DEPARTMENT OF
ECOLOGY
State of Washington

Concise Explanatory Statement

Chapter 173-485 WAC

Petroleum Refinery Greenhouse Gas Emission Requirements

Summary of rule making and response to comments

Appendix B: Copies of all written comments

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Appendix B: Copies of all written comments

Appendix B contains all of the comments received during the public comment period in their original form, including attachments.

From: Cox, Rachel H. [mailto:RHCOX@STOEL.COM]
Sent: Friday, January 31, 2014 1:41 PM
To: Thompson, Margo (ECY)
Cc: Pritchett, Nancy (ECY); Newman, Alan (ECY); Cohen, Matthew; Frank Holmes (fholmes@wspa.org)
Subject: WSPA Comments on Refinery GHG RACT Rule - WAC ch. 173-485

WSPA respectfully submits the attached comments on Ecology's proposed RACT rule to limit GHG emissions from Washington refineries. The comments include a redline with suggested revisions to the text of the rule and documents referenced in the comments.

Please feel free to call if you have any questions regarding WSPA's comments or suggested revisions.

Thank you,

Rachel

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WSPA

Western States Petroleum Association
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January 31, 2014

Margo Thompson
Washington Dept. of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

Re: WSPA Comments on Proposed Refinery RACT Rule for Greenhouse Gases

Dear Ms. Thompson:

The Western States Petroleum Association ("WSPA") is pleased to provide the following comments on Ecology's proposed WAC ch. 173-485, establishing reasonably available control technology ("RACT") for emissions of greenhouse gases ("GHG") from petroleum refineries in Washington State (the "RACT rule"). WSPA is a non-profit trade organization representing twenty-six companies that explore for, produce, refine and market petroleum, petroleum products, natural gas and other energy products in Washington and five other western states. WSPA members own and operate each of Washington's five petroleum refineries regulated under this proposed rule.

Ecology undertook this rulemaking in response to an order from the U.S. District Court for the Western District of Washington in *Washington Environmental Council v. Sturdevant*. *See also* CR-102 (June 2012) (Ecology cites the court order as the reason the rule was developed). On October 17, 2013, the Ninth Circuit Court of Appeals reversed and vacated that decision. *See Washington Environmental Council v. Bellon,* 732 F.3d 1131, 1147 (9th Cir. 2013). Since Ecology is no longer under court order to undertake this rulemaking, the authority for the rulemaking must be derived from the Revised Code of Washington. *See e.g., Campbell v. Dep't of Soc. & Health Servs.,* 150 Wn.2d 881, 892 (2004) ("In order for an administrative rule to have the force of law, it must be promulgated pursuant to delegated authority."). As explained below, Ecology has not followed the procedural requirements of RCW § 70.94.154 in developing the proposed RACT rule, nor does the statute allow Ecology to address refineries ahead of the source categories that Ecology prioritized for RACT rule development.

I. Ecology failed to comply with the procedural requirements for a RACT rulemaking in RCW § 70.94.154.

RCW § 70.94.154 defines several circumstances under which Ecology may make source-specific RACT determinations, but the legislature prescribed one process that Ecology must follow to establish RACT by rule. Per RCW § 70.94.154(4), the process begins with development of a list of sources and source categories that require RACT review and a schedule for conducting the review. Ecology developed such a list and schedule in 1994, after evaluating the requisite criteria and consulting with various stakeholders, and updated the list in 1996.[1] In the 1996 list Ecology listed refineries in the *second* group of source categories for RACT review, after a group that includes hog fuel boilers, fiberglass fabrication and municipal waste combustors. Ecology commenced work on a RACT rule for hog fuel boilers, the first category on the list, but never completed it.[2] Ecology has never finalized a rule to set RACT limits for any source category. As evidenced by the list and in Ecology's own words: "neither refineries nor greenhouse gases have ever been prioritized by the Agencies for RACT determinations." Defendant Agencies' Reply Brief, *Washington Environmental Council v. Bellon*, No. 12-35323 at 47 (9th Cir. Dec. 5, 2012).

By leapfrogging petroleum refineries to the top of the priority list and schedule, Ecology's proposed RACT rule violates the process mandated by RCW § 70.94.154. This proposed rule ignores the RACT list and schedule that Ecology published to comply with the RCW after evaluating the requisite criteria and consulting with key stakeholders. WSPA understands that Ecology initiated the RACT rulemaking in response to a court order, but the court order has been vacated. Failure to follow the statutorily prescribed rulemaking process for adopting RACT rules will result in an unlawful rule that may be vacated through a judicial challenge. *See* RCW § 34.05.570(2)(c) (court shall invalidate rule if "the rule was adopted without compliance with statutory rule-making procedures.").

II. The potential costs of the proposed "emission reduction requirement" far exceed the potential benefits in violation of RCW § 34.05.328.

RCW § 34.05.328 requires Ecology, when proposing a significant substantive rule, to develop a preliminary cost-benefit analysis for the rule and make a determination that the probable benefits of the rule exceed the probable costs. *See e.g. Rios v. Wash. Dep't of Labor & Indus.*, 145 Wn.2d 483, n.10 (2001) ("Before adopting a rule…, an agency shall … determine that the probable benefits of the rule are greater than its probable costs..."). Ecology's comparison of the costs and benefits of the RACT rule is provided in the Preliminary Cost-Benefit and Least-Burdensome Alternative Analysis issued with the proposed rule (the "Cost-Benefit Analysis"). Ecology proposes to find

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[1] Ecology, 1996 RACT List and Schedule (copy attached).

[2] Ecology published a report in 2003 that contains Ecology's findings on what controls are RACT for various pollutants from various sizes of hog fuel boilers. *See* Ecology, Hog Fuel Boiler RACT Determination, ECY No. 03-02-009 (April 2003) (excerpt attached).

that the probable benefits of WAC ch. 173-485 outweigh the probable costs. WSPA submits that Ecology failed to adequately analyze the costs and benefits of the RACT rule and that the rule is invalid as a matter of law. *See* RCW § 34.05.375 ("No rule … is valid unless it is adopted in substantial compliance with RCW [34.05.328]."); *see also* RCW § 34.05.570(2)(c) (court shall invalidate rule if "the rule was adopted without compliance with statutory rule-making procedures.").

Ecology's proposed RACT rule offers two options for a refinery to demonstrate that it meets RACT. The refinery can either demonstrate that it meets the "energy efficiency standard" or it must implement emission reduction projects and earn emission reduction credits that cumulatively equal 10 percent of the facility's "baseline greenhouse gas emissions" by the year 2025 (the "emission reduction requirement"). This comment relates only to the second method of meeting the RACT standard. The demands of the "emission reduction requirement" are critical because a refinery that cannot satisfy the "energy efficiency standard" would have no choice under the proposed rule but to satisfy the "emission reduction requirement." The cost benefit analysis required by RCW § 34.05.328 must focus on the emission reduction requirement, because, as Ecology points out, a refinery that meets the energy efficiency standard meets RACT with no incremental investments or GHG emission reductions. Cost-Benefit Analysis at 11-12.

Ecology estimated that the emission reduction requirement would cost the refineries between $8.8 and $13.3 million and that the effects from the resulting reduction in GHG emissions would have a value to Washington residents of between $361 and $657 million. Cost-Benefit Analysis at 15, 21. Both the estimated costs and benefits are based on unfounded assumptions.

Ecology made unfounded assumptions in estimating the cost that Washington refineries would bear to reduce GHG emissions by 10 percent. Ecology based its entire cost analysis on a table extracted from an EPA report that lists the average costs and CO2 emission reductions from various energy efficiency improvement projects for generic boilers.[3] EPA's report did not look specifically at the cost of potential emission reduction projects for *refinery* boilers. Based on EPA's table, but with no further explanation, Ecology somehow determined that a 1 percent reduction in total boiler GHG emissions from *all five refineries* (= 6,381 tpy CO2e) would cost approximately "$90,000 - $137,000." Cost-Benefit Analysis at 14-15. Ecology then estimated that a 1 percent reduction in total boiler GHG emissions would equate to a 0.1 percent in overall refinery GHG emissions. To estimate the overall cost of complying with the RACT rule, Ecology simply calculated the cost of multiple hypothetical boiler upgrades that in the aggregate would equate to the required 10 percent reduction in total GHG emissions from all five refineries (e.g. [$90,000 / 0.1 % reduction in refinery GHGs] x 10% = $9 million).

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[3] Cost-Benefit Analysis at 14-15; TSD at Table 7-1; EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers at Table 1 (Oct. 2010).

This approach does not make sense and is not representative of the actual costs refineries will face. First, boiler emissions account for only 11 percent of total Washington refinery GHG emissions.[4] A cost estimate based on projects to optimize GHG emissions from boilers would not yield a 10 percent reduction unless the refineries shut down nearly all of their boilers. Second, Washington refineries have already implemented many of the cost-effective GHG reduction measures. Indeed, they have implemented "significantly *more* measures than either the national average or the California average." TSD at 49 (emphasis added). To reduce GHG emissions by *an additional 10 percent*, refineries will have to undertake the more complex, expensive projects that Ecology did not consider in its cost estimate for the RACT rule. Ecology acknowledges that "an average GHG reduction goal of 10 percent is achievable at a reasonable cost *assuming* that refineries have not already implemented the identified efficiency measures." TSD at 83 (emphasis added).

Ecology never asked the refineries to provide an estimate of the costs associated with reducing GHG emissions by 10 percent at their facilities. If Ecology had asked that question, the refineries would have explained that it is *not economically feasible* to reduce GHG emissions by an additional 10 percent. Ecology distorted the potential costs of the proposed RACT rule by failing to consider the types of projects that refineries will actually need to undertake to comply with the emission reduction requirement.

One WSPA member ("Washington Refinery"), who will remain anonymous to protect confidential proprietary information, estimated the cost of retrofitting a Washington refinery to reduce GHG emissions by 10 percent. This estimate demonstrates the extreme disparity between Ecology's cost estimate and the actual costs a refinery would incur in complying with the emission reduction requirement:

A GHG Emission Reduction Scenario
"Washington Refinery" Example that emits 1,000,000 tons CO2e/year[5]

Boilers

In general, refineries operate boilers to produce steam to operate pumps, compressors, supply heat to the refinery processes, etc. Washington Refinery is configured such that its boilers contribute approximately 15 percent of the refinery's overall GHG emissions. Of the 15 percent, about 5 percent of the GHG emissions are generated from a new state-of-the-art boiler that cannot be further optimized. The remaining 10 percent is generated from older boilers that might have energy efficiency opportunities that have not yet been implemented.

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[4] Ecology, Washington State Oil Refinery RACT - Final Technical Support Document 46 (Nov. 25, 2013) ("TSD").

[5] The GHG emissions from the "Washington Refinery" have been normalized to a round number of 1,000,000 CO2e/year to simplify the math for the case study demonstration.

Washington Refinery evaluated its older boilers and determined that by investing **$2 million** in boiler upgrade projects, it could potentially reduce boiler GHG emissions by approximately 10 percent (**10,000 tpy** CO2e).

Process Heaters

In general, refineries operate process heaters to supply the heat needed to operate process units that convert crude oil to valuable, clean burning fuels (gasoline, jet, diesel, etc.). A significant portion of process heaters support process units that remove sulfur and benzene from fuels to comply with federal fuel regulations.

Washington Refinery's process heaters contribute approximately 35 percent of the refinery's overall GHG emissions. Efficiency upgrades for heaters are not easy to implement due to technical constraints. Some projects evaluated in the recent past could not be economically justified, and others had technical feasibility issues. Washington Refinery estimates that a 1 percent reduction in GHG emissions from the heaters (**3,500 tpy** CO2e) could be achieved with an investment of approximately **$250,000/year**. This efficiency upgrade would be achieved by optimizing operation of the heaters, which would require increased staff to monitor, evaluate and tune the heaters regularly. This cost would be incurred annually, but is conservatively represented below as a one-time cost.

Process Units

Refineries are uniquely configured with a combination of complex, expensive process units that work together to produce products to meet selected markets. These process units need energy to carry out the chemical reactions fundamental to producing clean fuels, and as a result, emit GHGs. About 50 percent of Washington Refinery's GHG emissions are from process units. Washington Refinery is not aware of a method to reduce GHG emissions from its process units without reducing the processing rate. Reducing the processing rate significantly jeopardizes the feasibility to continue operating and Washington Refinery's competitiveness in the petroleum industry.

Flares

All refineries, including Washington Refinery, are equipped with flares for emergency venting purposes, which are required for safe operations. While Washington Refinery flares very little gases, there are opportunities to reduce the flaring even more. Washington Refinery could invest over **$40 million** to reduce **7,000 tpy** of CO2e emissions from its flares (about 0.7 percent of its overall GHG emissions).

Other

It is possible that there could be other opportunities to reduce GHG emissions from Washington Refinery, like heat integration – whereby a refinery uses its process heat in an efficient manner to heat other process streams. Washington Refinery has routinely evaluated these opportunities using third party consultants. Many of these projects have already been implemented with only a few less cost-effective projects remaining. Based on previous evaluations of these types of opportunities, Washington Refinery estimates that it could reduce approximately **5,000 - 10,000 tpy** of CO2e at a cost of about **$5 million**.

Converting Steam Driven Equipment to Electric-Driven Equipment

Washington Refinery could reduce its on-site GHG emissions by retrofitting equipment that is powered by steam with equipment powered by electricity (a.k.a. electrification). However Washington Refinery uses its steam for multiple purposes. The steam that drives a large compressor still has useful power to drive a smaller turbine – and then that steam can be further used to supply heat to process units. Therefore it is not obvious that Washington Refinery should pursue electrification projects.

GHG Emission Reduction Summary for Washington Refinery

Boilers:	10,000 tpy	$ 2.0 million
Process Heaters:	3,500 tpy	$ 250,000
Flares:	7,000 tpy	$ 40.0 million
Other:	10,000 tpy	$ 5.0 million
Total:	30,500 tpy	~$ 47.25 million

Percentage of GHG emission reductions: **3%**

Cost: **$47.25 million**

A refinery owner estimated that it would cost approximately $47.25 million to achieve GHG emission reductions of 3 percent. In contrast, Ecology estimated that the total cost of all five Washington refineries reducing GHG emissions by 10 percent would be less than $14 million. Cost-Benefit Analysis at 15. The Washington Refinery example demonstrates that Ecology's cost estimation methods are arbitrary and unrealistic.

Ecology's estimate of the likely benefits of the emission reduction requirement is equally flawed. The benefits of the emission reduction requirement, i.e. a 10 percent reduction in refinery GHG emissions, are based entirely on hypothetical models derived to quantitatively estimate the "social cost of carbon." Cost-Benefit Analysis at 18-20. The social cost of carbon model assigns a dollar value to the effects that GHG emissions have on global warming and the damage it causes. This hypothetical approach to estimating the benefits of the RACT rule conflicts with the findings of the Ninth Circuit in *Washington Environmental Council v. Bellon*. The Court of Appeals found that "the effect of collective emissions from the [Washington refineries] on global climate change is 'scientifically indiscernible.'" 732 F.3d at 1144.[6] Even assuming that the RACT rule would entirely eliminate GHG emissions from the refineries, the court found no evidence that RACT controls would reduce global warming related injuries alleged by Plaintiffs in the case. *Id*. at 1146-47. The Court found that RACT controls on Washington refineries would not reduce the local effects of global climate change. *Id*. Ecology's Cost-Benefit Analysis underestimates the cost and overstates the benefits to the state of Washington of the emission reduction requirement in the proposed RACT rule. A more careful evaluation would indicate that the potential costs greatly outweigh the benefits. For this reason, adoption of the "emission reduction requirement" would be unlawful under RCW § 34.05.328.

III. WSPA's Substantive Comments on the Text of the Proposed RACT Rule

If Ecology rejects the arguments set forth above and proceeds with adoption of WAC ch. 173-485, WSPA recommends various edits to the text of the rule to improve its clarity and reduce the cost of compliance. WSPA is submitting with these comments a redline of the proposed RACT rule that includes suggested edits. The redline includes an explanation for most of the suggested revisions. The remainder of this letter provides additional support for proposed revisions that could not be explained in a footnote.

WAC 173-485-040 – Emission Reduction Requirement

The proposed rule limits creditable emission reduction projects to those completed in the years between 2010 and 2025. With a 2010 baseline, the requirement to reduce GHG emissions by 10 percent conflicts with the requirement in RCW § 70.94.030(20) that RACT limits must be economically feasible. WSPA requests that Ecology revise the emission reduction requirement to a 2.5 percent reduction in GHGs.

RCW § 70.94.030(20) defines RACT as follows:

> The lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and *economic feasibility*. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for a source or source category shall be adopted only after notice and opportunity for comment are afforded.

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[6] The Ninth Circuit relied on and was citing the August 19, 2011 declaration of expert witness, Thomas A. Umenhofer, in *Washington Environmental Council v. Bellon*, which is attached hereto.

WSPA's member refineries vary in size and complexity, but all are energy efficient facilities. Efficiency is an obvious goal for any sector of industry because of the great cost savings that can be realized from reductions in energy consumption. Washington's refineries have invested heavily in energy efficiency projects over the past 30 plus years. If there were *cost-effective* projects that could be implemented at a refinery to achieve an *additional 10* percent in GHG emission reductions, which translates to energy efficiency, it is likely that the projects *have already been undertaken*.

Ecology bases its proposed 10 percent GHG emission reduction goal on publications and reports cited in the technical support document for the rule. TSD at 82-83. The main source cited by Ecology is a report published in 2013 by the California Air Resources Board ("CARB").[7] CARB issued a regulation in July 2010 which required large industrial facilities to conduct a one-time energy efficiency assessment and report on potential energy efficiency improvement projects identified through the assessment and the GHG reductions associated with such projects. The CARB Report summarizes energy efficiency projects identified at twelve California refineries and the resulting GHG emissions reduction.

Ecology cites the CARB Report as a foundation for the 10 percent GHG reduction requirement in the proposed WAC 173-485-040(2), noting that the twelve California refineries were able to identify a 9 percent reduction in GHG emission reductions. TSD at 82-83. However, the most significant fact about the CARB Report, which Ecology acknowledges, is that "the rule allowed for projects completed *prior to the baseline year* to be included" in the calculation of GHG reductions. TSD at 82 (emphasis added). In fact, the CARB Report explains that approximately *half* of the estimated GHG reductions are from projects completed *before* the rule was issued in 2010. CARB Report at IS-1, 30-31. For example, the report references major GHG reduction projects that occurred at Chevron's Richmond refinery in 1992 and 1995. *Id*. at 41. The CARB Report also references major GHG reduction projects that occurred at Valero's Benicia Refinery as far back as 2002. *Id*. at 68. Ecology rejected the possibility of crediting emission reduction projects that were undertaken prior to the baseline year because it would result in "double counting" those reductions. Cost-Benefit Analysis at 25-26. The results in the CARB report are skewed from this type of "double counting" and should not be a basis for Ecology's 10 percent emission reduction requirement.

In addition, *approximately 22* percent of the GHG emission reductions counted in the CARB report were "under investigation" or "scheduled." *Id*. Therefore, *almost 75* percent of the GHG emission reductions cited in the CARB Report either occurred before 2010 or have not yet been achieved. Considering only the projects that have been completed since 2010, there has been an approximate **2.5 percent** reduction in GHG emissions at the twelve California refineries.

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[7] CARB, Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources - Refinery Sector Public Report (June 6, 2013) ("the CARB Report").

The CARB Report does not support a finding that Washington's refineries could achieve cost-effective reductions in GHG emissions of 10 percent over a 2010 or 2011 baseline. Nor do the other references cited by Ecology support the claim that a 10 percent reduction in GHG emissions between 2010 and 2025 is achievable at a reasonable cost. For example, the report published by the Canadian Fuels Association describes significant GHG emission reductions that were achieved by refineries between the years of 1990 and 2010.[8] Like their Canadian and California counterparts, Washington refineries completed significant energy efficiency projects during that timeframe, but these projects and the resulting GHG emission reductions do not count toward Ecology's proposed emission reduction requirement. The remaining reports relied on by Ecology either cite anecdotal evidence of a single refinery that has achieved impressive GHG emission reductions,[9] describe potential GHG emission reductions at a refinery without considering a set timeframe or whether the projects have already been implemented,[10] or do not consider the cost-effectiveness of the energy efficiency projects.[11] WSPA believes that the combination of the 10 percent emission reduction requirement and the 2010 look-back period for emission reduction projects is unreasonable, unsupported by the cited reports, and cannot be achieved when considering cost effectiveness.

In response to information requests WSPA members produced substantial information about energy efficiency at their refineries, but Ecology never asked the most critical inquiry - would it be economically feasible to reduce refinery emissions by an additional 10 percent over a 2010 baseline? If Ecology had asked that question, the refineries would have explained that it is not economically feasible to reduce GHG emissions at the refineries by an additional 10 percent. The Washington Refinery example provided in Part II of these comments demonstrates that it could cost one refinery approximately $47.25 million to achieve a 3 percent reduction in GHG emissions. $47.25 million is not economically feasible. Requiring a 10 percent reduction in GHG emissions is not economically feasible, and it is questionable whether it is even *technically feasible* for a refinery to achieve these reductions without shutting down major process units.

WSPA requests that Ecology revise the proposed emission reduction requirement in WAC 173-485-040(2) to 2.5 percent from a 2010 baseline, a number that Ecology could infer is achievable from the data presented in the CARB report. Without adjusting the GHG emission reduction requirement, refineries that have already undertaken the

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[8] Canadian Fuels Association, Fact Sheet: Our Industry is Getting Greener Every Year 2 (Mar. 2013).

[9] R. M. Spoor, Low-Carbon Refinery: Dream or Reality?, Hydrocarbon Processing, Nov. 2008.

[10] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers (Oct. 2010); J. Mertens & J. Skelland, Rising to the CO2 Challenge - Part 3, Hydrocarbon Engineering, Mar. 2010.

[11] U.S. Department of Energy, Energy Bandwidth for Petroleum Refining Processes (Oct. 2006).

most cost-effective emission reduction projects are in effect being punished for proactively achieving GHG emission reductions before the 2010 baseline year.

WAC 173-485-040 –Emission Reduction Requirement; Energy Assessment

If Ecology does not accept WSPA's suggestion to revise the emission reduction requirement to a level that is achievable, then WSPA requests that Ecology include an additional option for refineries to demonstrate compliance by having an energy assessment of the refinery completed by a third party energy assessor. If a refinery selects this alternative it would be required to implement projects that the third party energy assessor determines to have a 4-year or less payback period. This alternative would accomplish the purpose of the RACT rule, which is to achieve emission reductions "by the application of control technology that is reasonably available considering technological and *economic feasibility*." The refineries would be able to demonstrate compliance with the RACT rule by implementing all projects identified to be *cost-effective*, even if they do not cumulatively result in a 10 percent reduction in GHG emissions.

Ecology states that basic equipment upgrades and no-to-low-cost operational improvements are "generally considered to be on the level of RACT." TSD at 78, 90. This type of project typically has a two to four year payback period. TSD at 86. Requiring refineries to implement energy reduction projects with a four year or shorter payback period meets the RACT standard, while protecting refineries that cannot meet the energy efficiency standard from a refinery-wide GHG percentage reduction requirement that may not be achievable at a reasonable cost.

It is important that the RACT rule either have a realistic emission reduction requirement (*2.5 percent*) or have a hard stop related to cost effectiveness. Including this alternative would reduce the challenge facing refineries that have already implemented the cost-effective projects that have resulted in large GHG emission reductions. Those refineries would not be penalized for the emission reductions they have already achieved and would be required to implement only *economically feasible* projects. The attached redline presents this option as a new paragraph in WAC 173-485-040(3).

WAC 173-485-060(3) –Demonstrating Compliance with the Emission Reduction Requirement; Upgrades to Electrical Equipment

The proposed WAC 173-485-060(3) would prohibit refineries from claiming credit against the emission reduction requirement for "Improvements in the efficiency of existing electrical equipment or electrical equipment upgrades . . ." Ecology proposes to exclude such emission reductions from being creditable because they "do not occur at the refinery." TSD at 90. In WAC 173-485-060(4), however, Ecology requires refineries to reduce any credit claimed for the replacement of steam-driven equipment with electrical equipment by the incremental emissions from off-site generation of the electricity used to drive the new equipment. Ecology explains that this is necessary because GHGs would be generated "at another facility" as a result of the project. TSD at 84.

These two provisions conflict with each other. Refineries must either be allowed to take credit for all GHG emission reductions that occur at the refinery, without regard to emission increases at off-site power plants, or they should be able to take credit for emission reductions at off-site power plants resulting from efficiency improvements to electrical equipment at the refinery. The simplest solution to this conflict is to delete WAC 173-485-040(3) to make the proposed RACT rule internally consistent. WSPA recommends that deletion.

Thank you for carefully considering the concerns of WSPA in the development of the RACT rule. Please call me at (360) 352-4506 if I can provide any additional information in support of these comments.

Very truly yours,

Frank E Holmes

Frank E. Holmes
Director, Northwest Region

Enclosures

cc: Alan Newman, Ecology
Nancy Pritchett, Ecology

Redline Edits to Accompany WSPA Comments of 1/31/14

Chapter 173-485 WAC

PETROLEUM REFINERY GREENHOUSE GAS EMISSION REQUIREMENTS

NEW SECTION

WAC 173-485-010 Policy and purpose. The purpose of this rule is to determine reasonably available control technology for emissions of greenhouse gases emitted by petroleum refineries located in Washington state. The emission standards in this rule were developed under the requirements of RCW 70.94.154.]

NEW SECTION

WAC 173-485-020 Applicability. (1) This chapter applies to all petroleum refineries in Washington state ~~identified~~ as defined[1] in WAC 173-485-030.

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[1] WSPA suggests a revised definition for "petroleum refineries" that defines the term by SIC code, rather than simply naming the five existing refineries in Washington. Several Washington refineries are located on complex sites that host operations *other* than refineries, e.g. cogeneration plants owned by third parties. In addition, if one of the listed refineries permanently shuts down, it is no longer subject to this rule. WSPA's edit clarifies that the rule regulates only active refinery operations on these sites.

(2) All ~~federal regulations referenced~~ references in this regulation to federal regulations are ~~adopted~~ to the versions in effect ~~as they exist~~ on July 1, 2013.[2]

NEW SECTION

WAC 173-485-030 Definitions. Definitions in chapter 173-400 WAC apply to this chapter. Definitions specific to this chapter include:

"Baseline greenhouse gas emissions" means greenhouse gas emissions, reported to the United States Environmental Protection Agency (EPA) to comply with 40 C.F.R. Part 98. The baseline greenhouse gas emissions are for either calendar year 2010 or 2011, as determined by the refinery, so long as the refinery did not experience more than 30 continuous days of outage in the crude unit that year.[3] ~~If petroleum refinery operations during 2010 were not representative of typical refinery operations, then the petroleum refinery must use its 2011 emissions.~~ Emissions must be provided in units of metric tons of CO_{2e}. Emissions attributable to the production of electricity from on-site

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[2] WSPA suggests revising this provision to reference rather than adopt EPA's GHG reporting rules. The EPA rules conflict in some ways with WAC ch. 173-441, and Ecology can achieve the purposes of this rule simply by referencing 40 CFR Part 98.

[3] Ecology should give the refineries a limited choice in selecting the baseline year because many factors apart from turnarounds affect GHG emissions. Refineries should have limited flexibility to select 2010 or 2011 as the baseline year taking into account relevant factors, such as characteristics of crude slate, as long as the refinery did not experience more than 30 days of outage in the crude unit that year. Under this approach it is no longer necessary to define the term "typical refinery operations."

cogeneration equipment are not included in the baseline emissions. Emissions attributable to the production of steam by the cogeneration equipment are included in the baseline emissions.

"Carbon dioxide equivalent" or **"CO_{2e}"** means the number of metric tons of carbon dioxide emissions with the same global warming potential as one metric ton of another greenhouse gas. CO_{2e} is calculated using Equation A-1 of 40 C.F.R. Part 98.2 and the global warming potential values contained in Table A-1 of 40 C.F.R. Part 98, Subpart A.

"Credit" means the reduction of CO_{2e} emitted resulting from one or more projects performed at a petroleum refinery during or prior to a reporting year. A credit is established according to WAC 173-485-060.

"**Energy efficiency standard**" means the EII® value representing the fiftieth percentile EII® of similar sized United States refineries, using the EPA EnergyStar® calculation methodology, which is based on the United States refineries participating in the EII® process in 2006.

"Energy Intensity Index®" or **"EII®"** means the Solomon Associates proprietary petroleum refinery energy efficiency metric that compares actual energy consumption for a petroleum refinery with the standard energy consumption for a petroleum refinery of similar size. The standard energy consumption is based on an analysis of refining capacity as contained in the data base maintained by Solomon Associates. The ratio of a facility's actual energy consumption to the standard energy consumption is multiplied by one hundred to arrive at the EII® for a refinery.

"Greenhouse gases (GHGs)" ~~include~~ mean[4] carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

"Petroleum refinery" or **"petroleum refineries"** means Washington refineries operating within the Standard Industrial Classification Code 2911 (petroleum refining), which as of the effective date of this rule include[5] the following facilities, regardless of future changes in ownership or name:

(a) BP Cherry Point Refinery in Blaine, WA;

(b) Phillips 66 Company Refinery in Ferndale, WA;

(c) Shell Oil Company Refinery in Anacortes, WA;

(d) Tesoro Refining & Marketing Company, LLC Anacortes Refinery in Anacortes, WA; and

(e) U.S. Oil & Refining Co. Tacoma Refinery in Tacoma, WA.

"RACT" means reasonably available control technology.

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[4] This edit clarifies that "greenhouse gases" means *only* the gases identified in the definition.

[5] Note 1 explains the basis for this definition.

"Similar sized United States refineries" means refineries determined to be of similar size using the petroleum refinery capacity categories established for EPA's EnergyStar® program.

~~**"Typical refinery operation"** means a calendar year during which the petroleum refinery experienced no planned turnaround projects or unplanned upsets to unit operations neither of which~~ that in the aggregate ~~resulted in cessation of the processing of crude petroleum oil for more than thirty days.~~[6]

NEW SECTION

WAC 173-485-040 Greenhouse gas reasonably available control technology emission standard. (1) **Energy efficiency standard.** The owner/operator of each petroleum refinery subject to this rule shall meet the requirement to use reasonably available control technology (RACT) for greenhouse gas emissions by demonstrating that the petroleum refinery has a calculated EII® equal to or more efficient than the EII® value representing the fiftieth percentile EII® of similar sized United States refineries, based on 2006 data and the EPA EnergyStar® calculation methodology. The petroleum refinery must demonstrate compli-

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[6] WSPA suggests that Ecology delete this definition per note 3 above. If Ecology does not delete this definition as recommended in note 3, then it should be clarified as noted.

ance with WAC 173-485-050 in the annual report required in WAC 173-485-090 using any EII® report issued between 2006 and ~~the first annual report~~2024[7]. If a petroleum refinery is unable to or chooses not to demonstrate compliance with the energy efficiency standard~~ in the first annual report required in WAC 173-485-090~~, the petroleum refinery shall document that it has met the requirements of subsections (2) or (3) of this section no later than October 1, 2025.

(2) As an alternative to the Solomon Associates EII® methodology, the owner/operator of each petroleum refinery subject to this rule may meet the requirement to use RACT for GHG emissions using other acceptable protocols, methodologies or evaluation as deemed acceptable by the agency.[8]

(3) Emission reduction requirement. A petroleum refinery that does not meet the requirements of either subsection (1) or (2) of this section, must:

(a) No later than October 1, 2025, ~~have ~~implement~~ed~~ greenhouse gas reduction projects that~~:~~

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[7] WSPA believes it is Ecology's intent to allow a refinery to demonstrate compliance with energy efficiency standard using an EII report from any year between 2006 and 2024. This edits clarifies that intent.

[8] WSPA requests that Ecology provide this alternative option for compliance because codifying Solomon Associates as the sole provider of service as a regulatory requirement potentially leads to anti-competitive pricing and practices for which the recipient of those services lacks market freedom and choice.

~~(i) ~~r~~R~~esult in cumulative annual emissions reduction(s) equivalent to ~~ten ~~2.5[9] percent of the facility's baseline greenhouse gas emissions (as CO_{2e}). Compliance with this option shall be demonstrated using the procedures outlined in WAC 173-485-060; or

~~(ii) Result in the petroleum refinery meeting the energy efficiency standard in subsection (1) of this section.~~[10]

(b) ~~Demonstrate compliance with the emission reduction requirement in WAC 173-485-060.~~Complete an energy assessment of the refinery as provided in this subsection and implement those projects that meet the criteria described in this subsection:

(i) the energy assessment shall be completed by a third party energy assessment company no later than one year from the effective date of this rule.

(ii) the energy assessment shall include a list of energy reduction projects that include the information specified in WAC 173-485-060 (1)(a) – (c).

(iii) all projects identified in the energy assessment study that have a 4-year or less payout shall be completed by October 1,

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[9] WSPA's cover letter submitted with this redline explains the rationale for revising the emission reduction requirement.

[10] This deletion does not change the rule substantively but clarifies an otherwise confusing provision. The energy efficiency option is already provided for in subsection 173-485-040(1), and so does not need to be included as an option in -040(2). With WSPA's edit to 173-485-040(1), a refinery can demonstrate compliance with the energy efficiency option using an EII report from any year between 2006 to 2024.

2025; unless prior to completion of all the identified projects, the petroleum refinery is able to satisfy the requirements of this chapter by meeting either the energy efficiency standard in 173-485-040(1) or the emission reduction requirement in 173-485-040(3)(a).

NEW SECTION

WAC 173-485-050 Demonstrating compliance with the energy efficiency standard. (1) Owners/operators of a petroleum refinery demonstrating compliance with the energy efficiency standard shall as part of the annual report required in WAC 173-485-090(1) submit the following information:

(a) The letter from Solomon Associates certifying that the petroleum refinery has a calculated EII® for the refinery that meets the requirements in WAC 173-485-040(1);

(b) Identification of the calendar year of the petroleum refinery's operational data submitted to Solomon Associates to reach that conclusion. The calendar year used may be any year between 2006 through 2024; and

(c) Confirmation that the operational data submitted to Solomon Associates for these calculations were reviewed and certified by a professional engineer licensed in the state of Washington, including the date the operational data ~~was~~ were certified and the name and license number of the professional engineer who made the certification.

(2) According to WAC 173-485-090, once this certification has been made, no additional annual reports are required.

NEW SECTION

WAC 173-485-060 Demonstrating compliance with the emission reduction requirement. (1) **Requesting credit.** Owners/operators of a petroleum refinery demonstrating compliance through the emission reduction requirement in WAC 173-485-040(~~2~~3) shall submit, as part of each annual report required in WAC 173-485-090(1), requests for a credit against the greenhouse gas emission reduction requirement. A credit request must be based on specific projects that have been completed at the petroleum refinery since the previous annual report. Each request must include the following information:

(a) An engineering description and analysis of the project, including the emission reduction and energy efficiency objectives for the project.

(b) A quantitative analysis of the project documenting the annual metric tons of CO_{2e} emission reductions the project is designed to[11] achieve~~d~~ as a result of completing the project.

(c) Information supporting the quantitative analysis including engineering assumptions, measurements, or monitoring data.

(d) Requests for credits shall be submitted as part of the first annual report submitted after the petroleum refinery project has been completed.

(2) **Processing a credit request.**

(a) Each request for credit shall be reviewed and certified by a professional engineer licensed in the state of Washington. The certification must contain the name and license number of the professional engineer who performed the review and certified the submittal.

(b) Within thirty days after the receipt of a request for credit, the permitting authority may require the submission of additional information needed to review the request.

(c) Within thirty days after all required information has been received, the permitting authority shall propose to approve or deny the request for credit. Final approval or denial of a request shall be

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[11] Demonstrating the exact amount of CO2e emission reductions achieved from a single project would be very difficult for a complex refinery, so WSPA recommends that this provision be based on the emission reductions the project is *designed* to achieve.

established through the issuance of a ~~regulatory~~ credit order. The regulatory order must be issued in accordance with the procedures of the permitting authority for issuing such orders. Each regulatory order issued to approve a request shall include both the quantity of greenhouse gas reduction credit awarded and any conditions necessary to support the validity of the credit award.

~~(3) Improvements in the efficiency of existing electrical equipment or electrical equipment upgrades are not eligible for credits.~~[12]

(~~4~~3) Greenhouse gas reductions for the replacement of direct fired or steam-driven equipment with electrical equipment will be credited based on the calculated difference between the greenhouse gas emissions reduced at the refinery and the greenhouse gas emissions ~~calculated~~ from generation of ~~for~~ the electricity required. The greenhouse gas emissions for electricity used will be 331 lbs CO2/MWh, the statewide average of greenhouse gas emissions ~~specific to the petroleum refinery's~~from statewide sources of electricity.[13]

(5) Greenhouse gas emission reductions at the petroleum refinery that occurred prior to January 1, 2010, are not eligible for credits.

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[12] WSPA's cover letter submitted with this redline explains the rationale for deleting this provision.

[13] It is necessary to use the statewide average emissions, rather than emissions specific to a given refinery's source of electricity, to avoid penalizing refineries that do not have access to lower greenhouse-emitting sources of electricity. The statewide average of 331 lbs CO2/MWh is cited from EPA Emissions & Generation Resource Integrated Database, 2005 eGRID 2007 Version 1.0, Year 2005 Summary Tables, *available at*: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

NEW SECTION

WAC 173-485-070 Monitoring. (1) ~~Each~~ To demonstrate compliance with the emission reduction requirement,[14] each petroleum refinery must use monitoring measures that satisfy requirements for petroleum refinery owners/operators reporting greenhouse gas emissions to EPA under 40 C.F.R. Part 98. ~~Unless additional monitoring is required by the credit order issued under WAC 173-485-060 (2)(c), t~~The 40 C.F.R. Part 98 monitoring is considered sufficient for quantifying annual emissions for this regulation.

~~(2) The permitting authority may require additional monitoring, recordkeeping, and reporting to document compliance with a credit established through this regulation. The additional monitoring, recordkeeping, and reporting must be identified in the credit order issued under WAC 173-485-060 (2)(c).~~[15]

NEW SECTION

WAC 173-485-080 Recordkeeping. (1) All records used for preparing submittals to Solomon Associates to support a showing of compliance

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[14] The monitoring described in this paragraph should not be required of a refinery that demonstrates compliance with the energy efficiency standard.

[15] There is no basis to require additional monitoring because the monitoring specified in 40 CFR Part 98 is sufficient to demonstrate compliance with RACT.

with the energy efficiency standard[16] or for preparing reports to the permitting authority shall be retained at least five years beyond the date of the ~~last~~ associated[17] annual report required by WAC 173-485-090(2).

(2) Records related to emission calculations and reports shall be provided to the permitting authority upon request. The petroleum refinery owner/operator retains the rights to keep specified records and information confidential as provided in RCW 70.94.205.

NEW SECTION

WAC 173-485-090 Reporting. (1) **~~Annual~~Biennial reports.**[18] Starting on October 1, ~~2014~~2015, and by October 1 of each odd numbered year until October 1, 2025, unless compliance has been demonstrated on an earlier date, the owners/operators of a petroleum refinery subject to

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[16] Every two years Washington refineries submit huge volumes of data to Solomon Associates. The "records used for preparing submittals to Solomon" include operating data from all of the process equipment at the refinery. This rule should require a refinery to retain only those records that are used to show compliance with the energy efficiency standard, the only part of this rule for which records used to prepare submittals to Solomon are relevant.

[17] If a refinery does not demonstrate compliance for several years, retaining all records until 5 years after the final report is a very burdensome requirement.

[18] Where the main goal of reporting is to document progress toward meeting the emission reduction requirement, a biennial report is adequate to show progress, while reducing the cost of reporting. Nothing would prevent a refinery that satisfies the performance standards of this chapter from filing a report less than two years after a previous report.

this ~~standard~~ chapter shall submit reports to ~~their~~ its permitting authority that include the following information:

(a) Identification of the option the petroleum refinery intends to use to demonstrate compliance with this ~~standard~~chapter, including the baseline greenhouse gas emissions year the refinery has selected and justification to utilize that year.

(b) Activities completed since the last biennial~~annual~~ report to reduce greenhouse gas emissions.

(c) Any changes since the last biennial~~annual~~ report regarding the compliance option utilized by the petroleum refinery.

(d) Baseline greenhouse gas emissions for the petroleum refinery, actual greenhouse gas emissions for the previous two calendar years, total greenhouse gas emission reductions already credited to the petroleum refinery, and any emission reductions previously approved through ~~regulatory~~ credit order to comply with WAC 173-485-040(3), since the effective date of this regulation.

(e) ~~All c~~Compliance documentation submittals required in WAC 173-485-050 or 173-485-060(1), as applicable.

(f) If the first biennial~~annual~~ report does not indicate compliance with the requirements in WAC 173-485-040, the first report must contain an overview plan of how the refinery intends to comply with the requirements of WAC 173-485-040.

(2) ~~Annual~~ Biennial reports must be submitted to the permitting authority until compliance has been demonstrated with either WAC 173-485-040 (1), (2) or (3). The owner/operator of a petroleum refinery shall identify in the biennial~~annual~~ report that the report is the final report that will be submitted to the authority.

173-485-100 Confidential Business Information. All proprietary information submitted by a refinery to demonstrate compliance with this chapter shall be treated as confidential information within the meaning of RCW 70.94.205.[19]

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[19] The reports required to be submitted regarding the proposed emission reduction projects under WAC 173-485-060(1) and the annual reports required by WAC 173-485-090(1) contain sensitive, proprietary information about a refinery's operations. WSPA requests that Ecology include this provision classifying this information as CBI and protecting it from public disclosure.

WASHINGTON STATE
DEPARTMENT OF
ECOLOGY

Reasonably Available Control Technology (RACT)

1996 List and Schedule

All existing industrial sources in Washington are required to use Reasonably Available Control Technology, or RACT, to control air emissions. In 1993, the Washington State Legislature required the Department of Ecology (Ecology) to establish a framework for systematically performing RACT determinations. This framework is the RACT List and Schedule. The following is the 1996 RACT List and Schedule. (Please see Page 5 for a definition of terms/acronyms used in this document.)

Any source or source category's basic obligation is to be at RACT. This List and Schedule is only meant to prioritize which sources and source categories are expected to be evaluated in the near future. In setting these priorities, Ecology will take into account, among other factors, air quality problems associated with emissions from the particular source or source category.

The List and Schedule is meant to be an informational document, and is not a limit to any regulatory authority. RACT is a regulatory tool that can be used at any time by Ecology or local air pollution control authorities to address air quality problems. Ecology or local air authorities may need to perform RACT analyses on sources not on this List and Schedule in order to address such problems.

Group A1: Sources/Source Categories for Which the Responsible Agency Will Begin RACT Review Within the Next Two Years

Source/Source Category:	Responsibility:	Start:
Hog Fuel Boilers	Ecology	12/96
Fiberglass Fabrication	Ecology	7/97
Municipal Waste Combustors	Ecology	6/96

Group A2: Sources/Source Categories Formerly in Group B That Were Finalized And Now Will Be Incorporated Into Washington's Rules

The federal Environmental Protection Agency (EPA) has finalized Maximum Achievable Control Technology (MACT) standards for the following source categories. Ecology and the local authorities are evaluating whether to adopt the federal MACT standards by

(Group A2, continued)

reference, whether the rules can be simplified while still adhering to federal standards, and whether the circumstances in Washington call for other requirements (such as RACT). Ecology has 18 months from the date of finalization to either adopt EPA's MACT standards or develop our own. For purposes of regulatory efficiency, Ecology will attempt to time RACT evaluations with the timing of MACT evaluations. It should be noted that MACT and RACT are different regulatory requirements, and readers should not confuse the requirements or evaluation process of one with the other.

Industry Group/ Source Category	**EPA's Finalization Date**
Sewage Sludge Incineration	2/93
Industrial Cooling Towers	9/8/94
Offsite Waste & Recovery Operations	10/13/94
Halogenated Solvent Cleaners	11/9/94
Commercial Sterilization Facilities	12/6/94
Gasoline Distribution (Stage I)	12/14/94
Polymers & Resins II	3/8/95
Secondary Lead Smelting	6/23/95
Petroleum Refineries (Other Than Catalytic Cracking or Reforming Units and Sulfur Plant Units)	8/19/95
Aerospace Surface Coating	9/1/95
Marine Vessel Loading & Unloading	9/19/95
Municipal Landfills (NSPS)	3/14//96
Consumer Products List (Section 183(e) of the federal Clean Air Act Amendments)	9/29/95
Wood Furniture Coating	11/14/95
Chromium Electroplating & Anodizing Rules	11/25/95
Ship Building & Repair	12/95

Group A3: Sources/Source Categories Formerly in Group B That Are Expected To Be Finalized Within the Next Two Years And Are Expected To Be Incorporated Into Washington's Rules

EPA is expected to finalize MACT standards for the following source categories within the next two years. Ecology and the local authorities will evaluate whether to adopt the federal MACT standards by reference, whether the rules can be simplified while still adhering to federal standards, or whether the circumstances in Washington call for other requirements. Ecology will have 18 months from the date of promulgation to either adopt EPA's MACT standards or develop our own. For purposes of regulatory efficiency, Ecology will attempt to time RACT evaluations with the timing of MACT evaluations. It should be noted that MACT and RACT are different regulatory requirements, and readers should not confuse the requirements or evaluation process of one with the other.

(Group A3 continued)

Industry Group/ Source Category	**EPA's Proposal Date**
Hazardous Waste TSDF Phase II (RCRA)	7/22/91
Electric Utility Generators (Nitrogen Oxide (NO_x))	5/30/94
SOCMI, Secondary Sources (NSPS)	8/31/94
Medical Waste Incinerators (NSPS)	2/1/95
Pulp & Paper Combustion	2/27/95
Printing/Publishing	3/1/95
Polymers & Resins IV	3/15/95

Industry Group/Source Category	**EPA's Proposal Date**
Architectural/Industrial Coating (Section 183(e) of the federal Clean Air Act Amendments	5/5/95
Polymers & Resins I	6/15/95
Off-Site Waste Operations	9/95
Pulp & Paper Chemical	10/29/95
Electric Utility Generators (NO_x) (Section 407(c) of the federal Clean Air Act Amendments)	1/22/96
Portland Cement Manufacturing	1/96
Primary Aluminum Production	2/96
Mineral Wool Manufacturing	2/96
Pharmaceutical Production	3/96
Secondary Aluminum Production	8/96
Ferro-alloys Production	4/96
Oil/Natural Gas Production	1/97
Publicly Owned Treatment Works	3/97
Chlorine Production	11/97
Petroleum Refiners (Catalytic Cracking)	11/97
Primary Copper Smelting	11/97
Non-stainless Steel Manufacturing (Electric Arc Furnace Operation)	12/97

Group B: Sources/Source Categories Subject to Federal MACT Rule-Makings Under the Federal Clean Air Act

Group B is comprised of source categories for which EPA is currently developing MACT regulations under the federal Clean Air Act and which have at least one source in Washington State.

The following list of source categories are those for which MACT standards have not yet been set. Ecology will generally wait until EPA's rule-making has been completed before determining whether further regulatory efforts are warranted at the State level. Such efforts may be warranted

(Group B continued)

where, for example, Ecology determines that residual emissions (after application of the MACT) would likely result in unacceptable air quality impacts or where available pollution prevention measures are more likely to effectively reduce or avoid pollution.

Industry Group/ Source Category	**Anticipated Proposal Date**
Asphalt Concrete Manufacturing	2000
Asphalt Manufacturing	2000

Industry Group/Source Category	**Anticipated Proposal Date**
Asphalt Processing	2000
Asphalt Roofing Manufacturing	2000
Auto/Truck Surface Coating	2000
Baker's Yeast Manufacturing	2000
Boat Manufacturing	2000
Clay Products Manufacturing	2000
Coke By-Products	2000
Coke Ovens	2000
Explosives Production	2000
Flat Wood Paneling	2000
Fuel Combustion (Industrial)	2000
Fuel Combustion (Process Heaters)	2000
Fuel Combustion (Stationary Engines)	2000
Hazardous Waste Incineration	2000
Hazardous Waste TSDF, Phase II (RCRA)	(?)
Iron Foundries	2000
Lead Acid Battery Manufacturing	2000
Lime Manufacturing	2000
Metal Can and Coil Coating	2000
Municipal Landfills (MACT)	2000
Paint Stripper Users	2000
Paints, Coatings, Adhesives Manufacture	2000
Paper and Other Webs Coating	2000
Phosphate Fertilizer Production	2000
Photographic Chemical Production	2000
Phthalate Plasticizer Production	2000
Plastic Parts and Products	2000
Plywood/Particle Board Manufacturing	2000
Primary Magnesium Refining	2000
Rayon Manufacturing	2000
Rocket Engine Test Firing	2000

(Group B, continued)

Semiconductor Manufacturing	2000
Site Remediation	2000
Steel Foundries	2000
Uranium Hexaflouride Production	2000
Vegetable Oil Production	2000
Wool Fiberglass Manufacturing	2000

Group C: Sources/Source Categories Requiring Further Data Collection to Evaluate Placement Under Group A

All sources and source categories that are not listed under Group A or Group B comprise Group C. However, due to workload and other priorities, Ecology has not attempted to identify specific categories that would fall into a Group C. Ecology believes that additional information will be needed to determine at what point a source category not listed in A or B would be added to those lists. Ecology will continue to review information collected through the operating permit program, EPA's rulemaking efforts and other information sources in order to make these determinations. As appropriate, additional source categories will be added to Group A or B as part of the periodic review of the RACT List in order to fulfill the requirement that "RACT . . . is required for existing sources."

Definitions of Terms/Acronyms

Best Available Control Technology (BACT): An emission limitation based on the maximum degree of reduction for each regulated air pollutant emitted from or that results from any new or modified stationary source. BACT is the emission rates that are achievable for a source or modification, determined on a case-by-case basis and taking into account energy, environmental and economic impacts and other costs.

Lowest Achievable Emission Rate (LAER): The most stringent of the following:
- (a) The most stringent emission limitation that is contained in the implementation plan of any state for a class or category of sources; or
- (b) The most stringent emission limitation that is achieved in practice by a class or category of sources.

Maximum Available Control Technology (MACT): An emission standard for the control of hazardous/toxic air pollutants. For existing sources, MACT may be no less than the average level of control achieved by the best performing 12 percent of existing sources in a source category. More stringent standards may be set by the state or local agencies or on a case-by case basis.

(Group C continued)

National Emission Standards for Hazardous Air Pollutants (NESHAPS): Federal regulations (40 CFR Part 61) that govern emission of certain toxic air pollutants from a variety of source categories. These regulations set a national minimum level of emissions control for these pollutants.

New Source Performance Standards (NSPS): Federal regulations (40 CFR Part 60) that govern emissions of certain air pollutants from a variety of source categories. These regulations set a national, minimum level of emissions control for these pollutants.

Prevention of Significant Deterioration (PSD): A permitting review program for major pollutant sources that looks at the impact of those sources on ambient air quality, as well as air quality related impacts on national parks and certain wilderness areas.

Reasonably Available Control Technology (RACT): The lowest emission limit that a particular source or source category is capable of meeting through application of control technology that is reasonably available considering technological and economic feasibility.

Resource Conservation and Recovery Act (RCRA): This Act provides standards for the treatment, storage, and disposal of hazardous waste, defined as solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations.

For More Information

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WASHINGTON STATE
DEPARTMENT OF
ECOLOGY

Hog Fuel Boiler RACT Determination

Publication # 03-02-009

If you need this document in another format, call Tami Dahlgren at (360) 407-6800. If you are a person with a speech or hearing impairment, call 711 or 1-800-833-6388 for TTY.

Hog Fuel Boiler RACT Determination

Summary

The purpose of this project was to determine the reasonably available control technology (RACT) for wood and combination-wood (also known as hog fuel) fired boilers that are typically used in the pulp and paper industry in order to meet their steam and heat needs. This report sets forth procedures for RACT development, and provides technical information that will assist state and local air pollution control agencies in developing guidelines for RACT for certain criteria pollutants from existing stationary sources on a case-by-case basis.

Furthermore, this RACT review evaluates costs for effective removal of "pollutants of concern" (POCs) and air quality benefits for different size boilers: (1) small, (2) medium, and (3) large. For small size boilers (<3,500 lb/hr steam), multi-cyclone (MC) alone is capable of removing particulate matter (PM) at a reasonable cost ($180 per ton), while meeting air quality standards for other criteria pollutants. On the other hand, PM control cost for small size boiler would be far greater using either electrostatic precipitator (ESP) ($594/ton) or fabric filter (FF) ($958/ton). This analysis, therefore, indicates that MC is RACT for PM for small size boiler. Similarly, the cost analysis indicates that both ESP and FF are RACT for PM for medium size boilers (15,000-45,000 lb/hr steam), while venturi scrubber (VS) represents RACT for acid gases. For large size boilers (200,000-700,000 lb/hr steam), all three control options (FF, ESP, and VS), based on their cost effectiveness, represent RACT for POCs.

This report is divided into three chapters and five Appendices. The first chapter describes the steps of selecting POC from the wood-fired boiler. The first step in the POC selection process involved a wide search of sources of emission data including but not limited to:

(1) Washington State Emission Inventory;
(2) Title V Air Operating Permit;
(3) National Council of the Industry for Air and Stream Improvement (NCASI) Technical Bulletins;
(4) Air Chief Version 6.0 CD ROM;
(5) Toxic Release Inventory (TRI);
(6) Literature Search Database developed by Ecology's Air Quality Program Staff.

By consolidating all the candidate pollutants of concern, pollutants were selected that are most-representative as far the criteria and toxic pollutants emission from wood-fired boilers were concerned.

The second chapter summarizes a qualitative analysis of all reasonably available control technologies for each of the categories of POC. This chapter is divided into the following sections: particulate-related controls, carbon monoxide related controls, acid gases and sulfur compounds controls, and nitrogen oxide controls. For each POC category, control technologies are described and evaluated using the Source Category RACT Guidelines.

The third chapter describes the energy, environmental, and economic impacts of each control option and the selection of the final level of control for hogged fuel boilers as RACT. The final RACT for each category POC was determined based on cost per ton of pollutant removal and air quality impacts relative to ambient standards. Appendix A shows the detailed calculations on how total annualized costs were estimated for air pollutant control devices, including mechanical collectors, venturi scrubbers, electrostatic precipitators, fabric filters, and gas absorbers for acid gas control. Appendix B shows calculations of pollutant removal in tons per year, and dollars per ton of pollutant removal. Appendix C presents a summary of all ash production, handling, and landfill disposal costs at facilities with wood fired boilers in Washington. And Appendix D presents values of maximum ambient concentration of pollutant of concern and its corresponding distances where these maximum concentrations may occur. These values were obtained by using the SCREEN 3 model for three different size boilers: small, medium, and large.

The Appendix E provides detailed background information on dioxin and furan formation in wood and combination wood-fired boilers. This report provides information on different control strategies for dioxin/furan, and its distribution factors (emission factors) between flue gas and ash particles.

The Appendix F presents a detailed health risk analysis that identified two specific chemicals, acrolein and formaldehyde, whose hazard quotient exceeded, as well as exceeded the acceptable source impact level (ASIL). And due to exceedences of hazard quotient and ASIL for two chemicals, health risk analysis was carried out in greater details in order to characterize the risk they might pose. This analysis used EPA's risk-based models to determine acrolein and formaldehyde risk distributions for a typical person in the State of Washington, and based on this information, health risk analyses followed with recommendations and implementations of RACT for wood-fired boiler were made.

Acknowledgements

The author would like to acknowledge Matt Kadlec, Toxicologist for the Department of Ecology's Air Quality Program, for his detailed toxicological analysis of ambient air quality due to emissions from hog fuel boilers. The author would also like to acknowledge Judy Schwieters (formerly with the Air Quality Program and now with the Industrial Section), Leslie Keill (with the Puget Sound Clean Air Agency) for providing data and invaluable input to the documents, Alan Newman and Bernard Brady for providing expert comments, continued editing efforts, and encouragement towards the completion of this report.

THE HONORABLE MARSHA J. PECHMAN

UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF WASHINGTON
AT SEATTLE

WASHINGTON ENVIRONMENTAL COUNCIL and SIERRA CLUB WASHINGTON STATE CHAPTER, Plaintiffs, v. THEODORE "TED" L. STURDEVANT, DIRECTOR, WASHINGTON STATE DEPARTMENT OF ECOLOGY, in his official capacity, MARK ASMUNDSON, DIRECTOR, NORTHWEST CLEAN AIR AGENCY, in his official capacity, and CRAIG T. KENWORTHY, DIRECTOR, PUGET SOUND CLEAN AIR AGENCY, in his official capacity,, Defendants, and WESTERN STATES PETROLEUM ASSOCIATION, Intervener-Defendant.	No. 2:11-cv-00417-MJP **DECLARATION OF THOMAS A. UMENHOFER**

I, THOMAS A. UMENHOFER state and declare as follows:

1. My name is Thomas A. Umenhofer. I am a Principal at Natural Resource Group, LLC (NRG), which is located in Las Vegas, Nevada.

2. Attached as Exhibit 1 to this declaration is my current resume, which includes a summary I prepared of my qualifications and expertise. My areas of expertise, based upon over 35 years of professional work, and based upon my education include, air quality engineering, applied meteorology, air pollution control, and environmental policy development. My expertise includes extensive experience and involvement in both development of implementation plans consistent with federal Clean Air Act (CAA), and greenhouse gas (GHG) policies and regulation, including in the development and implementation of GHG emission reporting, benchmarking and mitigation at federal, state and local levels.

3. The matters addressed and the opinions expressed in this declaration are based upon my knowledge, experience, training and education, and reflect the current state of scientific consensus, based upon generally accepted data and scientific methods, regarding global climate change, GHG atmospheric characteristics, and the effects of source-specific GHG emissions.

4. Global climate change, sometimes referred to as "global warming," refers to long-term fluctuations in temperature and other elements of the Earth's climate system. Although scientific debate continues regarding causes, projections of future trends, and resultant effects, it has been shown that global temperatures have increased over the past 50 years, and there is, in general, a scientific consensus that increases in atmospheric concentrations of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), and synthetic halocarbons, collectively known as "greenhouse gases" or "GHGs", are contributing to global climate change.

5. GHGs originate for natural and anthropogenic sources around the world, and are globally mixed into the atmosphere with relatively long residence times. Because of this global dispersion and mixing, there is no resultant direct correlation between a specific GHG emission source and atmospheric concentrations of GHGs at any local or regional receptor. Similarly, there is no direct correlation between specific GHG emission sources and local or regional climate change.

6. General predictions of increasing climate change include an additional increase in average surface temperatures, a rise in sea level, changes in oceanography (including changes in temperature, salinity, pH and sea-ice), and increases in the severity of storms, floods, droughts, rainfall, heat waves and other weather anomalies. Some areas are expected to experience greater effects than other areas; however, current climate models cannot reliably predict future local or regional effects.

7. There is no present generally accepted scientific consensus regarding methodology, reliability or relevance of relating environmental impact significance to source-specific emissions of GHGs. There is, however, a clear scientific consensus that it is currently beyond the scope of existing science to identify a specific source of CO_2 emissions and designate it as the cause of specific climate change impacts at an exact location or region.

8. Thus, it is not possible to quantify a causal link, in any generally accepted scientific way, between GHG emissions from any single oil refinery in Washington, or the collective emissions of all five oil refineries located in Washington, and direct, indirect or cumulative effects on global climate change in Washington or anywhere else. This is the case whether climate change is viewed as an increase in atmospheric emissions levels, increases in surface or ocean temperatures, sea ice recession, ocean acidification, melting glaciers, rising sea level or other processes.

9. I am informed, and have accepted for purposes of this declaration, that the GHG emissions for the five refineries in Washington were approximately 5.9 million metric tons (MMt) of carbon dioxide equivalents (CO_2e) in 2008, and that this figure is generally representative of current GHG emission levels from the five refineries.

10. The global climate change effects of the collective emissions from the oil refineries in Washington are scientifically indiscernible given Washington refinery emissions levels, the uniform distribution of greenhouse gas concentrations globally, and the absence of

any meaningful nexus between Washington refinery emissions and global GHG concentrations now or as projected in the future.

11. This view is supported by a 2008 U.S. Environmental Protection Agency (EPA) study assessed through an atmospheric modeling simulation to determine whether anticipated GHG emissions from a single source could be reliably linked to an increased risk of harm to the most sensitive of species (i.e., species listed as threatened or endangered under the Endangered Species Act) and the habitats of such species. For this study, EPA used a hypothetical facility with approximately 14.5 MMt CO_2e emissions. This level of emissions was 20 percent greater than emissions expected from a proposed 1500 MW coal-fired steam electric generating plant. EPA assumed that the hypothetical facility would begin operations in 2013 and continue in operation for 50 years. The assumed annual GHG emissions rates for the hypothetical facility were nearly 2.5 times greater than the collective annual emissions of the Washington refineries. Based upon the results of this study, EPA concluded that for a project with emissions of the magnitude of the hypothetical facility or lower (e.g., the five Washington refineries, individually or collectively), wherever it might be located, the risk of harm to any species and the risk to the habitat of such species where ever located, would be of "an extremely small magnitude to physically measure or detect," and therefore insufficient to quantify potential adverse effects. *See* October 3, 2008 Letter from U.S. Environmental Protection Agency to U.S. Fish & Wildlife Service, entitled "Endangered Species Act and GHG Emitting Activities" (copy attached as Exhibit 2); May 14, 2008 Letter from Director, U.S. Geological Survey to Director, U.S. Fish & Wildlife Service, entitled "The Challenges of Linking Carbon Emissions, Atmospheric Greenhouse Gas Concentrations, Global Warming, and Consequential Impacts" (copy attached as Exhibit 3).

12. For the above reasons, there is no scientific data demonstrating, and there is no generally accepted scientific methodology or modeling that would demonstrate, that the GHG

emissions from the five oil refineries in Washington would cause or can be correlated with, local or regional GHG concentrations anywhere in Washington, local or regional climate change effects anywhere in Washington, or any local or regional climate change effects on public health and welfare, or business or property.

13. Furthermore for the same reasons identified above, no foreseeable changes in GHG emissions from the five Washington refineries, whether they are increases or decreases, would cause or can be correlated with, local or regional GHG concentrations anywhere in Washington, or local or regional climate change effects.

I swear under penalty of perjury under the laws of the United States that the foregoing information is true and correct to the best of my knowledge, information, and belief.

DATED this 19th day of August, 2011.

Thomas A. Umenhofer

CERTIFICATE OF SERVICE

I hereby certify that on August 22, 2011, I filed a copy of foregoing document with the Clerk of the Court for the United States District Court – Western District of Washington by using the CM/ECF system. Participants in this Case No. 2:11-cv-00417 who are registered CM/ECF users will be served by the CM/ECF system.

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NATURAL RESOURCE GROUP

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Tom Umenhofer is a Principal at Natural Resource Group, LLC (NRG) and been an environmental science, engineering, policy professional in the energy industry for over 35 years. Tom's expertise includes air quality engineering, applied meteorology, pollution control, and environmental policy development. He has served as an instructor at the U.S. Environmental Protection Agency. He has played key roles in the development and implementation of environmental policy including greenhouse gas policy and regulations.

Tom is a Certified Consulting Meteorologist (CCM) and California Registered Environmental Assessor (REA). He received his B.S. from Western Illinois University in Geography, an M.S. in Meteorology from Northern Illinois University and an M.S. in Environmental Engineering from Illinois Institute of Technology. He completed his Ph.D. coursework at the University of Chicago, focusing on Environmental Geomorphology.

Selected Project Experience

- **Energy Engineering Alternatives Assessment.** Tom has served as Principal Investigator for municipal utilities feasibility study for clean energy projects. This study incorporates the concept of "carbon intensity" with regard to the selection of fuel feedstock (for fossil-fuel facilities) as well as renewable energy (wind, solar) alternatives.

- **Greenhouse Gas Assessment Policy Development.** On behalf of a major western U.S. energy trade association, Tom has played a key role in the development and implementation of Greenhouse Gas Emission Reporting, Benchmarking, and Mitigation on both local and federal levels. With expertise on both the policy and technical arenas, he has served as a public/private interface in the development of implementation plans consistent with the federal Clean Air Act.

- **Land Use Planning.** For approximately 15 years, Tom served as a municipal and county planning and land use commisssioner in California. In this public capacity, he was involved to the review and approval of hundreds of environmental assessment documents purusant to state and federal (CEQA/NEPA) requirments. As Chair on both commissions for several terms, Tom played a significant role in the implelnetation of envrimental policy related to major land use decisions that involved endangered species, cultural resources, and community impacts.

- **Energy Strategic Planning.** Tom has been a technical consultant in the strategic planning of future power requirements and potential emission control regulations for a municipal utility. This assignment has included evaluating the impact of load balancing, repowering, and acquisition of electricity. Boiler performance, emissions, and controls were assessed with focus on the cost effectiveness of pollution control.

Education and Registrations

- M.S., Environmental Engineering, Illinois Institute of Technology
- M.S., Meteorology, Northern Illinois University
- B.S., Geography, Western Illinois University
- Ph.D. Studies, Environmental Geomorphology, University of Chicago
- Certified Consulting Meteorologist No. 398
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OCT 03 2008

OFFICE OF
AIR AND RADIATION

Mr. H. Dale Hall
Director
U.S. Fish and Wildlife Service
1849 C Street, NW
Washington, DC 20240

Mr. James Lecky
Director, Office of Protected Resources
National Marine Fisheries Service
1315 East-West Highway, 13th Floor
Silver Spring, MD 20910

Dear Messrs. Hall and Lecky:

Re: Endangered Species Act and GHG Emitting Activities

The U.S. Environmental Protection Agency is currently evaluating several permits under the Clean Air Act for activities that emit various air pollutants, including carbon dioxide (CO_2) and other greenhouse gases (GHG).[1] Public comments on draft permits and the environmental impact statements for related approvals have alleged that authorization of GHG-emitting activities requires that EPA and various lead federal agencies address certain species in consultations with the relevant wildlife Services under section 7(a)(2) of the Endangered Species Act (ESA) due to possible impacts of the GHG emissions from these activities. This letter seeks to confirm your agreement with EPA's determination, based on the following analyses, that issuance of permits under the Clean Air Act for activities that emit GHGs in amounts equal to or less than those analyzed below does not require consultation with NOAA Fisheries or the U.S. Fish and Wildlife Service (FWS) under section 7(a)(2) of the ESA to address the remote potential risks that public commenters suggest GHG emissions from an individual source could present for certain listed species.

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[1] These permits are in various stages of the review process within the Agency, including administrative appeals before the Agency's Environmental Appeals Board that delay the effective date of and final agency action on the permit (and thus preclude the construction authorized by the permit) until the EAB completes its review. 40 U.S.C. § 124.15(b)(2), 124.19(f). In addition, EPA has included conditions in some permits that prohibit construction of the facility until EPA notifies the permittee that EPA has fulfilled any ESA obligations. The conditions also explicitly retain authority for EPA to ensure that the permit applications or terms are amended as appropriate to address any issues regarding the protection of listed species that may be identified.

Background regarding ESA Section 7(a)(2) and GHGs

Section 7(a)(2) of the ESA requires federal agencies, in consultation with NOAA Fisheries and/or the FWS (the Services), to ensure that actions they authorize, fund or carry out are not likely to jeopardize the continued existence of federally-listed threatened or endangered species, or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. § 1536(a)(2). Under relevant implementing regulations, consultation is required only for actions that "may affect" listed species or critical habitat that are present in the action area of the proposed action. 50 C.F.R. § 402.14. Consultation is not required where the action has "no effect" on such listed species or critical habitat. The effects of the action are defined by regulation to include both the direct and indirect effects on species or critical habitat. 50 C.F.R. § 402.02. Indirect effects are those that are caused by the action and are later in time, but still are reasonably certain to occur. *Id.*; *see also* 51 Fed. Reg. 19926, 19932-33 (June 3, 1986) (discussing "reasonably certain to occur" in the context of cumulative effects analysis and noting that only matters that are likely to occur – and not speculative matters – are included within the standard).

Neither the ESA, nor the implementing regulations at 50 C.F.R. Part 402, require a federal agency to obtain the Services' agreement on a determination that the agency's action does not trigger the consultation requirements of section 7(a)(2). By seeking the Services' agreement with our determination on this matter, we do not intend to create any new process for EPA's compliance with section 7(a)(2) or to otherwise establish new interagency coordination procedures where consultation is not required. However, given the relative novelty of issues relating to GHG emissions from facilities permitted under EPA's Clean Air Act authorities and certain listed species, we are seeking to confirm that our agencies' respective understandings of relevant ESA obligations are consistent.

EPA is aware, for instance, that NOAA Fisheries has jurisdiction over two species of coral (elkhorn and staghorn) present in the Caribbean that are listed as threatened under the ESA. 71 Fed. Reg. 26852 (May 9, 2006). EPA understands that NOAA Fisheries has identified elevated sea surface temperature and increased CO_2 concentrations as stresses on the listed coral species. *Id.* at 26854-59. We note, however, that these species are not located in or near the area of the activities covered by permits under review at EPA.

EPA is also aware that the FWS has jurisdiction over polar bears present in Arctic regions that are listed as threatened under the ESA. 73 Fed. Reg. 28212 (May 15, 2008). EPA is currently considering one permitting action for activities in the Arctic, but the polar bear is not located in or near the area of the majority of the activities covered by permits under review at EPA. Nevertheless, EPA understands that FWS has identified loss of sea ice habitat due to rising global temperatures as a stress on the listed polar bear species. *Id.* at 28225-26.

FWS and NOAA Fisheries share responsibility for implementing the ESA. Accordingly, these agencies have primary expertise regarding, and familiarity with, the requirements of the ESA.

Polar Bear Listing

FWS recently considered the issue of GHG emissions from a single source and the triggering of ESA Section 7(a)(2) requirements.

In the context of the final listing of the polar bear as a threatened species under the ESA, FWS determined, with supporting analysis provided by the U.S. Geological Survey, that the best currently available scientific data do not support drawing a causal connection between GHG emissions from a particular facility and effects on listed species or their habitats, for ESA purposes. In addition, FWS explained that it does not believe there is sufficient data to establish that such impacts are reasonably certain to occur, for ESA purposes. Based on these determinations, FWS concluded that action agencies need not consult with respect to any such impacts.[2]

As FWS explained in the final polar bear listing:

> Formal consultation is required for proposed Federal actions that "may affect" a listed species, which requires an examination of whether the direct and indirect effects of a particular action meet this regulatory threshold. GHGs that are projected to be emitted from a facility would not, in and of themselves, trigger formal section 7 consultation for a particular licensure action unless it is established that such emissions constitute an "indirect effect" of the proposed action. To constitute an "indirect effect," the impact to the species must be later in time, must be caused by the proposed action, and must be "reasonably certain to occur" .... [T]he best scientific data available today are not sufficient to draw a causal connection between GHG emissions from a facility in the conterminous 48 States to effects posted to polar bears or their habitat in the Arctic, nor are there sufficient data to establish that such impacts are "reasonably certain to occur" to polar bears. Without sufficient data to establish the required causal connection – to the level of "reasonable certainty" – between a new facility's GHG emissions and impacts to polar bears, section 7 consultation would not be required to address impacts to polar bears.

73 Fed. Reg. at 28300.

Additionally, the U.S. Department of the Interior today is issuing a Solicitor's Opinion in which it details why proposed actions that involve the emission of GHGs would not meet the "may affect" threshold set forth in the ESA regulations and therefore would not trigger the consultation requirements under section 7(a)(2) of the ESA. The Opinion explains that, for purposes of the ESA "may affect" test, neither direct effects nor indirect effects result from the GHG emissions from a single source. Citing to the U.S. Geological Survey's analysis and its continuing validity, the Opinion concludes that where the effect at issue is climate change in the

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[2] See Memorandum from H. Dale Hall, Director, U.S. Fish and Wildlife Service re: "Expectations for Consultation on Actions that Would Emit Greenhouse Gases" (May 14, 2008); Memorandum from Mark D. Myers, Director, U.S. Geological Survey re: "The Challenges of Linking Carbon Emissions, Atmospheric Greenhouse Gas Concentrations, Global Warming, and Consequential Impacts" (May 14, 2008).

form of increased temperatures, proposed actions that involve the emission of GHGs cannot pass the "may affect" test and therefore are not subject to ESA consultation.

Accordingly, given the statements by FWS in the polar bear listing and by the DOI Solicitor, EPA believes the FWS would conclude that consultations with FWS under ESA section 7(a)(2) are not required to address the possible impacts of the GHG emissions from the permit activities pending before the EPA.

Modeling Analysis

As an additional basis for considering its ESA section 7(a)(2) obligations, EPA has analyzed whether the GHG emissions from a single source could be modeled to determine whether the risk of harm to any listed species – including the listed corals or polar bears, or to the habitat of such species – from the anticipated emissions of that single source would trigger ESA section 7(a)(2) consultation. As explained below, this additional analysis supports the same conclusion reached by FWS: consultation under ESA section 7(a)(2) would not be required based on GHG emissions from a single source authorized by EPA.

To date, research on how emissions of CO_2 and other GHGs influence global climate change and associated effects has focused on the overall impact of emissions from aggregate regional or global sources. This is primarily because GHG emissions from single sources are small relative to aggregate emissions, and GHGs, once emitted from a given source, become well mixed in the global atmosphere and have a long atmospheric lifetime. The climate change research community has not yet developed tools specifically intended for evaluating or quantifying end-point impacts attributable to the emissions of GHGs from a single source, and we are not aware of any scientific literature to draw from regarding the climate effects of individual, facility-level GHG emissions.

The current tools for simulating climate change generally focus on global and regional-scale modeling. Global and regional-scale models lack the capability to represent explicitly many important small-scale processes. As a result, confidence in regional- and sub-regional-scale projections is lower than at the global scale. There is thus limited scientific capability in assessing, detecting, or measuring the relationship between emissions of GHGs such as CO_2 from a specific single source and any localized impact on a listed species, its habitat, or its members for purposes of ESA considerations. This is consistent with the U.S. Geological Survey's analysis, which observed:

> It is currently beyond the scope of existing science to identify a specific source of CO2 emissions and designate it as the cause of specific climate impacts at an exact location.[3]

EPA has developed considerable expertise in current global climate change research and has substantial experience in utilizing the available models to analyze GHG emissions. Notwithstanding the uncertainties associated with modeling single-source emissions and localized regional or sub-regional end-point impacts, EPA has conducted the following analysis

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[3] *See* note 2 *supra*.

and considered the anticipated GHG emissions from an individual source with the emissions estimates described above, in relation to the two listed coral species and the polar bears.

The proposed facilities for which Clean Air Act permits are pending vary in size and associated magnitude of GHG emissions. To assess the potential impact of the GHG emissions from EPA-permitted sources – and to help ensure that our analysis covers all such proposed sources that are foreseeable – EPA has conducted an assessment for a model facility using emissions estimates that are substantially greater than the emissions estimates from any actual project currently pending before EPA.[4] In the analysis that follows, EPA used emissions estimates of 14,132,586 metric tons per year of CO_2, 273.6 metric tons per year of nitrous oxide (N_2O) and 136.8 metric tons per year of methane (CH_4), which are also GHGs.[5] The following criteria pollutant emissions were used:[6]

- Ozone (O_3) (180.7 metric tons per year of volatile organic compounds)
- Carbon monoxide (CO) (6019 metric tons per year)
- Sulfur dioxide (SO_2) (3609 metric tons per year)
- Nitrogen oxides (NO_X) (3018.5 metric tons for first five years, then 2326.2 annual metric tons for the remaining 45 years)

Furthermore, based on the information we have on several pending facilities, EPA assumed that the model facility would have a useful life of approximately 50 years.

Using the well-established Model for the Assessment of Greenhouse-gas Induced Climate Change (MAGICC),[7] changes in global CO_2 concentrations, global-mean surface air temperature and sea-level were projected resulting from the model facility's annual emissions of CO_2, N_2O and CH_4, as well as the relevant criteria pollutants (listed above), between 2013 and 2063,[8] over

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[4] For the model facility, EPA used criteria pollutant and GHG emissions rates that are 20 percent greater than the emissions estimates from one of the largest of the proposed facilities – the Desert Rock Energy Facility. This source is a 1500 MW coal-fired steam electric generating unit to be located on lands of the Navajo Nation near Shiprock, New Mexico.

[5] The Draft Environmental Impact Statement (EIS) for Desert Rock prepared by the U.S. Bureau of Indian Affairs estimates this facility will emit 12.7 million tons per year of CO_2. EPA calculated the methane and nitrous oxide rates by using AP-42 emissions factors and certain parameters reflected in the calculation of CO_2 emissions in the EIS for Desert Rock. We then converted these estimates to metric units and increased each number by 20 percent.

[6] Criteria pollutant emissions are based on the Desert Rock permit application and final permit. The model facility emissions are 20 percent greater than these figures and converted to metric units.

[7] Wigley, T.M.L. 2008. MAGICC/SCENGEN 5.3 (Model for the Assessment of Greenhouse-gas Induced Climate Change/SCENario GENerator): User's Manual. Boulder, Colo.: National Center for Atmospheric Research. http://www.cgd.ucar.edu/cas/wigley/magicc/

[8] We presumed that a large facility receiving a PSD permit in 2008 would not begin operations, and hence emissions, until approximately 2013 due to construction and other activities. If the climate modeling exercises described in this letter were to start a few years before 2013, it is expected that the timing of results would vary only slightly but that the magnitude of results would be essentially the same. If the modeling analysis were to be conducted over a time frame longer than 50 years (i.e., assuming a power plant lifetime of 75 years for example), but with the same amount of annual emissions, the climate effects described in this letter would still be the same over the initial 50-year period, but would then be slightly greater after 50 years, showing greater and longer-lasting climate effects.

which time these annual emissions (with the exception of NOx) are assumed to remain constant.[9] The results are relative to one global GHG emissions scenario (A1B) used by the IPCC, but with a range of different climate sensitivities.[10] Going out to 2100, the model estimates that the maximum global atmospheric CO_2 concentration increase resulting from the model facility's emissions occurs approximately 50 years after the facility begins emitting and is approximately 0.06 parts per million, corresponding to approximately 0.01 percent of total global atmospheric CO_2 concentrations projected over this time period. The maximum global mean temperature increase resulting from the emissions occurs approximately 50 years after the facility begins emitting and ranges approximately between 0.00022 to 0.00035 degrees Celsius (°C) (0.00037 to 0.00063°F), corresponding to approximately 0.01 percent of the total global mean temperature increase resulting from the projected global GHG emissions over this time period.

Regarding climate change over the Caribbean and Arctic (habitat for the listed coral and polar bear species, respectively), regional models can project temperature changes resulting from global-scale GHG emissions. A widely-accepted and used regional model is the SCENario GENerator (SCENGEN) model.[11] SCENGEN operates in conjunction with MAGICC and projects a warming of 1.4-2.5 °C (2.5-4.5°F) for global emissions (based on scenario A1B) for an area (5 degree by 5 degree grid box) centered over the U.S. Virgin Islands (20 degrees north by 65 degrees west) in 2070 (approximately 50 years after the facility begins emitting, coinciding with the maximum warming in the global mean temperatures analysis).[12] In addition, SCENGEN projects a warming of 3.6-6.3 °C (6.5-11.3°F) for global emissions (based on scenario A1B) for an area (5 degree by 5 degree grid box) centered over the southern Beaufort Sea in the Arctic (off the northern coast of Alaska, 75 degrees north by 145 degrees west) in approximately 50 years after the facility begins emitting, coinciding with the maximum warming in the global mean temperatures analysis.

SCENGEN, however, cannot process the changes due to a single source's emissions. Nonetheless, we note that applying the proportion of the global mean warming potentially due to the model facility as indicated above through use of MAGICC (approximately 0.01 percent) to the Caribbean results gives a maximum projected regional warming of 0.00014-0.00025°C

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[9] As described above, the CO_2 emissions rate for the model facility reflects a rate of CO_2 emissions substantially greater than the rate estimated for any of the proposed facilities currently under review within EPA. With regard to NOx emissions, the permit for the Desert Rock facility (which formed the basis for the model facility emissions) decreases the NOx emission limits (and thus associated emissions) over time.

[10] Range accounts for model runs with climate sensitivities varying between 2 and 4.5°C. Climate sensitivity refers to the equilibrium change in global mean surface temperature following a doubling of the atmospheric CO_2 concentration. This value is estimated by the IPCC Fourth Assessment Report as likely to be in the range 2 to 4.5°C with a best estimate of about 3°C.

[11] Wigley, T.M.L. 2008. MAGICC/SCENGEN 5.3 (Model for the Assessment of Greenhouse-gas Induced Climate Change/SCENario GENerator): User's Manual. Boulder, Colo.: National Center for Atmospheric Research. http://www.cgd.ucar.edu/cas/wigley/magicc/

[12] SCENGEN was only run using the global emissions scenario (A1B). SCENGEN was not run using the emissions estimates described above alone. Instead, the global emissions results were scaled to the single source level according to the proportion of the global mean warming due to the single source computed in MAGICC.

(0.00025-0.00045°F) potentially due to the model facility's GHG emissions.[13] Applying a similar scaling to the Arctic results (for global-scale emissions) gives a maximum projected regional warming of 0.00036-0.00063°C (0.00065-0.00113°F) potentially due to the GHG emissions analyzed here. Although confidence in regional temperature projections is generally lower than confidence in global average projections, these results are consistent with the well-established notion that warming over the tropical oceans will be less than the global average and that warming over the high latitudes will be significantly more than the global average.

As noted earlier, once CO_2 is emitted it becomes well mixed in the global atmosphere due to its long atmospheric lifetime. Some of the CO_2 emitted, however, is absorbed by land vegetation and the oceans. Since the 1980s, about half of the anthropogenic CO_2 emissions have been taken up by the terrestrial biosphere and the oceans. Uptake of CO_2 can increase the acidic levels of the oceans. The IPCC has noted that ocean acidification due to the direct effects of elevated CO_2 concentrations will impair a wide range of planktonic and other marine organisms that use aragonite to make their shells or skeletons. To project the change in tropical ocean pH that would occur as a result of a change in atmospheric CO_2 from the model facility analyzed above (0.06 ppm), EPA used the Program Developed for CO_2 System Calculations.[14] The program computed a pH reduction of approximately 0.0001 units in 2070 (approximately 50 years after the facility begins emitting, coinciding with the maximum 0.06 ppm CO_2 concentration increase).

Our review of the relevant scientific literature provides no information that would indicate that corals would be sensitive to temperature or pH changes of this magnitude. Furthermore, such changes cannot be physically measured or detected. There are limited tools available for assessing the effects of projected climate changes on listed species. EPA is aware of the COMBO model,[15] used to project the effects of climate changes on corals at regional scales. The COMBO model for coral assessment has only recently been accepted for publication, and its methods have not been widely vetted by the research community, nor its application widely tested by users. The COMBO model may be used to calculate the impacts to Caribbean coral reefs from changes in average sea-surface temperature and CO_2 concentrations due to projected global emissions, such as scenario A1B from IPCC. However, this model cannot process the single-source incremental changes in CO_2 concentrations and temperature discussed above. Moreover, any attempt to scale COMBO results based on the incremental CO_2 concentrations that would be due solely to a single source's emissions would represent a novel and untested application of model results. At this time, EPA does not believe that such a novel application would be consistent with the best available data standard for ESA purposes to assess potential impacts of single-source emissions on the corals at a regional scale. We note, however, that any such scaling would necessarily substantially reduce any projected potential impacts.

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[13] Over the tropical oceans, on average, the surface air temperature is about the same as the sea surface temperature.

[14] Lewis, E., and D. W. R. Wallace. 1998. Program Developed for CO_2 System Calculations. ORNL/CDIAC-105. Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tennessee.

[15] Buddemeier, R., P. Jokiel, K. Zimmerman, D. Lane, J. Carey, G. Bohling, and J. Martinich, 2008. A modeling tool to evaluate regional coral reef responses to changes in climate and ocean chemistry. *Limnology and Oceanography Methods*: In Press.

Likewise, our review of the relevant scientific literature provides no indication that any specific degree of polar bear sensitivity can be attributed to global or regional temperature changes of the magnitudes described above. EPA is also aware of the extensive analysis performed by the U.S. Department of the Interior (DOI) to support listing the polar bear as a threatened species, using sea ice projections from general circulation models (GCMs), carrying capacity (considering population and habitat) models and a Bayesian[16] network model. EPA is not aware of modeling tools that could be used to analyze the implications of single source emissions on polar bear populations. Any attempt to scale the results of DOI's analysis based on the incremental CO_2 concentrations that would be due solely to a single source's emissions would represent a novel and untested application of model results, and thus would not be consistent with the best available data standard for ESA purposes.

The best available climate change modeling tools predict that a source with GHG emissions in amounts equal to or less than those of the model facility analyzed above will have at most an extremely small impact on average global temperature and global atmospheric CO_2 concentrations over and beyond the anticipated functional lifetime of the proposed source. Regional modeling and any associated downscaling calculations to predict effects at a specific species location introduce untested approaches and additional uncertainties. It is clear that any such temperature and ocean acidification outputs, or any specific impact on the corals or polar bears, would be too small to physically measure or detect in the habitat of these species. Known tools for assessing the impacts of these small climate changes on the two listed coral species and polar bears are presently insufficient for quantifying potential effects. While the foregoing conclusions apply to the listed coral species and polar bears, the MAGICC modeling is not specific to any particular species or its members or any specific location, and the same outputs would constitute the first step in an assessment of impacts on other species. Given the very small global mean climate change magnitudes projected based on the emissions of this type of single source, we believe the outputs of such a single-source impact analysis for other species in other locations would also be of an extremely small magnitude that is too small to physically measure or detect.

In these circumstances, and also in light of the uncertainties in attempting to use the models' outputs to predict impacts at a local level, EPA has determined that the risk of harm to any listed species, including the listed corals or polar bears, or to the habitat of such species based on the anticipated emissions of the model facility as described above, or any facility with lower emissions, is too uncertain and remote to trigger ESA section 7(a)(2) obligations. Section 7(a)(2)'s purpose of ensuring no likely jeopardy to listed species and no destruction or adverse modification of designated critical habitat is not implicated by such remote potential risks. *See, e.g., Ground Zero Center for Non-Violent Action v. U.S. Department of the Navy*, 383 F.3d 1082 (9th Cir. 2004) (where the likelihood of jeopardy to a species is extremely remote, consultation is not required). This reasoning is consistent with the conclusion reached by FWS and DOI that consultation under ESA section 7(a)(2) is not required for GHG emissions from a single source.

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[16] Bayesian Network models represent a set of interacting variables that are linked by probabilities. They provide an efficient way to represent and summarize understanding of a system, and can combine empirical data and expert knowledge into the same modeling structure. They are also particularly useful in synthesizing large amounts of quantitative and qualitative information to answer "what if" kinds of questions.

While FWS has already determined that ESA consultation in general would not be required on proposed permits or licenses for individual facilities that emit GHGs, we nonetheless would appreciate a response from each of you regarding our determination at your earliest convenience.

Sincerely,

Robert J. Meyers

Robert J. Meyers
Principal Deputy Assistant Administrator
Office of Air and Radiation

United States Department of the Interior
U.S. GEOLOGICAL SURVEY
Office of the Director
Reston, Virginia 20192

In Reply Refer To:
Mail Stop 104
#2008438-DO

MEMORANDUM

MAY 1 4 2008

To: Director, Fish and Wildlife Service
Solicitor

From: Mark D. Myers Mark D. Myers
Director, U.S. Geological Survey

Subject: The Challenges of Linking Carbon Emissions, Atmospheric Greenhouse Gas Concentrations, Global Warming, and Consequential Impacts

In response to a request from Dale Hall, Director, U.S. Fish and Wildlife Service, the U.S. Geological Survey has summarized some of the latest climate results from the science community in defining CO_2 loading from individual actions and specific biological responses. These results indicate that current science and models cannot link individual actions that contribute to atmospheric carbon levels to specific responses of species, including polar bears.

Output of Human-induced CO_2 from numerous sources is leading to greater concentrations of CO_2 and other greenhouse gases (GHG) in the Earth's atmosphere. The Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Synthesis Report states:

Global GHG emissions due to human activities have grown since pre-industrial times, with an increase of 70% between 1970 and 2004.

Global Atmospheric concentrations of CO_2, methane, and nitrous oxide have increased markedly as a result of human activities since 1750 and now far exceed pre-industrial values determined from ice cores spanning many thousands of years.

Most of the observed increase in global average temperatures since the mid 20th century is very likely due to the observed increase in anthropogenic GHG concentrations. It is likely that there has been significant anthropogenic warming over the past 50 years averaged over each continent (except Antarctica).

Consequently,

Warming of the climate system is unequivocal, as is now evidenced from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea level.

Mix 1.10

Past and current models regarding climate change and its subsequent impacts (including global warming-related sea ice loss) have primarily been developed at global to continental scales. GHG emissions, while occurring at point sources, are considered in these climate modeling studies to be representative of continental to global atmospheric composition.

The Climate Change Science Program's (CCSP) Synthesis and Assessment Product (SAP) 1.1, *Temperature Trends in the Lower Atmosphere*, states:

In an ideal world, there would be reliable quantitative estimates of all climate forcings- both natural and human induced- that have made significant contributions to surface and tropospheric temperature changes. We would have detailed knowledge of how these forcings had changed over space and time. Finally, we would have used standard sets of forcings to perform climate change experiments with a whole suite of numerical models thus isolating uncertainties arising from structural differences in the models themselves. Unfortunately, this ideal situation does not exist.

In regard to the linkage between climate change related warming and associated impacts, the IPCC Fourth Assessment states:

Difficulties remain in simulating and attributing observed temperature changes at smaller than continental scales.

The final conclusion that can be reached from this information is that human-induced global warming can be observed and verified at global to continental scales where cumulative GHG concentrations can be measured and modeled. Climate impacts, however, are observed at specific locations, at much more specific and localized scales--incongruent with the global scale of the aforementioned measured and modeled climate forces. It is currently beyond the scope of existing science to identify a specific source of CO_2 emissions and designate it as the cause of specific climate impacts at an exact location. This point is emphasized in the CCSP's SAP 1.1, *Temperature Trends in the Lower Atmosphere*:

The positive detection results obtained for GHG-only fingerprints were driven by model-data pattern similarities at very large spatial scales (e.g. at the scale of individual hemispheres, or land-vs.-ocean behavior). Fingerprint detection of GHG effects becomes more challenging at continental or sub-continental scales. It is at these smaller scales that spatially heterogeneous forcings, such as those arising from changes in aerosol loadings and land use patterns, may have large impacts on regional climate.

From: Janette Brimmer [mailto:jbrimmer@earthjustice.org]
Sent: Thursday, January 30, 2014 3:16 PM
To: Thompson, Margo (ECY); ECY RE AQComments
Cc: 'Sasha Pollack'; Becky Kelley; 'Aaron Robins' (arobns@gmail.com); Joshua Osborne-Klein (joshok@ziontzchestnut.com); 'Ranajit Sahu'
Subject: Proposed Rule, RACT for Refineries, Ecology AO#13-03

Dear Ms. Thompson:
Please find enclosed the comments (with attachments) of Washington Environmental Council and Sierra Club regarding the Department of Ecology's proposed rule for Reasonably Available Control Technology for the control of greenhouse gas emissions at refineries. Please feel free to contact me or Joshua Osborne-Klein should you have any questions or if there is any problem with receipt of the comments or attachments. Thank you for the opportunity to comment.

Janette Brimmer
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EARTHJUSTICE

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

January 30, 2014

Via Email

Margo Thompson
Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

Re: New Rule Proposal: Chapter 173-485 WAC Petroleum Refinery Greenhouse Gas Emission Requirements
Comments of Washington Environmental Council and Sierra Club

Dear Ms. Thompson:

These comments are submitted on behalf of the Washington Environmental Council and Sierra Club (the "Conservation Organizations"). The Conservation Organizations continue to request that the Department of Ecology (along with the Northwest and Puget Sound Clean Air Agencies) (collectively "Ecology") reconsider the proposed approach to developing and requiring Reasonably Available Control Technology ("RACT") for control of greenhouse gas emissions at Washington's five oil refineries because Ecology's approach using an "average" benchmark does not conform to the RACT requirement and it appears that the proposed RACT rule will achieve few, if any, reductions in emissions.

INTRODUCTION

Washington's five oil refineries are collectively the second largest stationary source of greenhouse gas emissions ("GHGs") in the state, second only to the TransAlta coal-fired power plant which is slated to begin shutting down units in 2020. GHGs at the refineries account for approximately 6 million metric tons of carbon dioxide (CO2) emissions annually (as reported by the refineries themselves), the equivalent of 1.25 million cars every year. (from EPA GHG calculator: http://www.epa.gov/cleanenergy/energy-resources/calculator.html.) This is larger than many countries' total GHG emissions as reported by the United Nations (more than most Asian and African nations). http://mdgs.un.org/unsd/mdg/SeriesDetail.aspx?srid=749&crid=. The four refineries operating in Northwest Washington have either expanded their operations in recent years (Tesoro) or have increased or are increasing or altering their capacity to handle the large amounts of crude available from the tar sands regions of Alberta and/or the Bakken Shale in North Dakota. GHG emissions at the refineries have been unaddressed by regulation or order previously despite provisions in Washington law requiring RACT for all air contaminants (including GHGs) from all major sources (including refineries.) *See* Declaration of Stuart Clark dated August 22, 2011, submitted in district court litigation before Judge Pechman. The Conservation Organizations fully support Ecology moving ahead with a RACT determination and implementation, but are concerned that the method and standards proposed by Ecology will result in fewer GHG reductions at the refineries than is plainly reasonably available and that this very important opportunity to address a significant source of GHG emissions in Washington will be squandered.

Early in the RACT development process, Ecology and the regional agencies obtained extensive training and information from Kumana & Associates regarding potential for efficiencies at refineries that would result in 15 to 40% reductions in GHG emissions. This was in line with what had been reported in the research literature from EPA and work conducted in California designed to help that state meet is GHG reduction goals. *See* documents submitted previously with Sahu comments. *See also* Sahu declarations, with exhibits, submitted in remedies phase of district court case before Judge Pechman. Unfortunately, as the RACT process progressed, Ecology decided to avoid making actual determinations of what controls are reasonably available to reduce GHG emissions at the refineries, and instead require minimal reductions in GHG emissions from Washington refineries by using a "black box" benchmarking system and setting the requirement to a level of energy efficiency (and resulting emissions reductions) purportedly met by 50% of North American refineries in 2006.

Ecology continues to propose to use a proprietary benchmarking model developed by Solomon Associates, called "Solomon EII," and to set the required level of energy efficiency performance for Washington refineries at 50% of what Solomon EII says was the performance levels across some undisclosed number of North American refineries in 2006. *See* proposed WAC 173-485-030 and 173-485-040. If a Washington refinery chooses not to participate in the Solomon EII process (because this process is voluntary and subject to a fee payable to Solomon so not all US refineries share data with Solomon) then the Washington refinery must reduce its emissions by 10% cumulatively, by 2025. *Id.*[1] While comparisons within the industry are an expected and important component of determining RACT, Ecology's proposed approach relying on a non-public, opaque methodology and an anemic goal is inconsistent with the legal requirements for RACT, the facts in Ecology's record of what can be accomplished as RACT, and evidence of how RACT has been determined and applied by other agencies. In proposing such a weak standard, divorced from the RACT legal requirement, Ecology misses an opportunity to make real, lasting, and cost-effective reductions to GHG emissions from Washington's second-largest source of those emissions. The Conservation Organizations continue to request that Ecology strengthen the proposal in the manner detailed below and in previous comments submitted on behalf of the Conservation Organizations to make the proposal more consistent with RACT legal requirements and to achieve real reductions in GHG emissions.

DISCUSSION AND ARGUMENT

The Conservation Organizations hereby adopt and incorporate the comments submitted on their behalf by Dr. Ranajit Sahu on October 21, 2013, and all attachments or enclosures thereto. Dr. Sahu's comments on behalf of the Conservation Organizations remain fully relevant

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[1] It appears that a refinery choosing this method could reduce 1% a year for 10 years or could simply wait until year 9, emitting large quantities of GHGs until then, and then take the full reduction the last year of the period. *See* proposed WAC 173-485-040(2).

and remain the position of the Conservation Organizations as Ecology's proposal is unchanged since that time. Below, the Conservation Organizations summarize their positions with respect to the refineries RACT proposal and detail a few additional points.

I. RACT IS A DEFINED TERM THAT IS NOT SYNONYMOUS WITH "AVERAGE."

RACT is defined in Washington law (incorporated into Washington's State Implementation Plan or "SIP") as:

> the *lowest emission limit* that a particular source or source category is capable of meeting by the application of *control technology that is reasonably available considering technological and economic feasibility*. RACT is determined on a case-by-case basis for an individual source or source category *taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls*.

WAC 173-400-030(77) (emphasis added). Nowhere in this definition is there a concept that supports Ecology's claim that average performance, as measured across an undisclosed number of refineries, some potentially outside the U.S., through voluntary and unverifiable reporting, is RACT under Washington law.

While what is technologically or economically feasible under the RACT requirement has not been specifically defined by a court, Washington case law has explored the meaning of "feasible" when used in other environmental and worker protection contexts and has turned to federal law for guidance. The Washington Supreme Court has determined that "to the extent feasible" (whether technological or economic) must look to the starting point of the dictionary definition which is 'capable of being done, executed, or effected.' *Rios v. Washington Dep't of Labor and Indus.*, 145 Wn.2d 483, 497 (2002). More specifically, the Washington Supreme Court has stated that "to the extent feasible" in another Washington statute, means "to the extent the standard is capable of being economically and technologically accomplished." *Rios,* 145 Wn. 2d at 498-99. The Court also noted that in determining economic feasibility, the agency should consider the degree to which a standard will affect the regulated industry's competitive stability. *Id.*

Ecology's shortcut to "average" performance also finds no support in Environmental Protection Agency ("EPA") statements or guidance or approvals of RACT for other pollutants. As set forth in Dr. Sahu's earlier comments, EPA has developed Control Technology Guidance documents for a number of pollutants. While none of the documents address GHG emissions, it is plain from a review of those documents that EPA does not contemplate that development of RACT standards is nothing more than an average level of existing performance among sources of pollution. *See* http://www.epa.gov/ttnatw01/ctg_act.html for list of Control Technology Guidance documents that have been developed by EPA. EPA further emphasizes its expectation that RACT technology is something more than existing average controls when it directs that in instances where a state claims existing controls are adequate for RACT, a state must specifically *demonstrate that more effective controls are not economically or technically feasible*. *See* Attachment 1 to Sahu Comments, EPA May 2006 RACT Q&A Document (previously submitted to Ecology). That is, the presumption is that all additional controls are considered, and that those controls are RACT absent an affirmative demonstration that a particular control is not economically or technically feasible.

II. ECOLOGY'S PROPOSAL IS NOT RACT.

Here, Ecology simply states it is "infeasible" from an agency perspective to determine RACT on a source by source basis or do anything other than the proposed black box averaging. "Feasibility" as that concept is used in the RACT requirements, speaks to what is feasible at a specific refinery, not to what is feasible for the agency. Ecology has made no apparent examination of what is or is not feasible at the refineries, either technologically or economically (in fact these efficiency measures may ultimately save the refineries money). Ecology has made no apparent examination or showing that anything better than the 50% or average level of efficiency measures (which appears to amount to existing practices at the refineries) is not technically or economically feasible. Ecology has effectively abdicated its obligation to determine and apply RACT to an outside proprietary process, about which neither Ecology nor the public has any information, which neither Ecology nor the public can verify, and which may not actually be representative of refinery performance. Ecology's proposal is not RACT.

A. Ecology's Record Provides No Evidence of What Factors Ecology Considers Relevant in Determining Economic or Technical Feasibility and No Evidence of How Ecology Made its Determinations.

While it is likely appropriate for Ecology to look to industry examples and measures in determining RACT, and it might be appropriate to use a modeling tool, Ecology's process is too opaque and lacking in detailed analysis to be entitled to any analytical deference—there is no expertise exercised here. This is particularly unfortunate given the time and resources spent by Ecology on Kumana & Associates early in the process where Ecology was shown tools to make a RACT determination that is something more than blind reliance on an industry-driven black box. *See also* pp. 4-5 of Sahu Comments, Oct. 21, 2013. Kumana & Associates is Ecology and the agencies' chosen advisor in the RACT process, yet the expert advice and information appears to have been cast aside.

In Section 8.2 of its Technical Support Document ("TSD") the most that Ecology says about economic feasibility is that, if a refinery is hitting the 50% mark, then there are economic benefits to the refinery, but that performing better than 50% (Ecology makes no distinction other than over or under 50%) would involve "increasingly great capital expense to accomplish." That is the extent of Ecology's analysis. Even if this fact is correct, that is not the RACT standard; "narrowing opportunities" and increased cost is not synonymous with economic infeasibility. Ecology's claim that only "no-to-low-cost" operational improvements and basic equipment upgrades are RACT includes no explanation, no analysis, no real justification, and suggests that business as usual, as opposed to the "lowest emissions" using "control technology that is reasonably available" that is "technically and economically feasible" is RACT. Ecology's approach is not RACT and does little to nothing to advance emissions controls.[2]

B. Setting the Benchmark for Refinery RACT at What Half Some Unknown Number of North American Refineries May Be Accomplishing Is Inadequate and Unsupported.

EPA has said to states that "[T]o conclude that the existing level of control is RACT for a source or source category, the State's analysis should demonstrate that more effective controls are not economically or technically feasible." EPA Q & A for RACT (May 2006) (provided to Ecology with Sahu Comments, Oct. 21, 2013). EPA's RACT approvals and the statement above dictate a process whereby RACT controls are first determined by what is technically feasible and reasonably available. Ecology then would examine economic feasibility—an assessment of whether a control will significantly alter a refineries' competitive stability. Ecology decision to peg RACT at average performance has none of these hallmarks and no evidence to support it.

Ecology and the agencies originally claimed that a "Canadian Study" supported the proposed approach, but upon closer inquiry, the study does not appear to exist. Instead, Ecology has offered the Kumana & Associates ("Kumana") materials as support for its approach. In fact, the Kumana materials plainly suggest that something more than average is appropriate and "do-able". In Lecture 1c, slide 21, Kumana presents a benchmarking v. "best in class" graph showing "average", "better than average" and "best available." [3] Plainly, when Ecology protests that RACT is not an exercise in requiring "all possible control technologies" (TSD at p. 78), Ecology conflates better than average with best available, despite evidence showing they are not the same. "Better than average" under the Kumana graphic, would put performance, still with the use of a benchmark, at the top 20 to 30% of performers, more in keeping with a "lowest emissions" target that is still economically feasible. Ecology offers no explanation for why it would set the RACT requirement so low.

In Lecture 10, slide 30, Kumana provides that refineries can reduce GHG emissions, potentially by 15-40%, by improving energy efficiency. Ecology's 10% (over 10 years) targets are below even the bottom of that range. Further, Kumana notes that the principal barriers to

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[2] Ecology, on page 78 of its TSD, also makes claims about what a "typical outcome" of a RACT determination is. Ecology has rarely, if ever, done a RACT determination; never for refineries. It is therefore unclear (because Ecology gives no explanation with examples) how Ecology is making any judgment about "typical" RACT determinations. Ecology's approach is inconsistent with what EPA appears to consider a proper RACT determination as demonstrated in the examples provided with the Sahu comments.

[3] The Kumana & Associates Lectures and slides are part of Ecology's files and record in this matter and the Kumana information was cited in the Sahu Comments, Oct. 21, 2013. Copies of the particular slides cited here are provided with these comments for ease of reference.

implementation of energy efficiency that achieve 15 to 40% GHG emission reductions are not technical and economic (that is they are not barriers under a proper RACT analysis), but rather "cultural and institutional" suggesting that refineries are disinclined to change simply by virtue of inertia and resistance to regulation generally. Again, Ecology appears to disregard its own expert advisor and training in settling for efficiency measures that meet only "average or 10% over 10 years" and Ecology offers no RACT analysis regarding technical and economic feasibility as opposed to cultural and institutional opposition.

Finally, in Lecture 11, slides 3, 4 and 11, Kumana illustrates how implementation of 10-25% energy efficiency measures at refineries resulting in 20% reduction in energy costs with a payback of less than four years (as opposed to Ecology's anemic target of 10% reduction over 10 years) is "very do-able." Requiring "better than average" levels of performance is not requiring "best available" or economically-questionable techniques—Ecology's target amounts to business as usual and nothing more. As recognized by EPA, business as usual is generally not RACT.

Ecology then compounds its errors of choosing a weak level of performance for Washington refineries, by using an outdated benchmark year, 2006, with no apparent tie to what refineries are actually accomplishing now. Even using the Solomon EII process, information is updated every two years. It is therefore possible to use 2010 or even 2012 data on what constitutes "average" (or better than average) performance at refineries that report to Solomon. Ecology offers no reason for pegging performance to such outdated data other than EPA's EnergyStar information. There is no indication that even EPA would continue to consider 2006 relevant for benchmarking and certainly no rationale offered by Ecology for why that should be considered RACT in a benchmarking scenario when more recent data is readily available. The only possible reason behind Ecology's choice is that the "average" has possibly (probably) improved since 2006 raising the bar for Washington RACT.[4]

Finally, the use of the Solomon EII benchmark presents some inherent problems that Ecology should consider and account for when choosing a RACT level of performance, but that Ecology appears to have ignored or glossed-over. First, the Solomon data is voluntary and refineries pay a fee to report/participate. As a result, Solomon cannot represent that its benchmark is the result of a fully-comprehensive report on actual performance at all U.S. refineries. Solomon reports that it has 90% participation, more or less, but because Solomon will not allow access to its data nor detailed information about its process, neither Ecology nor the

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[4] Ecology's use of barrels per day as a mode of comparison across refineries also is somewhat confounding in that the TSD at one point says this approach is too simplistic (something echoed in the EcoFys report referenced earlier in the Sahu Comments). It is unclear if this is the best approach for comparison and why. Ecology also excludes co-generation facilities at refineries from the RACT requirement with no explanation why. Co-generation facilities appear to be included in California and, given that this is an energy efficiency exercise, it is unclear why those facilities at refineries should not also be subject to efficiency improvement measures. Again, Ecology's utter lack of reasoned, transparent analysis on this point makes it impossible for the public or a reviewer to assess the reasonableness and foundation for Ecology's judgments.

public has any way of knowing just how representative, or not, the data is. Second, the level of participation reported by Solomon includes data from more than just U.S. refineries; Mexico and Canada appear to be included. It is unclear, again because Solomon will not share data, what effect that has on the "average" that Ecology is using as a benchmark, but it is likely that more lax environmental regulation in those two countries contributes to downward pressure on those numbers if refineries from those countries are included. The quality and veracity of the data is also open to question. As the Kumana training highlighted, the data from refineries is voluntary and can be highly varied in its quality. Most refineries to do not rigorously reconcile their data and Kumana reports some refineries have been known to deliberately misreport. *See* Kumana Lecture 1c, slide 35. While Solomon flags suspect data, it does not independently verify whether any of the numbers reported are in fact correct. *Id.* Ecology, while briefly recognizing this criticism, generally pushes it aside by claiming that it trusts that engineers will want to be viewed as honest and professional. From a regulatory agency, this seems particularly cavalier. Ecology has done no due diligence to determine the quality and representative nature of the benchmark data. While choosing a black box approach like Solomon EII might always have these problems, Ecology could combat or account for those potential errors or weakensses in the data by setting a more ambitious target for performance—something more than run of the mill average as voluntarily reported and measured across three countries by an industry with an incentive to under-report.

CONCLUSION

The Conservation Organizations appreciate the challenges in determining RACT for refineries given the complexities of the refining process and are not necessarily opposed to a benchmarking kind of approach. However, the combined effect of Ecology's use of a black-box benchmark process with known weaknesses and gaps, coupled with a weak and ineffectual standard of "average" and an outdated benchmark year, results in a process that is not well-reasoned, not supported, and does not meet the definition of RACT in Washington law. Even adjusting the standard of performance to something better than average using an up-to-date year, would improve the RACT determination. The Conservation Organizations urge Ecology to not squander this excellent opportunity to make real progress on GHG emissions and the opportunity to be a serious leader in the region, by settling for business as usual. Washington is capable of more and its citizens deserve better. The Conservation Organizations look forward to working with Ecology to improve RACT controls on GHG emissions for refineries in Washington State.

Sincerely,

Janette K. Brimmer

cc: Joshua Osborne-Klein

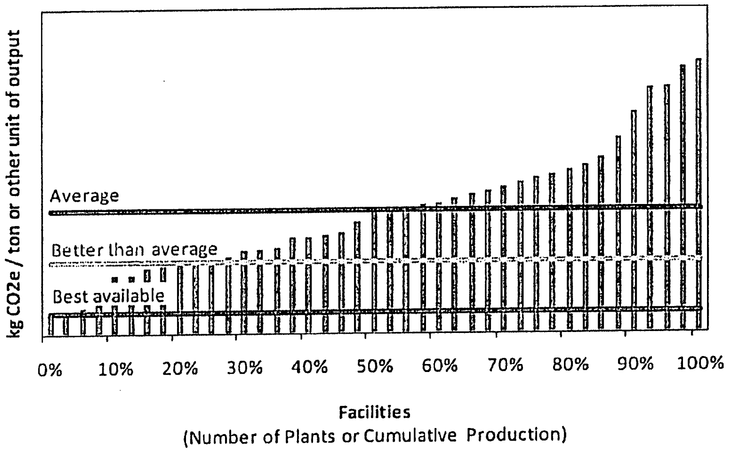
GHG EMISSIONS
in OIL REFINING

Lecture 1c
GHG Emissions Benchmarking

Outline

- Sources of GHG Emissions
- Benchmarking Methods
  - History
  - Recommended method
- Mitigation Strategies
- Effective Regulation

Benchmarking vs "Best in Class"



Kumana & Associates © 2012 REF. http://www.ecy.wa.gov/climatechange/GHGbenchmarking.htm

North America

- Canadian Petroleum Products Institute (CPPI) worked with Environment Canada to develop a complexity measure called Refinery Activity Index (RAI) based on Solomon EII.
- Oil Industry is reporting on this basis to Alberta Environment Agency.
- Complexity measures continue to evolve as "Complexity Weighted Barrel " (CWB) is being studied by the industry and may have a stronger correlation to GHGs than RAI.
- National Framework Petroleum Refinery Emissions Reduction (NFPRER) developed under the CCME umbrella in 2001.

GHG EMISSIONS in OIL REFINING

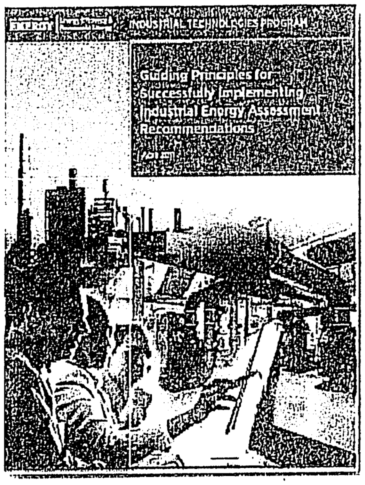
Lecture 10

Project Implementation

Brief Recap

- Up to now, we have focused almost exclusively on the technical aspects of identifying energy savings potential
- But the technical potential will never be realized unless the projects are implemented, and operational Best Practices are followed on a sustained basis

Excellent Resource



INDUSTRIAL TECHNOLOGIES PROGRAM

Guiding Principles for Successfully Implementing Industrial Energy Assessment Recommendations

- Based on experience with dozens of Govt funded energy projects
- Available as free download from DOE website:

http://www.eere.energy.gov/industry/pdfs/implementation_guidebook.pdf ← download

Key Take-aways

Key ←

- ① The absolute BEST way to reduce GHG Emissions (potentially by 15-40%) is to improve Energy Efficiency
- ② The principal Barriers to Implementation are neither Technical nor Economic, but Cultural and Institutional

GHG EMISSIONS in OIL REFINING

Lecture 11
Wrap-Up

Outline for Lecture 11

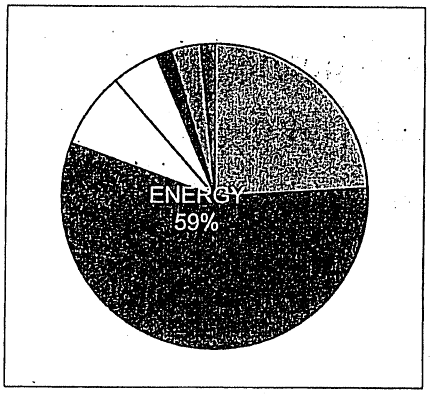
- GHG Emissions Targeting
- Energy Optimization strategy
- Making it Happen

Energy Consumption (US refineries, 2009)

	Fuel		Electricity	
	value	measure	value	measure
Total annual consumption	3178	quads	49	MM mwh
Consumption per MB crude	595	MMBtu	9.2	MWH
Typical cost of energy, $/unit	6.5	$/MMBtu	90	$/MWH
Average cost, MM/yr	166	MM$/yr	36	MM$/yr

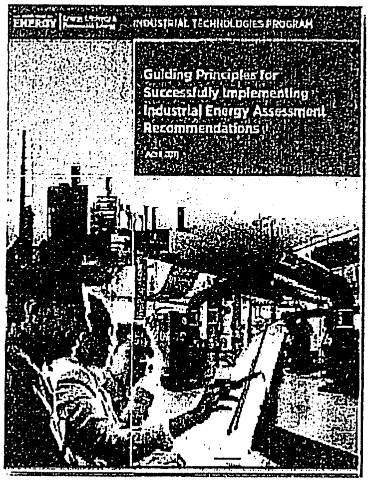
- Average refinery size = 120 MBD
- Total energy costs = $4.70 /bbl
  ~ $ 200 MM/yr

Energy Cost Control is where the Action is !



20% reduction in Energy Costs at a Payback of < 4 yr is very do-able.

Project Implementation is the Key



ENERGY | INDUSTRIAL TECHNOLOGIES PROGRAM

Guiding Principles for Successfully Implementing Industrial Energy Assessment Recommendations

April 2011

- Expect 10-25% reduction in GHG emissions, up to limit
- Follow Guidebook recommendations
- Barriers to Implementation are neither Technical nor Economic, but Cultural and Institutional

Evaluation Factors for Energy Projects

- Capital cost offsets
- Risk-adjusted ROI
- Environmental credits
- Health cost credits
- Social cost credits (eg. disaster relief)
- Strategic (eg. long-term access to energy sources)

WASHINGTON OIL REFINERY RACT

Initial Informal Comments

by

Dr. Ranajit (Ron) Sahu, Consultant

Submitted On Behalf of Washington Environmental Council and Sierra Club Washington State Chapter

October 21, 2013

Abstract

These initial, informal comments are provided prior to the formal rulemaking on the above greenhouse gas (GHG) RACT proposed by various environmental agencies[1] (collectively, "Agencies") in Washington state for the 5 petroleum refineries in Washington.

Briefly, the proposed RACT proposal relies on benchmarking to compare these 5 refineries to their unspecified peers in the US (using a metric, the Solomon EII, that is not only non-public and thus opaque) on the basis of their energy efficiency. Key aspects of the proposed benchmarking approach are anchored, for some inexplicable reason, to EPA's voluntary EnergyStar program dating back to 2006. This approach will simply not meet the statutory legal obligations of RACT. Compounding this major legal flaw, the Agencies seem to have made many key unsupported technical choices and errors that render this proposed RACT arbitrary and which will, in all likelihood, result in no actual energy efficiency improvements and/or GHG reductions at the 5 refineries for the foreseeable future.

We recommend that the Agencies fix the many fundamental flaws in this proposed rule before the rule is formally proposed for public comments.

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[1] The Agencies are the Northwest Clean Air Agency, the Puget Sound Clean Air Agency, and the Washington State Department of Ecology.

Summary of Proposal

As stated in the Technical Support Document (TSD) prepared by the Agencies, dated September 9, 2013, the reason for this proposed rule is as follows:

"[T]he reasonably available control technology (RACT) determination process …. was undertaken in response to a March 27, 2012, Remedy Order entered in the United States District Court – Western District of Washington at Seattle (Case No. C11-417 MJP, Washington Environmental Council, et al. vs. Sturdevant, et al.). In that order, the Washington State Department of Ecology (Ecology), Puget Sound Clean Air Agency (PSCAA), and Northwest Clean Air Agency (NWCAA) (collectively referred to as "the Agencies" in this document) were ordered to complete a RACT determination process pursuant to Revised Code of Washington (RCW) 70.94.154 within 26 months addressing greenhouse gases (GHGs) for each of five Washington State petroleum oil refineries owned and operated by the following companies: BP PLC (BP), Phillips 66 Company (Phillips 66), Shell Oil Company (Shell), Tesoro Refining & Marketing Company (Tesoro), and US Oil & Refining Company (US Oil)."

Further, the actual proposal is summarized as follows in the TSD:

"[T]he Agencies propose that the GHG RACT for the five Washington oil refineries be a dual-path process as follows:

- A refinery may demonstrate reasonably available energy efficiency performance by scoring in the top 50th percentile of similar sized US refineries, or
- A refinery must implement projects or work practices to achieve GHG emission reductions that cumulatively add up to 10% of the baseline-year facility GHG emissions, with those reductions allowed to occur over approximately a 10-year period, whichever path is completed first

The Agencies propose to use the Solomon EII® scoring system for the oil refineries as the benchmark demonstration of an investment in energy efficiency measures at the facility. Specifically, if a facility is among the top performing half (i.e., top 50%) of US similar-sized refineries, according to the Solomon EII® score, the facility has demonstrated compliance with GHG RACT.

For a facility that does not meet the energy efficiency benchmark of the top 50th percentile, the required GHG reduction is calculated as 10% of the total facility GHG emissions in the baseline year of 2010. An alternative year of 2011 may be used as the baseline emissions year in the event that 2010 is not representative of typical facility operation due to extended process outages (i.e., greater than 30 days)."

Comments

At the outset, we do not believe that the proposal conforms to the statutory requirements of RACT. As noted in the TSD by the Agencies themselves, the RACT requirement is as follows:

"WAC 173-400 defines 'reasonably available control technology (RACT)' as 'the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for any source or source category shall be adopted only after notice and opportunity for comment are afforded.'"

The RACT proposal does not adhere to this definition—the proposal (even if properly implemented) will not require the refineries to meet the "lowest emission limit" standard that is "reasonably available" considering "technological and economic feasibility."

Critically, in the RACT proposal, the Agencies erroneously equate the "reasonably available" standard which applies, plainly, to "control technology" in the definition above to instead mean simply the "average" energy efficiency level of an unspecified number of peer refineries. Even if the peers were properly selected, which, as we point out below is simply unknowable (and likely incorrect) based on the proposal, the RACT standard as defined in state law would still not be met.

As the TSD states, "[I]n short, the goal of this RACT determination can be restated as: to define a reasonably efficient refinery operation in Washington State in the 2010-2012 timeframe…" and "[T]he proposed RACT defines a reasonably efficient refinery as a refinery that demonstrates an average energy efficiency performance comparable to or above those of similar-sized US refineries as established in 2010…" This characterization of the RACT goal and result is not consistent with the RACT definition in the statute, and fails to take into account several important considerations, including:

- The proposal does not do an adequate analysis for the RACT at each refinery either on a case-by-case basis or on a source category basis. Of course, it is important to note that in this situation the source category includes just 5 refineries, with differing characteristics – unavoidably requiring therefore, a look as emissions at each refinery as well as emission control opportunities and costs at each refinery.
- The proposal does not discuss economic feasibility using any sort of cost metric, whether capital or operating.

We suggest that the Agencies carefully review RACT approaches developed by others, including the EPA. As EPA's May 2006 RACT Q&A documents (Attachment 1) notes, "States may rely on past EPA guidance, such as CTGs, for help…" in determining RACT. "CTGs" denote Control Technology Guidance documents that EPA developed for many different source categories. They are available at http://www.epa.gov/ttnatw01/ctg_act.html. In our review of many of these documents we did not encounter any instances in which RACT was assumed to be the "average" level of control, notwithstanding the Agencies' further leap in equating "control technology" with bench-marking of energy efficiency. Importantly, EPA states "[T]o conclude that the existing level of control is RACT for a source or source category, the State's analysis should demonstrate that more effective controls are not economically or technically feasible." (emphasis added) Thus, the determination of RACT level of controls is fundamentally based on technical feasibility followed by a further winnowing of the universe of technically feasible options by applying an economic feasibility metric. The Agencies' approach does not follow this framework. The TSD does not contain any discussion of what economic feasibility criteria are applicable, for instance. Other than vaguely rejecting examples of some projects that the Agencies deem to be too capital intensive[2] (without specifying any cost details), there is no economic feasibility (for emissions reduction) discussion in the record.

We believe that conformance with the statutory requirements compels that any proposal be based: (a) on an assessment of the actual GHG emissions reduction opportunities for each GHG source at each of the 5 refineries (this information should be readily available based on the annual GHG emissions inventories being prepared by each refinery for submittal to the EPA); (b) a determination of all "reasonably feasible" control or reduction approaches for the GHG sources identified in (a) based on public and proprietary research, like those discussed in the training materials available to the Agencies;[3] (c) a screening of the technically feasible list controls that are feasible in (b) by using a cost feasibility criterion that is publicly stated and defended by the Agencies.

This approach would not only meet the statutory requirements, it would do so by avoiding all of the other flaws of the current proposal, including, in no particular order:

- Reliance on an opaque and non-public bench-marking metric (i.e., the Solomon EII), whatever its technical merits;
- Reliance on EPA's EnergyStar program;

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[2] The Agencies discuss this in Section 8.2 of the TSD in the context of rejecting certain projects that were deemed appropriate to receive EPA's voluntary EnergyStar certification as being inappropriate for RACT because the projects "…would set a bar that is beyond the expectation of RACT…" without stating what the basis of such "expectation" is, other than it is more stringent that the "average" level of performance as noted above. Critically, the Agencies fail to distinguish between those projects that various refineries may have conducted to meet other objectives for which they then applied for EnergyStar certification versus projects that were conducted specifically to meet EnergyStar objectives. Conflating between these very different motivations for implementing projects, as the Agencies have done, makes the use of EnergyStar project comparisons useless in this regard.

[3] See the various training materials provided by Kumana and Associates, available in the record. We note, for the record, that the Agencies seem to have disregarded almost all of the useful information that they obtained in the Kumana training materials in developing their proposed rule. Kumana notes that there are significant energy reduction opportunities of the order of 15-40% (i.e.., which are technically feasible, and which are far greater than the "10% over 10 years" discussed in the proposal) and that the main barriers to reducing energy use are "neither technical nor economic but cultural and institutional…" This "key take-away" by Kumana directly undercuts the proposed approach because it explicitly states that significant energy reduction opportunities would meet any reasonable technical and economic test.

- Reliance on an outdated (i.e., year 2006) bench-mark year, simply because that was the year that the EnergyStar certification seems to be based on (i.e., the proposal conforms to an outdated bench-mark year simply because EPA has not updated its bench-mark year in its EnergyStar program[4]);
- Reliance on a completely erroneous approach to selecting a "peer" group of refineries from all US refineries based on the simple barrel per day process throughput comparison (again, because EPA, in developing EnergyStar seems to have used this approach, now widely discredited, as we will show below), notwithstanding the opaque (and inconsistent) nature of this peer group selection by Solomon.
- Reliance on the 50th percentile metric (i.e., reasonable = average)
- Reliance on a 10% GHG reduction goal over 10 years.

We will briefly now discuss these flaws above.

First, it is without question that the Solomon EII, which is to be used as the energy bench-marking approach[5] is a proprietary and non-public metric developed by Solomon and Associates, a private entity, whose details are simply not available to any member of the public.[6] In fact, details on the EII could not be explained by Agency staff themselves who rightly describe it as a "black box." Discussions with Solomon confirm this. Thus, any use of such a metric should be a last resort – after all other options have been exhausted, which is far from the case in this matter. As we have noted above, had the Agencies simply followed the approach demanded by statute and followed the RACT determination approach in numerous prior instances by EPA, such a reliance on the Solomon EII would be unnecessary. While we have no reason to doubt the credibility of Solomon's methods and approaches, the fact remains that there is no way for any member of the public (or even any Agency personnel) to check or audit any of the

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[4] In informal discussions, Agency staff have pointed out the purported usefulness of 2006 as a benchmark year because doing so would preserve "consistency" in the analysis. This is nonsense. Selecting a more recent year (Solomon's EII is calculated based on data submitted by refineries every 2 years, as the Agency is well aware) would also preserve consistency.

[5] The TSD states that "[T]he Agencies propose to use the Solomon EII® scoring system as the measurement and demonstration of energy efficiency at the refineries."

[6] As the TSD correctly notes, "[T]here may be perceived drawbacks to using the Solomon EII® benchmark. The system is proprietary and considered to be highly sensitive commercially. Neither the basis data nor the calculation methodology are available to the public for review."

conclusions from this "black box." We are particularly perturbed by indications that Solomon's fact checking may not be adequate. For example, in its training materials provided to the Agencies, Kumana and Associates explicitly caution that in submitting data to Solomon for its analysis "[M]ost refineries do not reconcile their data rigorously…." and that "Some refiners have been known to deliberately mis-report…" and finally "Solomon Associates flags "suspect" data reported by refinery customers, but does not independently verify if the numbers are correct…" These are extremely serious and disturbing words of caution and there is no indication in the development of this proposal that the Agencies have paid this any heed. Rather, the justification the Agencies' provide[7] for using the Solomon approach is suspect. Maintaining the "integrity of the global business" is not a reliable standard on which to base regulatory standards. We refrain from pointing out the many examples where such "business integrity" assumption has been found to be utterly lacking. The Agencies cannot abdicate their responsibilities simply because a professional engineer is expected to have ethical standards.

Our own discussions with Solomon could not confirm the extent of the rigor of their audit process in this regard. Until there is factual and supported documentation from Solomon that sheds far more light on this audit issue, we cannot simply assume that there is data integrity in this process. The burden is squarely on Solomon (and the Agencies) in this regard. At this point, it is clear that the Agencies attitude is one of "trust in the black box, which we don't understand…" It should be apparent to the Agencies why this approach has not inspired public confidence in their proposal, all of the other notable flaws aside.

Second, we fail to see why the Agencies believe the RACT has to be consistent with EPA's voluntary EnergyStar program, while distancing itself from the actual emissions reductions that this program actually demands as a condition of its certification.[8] While the EnergyStar program

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[7] The TSD notes "[H]owever, the integrity of the global business of Solomon weighs against compromising the calculation, and the data submitted to Solomon is under the direction of a licensed professional engineer who is held to strict ethical standards that are similar to those established for responsible official certification under the Title V program."

[8] The EnergyStar certification requires that candidates meet a 25th percentile standard as compared to their peer group. The current proposal demands only that a refinery be in the 50th percentile or better group as compared to its peers. The incongruity (and indefensibility) of having a regulatory, RACT proposal that is significantly weaker than a voluntary program seems to have escaped the Agencies' attention. That this is a direct result of the erroneous assumption that "reasonable = average" which underpins the current, flawed proposal, should have raised red flags and caused the Agencies' to revisit this bad assumption.

can be one (but not the exclusive) of a number of useful repositories of information sources to determine the universe of technically feasible control or emission reduction approaches that need to be identified in the RACT analysis at the outset, that should be the extent of its connection to the RACT program. Going beyond its simple usefulness as a source of prior historical projects conducted at various refineries is not required anywhere in the RACT analysis.

Third, and related to the second point, is the proposal's inexplicable and mistaken adherence to the outdated bench-mark year of 2006[9] simply because that would make it consistent with EnergyStar (which, as we have discussed above is not a regulatory program) or doing so somehow makes the analysis "consistent" from refinery to refinery.[10] Even if every other aspect of this proposal was correct, the Agencies are well aware (and Solomon has confirmed) that its EII is updated every two years. Thus, EII bench-marking could have been done using available data from 2008, 2010, and 2012. Yet, the inconsistency of using bench-mark years of 2010/2011 (so much for consistency) and the EII of 2006 is not explained in the record. We believe that using a 2006 "curve" to grade performance from 2010 or 2011 simply means that the probability of "passing" (i.e., in this case, getting a 50th percentile or better score) is enhanced. Of course in the current proposal, "passing" means that even the feeble "10% in 10 years" reduction of GHGs will not apply. Thus, the proposal is designed to deem "no action" as RACT, in direct contravention of EPA guidance as noted earlier.

Fourth, the proposal requires that peer refineries be identified using a simple process capacity (i.e., bbls/day) for all US refineries. This approach is flawed for numerous reasons:

One, it is not at all clear that Solomon will or can develop the peer group using "…all US refineries..." as the proposal seems to believe will be done.[11] Solomon confirmed to us in

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[9] The TSD states in this regard "[I]t is also reasonable to allow facilities to use operational demonstrations for the years prior to the RACT rule issuance back to 2006; the Energy Star Program data set year establishing the performance benchmarks."

[10] Consistency with EnergyStar was mentioned as a justification for using the outdated bench-mark year of 2006 in a recent e-mail dated October 15, 2013 from Mr. Mark Buford, staff for NWCAA. Such justification, however, is not included in the TSD itself.

[11] The TSD implies that the comparison will be to all US refineries, aggregated into size classes. It states that "[T]he Agencies propose using US refineries nationwide as the comparison group because they are subject to similar regulations and represent a reasonably large number of facilities for comparison. US refineries also experience

discussions that they only collect data for a subset of US refineries (i.e., those refineries that pay Solomon the appropriate fee to be in their program). This is a fluctuating number since refineries can choose to (or not) be in the program. At this point Solomon believes (but did not confirm exactly) that there are somewhere around 85-95 US refineries in the program – this is considerably smaller than the 139 refineries that the TSD believes will be the underlying dataset. More problematically, Solomon confirmed to us that there are likely to be a smaller number of their clients in the very small size class (i.e., less than 50,000 bbl/day). Since at least one Washington refinery will fall into this class, it raises significant questions as to the extent and appropriateness of the "peer" group for this smallest refinery. Even for the other 4 Washington refineries, it is clear that they "peer" group will not contain all of their similarly sized US counterparts. Thus, the TSD is at best misleading on this important point, and indicates a lack of understanding by the Agency staff of what happens in the Solomon "black-box", even after months of work on this proposal. More confusingly, Solomon reiterated to us that its dataset includes other "North American" refineries as appropriate. Thus, the peer group can include refineries from, say, Mexico and Canada, making the bench-marking even more unrepresentative.

Two, as if the above was not problematic enough, the proposal requires that the peer group comparison be made on a simple process throughput (i.e., barrels per day) basis. As Table 6-1 of the TSD makes clear, refinery GHG emissions do not track the simple process capacity (bbls/day) because of many factors including differing input crude slates and varied processing steps in each refinery. For example, compare the 2011 GHG emissions of the Shell and Tesoro refineries. While the simple process capacities are, respectively, 149,000 per day and 125,000 per day for these two refineries, Shell's reported 2011GHG emissions are far greater than that of Tesoro.

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similar energy prices, overall economic climates, and fuels markets. The global refinery pool was rejected as the comparison group for two primary reasons: a wide range of energy prices directly influence the economics of efficiency and fuel market product specifications and prices vary significantly on a global scale."

This fact has been widely recognized and, as a result, any competent bench-marking done today uses measures that explicitly consider refinery complexity.[12] Kumana and Associates' training materials attest to this fact. And, as the Attachments 2 and 3 to these comments show, the fact that a Complexity Weighted Barrel (CWB) better tracks and predicts GHG emissions (see Attachment 3, Section 2.2, in particular) is without question. Ironically, WSPA, the same industry group that represents the 5 Washington state refineries, is itself a proponent of this better approach in its interactions with California regulators presently (see Attachment 3) (Attachment 3 is prepared by none other than Solomon and Associates for WSPA). It stretches credulity that the Agencies in the current matter are not aware of these developments. And, if they are aware, there is no justification for disregarding a clearly superior bench-marking approach, other than some misplaced need to be consistent with EPA's EnergyStar program, as noted earlier. We believe that bench-marking using a simple process barrels comparison is wrong and should be set aside.

<u>Fifth</u>, for the reasons detailed above, we explicitly reject the use of the 50th percentile "passing" score approach[13] because it has no relationship whatsoever to the legal definition of RACT, which requires the Agencies to impose the "lowest emission limit" standard that is "reasonably available" considering "technological and economic feasibility." We are aware of no precedent or support in the record for the Agencies' conclusion that this RACT standard can be conflated with "average" efficiency, and Agency staff have been unable to produce any support for this conclusion despite our multiple requests.[14]

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[12] See for example, Attachment 2. "Development of GHG efficiency benchmarks for the distribution of free emissions allowances in the California Cap-and-Trade Program," by ECOFYS, dated August 20, 2012, prepared for the California Air Resources Board. See also, Attachment 3. "Report on CWT-CWB for California Regulatory Support," prepared by Solomon and Associates for the Western States Petroleum Association, May 17, 2013.

[13] The TSD states that "[I]f a facility is within the top 50% of the Solomon EII® scores of all similar-sized US refineries as established in the EPA Energy Star Program, the facility has demonstrated that it is a reasonably efficient refinery."

[14] At a stakeholder meeting on October 9, 2013, Agency staff indicated that support for this approach to RACT was located in a "Canadian study" that they would disclose to us. However, in a subsequent email dated October 15, 2013 from Mark Buford of the NWCAA, Mr. Buford conceded that he had "not been able to locate a Canadian study" and pointed us to "similar general information in the Kumana training materials" that had been previously provided by the Agencies. We have reviewed the identified Kumana materials and have located no support in those materials (or elsewhere in the record) for the Agencies' decision to equate RACT with "average" energy efficiency.

Sixth, we do not find support for the RACT emission reduction of 10 percent reduction in 10 years, which a refinery would have to meet in the unlikely event that it did not obtain a passing grade in the proposal's current scheme. Rather, we find support in the record that significantly greater cost-effective and technologically available reductions are possible. For example, as noted earlier, Kumana and Associates state that there are "…significant energy reduction opportunities of the order of 15-40%..." In addition, in their training materials Kumana and Associates also note that "…20% reduction in energy costs at a payback of < 4 years is very do-able…" Presumably energy reduction costs and energy reduction are related, leading to GHG reduction. And, we note that the "very do-able" aspect certainly seems eminently consistent with the "reasonably available" analysis that should be included in a proper RACT rule.

Conclusion

For all of the reasons stated above, we believe that the Agencies' proposal for GHG RACT for the 5 Washington state refineries is deeply flawed and we call on the Agencies to revise the proposal to address the issues raised above so it complies with the state definition of RACT and achieves meaningful reductions in GHG emissions from the 5 refineries.

MAY 18, 2006

NOTE

SUBJECT: RACT Qs & As – Reasonably Available Control Technology (RACT): Questions and Answers

FROM: William T. Harnett
Director, Air Quality Policy Division (C539-01)

TO: Regional Air Division Directors

The attached Reasonably Available Control Technology (RACT) Questions and Answers (Q&A) document addresses issues we have received from the Regional Offices and States. The document provides additional clarification that will be helpful for the RACT State implementation plans (SIPs) which are due September 15, 2006. Please distribute this document to your States, local control agencies, and tribal governments. Regional Office staff may contact William Johnson at (919) 541-5246 or Johnson.WilliamL@epa.gov, with any questions.

May 18, 2006

Questions Related to RACT in 8-hour ozone implementation

A. What is RACT?

1. **Q**: Is the facility expected to perform the RACT analysis? Is this similar to a BACT analysis?

A: The State is responsible for the RACT determination but is likely to have considerable interaction with the affected facilities. States may rely on past EPA guidance, such as CTGs, for help and should also review other available information regarding the appropriate controls. BACT requires that new or modified sources adopt the best available controls and, as such, the analysis is a "top-down" analysis that first looks at the most stringent level of control available for a source. Industries applying for a construction permit list in their application what are the currently most stringent levels of control. The State verifies this by checking the application against other data sources including EPA's RACT/BACT Clearinghouse. RACT requires that sources adopt controls that are reasonably available and thus they may not be the most stringent controls that have been adopted for other similar sources.

2. **Q**: If a State in or near the Ozone Transport Region failed to adopt one of the model rules which the Ozone Transport Commission developed to help meet the ozone standard in that region, would this mean that a rule the State may have for that source is no longer considered to be RACT?

A: No, not necessarily. The model rules developed for the Ozone Transport Region were for the purpose of bringing areas in the OTR into attainment with the 1-hour NAAQS and thus may be more stringent than what would be considered RACT. In performing a RACT analysis, States should look at available controls, such as those that were the basis for the model rules developed by the OTR, to conclude whether they are reasonably available for a specific source or source category. However, the fact that another similar source has such controls in place does not mean that such a control is reasonably available for all other similar sources across the country.

3. **Q**: Some moderate 8-hour areas were severe 1-hour nonattainment areas. As such, the "major source" threshold for 1-hour RACT rules was 25 TPY potential emissions. For the purposes of certifying 1-hour RACT determinations, must the State address only down to the applicable 8-hour threshold [which is 100 TPY or in the Ozone Transport Region 50 TPY for VOC non-CTG major sources and the 100 TPY for all NOx sources] or down to the 1-hour threshold of 25 TPY?

A: For purposes of meeting the 8-hour RACT requirement, the State's RACT analysis only needs to include an evaluation of RACT for CTG sources and for non-CTG major sources based on the area's 8-hour classification.

We note however, that under the anti-backsliding requirements, the State may not remove RACT requirements for sources that were subject to RACT for the 1-hour standard (but that would not be subject to RACT based on the area's 8-hour classification). Similarly, if the State has never met the RACT requirement for one or more sources for the 1-hour standard, the anti-backsliding requirements require the State to meet that obligation. The anti-backsliding provisions may be found at 40 CFR 51.905 and apply to all former 1-hour non-attainment areas.

4. **Q**: Where a State determines that sources subject to Federal rules, such as NESHAPs, the municipal waste incinerator rules under CAA section 111(d), and NSR/PSD settlement agreements, meet RACT by compliance with those requirements, how should those requirements be addressed as part of the SIP?

A: To rely on federal rules to meet the RACT requirement, the State must incorporate these requirements into the SIP. For example, a State could incorporate by reference the Federal requirement or could submit a permit that includes this provision as a SIP revision.

5. **Q**: Can a State rely for RACT determinations on control obligations in Federally enforceable permits issues under a State approved nonattainment new source review program (or a PSD program)?

A: Yes, a State may rely on control obligations required by federally enforceable permits. The State would need to submit the relevant portions of these permits (i.e., the portions establishing the VOC and NOx obligations) as SIP revisions along with a demonstration that such controls are RACT.

6. **Q**: For NOx RACT for stationary source categories, other than wall and tangentially fired electric utility boilers, EPA guidelines in 1994 indicate States should consider in their RACT determinations technologies that achieve 30-50 percent reduction within a cost range of $160-1300 per ton of NOx removed. Do EPA VOC guidance documents, CTGs and ACTs, give percentage reductions and cost per ton removed guidelines for VOC?

A. The VOC CTGs and ACTs usually do not give percent reductions. The emission levels are typically expressed as weight of VOC emitted per some unit of production. For example, for coatings the units are often pounds of VOC emitted per gallon of coating. However in calculating the emission limits, EPA made an assumption of 90% capture of emissions and 90% control of these captured emission for an 81% overall control in many cases. Some of the CTGs, such as for degreasers and storage tanks, define RACT as certain types of equipment, rather than an emission limit.

EPA has never issued a general cost of control guideline for VOC, but costs of control in the CTGs generally ranged around $2000/ton in 1980s dollars. However, EPA never published this figure as a cut-point that had should not be exceeded.

7. **Q**: What is the primary difference between an ACT and a CTG?

A: The ACTs give percent reductions that can be achieved with various controls at various levels of stringency and the costs per ton to achieve those levels of control. The ACTs do not recommend a particular level as being RACT. The CTGs do specify a particular level of control as being presumptive RACT.

8. **Q**: Does EPA maintain a website containing all the RACT Control Techniques Guidelines and Alternative Control Techniques documents for both NOx and VOC?

A: The EPA web site http://www.epa.gov/ttn/atw/ctg_act.html contains a list of all published CTGs. This web site also contains a partial list of ACTs, although this ACT list is missing the ACTs for bakeries, organic waste process vents and polyester foam manufacture. The following website includes two updates to NOx ACTs (see items J.3-4): http://www.epa.gov/ttn/naaqs/ozone/ozonetech/#nox . A list of CTGs and ACTs is also attached to this list of Qs & As.

9. **Q:** Does a RACT analysis need to be done for source categories for which an Alternative Control Techniques (ACT) document has been published?

A: Yes. A RACT analysis needs to be done for all CTG sources and all major non-CTG sources. While the CTGs and ACTs provide a starting point for such an analysis, RACT can change over time as new technology becomes available or the cost of existing technology adjusts. States are encouraged to use the latest information available in making RACT determinations, whether that information is in CTGs, ACTs, other guidance that is available or through information submitted during the public review process.

10. **Q**: Would EPA's “Beyond VOC RACT CTG Requirements” guidance (EPA-53/R-010. April 1995) found at http://www.epa.gov/ttn/catc/dir1/byndract.pdf be of help in determining RACT? How about documents such as “Control Techniques for Volatile Organic Emissions from Stationary Sources,” EPA-450/2-78-022, May 1978, or “Fugitive Emission Sources of Organic Compounds –Additional information on Emission, Emissions Reductions, and Costs,” EPA-450/3-82-010, April 1982?

A: The “Beyond RACT” document could be a source to evaluate in performing a RACT analysis. We note that this document was originally written primarily for States that needed to get reductions beyond RACT in order to attain and maintain the ozone NAAQS. However, in the ten years since that document was issued these controls may have become more economically feasible and thus it is possible that controls considered beyond RACT in that document could be considered RACT for certain sources. The second two documents are somewhat analogous to ACT documents which describe various control techniques that can be applied to various industry sectors but do not identify a presumptive RACT-level of control. Some of the industry sectors addressed in these documents are also covered by a CTG, while others are not.

11. **Q**: For source categories for which an NSPS has been adopted, would a statement that there are no sources that preexisted the NSPS be an acceptable RACT analysis? In other words, does the fact that all existing sources meet the NSPS mean that they also meet RACT?

A: The NSPS and RACT requirements are separate obligations under the Act and both must be met. So the fact that a source meets a NSPS does not necessarily mean that it also meets RACT. A State should evaluate the control obligation required through NSPS to determine whether the source is currently meeting the RACT obligation or whether additional control is necessary for RACT.

B. Certifications

12. **Q**: If a source is subject to a rule that is beyond 1-hour RACT, can a State give a certification that this source meets RACT?

A: Even though a source may have been subject to control that was beyond RACT for the 1-hour standard, the State needs to evaluate whether that requirement is, at a minimum, RACT based on the current information that is available.

13. **Q**: Would a certification need to include a commitment to upgrade rules in the future if/when we determine that RACT levels of control have become more stringent?

A: No. The RACT analysis needs to be performed at the time the RACT SIP is being developed and once the RACT SIP is approved there is no additional duty to reconsider this control obligation for a source.

14. **Q**: By what date does a facility need to have a federally enforceable permit to meet requirements for RACT?

A: A RACT SIP is due by September 15, 2006 for subpart 2 areas and with submission of an attainment demonstration request for subpart 1 areas seeking an attainment date more than 5 years after designation. RACT must be implemented no later than the beginning of the first ozone season or portion thereof that occurs 30 months after the required submission date. States should have enforceable measures in place by that date. If a source has or is required to have a Title V operating permit, the provisions of Title V program would govern when the RACT requirement must be incorporated into the SIP and a facility should consult with the permitting authority regarding that issue.

15. **Q**: Must RACT based emission limits, and associated monitoring, record keeping and reporting be included in a Federally enforceable permit (Title V operating permit)?

A: For purposes of meeting the requirements of Title I of the Act (i.e., the nonattainment area provisions), RACT needs to be adopted and approved into the SIP. This can be accomplished in a variety of ways. Typically, States have adopted regulations.

However, the State could first specify the obligation in an enforceable permit and submit the permit (or portions of the permit) for inclusion into the SIP. In some cases, States have also submitted enforceable consent orders as SIP revisions. In general, the RACT requirement for a specific source or source category would include a requirement for a specific control measure or for a specific level of reduction and, as appropriate, monitoring, recordkeeping and reporting requirements.

16. **Q**: Does EPA intend to issue guidance on how States should reassess their rules in light of currently available technologies to determine if their rules incorporate RACT?

A: At this time, EPA is not working on further RACT guidance. States should consult with the appropriate EPA Regional office if they have questions regarding how the analysis for a specific source or source category should be performed.

17. **Q**: What should a State do if it concludes that for a specific source or source category no additional controls are necessary beyond what was required by the RACT analysis under the 1-hour standard?

A: Where a State concludes that the no control is required beyond what was required for purposes of the 1-hour NAAQS, the State should submit its analysis justifying such a conclusion as part of its RACT SIP.

18. **Q**: What is required in a RACT analysis in order for a State to give a certification that previously required RACT controls or newly applied controls represent RACT for 8-hour implementation purposes?

A: A State should evaluate RACT for a source or source category by examining existing EPA guidance as well as other available information such as that identified in the responses above. To conclude that the existing level of control is RACT for a source or source category, the State's analysis should demonstrate that more effective controls are not economically or technically feasible.

C. Relationship between RACT and the Clean Air Interstate Rule (CAIR) and the NOx SIP Call

19. **Q**: Can a State rely on its participation in the CAIR trading programs to demonstrate that certain source categories meet RACT?

A: EPA has received a petition for reconsideration asking it to reconsider and reopen for public comment its determination that certain sources in States participating in the EPA-administered CAIR NOx trading program meet ozone NOx RACT requirements. EPA intends to grant the petition for reconsideration on this issue. If necessary, EPA will provide further guidance on this subject after the reconsideration process is complete.

20. **Q**: Do all sources subject to a State's NOx SIP call trading program presumptively meet RACT even if the trading program covers non-EGU sources?

A: Yes, EPA believes that the NOx SIP Call constitutes RACT for those sources covered by the NOx SIP Call. However, whether our judgment that non-EGU sources subject to the NO_x SIP Call trading system meet RACT will continue to apply in the future depends upon how the State chooses to make the transition from the NO_x SIP Call trading system to the CAIR trading system. This issue is discussed in greater detail in the preamble to the November 29, 2005 8-hour implementation rule at 70 Fed. Reg. 71657.

21. **Q:** If electrical generating units (EGU) in a State are covered by the NOx SIP Call trading program, would any EGU be presumed to have met the requirements of NOx 8-hour ozone RACT even though the source just buys additional needed allocations to comply? Or does the State need to look to see if combustion modifications (e.g. adding low NOx burners or over fire air) are RACT?

A: As stated in the preamble to the November 29, 2005 8-hour implementation rule, the NOx SIP Call is estimated to achieve a beyond-RACT degree of control regionally, and sources were required to install any controls needed for compliance no later than May 2004. Under these circumstances, EPA believes that the NOx SIP call constitutes RACT for those sources covered by the NOx SIP Call, regardless of the manner of compliance of individual sources (e.g., control equipment installation or purchase of allowances from other sources).

22. **Q**: Does a source that came into existence after the State's NOx SIP call rule was adopted meet RACT if it is subject to the State's SIP call rule?

A: Yes, if that source is covered by the NOx SIP Call trading program. A large EGU will automatically become part of the NOx SIP Call trading program and thus will be considered to meet ozone NOx RACT requirements. If the source is a cement kiln or stationary internal combustion engine, a control level of at least a 30 percent or 82 percent reduction respectively from uncontrolled levels would be considered RACT.

23. **Q**: May a State rely on its compliance with the NOx SIP Call to show that cement kilns and stationary internal combustion engines are meeting the RACT requirements?

A: Yes, if the cement kilns and stationary internal combustion engines are subject to a SIP approved as meeting the NOx SIP Call obligation to install and operate controls that are expected to achieve at least a 30 percent and 82 percent reduction, respectively, from uncontrolled levels.

24. **Q**: The November 29, 2005 preamble to the 8-hour ozone implementation rule says, at page 71656, that: "….a State need not perform a NOx RACT analysis for non-EGU sources that after 2008 continue to be subject to a SIP that regulates those non-EGU sources equally or more stringently than the State's current rules meeting the NOx SIP call." Does this apply to the whole facility or just to the unit that is subject to the NOx SIP call?

A: The State need not perform such an analysis (and may instead rely on the analysis performed by EPA) only for the unit covered by the NOx SIP call.

D. Negative Declarations

25. **Q**: Are negative declarations required? That is, must a State certify that it has no sources in a particular CTG category if the State does not adopt a RACT rule for this category?

A: A negative declaration that there are no sources in a specific CTG category or no major non-CTG sources would need to be included as part of the RACT SIP submittal. As part of the RACT submission, the negative declaration and the information supporting the declaration would be subject to the SIP public hearing at the State level.

26. **Q**: If the State area believes that there are no major non-CTG sources located in the nonattainment area, would the area need to submit a negative declaration?

A: Yes, the negative declaration would need to assert that there are no major non-CTG sources in the area, and the accompanying analysis would need to support that conclusion.

E. Other Issues

27. **Q**: Can the State calculate the potential to emit (PTE) for an emission unit based on emissions after a control device if the operation and installation of the control device are federally enforceable, e.g., a NSPS or MACT standard requires the control device to be installed and operated?

A: Yes. Where a source has a federally enforceable limit on emissions or a federally enforceable restriction on the hours of operation, then the analysis of whether the source is subject to RACT would be based on emissions considering those restrictions.

28. **Q**: What must a State do for sources in a subpart 2 area not subject to 1-hour RACT SIP regulation?

A: The State must perform a RACT analysis for all CTG and major non-CTG sources in the nonattainment area. Where a source is currently not regulated, the State could start its analysis by considering EPA guidance documents (e.g., CTGs and ACTs). After considering these documents as well other available information, the State would need to submit a SIP revision providing for RACT for all CTG and major non-CTG sources in the area, and a negative declaration where no sources within a category are located in the area. Additionally, section §182(f) provides for an exemption from NOx RACT if certain criteria are met.

29. **Q**: What must a State do for sources which were subject solely to 1-hour RACT rules in their SIP (excluding sources covered by certain NOx SIP call/CAIR trading programs)?

A: For sources subject to 1-hour RACT, the State should review available EPA guidance and other available information to determine whether additional control is needed to meet 8-hour RACT. If no additional control is needed, the State may submit a certification with an accompanying analysis demonstrating that the current level of control is RACT. The State need not resubmit the existing SIP-approved 1-hour RACT rules. If additional control is needed, the State would need to make that obligation federally enforceable through a SIP revision.

30. **Q**: What must a State do for sources (excluding sources covered by certain NOx SIP call/CAIR trading programs) subject to 1-hour RACT rule in the SIP, but subsequently subject to a more stringent regulation ("beyond 1-hour RACT rule") in State rule which is already in the approved SIP where such rule was adopted as necessary for ROP/attainment?

A: See previous answer to question 29.

31. **Q**: Would the units covered by EPA's January 1, 1995 memorandum "De Minimis Values for NOx RACT" also fall into the category where the State used this guidance/policy to set cut-offs for small emissions units?

A: The purpose of the January 1, 1995 memorandum is to provide technical data that may be used to evaluate de minimis NOx for various categories of sources. EPA does not recommend specific de minimis values, but presents factors as a guide in the development and review of State de minimis rules. Similar to other RACT guidance issued for the 1-hour ozone standard, a State may continue to use this guidance--along with any other relevant infomation--for purposes of the 8-hour ozone RACT SIP.

32. **Q**: Subpart 1 areas must demonstrate they will attain the 8-hour standard within 5 years of designation, or submit RACT rules with their attainment date extension request. A State/Air District in a subpart 1 nonattainment area plans to submit an extension request and will need to adopt RACT rules for EGUs. In the meantime, a facility has shutdown an old EGU. They submitted a package to bank the shutdown emissions as emission reduction credits (ERCs). Do the calculated ERCs in the facility's submittal need to be reduced to account for the future RACT rule the State/Air District needs to adopt?

A: If the State plans to ask for an attainment date extension for a subpart 1 area beyond 5 years, RACT rules must be submitted. The ERCs must be discounted to the extent that emissions must be reduced to meet the new RACT rule. That is, the ERCs only continue to exist to the extent that the emissions reductions in the ERC represent lower emissions than those which would have been allowed under the new RACT rule if the rule had existed when the ERCs were generated.

Additional guidance on the issue of ERCs and RACT may be found in the 1994 memo, "Response to Request for Guidance on Use of Pre-1990 ERC's and Adjusting for RACT at Time of Use," dated August 26, 1994 from John S. Seitz, Director Office of Air Quality Planning and Standards to David Howekamp, Director Region IX Air and Toxics Division. This memo may be found at this web site: http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/pre-1990.pdf

33. **Q**: Is there any option for using Title V permits as the means of complying with the non-CTG major stationary source obligation – either submitting the permits for SIP approval or pulling the salient pieces from them and submitting these components, rather than going to the trouble of adopting a prohibitory rule for the source category?

A: Because Title V permits must be renewed every 5 years, the permits themselves should not be submitted as RACT rules because they are not permanent. However, if State law allows, the State may submit components of the permit as requirements that would remain enforceable until such time as the SIP is revised.

34. **Q**: May a State's RACT submission include commitments to adopt one or more RACT rules in the future?

A: A RACT submission that does not address RACT for all CTG and non-CTG sources would not be a complete official submission as required by the RACT provisions of the CAA. The State may address RACT through adoption of rules or submission of permits or consent orders; through one or more negative declarations; or through a request for a NOx RACT exemption. In addition, for non-CTG sources, some states have taken the approach of submitting a RACT rule that provides a process for the source-specific adoption of RACT through a future process. However, such a rule must also provide a backstop control obligation that would apply no later than the RACT compliance date if a source-specific rule had not been adopted, approved and implemented by that date.

35. **Q**: If a state includes its RACT SIP with its 8-hr ozone attainment demonstration as a submittal sometime after September 15, 2006, would that State's compliance date remain the same, or be adjusted to correspond with the actual submittal date?

A: The RACT compliance date would not change where a State chooses to delay submission of its RACT SIP beyond the required submission date.

36. **Q**: When are RACT SIPs due?

A: Subpart 2 moderate and above areas must submit RACT SIPs no later than September 15, 2006. Subpart 1 areas that seek an attainment date later than five years following designation are required to submit their RACT SIP at the time they request the attainment date extension, which can be no later than the time required for submission of the attainment demonstration – i.e., June 15, 2007. Subpart 1 areas that do not request an extension of the attainment date would meet RACT through submission of an attainment demonstration that demonstrates attainment as expeditiously as practicable. Thus, the area's attainment demonstration, which is due June 15, 2007, would also be the RACT submission for such area.

37. **Q**: For an area with a year-long ozone season, such as California, when does the implementation date for RACT begin?

A: Areas are required to implement RACT no later than the first ozone season or part thereof that occurs 30 months after the RACT SIP is due. Thus areas with a year-long ozone season would be required to implement RACT 30 months after the SIP submission is required – i.e., March 15, 2009.

38. **Q**: The maximum attainment date for a moderate 8-hour nonattainment area is June 15, 2010. All reductions needed for attainment are supposed to be achieved by the beginning of the ozone season prior to the attainment date. For areas with full year ozone seasons (such as California), the final full ozone season prior to the required attainment date would be the ozone season beginning January 1, 2009. RACT requirements must be implemented by 30 months after SIP submittal, which would be March 15, 2009. When must the RACT requirements be implemented – by January 1, 2009 or by March 15, 2009?

A: Where a State is relying on RACT reductions as part of its attainment demonstration, then those reductions would need to be achieved by the beginning of the final full ozone season prior to the area's attainment date. For some areas, that may mean that RACT requirements will need to be implemented earlier than required under the RACT provisions of the Act and our regulations.

39. **Q**: What is the reference size cut-offs for major non-CTG source categories?

A: RACT applies to CTG sources and to major non-CTG stationary sources of VOC and/or NOx. The major-source threshold is based on the classification of the nonattainment area and are specified in Clean Air Act section 182(d) for VOC and 182(f)(1) for NOx. For example, for a severe 8-hour ozone non-attainment area, such as South Coast, ''major source'' means 25 tpy or more of VOCs or NOx.

40. **Q**: Does a VOC or NOx stationary source cut-off (e.g. 25 tpy for NOx or 25 tpy for VOC in any severe nonattainment area) represent an uncontrolled or controlled level?

A: In general, RACT applicability is based on the source's potential to emit – i.e., uncontrolled emissions. However, if the source has a federally enforceable restriction on the emission level or on the hours of operation, those restrictions would be considered in determining whether the source is a major source (see, e.g., Blue Book pages 2-3 at http://www.epa.gov/ttn/naaqs/ozone/ozonetech/voc_bluebook.pdf). The emissions restriction cannot be solely on the emissions, but must be on the operation of the source so that the potential to emit is below the applicability threshold.

41. **Q**: Does "major source" in the context of a RACT determination represent "equipment" or "facility."

A: EPA guidance provides that when assessing whether a source is “major” for purposes of non-CTG RACT, the State should consider the building, structure, facility or installation. See the Blue Book at: (http://www.epa.gov/ttn/naaqs/ozone/ozonetech/voc_bluebook.pdf). As provided in the guidance, the State should consider the emissions from all sources that were not required to install RACT (e.g., the source emissions are below those that would be subject to RACT under the applicable CTG) as well as any other sources at the facility. For purposes of determining whether a facility is subject to RACT pursuant to a CTG, the State should examine the aggregate of all emissions from sources in that particular CTG category at the facility.

42. **Q.** May States adopt generic RACT provisions in their 8-hour RACT SIP rules for VOC and/or NOx?

A. On November 7, 1996, EPA issued a policy memorandum providing additional guidance for approving regulations that contains these generic provisions (Sally Shaver, Director, Air Quality Strategies and Standards Division, memorandum to EPA Division Directors, “Approval Options for Generic RACT Rules Submitted to Meet the non-CTG VOC RACT Requirement and Certain NOx RACT Requirements”). A State may adopt generic RACT rules as part of its SIP. EPA encourages States to follow the provisions of the November 7, 1996 memorandum.

43. **Q**: Can you provide a complete list of CTGs and ACTs?

A: Here is as complete a listing as we have been able to compile. The CTG list is complete. We believe the ACT list is complete:

Pre 1990 CTGs

1. Design Criteria for Stage I Vapor Control Systems - Gasoline Service Stations, November 1975. [Note – this document is regarded as a CTG although it was never published with an EPA document number.]

2. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume I: Control Methods for Surface Coating Operations, EPA-450/2-76-028, November 1976 [Note – although often listed with the CTGs for historical reasons, this document does not define RACT for any source. It is a compilation of control techniques.]

3. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume II: Surface Coating of Cans, Coils, Paper, Fabrics, Automobiles, and Light-Duty Trucks, EPA-450/2-77-008, May 1977.

4. Control of Volatile Organic Emissions from Solvent Metal Cleaning, EPA-450/2-77-022, November 1977.

5. Control of Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds, EPA-450/2-77-025, October 1977.

6. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA-450/2-77-026, December 1977.

7. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume III: Surface Coating of Metal Furniture, EPA-450/2-77-032, December 1977

8. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume IV: Surface Coating for Insulation of Magnet Wire, EPA-450/2-77-033, December 1977

9. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume V: Surface Coating of Large Appliances, EPA-450/2-77-034, December 1977.

10. Control of Volatile Organic Emissions from Bulk Gasoline Plants, EPA-450/2-77-035, December 1977

11. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed Roof Tanks, EPA-450/2-77-036, December 1977.

12. Control of Volatile Organic Compounds from Use of Cutback Asphalt, EPA-450/2-77-037, December 1977

13. Control Techniques for Volatile Organic Emissions from Stationary Sources, EPA-450/2-78-022, May 1978. [Note – This document is often listed with CTGs, but it does not define RACT for any particular source.]

14. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume VI: Surface Coating of Miscellaneous Metal Parts and Products, EPA-450/2-78-015, June 1978

15. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume VII: Factory Surface Coating of Flat Wood Paneling, EPA-450/2-78-032, June 1978.

16. Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment, EPA-450/2-78-036, June 1978.

17. Control of Volatile Organic Emissions from Manufacture of Synthesized Pharmaceutical Products, 450/2-78-029, December 1978.

18. Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires, EPA-450/2-78-030, December 1978.

19. Control of Volatile Organic Emissions from Existing Stationary Sources, Volume VIII: Graphic Arts - Rotogravure and Flexography, EPA-450/2-78-033, December 1978.

20. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA-450/2-78-047, December 1978.

21. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA-450/2-78-050, December 1978. [Note – Perchloroethylene has been exempted as a VOC, so this CTG is no longer relevant. However, there is a MACT standard for perchloroethylene dry cleaners.]

22. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA-450/2-78-051, December 1978.

23. Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reductions, and Costs, EPA-450/3-82-010, April 1982. [Note – This document does not define RACT for any particular source.]

24. Control of Volatile Organic Compound Emissions from Large Petroleum Dry Cleaners, EPA-450/3-82-009, September 1982

25. Control of Volatile Organic Compound Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins, EPA-450/3-83-008, November 1983

26. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants, EPA-450/2-83-007, December 1983.

27. Control of Volatile Organic Compound Fugitive Emissions from Synthetic Organic Chemical Polymer and Resin Manufacturing Equipment, EPA-450/3-83-006, March 1984

28. Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry, EPA-450/3-84-015, December 1984.

Post 1990 CTGs

1. SOCMI Distillation and Reactor Processes CTG (EPA 450/4-91-031, August 1993).

2. Wood Furniture (CTG-MACT) - draft MACT out 5-94; Final CTG, EPA-453/R-96-007, April 1996; see also 61 FR 25223, and, 61 FR 50823, September 27, 1996.

3. Shipbuilding/repair ACT (EPA 453/R-94-032, April 1994) and CTG, see 61 FR 44050, August 27, 1996.

4. Aerospace (CTG & MACT) (see 59 FR 29216, June 6, 1994); CTG (Final), EPA-453/R-97-004, December 1997.

The VOC Available Control Technology (ACTs) Documents

1. Control Techniques for Organic Emissions from Plywood Veneer Dryers, EPA-450/3-83-012. May 1983. [This document is labeled as a control technique document (CTD) rather than an ACT. However, the information is similar to that in an ACT.]

2. Reduction of Volatile Organic Compound Emissions from Application of Traffic Markings – EPA-450/3-88-007, August 1988. [Note – the Architectural and Industrial Maintenance coatings (AIM) national rule issued in 1998 includes limits for traffic coatings and superseded the ACT.]

3. Ethylene Oxide Sterilization ACT (EPA 450/3-89-007) March 1989.

4. Alternative Control Technology Document – Halogenated Solvent Cleaners – EPA-450/3-89-030. August 1989.

5. Alternative Control Technology Document – Organic Waste Process Vents – EPA-450/3-91-007, December 1990.

6. Polystyrene Foam Manufacturing – EPA-450/3-90-020, 1990.

7. Bakery Ovens ACT (EPA 453/R-92-017, December 1992)

8. Control Techniques for Volatile Organic Compound Emissions from Stationary Sources, EPA-453/R-92-018, December 1992

9. Industrial Wastewater CTG (draft) (EPA-453/D-93-056, September 1992); ACT: April 94 ACT consists of cover memo with option tables + CTG (draft).

10. Control of VOC Emissions from the Application of Agricultural Pesticides, EPA-450/R-92-011, March 1993.

11. Alternative Control Techniques Document: Volatile Organic Liquid Storage In Floating and Fixed Roof Tanks, EPA 453/R-94-001, January 1994.

12. Control of Volatile Organic Compound Emissions from Batch Processes ACT (EPA 453/R-93-017 or EPA 453/R-93-020, February 1994)

13. Alternative Control Techniques Document – Industrial Cleaning Solvents, EPA-453/R-94-015, February 1994

14. Business Machine Plastic Parts coating/Automobile Plastic Parts coating ACT (EPA 453/R-94-017, February 1994)

15. Automobile Body refinishing ACT (EPA 453/R-94-031, April 1994) [Note – a national rule for autobody refinishing was issued in 1998 after the ACT.]

16. Ship building coatings ACT, EPA 453/R-94-032, April 1994. [This was superseded by the Ship building CTG which was issued in August 1996.]

17. Offset Lithography ACT (EPA 453/R-94-054, June 1994)

The NOx ACT documents:

1. NOx Emissions from Nitric and Adipic Acid Manufacturing Plants (EPA-453/3-91-026- December 1991.

2. NOx Emissions from Stationary Combustion Turbines (EPA-453/R-93-007) - January 1993.

3. NOx Emissions from Process Heaters (EPA-453/R-93-034) - revised September 1993.

4. NOx Emissions from Stationary Internal Combustion Engines (EPA-453/R-93-032), July 1993 – [Updated September 2000.]

5. NOx Emissions from Utility Boilers - (EPA 453/R-94-023) March 1994.

6. NOx Emissions from Cement Manufacturing - (EPA 453/R-94-004) March 1994 – [Updated September 2000.]

7. NOx Emissions from Industrial, Commercial & Institutional Boilers - (EPA 453/R-94-022) March 1994.

8. NOx Emissions from Glass Manufacturing - (EPA 453/R-94-037), June 1994.

9. NOx Emissions from Iron and Steel - (EPA 453/R-94-065) September 1994.

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Refineries – Preliminary Work Product

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Table of Contents

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 benchmark[2]. 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,

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[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 document[3] 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 CO_2 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.

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[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.

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[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 ktCO$_2$ 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.[6]A 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 CO_2 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 CO_2. 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.

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

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
NAICS 324110 - Petroleum Refineries						
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

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
NAICS 325188 - All Other Basic Inorganic Chemical Manufacturing						
Tesoro Refining and Marketing Co. - SRP[d]	101492	Carson		133,275	121,531	105,895
NAICS 324191 - Petroleum Lubricating Oil and Grease Manufacturing						
Evergreen Oil, Inc, Refinery	101035	Newark		10,753[C]	9,876	n.a
NAICS 324121 - Asphalt Paving Mixture and Block Manufacturing						
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 Report[7] by the U.S. Energy Information Administration (EIA).

Capacity can either be reported per stream day or as per calendar day[8]:

- 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.

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[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] Alon Bakersfield Refinery - Area 3[10]	-[9]		14,500[a]	8,000[a]	8,000[a]							22	300[a] 500[b] 200[c]			70
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[e] 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] ConocoPhillips Santa Maria 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 Los Angeles Refinery Wilmington Plant[11] ConocoPhillips Los Angeles Refinery, Carson 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
Edgington Oil Company[13]	35,000							25,000			15,000					

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 (mmcfd) and sulphur in short tons per day (st/d)

[3] The feeds used for catalytic cracking are [a]fresh feed and [b]recycled feed.

[4] The feeds used for catalytic hydrocracking are [a]gas oil and [b]distillate.

[5] Catalytic reforming can occur at [a]low pressure or [b]high pressure.

[6] The feeds used for desulphurisation: [a]naphtha/reformer, [b]diesel oil, [c]kerosene and jet, [d]gasoline, [e]heavy gas oil and [f]other distillate.

[7] The types of thermal cracking used are [a]delayed cooking, [b]fluid cooking and [c]vis breaking.

[8] Isomerisation of [a]isobutane, [b]isopentane/isohexane and [c]isooctane; 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 CO_2 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):

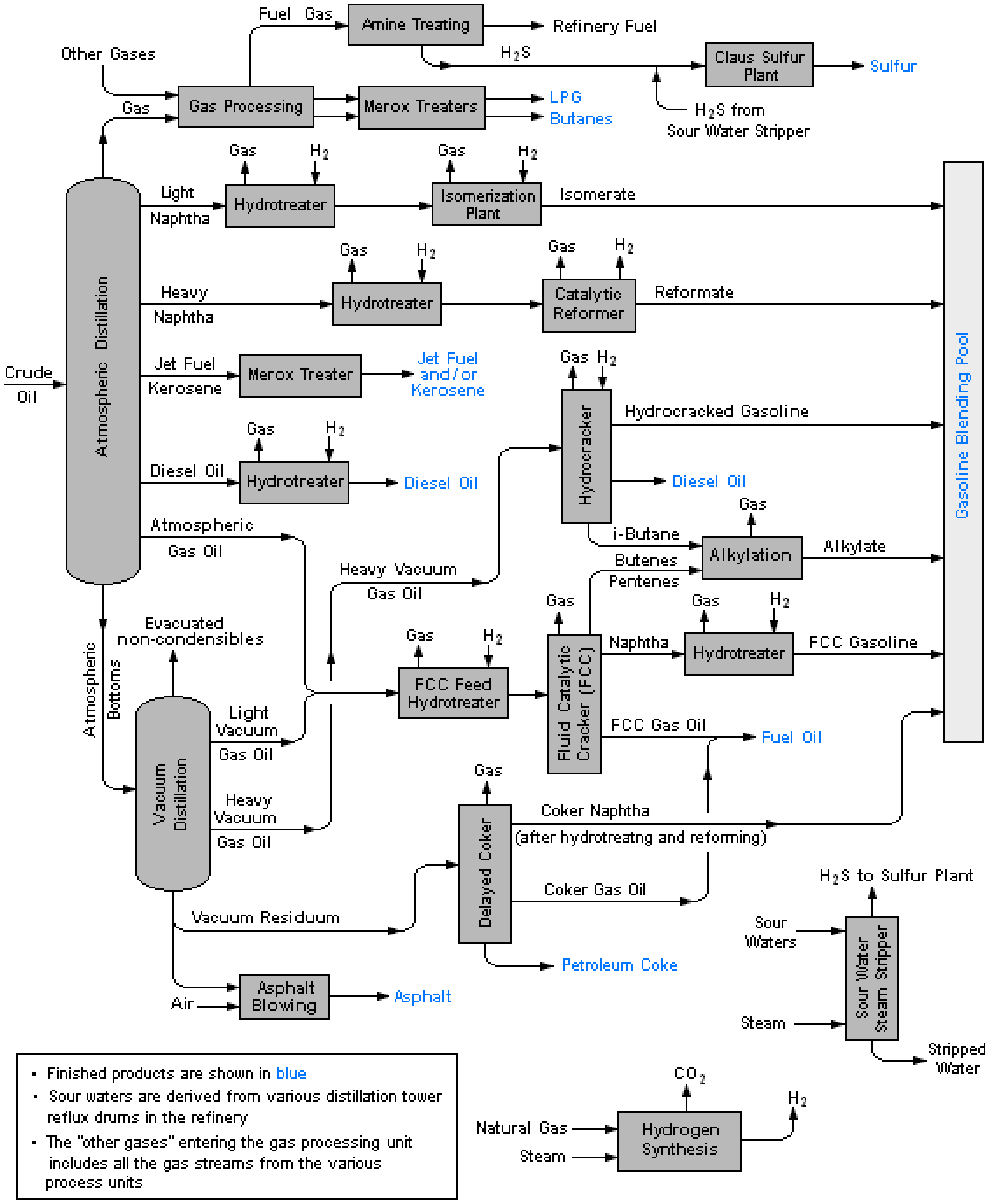
- Distillation processes: physical separation methods to decompose homogeneous liquid mixtures under usage of the different boiling behavior of the mixture components.
- Conversion processes: chemical methods to change the chemical structure of hydrocarbons contained in the different crude oil fractions (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).



- Finished products are shown in blue
- Sour waters are derived from various distillation tower reflux drums in the refinery
- The "other gases" entering the gas processing unit includes all the gas streams from the various process units

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 reformate 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.

Polimerization: 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 CO_2 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 CO_2 Emissions

The sources of CO_2 emissions that are associated with refineries can be summarized as follows:

- Direct emissions occurring on site[9]
    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).

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[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 CO_2 emission.
- Product mix: a high share of light products (gasoline and diesel) requiring higher processing and more CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 footprints to make a certain product and production routes and products are interdependent, i.e., a refinery cannot produce only gasoline. Energy consumption and CO_2 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

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[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)

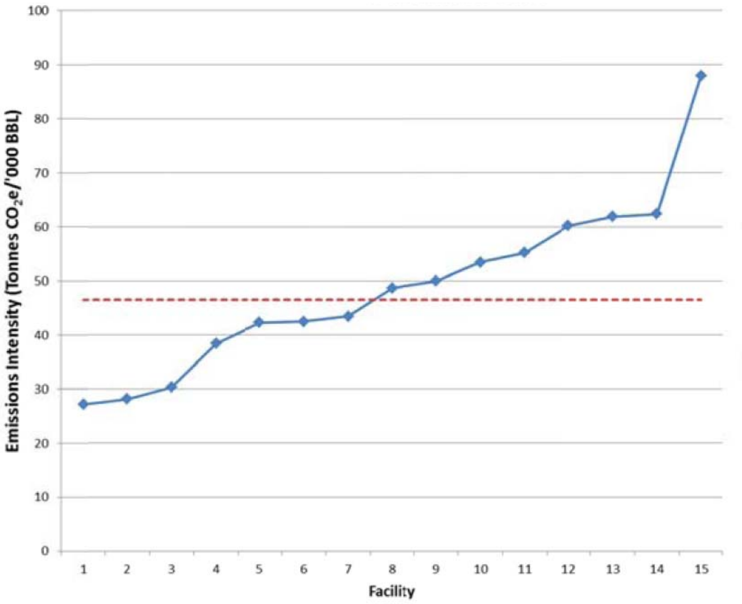

Figure 3. Emissions intensity of California refineries in terms of primary products produced together with benchmark based on 90% of weighted average emissions intensity (CARB, 2011a).

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 4[12] which shows:

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

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[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 CO_2/MWh and 0.06244 tCO_2/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 benchmark[13], 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.

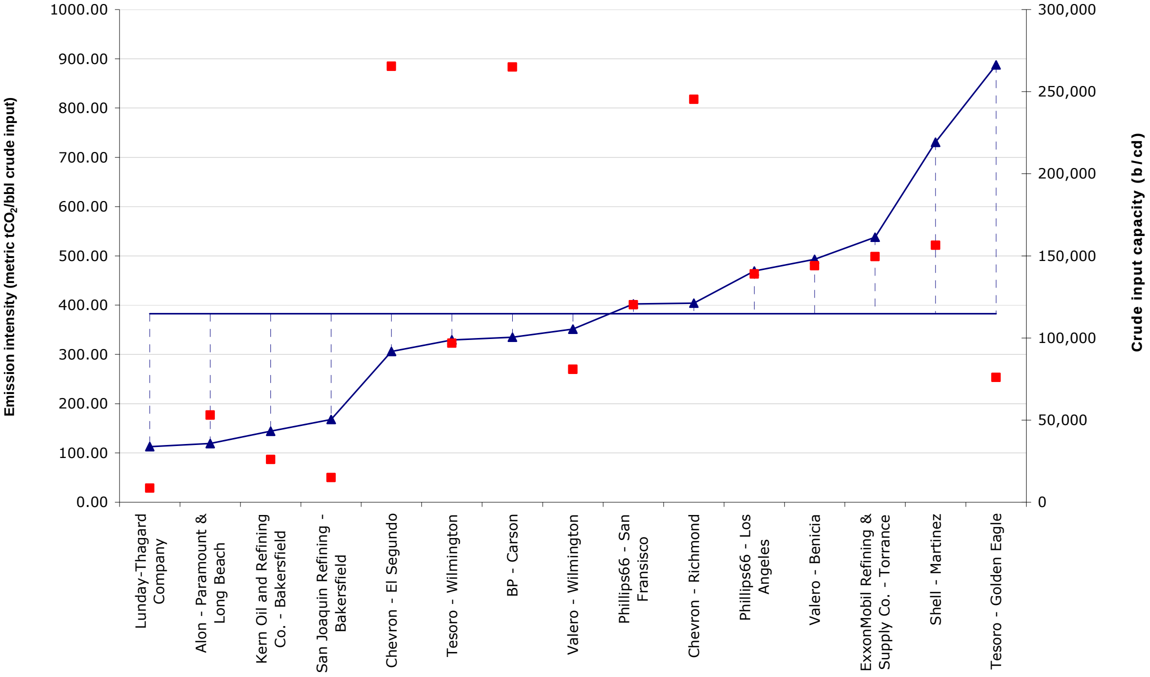

Figure 4. 2010 estimated emissions intensity of California refineries in terms of crude input (triangles; left axis) together with together with benchmark (horizontal line; left axis) and 2010 capacity of crude distillation unit (squares; right axis).

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

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[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.

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[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 CO_2 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 CO_2 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
$1.0183 \cdot \ldots + 298 + 0.315 \cdot TP_{AD,k}$:	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.

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[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, CO_2 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 CO_2 emissions.[18]
- Similarly, heavier crude, in general requires more processing leading to increased CO_2 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

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[17] See § 95891 of the Final Regulation Order

[18] Primarily because of its linkage to hydrogen consumption, incremental CO_2 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 refined[19] and CONCAWE developed a template to collect the data required to calculate the final benchmark values (in tonnes CO_2/CWT).

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[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 CO_2 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 tCO_2e/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 CO_2-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.

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[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

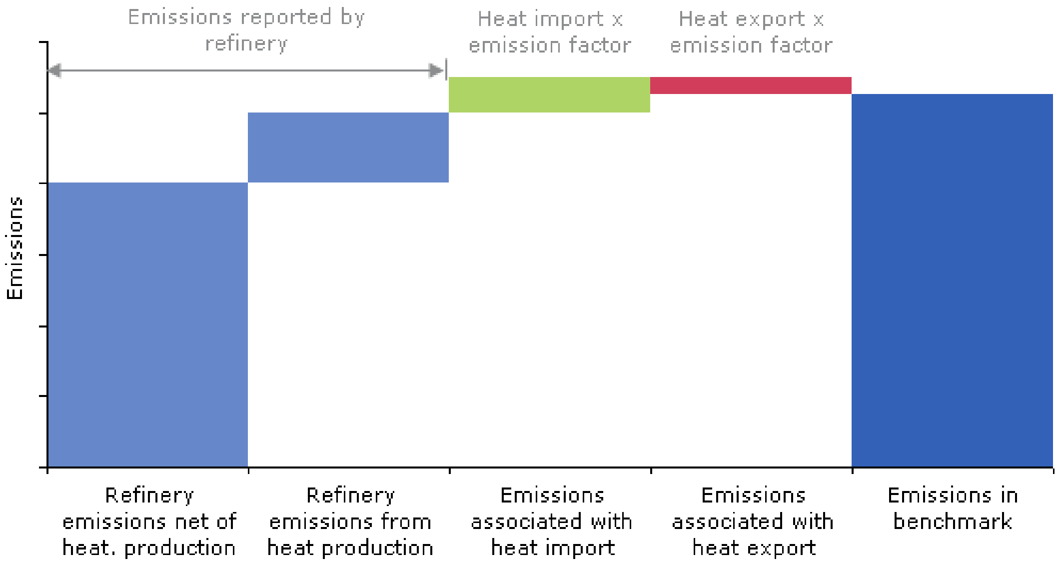

Figure 5. Benchmarked emissions include emissions related to heat consumption and exclude emissions related to heat export

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.

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

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)	- 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	- 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)	- 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)	- 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)	- 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 CO_2e 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.

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[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.

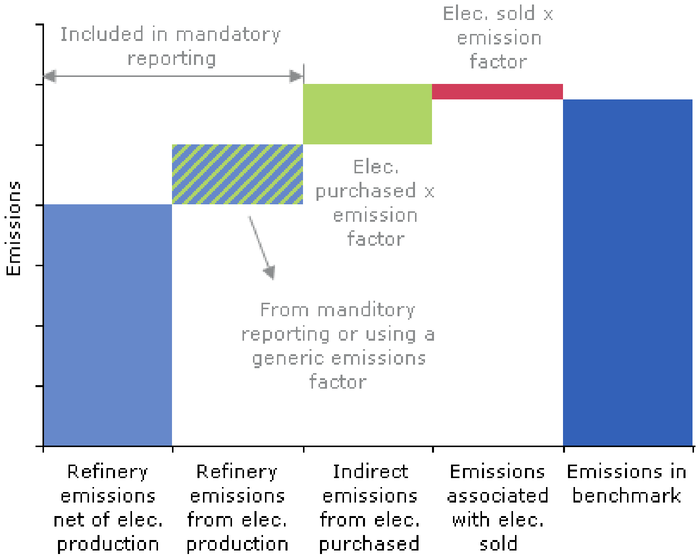

Figure 6. Benchmarked emissions include all emissions-related electricity consumption and exclude emissions related to electricity sold.

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.

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

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	$E_{\text{Refining}} + E_{\text{Elec.Produced}} + E_{\text{Elec.Purchased}} - E_{\text{Elec.Sold}} = \ldots$ $\ldots = E_{\text{Reported}} + E_{\text{Elec.Purchased}} - E_{\text{Elec.Sold}} = \ldots$ $\ldots = E_{\text{Reported}} + Elec.Purchased \cdot EF_{Elec.Purchased} - \ldots$ $\ldots Elec.Sold \cdot EF_{Elec.Sold}$	$E_{\text{Refining}} + E_{\text{Elec.Produced}} + E_{\text{Elec.Purchased}} - E_{\text{Elec.Sold}} = \ldots$ $\ldots = E_{\text{Reported}} - E_{\text{Elec.Produced}} + E_{\text{Elec.Consumed}} = \ldots$ $\ldots = E_{\text{Reported}} - E_{\text{Elec.Produced,actual}} + \ldots$ $\ldots Elec.Cons. \times EF_{Elec.Consumed}$
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)	- 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	- 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)	- 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	- 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)	- 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)	- 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 CO_2/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 CO_2 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 *production* 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)	- 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 *production* in refineries; hydrogen benchmarks based on actual efficiency for other production.	- 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	- 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)	- 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 *production* in refineries; separate benchmark based on actual efficiency for other entities	- 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.	- 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 CO_2/MWh and 0.06244 tCO_2/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.

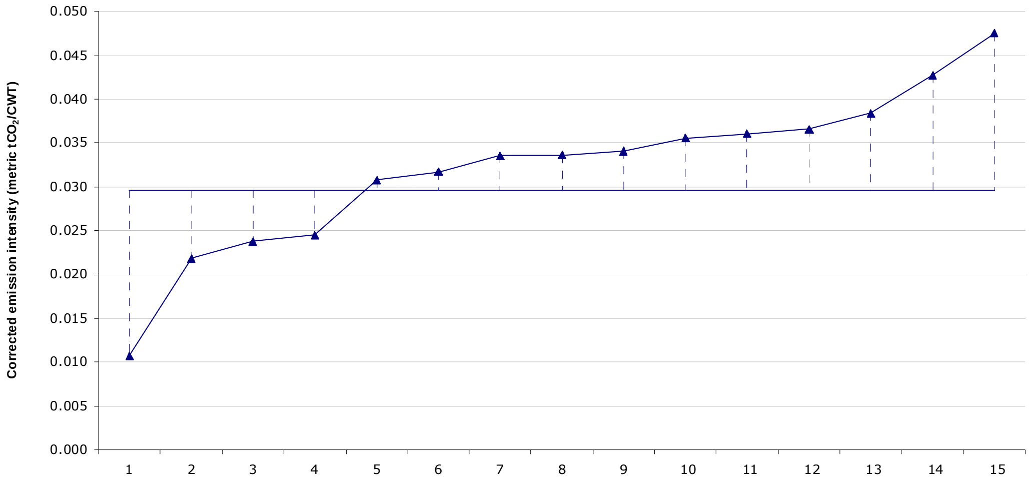

Figure 7. 2010 Estimated emissions intensity of California refineries in terms of CWT (triangles; left axis) together with benchmark based on 90% of weighted average (horizontal line; left axis) and 2010 capacity of crude distillation unit (squares; right axis).

This assessment finds an average weighted emissions intensity of 0.033 metric ton CO_2/CWT and a typical range of 0.02 – 0.05 metric ton CO_2/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 CO_2/CWT and a typical range of 0.02 – 0.05 metric ton CO_2/CWT (see Figure 8) (Lane, 2011). A benchmark based on 90% of this average would have a value of 0.030 metric ton CO_2/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 CO_2/CWT)

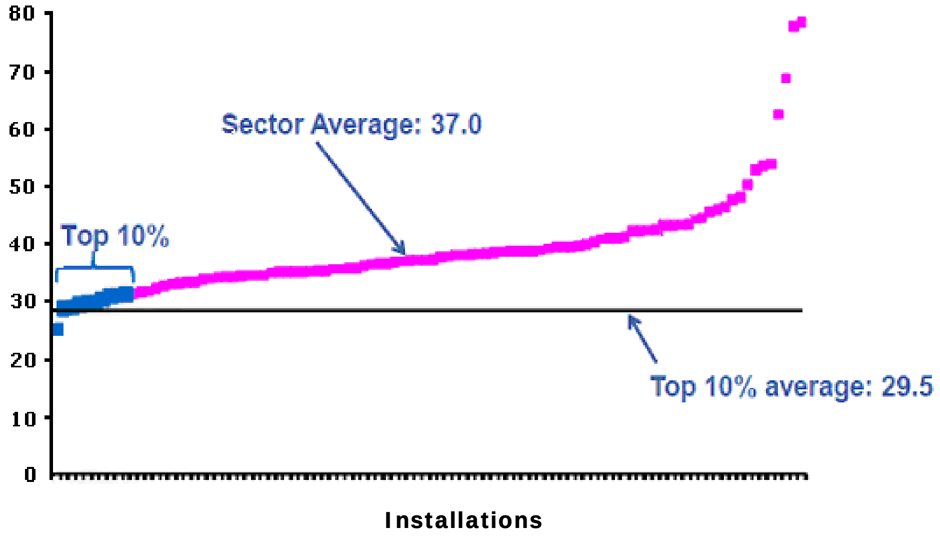

Figure 8. CO_2 benchmarking curve for 89 mainstream refineries in EU ETS; Curve based on 2007/2008 data (Lane, 2011; reformatted)

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 CO_2 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 CTW approach has been shown to reduce differences in emissions intensities (tCO_2/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)		(-)		(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$_{\text{Basic}}$ + 0.315 x TP$_{\text{AD}}$ + 298) (for TD$_{\text{AD}}$ 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	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. 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.	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	Distillation of atmospheric residues under vacuum. The process line up must include a heater. Some units may have more than one main distillation column. 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.	Atmospheric residue	Vacuum gasoils, vacuum residue
Mild Vacuum Fractionation		MVU					
Standard Vacuum Column		VAC					
Vacuum Fractionating Column		VFR					
Vacuum Flasher Column		*VFL*	***n.c.***	***n.c.***	*Normally associated with a visbreaker (VBR) or a thermal cracker (TCR). It does not include a heater. Its*		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
					contribution is included in the CWT factor of the VBR and TCR units		
Heavy Feed Vacuum Unit		*HFV*	***n.c.***	***n.c.***	*Additional column taking feed from the bottom of an MVU. Its contribution is included in the generic CWT factor for VAC.*		
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 produced calcined coke.	Green coke	Waste gases, calcined coke
Vertical-Axis Hearth		HRTH					
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	
Thermofor 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: • Total operating reactor pressure: ≥ 70 barg • Conversion (defined as the % of feed material boiling over 350°C that is upgraded to lighter products): ≥20% mass on feed	Vacuum gasoils and cracked heavy distillates, deasphalted oils, hydrogen	Full range of hydrocracked distillates from light gases to gasoil, hydrocracked bottoms
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					
Reactor for Selective Hydrotreating		*RXST*	n.c.	n.c.	*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.*		
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			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.		
Conventional H/T		CONV/KUS			Desulphurisation of virgin kerosene over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen.		
Solvent aromatics hydrogenation					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 proprietory absorbtion process. Does not involve hydrogen.	Gasoils	
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/denitrification		VHDN					
Hydrodesulphurisation		VHDS					
Hydrogen production	HYG		Product	300.00			Hydrogen, CO_2
Gas feeds					Hydrogen production from light hydrocarbons through either steam reforming or partial oxidation. Includes hydrogen purification.	C1 to C4 hydrocarbons	
Steam Methane Reforming		HSM					
Partial Oxidation Units of Light Feeds		POX					
Steam Naphtha Reforming		HSN			Hydrogen production by steam reforming of naphtha.	Naphtha	
Hydrogen Purification	*H2PURE*			***n.c.***	*Purification of hydrogen-rich streams for use in*		

Process Unit	Solomon Process ID	Solomon Process Type	Activity basis	CWT factor	Description	Typical feed(s)	Typical product(s)
Cryogenic Unit		*CRYO*			*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.*		
Membrane Separation Unit		*PRSM*					
Pressure Swing Absorption Unit		*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 reformate splitters, DIP etc) on an average EU-27 basis .	Desulphurised naphtha	Reformate for gasoline blending or aromatics production, hydrogen
Continuous Regeneration		RCR					
Cyclic		RCY					
Semi-Regenerative		RSR					
AROMAX	U60				Special application of catalytic reforming for the specific purpose of producing light aromatics		
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.		C6 to C8 high octane gasoline blending components
Alkylation with HF Acid	ALKY	AHF				C3 and C4 olefins, isobutane	
Alkylation with Sulfuric Acid		ASA					
Polymerization C3 Olefin Feed	POLY	PC3				C3 olefins	
Polymerization C3/C4 Feed		PMIX				C3/C4 hydrocarbons	
Dimersol	DIM					C3 olefins	
Sulphuric Acid Regeneration	*ACID*				*Contribution included in ALKY/POLY*		

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	*U18*	*ISOSIV*	*n.c.*	*n.c.*	*Contribution included in C5ISOM*		
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					
ETBE	ETBE					Ethanol, isobutene	
TAME	TAME					Methanol, C5 olefins	
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 reformate 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.	Reformate, 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					
Benzene Column		*BZC*	*n.c.*	*n.c.*	*The contribution of all columns and associated equipement required to purify individual aromatics is included in ASE.*		
Toluene Column		*TOLC*	*n.c.*	*n.c.*			
Xylene Rerun Column		*XYLC*	*n.c.*	*n.c.*			
Heavy Aromatics Column		*HVYARO*	*n.c.*	*n.c.*			
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
Xylene Splitter		*XYLS*			*The contribution of these columns and associated equipment is included in PXYL.*		
Orthoxylene Rerun Column		*OXYLRC*					
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
Ethylbenzene Distillation		*EBZD*			*The contribution of this column and associated equipment is included in EBZ.*		
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 CO2 and hydrogen for methanol synthesis. *This factor can only be applied in combination with U72 above.*	Hydrogen, CO, CO2	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
De-ethaniser	*DETH*		*n.c.*	*n.c.*	*The CWT factor refers to fresh NGL feed, therefore no separate contribution from individual columns*		
De-propaniser	*DPRO*		*n.c.*	*n.c.*			
De-butaniser	*DBUT*		*n.c.*	*n.c.*			
Special Fractionation					*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.*		
Deethanizer							
Depropanizer							
DeIsobutanizer		*DIB*					
Debutanizer							
Deisopentanizer		*DIP*					
Depentanizer							

Process Unit	**Solomon Process ID**	**Solomon Process Type**	**Activity basis**	**CWT factor**	**Description**	**Typical feed(s)**	**Typical product(s)**
Deisohexanizer							
Dehexanizer							
Deisoheptanizer							
Deheptanizer							
Naphtha Splitter							
Conventional Splitter		*CONV*					
Splitter with single Heartcut		*HC1*					
Splitter with two Heartcuts		*HC2*					
Standard Column with Heartcut Draw		*HCD*					
Alkylate Splitter							
Conventional Splitter		*CONV*					
Special Fractionation (continued)							
Splitter with single Heartcut		*HC1*					
Splitter with two Heartcuts		*HC2*					
Standard Column with Heartcut Draw		*HCD*					
Reformate Splitter							
Conventional Splitter		*CONV*					
Splitter with single Heartcut		*HC1*					
Splitter with two Heartcuts		*HC2*					
Standard Column with Heartcut Draw		*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		Compressor 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 Energy[24].

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.

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[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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Report on CWT-CWB for California Regulatory Support

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1.0 Use Restrictions

This report ("the Report") is delivered under the agreement between HSB Solomon Associates LLC (Solomon) and Western States Petroleum Association (WSPA), containing information for the Complexity-Weighted Barrels methodology for California refineries (CA-CWB™). WSPA may use part or all information contained in this Report to the purpose ("the Purpose") of implementing the CA-CWB methodology within the State of California for State carbon emission regulations, such as for California Air Resources Board (CARB) Greenhouse Gas Emissions Mandatory Reporting Regulation (MRR) advocacy, in allocating emission allowances under California's greenhouse gas (GHG) cap-and-trade program, AB-32.

Within the State of California and limited to the Purpose, WSPA has unrestricted use of the Report and methodologies described therein, whether in verbal or written form (physical, electronic, or otherwise), in communicating with third parties.

2.0 The Complexity-Weighted Barrels (CWB) Methodology for California Refineries

Both of the Complexity-Weighted Barrels methodology (CWB™) and the Complexity-Weighted Tonnes methodology (CWT™) are proprietary to Solomon. Under each individual Consulting Service Agreement, Solomon grants the client, typically a regional Industry Association, limited rights to use or promote the CWB or CWT methodology for the purpose of GHG regulations only.

Under the Agreement between Solomon and Western States Petroleum Association (WSPA), Solomon conveys the ownership of the CA-CWB™ methodology to WSPA. The analysis and calculations presented in the Report are based on the definitions and input data in Solomon's *Fuels Refinery Performance Analyses (Fuels Study)* and the *Worldwide Paraffinic Lube Refinery Performance Analysis (Lube Study)*. The lower heating value (LHV) was used in all energy calculations.

At the discretion of WSPA while working with Air Resources Board (ARB), the content of the methodologies within, including factors[1], calculations, and data collection protocol, may be modified for California refineries, since the CA-CWB methodology was originally developed for accommodating the entire refining industry around the world.

2.1 Background

Over the past decade, Solomon has developed several methods for benchmarking greenhouse gas (GHG) emissions performance. Unlike simplified approaches which are based solely on raw material input or product output volumes, Solomon's GHG benchmarking metrics take into account the process unit configuration and complexity of each individual refinery. The Carbon Emissions Index (CEI™) is Solomon's proprietary and most rigorously calculated benchmarking metric for assessing a refinery's carbon dioxide-equivalent (CO_2e) emissions relative to a carbon dioxide (CO_2) emissions standard.

In the CEI methodology, standard emissions are in large part derived from Solomon's proprietary Energy Intensity Index™ (EII®) standard energy. CEI is calculated by the following equation:

$$CEI = \frac{CEICO_2eActual}{CEICO_2eStd.} \times 100$$

where

- *CEI $CO_2eActual$* is Solomon's calculation of CO_2-equivalent (CO_2e) emissions incurred
- *CEI $CO_2eStd.$* is the CO_2e emissions standard for the refinery

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[1] It was suggested that the current CWB factor for coke calciners is not appropriate for California refineries, and will not be used for determining the allocation. Instead, coke calciners will receive allocation separately from refineries via a unique efficiency benchmark in cap-and-trade Regulation Section 10395 (Table 9-1). The determination of an appropriate benchmark for California coke calciners will be developed separately.

Solomon's calculation of CO_2e emissions (*CEI* $CO_2eActual$) are based on the detailed energy balance data (including actual energy types and quantities for imported, exported, and produced energy, as well as gas compositions) and process data (including process unit types, operating conditions, fresh feed compositions and characteristics, and product yields), reported in Solomon's *Fuels Study* and *Lube Study*. The CO_2 emissions equivalent for each fuel type is determined by multiplying the quantity of energy consumed (expressed in MBtu) by the appropriate CO_2 emission factor (CEF) in tonnes of CO_2 equivalent per MBtu, or tonne CO_2/MBtu. The description of Solomon's calculation of CO_2e emissions can be found in Section 2.6.

The concept of CWB was originally developed during an Emissions Allocation Study for WSPA around 2008. In this study, it was found that a Process-Based Model, i.e., a model based on specific refinery configuration using actual process unit yields or throughput, was superior to a simplistic approach based on actual barrels of total refinery product only (referred as the Simple Barrels Method) for achieving fairness and equity in allocations. This was accomplished by appropriately accounting for processing complexity (operating intensity) of a refinery. The CA-CWB methodology described in this report is based specifically on Complexity-Weighted Throughput Barrels (CWTB, referred as CWB hereafter), which is a modified version of the original Process-Based Model on the basis of throughput.

The CA-CWB methodology was developed with the objectives of minimal data requirements, simplicity, and suitability for public disclosure for the purpose of equitably allocating carbon emission allowances. The CWB factors were developed based on Solomon's proprietary EII methodology. Simplification was achieved by combining process units according to operating characteristics of more than 200 refineries operating in Organization for Economic Co-operation and Development (OECD) countries that participated in Solomon's *Fuels Study* and *Lube Study* for operating year 2006.[2] This data is sufficient to estimate both combustion- and process-related emissions at each refining site. Solomon has applied the CWB methodology for both fuels and lubricants refineries around the world and has found it to be sufficiently robust to benchmark the entire range of refining process configurations.

2.2 CWB Robustness in Allocating Emission Allowances

The robustness of Solomon's CWB methodology in allocating carbon emission allowances is determined in a regression analysis for the correlation between Solomon's calculation of CO_2e emissions (based on actual energy balance data) and CWB, for the following three peer groups:

- OECD refineries
- US refineries
- US California (CA) refineries

Figures 1a–1d (page 2-3) show the distribution of total CO_2e emissions (including indirect emissions arising from imported steam and electricity) vs calculated CWB for approximately 200 OECD refineries in operating years 2004, 2006, 2008, and 2010, with an r^2 coefficient (the coefficient of determination) in regression for all three peer groups. The intercept of the fitted lines was forced to the origin (0, 0) in each chart, with an r^2 coefficient ranging between 0.96 and 0.98 for all peer groups in all study years, as summarized in Table 1 (page 2-4). This indicates a strong predictability of CO_2e emissions by calculating the CWB. A certain degree of deviation from the distribution is anticipated, due to variance in emission efficiency among refineries in each peer group. A wide range of OECD refineries are covered in the

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[2] Excludes refineries located in Eastern Europe, Greece, and Mexico.

analysis, processing crude oil from 17,000 b/d to over 700,000 b/d; the complexity of these refineries (indicated by a ratio of total Equivalent Distillation Capacity™ (EDC™) of the refinery to its crude unit capacity) ranging from 3.5 to over 25. California refineries are typically more complicated than average, requiring more extensive processing facilities downstream of the crude unit for upgrading the products. The average complexity (Configuration Factor) for all 12 California refineries in Solomon's *2010 Fuels Study* was 17, versus the US average of 13 or the worldwide average of 11.7. It is thus particularly important to take processing complexity into account for equitably allocating emission allowances for California refineries.

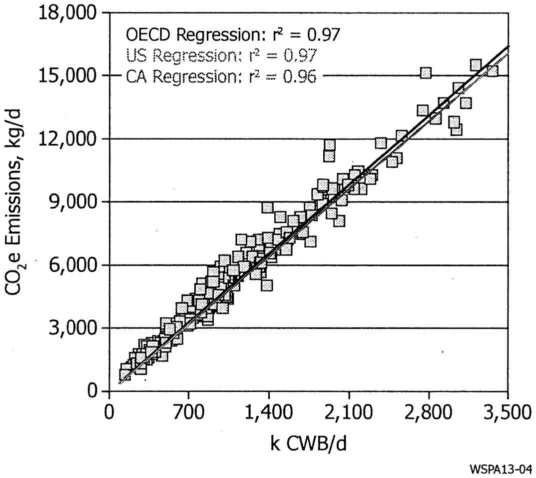

Figure 1a. 2004 OECD Refineries Total Emissions vs CWB

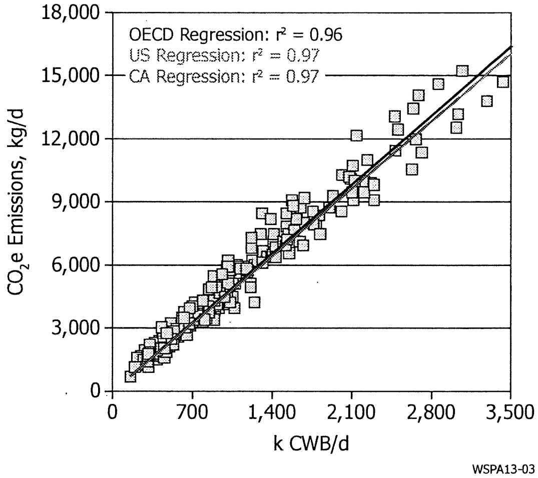

Figure 1b. 2006 OECD Refineries Total Emissions vs CWB

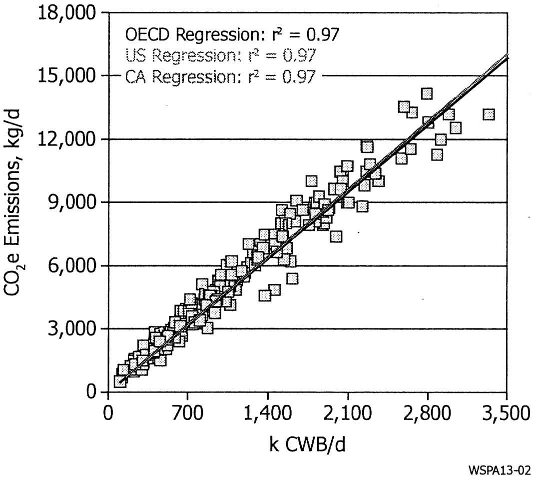

Figure 1c. 2008 OECD Refineries Total Emissions vs CWB

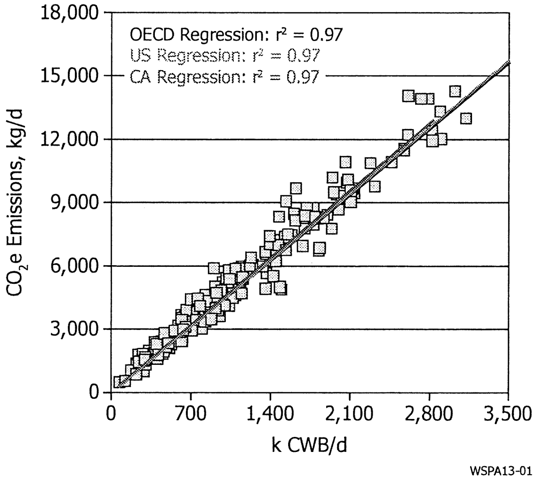

Figure 1d. 2010 OECD Refineries Total Emissions vs CWB

Table 1.Summary of r^2 in Regression Analysis for OECD, US, and US California Refineries in 2004–2010

	Operating Year 2004	**Operating Year 2006**	**Operating Year 2008**	**Operating Year 2010**
Number of OECD Refineries [(1)]	~200	~200	~200	~200
r^2	0.97	0.96	0.97	0.97
Number of US Refineries	88	86	86	80
r^2	0.97	0.97	0.97	0.97
Number of CA Refineries	11	12	12	12
r^2	0.96	0.97	0.97	0.97

(1) Excludes refineries located in Eastern Europe, Greece, and Mexico.

2.3 CWB versus CWT

Both of Solomon's CWB and its equivalent in metric unit, CWT, are intended for use as a reliable greenhouse gas (GHG) intensity metric or as a basis for GHG allocations in the regulatory arena. The CWT method was developed for refineries located in countries using metric units of measure, while the CWB method was developed for American refineries, measuring refinery throughput in barrels.

For the CWB or CWT application in regulations, Solomon works through local or regional Industry Associations, and conveys the ownership of the methodology to the Industry Association for working with regulators for legislation. Under each agreement, Solomon grants rights for use and promote the CWB or CWT methodology, limited to the specific region, and for the particular purpose of regulatory use only. After the official transfer of ownership, the Industry Association may work directly with regulators for modifying the content of the methodologies as needed. The potential roles and responsibilities of Solomon during the collaboration with an Industry Association, before and after the transfer of ownership of the CWB or CWT methodology, are briefly summarized in Appendix A.

Solomon was approached by CONCAWE (Conservation of Clean Air and Water in Europe) in 2008 to develop a complexity-weighted methodology for benchmarking CO_2 emissions for European Union (EU) refining industry, under the EU GHG Emissions Trading Scheme (ETS) Directive. The study was initiated in November 2008, and the final product, a report on the EU-CWT methodology, was delivered to CONCAWE at the end of February 2009. Under the agreement between Solomon and CONCAWE, CONCAWE acquired the rights to use and promote the EU-CWT methodology in Europe for the specific purpose of complying with the EU ETS. Starting in 2013, a modified version of Solomon's EU-CWT methodology since the transfer of ownership to CONCAWE, referred to as the "CONCAWE EU-CWT", is being implemented in the third phase of EU ETS Directive.

The description of the CONCAWE EU-CWT methodology and the CWT factors can be found in a report published by CONCAWE, *"Developing a Methodology for an EU Refining Industry CO_2 Emissions Benchmark"* (Report No. 9/12).

The EU-CWT method was developed for EU refineries, which typically measure refinery throughput and production in tonnes. The CWB method was developed for American refineries, which typically use volumetric measures expressed in barrels of throughput, except for certain process units such as hydrogen generation and purification (in k SCF of hydrogen product or feed gas), sulfur recovery unit (in long tons, LT, of product sulfur), and coke calciner (in short tons, ST, of product), in accordance with industry convention.

As simplifications of Solomon's CEI methodology, the CWB and CWT factors are largely an adaptation of the EII standard energy. The CWB and CWT factors express the GHG emissions intensity inherent to various refinery processes relative to the emissions intensity of a standard atmospheric crude distillation unit. CWB and CWT are used in the denominator of an emission intensity metric, expressed in tonnes of CO_2e per CWB or tonnes of CO_2 per CWT, versus emissions standard used in CEI.

The EU-CWT methodology was developed for the purpose of allocating emission allowances under the EU ETS. To comply with the requirements of EU ETS, Solomon's EU-CWT methodology differs from the CWB methodology in several respects:

- Boundary Condition – Excludes actual or allocated emissions from all electricity generation and cogeneration that takes place within refineries
- Fuel Standard – Uses the EU refineries' average carbon intensity of refinery fuels as the reference fuel instead of pipeline natural gas, a standard used in Solomon's EII and CEI methodologies
- Customized EU Operating Characteristics – Uses EU refineries' average parameters for other refinery characteristics rather than average parameters developed from Solomon's entire database of refineries located in developed economies
- Level of Simplification – Employs a number of simplifications in process unit categories and process types, reducing the number of factors

The CWB and CWT factors differ due to the fundamental difference in unit of measure. In the CWB method, throughputs to most units are measured in barrels. In the CWT method, throughputs to most units are measured in tonnes. CWB and CWT factors are relative to the atmospheric crude distillation unit (CDU). The CWB factor for a process unit is the ratio of emissions from this particular unit, usually per barrel of feed, relative to an atmospheric crude distillation unit per barrel of feed. The CWT factor for a process unit is the ratio of emissions from this particular unit, usually per tonne of feed, relative to an atmospheric crude distillation unit per tonne of feed. Because the densities of crude and process unit feeds and products vary from one refinery to another, there was no simple and straightforward conversion between CWB and CWT.

A comparison of the CA-CWB methodology, Solomon EU-CWT methodology, and the CONCAWE EU-CWT methodology, is provided in Appendix B.

A comparison of the CWB and CWT factors between the CA-CWB methodology and Solomon EU-CWT methodology is summarized in Appendix C to highlight the differences in unit of measure and consolidation of process units.

2.4 CWB Boundary Conditions

One key consideration in assessing the GHG emissions performance for a refinery is defining the "boundary" for benchmarking, in order to assure comparability of results.

The CA-CWB boundary includes the process units, utilities, and off-site infrastructure used at a refinery to produce the following petroleum products:

- Liquefied petroleum gas
- Naphtha
- Jet fuel
- Bitumen and asphalt
- Unfinished oils
- Lube feedstock
- Sulfur by-product
- Propylene
- Lubricants and waxes
- Gasoline
- Distillate fuel
- Residual fuel
- Petroleum coke
- Specialty solvents
- Chemical feedstock
- Aromatic petrochemicals
- Liquefied CO_2 by-product for sales
- Refinery-produced fuel gas and other fuels consumed

Although the refinery-produced propylene is reported in Solomon's *Fuels Study* as a product, olefin cracking plants and all derivative petrochemical plants are specifically excluded.

Figure 2 illustrates the allocation of utilities and off-site infrastructure shared among the fuels refinery and other plants in a refining and petrochemical manufacturing complex. The estimated or calculated GHG emissions (the numerator) must be consistent with the capacity and throughput of process units and supporting facilities defined, to calculate the appropriate CWB (the denominator) in an intensity metric.

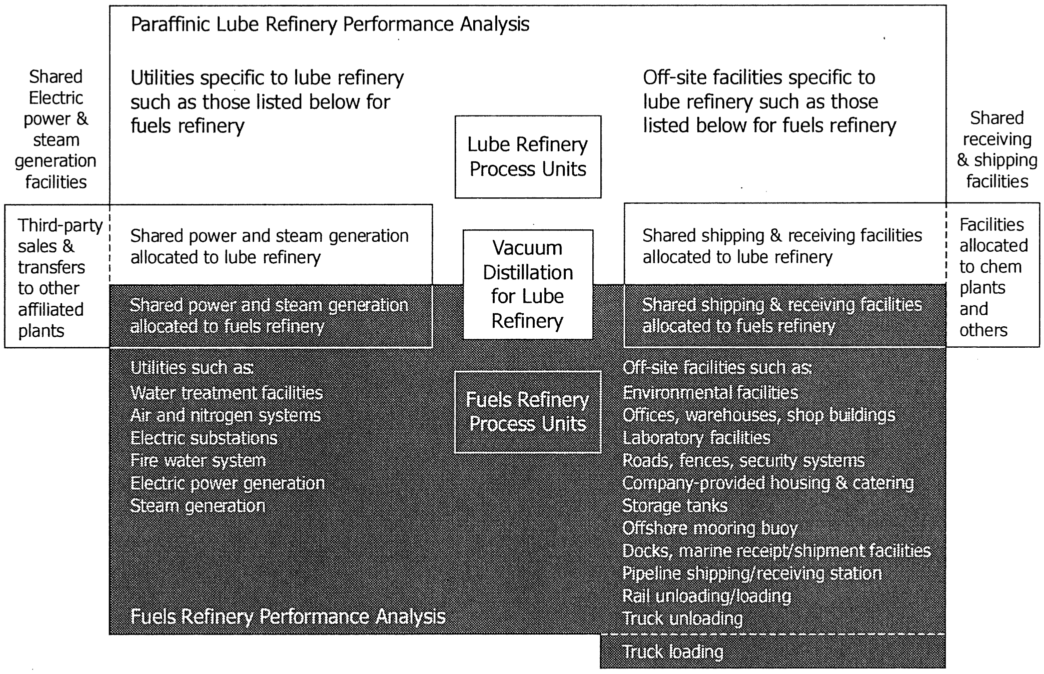

Figure 2. A Shared Complex Between a Fuels Refinery and a Lube Refinery

In this example, vacuum distillation may be either included as a fuels refinery function or excluded as a lubricant refinery function. For participants in both Solomon's *Fuels Study* and *Lube Study*, Solomon provides a consolidated report covering the integrated fuels/lube complex. Similarly, the CWB method can accommodate either a fuels refinery or an integrated fuels/lube complex. If electric power and steam generation systems are shared with non-refinery facilities, only the portion of the capacity required for the refinery under study is included. If raw material receiving or product shipment facilities are shared, allocation is also required for the refinery under study. Refer to Appendix D for complete listings of refinery process types and functions covered in the CA-CWB methodology, per Solomon definition.

Figure 3 illustrates how the CWB method applies to the physical boundary described above. The boundary condition for CWB is basically on a "Total Emissions" basis, including indirect emissions for purchased steam and electricity (but excludes by-product emissions due to imported hydrogen).

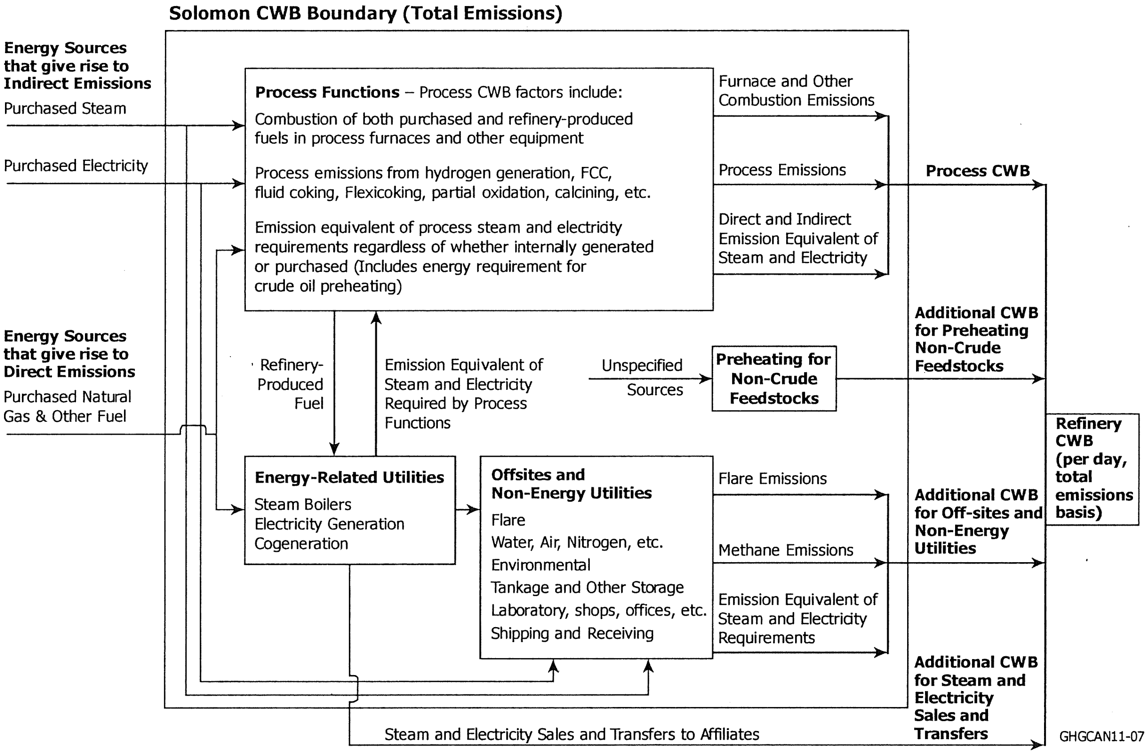

Figure 3. CWB Boundary Conditions

Figure 4 illustrates the difference in boundary conditions between Solomon's CWB and EU-CWT methodologies. The key difference is that electricity generation (in any form, either conventional or cogeneration) is carved out per EU ETS requirement.

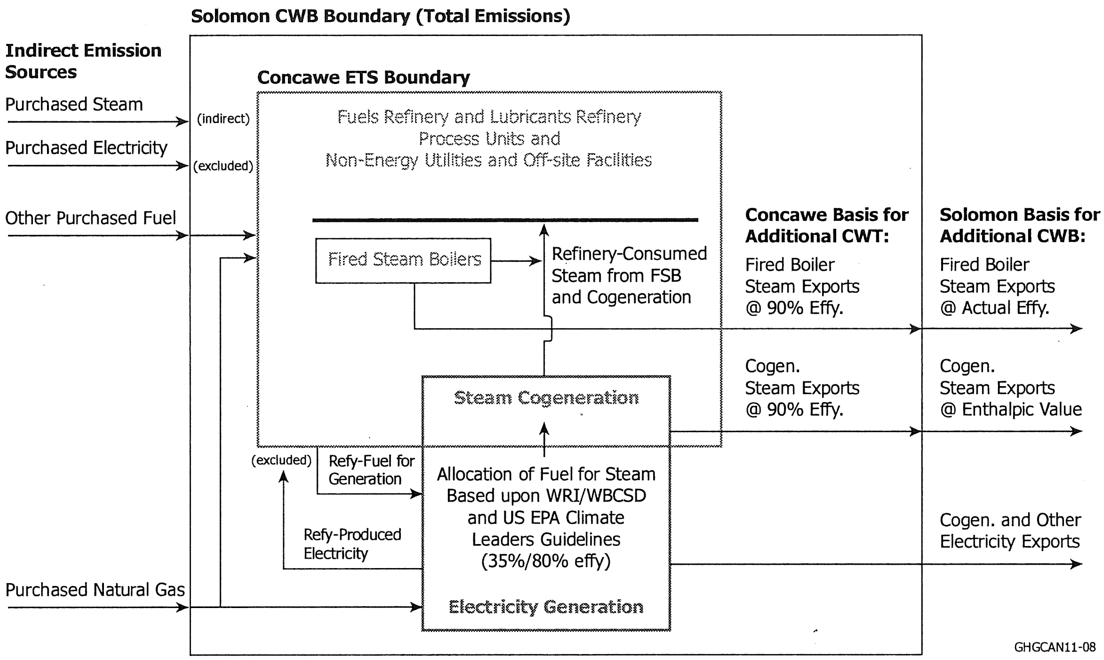

Figure 4. CWB vs CWT Boundary Conditions

In the CWB method, all purchased fuels, refinery-produced fuels, and process emissions of facilities located within its refinery boundary are included, as well as the emission equivalent of purchased steam and electricity, on a "Total Emissions" basis. The EU-CWT method developed for CONCAWE further excludes *on-site* emissions from fuels consumed in electricity generation within the refinery boundary. For refineries with cogeneration facilities, a specific method based on World Resources Institute (WRI) and World Business Council for Sustainable Development (WBCSD) is employed to allocate emissions from electricity generation and steam generation, respectively. The EU-CWT method also employs a refinery-specific electricity utilization factor (EUF) to make appropriate adjustments for the extent of on-site electricity consumption.

2.5 CWB Calculations

In this section, the calculation of Total CWB for a refinery is discussed.

There are four components in calculating the Total CWB for a refinery:

- Process CWB – CWB for all refining process units
- Off-Sites and Non-Energy Utilities – CWB credit for supporting off-site facilities and utilities (excluding steam and electricity) allocated based on the refinery Process CWB and total input barrels (including both crude and non-crude inputs)
- Non-Crude Sensible Heat – CWB credit for heating up non-crude raw materials into a refinery

- Adjustments for Sales and Exports of Steam and Electricity – CWB credit for thermal equivalent of exported steam and electricity

2.5.1 Process CWB

For each process unit, CWB is calculated by multiplying actual process unit throughput by a dimensionless coefficient, i.e., the CWB factor, and is thus expressed in barrels per day (b/d). The CWB factor is the ratio of CO_2e emissions standard per barrel for a certain process unit over the CO_2e emissions standard per barrel for a crude distillation unit. Appendix C summarizes the CWB factors for various process units and types included in the CA-CWB methodology, mapped to Solomon definition of standard refining process units. This extensive list encompasses all process units reported by California refineries in Solomon's *Fuels Study* and *Lube Study*.

Because GHG emissions originate mostly from energy consumption, the CO_2e emissions standard for a certain process unit is determined by its *energy standard* multiplying the CO_2 emission factor of the fuel. For each major refinery function, the standard energy requirement is determined by the weighted-average EII standard energy of all relevant process units operated by participating refineries located in developed economies, in operating year 2006. Pipeline natural gas with a CO_2 emission factor of 0.059 tonne CO_2/MBtu is the reference fuel used to convert EII standard energy to emissions standard regardless of geographic location or actual fuel mix.[3] EII standard energy includes all of the energy required for a refinery regardless of whether it gives rise to direct CO_2e emissions on site.

As examples, below are the descriptions of CWB factors for three major process units or functions:

- Atmospheric Crude Distillation – Its emissions standard is calculated by the average EII standard energy (Solomon proprietary information) for atmospheric crude distillation units in Solomon's *Fuels Study* database, in k Btu per barrel of throughput, multiplying the CO_2 emission factor of 0.059 tonne CO_2/MBtu for pipeline natural gas. Since all CWB factors are relative to CO_2 emissions per barrel of atmospheric crude distillation, the factor for a CDU is precisely 1.00.
- Vacuum Distillation – Its CWB factor, 0.91, represents the ratio of its emission standard, i.e., the average EII standard energy for all vacuum distillation units multiplying the CO_2 emission factor of 0.059 tonne CO_2/MBtu for pipeline natural gas, to the emission standard for CDU.
- Fluid Catalytic Cracker (FCC) – The evaluation of the CWB factor for a FCC is more complicated. The emission standard of a FCC is based on a proprietary multi-variable function statistically derived from nearly one thousand (1,000) reactor-years of FCC in Solomon's *Fuels Study* database, depending on variables such as the unit type, ConCarbon, UOP-K factor, etc. The resulting expression for its CWB factor is simplified as $1.15 + 1.041\times$ FCC Coke on Catalyst vol %. For example, for a FCC unit with coke on catalyst consumption equal to 5 vol% of fresh feed, its CWB factor would be 6.355.[4]

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[3] Pipeline natural gas is the reference fuel used in the CWB methodology. The average mix of fuels consumed by EU refineries is the reference fuel for EU-CWT factors, with a CO_2 emission factor of 65.21 tonne CO_2/TJ or 0.069 tonne CO_2/MBtu.

[4] The EU-CWT factors for FCC units are further simplified. It is a constant based on average EU refineries' coke on catalyst rather than calculated by actual coke on catalyst yield for each refinery. Other process unit simplifications in EU-CWT factors include combining kerosene and diesel hydrotreating into one single factor, using EU average by-product CO_2 emissions for both steam-methane reforming and steam-naphtha reforming, and eliminating the requirement to separately identify and quantify capacity for most special fractionation units.

The summation of CWB's for all refinery process units or functions yields the total Process CWB for a refinery:

$$\text{Process CWB} = \Sigma\ (\text{Daily Throughput Barrel} \times \text{CWB Factor})$$

2.5.2 Off-Sites and Non-Energy Utilities

The "Off-Sites and Non-Energy Utilities" component of CWB include the emissions standard arising from the energy requirements for "Off-Sites and Utilities", such as product and intermediate movements, water treatment, air compression, other non-fired utilities, environmental treatment facilities, tankage outside battery limits, flares, truck, rail, and marine shipping facilities, etc.

In Solomon's EII method, the standard energy (in k Btu per daily input barrel) for "Off-Sites and Utilities" is expressed as a linear equation, Constant A + (Constant B × Complexity), where the Complexity of a refinery is calculated as the refinery Equivalent Distillation Capacity (EDC) divided by its crude distillation unit capacity.

In the CA-CWB method, a regression analysis was performed for allocating energy contribution by the refinery Complexity, in order to eliminate the need for calculating each individual refinery's Complexity. This yields the final equation for calculating CWB for "Off-Sites and Non-Energy Utilities" based on the Process CWB and total input barrels:

$$\begin{aligned}&\text{Off-Sites and Non-Energy Utilities CWB} =\\&0.327 \times \text{Total Input Barrels} + 0.0085 \times \text{Process CWB}\end{aligned}$$

In this equation, *Total Input Barrels* to a refinery includes the following:

- Crude oil & condensate, excluding basic sediment and water (BS&W)
- Finished product additives (dyes, diesel pour point depressants, cetane improvers, etc.)
- Antiknock compounds
- Other raw materials, including crude diluents, feedstock processed in other process units or blend stock blended into refinery products

2.5.3 Non-Crude Sensible Heat

In Solomon's EII method, a standard energy credit (in k Btu per bbl of throughput) is assigned for preheating non-crude raw materials prior to entering the process units, such as for raising the temperatures of naphtha and vacuum gas oil (VGO) streams by approximately 200–220 °F. The CWB factor for "Non-Crude Sensible Heat" is simply:

$$\text{Non-Crude Sensible Heat CWB} = 0.44 \times \text{Non-Crude Input Barrels}$$

In this equation, *Non-Crude Input Barrels* refers the daily non-crude input barrels of raw materials processed in process units, excluding returns from a lube refinery or a chemical plant within a refining/petrochemical complex, and non-processed blend stock.

2.5.4 Sales and Exports of Steam and Electricity

For a refinery, the sale and export of steam and electricity receives additional credit for CWB, because the emissions arising from purchased steam and electricity is included in Solomon's calculation of CO_2e emissions. The CWB for the steam and electricity exported or sold is calculated by a constant factor multiplying their thermal equivalents in k Btu per day:

CWB Adjustments for Sales and Exports of Steam and Electricity =
0.0125 × Thermal Equivalent in k Btu/d

The thermal equivalent of steam and electricity transferred should be reported as follows:

- Steam – Estimate the energy required to generate this steam, rather than heat content of the steam. This estimate should include boiler efficiency, boiler feedwater treatment energy, and boiler feedwater sensible heat, etc. If the steam was produced in a cogeneration unit, use the enthalpy of the vapor at pressure and temperature less saturated feedwater at 220 °F (100% efficiency). In all cases, if the condensate is not returned to the refinery condensate system, be sure to include an estimate of the energy required to produce the boiler feedwater make up from raw water.
- Electricity – If a refinery both imports and exports electricity, a factor of 9,090 Btu/kWh is used to calculate the energy required for generating the electricity sold or exported, up to the point when the quantity sold/exported is equal to the quantity purchased/imported. Since the thermal energy of all purchased/imported electricity is calculated based on 9,090 Btu/kWh, this netting method would avoid gaining from importing/exporting the electricity. If the quantity of electricity sale and export is greater than purchased/imported, the energy requirement for this difference is calculated by the refinery's weighted average efficiency for producing the electricity, i.e., the summation of Btu per kWh multiplying the MWh of each respective power generation unit (such as generators with steam condensing turbines or steam-topping turbine drivers, or fired-turbine cogen) divided by total MWh produced.

2.5.5 Total CWB for a Refinery

A refinery's Total Complexity-Weighted Throughput Barrels per day is determined as the sum of the four components described above, and can be expressed as follows:

Total CWB

= Process CWB + Off-Sites and Non-Energy Utilities CWB + Non-Crude Sensible Heat CWB + CWB Adjustments for Sales and Exports of Steam and Electricity

= Σ (Daily Throughput Barrel × CWB Factor) + 0.327 × Total Input Barrels + 0.0085 × Σ (Daily Throughput Barrel × CWB Factor) + 0.44 × Non-Crude Input Barrels + 0.0125 × Thermal Equivalent in k Btu/d

= 1.0085 × Σ (Daily Throughput Barrel × CWB Factor) + 0.327 × Total Input Barrels + 0.44 × Non-Crude Input Barrels + 0.0125 ×Thermal Equivalent in k Btu/d

Appendix F provides an example for calculation of Total CWB for a refinery in the CA-CWB.

The calculation of Total CWB requires the input of daily throughput (expressed as the utilized capacity) for all process units as defined in Solomon's *Fuels Study* and *Lube Study*, mapped to the CA-CWB methodology. A detailed description of process units and process types in each grouping, as well as the capacity basis (feed- or product-based) and unit of measure are provided in Appendix D, which sufficiently cover all process units reported by California refineries in Solomon's *Fuels Study* and *Lube Study*.

Following are a few tips for calculating the CWB for a refinery, as outlined in the calculation example (Appendix F):

- *Identify the Process Type* – For example, in calculating the CWB for the catalytic cracking process, a fluid catalytic cracking (FCC) unit was identified, i.e, Feed ConCarbon less than 2.25 wt % per Solomon definition.
- *Report the Throughput* – Per Solomon definition, the capacity for catalytic cracking units is based on fresh feed only, excluding slop and recycle rates. The daily throughput of process units was calculated based on the capacity and utilization data reported in Solomon's *Fuels Study*, i.e., annualized stream day capacity multiplying the utilization rate and then divided by 365 (or 366) days in operating year.
- *Calculate the CWB for FCC* – In this example, the FCC coke on catalyst in vol %, 4.413 vol %, was calculated from the "Full Burn Coke yield, wt % Fresh Feed" reported in Solomon's *Fuels Study*. The CWB for a FCC is calculated as 1.150+1.041×(FCC Coke on Catalyst vol %), as defined in Appendix D. This yields a refinery-specific CWB factor for FCC as 5.74, and the CWB for FCC as 353,276 b/d, in the calculation example.
- *Combine the Reporting of Process Units Under the Same Group (Streamlining)*– As defined in Appendix D, the daily throughput for the "Alkylation/Poly/Dimerol" group indicates a combined throughput on product basis for all process units under this group including polymerization of C_3 or C_3/C_4, dimersol, and alkylation with either hydrofluoric acid or sulfuric acid. Similarly, the daily throughput under "Sulfur" includes the combined throughput of product sulfur for Sulfur Recovery Unit, Tail Gas Recovery Unit, and sulfur sprung for H_2S Springer Unit.
- *Recognize CWB Embedded in Other Major Process Units* – For simplification, the CWB for certain process units are embedded in other major process units by elevating their CWB factors. For example, there are no CWB factors for ancillary lube functions such as Wax/Acid/Clay Treating, Wax Sweating, Lotox, and so on. These are allocated among other major lubricant refining units. Similarly, the CWB factors for Hydrogen Purification are allocated among Hydrogen Generation units.

The streamlining and simplification applied in the CA-CWB methodology can be further evaluated and tailored for the California refining industry as needed.

For comparison, a calculation example for CWT using Solomon's EU-CWT methodology is provided in Appendix F, for the same refinery.

2.6 Solomon's Calculation of CO_2e Emissions

Solomon's calculation of CO_2e emissions is used in the numerator of the benchmark, in both CEI and the CA-CWB method. It is calculated using the data reported by study participants in Solomon's *Fuels Study* and *Lube Study*. The CO_2 emissions equivalent for each fuel type is determined by multiplying the quantity of energy consumed (expressed in MBtu) by the appropriate CO_2 emission factor (in tonnes of CO_2 equivalent per MBtu, or tonne CO_2/MBtu).

The assignment or calculation of appropriate carbon emission factors is essential to the measurement of CO_2e emissions. A complete description of Solomon's calculation of CO_2e emissions is beyond the scope of this Report. The determination of carbon emission factors for various fuel types is briefly described as follows:

- Fuels such as ethane, propane, LPG, naphtha, distillates, pipeline natural gas, and residual fuels – based on the *API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (API Compendium)*; adjusted according to the sulfur content for residual fuels
- Refinery Fuel Gas – based on its composition as reported in Solomon's *Fuels Study*
- FCC Coke on Catalyst – derived from a proprietary multivariable, non-linear model developed by Solomon for this purpose. Independent variables used in this model include the type of FCC unit, feedstock density, coke yield, and other relevant operating parameters reported in Solomon's *Fuels Study*.
- Low-Btu Gas (LBG) – depends on the energy consumption of various types of process units that produce LBG (such as flexicoker, fluid coker, POX, hydrogen purification pressure swing adsorption off-gas)
- Marketable Coke – depends on the extent of coke calcining at the refinery

Solomon's calculation of CO_2e emissions also include CO_2 from flaring and by-product from hydrogen production and asphalt blowing. CO_2e emissions may be reduced by the amount of carbon disposed in liquefied CO_2 sale and synthesized in methanol production. The CO_2 equivalent of actual methane emissions is estimated using the US EPA's Annex F methodology. A simple estimate of the CO_2 equivalent of actual nitrous oxide (N_2O) emissions is also incorporated in Solomon's calculation. For indirect emissions from steam imports, an emission factor of pipeline natural gas, 0.059 tonne CO_2/MBtu, is used to multiply the actual energy reported on a fuel-equivalent basis. For indirect emissions from purchased electricity, a national average carbon intensity of electricity, Electricity Emission Factor (EEF), expressed in tonne CO_2e/MWh, is used for estimating emissions. Values for EEF are based on data published in the *API Compendium* and by the World Bank.

The sum of the energy-related CO_2 emissions, non-energy CO_2 emissions, indirect emissions, and the CO_2 equivalent of emissions other than carbon dioxide yields the total CO_2e emissions for the refinery. The equation below illustrates a simplified version for Solomon's estimate of actual CO_2e emissions.

$$\begin{matrix} CEI \\ CO2e \\ Actual \end{matrix} = \left[\left(\sum_{\substack{Fuel \\ Consumption}} AE_i \times CEF_i \right) + CE_{Steam} + CE_{Elect} + CE_{\substack{H2\,and \\ Other \\ Mfg.}} + CE_{Flare} + CE_{\substack{CH4 \\ and \\ N2O}} - CE_{\substack{MeOH \\ and\,CO2 \\ Sales}} \right]$$

where

- *CEI $CO_2eActual$* is Solomon's estimate of actual carbon dioxide equivalent emissions
- AE_i is the quantity of actual energy from fuel type *i* consumed on-site as reported in Solomon's *Fuels Study*
- CEF_i is CO_2 emission factor applicable to fuel type *i*
- CE_{Steam} is the quantity of actual CO_2 emissions from steam imports (indirect emissions)
- CE_{Elect} is the quantity of actual CO_2 emissions from purchased electricity (indirect emissions)

- $CE_{H_2\ and\ Other\ Mfg.}$ is the quantity of non-energy CO_2 emissions from hydrogen production and other manufacturing operations, based upon process stoichiometrics and actual unit loss rates reported in Solomon's *Fuels Study*
- CE_{Flare} is the estimate of CO_2 emission from flaring, which is based upon actual refinery flare losses and a standard CO_2 emission factor
- $CE_{CH4\ and\ N2O}$ is the estimated CO_2e of methane and nitrous oxide emissions
- $CE_{MeOH\ and\ CO_2\ Sales}$ is a reduction for carbon rejection in methanol synthesis and for sales of liquefied carbon dioxide

About Solomon Associates (www.SolomonOnline.com)

Based in Dallas, TX, Solomon is the world's leading performance improvement company for the refining industry. Solomon's greenhouse gas (GHG) benchmarking and consulting methodologies stem from the industry's largest proprietary database of energy and process units and in-depth understanding of the industry.

As a trusted industry advisor, Solomon has worked with study participants and their respective industry associations in Europe, Canada, Japan, Singapore, New Zealand, and the United States for benchmarking GHG emission efficiency. The key metrics include EII®, CEI™, CWB™, and CWT™. Services are tailored for each specific goal and objective, such as custom peer analysis, *pro forma* analysis, trend analysis, combined energy/GHG analysis, allocation studies for regulatory support, or other custom consulting services for identifying gaps and capturing improvement opportunities.

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Appendix A Roles of Solomon in Supporting CWB/CWT Application in Regulatory Use

A.1 Before the Transfer of CWB or CWT Methodology Ownership

- Solomon met with members of the Industry Association for explaining the methodology.
- Solomon met with key stakeholders and regulators for educational sessions with Q&A on the methodology.
- Solomon met with other technology firms or consultants for exchanging professional opinions.
- Solomon worked with the Industry Association in developing the region-specific methodology, such as adding additional factors, modifying the existent factors or process type consolidations (streamlining), and defining the boundary conditions. The requirements for customization would be driven by the Industry Association.
- Solomon developed a Report on the Methodology suitable for public disclosure. A Consulting Service Agreement conveyed ownership of the Report and methodology to the Industry Association and granted a perpetual, non-transferable, non-exclusive and indivisible right to use all information in the Report for the purpose of GHG regulations, limited to the particular region.

A.2 After the Transfer of CWB or CWT Methodology Ownership

On an as-needed basis,

- Solomon assisted the Industry Association in performing internal industry review meetings to work out details on key assumptions, process type consolidations, unique process unit considerations, harmonization of metrics, etc.
- Solomon assisted the Industry Association in developing the strategy for carrying the methodology forward to the regulatory arena.
- Solomon assisted the Industry Association in discussions with regulators and government sub-groups/committees to review and seek approval.
- Solomon assisted the Industry Association in responding to inquiries from regulatory agencies following detailed technical reviews by outside technical reviewers.
- Solomon assisted the Industry Association in continued performance benchmarking and review & update of the factors.

Appendix B Comparison Matrix

Comparison of CA-CWB, EU-CWT, and CONCAWE EU-CWT

	CA-CWB	**Solomon EU-CWT** (1)	**CONCAWE EU-CWT** (1)
Owner	WSPA	Solomon	CONCAWE
Region	Applied to California Refineries	Developed for European Refineries	Applied to European Union (EU) Refining Industry
Year Developed	2013	2008–2009	Transferred to CONCAWE in 2009 (1)
Foundation	Solomon EII® Methodology	Solomon EII® Methodology	Solomon EII® Methodology
Basis	Throughput	Throughput	Throughput
Operating Characteristics for Grouping	>200 Select OECD Refineries (2006)	>200 Select OECD Refineries (2006)	>200 Select OECD Refineries (2006)
Units of Measure	barrels per day	tonnes per day	tonnes per day
Reference Fuel	Pipeline Natural Gas (0.059 tonne CO_2/MBtu)	EU Average Fuel Mix (0.069 tonne CO_2/MBtu)	EU Average Fuel Mix (0.069 tonne CO_2/MBtu)
Boundary Condition(s)	Total Emissions (2)	EU GHG ETS* Directive (excluding on-site electricity production)	EU GHG ETS* Directive (excluding on-site electricity production)
Level of Complexity (3)	Higher	Simplified vs CWB	Simplified vs CWB
Number of Factors for Process Units	~60	~52	*56 (a few added by CONCAWE)*
Factors for Fluid Catalytic Cracking (4)	3	1	1
Factors for Hydrogen Production (4)	3	2	2
r^2 for Regression Analysis (5)	0.97	0.92	Expected to be similar to Solomon EU-CWT
Emissions	CO_2-equivalent	CO_2	CO_2
Factor Adjustments by Feed/Product Quality	None	Customized using EU Refineries' Average Properties	Customized using EU Refineries' Average Properties

* ETS = Emissions Trading Scheme

(1) Solomon EU-CWT was developed specifically for CONCAWE. The ownership was transferred to CONCAWE in 2009.

(2) Total Emissions include indirect emissions from purchased steam and electricity.

(3) Solomon's proprietary CEI™ is the most complete and rigorously calculated methodology for benchmarking GHG emissions efficiency. Solomon's CEI, CWB, and EU-CWT all originate from the EII methodology. The level of complexity is CEI > CWB > EU-CWT.

(4) In CWB, there are three factors for FCC, based on FCC Coke on Catalyst (vol %) and type of FCC for individual refineries. In EU-CWT, the factor for FCC is simplified as one constant based on EU average. Other process unit simplifications in EU-CWT factors include combining kerosene and diesel hydrotreating into one single factor, using EU average by-product CO_2 emissions for both steam-methane reforming and steam-naphtha reforming, and eliminating the requirement for reporting most special fractionation units separately.

(5) Referred to a regression analysis (data from Solomon's *Fuels Study* and *Lube Study*) for the correlation between Solomon's calculation for CO_2e emissions and CWB for all select OECD refineries for operating year 2010; or between Solomon's calculation for CO_2 emissions and EU-CWT for all EU refineries for operating year 2006.

Appendix C Comparison of CWB and CWT Factors for Process Units (CA-CWB vs Solomon EU-CWT)

A side-by-side comparison of CWB factors (in CA-CWB) and CWT factors (in Solomon EU-CWT) is provided in the following table. This is for sole use in California regulatory support.

	Units of Measure (1)	CWB Factor	CWB Factor, FCC Coke on Catalyst			Units of Measure (1)	CWT Factor
Atmospheric Crude Distillation	T b/cd	1.00	▨		Atmospheric Crude Distillation	tonne/cd	1.00
Vacuum Distillation	T b/cd	0.91	▨		Vacuum Distillation	tonne/cd	0.85
Visbreaker	T b/cd	1.60	▨		Visbreaker	tonne/cd	1.40
Delayed Coker	T b/cd	2.55	▨		Delayed Coker	tonne/cd	2.20
Fluid Coking			▨		Fluid Coking		
Fluid Coker	T b/cd	10.30	▨		Fluid Coker	tonne/cd	7.60
Flexicoker	T b/cd	23.60	▨		Flexicoker	tonne/cd	16.60
Catalytic Cracking					Catalytic Cracking		
FCC	T b/cd	1.15	1.041		FCC	tonne/cd	5.50
Mild Residual FCC	T b/cd	0.66	1.1075		Mild Residual FCC	tonne/cd	5.50
Residual FCC	T b/cd	0.00	1.1765		Residual FCC	tonne/cd	5.50
Other FCC	T b/cd	4.65	▨		Other FCC	tonne/cd	4.10
Thermal Cracking	T b/cd	2.95	▨		Thermal Cracking	tonne/cd	2.70
Naphtha/Distillate Hydrocracker	T b/cd	3.15	▨		Naphtha/Distillate Hydrocracker	tonne/cd	2.85
Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	T b/cd	4.40	▨		Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	tonne/cd	3.75
Naphtha Hydrotreater	T b/cd	0.91	▨		Naphtha Hydrotreater	tonne/cd	1.10
Kerosene Hydrotreater	T b/cd	0.75	▨		Kerosene Hydrotreater	tonne/cd	0.90
Diesel/Selective Hydrotreater	T b/cd	0.90	▨		Diesel/Selective Hydrotreater	tonne/cd	0.90
Residual Hydrotreater	T b/cd	1.80	▨		Residual Hydrotreater	tonne/cd	1.55
VGO Hydrotreater	T b/cd	1.00	▨		VGO Hydrotreater	tonne/cd	0.90
Reformer – including AROMAX	T b/cd	3.50	▨		Reformer – including AROMAX	tonne/cd	4.95
Solvent Deasphalter	T b/cd	2.80	▨		Solvent Deasphalter	tonne/cd	2.45
Alkylation / Poly / Dimersol	P b/cd	5.00	▨		Alkylation / Poly / Dimersol	P tonne/cd	7.25
C_4 Isomer Production	P b/cd	1.25	▨		C_4 Isomer Production	P tonne/cd	3.25
C_5/C_6 Isomer Production – including ISOSIV	P b/cd	1.80	▨		C_5/C_6 Isomer Production – including ISOSIV	P tonne/cd	2.85
Coke Calciner	ST/cd	96.00	▨		Coke Calciner	P tonne/cd	12.75
Hydrogen Generation			▨		Hydrogen Generation		

	Units of Measure [1]	CWB Factor	CWB Factor, FCC Coke on Catalyst			Units of Measure [1]	CWT Factor
Steam-Methane Reforming	k SCF/cd	5.70			Gas Feed	tonne/cd	296.00
Steam-Naphtha Reforming	k SCF/cd	6.70			Naphtha Feed	tonne/cd	348.00
Partial Oxidation	k SCF/cd	7.10			POX Syngas to H_2 or Methanol	tonne SG/cd	44.00
					Air Separation Plant	k nm^3 O_2/cd	8.80
POX Syngas for Fuel	k SCF/cd	2.75			POX Syngas for Fuel	tonne SG/cd	8.20
Sulfur	LT/cd	140.00			Sulfur	tonne/cd	18.60
Aromatics Production (All)	T b/cd	3.30			Aromatics Production (All)	P tonne/cd	5.25
Hydrodealkylation	P b/cd	2.50			Hydrodealkylation	P tonne/cd	2.45
Toluene Disproportionation / Transalkylation	P b/cd	1.90			Toluene Disproportionation / Transalkylation	P tonne/cd	1.85
Cyclohexane Production	P b/cd	2.80			Cyclohexane Production	P tonne/cd	3.00
Xylene Isomerization	P b/cd	1.90			Xylene Isomerization	P tonne/cd	1.85
Paraxylene Production	P b/cd	6.50			Paraxylene Production	P tonne/cd	6.40
Ethylbenzene Production	P b/cd	1.60			Ethylbenzene Production	P tonne/cd	1.55
Cumene Production	P b/cd	5.00			Cumene Production	P tonne/cd	5.00
Lubricants					Lubricants		
Solvent Extraction	T b/cd	2.20			Solvent Extraction	tonne/cd	2.10
Solvent Dewaxing	T b/cd	4.55			Solvent Dewaxing	tonne/cd	4.55
Catalytic Dewaxing	T b/cd	1.60			Wax Isomerization	tonne/cd	1.60
Lube Hydrocracking	T b/cd	2.50			Lube Hydrocracking	tonne/cd	2.50
Wax Deoiling	T b/cd	11.80			Wax Deoiling	tonne/cd	12.00
Lube and Wax Hydrofining	T b/cd	1.15			Lube and Wax Hydrofining	tonne/cd	1.15
Asphalt Production	P b/cd	2.70			Asphalt Production	P tonne/cd	2.10
Oxygenates	P b/cd	4.90			Oxygenates	P tonne/cd	5.60
Methanol Synthesis	P b/cd	(36.00)			Methanol Synthesis	P tonne/cd	(36.20)
CO_2 Liquefaction	ST/cd	(160.00)			CO_2 Liquefaction	tonne/cd	(19.20)
Desalination	k gal/cd	32.70			Desalination	P tonne/cd	1.15
Special Fractionation	T b/cd	0.80			Special Fractionation – Purchased NGL Only	tonne/cd	1.00

	Units of Measure [1]	CWB Factor	CWB Factor, FCC Coke on Catalyst			Units of Measure [1]	CWT Factor
Propane/Propylene Splitter (Propylene Production)	P b/cd	2.10			Propane/Propylene Splitter (Propylene Production)	tonne/cd	3.45
Fuel Gas Sales Treating & Compression	hp	2.52			Fuel Gas Sales Treating & Compression	kW	0.45
Sulfuric Acid Regeneration	ST/cd	37.80					
Ammonia Recovery Unit	ST/cd	453.00					
Cryogenic LPG Recovery	k SCF/cd	0.25					
Flare Gas Recovery	k SCF/cd	0.13					
Flue Gas Desulfurizing	k SCF/cd	0.02					
					Solvents		
					Solvent Hydrotreating	tonne/cd	1.25
					Solvent Fractionation	tonne/cd	0.90

[1] Please refer to Appendix G.

Appendix D Solomon Definition of Standard Refining Process Units and CWB Factors

Solomon definitions of standard refining process units and the corresponding CWB factors in CA-CWB are provided in the following table. This list is for the sole use by California refineries only, encompassing all process units in California refineries reported in Solomon's *Fuels Study* and *Lube Study*.

Processing Facilities	Process Type	Process ID	Process Type ID	Feed	Products	Typical Equipment	Capacity Basis	Unit of Measure	CWB Factor
Atmospheric Crude Distillation	Mild Crude Unit	CDU	MCU	Crude Oil, Condensate, & Commingled Liquids	Fuel Gas, Propane, Mixed Butanes, Light & Heavy Naphtha, Kerosene, Diesel, Atmospheric Gas Oil, & Atmospheric Resid	Heaters, Preflash Tower, Outboard Flash Tower, Desalters, Crude Distillation Column, Sidestream Stripper Columns, Pumparound Circuits, Merox Treating, Saturate Gas Plant (including: Gas Compression, Absorber, Stripper, Deethanizer, Depropanizer, Debutanizer, Naphtha Splitter, & Sour Water Stripper)	Feed	b/sd	1.00
	Standard Crude Unit	CDU	SCU						
Vacuum Distillation	Mild Vacuum Fractionation	VAC	MVU	Atmospheric Resid	Fuel Gas, Vacuum Gas Oils to Vacuum Resid	Heater, Vacuum Distillation Column, multiple towers in series counted as one unit	Feed	b/sd	0.91
	Standard Vacuum Column	VAC	VAC						
	Vacuum Fractionating Column	VAC	VFR						
	Vacuum Flasher Column	VAC	VFL						
	Heavy Feed Vacuum Unit	VAC	HFV						
Visbreaking	Processing Atmospheric Resid (w/o a Soaker Drum)	VBR	VAR	Atmospheric or Vacuum Resid	Fuel Gas, Naphtha, Distillates, Heavy Gas Oil, & Resid	Furnace, Soaker Drum, Atmospheric Product Fractionator, Sidestream Column	Feed	b/sd	1.60
	Processing Atmospheric Resid (with a Soaker Drum)	VBR	VARS						
	Processing Vacuum Bottoms Feed (w/o a Soaker Drum)	VBR	VBF						
	Vacuum Bottoms Feed (with a Soaker Drum)	VBR	VBFS						
Coking	Fluid Coking	COK	FC	Vacuum Resid	Fuel Gas, C_3s, C_4s, Naphtha, Distillates, Heavy Gas Oil, Coke	Reactor, Coke Handling, Coke Burner, Fractionator, Light Ends Processing (incl. Unsat Gas Plant), Waste Heat Steam Generation, CO Boiler	Feed	b/sd	10.30
	Flexicoking	COK	FX	Vacuum Resid	Fuel Gas, C_3s, C_4s, Naphtha, Distillates, Heavy Gas Oil, Low-Btu Gas	Reactor, Coke Burner, Gasifier, Fractionator, Light Ends Processing, Waste Heat Steam Generation	Feed	b/sd	23.60
	Delayed Coking	COK	DC	Vacuum Resid	Fuel Gas, C_3s, C_4s, Naphtha, Distillates, Heavy Gas Oils, Coke	Heater, Coke Drums, Fractionator, Sidestream Column, Light Ends Processing (incl. Unsat Gas Plant), Coke Cutting (Resources for coke handling & storage are reported separately)	Feed	b/sd	2.55
Thermal Cracking	Thermal Cracking	TCR		Vacuum Gas Oil	Fuel Gas, Naphtha, Distillates, Heavy Gas Oil, & Bottoms	Gas Oil Furnace, Product Fractionator	Feed	b/sd	2.95
Catalytic Cracking	Fluid Catalytic Cracking (Feed ConCarbon <2.25 wt %)	FCC	FCC	Vacuum Gas Oil, Atmospheric Resid	Fuel Gas, C_3s, C_4s, Gasoline, Cycle Oils, Decant Oil	Feed Preheater, Reactor, Fractionator, Regenerator, CO Boiler, Waste Heat Steam Generator, Tertiary Flue Gas Separator, Electrostatic Precipitators, Catalyst Hoppers	Feed	b/sd	1.150+1.041×(FCC Coke on Catalyst vol %)
	Mild Residual Catalytic Cracking (Feed ConCarbon 2.25–3.5 wt %)	FCC	MRCC				Feed	b/sd	0.6593+1.1075×(FCC Coke on Catalyst vol %)
	Residual Catalytic Cracking (Includes two-stage regeneration; Feed ConCarbon ≥3.5 wt %)	FCC	RCC				Feed	b/sd	1.1765×(FCC Coke on Catalyst vol %)
	Houdry Catalytic Cracking	FCC	HCC				Feed	b/sd	4.65
	Thermofor Catalytic Cracking	FCC	TCC						
Naphtha/Distillate Hydrocracking	Mild Hydrocracking (Normally less than 1,500 psig and consumes between 100 and 1,000 SCF H_2/b)	HYC	HMD	Heavy Naphthas through Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Light & Heavy Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heater; Reactors; Fractionator; Hydrogen Compression, Scrubbing & Recycle	Feed	b/sd	3.15
	Severe Hydrocracking (Normally more than 1,500 psig and consumes more than 1,000 SCF H_2/b)	HYC	HSD			Saturate Gas Plant (including: Fuel Gas Treating, Absorber Stripper, Deethanizer, Depropanizer, Debutanizer, Deisobutanizer, Naphtha Splitter, Sour Water Stripper)			
	Naphtha Hydrocracking	HYC	HNP						
H-Oil	H-Oil	HYC	HOL	Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heaters; Reactors; Regenerator; CO Boiler; Hydrogen Compression, Scrubbing & Recycle; Catalyst Hoppers; Atmospheric & Vacuum Fractionation	Feed	b/sd	4.40
LC-Fining™ and Hycon	LC-Fining™ and Hycon	HYC	LCF	Atmospheric or Vacuum Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heaters; Reactors; Hydrogen Compression, Scrubbing & Recycle; Atmospheric & Vacuum Fractionation	Feed	b/sd	4.40

Processing Facilities	Process Type	Process ID	Process Type ID	Feed	Products	Typical Equipment	Capacity Basis	Unit of Measure	CWB Factor
Gasoline/Naphtha Desulfurization & Treating	Benzene Saturation	NHYT	BSAT	Naphtha/Gasoline, Hydrogen	Low Benzene Content Naphtha/Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System	Feed	b/sd	0.91
	Desulfurization of C_4–C_6 Feeds	NHYT	C4C6	C_4–C_6, hydrogen	Fuel Gas, Low Sulfur C_4–C_6	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Conventional Naphtha Hydrotreating	NHYT	CONV	Naphtha, Gasoline, Hydrogen	Fuel gas, Low sulfur naphtha, gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Diolefin to Olefin Saturation of Gasoline	NHYT	DIO	Light Naphtha, Hydrogen	Treated Light Naphtha	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	FCC Gasoline Hydrotreating with Minimal Octane Loss	NHYT	GOCT	Heavy FCC Naphtha/Gasoline, Hydrogen	Fuel Gas, Low Sulfur Heavy FCC Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Olefinic Alkylation of Thiophenic Sulfur	NHYT	OATS	Full range FCC Naphtha/Gasoline	Low Sulfur FCC Gasoline	Exchangers, Reactors, Separators, & Recycling System			
	Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization	NHYT	PYGC	Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low-Sulfur, Low-Olefin Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Pyrolysis Gasoline/Naphtha Desulfurization	NHYT	PYGD	Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low Sulfur Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization	NHYT	PYGS	Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low Olefin Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	Reactor for Selective Hydrotreating	NHYT	RXST	Light FCC Naphtha/Gasoline	Low Sulfur Light FCC Gasoline	Reactors			
	S-Zorb™ Process	NHYT	ZORB	Full range FCC Naphtha/Gasoline	Low Sulfur FCC Gasoline	Heater, Reactor, Recycle Compressor, Exchangers, Separators, Stabilizer, & Sorbent Regenerator			
Kerosene Desulfurization & Treating	Aromatic Saturation of Kerosene	KHYT	ASAT	Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Reactor, Separator, Stripper/Stabilizer, Hydrogen Compression & Recycle System	Feed	b/sd	0.75
	Conventional Hydrotreating of Kerosene/Jet Fuel	KHYT	CONV	Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System			
	High Severity Hydrotreating of Kerosene/Jet Fuel	KHYT	KUS	Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
Distillate Desulfurization & Treating	Aromatic Saturation of Distillates	DHYT	ASAT	Low Sulfur Distillate, Hydrogen	Low Olefins Distillate	Heater, Reactor, Separator, Stripper/Stabilizer, Hydrogen Compression & Recycle System	Feed	b/sd	0.90
	Conventional Distillate Hydrotreating	DHYT	CONV	Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
	High Severity Distillate Hydrotreating	DHYT	DHS	Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
	Ultra-High Severity Hydrotreating	DHYT	DUS	Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
	Middle Distillate Dewaxing	DHYT	MDDW	Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Wax Content Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
	S-Zorb™ Process	DHYT	ZORB	Distillate/Gasoil	Low Sulfur Distillate	Heater, Reactor, Recycle Compressor, Exchangers, Separators, Stabilizer, & Sorbent Regenerator			

Processing Facilities	Process Type	Process ID	Process Type ID	Feed	Products	Typical Equipment	Capacity Basis	Unit of Measure	CWB Factor
Selective Hydrotreating	Diolefin to Olefin Saturation of Alkylation Feed	SHYT	DIO	C_3s, C_4s, C_5s containing Dienes & Acetylenes, Light Cracked Gasoline, Light Distillate, Hydrogen	C_3s, C_4s, C_5s with no Dienes or Acetylenes, Low-Olefin Cracked Gasoline, Light Distillate	Reactor	Feed	b/sd	0.90
	Selective Hydrotreating of Distillate Fuels	SHYT	DIST	Distillate	Low Contaminant Distillate	Heater, Reactor, Separator, Stripper/Stabilizer			
Residual Desulfurization	Desulfurization of Atmospheric Resid	RHYT	DAR	Hydrogen, Atmospheric Resid	Fuel Gas, Atmospheric Resid	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System	Feed	b/sd	1.80
	Desulfurization of Vacuum Resid	RHYT	DVR	Hydrogen, Vacuum Resid	Fuel Gas, Vacuum Resid	Heater, Guard Bed, Reactor, Separators, Hydrogen Compression & Recycle System			
Cracking Feed or Vacuum Gas Oil Desulfurization	Cracking Feed or Vacuum Gas Oil Hydrodesulfurization and Hydrodenitrification	VHYT	VHDN	Vacuum Gas Oil/Cracking Feed, Hydrogen	Fuel Gas, Distillate, Vacuum Gas Oil/Cracking Feed	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System	Feed	b/sd	1.00
	Cracking Feed or Vacuum Gas Oil Hydrodesulfurization	VHYT	VHDS	Vacuum Gas Oil/Cracking Feed, Hydrogen	Fuel Gas, Distillate, Vacuum Gas Oil/Cracking Feed	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System			
Catalytic Reforming	Continuous Regeneration	REF	RCR	Naphtha	Fuel Gas, Butanes, Reformate, Hydrogen	Heaters, Reactors, Regenerator, Debutanizer, Light Ends Processing, Hydrogen Compression & Recycle System	Feed	b/sd	3.50
	Cyclic	REF	RCY						
	Semi-Regenerative	REF	RSR						
AROMAX®	AROMAX	U60							
Fuels Solvent Deasphalting	Conventional Solvent	SDA	CONV	Resid, Solvent	Deasphalted Oil, Asphalt	Heater plus Contactors & Separators or Extraction Column & Strippers, Solvent Recovery	Feed	b/sd	2.80
	Supercritical Solvent	SDA	SCRT						
Alkylation	Polymerization of C_3 Olefin Feed	POLY	PC3	Propane/Propylene	LPG, Polymer Naphtha, Low-Boiling Paraffins	Reactors, Product Fractionator	C5+ Product	b/sd	5.00
	Polymerization of C_3/C_4 Feed	POLY	PMIX	Mixed C_3 & C_4 Olefins & Paraffins	LPG, Polymer Naphtha, Low-Boiling Paraffins	Reactors, Product Fractionator			
	Dimersol	DIM		Propane/Propylene	Dimate (Nonene), LPG	Reactors, Catalyst Removal, Stabilizer, Fractionator			
	Alkylation with Hydrofluoric Acid	ALKY	AHF	Olefins, Isobutane	Alkylate, Normal Butane, Isobutane, Propane	Feed Drums, Acid Contactor, Acid Recovery, Acid Regeneration (HF only), Depropanizer, Debutanizer, Deisobutanizer, Refrigeration System	C5+ Alkylate	b/sd	
	Alkylation with Sulfuric Acid	ALKY	ASA						
Sulfuric Acid Regeneration	Sulfuric Acid Regeneration	ACID		Spent Acid	Sulfuric Acid	Combustor, Waste Heat Boiler, Converter, Absorber, SO3 Recycle, Gas Cleaning including Electrostatic Precipitator, Amine Regenerator	Product	ST/sd	37.80
Aromatics Production	Aromatic Solvent Extraction: Extraction Distillation	ASE	ED	C_6–C_8 Aromatic Rich Stream from Reformate or Pyrolysis Gasoline	High Purity Aromatic Stream	Extractor, Raffinate Wash, Stripper, Recovery Column, Solvent Regenerator, Water Stripper, Clay Treaters	Feed	b/sd	3.30
	Aromatic Solvent Extraction: Liquid/Liquid Extraction	ASE	LLE				Feed	b/sd	
	Aromatic Solvent Extraction: Liquid/Liquid Extraction w/ Extraction Distillation	ASE	LLED				Feed	b/sd	
	Benzene Column	BZC		Mixed C_6+ Aromatics from extraction process	Benzene (95+%), C_7+ Aromatics	Fractionating Column	Feed	b/sd	
	Toluene Column	TOLC		Mixed C_7+ Aromatics from extraction process	Toluene, C_8+ Aromatics	Fractionating Column	Feed	b/sd	
	Xylene Rerun Column	XYLC		Mixed C_8+ Aromatics	Mixed Xylenes, C_9+ Aromatics	Fractionating Column	Feed	b/sd	
	Heavy Aromatics Column	HVYARO		Mixed C_9+ Aromatics	C_9 Aromatics, C_{10}+ Aromatics	Fractionating Column	Feed	b/sd	
Hydrodealkylation	Hydrodealkylation	HDA		Toluene, Heavy Alkylbenzenes, Hydrogen	Mixed Benzene & Heavy Aromatics	Heater, Reactor, Separator, Stripper, Clay Treaters, Fractionators, Hydrogen Compression	Feed	b/sd	2.50
Toluene Disproportionation/ Transalkylation	Toluene Disproportionation / Transalkylation	TDP/TDA		Toluene, C_9 Aromatics, Hydrogen	Mixed Benzene, C_8 Aromatics, C_{10}+ Aromatics	Heater, Reactor, Clay Treating, Light Ends Stripper, Separator, Recycle Gas Compressor	Feed	b/sd	1.90
Cyclohexane Production	Cyclohexane	CYC6		Benzene, Hydrogen	Cyclohexane	Reactor, Separator, Stabilizer, Steam Generator, Recycle Compressor, Makeup Compressor	Cyclohexane Product	b/sd	2.80

Processing Facilities	Process Type	Process ID	Process Type ID	Feed	Products	Typical Equipment	Capacity Basis	Unit of Measure	CWB Factor
Xylene Isomerization	Xylene Isomerization	XYISOM		Mixed Xylenes low in p-xylene content, Hydrogen	Mixed Xylenes in Equilibrium	Heater, Reactor, Stabilizer, Deheptanizer	Feed	b/sd	1.90
Paraxylene Production	Paraxylene: Adsorption	PXYL	ADS	Mixed Xylenes	p-Xylene, Mixed Xylenes low in p-Xylene Content	Adsorption Chamber, Rotary Valve, Extract & Raffinate Columns, Finishing Column	Paraxylene Product	b/sd	6.50
	Paraxylene: Crystallization	PXYL	CRY	Mixed Xylenes	p-Xylene, Mixed Xylenes low in p-Xylene Content	Crystallizers, Centrifuge	Paraxylene Product	b/sd	
	Xylene Splitter	XYLS		Mixed C_8+ Aromatics	Mixed p-/m-Xylenes, Mixed o-Xylene & C_9+ Aromatics	Fractionating Column	Feed	b/sd	
	Orthoxylene Rerun Column	OXYLRC		Mixed o-Xylene & C_9+ Aromatics	o-Xylene, C_9+ Aromatics	Fractionating Column	Feed	b/sd	
Ethylbenzene	Ethylbenzene Manufacture	EBZ		Benzene, Ethylene or Refinery Off-Gas Containing Ethylene	Ethylbenzene	Reactors, Heater, Benzene Recycle Column, Fractionator, Recycle Compressor, Makeup Compressor	Ethylbenzene Product	b/sd	1.60
	Ethylbenzene Distillation	EBZD		Mixed C_8 Stream	Ethylbenzene, Mixed C_8 Stream	Fractionator, Heat Exchange	Feed	b/sd	
Cumene	Cumene	CUM		Propylene, Benzene	Propane, Cumene, Heavy Aromatics	Reactor, Hot Oil or Steam Heater, Flash Towers, Benzene Recovery Column, Clay Treater, Fractionator	Cumene Product	b/sd	5.00
Asphalt Production	Asphalt Production	ASP		Short Resid	Fuel Gas, Asphalt	Steam Generation, Oxidizer, Air Blower, Incinerator	Total Asphalt Production	b/sd	2.70
C_4 Isomerization	C_4 Isomerization	C4ISOM		Normal Paraffins, Hydrogen	Mixed Isoparaffins & Normal Paraffins	Once through operation with no feed preparation or internal recycle of unconverted products. Heater, Reactor, Stabilizer, Hydrogen Recycle	Feed	b/sd	1.25
C_5/C_6 Isomerization	C_5/C_6 Isomerization	C5ISOM					Feed	b/sd	1.80
ISOSIV	ISOSIV	U18		Mixed C_5/C_6 Paraffins	Isoparaffins, Normal Paraffins	Sieve Beds	Feed	b/sd	1.80
Lubricants [(1)]	Extraction: Solvent is Duo-Sol	SOLVEX	DOS	Vacuum Gas Oil, Deasphalted Oil, Vacuum Tower Bottoms	Raffinates, Extracts	Heater, Extraction Tower, Raffinate and Extract Solvent Recovery	Feed	b/sd	2.20
	Extraction: Solvent is Furfural	SOLVEX	FUR						
	Extraction: Solvent is NMP	SOLVEX	NMP						
	Extraction: Solvent is Phenol	SOLVEX	PHE						
	Extraction: Solvent is SO_2	SOLVEX	SDO						
	Dewaxing: Solvent is Chlorocarbon	SDWAX	CHL	Extracted Gas Oil, Hydrocrackates, Vacuum Distillates	Dewaxed Oils, Slack Wax, Scale Wax	Solvent/Oil Refrigeration, Scraped Surface Coolers/Chillers, Filter Feed Drum, Crystallizer, Rotary Filters, Solvent Recovery, Solvent Dehydration, Solvent Splitter	Feed	b/sd	4.55
	Dewaxing: Solvent is MEK/Toluene	SDWAX	MEK						
	Dewaxing: Solvent is MEK/MIBK	SDWAX	MIB						
	Dewaxing: Solvent is propane	SDWAX	PRP						
	Catalytic Wax Isomerization and Dewaxing	CDWAX	ISO	Extracted Gas Oil, Hydrocrackates, Vacuum Distillates	Dewaxed Oils, Light Ends, Distillates	Heater, Reactor, Hydrogen Recycle and Make-up Compression , HP Separator, LP Separator, Recycle Gas Treater, Atmospheric Product Fractionation and/or Stripping. Additionally, an Iso-Dewaxer includes a Hydrofinishing Reactor and Product Stripper	Feed	b/sd	1.60
	Selective Wax Cracking	CDWAX	SWC						
	Lube Hydrocracker with Multi-fraction Distillation	LHYC	HCM	Vacuum Gas Oil	Base Oil Feedstocks, C_3 to 650 °F+ Clean Products, Fuel Gas	Heater, Reactor, Product Fractionation, Hydrogen Recycle and Make-up Compression, Hydrogen Scrubbing and Recycle, Atmospheric and Vacuum Distillation Columns	Feed	b/sd	2.50
	Lube Hydrocracker with Vacuum Stripper	LHYC	HCS						
	Lube Hydrofinishing with Vacuum Stripper	LHYFT	HFS	Raffinate or Dewaxed Oil	Base Oil Feedstocks, Dewaxed Oils, Fuel Gas	Heater, Reactor, Separators, Fractionation, Hydrogen Recycle and Make-up Compression , Atmospheric Product Fractionation and/or Stripping	Feed	b/sd	1.15
	Lube Hydrotreating with Multi-fraction Distillation	LHYFT	HTM			Heater, Reactor, Fractionation, Hydrogen Recycle and Make-up Compression , Atmospheric Product Fractionation and/or Stripping			
	Lube Hydrotreating with Vacuum Stripper	LHYFT	HTS						
	Deoiling: Solvent is Chlorocarbon	WDOIL	CHL	Slack Wax	Refined (Hard) Wax, Foots Oil/Soft Wax	Refrigeration, Rotary Filter, Solvent Recovery	Product	b/sd	11.80
	Deoiling: Solvent is MEK/Toluene	WDOIL	MEK						
	Deoiling: Solvent is MEK/MIBK	WDOIL	MIB						
	Deoiling: Solvent is propane	WDOIL	PRP						
	Wax Hydrofinishing with Vacuum Stripper	WHYFT	HFS	Refined Wax, Slack Wax, Scale Wax	HF Refined Wax, HF Scale Wax, HF Slack Wax	Heater, Reactor, Separators, Fractionation, Hydrogen Recycle and Make-up Compression	Feed	b/sd	1.15
	Wax Hydrotreating with Multi-fraction Distillation	WHYFT	HTM						
	Wax Hydrotreating with Vacuum Stripper	WHYFT	HTS						

Processing Facilities	Process Type	Process ID	Process Type ID	Feed	Products	Typical Equipment	Capacity Basis	Unit of Measure	CWB Factor
Hydrogen Generation [2]	Steam Methane Reforming	HYG	HSM	Fuel Oil, Naphtha, Natural Gas	Hydrogen, Carbon Dioxide	Desulfurizer, Heaters, Reformer or Partial Oxidizer, Shift Converter, Methanation, CO2 Rejection, Hydrogen Compression	Product	k SCF/sd	5.70
	Steam Naphtha Reforming	HYG	HSN				Product	k SCF/sd	6.70
	Partial Oxidation Units	HYG	POX				Product	k SCF/sd	7.10
Sulfur	Sulfur Recovery Unit	SRU		Acid Gas	Sulfur, Tail Gas	Burner/Reactor, Waste Heat Boiler, Converters, Condensers, Amine Unit Regenerator, Sour Water Stripper (exclude pelletizers)	Product Sulfur	LT/sd	140.00
	Tail Gas Recovery Unit	TRU		Tail Gas	Sulfur, Off-Gas	Reactor, Quench Tower, Absorber, Regenerator for SCOT Process & equivalent for other processes	Product Sulfur	LT/sd	
	H_2S Springer Unit	U32		H_2S Rich Gas, Spent Caustic	Sweet Gas, Sulfur/H_2S		Sulfur Sprung	LT/sd	
Special Fractionation[3]	All Special Fractionation ex Solvents, Propylene, and Aromatics	Various		Various	Various	Fractionator, Heat Exchange	Feed	b/sd	0.80
Oxygenates – MTBE	Distillation Units	MTBE	DIST	Methanol, C_4 Olefins	MTBE, Unreacted C_4 Olefins	Reactor & Fractionator or Catalytic Distillation Vessel	Product	b/sd	4.90
	Extraction Units	MTBE	EXT	Methanol, C_4 Olefins	MTBE, Unreacted C_4 Olefins	Reactor & Fractionator or Catalytic Distillation Vessel; Methanol Recovery & Recycle	Product	b/sd	
Oxygenates – ETBE	ETBE	ETBE		Ethanol, C_4 Olefins	ETBE, Unreacted C_4 Olefins	Reactors, Fractionator, Ethanol Extraction & Recycle	Product	b/sd	
Oxygenates – TAME	TAME	TAME		Methanol, C_4–C_6 Mixed Olefins	Mixed Ethers, Unreacted C_4–C_6 Mixed Olefins	Reactors, Fractionator, Methanol Extraction & Recycle	Product	b/sd	
Coke Calciner	Vertical-Axis Hearth	CALCIN	HRTH	Green Petroleum Coke	Calcined Coke	Combustion Chamber, Vertical Rotary Kiln, Electrostatic Precipitator or other air pollution control equipment (Coke Handling & Storage Equipment reported separately. Report Waste Heat Recovery under Fired Boilers – Solid)	Product	ST/sd	96.00
	Horizontal-Axis Rotary Kiln	CALCIN	KILN	Green Petroleum Coke	Calcined Coke	Combustion Chamber, Horizontal Rotary Kiln, Electrostatic Precipitator or other air pollution control equipment (Coke Handling & Storage Equipment reported separately. Report Waste Heat Recovery under Fired Boilers – Solid)	Product	ST/sd	
Methanol Synthesis	Methanol Synthesis	U70		Hydrogen & CO	Methanol	Reactor Section, Steam Generation, Distillation	Product	b/sd	-36.00
POX Syngas for Fuel	POX Syngas for Fuel	U73		Resid	H_2, CO, CO_2	POX Reactor, Scrubber, Soot Recovery, Gas Cleanup & Sulfur Removal	Product	k SCF/sd	2.75
	Air Separation Unit	U79		Air	Oxygen, Nitrogen	Compressor, Cold Box, Separation Equipment	Product	k SCF/sd	
Solvent Hydrotreating	Solvent Hydrotreating	U1		Solvents, Hydrogen	Treated Solvents	Reactor, Stabilizer	Feed	b/sd	N.A. (Included in Hydrotreating and Special Fractionation)
	Solvent Fractionation	SOLVF		Distillate Mixture	High Purity Solvent, By-Product Stream	Special Fractionation for Solvent Purification	Feed	b/sd	
Propane/Propylene Splitter	Chemical Grade	C3S	CHEM	Mixed C_3s	High Purity Propylene, Propane	Splitter Column	Feed	b/sd	2.10
	Polymer Grade	C3S	POLY	Mixed C_3s	High Purity Propylene, Propane, C_2- Off-Gas	Deethanizer, Splitter Column, Compressor, Driers, Treaters	Feed	b/sd	
Desalination	Desalination	DESAL		Sea or Contaminated Water	Potable Water, Brine	Heater, Boilers, Fractionation	Product	k gal/sd	32.70
CO_2 Liquefaction	CO_2 Liquefaction	CO_2		Gaseous CO_2	Liquid CO_2	Multi-Stage Compression, Dehydrators, Stripper	CO_2 Product	ST/sd	-160.00
Ammonia Recovery Unit	PHOSAM	U59		Sour Water Stripper Overhead	Ammonia, Treated Water	Adsorber, Stripper, Fractionator	Product	ST/sd	453.00
Cryogenic LPG Recovery	Cryogenic LPG Recovery	U60		Refinery Gas Streams	C_3s, C_4s, Other Gases	Refrigeration, Drier, Compressor, Absorber Stripper, Fractionation	Feed	k SCF/sd	0.25
Flare Gas Recovery	Flare Gas Recovery	U9		Waste Gases, Steam	Compressed Gases	Compressor, Separator	Feed	k SCF/sd	0.13
Fuel Gas Sales Treating & Compression	Fuel Gas Sales Treating & Compression	U31		Raw Fuel Gas	High-Pressure Sweet Fuel Gas	H_2S Absorber, Compressor, Miscellaneous Purification	Horsepower	hp	2.52
Flue Gas Desulfurizing	Flue Gas Desulfurizing	U35		Flue Gas with Contaminants	Clean Flue Gas	Contactor, Catalyst/Reagent Regeneration,Scrubbing Circulation, Solids Handling	Feed	k SCF/sd	0.02

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(1) The CWB factors for additional lubricants refinery units, such as Wax/Acid/Clay Treating, Wax Sweating, Lotox, and Rerun Vacuum Distillation are allocated among major lubricant refining units.

(2) The CWB factors for hydrogen purification units, such as Cryogenic Unit, Membrane Separation Unit, and Pressure Swing Adsorption (PSA) unit, as well as U71 (CO Shift & H_2 Purification) and U72 (POX Syngas for H_2 Generation), are allocated among Hydrogen Generation units.

(3) Special Fractionation units include the following: Deethanizer, Depropanizer, Deisobutanizer, Debutanizer, Deisopentanizer, Depentanizer, Deisohexanizer, Debutanizer, Deisopentanizer, Depentanizer, Deisohexanizer, Dehexanizer, Deisoheptanizer, Deheptanizer, Naphtha Splitter, Alkylate Splitter, and Reformate Splitter.

Appendix E Example for Calculating Total CWB for a Refinery (CA-CWB)

The following table illustrates the calculation of Total CWB for an example refinery.

	Utilized Capacity	Units of Measure(1)	CWB Factor	FCC Coke on Catalyst, vol %	CWB Factor, FCC Coke on Catalyst	CWB (b/d)
Atmospheric Crude Distillation	214,009	T b/cd	1.00			214,009
Vacuum Distillation	114,933	T b/cd	0.91			104,589
Visbreaker	-	T b/cd	1.60			-
Delayed Coker	73,236	T b/cd	2.55			186,752
Fluid Coking						
Fluid Coker	-	T b/cd	10.3			-
Flexicoker	-	T b/cd	23.6			-
Catalytic Cracking						
FCC	61,510	T b/cd	1.150	4.41	1.041	353,276
Mild Residual FCC	-	T b/cd	0.659	4.41	1.1075	-
Residual FCC	-	T b/cd	-	4.41	1.1765	-
Other FCC	-	T b/cd	4.65			-
Thermal Cracking	-	T b/cd	2.95			-
Naphtha/Distillate Hydrocracker	30,290	T b/cd	3.15			95,412
Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	-	T b/cd	4.40			-
Naphtha Hydrotreater	95,000	T b/cd	0.91			86,450
Kerosene Hydrotreater	23,100	T b/cd	0.75			17,325
Diesel/Selective Hydrotreater	70,366	T b/cd	0.90			63,329
Residual Hydrotreater	-	T b/cd	1.80			-
VGO Hydrotreater	46,930	T b/cd	1.00			46,930
Reformer – including AROMAX	30,019	T b/cd	3.50			105,066
Solvent Deasphalter	-	T b/cd	2.80			-
Alkylation / Poly / Dimersol	16,720	P b/cd	5.00			83,601
Sulfuric Acid Regeneration	-	ST/cd	37.80			
C_4 Isomer Production	-	P b/cd	1.25			-
C_5/C_6 Isomer Production – including ISOSIV	-	P b/cd	1.80			-
Coke Calciner	-	ST/cd	96			-
Hydrogen Generation						
Steam-Methane Reforming	-	k SCF/cd	5.70			-
Steam-Naphtha Reforming	-	k SCF/cd	6.70			-
Partial Oxidation	-	k SCF/cd	7.10			-
Sulfur(2)	783	LT/cd	140			109,674
Aromatics Production (All)	-	T b/cd	3.30			-
Hydrodealkylation	-	P b/cd	2.50			-
Toluene Disproportionation / Transalkylation	-	P b/cd	1.90			-
Cyclohexane Production	-	P b/cd	2.80			-
Xylene Isomerization	-	P b/cd	1.90			-
Paraxylene Production	-	P b/cd	6.50			-

	Utilized Capacity	Units of Measure(1)	CWB Factor	FCC Coke on Catalyst, vol %	CWB Factor, FCC Coke on Catalyst	CWB (b/d)
Ethylbenzene Production	-	P b/cd	1.60			-
Cumene Production	-	P b/cd	5.00			-
Lubricants						
Solvent Extraction	-	T b/cd	2.20			-
Solvent Dewaxing	-	T b/cd	4.55			-
Catalytic Dewaxing	-	T b/cd	1.60			-
Lube Hydrocracking	-	T b/cd	2.50			-
Lube Hydrofining	-	T b/cd	1.15			-
Wax Deoiling	-	T b/cd	11.80			-
Wax Hydrofining	-	T b/cd	1.15			-
Asphalt Production	-	P b/cd	2.70			-
Oxygenates	-	P b/cd	4.90			-
POX Syngas for Fuel	-	k SCF/cd	2.75			-
Methanol Synthesis	-	P b/cd	(36.00)			-
CO_2 Liquefaction	-	ST/cd	(160.00)			-
Ammonia Recovery Unit		ST/cd	453			
Desalination	-	k gal/cd	32.70			-
Special Fractionation	25,725	T b/cd	0.80			20,580
Propane/Propylene Splitter (Propylene Production)	-	P b/cd	2.10			-
Cryogenic LPG Recovery	-	k SCF/cd	0.25			
Flare Gas Recovery	-	k SCF/cd	0.13			
Fuel Gas Sales Treating & Compression	-	hp	2.52			
Flue Gas Desulfurizing	-	k SCF/cd	0.02			
Subtotal: Process CWB						**1,486,994**
Off-Sites and Non-Energy Utilities	**Total Throughput**	**Units of Measure(1)**	**CWB Factor for Throughput**		**CWB Factor for Process CWB**	
Total Input Barrels	248,128	T b/cd	0.327		0.0085	**93,777**
Non-Crude Sensible Heat	**Total Throughput**	**Units of Measure(1)**	**CWB Factor**			
Qual. Non-Crude Input Barrels	20,863	T b/cd	0.44			**9,180**
Sales and Exports of Steam and Electricity	**Thermal Equivalent**	**Units of Measure(1)**	**CWB Factor**			
Steam Transfers to Affiliates	-	k Btu/cd	0.0125			-
Steam Sales	9,165,492	k Btu/cd	0.0125			114,569
Electricity Transfers to Affiliates	-	k Btu/cd	0.0125			-
Electricity Sales	987,240	k Btu/cd	0.0125			12,340
Subtotal: CWB for Sales and Exports of Steam and Electricity						**126,909**
Total CWB						**1,716,860**

(1) Units of measure in this column are as follows:

T b/cd – Throughput on feed basis in barrels per calendar day

P b/cd – Throughput on product basis in barrels per calendar day

ST/cd – Throughput in short tons per calendar day; 1 ST = 2,000 lbs

k SCF/cd – Throughput in thousand standard cubic feet (dry @ 60 °F and 14.696 psia or 15 °C and 1 atmosphere) per calendar day

LT/cd – Throughput in long tons per calendar day; 1 LT = 2,240 lbs

k gal/cd – Throughput in thousand gallons (US liquid) per calendar day

hp – Horsepower

k Btu/cd –Thousand British thermal units per calendar day; 1 Btu = 1,055 joules

(2) Includes the combined throughput of product sulfur for Sulfur Recovery Unit and Tail Gas Recovery Unit, and sulfur sprung for H_2S Springer Unit.

Appendix F Example for Calculating Total CWT for a Refinery (Solomon EU-CWT)

The following table illustrates the calculation of Total CWT for the same example refinery used in Appendix E.

	Utilized Capacity	Units of Measure(1)	EU-CWT Factor	FCC Coke on Catalyst, wt %	CWT (tonne/d)
Atmospheric Crude Distillation	31,591	tonne/cd	1.00		31,591
Vacuum Distillation	18,525	tonne/cd	0.85		15,746
Visbreaker	-	tonne/cd	1.40		-
Delayed Coker	10,864	tonne/cd	2.20		23,900
Fluid Coking		tonne/cd			
Fluid Coker	-	tonne/cd	7.60		-
Flexicoker	-	tonne/cd	16.60		-
Catalytic Cracking		tonne/cd			
FCC	8,951	tonne/cd	5.50	4.68	49,229
Mild Residual FCC	-	tonne/cd	5.50		-
Residual FCC	-	tonne/cd	5.50		-
Other FCC	-	tonne/cd	4.10		-
Thermal Cracking	-	tonne/cd	2.70		-
Naphtha/Distillate Hydrocracker	4,667	tonne/cd	2.85		13,302
Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	-	tonne/cd	3.75		-
Naphtha Hydrotreater	9,592	tonne/cd	1.10		10,552
Kerosene Hydrotreater	3,006	tonne/cd	0.90		2,706
Diesel/Selective Hydrotreater	9,819	tonne/cd	0.90		8,838
Residual Hydrotreater	-	tonne/cd	1.55		-
VGO Hydrotreater	7,090	tonne/cd	0.90		6,381
Reformer – including AROMAX	3,564	tonne/cd	4.95		17,642
Solvent Deasphalter	-	tonne/cd	2.45		-
Alkylation / Poly / Dimersol	1,858	P tonne/cd	7.25		13,468
C_4 Isomer Production	-	P tonne/cd	3.25		-
C_5/C_6 Isomer Production – including ISOSIV	-	P tonne/cd	2.85		-
Coke Calciner	-	P tonne/cd	12.75		-
Hydrogen Generation					
Gas Feed	-	tonne/cd	296.00		-
Naphtha Feed	-	tonne/cd	348.00		-

	Utilized Capacity	Units of Measure[1]	EU-CWT Factor	FCC Coke on Catalyst, wt %	CWT (tonne/d)
Sulfur	796	tonne/cd	18.60		14,805
Aromatics Production (All)	-	P tonne/cd	5.25		-
Hydrodealkylation	-	P tonne/cd	2.45		-
Toluene Disproportionation / Transalkylation	-	P tonne/cd	1.85		-
Cyclohexane Production	-	P tonne/cd	3.00		-
Xylene Isomerization	-	P tonne/cd	1.85		-
Paraxylene Production	-	P tonne/cd	6.40		-
Ethylbenzene Production	-	P tonne/cd	1.55		-
Cumene Production	-	P tonne/cd	5.00		-
Lubricants					
Solvent Extraction	-	tonne/cd	2.10		-
Solvent Dewaxing	-	tonne/cd	4.55		-
Wax Isomerization	-	tonne/cd	1.60		-
Lube Hydrocracking	-	tonne/cd	2.50		-
Wax Deoiling	-	tonne/cd	12.00		-
Lube and Wax Hydrotreating	-	tonne/cd	1.15		-
Asphalt Production	-	P tonne/cd	2.10		-
Oxygenates	-	P tonne/cd	5.60		-
POX Syngas for Fuel		tonne SG/cd	8.20		-
POX Syngas to H_2 or Methanol	-	tonne SG/cd	44.00		-
Methanol Synthesis	-	P tonne/cd	(36.20)		-
CO_2 Liquefaction	-	tonne/cd	(19.20)		-
Desalination	-	P tonne/cd	1.15		-
Special Fractionation – Purchased NGL Only	1,153	tonne/cd	1.00		1,153
Propane/Propylene Splitter (Propylene Production)	-	tonne/cd	3.45		-
Solvents					
Solvent Hydrotreating	-	tonne/cd	1.25		-
Solvent Fractionation	-	tonne/cd	0.90		-
Treatment & Compression of Fuel Gas for Sale	-	kW	0.45		-
Air Separation Plant	-	k nm³ O_2/cd	8.80		-
Subtotal: Process EU-CWT					**209,312**
Off-Sites, Non-Energy Utilities, and Non-Crude Sensible Heat					**14,599**
Sales and Other Exports of Steam	**Thermal Equivalent**	**Units of Measure**	**EU-CWT Factor**		
Steam Transfers & Sales	9,670	GJ/cd	1.62		**15,665**
Subtotal: EU-CWT Before Adjustments for Steam Imports and Electricity					**239,576**
Total CWT – per EU-ETS Boundary [2]					**140,152**

(1) Units of measure in this column are as follows:

tonne/cd – Throughput on feed basis in tonnes per calendar day

P tonne/cd – Throughput on product basis in tonnes per calendar day

ST/cd – Throughput in short tons per calendar day; 1 ST = 2,000 lbs

tonne SG/cd – Throughput in tonnes of syngas per calendar day

LT/cd – Throughput in long tons per calendar day; 1 LT = 2,240 lbs

k gal/cd – Throughput in thousand gallons (US liquid) per calendar day

kW – Kilowatts; 1,000 watts

k nm^3 O_2/cd – Throughput in thousand normal cubic meters of oxygen (dry @ 0 °C and 1 atmosphere) per calendar day

GJ/cd – Gigajoules per calendar day; 1 GJ = 109 joules

(2) The adjustments were made by multiplying Solomon's Electricity Utilization Factor (EUF) and Steam Import Factor.

Appendix G Glossary and Solomon Units of Measure

Solomon Usage	Description
°C	Degrees Celsius
°F	Degrees Fahrenheit
9,090 Btu per kilowatt-hour (kWh)	Conversion Factor for Purchased/Imported Electricity to Thermal Energy
ASTM	American Society for Testing and Materials
b, bbl, barrels	API barrels; 42 US liquid gallons; 0.159 cubic meters
b/cd	Barrels per calendar day
b/sd	Barrels per stream day
bar a	Bar absolute; 14.504 lb-force per square inch absolute; 1.0197 kg-force per m^2 absolute; 100 kilopascal absolute; 0.987 atmosphere absolute
bar g	Bar gauge; 14.504 lb-force per square inch gauge; 1.0197 kg-force per m^2 gauge; 100 kilopascal gauge; 0.987 atmosphere gauge
bhp	Brake horsepower, 745.7 watts
BS&W	Bottom sediment and water
Btu	British thermal unit; 1,055 joules
CA	California
CA-CWB™	The Complexity-Weighted Barrels Methodology for California Refineries
CDU	Atmospheric Crude Distillation Unit
CEF	CO_2 Emission Factor; in tonne CO_2/MBtu
CEI	Carbon Emissions Index
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide-Equivalent
Complexity	Configuration Factor; a ratio of Total Equivalent Distillation Capacity (EDC) of the Refinery to its Crude Unit Capacity
CONCAWE	Conservation of Clean Air and Water in Europe
cu ft, ft^3	Cubic feet; 0.02832 cubic meters for liquids & solids. SCF; 0.02679 for NM^3 for gases
CWB	Complexity-Weighted Barrels
CWTB	Complexity-Weighted Throughput Barrels, referred as CWB
CWT	Complexity-Weighted Tonnes
EDC	Equivalent Distillation Capacity
EEF	Electricity Emission Factor
EII	Energy Intensity Index
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EU-CWT	The Complexity-Weighted Tonnes Methodology for European Union Refining Industry

EUF	Electricity Utilization Factor
FCC	Fluid Catalytic Cracking
FOE (bbl)	Fuel Oil Equivalent barrel (Lower Heating Value); 6.05 MBtu; 6,383 MJ
gal	Gallon (US liquid)
GHG	Grrenhouse Gas
GJ	Gigajoule; 10^9 joules
hp	Horsepower
k	Thousands of units specified
kg	Kilogram
kg/m^3	Kilograms per cubic meter (density)
k lb/h	Thousand pounds per hour
kW	Kilowatts; 1,000 watts
kWh	Kilowatt-hour
L	Liter
lb	Pound (avoirdupois)
LBG	Low-Btu Gas
LHV	Lower Heating Value; used in Energy Reporting in Solomon Studies
LPG	Liquefied Petroleum Gas
LT	Long ton; 2,240 lb (avoirdupois)
M	Millions of units specified
m3	Cubic meter; 6.289 bbl
MJ	Megajoule; 106 joules
mm	Millimeters
mol %	Molecular fraction (expressed as a percent)
nm^3	Normal cubic meters; dry @ 0 °C and 1 atmosphere
°API	Specific gravity (SG) expressed in °API; ((141.5/SG) – 131.5)
OECD	Organization for Economic Co-operation and Development
POX	Partial Oxidation Unit
ppm (vol)	Parts per million (volume)
ppm (wt)	Parts per million (weight)
psia	Pounds per square inch absolute (pressure)
psig	Pounds per square inch gauge (pressure)
SCF	Standard cubic feet; dry @ 60 °F and 14.696 psia or 15 °C and 1 atmosphere
Solomon	HSB Solomon Associates LLC
ST	Short Ton; 2,000 lb (avoirdupois)
TJ	Terajoule; 10^{12} joules
US EPA	United States Environmental Protection Agency
vol %	Percent by volume
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute
WSPA	Western States Petroleum Association

From: Ben Serrurier [mailto:ben@climatesolutions.org]
Sent: Thursday, January 23, 2014 4:04 PM
To: ECY RE AQComments
Cc: Jessica Finn Coven
Subject: Comments on 173-485 WAC Petroleum Refinery Greenhouse Gas Emission Requirements

Please find the attached comments regarding the proposed RACT rules on petroleum refinery greenhouse gas emissions. Please feel free to contact me if you have any questions. Thank you.

Sincerely,
Ben Serrurier

Ben Serrurier | Program Associate
Climate Solutions - Practical Solutions to Global Warming
w: 206-443-9570 x22 | c: 650-804-9994

Climate Solutions
PRACTICAL SOLUTIONS TO GLOBAL WARMING

Margo Thompson
Washington State Department of Ecology
P.O. Box 47600
Olympia, WA 98504

Re: 173-485 WAC Petroleum Refinery Greenhouse Gas Emission Requirements

Dear Ms. Thompson,

Thank you for the opportunity to comment on the proposed Reasonably Available Control Technology (RACT) rules for oil refinery greenhouse gas (GHG) emissions. Climate Solutions is a non-profit climate and clean energy advocacy in the Pacific Northwest. Climate change presents a tremendous challenge to Washington State's economy, health and culture. Only by rapidly reducing greenhouse gas emissions in the near term can we help avoid runaway global warming, climate change, ocean acidification and their associated damages. By crafting rules to increase refinery efficiency and reduce greenhouse gas emissions – the first of their kind – Department of Ecology demonstrates how Washington State can be a leader in the fight against climate change. Unfortunately, this rulemaking fails to live up to that leadership. As proposed, the RACT rules for oil refinery greenhouse gas emissions do little to compel reductions in refinery greenhouse gas emissions, nor do they allow for meaningful public oversight of refinery compliance.

Washington State is home to five oil refineries. All four facilities with capacity greater than 100,000 bbls/day are among the six largest sources of greenhouse gas emissions in the state, according to the Environmental Protection Agency. Rules to reduce these emissions represent a huge opportunity to reduce pollution and will help clean our air while spurring innovation and investment in new technologies and more efficient processes. For pollution control rules to have these environmental and economic benefits, they must require meaningful emission reductions.

Under the proposed rules, a refinery is given two options for compliance: score in the top 50th percentile of comparably sized facilities from across the country, or alternatively undertake projects or processes over a ten year period that add up to a 10% reduction in GHG emissions from a 2006 baseline. Both of these standards appear to be ineffectual in reducing emissions. Needing only to land 50th percentile does little to inspire innovation, and may allow for substantial emissions increases. Instead of setting a goal for climate leadership, these rules make sure that Washington's refineries are merely not the very worst. Relying on a simplistic barrels-per-day metric to determine a refinery's peer group and an opaque, propriety algorithm to compare refinery efficiencies further diminishes the 50th percentile requirement.

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For energy benchmarking, the rules utilize Solomon EII® data that is created using a “blackbox” of propriety information and algorithms that is unknown even to the Department of Ecology. Using a non-public data source for information that is necessary for compliance is not in the best interest of Washington. Without transparency into Solomon Associates information on peer refinery emissions, it is impossible to know whether Washington refineries are actually doing everything they can to actually implement reasonably available control technology. Data that cannot be independently verified is not appropriate for pollution control rulemaking. Given the importance of these emissions rules, meaningful oversight and disclosure is essential.

Using the Solomon dataset further weakens the 50th percentile requirement by reducing the size of the comparable peer group. Aggregating refineries into barrels-per-day groups overly simplifies differences in production methods and technologies, obscuring where efficiency gains exist. The Solomon dataset does not provide a comprehensive list of refineries in the US, but only those participating in and paying for their programs. As the comparable peer group shrinks, achieving the 50th percentile becomes a weaker standard.

These deficiencies indicate that the proposed rule do not meet the “lowest emission limit” that is “reasonably available” as required by WAC 173-400. Indeed, it is reasonable to believe Washington’s refineries are capable of achieving considerably better efficiency than the 50th percentile. We encourage the Department of Ecology to consider rules that focus on continuous emissions reductions and ensure that Washington State oil refineries are among the very cleanest in US, if not the world.

Sincerely,

Ben Serrurier
Policy Associate

From: Mike Ruby [mailto:mruby@envirometrics.com]
Sent: Thursday, January 30, 2014 11:34 AM
To: ECY RE AQComments
Subject: Refinery GHG RACT rule

Please place the attached comments in the docket. Thank you.

--
Mike Ruby
Envirometrics, Inc.
206 633 4456
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Comments on the proposed Refinery RACT rule WAC 173-476 proposed 1/2/2014 by
Mike Ruby
4128 Burke Ave N
Seattle WA 98103

The RACT report prepared by Ecology and Puget Sound and Northwest Clean Air Agencies is well written and extensively researched. Staff are to be thanked for their hard work. The staff who worked on this are among the best we have in Washington. Their failure to come up with a productive way forward only emphasizes the difficulty of the task.

While their basic approach of evaluating RACT-eligible projects is direct to the point, they have unfortunately confused it by introducing an approach that is the wrong tool to fix the problem. Ecology has come to a point where they must either adopt the rule fairly close to what is being proposed or, basically, abandon this process and make a new proposal. Regrettably I would counsel the latter course. I believe the current proposal is fatally flawed and cannot be supported or defended by Ecology. Even if Ecology can persuade a court to accept this approach as valid under the RACT statute it is not clear that it will produce a favorable result in the objective, that is, movement toward achieving RACT at the existing Washington refineries.

Ecology's report cites RCW 70.94.153 as the basis for its RACT determination here. The proposed rule itself cites the never-implemented RCW 70.94.154 as there are more than three distinct sources that are subject to this proposed rule. Section 154 relies on RCW 70.94.030(20) for its initial definition of RACT but adds additional description in 154(5). Neither the base description in 030(20) nor the additional description in 154(5) provides a definition that does not require further elaboration by Ecology. Because this is the first implementation of this statute provision by Ecology it is doubly important that Ecology gets it right. This proposal will be an unfortunate precedent for other RACT rules.

The proposed rule requires refineries to demonstrate compliance with RACT by showing they have already achieved an overall plant energy intensity that is assumed to demonstrate that they have already completed all RACT-eligible projects. This demonstration relies on a proprietary, non-transparent energy intensity index by Solomon Associates, termed the EII. [It is important to point out that the EII is opaque not only to the public but also to Ecology.] The EII compares the energy intensity at the subject refinery to the average of a set of other refineries. The RACT rule defines the comparable refineries and the computation procedures by an oblique reference to an Energy Star program refinery evaluation that was done in 2006 and then proceeds to establish this as the baseline for this analysis path. This was not a regulatory exercise by EPA so it has no more qualification for reliance by the agency than any study that could be produced by any consultant. It would be better for Ecology to specify the facility ranges in the referenced study directly in the rule itself rather than in a third source and establish a more recent baseline year.

As a "circuit breaker" the refinery has the alternative of reducing their overall GHG emissions by 10% by 2025. While this is much more direct in targeting the primary objective of the rule it still does not relate directly to the purpose of the RACT, to achieve all technically and economically efficient projects. Ecology never justifies this 10% reduction in terma of technical or economically feasible reductions in emissions nor presents any convincing evidence that it would include any or all feasible projects.

To compute the EII the subject refinery's calculated energy intensity (energy expended per barrel of oil processed) value is divided by the score of the average refinery in the comparison set and then is multiplied by 100 to obtain an index value centered at 100. They report that six "World's Best" refineries in 2008 had an average value of 73.5 (Proops, 2010). [It should be noted that a number below 100 is better, so these it must be that these refineries are being compared to a larger set of refineries that are less efficient.] The average of a subset of the refineries used to calculate the EII for a given refinery would thus not necessarily be 100. The dominant sources of EII scoring points are described as Heater Process Duty and Steam from Fuel. Heater efficiency is only a minor contributor (Proops, 2010). Thus, it is not at all clear that there is any relationship between the EII and GHG emissions of the facility.

In the only publicly available record of actual index values of a set of refineries I was able to locate, the values of 21 refineries in California range from 91 to 110 in a self-referential set and each differs from the next lower by a value of 1 (WSPA, 2011). That is, this is a "square" or flat distribution. It is not a normal distribution. This particular set includes refineries from 500,000 CO_2e MetricT/yr to 4,000,000 MT/yr (the two least efficient are non-reporting of GHG emissions). The average value of this set is 101 and the sample standard deviation is 6.2, and exactly balanced around the average. There is no indication that those with scores less than the average in this set have completed all reasonably available control projects that would reduce GHG emissions. The use of this distribution to argue for using the average of the EII for any regulatory purpose is without any statistical merit.

A different set of EII values on a graph was provided to me by Northwest Clean Air Agency that was said to have been taken from proprietary "Kumana training materials". There are 16 refineries displayed on the graph that have EII scores readable as ranging from 73.5 to 119.4. There is no indication of their locations or character. Those 16 refineries have an average EII of 97.9 and a sample standard deviation of 12. The standard deviation excludes only the lowest value and the three highest values. There are five values clustered between 95.9 and 97.6. The average reported on the graph is 94.7 so there may be more refineries in the set not presented on the graph. From the calculated z scores for the values, we can observe that this is not possible to say that it is not a normal distribution, although one that is skewed low and quite broad. There is very little in either of these small distributions provided by Ecology that would give me any confidence that an average of a set of refinery EII scores is a meaningful metric. There is no information presented as to the control technologies implemented at these facilities and whether or not any of them would be economically reasonable at another refinery. This study contributes no additional weight to the choice of an average of EII values as having any merit.

Solomon reports that as little as 59% of the GHG emissions from an oil refinery may be represented by the EII. Solomon has also developed an alternative, called a Carbon Emissions Intensity or CEI, in which the energy utilized at the refinery from each fuel type is multiplied by an emission factor to convert the value into CO_2e terms. The dominant sources of CEI points are described as fuel consumption and combustion of FCC coke-on-catalyst (He, 2010). There is no indication how the results of the CEI are related to the EII, while in another presentation Solomon describes the CEI to be "too complex for regulatory purposes". In this same presentation they describe a metric they term CWT, or complexity-weighted tons that they believe shows strong correlation with CO_2 emissions by taking into account the carbon emission factors for major process units (Henke, 2010). It is not clear that the CWT can be calculated solely from the data a refinery has submitted for an EII evaluation or if CWTs have been calculated for enough other facilities that a useful comparison could be made. While these other metrics developed by Solomon may have more relation to GHG emissions, by their own admission they are probably not ready for regulatory use.

The use of the EII as the basis for a RACT determination to escape compliance through implementing RACT-eligible projects is fatally flawed.

- First, there is only an indirect, potentially non-linear and mysterious link between the EII and GHG emissions.
- Second, the comparison set of refineries may have no relationship to the availability of RACT-eligible projects at the subject refinery. The EII is an overall refinery value. Because of the crude and product slates of each refinery are so different and the resulting differences in compexity of their facilities, the comparative EII scores say nothing about the success with completing RACT-eligible projects at the subject refinery.
- Third, the refineries in the sub-sets specified by the Energy Star classes as specified by Ecology could be in any region of the country, and in any given class, may be concentrated in a particular locale. What measures have been implemented, and thus are seen as technically feasible, by a refinery on the Gulf Coast, with the notoriously lax environmental enforcement in those states, as evidenced by EPA actions against some state authorities, will be distinctly different from a refinery in California, with its well-regarded strict implementation of environmental rules. Because the refineries that make up the database in the EII will never be know to us, we cannot say which we are comparing against. Similarly, what is economically feasible will be very different for refineries in one part of the county that receives the bulk of its crude from a particular source as compared to another part of the country with a different source of crude.
- Fourth, the use of the average of a set of similar sized refineries as the metric for exempting a refinery from further action is even more remote and less demonstrable as proof of achieving all RACT-eligible projects. Under the proposed Energy Star procedure the comparison refineries share only a similarity in crude processing capacity. Because of the wide difference in crude and product slates among refineries and therefore the wide difference in refinery processes at the refineries, the average of a set of heterogeneous facilities is completely meaningless. "Average" has no holy sanction in statistics.

- Finally, what is “reasonable” to a given corporation is very much a function of the ability of that firm to access capital. Some of the companies that own and operate these refineries are the richest in the world and do not require any outside financing. For them it is only a case of where they can get the most return on their investment. If they have high return opportunities, even if they may be high risk, it may not be “reasonable” for them to invest any funds in a low risk project that may easily pay for itself in a few years but not reach the returns of other potential projects. Thus, “reasonable” needs to be defined in terms of the needs of Washington state and not in terms of the firm’s return on its investment. Unfortunately, the use of the EII average metric relies directly on the voluntary investments of the refinery owners. It is therefore, by definition, “reasonable” to the firms and not what is “reasonable” to Washington state. It will, by definition, set a lower bar than what is required by law.
- Further, representatives of the oil refineries have indicated in informal comments that they believe “reasonable” is represented by a four-year internal rate of return on investment. This represents a high bar for reasonableness even for corporate investments, which are often set at different periods for different types of investments in different sectors of the company and can often range from two to twelve years. The important point is that the corporate-desirable rate of return on investment is very different from the socially-desirable rate of return on an investment. An example is the investment by the public in the hydroelectric facilities in the northwest, which were often calculated by the Corp of Engineers at periods in excess of 20 years. I would argue that “reasonable” for the purpose of environmental regulation should be much closer to the socially-desirable rate of return rather than that desired by Wall Street analysts.

Ecology’s proposed rule for a refinery that relies on emissions reductions uses a 2010 baseline year but defaults to 2011 if the 2010 year represents an abnormal period of operation.. The EII baseline is 2006. There is no justification for this difference between the two baselines for the two approaches other than the date of the obsolete Energy Star study. At a minimum both should rely on a 2010 baseline, since this is a year when Solomon Assoc. conducted an EII study. If a refinery is not eligible for the 2010 baseline year, then the option should be 2012, since this is another Solomon Assoc. evaluation year. This selection of baseline years should apply equally to either path. This would also mean that a refinery using the EII approach must compare between the baseline year of 2010 and a future year and not a year going back to 2006. The rule also is vague on the timing of the acceptability of projects executed in the time frame of approximately 2010. It should be more precise in saying that projects are acceptable if they are completed in 2010 or later.

The proposed Ecology rule allows a refinery to cease making comparisons to the EII in any year when it achieves a score more efficient that the average of the 2006 EII scores. This means that in all future years what is technically and economically feasible is compared to what the average refinery did in 2006 and no update is needed. This has no relationship to what might be achieved by the changing and improving technology in 2016 or later years. Technology may become available in later years that makes it much less expensive to implement an energy efficient project. To be locked in to the 2006 definition is another failing of this approach and illustrates the illegitimacy of its genesis. Even using 2010 as a baseline year rather than resetting the baseline every two years raises questions about the faithfulness of this approach to the definition of RACT.

It has also been suggested by some commentators that the MACT Boiler and Process Heaters NESHAP rule (Subpart DDDDD) could be required as a substitue for RACT-eligible project evaluation. This suffers the difficulty of not being directly linked to GHG emissions and has the additional difficulty of selecting one of a dozen different ways the applicability of the rule and the due dates for completing the requirements could be modified to fit the needs of the RACT rule. In brief, all the requirements of the MACT rule are focused on burner efficiency to reduce conventional pollutants. While low CO emissions, for example, will optimize the amount of fuel burned by a given burner, it does not optimize the thermal efficiency of the boiler or heater itself, which drives the total amount of fuel demanded by that boiler or heater, and thus the GHG emissions. It is an attempt to get at this thermal efficiency of the boilers, heaters and heat transfer equipment that leads to the EII as an approach to evaluating a refinery. So between the two approaches, the EII would be more comprehensive, but evaluating what the EII means and how it can responsibly drive selection of RACT-eligible projects remains unsolved.

It is possible to learn the relative importance of the major sources of CO_2 emissions from the five Washington refineries from the data presented in the RACT report. The results of combining the 2011 data from Tables 6.1 (converted to Imperial tons) through 6.9 of the report are presented in Table I. This table shows the percent of reported CO_2 emissions that come from each listed source at each refinery.

Table I. Percent of CO_2e emissions from each process at Washington refineries

	%Boiler	%Heater	%FCC	%H	%CHP	%explained
BP	11.5%	56.5%		17.4%		85.4%
Phillips 66	18.8%	40.7%	41.9%			101.4%
Shell	2.7%	26.1%	31.0%		29.5%	89.2%
Tesoro	17.2%	14.2%	56.6%			87.9%
US Oil	23.4%	80.4%				103.9%

A very large percentage of the total GHG emissions from these refineries are from the process units listed in this table: boilers, process heaters, the fluidized catalytic cracking unit, hydrogen production and combined heat and power generation. RACT-eligible projects for each of these, and some additional processes at the refineries, are described in detail in Section 7.2 of the RACT report. Completion of the projects determined to be RACT-eligible would appear to be a reasonable and straight-forward requirement to meet RACT and would directly address GHG emissions. Ecology could continue to develop potential projects at refineries and add RACT-eligible projects for refineries to evaluate.

An alternative would be to ask each refinery to begin the process by developing an incremental 10-year plan for implementing all reasonable RACT-eligible projects at their facility with projects staged over the time period based on spreadying the cost of the investment. This would be similar to the highly successful Pollution Prevention effort that was initiated by RCW 70.95C.200.

The method of identifying which RACT-eligible projects should be undertaken by each refinery would traditionally be done by submission of NOC applications by the facility. A refinery would propose to conduct a project identified by Ecology as RACT-eligible. They would also have the ability to present evidence that a particular approved project is not “reasonable” at their facility, given their particular process design. But they would each face the need to either reach the 10% reduction in GHG emissions or demonstrate that all potential projects are uniquely not “reasonable” at their facility.

It has been suggested by some commentators that a refinery could simply propose to Ecology an energy efficiency metric other than the Solomon Assoc. EII to achieve during the ensuing 10-year period. This would be a poor choice compared to an actual schedule of proposed technically and economically feasible projects.

There is an additional difficulty in Ecology’s proposed 2025 deadline for completing RACT-eligible projects. If an approach such as approval of a staged 10-year plan is not adopted then there should be two shorter 5 year periods for achieving 5% and then 10% reductions. Otherwise all the projects could be left to the end without any enforcement, even though there is an annual report due. If the projects submitted in 2025 are rejected for credit by Ecology, what do we do then? What is the penalty for non-compliance?

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Henke, Kevin *Benchmarking Energy and Emissions in Refineries*, Solomon Associates, 2010

From: DLyons123@aol.com [mailto:DLyons123@aol.com]
Sent: Tuesday, January 28, 2014 11:52 AM
To: Thompson, Margo (ECY)
Subject: CO2

I would hope that CO2 emission is not included, Note that water vapor is 97% of the content of greenhouse gases. That leaves 3% for all other gases of which CO2 is 10% or 0.3%. That is an insignificant amount. Further there is no scientific proven link between CO2 and global warming or any other climate effect. In fact CO2 is beneficial to plant growth and is even used in green houses to promote plant growth.

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