i>Pressure Swing Absorption Unit</i>		PSA					
Catalytic Reforming (inc. AROMAX)	REF		Fresh feed	4.95	Improvement of the octane rating of naphtha by dehydrogenation of naphthenic rings and paraffin isomerisation over a noble metal catalyst at low pressure and high temperature. The process also produces hydrogen. RCR, RCY and RSR represent different configurations of the process. CWT factor includes contribution for special fractionation linked with reforming (naphtha and reformat splitters, DIP etc) on an average EU-27 basis . Special application of catalytic reforming for the specific purpose of producing light aromatics	Desulphurised naphtha	Reformat for gasoline blending or aromatics production, hydrogen
Continuous Regeneration		RCR					
Cyclic		RCY					
Semi-Regenerative		RSR					
AROMAX	U60						
Alkylation/Polymerisation/Dimersol			Product	7.25	A range of processes transforming C3/C4 molecules into C7/C8 molecules over an acidic catalyst. CWT factor includes contribution for special fractionation linked with such processes and acid regeneration where applicable on an average EU-27 basis.	C3 and C4 olefins, isobutane C3 olefins C3/C4 hydrocarbons C3 olefins	C6 to C8 high octane gasoline blending components
Alkylation with HF Acid	ALKY	AHF					
Alkylation with Sulfuric Acid		ASA					
Polymerization C3 Olefin Feed	POLY	PC3					
Polymerization C3/C4 Feed		PMIX					
Dimersol	DIM						
<i>Sulphuric Acid Regeneration</i>	<i>ACID</i>				<i>Contribution included in ALKY/POLY</i>		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
C4 Isomerisation	C4ISOM		Reactor feed inc. recycle	3.25	Conversion of normal butane into isobutane over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure. CWT factor includes contribution for special fractionation linked with C4 isomerisation on an average EU-27 basis .	n-butane, hydrogen	iso-butane
C5/C6 Isomerisation	C5ISOM		Reactor feed inc. recycle	2.85	Conversion of normal paraffins into isoparaffins over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure. CWT factor applies to both once-through and recycle units and includes contribution for mole sieve separation and special fractionation linked with C5/C6 isomerisation on an average EU-27 basis.	Light virgin naphtha, hydrogen	Isomerate for gasoline blending
Mol sieve separation	<i>U18</i>	<i>ISOSIV</i>	<i>n.c.</i>	<i>n.c.</i>	<i>Contribution included in C5ISOM</i>		
Oxygenate production			Product	5.60	Production of ethers by reacting an alcohol with olefins		
MBTE Distillation Units	MTBE	DIST				Methanol, isobutene	Oxygenates for gasoline blending
MTBE Extractive Units		EXT				Ethanol, isobutene	
ETBE	ETBE					Methanol, C5 olefins	
TAME	TAME						
Isooctene Production	IOCT				Combination of two isobutene molecules. Although this process does not produce oxygenates, it is included under the same CWT factor as it can be produced in virtually the same unit with very similar associated	Isobutene	Isooctene

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
					emissions.		
Propylene Production	C3S		Fresh feed	3.45	Separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC. "Chemical" and "polymer" are two grades with different purities.	C3/C4 FCC cut	Propylene
Chemical Grade		CHEM					
Polymer grade		POLY					
Asphalt & Bitumen Manufacture	ASP		Product	2.10	This CWT function represents the equipment and processing required to produce asphalts and bitumen, including bitumen oxidation (mostly for road paving). Asphalt later modified with polymers is included.	Vacuum and cracked residues	Asphalts and bitumen
Polymer-Modified Asphalt Blending	U77		Product	0.55	Additional asphalt processing step to produce special polymer-modified grades. This CWT function is in addition to the previous one.	Asphalt, polymers	Polymer modified asphalt
Sulphur Recovery	SRU		Product	18.60	Partial oxidation of hydrogen sulphide into elemental sulphur. This CWT function represents the main process (Claus) and the tail gas units for enhanced recovery. It also includes hydrogen sulphide separation from refinery sour gas process streams using amines and amine regeneration.	Refinery sour gas process streams	Sulphur
AROMATICS							

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Aromatics Solvent Extraction	ASE		Fresh feed	5.25	Extraction of light aromatics from reformat and/or hydrotreated pyrolysis gasoline by means of a solvent. The CWT factor for this refinery function includes all columns and associated equipment required to purify individual aromatic products as well as solvent regeneration.	Reformat, hydrotreated pyrolysis gasoline	Mixed aromatics or purified benzene, toluene, mixed xylenes, C9+ aromatics, paraffinic raffinate
ASE: Extraction Distillation		ED					
ASE: Liquid/Liquid Extraction		LLE					
ASE: Liq/Liq w/ Extr. Distillation		LLED					
<i>Benzene Column</i>		<i>BZC</i>	<i>n.c.</i>	<i>n.c.</i>	<i>The contribution of all columns and associated equipment required to purify individual aromatics is included in ASE.</i>		
<i>Toluene Column</i>		<i>TOLC</i>	<i>n.c.</i>	<i>n.c.</i>			
<i>Xylene Rerun Column</i>		<i>XYLC</i>	<i>n.c.</i>	<i>n.c.</i>			
<i>Heavy Aromatics Column</i>		<i>HVYARO</i>	<i>n.c.</i>	<i>n.c.</i>			
Hydrodealkylation	HDA		Fresh feed	2.45	Dealkylation of toluene and xylenes into benzene over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure.	Toluene, Xylenes, hydrogen	Benzene
Toluene Disproportionation / Dealkylation	TDP		Fresh feed	1.85	Fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen		
Cyclohexane production	CYC6		Product	3.00	Hydrogenation of benzene to cyclohexane over a catalyst at high pressure.	Benzene, hydrogen	Cyclohexane
Xylene Isomerisation	XYISOM		Fresh feed	1.85	Isomerisation of mixed xylenes to paraxylene	Mixed xylenes	Paraxylene-rich mixed xylenes
Paraxylene Production	PXYL		Product	6.40	Physical separation of para-xylene from mixed xylenes.	Paraxylene-rich mixed	Paraxylene, other mixed
Paraxylene Adsorption		ADS					

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Paraxylene Crystallization		CRY				xylenes	xylenes
<i>Xylene Splitter</i>		<i>XYLS</i>			<i>The contribution of these columns and associated equipment is included in PXYL.</i>		
<i>Orthoxylene Rerun Column</i>		<i>OXYLRC</i>					
Metaxylene production	U82		Product	11.10	Production of metaxylene from mixed xylenes	Mixed xylenes	Metaxylene
Phthalic anhydride production			Product	14.40	Production of phthalic anhydride from orthoxylene and naphthalene	Orthoxylene, naphthalene	Phthalic anhydride
Maleic anhydride production			Product	20.80	Production of maleic anhydride by oxidation of n-butane or benzene	n-butane, benzene, oxygen	Maleic anhydride
Ethylbenzene production	EBZ		Product	1.55	Combination of benzene and ethylene	Benzene, ethylene	Ethylbenzene
<i>Ethylbenzene Distillation</i>		<i>EBZD</i>			<i>The contribution of this column and associated equipment is included in EBZ.</i>		
Cumene production	CUM		Product	5.00	Alkylation of benzene with propylene	Benzene, propylene	Cumene
Phenol production			Product	1.15	Production of phenol from benzene and propylene		
LUBRICANTS AND WAXES							
Lube Solvent Extraction	SOLVEX		Fresh feed	2.10	Solvent extraction of aromatic compounds from intermediate streams in the manufacture of base luboils. Includes solvent regeneration. Different Proprietary processes use different solvents.	Various luboil intermediate streams	Dearomatised intermediate luboil streams, aromatic extract
Solvent is Furfural		FUR					
Solvent is NMP		NMP					
Solvent is Phenol		PHE					
Solvent is SO2		SDO					
Lube Solvent Dewaxing	SDWAX		Fresh feed	4.55	Solvent removal of long paraffinic chains (wax) from intermediate streams in the manufacture of luboils.	Various luboil intermediate	Dewaxed intermediate
Solvent is Chlorocarbon		CHL					

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Solvent is MEK/Toluene		MEK			Includes solvent regeneration. Different Proprietary processes use different solvents.	streams	luboil streams, wax
Solvent is MEK/MIBK		MIB					
Solvent is Propane		PRP					
Catalytic Wax Isomerisation	CDWAX		Fresh feed	1.60	Catalytic breakdown of long paraffinic chains in intermediate streams in the manufacture of luboils.	Various luboil intermediate streams	Dewaxed intermediate luboil streams
Catalytic Wax Isomerization and Dewaxing		ISO					
Selective Wax Cracking		SWC					
Lube Hydrocracker			Fresh feed	2.50	Hydrocracking of heavy feedstocks for the manufacture of luboils	Vacuum Gas Oils	Full range of hydrocracked products from light gases to gasoil, luboil intermediate streams
Lube Hydrocracker w/ Multi-Fraction Distillation	LHYC	HCM					
Lube Hydrocracker w/ Vacuum Stripper		HCS					
Lube H/F w/ Vacuum Stripper	LHYFT	HFS					
Lube H/T w/ Multi-Fraction Distillation		HTM					
Lube H/T w/ Vacuum Stripper		HTS					
Wax Deoiling	WDOIL		Product	12.00	Solvent removal of lighter hydrocarbons from wax obtained from lube dewaxing (SDWAX)	Raw wax	Deoiled wax, light oil
Solvent is Chlorocarbon		CHL					
Solvent is MEK/Toluene		MEK					
Solvent is MEK/MIBK		MIB					
Solvent is Propane		PRP					
Lube /Wax Hydrotreating			Fresh	1.15	Hydrotreating of luboil fractions and wax for quality	Luboil	Hydrotreated

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Lube H/F w/ Vacuum Stripper	LHYFT	HFS	feed		improvement	intermediate streams, wax, hydrogen	luboil fractions, wax
Lube H/T w/ Multi-Fraction Distillation		HTM					
Lube H/T w/ Vacuum Stripper		HTS					
Wax H/F w/ Vacuum Stripper	WHYFT	HFS					
Wax H/T w/ Multi-Fraction Distillation		HTM					
Wax H/T w/ Vacuum Stripper		HTS					
SOLVENTS							
Solvent Hydrotreating	U1		Fresh feed	1.25	Hydrotreating of various distillate cuts for solvent manufacture	Distillate cuts, hydrogen	Hydrotreated solvent cuts
Solvent Fractionation	SOLVF		Fresh feed	0.90	Fractionation of various distillate cuts for solvent manufacture	Distillate cuts	Solvent cuts
Mol sieve for C10+ n-paraffins	U88		Product	1.85	Separation of heavy paraffins from kerosene/light gasoil cuts for solvent manufacture	Kerosenes/light gasoils	Solvent cuts
RESID GASIFICATION							
POX Syngas for Fuel	U73		Syngas	8.20	Production of synthesis gas by gasification (partial oxidation) of heavy residues. Includes syngas clean-up.	Heavy residues, oxygen	Syngas, CO2
POX Syngas for Hydrogen or Methanol	U72		Syngas	44.00	Production of hydrogen by gasification of heavy residues and conversion of syngas to hydrogen via the shift reaction. Includes syngas clean up and CO2 separation.	Heavy residues, oxygen, steam	Hydrogen, CO2. Also, CO if methanol synthesis occurs

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
							downstream.
Methanol	U70		Product	-36.20	Recombination of CO ₂ and hydrogen for methanol synthesis. <i>This factor can only be applied in combination with U72 above.</i>	Hydrogen, CO, CO ₂	Methanol
Air Separation	U79		Oxygen (MNm ³ /a)	8.80	Separation of air into its components including oxygen. Usually cryogenic but factor applies to all processes.	Air	Oxygen, other air components
MISCELLANEOUS							
Fractionation of Purchased NGL			Purchased Fresh feed	1.00	Fractionation of NGL (light liquid hydrocarbons obtained as by-product of natural gas production) into usable fractions. Includes all columns for production of separate cuts, but only to the extent that they are used to fractionate purchases of NGL..	NGL	Various light fractions
<i>De-ethaniser</i>	<i>DETH</i>		<i>n.c.</i>	<i>n.c.</i>	<i>The CWT factor refers to fresh NGL feed, therefore no separate contribution from individual columns</i>		
<i>De-propaniser</i>	<i>DPRO</i>		<i>n.c.</i>	<i>n.c.</i>			
<i>De-butaniser</i>	<i>DBUT</i>		<i>n.c.</i>	<i>n.c.</i>			
Special Fractionation					<i>These fractionation columns are found in various locations in refineries. Their contribution has been included in the CWT factors of appropriate units or in the off-site factor on a statistical basis. They therefore do not give rise to additional CWT.</i>		
<i>Deethanizer</i>							
<i>Depropanizer</i>							
<i>Delsobutanizer</i>		<i>DIB</i>					
<i>Debutanizer</i>							
<i>Deisopentanizer</i>		<i>DIP</i>					
<i>Depentanizer</i>							

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
<i>Deisohexanizer</i>							
<i>Dehexanizer</i>							
<i>Deisoheptanizer</i>							
<i>Deheptanizer</i>							
<i>Naphtha Splitter</i>							
<i>Conventional Splitter</i>		CONV					
<i>Splitter with single Heartcut</i>		HC1					
<i>Splitter with two Heartcuts</i>		HC2					
<i>Standard Column with Heartcut Draw</i>		HCD					
<i>Alkylate Splitter</i>							
<i>Conventional Splitter</i>		CONV					
Special Fractionation (continued)							
<i>Splitter with single Heartcut</i>		HC1					
<i>Splitter with two Heartcuts</i>		HC2					
<i>Standard Column with Heartcut Draw</i>		HCD					
<i>Reformate Splitter</i>							
<i>Conventional Splitter</i>		CONV					
<i>Splitter with single Heartcut</i>		HC1					
<i>Splitter with two Heartcuts</i>		HC2					
<i>Standard Column with Heartcut Draw</i>		HCD					
Flue gas treatment	U35/U89		MNm ³ /a	0.10	Desulphurisation and clean-up of flue gases from refinery heaters and boilers. Includes all such	Refinery flue gases	Cleaned flue gases

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
					processes.		
Treatment and Compression of Fuel Gas for Sales	U31		Compress or power consumption (kW)	0.15	Treatment and compression of refinery fuel gas for sale to third party.	Refinery fuel gas	Treated refinery fuel gas
Seawater Desalination	DESAL		Product (Water)	1.15	Desalination of sea water. Includes all such processes.	Sea water	Desalinated water

Appendix C: Efficiency vs. Intensity

This Appendix describes the difference between efficiency and intensity of energy use. The difference between emissions efficiency and intensity are similar. Text in the appendix was taken from the website of the U.S. Department of Energy - Energy Efficiency and Renewable Energy²⁴.

Energy Intensity is measured by the quantity of energy required per unit output or activity, so that using less energy to produce a product reduces the intensity.

Energy Efficiency improves when a given level of service is provided with reduced amounts of energy inputs or services are enhanced for a given amount of energy input.

Efficiency improvements in processes and equipment and other explanatory factors can contribute to observed changes in energy intensity. Within the category "other explanatory factors" we can identify two separate effects: structural changes and behavioral factors, which are further discussed in item 2) below.

(1) Declines in energy intensity are a proxy for efficiency improvements, provided a) energy intensity is represented at an appropriate level of disaggregation to provide meaningful interpretation, and b) other explanatory and behavioral factors are isolated and accounted for.

Energy efficiency refers to the activity or product that can be produced with a given amount of energy; for example, the number of tons of steel that can be melted with a megawatt hour of electricity. At the level of a specific technology, the difference between efficiency and energy intensity is insignificant — one is simply the inverse of the other. In this example, energy intensity is the number of megawatt hours used to melt one ton of steel.

At the level of the aggregate economy (or even at the level of an end-use sector) energy efficiency is not a meaningful concept because of the heterogeneous nature of the output. The production of a huge number of goods, the mixing of the transport of freight and people, and the variety of housing and climates makes an aggregate energy intensity number based on Gross Domestic Product (GDP), a number that disguises rather than illuminates. A simple intensity measure can be calculated (as Energy/GDP), but this number has little information content without the underlying sector detail.

The distinction between energy intensity and energy efficiency is important when multiple technologies or multiple products underlie what is being compared. While it would not be sensible to compare the energy efficiency of steel production with the energy efficiency of ethanol production, it is possible to examine the energy intensity of all manufacturing.

²⁴ See: http://www1.eere.energy.gov/ba/pba/intensityindicators/printable_versions/efficiency_intensity.html

(2) Other explanatory factors cause changes in the energy use that have no bearing on the efficiency with which energy is used. These changes may be structural, they may be behavioral, or they may be due to factors, such as the weather, over which we have no control. These are sometimes collectively referred to as structural elements and they give rise to a change in energy use per unit measure of output, but do not reflect improvements in the underlying efficiency of energy use. We provide examples of these below:

(2a) Structural changes in the economy are major movements in the composition of the economy and in any of the end-use sectors that can affect energy intensity but are not related to energy efficiency improvements. In the industrial sector, a shift in manufacturing emphasis from the energy intensive industries — primary metal, chemicals, and forest products — to less energy-intensive industries such as transportation equipment or food would cause a decline in the index of energy intensity that does not necessarily reflect an increase in energy efficiency. By the same token, if the population shifts to warmer climates, both commercial and residential heating intensity in the winter will decline, but air conditioning intensity in the summer will likely increase. Similarly, if the number of people in a household changes, overall energy use will likely change. We think of changes in the industry structure, shifts in regional population, and changes in household size as the structural components of "other explanatory factors" changes.

(2b) Changes in energy use per unit measure of output that are a result of behavioral factors also may not reflect improvements in the underlying efficiency of energy use. For example, it is well known that as people age, they will use more electricity or fuel to warm their home during the winter. While the efficiency of heating equipment in the building has not changed, the energy intensity of the house has increased to maintain a suitable living environment (conditioned space). It is sometimes difficult to separate people's behavior from structural change — for example, demographic changes, like the aging of the population, may be contributing factors to the behavioral changes.

(2c) There are also changes over which we have little or no control: Weather is the classic example. Yet changes in weather can have a profound effect on the amount of energy used, especially for space conditioning of homes and businesses. It is for these reasons that the national system of energy intensity indicators presented on this website has attempted to build up the aggregate numbers from the sector details. By building up from the details, and incorporating changes in other explanatory factors (to the extent these factors can be identified from the available data), the measures of intensity more closely approximate changes in the underlying efficiency of energy use.

Appendix C: Linking of refineries listed by different data sources

Facility as listed in ARB MRR	Facility as listed in U.S. EPA emissions data	Facility as listed in US EIA 2010 capacity data
Alon Bakersfield Refinery - Area 3 (formerly Big West of California Bakersfield Refinery)	Alon Bakersfield Refining	ALON BAKERSFIELD OPERATING INC - BAKERSFIELD
Alon Bakersfield Refinery - Areas 1&2 (formerly Big West of California Bakersfield Refinery)		
Paramount Petroleum Corporation	PARAMOUNT PETROLEUM CORPORATION	PARAMOUNT PETROLEUM CORPORATION-PARAMOUNT
Edgington Oil Company	EDGINGTON OIL COMPANY	PARAMOUNT PETROLEUM CORPORATION - LONG BEACH
Kern Oil and Refining Company	KERN OIL & REFINING COMPANY	KERN OIL & REFINING CO-BAKERSFIELD
San Joaquin Refining Company	SAN JOAQUIN REFINING CO INC	SAN JOAQUIN REFINING CO INC-BAKERSFIELD
Chevron Products Company - El Segundo Refinery, 90245	CHEVRON PRODUCTS, EL SEGUNDO REFINERY	CHEVRON USA INC - EL SEGUNDO
Chevron Products Company - Richmond Refinery, 94802	CHEVRON PRODS.CO. RICHMOND REFY	CHEVRON USA INC-RICHMOND
ConocoPhillips Refining Company - SF Refinery	SAN FRANCISCO REFINERY AT RODEO	CONOCOPHILLIPS COMPANY-RODEO
ConocoPhillips Santa Maria Refinery	CONOCOPHILLIPS SANTA MARIA REFINERY	
ConocoPhillips Los Angeles Refinery, Carson Plant	ConocoPhillips Los Angeles Refinery - Carson Plant	CONOCOPHILLIPS COMPANY-WILMINGTON
ConocoPhillips Los Angeles Refinery Wilmington Plant	ConocoPhillips Los Angeles Refinery - Wilmington Plant	
Shell Oil Products US	SHELL OIL PRODUCTS US - MARTINEZ REFINERY	Shell Oil Products US-MARTINEZ
Tesoro Refining and Marketing Company, 94553	TESORO REFINING AND MARKETING COMPANY GOLDEN EAGLE REFINERY	TESORO REFINING & MARKETING CO-MARTINEZ
ExxonMobil Torrance Refinery	EXXONMOBIL OIL CORP - TORRANCE REFINERY	EXXONMOBIL REFINING & SUPPLY CO-TORRANCE
Lunday-Thagard Company	LUNDAY-THAGARD COMPANY	LUNDAY THAGARD CO-SOUTH GATE
BP West Coast Products LLC, Refinery	BP CARSON REFINERY	BP West Coast Products LLC - LOS ANGELES
Tesoro Refining and Marketing Co. - SRP	Tesoro Refining and Marketing Company - SRP	TESORO REFINING & MARKETING CO-WILMINGTON
Tesoro Refining and Marketing Co. - LAR	TESORO CORPORATION	
Ultramar Inc - Valero	Ultramar Inc.	VALERO REFINING CO CALIFORNIA-WILMINGTON REFINERY

Facility as listed in ARB MRR	Facility as listed in U.S. EPA emissions data	Facility as listed in US EIA 2010 capacity data
		VALERO REFINING CO CALIFORNIA-WILMINGTON ASPHALT PLANT
Valero Refining Company -California, Benicia Refinery and Benicia Asphalt Plant	Valero Refining Company – California	VALERO REFINING CO CALIFORNIA-BENICIA

Note: this table does not include Santa Maria Refining Company, Evergreen Oil, Inc, Refinery listed in ARB MRR; TRICOR REFINING LCC listed in U.S. EPA emissions data and Greka Energy-SANTA MARIA LLC and TENBY INC-OXNARD listed in U.S. EIA capacity data.

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ECOFYS Netherlands B.V.

Kanaalweg 15G
3526 KL Utrecht

T: +31 (0) 30 662 33 00

F: +31 (0) 30 662 33 01

E: info@ecofys.com

I: www.ecofys.com